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Transcript Exhibit(s)

Docket #(s): E-04204A-09-0206

Exhibit # : ASBA1, ASBA2, RUCO1-RUCO12, S1-S4, S6-S9

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Date: February 25, 2010

Re: UNS Electric, Inc. / Rates
E-04204A-09-0206
February 4 through 11, 2010
Volumes I through V, Concluded

STATUS OF ORIGINAL EXHIBITS

FILED WITH DOCKET CONTROL

Arizona School Boards Association (ASBA Exhibits)

1 and 2

Residential Utility Consumer Office (RUCO Exhibits)

1 through 12

Staff (S Exhibits)

2 through 4,
6 through 9, and
11 through 17

UNS Electric (UNSE Exhibits)

1 through 35

LATE-FILED EXHIBITS

Staff (S Exhibits)

18

UNS Electric (UNSE Exhibits)

36

CONFIDENTIAL EXHIBITS

Staff (S Exhibits)

1, 5, and 10 Delivered this date to CALJ Farmer

Copy to:

Lyn A. Farmer, Chief Administrative Law Judge
Maureen Scott, Esq. – Staff
Daniel Pozefsky, Esq. – RUCO
Michael W. Patten, Esq. – UNS Electric
Philip J. Dion, Esq. – UNS Electric
Timothy M. Hogan, Esq. – AZ School Boards Association

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

KRISTIN K. MAYES, CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

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 ELECTIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	Docket No. E-04204A-09-0206

Direct Testimony of

CHUCK ESSIGS

on behalf of

Arizona School Boards Association (ASBA) and
Arizona Association of School Business Officials (AASBO)

November 6, 2009

EXHIBIT
ASBA-1
ADMITTED

Direct Testimony of Chuck Essigs, AASBO
Docket No. E-04204A-09-0206

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Chuck Essigs. My business address is 2100 North Central Avenue, Phoenix, Arizona 85004.

Q. WHAT IS YOUR POSITION?

A. I am the Director of Governmental Relations for the Arizona Association of School Business Officials. My background is described in more detail in the resume I have attached to this Testimony.

Q. ON WHOSE BEHALF ARE YOU PROVIDING TESTIMONY IN THIS PROCEEDING?

A. I am providing testimony on behalf of the Arizona School Boards Association and the Arizona Association of School Business Officials.
The Arizona School Boards Association ("ASBA") represents 1200 plus school board members and over 1.12 million Arizona children. ASBA's mission is to promote community volunteer governance of public education and continue improvement of student success by providing leadership and assistance to public school governing boards.
The Arizona Association of School Business Officials ("AASBO") provide services to members in school districts in Arizona. AASBO has approximately 1,300 members. It provides a number of conferences and training classes to school district employees and provides information to members on the laws and regulations that impact the business operation of school districts.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. This is the second time that ASBA/AASBO have intervened in a utility rate proceeding at the Commission. In previous proceedings, we have provided public comment but have been challenged by Commissioners to become more involved in rate proceedings to advance the interest of Arizona public schools. This case represents our second effort at doing so. ASBA/AASBO want to assist Arizona's public schools in managing their energy consumption in an economic and efficient manner.

Q. PLEASE DESCRIBE THE FUNDING OF ARIZONA'S PUBLIC SCHOOLS RELATIVE TO OTHER STATES.

A. The per pupil spending for operations by Arizona school districts ranks low when compared to per pupil spending in other states. The U.S. Census Bureau in its

latest report for FY 2007 reported that Arizona per pupil spending on K-12 education ranked 47th with expenditures of $7,196 per student. Only Utah, Idaho, and Tennessee spent less per pupil that Arizona. The U.S. Census Bureau reported Arizona spending per pupil was $2,470 below the national average of $9,666.

Q. ARE THERE ANY CONSTRAINTS ON THE FUNDING THAT IS AVAILABLE TO ARIZONA'S PUBLIC SCHOOLS?

A. Yes. The Arizona Legislature has prescribed budget limitations for Arizona school districts. For the upcoming 2009-10 school year, the legislative formula will determine the total amount that school districts will be allowed to spend. Increases in utility rates are not part of the funding formula and any increased costs due to utility rate increases will need to be paid for by reducing expenditures in other areas of school districts' budgets. Therefore, it is imperative to mitigate the impacts on Arizona's public schools of the rate request sought by UNS Electric in this proceeding.

Beginning with the 2009-10 school year, school districts no longer have a source of additional funds to help defray the costs of utility expenses. These additional funds had been provided by a formula called "Excess Utility Costs" and helped school districts adjust to increased utility costs due to rate increases. A new formula for school districts to assist with utility costs has not been funded by the Legislature.

Because of the significant impact that increased utility rates will have on Arizona school districts, ASBA and AASBO have taken the step of intervening in this proceeding to cooperate with the Commission and UNS Electric in developing solutions that are fair and equitable for Arizona's public schools.

Q. DO YOU HAVE ANY SPECIFIC RECOMMENDATIONS TO MAKE IN THIS PROCEEDING?

A. Yes. We want to work with UNS Electric to implement their demand side management ("DSM") programs to help school districts become more energy efficient. Through these efforts, we hope to reduce demands on the energy production needs of UNS Electric and also contribute to a reduction in utility costs for school districts.

Included in this effort would be a simplified process for funding lighting improvements and equipment upgrades with funding of those projects coming from a UNS Electric DSM funding Program. The districts' share of the costs come from district payments to UNS as outlined in A.R.S. 15-213.02. Implementation of a DSM program will be of assistance to both UNS Electric and the school districts that purchase their electric power from UNS Electric.

While school districts will continue to take advantage of incentives that are in place for the installation of renewable energy resources, we believe that school districts and UNS Electric could also work on cooperative programs to expand renewable energy resources. Under this proposal, UNS Electric would use school property for renewable energy projects. UNS Electric could lease school property and compensate the school district for the use of the school property. Compensation could reflect reduced costs for electricity to the participating school districts. A cooperative effort between school districts and UNS Electric could benefit both entities and the effort could provide valuable assistance to Arizona in becoming more energy efficient.

In addition, we would like to work with UNS Electric to develop a special rate for school districts that would promote a more efficient use of electric energy and to reduce utility costs. We have already started discussions with Arizona Public Service on the development of a special rate for school districts that would support that efficient use of electric energy.

Q. DID YOU MAKE SIMILAR RECOMMENDATIONS ON BEHALF OF ASBA/AASBO IN THE PENDING ARIZONA PUBLIC SERVICE COMPANY RATE CASE?

A. Yes.

Q. WHAT HAPPENED?

A. ASBA/AASBO participated in settlement discussions with the other parties to the APS rate case that culminated in the execution of a settlement agreement that has been filed with the Commission for its approval. The Commission conducted hearings regarding the settlement agreement and I testified in support of the agreement on behalf of ASBA/AASBO.

Q. CAN YOU DESCRIBE THE BENEFITS OF THE APS SETTLEMENT AGREEMENT FOR ARIZONA'S PUBLIC SCHOOLS?

A. Yes. In general, the settlement agreement contains specific benefits for Arizona public schools in the areas of energy efficiency, renewable energy and rate design.

With regard to energy efficiency, the APS settlement agreement provides that APS' 2010 implementation plan would include a customer repayment/financing program element for schools, municipalities and small businesses. This customer repayment element would be fully integrated from the perspective of the customer and not a separate offering. APS could use an actual on the bill or a parallel bill approach to implement this provision. Financing costs would be fully recoverable as a program cost.

Additionally, the settlement agreement established a goal for APS to serve, meaning the installation of measures, through its existing DSM programs or enhanced program elements, at least 100 schools by December 31, 2010.

With regard to renewable energy, the settlement agreement requires APS to file within 120 days of the Commission's order approving the settlement agreement a new program for on-site solar energy including photovoltaics, solar water heating and daylighting, at grades K-12 public (including charter) schools in its service territory that eliminates upfront customer costs. The settlement agreement establishes as a goal the installation of projects resulting in 50,000 MWhs of annual energy generation or savings within 36 months of program approval by the Commission. The settlement agreement provides further detail about how the priority of projects will be determined. In designing the program, APS is required to consider among its options, a request for proposals by developers to implement and install solar energy systems on multiple schools such that the schools pay no upfront costs. The proposal is also to include APS' estimate of costs associated with the program and its proposed method for cost recovery.

Finally, the settlement agreement requires APS to file a new optional time of use rate applicable to K-12 schools designed to provide daily and seasonal price signals to encourage load reduction during peak periods.

Q. DO YOU BELIEVE THIS SAME CONCEPTS REFLECTED IN THE APS SETTLEMENT AGREEMENT COULD BE APPLIED IN THIS CASE?

A. Yes. The APS settlement agreement reflects a collaboration between APS and Arizona public schools within the company's service territory to work together so that schools can more efficiently manage their energy costs and transfer those savings into actual classroom instruction. It is our hope that through our participation in this case we can achieve the same collaboration with UNS Electric.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

RESUME
CHUCK R. ESSIGS

ACADEMIC BACKGROUND

Ed.D. Education Administration (major)
Special Education Administration (minor)
University of Arizona, 1982

M.Ed. Special Education (major)
Educational Administration (minor)
University of Arizona, 1973

B.A. Elementary Education
William Patterson College
New Jersey, 1969

PROFESSIONAL POSITIONS

2003 – Present **Director of Government Relations**
Arizona Association of School Business Officials

2002-04 **Assistant to the Superintendent**
Mesa Public Schools

2001-02 **Special Advisor to the Superintendent of Public Instruction**
Arizona Department of Education

1985-2001 **Assistant Superintendent for Business Services and Government Relations**
Mesa Public Schools

1984-85 **Deputy Associate Superintendent**
Arizona Department of Education

1980-84 **Director of School Finance**
Arizona Department of Education

1979-80 **Staff Member**
Joint Select Committee on Tax Reform and School Finance of the Arizona Legislature

1978-79 **Director, Special Education**
Arizona Department of Education

1975-78 **Director of Administrative Services**
Division of Special Education, Arizona Department of Education

1974-75 **Assistant Director**
Pima County Special Services Cooperative, Pima County School Office

1973-75 **Doctoral Fellowship**
University of Arizona

1972-73 **Graduate Assistant**
University of Arizona

1967-72 **Teacher**
Butler High School, Butler, New Jersey

CHUCK ESSIGS

PUBLICATIONS AND TECHNICAL REPORTS

School Finance, In Boardmanship: A Guide for Governing Members, Arizona School Boards Association, Inc., 1994-2000

Public School and Community School Finance in Arizona, Arizona Legislature, November, 1979.

Special Education in Arizona, Joint Select Committee of the Arizona Legislature, October, 1975.

Planning for the Funding of Special Education, General-Special Education Administrative Conference, UCEA Western Region, May, 1975.

Video Tape Technology in Clinical Supervision of the Improvement of Special Education Instruction, National Council for Exceptional Children Convention, Los Angeles, April, 1975.

Special Education - Planning for Programs, Tucson: Bureau of School Services, University of Arizona, January, 1975.

Alternative Special Education Administrative Operations, In Program Alternatives for Special Services, E.S.E.A. Title III, 1974.

The Place of Clinical Supervision in Teacher Evaluation, Phi Delta Kappa Workshop, Tucson, November, 1974.

Funding Charter Schools, Arizona School Boards Journal, Arizona School Boards Association, Inc., 1995.

Funding Charter Schools in Arizona, School Business Affairs, Association of School Business Affairs International, 1997.

MISCELLANEOUS

Member, Joint Legislative Committee on Funding Priorities for Arizona School Districts
Member, Joint Legislative Committee on Goals for Arizona's Educational Excellence
Director, Arizona Principals' Academy III - July 1984, Northern Arizona University, Flagstaff, Arizona
Consultant, Development of Application Procedures for P.L. 94-142, National Association of Directors of Special Education, Washington, D.C.
Consultant, Development of a Management System for the Pierre Indian School, National Indian Training and Research Center, Tempe, Arizona
Past Member, Governor's Council on Developmental Disabilities
Past Member, Arizona Council for the Deaf
Board of Directors, The Arizona Partnership, 1990
Research Staff, Governor's Finance and Equalization Subcommittee, 1991
Past President, Arizona Association of School Business Officials
Past Member, Mesa Chamber of Commerce Education Committee
Past Member, Mesa Chamber of Commerce Legislative Committee
Board of Directors, Northeast Shea Property Owners Association, 1992
1992 Good Government Award, Arizona Tax Research Association
Board of Directors, Arizona State Retirement System
Past President, Arizona State Board for School Capital Facilities, 1998
Board of Directors, Mesa Chamber of Commerce
Board of Directors, Arizona Town Hall
Governor's School Readiness Board

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

KRISTIN K. MAYES, CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

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 ELECTIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	Docket No. E-04204A-09-0206

Surrebuttal Testimony of

CHUCK ESSIGS

on behalf of

Arizona School Boards Association (ASBA) and
Arizona Association of School Business Officials (AASBO)

January 15, 2010

EXHIBIT
ASBA-2
ADMITTED

Surrebuttal Testimony of Chuck Essigs, AASBO
Docket No. E-04204A-09-0206

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Chuck Essigs. My business address is 2100 North Central Avenue, Phoenix, Arizona 85004.

Q. WHAT IS YOUR POSITION?

A. I am the Director of Governmental Relations for the Arizona Association of School Business Officials. My background is described in more detail in the resume attached to my Direct Testimony.

Q. ON WHOSE BEHALF ARE YOU PROVIDING TESTIMONY IN THIS PROCEEDING?

A. I am providing testimony on behalf of the Arizona School Boards Association and the Arizona Association of School Business Officials. The Arizona School Boards Association ("ASBA") represents 1200 plus school board members and over 1.12 million Arizona children. ASBA's mission is to promote community volunteer governance of public education and continue improvement of student success by providing leadership and assistance to public school governing boards.

The Arizona Association of School Business Officials ("AASBO") provide services to members in school districts in Arizona. AASBO has approximately 1,300 members. It provides a number of conferences and training classes to school district employees and provides information to members on the laws and regulations that impact the business operation of school districts.

Q. DID YOU PROVIDE DIRECT TESTIMONY IN THIS MATTER?

A. Yes.

Q. HAVE YOU REVIEWED THE REBUTTAL TESTIMONY SUBMITTED BY MICHAEL J. DECONCINI THAT ADDRESSES YOUR DIRECT TESTIMONY?

A. Yes.

Q. WHAT IS YOUR RESPONSE TO MR. DECONCINI'S REBUTTAL TESIMONY?

A. First, with respect to renewable energy projects in Arizona public schools within UNS Electric's service territory, Mr. Deconcini states on pp. 14-15 that UNS

Electric is willing to engage ASBA and AASBO in discussions about renewable energy programs for public schools and that UNS Electric proposes to consider specific renewable energy programs and projects for schools within its service territory in its next Renewable Energy Implementation Plan. However, that Plan will not be filed until July 1, 2010 and there's no way of knowing when the Commission will act on the plan. Therefore, there is no reason why provisions similar to those approved by the Commission in the APS case could not be approved in this case as well without waiting for the next Renewable Energy Implementation Plan to be filed by UNS Electric. The provisions include a new program for on-site solar energy including photovoltaics, solar water heating and day lighting at Arizona public schools that eliminate upfront customer costs could not be approved in this case as well. The APS settlement agreement also established a goal of installing school projects resulting in 50,000 MWh's of annual generation or savings within 36 months of program approval by the Commission.

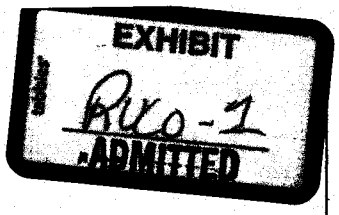
Second, although Mr. Deconcini states that UNS Electric is willing to engage in discussions about energy efficiency, his testimony fails to include any specific provisions for the implementation of energy efficiency measures in public schools. Again, there is no reason why a provision similar to those approved for APS could not be included in the order that is issued in this case. The order approved by the Commission in the APS case included a customer repayment/financing program element for schools, municipalities and small businesses. The order also established a requirement for APS to serve and install energy efficiency measures through existing DSM programs or enhanced program elements in at least 100 schools by December 31, 2010. Similarly specific provisions can and should be included in the rate order in this case.

Finally, Mr. Deconcini states that UNS Electric would be willing to work with ASBA/AASBO in designing a specific time of use rate for schools "in its next rate case." Like APS, UNS Electric should be ordered to design and file an optional time of use rate within 60 days from the Commission's order in this case. There is no reason to delay the benefits that can be achieved through a properly designed optional rate until UNS Electric's next rate case.

Q. DOES THAT CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

BEFORE THE ARIZONA CORPORATION C



COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

Arizona Corporation Commission
DOCKETED
MAY 27 2008
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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 REQEUST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783 DECISION NO. 70360 **OPINION AND ORDER**

DATES OF HEARING: September 10, 11, 12, 13, 14, 20, 21, and October 2, 2007.

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Teena Wolfe[1]

IN ATTENDANCE: William A Mundell, Commissioner
Kristin A. Mayes, Commissioner

APPEARANCES: Mr. Michael W. Patten and Mr. Jason Gellman, ROSHKA, DEWULF & PATTEN, PLC, on behalf of UNS Electric, Inc.;

Ms. Michelle Livengood on behalf of Unisource Energy Services;

Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office;

Mr. Marshall Magruder, in propria persona; and

Ms. Maureen Scott, Senior Attorney, and Mr. Kevin Torrey, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

[1] Administrative Law Judge Teena Wolfe conducted the hearing in this case and Administrative Law Judge Dwig Nodes drafted the Recommended Opinion and Order.

TABLE OF CONTENTS

INTRODUCTION 2
Rate Application 4
RATE BASE 5
Construction Work in Progress 5
Post-Test-Year Plant 9
Deduction of Customer Advances 10
AFUDC Accrual on New Construction Projects 11
Accumulated Deferred Income Tax 11
Accumulated Depreciation 12
Working Capital 13
Uncontested Rate Base Adjustments 14
Reconstruction Cost New Less Depreciation (RCND) 14
Fair Value Rate Base 15
Summary of Rate Base Adjustments 15
OPERATING INCOME 16
Revenues 16
Customer Annualization and Weather Normalization 16
CARES Discount 16
Service Fee Revenues 17
Expenses 17
Payroll Expense 17
Pension and Benefits Expense 18
Worker's Compensation (Injuries and Damages) 19
Incentive Compensation 19
Performance Enhancement Plan and Officer's Long-Term Incentive Program 20
Supplemental Executive Retirement Plan and Stock Base Compensation 21
Rate Case Expense 23
Bad Dept Expense 24
Fleet Fuel Expense 24
Postage Expense 25
Industry Association Dues 26
A&G Capitalization 27
Corporate Cost Allocations 27
Depreciation and Property Taxes for CWIP in Plant in Service 28
Customer Call Center Expense 28
Overhead Line Maintenance 29
Southwest Energy Services Markup 29
Miscellaneous "Unnecessary" Expenses 31
Valencia Turbine Fuel 33
M.A.R.C. Training 33
Outside Services for Demand Side Management ("DSM") Program 34
Depreciation and Amortization Expense 34
Property Tax Expense 35
Income Tax Expense 36
Interest Synchronization 37
New Depreciation Rates 37
Net Operating Income 37
COST OF CAPITAL 37
Capital Structure and Cost of Debt 37
Cost of Common Equity 38
UNSE 38
RUCO 41
Staff 42

Conclusion on Cost of Equity 43
Chaparral City Decision and Fair Value Rate Base 44
AUTHORIZED INCREASE 49
RATE DESIGN 49
Minimum Customer Charge 49
Mandatory Time-of-Use Rates 50
Inverted (Inclining) Block Rate Structure 52
Consolidation of Rates for Mohave and Santa Cruz 52
Demand Charge Differential 53
CARES Discount 54
Low-Income Customer Issues 55
Demand-Side Management Adjustor Mechanism 57
EPS/REST Adjustor Mechanism 57
Outages for Customers on Life Support Equipment 58
Nogales/Citizens 1999 Settlement Agreement 59
Magruder Proposed Rate Base Adjustment 60
Student Loans and Scholarships 61
Proposed Changes to Rules and Regulations 62
Line Extension Policies and Service Connection Contribution 62
Bill Payment Due Date 63
Bill Estimation 65
Magruder Suggestions Regarding UNSE Tariffs 66
OTHER ISSUES 66
Purchased Power and Fuel Adjustment Clause ("PPFAC") 66
"Other" Allowable Costs in PPFAC 68
PPFAC "Cap" 69
RUCO's Proposed PPFAC 71
Purchased Power Allocation 73
Black Mountain Generating Station 73
UNSE 74
Staff 75
RUCO 76
Conclusion 76
Financing Approval for BMGS 77
FINDINGS OF FACT 79
CONCLUSIONS OF LAW 83
ORDER 84

BY THE COMMISSION:

On December 15, 2006, UNS Electric, Inc. ("UNSE" or "Company") filed with the Arizona Corporation Commission ("Commission") an application requesting an increase in rates and approval of financing.

On January 11, 2007, UNSE filed a Supplement to its Application.

On January 12, 2007, the Commission's Utilities Division Staff ("Staff") filed a letter stating that the application, as supplemented by the additional information filed on January 11, 2007, met the sufficiency requirements outlined in A.A.C. R14-2-103, and classifying the company as a Class A utility.

On January 24, 2007, Staff filed a Request for Procedural Schedule.

On February 1, 2007, a Procedural Order was issued scheduling a hearing for September 10, 2007; directing UNSE to publish notice of the application and hearing date; and setting various other procedural deadlines.

On March 12, 2007, the Residential Utility Consumer Office ("RUCO") filed an Application to Intervene.

On March 15, 2007, Marshall Magruder filed a Motion to Intervene on his own behalf.

By Procedural Order issued March 27, 2007, RUCO and Mr. Magruder were granted intervention.

On April 5, 2007, the Company filed affidavits of publication and proof of mailing in accordance with the requirements of the February 1, 2007, Procedural Order.

On May 31, 2007, Arizona Public Service Company ("APS") filed a Motion to Intervene.

On June 12, 2007, Staff filed a Motion for Clarification regarding testimony filing date deadlines.

On June 18, 2007, a Procedural Order was issued granting intervention to APS.

On June 25, 2007, a Procedural Order was issued clarifying the due dates for testimony, as requested by Staff.

With its rate application, UNSE filed its required schedules in support of the application, as well as the direct testimony of D. Bentley Erdwurm, Edmund A. Beck, Michael J. DeConcini, Dallas

J. Dukes, Thomas J. Ferry, Kentton C. Grant, Kevin P. Larson, Karen G. Kissinger, and Dr. Ronald E. White.

On June 28, 2007, Staff filed the direct testimony of Ralph C. Smith, David C. Parcell, Alexander Igwe, Steve Taylor, Julie McNeely-Kirwan, and Bing Young; RUCO filed the direct testimony of Marylee Diaz Cortez, William A. Rigsby, and Rodney L. Moore; and Mr. Magruder filed his direct testimony.

On July 12, 2007, Staff filed the direct testimony of Jerry Anderson and Frank Radigan on rate design issues; and RUCO filed the direct testimony of Ms. Diaz Cortez and Mr. Moore on rate design issues. Mr. Magruder filed his direct rate design testimony on July 13, 2007.

On August 14, 2007, UNSE filed the rebuttal testimony of James Pignatelli, Denise Smith, Thomas Hansen, Mr. Ferry, Mr. Grant, Mr. Larson, Ms. Kissinger, Mr. Dukes, Mr. DeConcini, Mr. Beck, and Mr. Erdwurm.

On August 24, 2007, Staff filed the surrebuttal testimony of Mr. Smith, Mr. Parcell, Mr. Radigan, Mr. Young, and Ms. McNeely-Kirwan; and RUCO filed the surrebuttal testimony of Ms. Diaz Cortez, Mr. Rigsby, and Mr. Moore. Mr. Magruder filed his surrebuttal testimony on August 28, 2007.

On August 31, 2007, UNSE filed the rejoinder testimony of Mr. Pignatelli, Ms. Smith, Mr. Hansen, Mr. Ferry, Mr. Grant, Mr. Larson, Ms. Kissinger, Mr. Dukes, Mr. DeConcini, and Mr. Erdwurm.

On September 6, 2007, a prehearing conference was conducted to address the order of witnesses and exhibits.

The evidentiary hearing commenced as scheduled on September 10, 2007, and additional hearing days were held on September 11, 12, 13, 14, 20, and 21, 2007, and on October 2, 2007. At the close of the hearing, a briefing schedule was established, with initial briefs due on October 30, 2007, and reply briefs due on November 13, 2007.

On October 11, 2007, October 16, 2007, and October 17, 2007, respectively, UNSE, Staff, and RUCO filed their final schedules in this proceeding.

On October 26, 2007, Staff filed an Unopposed Motion for Extension of Time to File Briefs.

By Procedural Order issued October 29, 2007, Staff's Motion was granted, and initial briefs and reply briefs were directed to be filed by November 5, 2007, and November 19, 2007, respectively.

Initial briefs were filed on November 5, 2007, by UNSE, Staff, and RUCO. Mr. Magruder's initial brief was filed on November 6, 2007.

On November 6, 2007, Staff filed a Notice of Errata to correct clerical errors in its initial brief.

On November 8, 2007, RUCO filed revised final schedules.

On November 14, 2007, RUCO filed its reply brief.

On November 16, 2007, Mr. Magruder filed his reply brief.

On November 19, 2007, UNSE and Staff filed their reply briefs.

On November 21, 2007, UNSE filed an Appendix in support of its reply brief.

On December 21, 2007, UNSE filed its initial purchased power and fuel adjustment clause rate filing.

On December 27, 2007, Mr. Magruder filed late-filed exhibits in response to the Company's reply brief.

On January 9, 2008, UNSE filed a response to Mr. Magruder's late-filed exhibits.

On January 15, 2008, Mr. Magruder filed a reply to UNSE's response.

RATE APPLICATION

According to the Company's application, as modified, in the test year ended June 30, 2006, UNSE had adjusted operating income of $8,770,016, on an adjusted Original Cost Rate Base ("OCRB") of $141,036,562[2], for a 6.22 percent rate of return. UNSE requests a revenue increase of $8,468,638; Staff recommends a revenue increase of $3,687,885; and RUCO recommends an increase of $1,282,144. A summary of the parties' positions follows.

. . .

. . .

[2] UNSE submitted two separate sets of final schedules, one assuming the Black Mountain Generating Station ("BMGS") is excluded from rate base in this case and the other including the BMGS in rate base (see discussion below regarding the BMGS issue). The table below reflects the final schedules excluding the BMGS.

	Company Proposed	Staff Proposed	RUCO Proposed
ORIGINAL COST			
Adjusted Rate Base	$141,036,562	$130,740,050	$128,795,088
Rate of Return	9.89%	8.99%	8.07%
Req'd Operating Inc.	13,950,795	11,749,701	11,171,449
Op. Income Available	8,770,016	9,505,982	10,388,213
Operating Inc. Def.	5,180,780	2,243,719	783,236
Rev.Conver. Factor	1.6346	1.6346	1.6370
Gross Rev. Increase	8,468,638	3,667,642	1,282,144
FAIR VALUE			
Adjusted Rate Base	$177,847,579	$167,551,067	$161,635,350
Rate of Return	4.93%	7.02%	6.43%
Req'd Operating Inc.	17,592,000	11,762,085	11,171,449
Op. Income Available	8,770,016	9,505,982	10,388,213
Operating Inc. Def.	8,821,983	2,256,103	783,236
Rev.Conver. Factor	1.6346	1.6346	1.6370
Gross Rev. Increase	8,468,638	3,687,885[3]	1,282,144

RATE BASE

Based on the final schedules filed in this case, UNSE proposed an OCRB of $141,036,562; Staff recommends an OCRB of $130,740,050; and RUCO proposed an OCRB of $128,795,088. Each of the disputed issues regarding rate base items is discussed below.

Construction Work in Progress

Construction work in progress ("CWIP") is a regulatory concept under which, in limited circumstances, a regulatory body allows recovery in a company's rate base for plant that was under construction during the test year but not used and useful for purposes of serving customers. In this proceeding, UNSE seeks inclusion of approximately $10.8 million of CWIP (which would provide the Company with approximately $2.1 million in additional annual revenues). In support of its position, UNSE argues that CWIP is an accepted aspect of ratemaking that has been used in many states and that the Arizona Supreme Court previously upheld the allowance of CWIP, citing *Arizona Community Action Assoc. v. Arizona Corp. Comm'n*, 123 Ariz. 228, 230, 599 P.2d 184, 186 (1979). In that case, the Arizona Supreme Court stated that allowing CWIP "appears to be in the public

[3] Staff's gross revenue increase was calculated by applying a zero cost value to the "excess" between OCRB and FVRB.

interest to have stability in the rate structure within the bounds of fairness and equity rather than a constant series of rate hearings." (*Id.*).

UNSE contends that it will not be able to earn its authorized rate of return even if its full rate request is granted in this case, due to the high rate of growth in its service area, which requires higher levels of capital investment to serve new customers. The Company claims that approximately $5.6 million of the requested $10.8 million of proposed CWIP is related to substations, transmission and distribution facilities, improvements, and other infrastructure reinforcements, and that those capital expenditures will not produce new revenue or reduce the Company's expenses but, instead, will improve service reliability for both new and existing customers (Tr. 1068-69). UNSE witness Kentton Grant also stated that $8.7 million of the $10.8 million CWIP total was in service as of June 30, 2007, and is currently serving customers (Ex. A-35, at 19, 35; Tr. 995). The Company also claims that it is in the "unique" situation of having to replace its entire power supply portfolio by June 1, 2008 and must refinance $60 million of long-term debt in August 2008.

UNSE contends that its continuing revenue deficiency is due, in large part, to the gap between its embedded plant investment and the incremental plant investment calculated on a per-customer basis. The Company contends that its level of growth, and the corresponding revenue deficiency, is extraordinary and allowance of its CWIP request would improve the Company's cash flow and bolster its financial integrity. Mr. Grant claims that the Company's long-term financial integrity would be enhanced by allowing CWIP, because such an allowance would enable UNSE and its customers to avoid higher costs of debt and capital (*Id.* at 10).

UNSE cites to decisions in several other states to support its CWIP argument. For example, UNSE points out that the Virginia State Corporation Commission allowed CWIP in rate base in two separate decisions[4], and the Maryland Public Service Commission likewise recently allowed CWIP in rate base for two of its jurisdictional utilities[5]. UNSE also cites to decisions by regulatory commissions in South Carolina, Washington, Illinois, Michigan, Texas, Florida, and Nevada, to

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[4] *Application of Massanutten Public Service Corporation*, 2005 WL 2158929 (Va. S.C.C.), at 2; *Appalachian Power Co.*, 2007 WL 1616129 (Va.S.C.C.), at 4.

[5] *Potomac Energy Power Co.*, 2007 WL 2159658 (Md. P.S.C.), at 20-22; *Washington Gas Light Power Co.*, 2003 WL 23282178 (Md. P.S.C.), at 1, 15).

support its argument that allowance of CWIP in rate base is sometimes found to be necessary to maintain the financial integrity of regulated utility companies[6].

Staff and RUCO oppose inclusion of CWIP in the Company's rate base. Staff witness Ralph Smith stated that, although the Commission has previously allowed CWIP in rate base, the Commission's general practice has been not to allow CWIP. In support of Staff's disallowance recommendation, Mr. Smith claims that absent compelling reasons, which have not been shown by UNSE in this case, there is no valid reason to grant CWIP. Mr. Smith asserts that the Company has not demonstrated that its test year CWIP balance was for non-revenue-producing and non-expense-reducing plant. Mr. Smith stated that, although test year revenues have been annualized to year-end customer levels, revenues have not been extended beyond the test year to correspond to customer growth. Thus, according to Mr. Smith, inclusion of CWIP in rate base, without recognition of the incremental revenue the plant supports, would cause a mismatch for regulatory purposes (Ex. S-56, at 13-18; Ex. S-58, at 7-15).

RUCO witness Marylee Diaz Cortez also recommends disallowance of CWIP for many of the same reasons cited by Staff witness Ralph Smith. Ms. Diaz Cortez stated that the Commission has previously allowed CWIP only in extraordinary circumstances, which she claims are not present in this case. She claims that recovery of earnings on CWIP plant balances prior to the plant becoming used and useful is accomplished through an Allowance for Funds Used During Construction ("AFUDC"), through which the Company may accrue interest on the CWIP balances. The AFUDC accruals are ultimately recovered over the life of the plant through depreciation expense once the asset becomes used and useful in provision of utility service (RUCO Ex. 8, at 15-18; RUCO Ex. 10, at 8-10). Ms. Diaz Cortez testified that regulatory lag has always been a characteristic of rate of return regulation and that such lag may also provide a benefit to the Company, to the extent that plant retirements, accumulated depreciation, and expired amortizations allow it to earn a return on those items between rate cases. She also stated that the growth phenomenon in the UNSE service area has

[6] *South Carolina Electric & Gas Co.*, 2003 WL 1818431 (S.C. P.S.C.), at 36-7; *Puget Sound Energy, Inc.*, 2007 WL 184670 (Wash. U.T.C.), at 39; *Commonwealth Edison Co.*, 2006 WL 2101442 (Ill. C.C.), at 43; *Consumers Energy Co.*, 2006 WL 3421084 (Mich. P.S.C.), at 1; *Texas Utilities Electric Co.*, 1991 WL 354928 (Tex. P.U.C.), at 175-6, 456; *Tampa Electric Co.*, 49 P.U.R.4th 547 (1982); *Nevada Power Co.*, 132 P.U.R.4th 416 (1991); *Nevada Power Co.*, 2007 WL 2171450 (Nev. P.U.C.), ¶303.

a positive aspect due to the increase of revenues associated with serving new customers (RUCO Ex. 8, at 11-14).

We agree with Staff and RUCO that the request for CWIP in this case is not supported by the record. In the recent UNS Gas rate case (Decision No.70011, at 5-7), we rejected nearly identical arguments made by the Company, and we see no relevant distinction that would cause us to depart from that Decision. As the Staff and RUCO witnesses indicated in this proceeding, UNSE is not faced with an extraordinary situation that would justify inclusion of CWIP in rate base because the plant required to serve new customers will help produce revenues; UNSE has a means, through accrual of AFUDC, to mitigate the effect of the CWIP investment; allowance of CWIP would undermine the balancing of test year revenues and expenses; and the regulatory lag inherent in utility regulation may provide benefits to the extent that items such as plant retirements and accumulated depreciation occur between test periods and thereby help to mitigate periods of higher plant investment associated with customer growth.

As Staff points out in its brief, one of the few instances in which this Commission previously allowed inclusion of CWIP in rate base occurred in 1984 in a case involving Arizona Public Service Company. In that case, the Commission addressed the need for a CWIP allowance due to extraordinary circumstances involving the Palo Verde nuclear plant. The Commission allowed approximately $200 million of APS's $600 million CWIP balance as a means of addressing a critical cash-flow deficiency, and as a means to lessen the severe rate shock that would be experienced by customers if the entirety of the nuclear plant were placed in rate base at one time.[7] Staff argues that UNSE is not faced with a comparable cash-flow crisis, and that the $10.8 million of CWIP requested by the Company does not present a rate shock concern that would justify inclusion of CWIP in this case. We therefore decline the Company's request for rate base recognition of CWIP in this proceeding.

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[7] *Arizona Public Service Co.*, Decision No. 54247 (November 28, 1984), at 19-20.

Post-Test-Year Plant

UNSE proposes that, if its request for CWIP is denied, the Commission should alternatively allow inclusion of post-test-year plant in rate base. The Company argues that the Commission has approved post-test-year plant in a number of recent cases, and UNSE faces faster growth than many other utilities in Arizona. UNSE argues that, absent inclusion of CWIP, the Commission should recognize inclusion of post-test-year plant.

Staff opposes the Company's proposal for reasons similar to the arguments raised on the CWIP issue. Staff witness Ralph Smith testified that the post-test-year plant arguments suffer from the same flaws as the request for inclusion of CWIP. He stated his belief that recognition of post-test-year plant would be imbalanced because it fails to capture post-test-year revenue growth and decreases in maintenance costs associated with the new plant (Ex. S-56, at 17-18).

We agree with Staff that post-test-year plant should not be included in rate base for the same reasons stated above with respect to the Company's request for CWIP. This issue is virtually identical to that raised in the UNS Gas case (Decision No. 70011, at 7-8). As we stated in that Decision, "although the Commission has allowed post-test-year plant in several prior cases involving water companies, it appears that the issue was developed on the record in those proceedings in a manner that afforded assurance that a mismatch of revenues did not occur" (*Id.*) For example, in Decision No. 66849 (March 19, 2004), we stated that "we do not believe that adoption of this method would result in a mismatch because the post-test-year plant additions are revenue neutral (*i.e.*, not funded by CIAC or AIAC)" (*Id.* at 5). In the instant case, however, the Company's request appears to be simply a fallback to its CWIP position, and there is no development of the record to support inclusion of the post-test-year plant. The entirety of UNSE's argument consists of two questions in Mr. Grant's direct testimony, which essentially provided that: the Commission has approved post-test-year plant in some prior cases, UNSE is experiencing a high customer growth rate, and therefore the Company is entitled to inclusion of post-test-year plant if the Commission denies CWIP (Ex. A-34, at 29-30; Ex. A-35, at 35). Even if we were inclined to recognize post-test-year plant in this case, there is not a sufficient basis upon which to evaluate the reasonableness of the request (*i.e.*, whether a mismatch would exist). We therefore deny the Company's proposal on this issue.

Deduction of Customer Advances

The final issue raised by UNSE related to the allowance of CWIP is the Company's request that the Commission not reduce rate base to recognize funds received for customer advances, if the Commission rejects UNSE's request for CWIP or, alternatively, for post-test-year plant. The Company concedes that such advances are typically deducted from rate base because they represent customer-supplied capital. However, UNSE contends that it has received approximately $1.9 million in customer advances related to the $10.8 million in CWIP plant investment (Ex. A-35 at 19).

UNSE argues that it is inherently unfair to exclude the advances from rate base if the plant associated with those advances is not yet in service and not included in rate base. UNSE claims that the purpose of deducting advances (*i.e.*, recognizing customer-supplied capital) is not furthered when the plant is not in service. The Company also contends that the deduction of advances in this case would discourage utilities from seeking advances to offset infrastructure capital costs.

Staff opposed the Company's recommendation. Staff witness Ralph Smith stated that because advances represent non-investor-supplied capital, they should be reflected as a deduction to rate base. He stated that Staff is not aware of any instance in which CWIP was excluded for a major utility in Arizona and customer advances were not reflected as a deduction to rate base. Mr. Smith also cited to A.A.C. R14-2-103, Appendix B, Schedule B-1, which he claims requires companies to reflect advances as a deduction from rate base. Finally, Mr. Smith testified that the Company's computation of AFUDC does not reduce the project balance, on which the AFUDC rate is applied, for customer advances. Rather, UNSE records customer advances in a liability account (Ex. S-58 at 17; Tr. 1039-41).

Consistent with our treatment of this issue in the UNS Gas rate case, we agree with Staff that advances represent customer-supplied funds that are properly deducted from the Company's rate base. Indeed, the Commission's own rules contemplate that such a deduction is required, as Staff witness Smith testified. Had UNSE not requested the inclusion of CWIP in rate base, a ratemaking treatment that is only afforded under extraordinary circumstances (and apparently has not occurred for more than 20 years), there would presumably not have been an issue raised by the Company with respect to an alleged "mismatch" between exclusion of CWIP and deducting advances from rate base.

The Company's attempt to frame this issue as one in which it is being treated in a discriminatory manner is unpersuasive.

As we have stated in prior cases, regulated utility companies control the timing of their rate case filings and should not be heard to complain when their chosen test periods do not coincide with the completion of plant that may be considered used and useful and therefore properly included in rate base. We believe our conclusions regarding UNSE's CWIP-related proposals are entirely consistent with the treatment that has been afforded to other utility companies regulated by the Commission and provide a result that is fair to both the Company and its customers.

AFUDC Accrual on New Construction Projects

UNSE witness Grant proposed that, even if the Commission grants its request for inclusion of CWIP in rate base, the Company should be permitted to continue accruing AFUDC on all eligible construction projects on a going-forward basis (Ex. A-35, at 35-6). Given our denial of the Company's CWIP proposal, this issue becomes a moot point.

Accumulated Deferred Income Taxes

Based on its recommendations in this case, Staff adjusted rate base by $161,555 to account for removal of accumulated deferred income tax ("ADIT") related to its recommendation regarding the Company's Supplemental Executive Retirement Plan ("SERP"), and removal of the ADIT related to stock-based compensation (Ex. S-58 at 19-20). Staff claims that UNSE did not contest these ADIT adjustments, which Staff asserts are necessary to reconcile rate base with the components of operating income adjustments.

In its brief, UNSE does not dispute the ADIT issues raised by Staff, which are reconciliation adjustments flowing through from several operating income issues and are addressed below. However, the Company does take issue with RUCO's proposed adjustments related to ADIT for Contributions in Aid of Construction ("CIAC") and for Administrative and General ("A&G") expenses (Ex. A-7 at 11-12).

RUCO witness Marylee Diaz Cortez recommended removal of $888,390 from UNSE's rate base based on her claim that the Company failed to follow the NARUC Uniform System of Accounts ("USOA") requirement to include CIAC in Account 271 (RUCO Ex. 10-11). With respect to ADIT

for the Company's A&G expenses, Ms. Diaz Cortez recommends removal of $116,258 from rate base to reflect RUCO's proposed operating income adjustment for A&G expenses (RUCO Ex. 8, at 20).

UNSE witness Karen Kissinger testified that the Commission's rules (A.A.C. R14-02-212.G.2) require electric utilities to use FERC's USOA, which differs from the NARUC USOA because the FERC USOA does not include an Account 271. Instead, according to Ms. Kissinger, UNSE is required to directly credit the related plant or CWIP, and there is no separate account to deduct from rate base as RUCO proposes (Ex. A-13, at 2). She stated that, pursuant to Decision No. 55774 (October 21, 1987), the Company is permitted to create a tax deferred asset and claim rate base treatment when using the self-pay method (Ex. A-12, at 6-9).

With respect to RUCO's proposal for a rate base reduction for ADIT related to A&G expenses, Ms. Kissinger pointed out that the Company's proposal to reduce the test year level of A&G expense charged to CWIP, and correspondingly increase the amount remaining in operating expenses, is prospective only and therefore no further adjustment is necessary (Ex. A-12, at 9).

Based on the record before us, we agree that the appropriate reconciliation adjustments should be made to reflect the effect on ADIT in accordance with this Decision. However, we disagree with RUCO's recommendations to reduce rate base. Company witness Kissinger explained that UNSE is required by the Commission's rules to follow the FERC USOA, and that UNSE accounted for ADIT related to CIAC in accordance with those accounting standards. She also testified that, because the Company's A&G expense proposal is prospective only, there is no need to adjust ADIT even if the Commission rejects the Company's proposed expense treatment for A&G expenses. RUCO's ADIT recommendations are denied.

Accumulated Depreciation

UNSE proposed $159,524,693 for its test year accumulated depreciation. RUCO recommended an increase in the Company's accumulated depreciation of $2,295,112, for a total of $161,819,805. RUCO witness Rodney Moore claims that UNSE was unable to substantiate its December 31, 2003, accumulated depreciation balance, which he asserts is understated by $1,764,719, due to the fact that the Company did not record any plant additions or retirements

between August 11, 2003 (the date of UNSE's acquisition of the assets of Citizens Utilities Company ("Citizens")) and the end of 2003. He contends that accumulated depreciation during this period, as well as an additional amount of depreciation of $503,393 to the end of the test year, is not recognized by the Company's application (RUCO Ex. 7, at 4-6).

In response, UNSE argues that RUCO used incorrect depreciation rates for two classes of transportation equipment (25 percent instead of 12.5 percent), a point Mr. Moore conceded on cross-examination (Tr. 860-61; 867-68). According to UNSE, this error alone has an impact of more than $1.8 million (Ex. A-38). Ms. Kissinger also testified that RUCO failed to make other calculations in accordance with the FERC USOA (Ex. A-13, at 1), and cites as an example RUCO's use of a mid-year depreciation convention rather than the mid-month convention used by the Company (Ex. A-12, at 10). She further claims that RUCO failed to consider salvage and removal costs associated with retired assets, and improperly depreciated transportation equipment based on the group method rather than the unit method (Ex. A-12, at 10).

We agree with UNSE that it has adequately supported its proposed accumulated depreciation in this case. As Ms. Kissinger points out, RUCO's analysis contains several errors that have a substantial impact on the recommendations it puts forth. The Company's witness testified that RUCO's use of an incorrect depreciation rate for certain equipment could increase depreciation by more than $1.8 million, and that other errors in RUCO's calculations inflated its depreciation recommendation in this proceeding. We therefore reject RUCO's proposal on this issue.

Working Capital

As described by UNSE witness Karen Kissinger, working capital is generally defined as "investor funding in excess of the balance of net utility plant reflected in rate base that is required for the provision of utility service" (Ex. A-11 at 10). The components of working capital include materials and supplies, prepayments, and cash working capital. The amounts for materials and supplies, and prepayments, are determined based on test year recorded balances, whereas the cash working capital component was determined by UNSE based on a lead-lag study (*Id.*).

Staff witness Ralph Smith summarized the concept of cash working capital as follows:

> Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation, a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds (Ex. S-56 at 21).

Based on Staff's proposed adjustments, Mr. Smith proposed a corresponding adjustment to the Company's cash working capital requirements. Staff's recommendation results in a cash working capital requirement of negative $2.405 million, in accordance with Staff's other recommendations in this case (See Staff Final Schedules, Sched. B-4).

UNSE agrees that there should be a negative cash working capital allowance, but the amount of the Company's recommendation differs from that of Staff based on the rate base and operating expense adjustments advocated by the respective parties.

It does not appear from the record that the parties are in disagreement with regard to the underlying working capital requirements, subject to the various adjustments that necessarily flow from the revenue requirement established in this Decision.

Uncontested Rate Base Adjustments

According to UNSE, two rate base adjustments are unopposed: $9,574,286 for an acquisition adjustment, and a $440,000 reduction to rate base for plant held for future use (UNSE Initial Brief, at 20). None of the other parties disputed the Company's claim, and we will therefore adopt these unopposed adjustments.

Reconstruction Cost New Less Depreciation ("RCND")

To determine its RCND in this proceeding, UNSE used its final OCRB recommendation as a starting point, and added increased costs through indices of inflation, such as the Handy-Whitman Index (Ex. A-11, at 16-18). Although Staff accepted the Company's RCND methodology, Staff contends that UNSE should not be granted a revenue requirement on FVRB that was substantially higher, because the acquisition of Citizens at a substantial discount to book value cast doubt on

whether a traditional RCND measurement is a good indicator of the fair value under the facts of this case.

Fair Value Rate Base

UNSE, Staff and RUCO all determined FVRB based on an average of OCRB and RCND. The principal reason for the difference Staff and the Company FVRB recommendations is related to CWIP, which is discussed above.

Summary of Rate Base Adjustments

Based on the foregoing discussion, we adopt an adjusted OCRB of $130,740,050 and a Fair Value Rate Base ("FVRB") of $167,551,067.

ORIGINAL COST:

Plant in Service	$380,194,752
Less: Accumulated Depreciation	(159,524,693)
Net Plant in Service	220,670,059
Citizens Acquisition Discount	(93,273,341)
Less: Accum. Amort. – Citizens Acq. Disc.	(11,224,066)
Net Citizens Acq. Discount	(82,049,275)
Total Net Utility Plant	138,620,784
Deductions:	
CIAC	(8,692,444)
Customer Deposits	(3,778,419)
Accum. Deferred Income Taxes	993,278
Total Net Deductions and Additions	(11,477,585)
Allowance for Working Capital	3,596,851
Total OCRB	$130,740,050

RCND RATE BASE:

Plant in Service	$602,007,163
Less: Accumulated Depreciation	(257,585,628)
Net Plant in Service	344,421,535
Citizens Acquisition Discount	(150,061,415)
Less: Accum. Amort. – Citizens Acq. Disc.	(18,123,969)
Net Citizens Acq. Discount	(131,937,446)
Total Net Utility Plant	212,484,089
Deductions:	
CIAC	(9,559,141)
Customer Deposits	(3,778,419)
Accum. Deferred Income Taxes	1,618,703

Total Deductions	(11,718,857)
Allowance for Working Capital	3,596,851
Total RCND	$204,362,083
FAIR VALUE RATE BASE:	
Original Cost	$130,740,050
RCND	204,362,083
Total	335,102,133
Average (FVRB)	$167,551,067

OPERATING INCOME

According to the Company's Final Schedules, in the test year, the Company's reported adjusted operating revenues were $158,483,263, with reported adjusted test year operating expenses of $149,713,247, and test year net operating income of $8,770,016. As set forth in its Surrebuttal Schedules (Ex. S-60), Staff's proposed adjusted test year operating revenues were $158,539,827, with adjusted test year operating expenses of $149,033,845, resulting in test year net operating income of $9,505,982. RUCO's Final Schedules show proposed adjusted test year operating revenues of $158,531,911, with adjusted test year operating expenses of $148,143,698, yielding test year net operating income of $10,388,213. The disputed expense adjustments are discussed below.

Revenues

Customer Annualization and Weather Normalization

UNSE states that all parties have agreed with the Company's proposed customer annualization and weather normalization adjustments of $3,249,883 and ($410,061), respectively. Given that no dispute remains regarding these issues, the proposed adjustments shall be adopted.

CARES Discount

UNSE proposed a reduction to its test year revenues related to a change proposed by the Company for treatment of discounts received by customers on the CARES program (Ex. A-17, at 24). Staff witness Julie McNeely-Kirwan opposed the changes proposed by the Company (Ex. S-67, at 2-3), and Staff therefore recommended that the Company's test year revenues be increased by $52,937 (Ex. S-56, at 23).

The CARES issue is addressed below in the Rate Design section of this Order. Given our agreement with Staff on this issue, Staff's recommended adjustment to revenues will be adopted.

Service Fee Revenues

As discussed below in the Rate Design section of this Order, RUCO witness Marylee Diaz Cortez recommended that $48,648 should be added to the Company's revenues to reflect RUCO's claim that the proposed service fees for after-hours establishment and reconnection of service do not fully reflect the Company's actual costs (RUCO Ex. 8, at 21). UNSE witness D. Bentley Erdwurm stated that the Company shares RUCO's concerns regarding potential cross-subsidies, but the Company recommends that service fees be increased more gradually, consistent with the concept of gradualism (Ex. A-17, at 17).

We agree with UNSE's more gradual approach to increasing the service fees in question and therefore do not agree with RUCO's recommendation to adjust revenues.

Expenses

Payroll Expense

UNSE proposes an upward adjustment in its expenses of $339,184 to reflect known and measurable wage and salary increases that went into effect in 2007. Due to an oversight, the payroll expense increase proposal was not presented until the Company filed its rebuttal testimony. This amount includes normalized overtime expenses of $139,201, based on a two-year average including the test year and the year prior to the test year (Ex. A-25, at 11-12). UNSE contends that its adjustment only accounts for employee levels at the end of the test year and therefore does not create a mismatch. Company witness Dallas Dukes also claims that the Company's overtime normalization is consistent with the approach advocated by Staff in the recent UNS Gas case, which method was accepted by UNS Gas in that case (Ex. A-24, at 20).

Staff witness Ralph Smith testified that Staff opposes the increase recommended by UNSE. Staff claims that, with respect to the overtime adjustment, Mr. Smith's analysis is consistent with the position taken in the UNS Gas case, in which he used the lower of two calculations to reduce overtime costs for UNS Gas. In this case, Staff claims that Mr. Smith conducted the same calculations, one of which resulted in a reduction to overtime and the other showing an increase. Mr. Smith stated that "my analysis of overtime expense, which is presented in Attachment RCS-9, and which followed the same analysis format that I used in the UNS Gas case, indicates that the overtime

expenses in UNS Electric's original filing is within a range of reasonableness (i.e., it was bracketed by the results of the two alternative calculations I performed). Consequently, no additional adjustment to overtime for UNS Electric is necessary." (Ex. S-58, at 45-6).

Staff also takes issue with the Company's overall proposed payroll adjustment. Staff argues that the proposed adjustment was not presented until UNSE's rebuttal testimony was filed on August 14, 2007, leaving very little time for Staff to conduct discovery and develop surrebuttal testimony, which was filed on August 24, 2007. Staff asserts that, in addition to the lateness of the adjustment, the Company's proposal is also inconsistent with treatment of payroll in the UNS Gas case, in which payroll was annualized to the end of the year but not beyond.

Although we understand Staff's concern that the Company's proposed adjustment was not presented until its rebuttal testimony was filed, we believe UNSE's proposal should be adopted because it reflects known and measurable payroll changes that went into effect more than a year ago. Mr. Dukes explained that the failure to include the payroll changes in the initial application was due to an oversight, and that the changes have been normalized to minimize a mismatch between the test year and the later payroll increases. We will therefore adopt the Company's recommendation on this issue.

Pension and Benefits Expense

UNSE proposed an upward adjustment to test year levels of pension and benefits expense of $82,965. RUCO witness Rodney Moore recommends removing a portion of these expenses, $11,612, because in a data response UNSE described that portion of the expenses as related to "gifts, awards, employee dinners, picnics and social events" (RUCO Ex. 5, at 12). Mr. Moore stated that RUCO considers these benefits to be an inappropriate burden on ratepayers (*Id.*).

UNSE witness Dukes responded that the expenses identified by RUCO are properly included in rates because they are "primarily related to the recognition of employee service, safety accomplishments and other goal achievements by individual or groups of employees" (Ex. A-25, at 18). He indicated that rewarding employees enables the Company to retain qualified employees and therefore provides a benefit to customers (*Id.*).

We agree that, as a general principle, rewarding employees for performance and longevity provides at least an indirect benefit to customers because service is likely to be enhanced by recognizing employees. However, the Company and its shareholders also benefit from improved employee performance, at least as much as ratepayers, a fact that UNSE fails to acknowledge. If the Company wishes to provide gifts, awards, and other social events as a reward to employees, it should bear at least a portion of the burden associated with these discretionary expenditures. We will therefore reduce expenses by half of the amount identified by RUCO ($5,806).

Worker's Compensation (Injuries and Damages)

UNSE argues in its brief that, although it proposed a reduction of $98,161 to test year expenses booked in FERC Account 925, Staff and RUCO improperly advocated greater reductions. Mr. Dukes conceded that the test year level of $173,456 for worker's compensation appeared to be "abnormally high" and the Company therefore agreed to reduce that expense by $98,161 to reflect a three-year average of such costs (Ex. A-24, at 4-5). However, Mr. Dukes disagreed with Staff's and RUCO's proposals to reduce all of the expenses in FERC Account 925, because, according to Mr. Dukes, such reductions would not recognize costs associated with general liability insurance and Officers and Directors liability insurance (Ex. A-25, at 2).

Staff points out in its reply brief that its witness, Ralph Smith, agreed at the hearing to modify Staff's position in accordance with the Company's recommendation, and that Staff's revised position is included in its Final Schedules (Staff Initial Brief, at 15). Therefore, despite UNSE's protestations to the contrary, Staff has been in agreement with the Company's position on this issue since the date of Mr. Smith's testimony at the hearing[8]. RUCO did not address this issue in its briefs, and presumably has conceded its position on this issue.

Incentive Compensation

UNSE proposes to increase test year expenses by $39,026 to reflect a two-year average of expenses for incentive compensation programs maintained by the Company. UNSE recommends

[8] In this case, as well as the recent UNS Gas case the Company's brief failed to recognize changes in the positions taken by other parties (or its own witnesses), either through surrebuttal testimony, or at the hearing, and which changed positions were incorporated into the final schedules of that party (*See, e.g.*, Decision No. 70011, at 4, 29-31, 41).

recovery of $168,060 for its Performance Enhancement Plan and $48,970 for its Officer's Long-Term Incentive Program (Ex. A-23, at 9).

Performance Enhancement Plan and Officers' Long-Term Incentive Program

UNSE allows its non-union employees to participate in its parent company's Performance Enhancement Plan ("PEP"), which provides eligible employees compensation above their base pay for meeting financial targets (30 percent), cost containment goals (30 percent), and customer service goals (40 percent) (Ex. A-24 at 6-7). Company witness Dukes claims that the PEP is an integral part of its compensation package for employees and that UNSE would be required to increase base salaries to attract and retain qualified employees if the program were eliminated (*Id.*).

Staff proposes to adjust the PEP expenses by 50 percent, based on Staff's claim that incentive compensation programs benefit both ratepayers and shareholders. Staff cites to the Southwest Gas Decision to support its position. In that case, the Commission adopted Staff's recommendation to disallow 50 percent of a similar program's costs, based on a finding that the Southwest Gas management incentive program benefited both customers and shareholders. Staff witness Ralph Smith stated that there is no relevant distinction between the UNSE and Southwest Gas incentive programs and that the 50/50 sharing of costs is equally appropriate in this case (Ex. S-58 at 25-27).

RUCO proposes a complete disallowance of the PEP costs, based on its claim that it is not clear that the program is necessary to achieve the PEP's goals. RUCO witness Moore testified that, during 2005, no PEP payments were made because UniSource did not meet the program's financial goals. However, the UniSource Board of Directors authorized payment of a Special Recognition Award ("SRA") in 2005 to the employees eligible for the PEP. As a result, UNSE is seeking in this proceeding to recover the average of the 2004 PEP payments and the 2005 SRA costs. Mr. Moore contends that the SRA is unique and does not meet the criteria of a typical and recurring test year expense for which rate recovery should be granted (RUCO Ex. 5 at 14-16). He also stated that 60 percent of the PEP payments are related to financial performance and cost containment, which are goals that primarily benefit shareholders. Finally, Mr. Moore asserts that because the PEP does not apply to 70 percent of its employees (*i.e.*, union employees), it is not clear that the program is necessary or will achieve the stated goals (*Id.*; RUCO Ex. 7, at 8-9).

Consistent with our finding in the UNS Gas rate case (Decision No. 70011, at 26-27), we believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program. 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. However, 40 percent 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. For the same reasons, we also adopt Staff's recommendation to disallow 50 percent of the Officer's Long-Term Incentive Program (Ex. S-58, at 32). Given that the arguments raised in the UNS Gas case are virtually identical to those presented in this case, we see no reason to deviate from that recent Decision.

We also stated in Decision No. 70011 that although we believe, on balance, that the 50/50 sharing is reasonable, we share RUCO's concerns that the SRA offered to employees in 2005 may have the effect of undermining the very goals the PEP is intended to achieve (*i.e.*, providing an incentive for participating employees to improve performance and thereby benefit both the Company and its customers). As described by Mr. Moore, despite failing to meet the PEP goals, the UniSource Board of Directors decided nonetheless to provide the affected employees with a surrogate means of compensation. As we indicated in Decision No. 70011, it appears that the SRA sends a signal to employees that they will be compensated regardless of performance, which places the entire premise of the PEP at issue. We expect the program to be scrutinized in the Company's next rate case to determine the appropriateness of providing incentive compensation above base salaries to employees.

Supplemental Executive Retirement Plan and Stock Based Compensation

UNSE allows select executives to participate in a Supplemental Executive Retirement Plan ("SERP"). The SERP provides to eligible executives retirement benefits in excess of the limits allowed under Internal Revenue Service ("IRS") regulations for salaries in excess of specified amounts. UNSE contends that the $83,506 of test year SERP costs are reasonable and that neither Staff nor RUCO have shown that the Company's overall executive compensation costs are excessive or out of line with industry standards.

Staff and RUCO recommend disallowance of the SERP costs, in accordance with the Commission's Decision in the Southwest Gas case (Decision No. 68487, at 18-19). In that case, we disallowed Southwest Gas's SERP costs, finding:

> [T]he provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. (*Id.* at 19).

We disagree with the Company's argument that disallowance of the SERP costs effectively allows the IRS to dictate what compensation costs should be recovered. As was clearly stated in the passage cited above, and which passage was quoted in the UNS Gas case (Decision No. 70011, at 28), the issue is not whether UNSE may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent UNS Gas rate case,[9] and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

For these same reasons, we agree with Staff that test year expenses should be reduced to remove stock-based compensation to officers and employees. As Staff witness Ralph Smith stated, the expense of providing stock options and other stock-based compensation beyond normal levels of compensation should be borne by shareholders rather than ratepayers (Ex. S-58, at 34). The disallowance of stock-based compensation is consistent with the most recent rate case for Arizona Public Service Company (Decision No. 69663).

[9] *See also Arizona Public Service Co.*, Decision No. 69663, at 27 (June 28, 2007), and *Southwest Gas Co.*, Decision No. 68487, at 18-19 (February 23, 2006), wherein SERP costs were excluded in their entirety.

Rate Case Expense

UNSE requested inclusion of $600,000 for rate case expense, amortized over three years. UNSE contends that the proposals offered by Staff and RUCO ($265,000 and $251,000, respectively), which are based primarily on comparisons to the recent Southwest Gas rate case (Decision No. 68487), are deficient because they fail to recognize that Southwest Gas used internal personnel and support services, internal costs that are built into Southwest Gas' rate base. In comparison, UNSE does not have in-house legal or rate departments, but instead relies heavily on the rate and legal personnel of Tucson Electric Power Company ("TEP") to prosecute its rate cases. Mr. Dukes testified that an allocation from TEP for such costs ensures that TEP customers do not subsidize UNSE operations (Ex. A-24, at 16-17). The Company also argues that Staff and RUCO ignored the fact that UNSE received 21 sets of data requests.

RUCO witness Moore stated that RUCO's recommendation in this case is appropriate based on a comparison to the recent UNS Gas rate case, in which RUCO also advocated reducing rate case expense to $251,000, allocated over three years (RUCO Ex. 5, at 17). RUCO contends that the UNSE case shares similar characteristics with the UNS Gas case in that both companies extensively used in-house staff, and both companies used many of the same witnesses (*Id.*) RUCO therefore recommends a rate case expense allowance of $251,000, amortized over three years.

As indicated above, Staff recommends a rate case expense allowance of $265,000, normalized over three years, based on Staff's view that the Southwest Gas case raised many of the same issues addressed in this proceeding. Staff witness Ralph Smith disputed the rationale offered by UNSE for its proposed rate case expense. Mr. Smith stated that although this may be the first rate case for this company under its current ownership, the Company had a number of prior periodic rate cases when it was owned by Citizens Utilities. He contends that the transfer of ownership to UNSE should not be used as a basis for imposing "excessive" rate case costs (Ex. S-58, at 35-37). Mr. Smith also testified that because the UNSE rate case presents many issues that are similar to those considered in the Southwest Gas case, the rate case expense allowed in that case is a useful benchmark for the UNSE case (*Id.*). Mr. Smith added that the issue of the appropriateness of allocating TEP shared services would be better addressed in the pending TEP rate case (Docket No. E-01933A-05-0402, et al.).

We agree with Staff and RUCO that the Company's proposed rate case expense of $600,000 is excessive and should be reduced significantly. As both Staff and RUCO suggest, the recent Southwest Gas case presented many of the same issues that were raised in this case, and the Southwest Gas case is an appropriate measure of comparison for UNSE. An even better comparison is the recent UNS Gas rate case, in which we allowed rate case expense of $300,000 normalized over three years (Decision No. 70011, at 22). We believe that proposed rate case expense of $600,000 is excessive when compared with similar rate case expense allowances in a long line of cases before the Commission. Although Staff and RUCO present strong arguments in support of their recommendations, given that this is the first UNSE rate case since the acquisition of the Citizens assets, and that UNSE was required to respond to a substantial number of data requests, we will allow rate case expense of $300,000, normalized over three years.

Bad Debt Expense

In his rebuttal testimony, Mr. Dukes agreed with RUCO's claim that UNSE had mistakenly calculated its bad debt expense using "gross write-offs" rather than applying the write-off percentage to adjusted test year revenues (Ex. A-24, at 21). However, he disagreed with RUCO's proposal to apply the bad debt percentage to actual test year write-off amounts (RUCO Ex. 10, at 12-13). Instead, Mr. Dukes proposes applying the percentage to a three-year average in order to "smooth out" year-to-year fluctuations (Ex. A-24, at 22). Staff witness Smith accepted the Company's proposal to apply the bad debt percentage to a three-year average of net write-offs (Ex. S-58, at 41).

Based on the record, we agree with the Company's proposal to apply the bad debt percentage to a three-year average of net write-offs. As Mr. Dukes explained in his rejoinder testimony, bad debt expense fluctuates widely from year-to-year. He stated that UNSE's bad debt expense was $426,405 in 2004, $296,428 in 2005, $495,131 in 2006, and $715,267 for the period of June 2006 to June 2007 (Ex. A-25, at 13-14). We believe the Company's three-year average proposal provides an appropriate representative level of bad debt expense.

Fleet Fuel Expense

In his rejoinder testimony, UNSE witness Dukes proposed that the Company's fleet fuel expense be established based on an average gasoline cost of $2.82 per gallon applied to 214,716

gallons, for a total fleet fuel expense of $605,498 (Ex. A-25 at 1-2). In its brief, UNSE recognized that RUCO had accepted the Company's proposal (RUCO Ex. 10, at 13), but argues that Staff recommends applying the price per gallon to only 207,311 gallons, thereby understating UNSE's expenses (UNSE Initial Brief, at 32-33).

In his direct testimony on the witness stand, Staff witness Smith agreed with Mr. Dukes' proposed fleet fuel expense (Tr. 1193). Staff's revised position is also reflected in its Final Schedules. Although Staff reconciled its recommendation during the hearing, in accordance with the Company's position, UNSE's brief continues to advocate rejection of Staff's position. We assume that the Company failed to notice Mr. Smith's revised testimony agreeing with Mr. Dukes' rejoinder testimony, and we further assume that UNSE is not advocating that we reject a position that is identical to its own recommendation. Since there does not appear to be any remaining dispute between any of the parties on this issue, we will adopt the agreed-upon recommendation of the parties.

Postage Expense

UNSE witness Dallas Dukes proposed inclusion in operating expenses of $341,321 for postage costs, based on a 2.5 year average, from January 2004 through June 2006 (Ex. A-25 at 21). Staff witness Ralph Smith acknowledged that postage expense should also include recognition of a postal increase that became effective May 14, 2007 (from $.39 to $.41), thereby increasing total postage expense by $17,503, to $358,824 (Ex. S-56, at 25). Accordingly, no dispute remains between UNSE and Staff on this issue.

RUCO witness Rodney Moore continues to disagree with UNSE's averaging of postage expenses. Although RUCO agrees that the known and measurable postage rate increases should be recognized, Mr. Moore believes that the rate should be applied strictly to test year counts (RUCO Ex. 7 at 11). As reflected in its Final Schedules (Sched. RLM-9), RUCO's recommendation would reduce postage expense by $37,956.

We agree with the Company's postage expense recommendation, as accepted by Staff. Although RUCO contends that there is not a significant variation in postage expenses from year-to-year, Mr. Dukes testified that, over the past three years, UNSE's postage expenses were $415,524,

$257,881, and $365,567, respectively, even though customer counts and bills mailed by the Company have increased over that same time period (Ex. A-25, at 21). Mr. Dukes attributed the postage expense fluctuations primarily to inclusion of informational and educational materials (Ex. A-24, at 24, at 29-30). We believe the approach recommended by the Company is adequately supported by the record and should be adopted.

Industry Association Dues

In his rebuttal testimony, UNSE witness Dukes agreed to remove $13,759 from test year expenses associated with the Edison Electric Institute's ("EEI") Utility Air Regulatory Group ("UARG") dues (Ex. A-24, at 17-18). In his surrebuttal testimony, RUCO witness Rodney Moore stated that the RUCO was satisfied with the Company's removal of the UARG portion of the dues (RUCO Ex. 7, at 18). However, the Company disagrees with Staff witness Ralph Smith that 49.93 percent of UNSE's core EEI dues should also be disallowed on top of the UARG disallowance. Mr. Dukes claims that the dues support EEI in its efforts to advocate on behalf of electric utilities, which ultimately provide a benefit to the Company's customers through such advocacy (Ex. A-24, at 18).

Mr. Smith testified that EEI core dues related to legislative advocacy, regulatory advocacy, advertising, marketing, and public relations total 49.93 percent of the total dues, and should therefore be excluded. Mr. Smith cites a decision by the Arkansas Public Service Commission[10] in which a 49.93 percent disallowance of EEI dues was ordered (Ex. S-58, at 38-39). Mr. Smith contends that lobbying, advocacy or promotional activities should not be paid by customers because those activities do not benefit customers (Ex. S-58, at 18).

We agree with Mr. Smith's assessment that the portions of the EEI dues related to legislative and regulatory advocacy, advertising, marketing and public relations should not be included in recoverable test year expenses in this case. We believe Staff raises a valid point regarding the nature of EEI core dues, and whether a higher percentage of such dues should be disallowed as related to activities that are not necessary for the provision of service to UNSE customers. We therefore adopt Staff's position on this issue.

[10] *Entergy Arkansas, Inc.*, Docket No. 06-101-U, Order No. 10 (June 15, 2007)

A&G Capitalization

UNSE and Staff are in agreement that it is appropriate for the Company to increase test year expense by $301,187 for Administrative and General ("A&G") Capitalization. UNSE witness Dukes stated that these expenses are related to shared service group administrative costs associated with installation of equipment to serve customers, even though such costs can not be traced directly to individual capital projects (Ex. A-24, at 23). Mr. Dukes disputed RUCO's contention that adoption of the Company's proposal would result in a double recovery. He testified that, although a portion of the A&G costs were capitalized, the expenses sought by the Company reflect known and measurable recurring costs that will be incurred by the Company on a going-forward basis (*Id.* at 24).

RUCO witness Diaz Cortez claims that, if the Company insists on reclassifying test year capitalized expenses to test year expenses, it should make a corresponding reduction to rate base by the same amount. Otherwise, according to Ms. Diaz Cortez, adoption of the Company's position will result in a double recovery (RUCO Ex. 10, at 13-14).

We believe UNSE has properly supported the reason for its proposed adjustment to test year expenses for A&G Capitalization. As Mr. Dukes explained, the capitalization "rate" change took place after the test year, and it is common for capitalization rates for shared service, operational and construction departments to change over time (Ex. A-25, at 14). We therefore adopt UNSE's position on this issue.

Corporate Cost Allocations

During the test year, UNSE incurred, as adjusted, $710,736 in corporate cost allocations from TEP. Ms. Diaz Cortez testified that certain of these expenses were allocated into categories that RUCO contends should not be recovered from ratepayers: Meals and Entertainment - Discretionary; Travel – Meals and Entertainment; and Advertising – Corporate Relations/Communications. She claims that UNSE's share of the allocations in these categories is $10,010 (RUCO Ex. 8, at 28-29).

Company witness Dukes asserted that the expenses identified by RUCO are "normal, necessary and recurring expenses related to running a utility" and are not incurred solely or primarily to benefit shareholders (Ex. A-25, at 15). However, because of the "immaterial magnitude" of the amount of the meals portion of RUCO's proposed disallowance ($1,823), Mr. Dukes agreed to

elimination of that portion of the allocation (Ex. A-24, at 25). He continues to recommend allowance of $8,187 of expenses in the Advertising – Corporate Relations/Communications category.

Consistent with our treatment of the Miscellaneous Expenses identified by RUCO, we believe it is appropriate to grant half of RUCO's proposed disallowance of the expenses ($8,187/2 = $4,094).

Depreciation and Property Taxes for CWIP in Plant in Service

Given our rejection of UNSE's request for CWIP, the Company supports Staff's adjustments for depreciation and property tax expenses in the amount of $26,582 (Ex. S-60, Sched. C-3). Since there is no disagreement on this issue, Staff's recommendation shall be adopted.

Customer Call Center Expenses

On May 1, 2005, UNSE changed its method of responding to customer calls by implementing a consolidated call center operated by TEP, with a level of costs allocated to UNSE. RUCO witness Moore stated that, prior to May 1, 2005, UNSE operated its call center separately, at a cost of $321,640 per month (RUCO Ex. 5, at 24). After consolidation of the call center, UNSE began to incur allocated costs of $362,013 per month (*Id.*). Mr. Moore contends that the dramatic increase in costs due to consolidation is not warranted because the integrated call center provides the same level of customer service quality as was experienced before the transition. He states that because no improvement in quality has occurred, the higher costs associated with the consolidated call center should be disallowed (*Id.* at 25).

UNSE witness Thomas Ferry stated that the consolidated call center provides a higher level of service to customers and indicated that the prior individualized system would have required a significant investment in new systems to respond to rapid growth in the Company's service area. Mr. Ferry cited a number of benefits of the consolidated operations, including the ability to handle increased call traffic; expanded service hours; a credit card payment option; call volume tracking ability; and one number availability for gas and electric customers in Mohave and Santa Cruz counties (Ex. A-21, at 3-5).

As indicated in Decision No. 70011, we do not believe that the record supports the disallowance sought by RUCO on this issue. RUCO's analysis is based on a simple comparison of complaint data and system costs, but does not consider the underlying reasons why consolidation to a

modernized call center was necessary. The Company's witness cited a number of advantages associated with the new call center operations and pointed out that RUCO's proposal fails to account for the significant increase in call volume since the new system was put in place, and does not include recognition of the additional investment that would have been required to update the prior decentralized system of customer service. RUCO's recommendation on this issue is therefore denied.

Overhead Line Maintenance

By its application, UNSE seeks recovery of test year expenses for overhead line maintenance of $1,149,853. Although Staff does not oppose this expense item, RUCO contends that a normalization of such expenses should be employed to reduce the level of recovery. RUCO witness Rodney Moore testified that volatility of this expense in prior years supports normalization (RUCO Ex. 5, at 23).

Company witness Dukes responded that RUCO's proposed normalization over four years failed to recognize that expenses for 2003 were incurred for a partial year, from UNSE's acquisition of the Company in August 2003. He indicated that from 2004 through 2006, UNSE's first full three years of operation, the average overhead line maintenance expenses averaged $1,054,000 (Ex. A-24, at 31). Mr. Moore refused to concede this issue in his surrebuttal testimony but, on the witness stand, indicated that RUCO would agree to a three-year normalization of $1,054,000 (Tr. 853, 881-82).

We believe the Company has adequately supported the reasonableness of its test year overhead line maintenance expenses. UNSE's expenses were $916,000 in 2004, $1,360,000 in 2005, and 1,010,000 in 2006 (Tr. 881-82). Test year expenditures were within a range of reasonableness that is likely to be incurred on a going-forward basis. We therefore decline to adopt RUCO's recommendation on this issue.

Southwest Energy Services Markup

In his direct testimony, Staff witness Ralph Smith testified that an affiliate of UNSE, Southwest Energy Services ("SES") provides "supplemental work force services" to UNSE and other affiliates. He stated that SES performs supplemental meter reading services for UNSE at a 10 percent markup on base wages of the supplemental workers, plus the cost of the employer's taxes, workers' compensation and benefits (Ex. S-56, at 42). Mr. Smith indicated in his pre-filed testimony that the

markup amount should be disallowed because SES is an affiliate company, but that Staff was waiting for additional data responses to quantify the amount of the recommended expense reduction (*Id.*). In his surrebuttal testimony, Mr. Smith stated that $10,906 of such expenses should be eliminated for SES markups, and that this amount may be understated (Ex. S-58, at 41).

UNSE argues on brief that the proposed disallowance should be rejected because it "was first introduced in Mr. Smith's Surrebuttal Testimony" and "Staff presented no evidence that the cost incurred was unreasonable" (UNSE Initial Brief, at 36).

The Company's claim that Staff did not raise the issue prior to its surrebuttal testimony is simply inaccurate. As described above, Mr. Smith identified the issue in his direct testimony and indicated that Staff was awaiting additional information from the Company prior to quantifying the amount. Once that information was received, Mr. Smith quantified the amount through his surrebuttal testimony.

We agree with Staff that a markup by affiliate companies for work performed for a regulated utility should not be recovered through rates paid by captive customers. The issue of affiliate company profits was recently addressed in two Orders involving companies operated by Algonquin Water Resources of America. In Decision No. 69164 (December 5, 2006), we adopted Staff's recommendation to disallow a portion of costs incurred by Black Mountain Sewer Company ("Black Mountain") for services performed by an affiliated service company. We stated in that Order that it was inappropriate for Black Mountain to pay its affiliate a "profit margin" (*i.e.*, markup) for services performed by the affiliate (*Id.* at 17-19). We made the same finding with respect to a sister utility company, Gold Canyon Sewer Company ("Gold Canyon"), in Decision No. 69664 (June 28, 2007). In both Decisions, we indicated that it is unreasonable for an affiliate that performs work under an agreement not negotiated at arms length to add an additional margin of profit. There is not sufficient evidence in the record to ascertain the circumstances underlying the arrangement between UNSE and SES, including whether their agreement was openly bid or conducted in an arms-length manner. After Staff's testimony was filed raising the issue of affiliate markups, it was incumbent upon UNSE to provide additional information regarding the reasonableness of the affiliate markup arrangement.

Having failed to do so, we believe Staff's recommendation is appropriate. For these reasons, we adopt Staff's recommendation to remove $10,906 from test year expenses for UNSE.

Miscellaneous "Unnecessary" Expenses

RUCO witness Rodney Moore presented testimony requesting that the Company's test year expenses should be reduced by $73,620 for expenses that were "questionable, inappropriate and/or unnecessary" (RUCO Ex. 5 at 22). Mr. Moore claims that his proposed adjustment is related to payments made to chambers of commerce and non-profit organizations and for donations; club memberships; gifts; awards; extravagant corporate events; advertising, and various meals, lodging and refreshments (*Id.*). He cites a sampling of the 336 questionable expenses, which include $746 for a barbecue grill, $608 for flags, $8,078 for refreshments, $1,377 for various Chambers of Commerce, and $1,126 for chartered bus tours (*Id.*).

In response to RUCO's claims, UNSE witness Thomas Ferry testified that the expenses questioned by RUCO were appropriately incurred business expenses. He stated that purchases from Walgreens, WalMart or Home Depot were for office supplies or small tools and hardware. Mr. Ferry also claims that meals in restaurants or food brought into the office were incurred for business reasons or during employee training, and that the barbecue grill identified by Mr. Moore was purchased for employee appreciation hamburger lunches as a reward following a severe storm season. Finally, Mr. Ferry contends that air travel expenses between Tucson and Kingman are justified to avoid long single-day round trips and overnight stays (Ex. A-21, at 6-7).

As we stated in the recent UNS Gas case (Decision No. 70011, at 24-26), this issue is very similar to the position taken by Southwest Gas in its last rate case, wherein its witness attempted to deflect the burden of proving the reasonableness of Southwest Gas's claimed expenses for a number of "small ticket" items including jeep tours, balloon rides, club memberships, charitable donations, sports events, barbecues, flowers, and various food and drinks expenses. In that case, the Southwest Gas witness agreed to exclude what she perceived to be clearly inappropriate miscellaneous expenses, but indicated that many of the expenses were too small for even the company to determine whether they should be included in cost of service. Southwest Gas's witness therefore concluded that RUCO had not presented sufficient evidence to support its proposed disallowance.

Here, UNSE attempted to justify several of the expenses identified by RUCO, in a general sense, but did not address many of the specific expenses categories raised in Mr. Moore's testimony. For example, Mr. Ferry indicated that expenses incurred at stores such as Walgreens, WalMart or Home Depot are legitimate business expenses, and that employee recognition expenses should be recoverable through rates, but he did not respond directly to most of the specific expense categories described in RUCO's testimony. As set forth in Mr. Moore's surrebuttal testimony, RUCO contends that ratepayers should not be responsible for Company expenses in categories such as: liquor, coffee, water, bagels, donuts, sandwiches; flowers, sympathy cards, gift certificates, photographs; charitable and service club donations; recognition events, sports events, and club memberships; and numerous purchases made from Circle K, Walgreens, WalMart, Basha's, Frys, and Safeway (RUCO Ex. 7, at 14).

In both the UNS Gas and Southwest Gas Decisions, we rejected the argument that RUCO must prove the unreasonableness of individual expenses. As we stated in Decision No. 68487, "[i]t is curious that Southwest Gas seeks to cast the burden of proving the unreasonableness of expenses on RUCO, especially once RUCO has provided some evidence that certain claimed expenses are inappropriate and which evidence, by the Company's own admission, should result in additional exclusions" (*Id.* at 21).

Consistent with the UNS Gas and Southwest Gas Decisions, we find that a portion of the claimed expenses in this "miscellaneous" category should be disallowed. As we stated in the UNS Gas case, "[w]hile it may seem unfair for a utility company to be required to come forward with supporting evidence regarding the reasonableness of even small expenses, when the Company is seeking to place the burden of such expenses exclusively on the backs of its customers, it is required to prove that the expenses were reasonably necessary for the provision of service to those customers." (Decision No. 70011, at 25). Consistent with the UNS Gas and Southwest Gas Orders, because many of the expenses appear to be legitimate expenses related to items such as training and maintenance, we will disallow half of RUCO's proposed amount ($73,620 x 50% = $36,810).

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Valencia Turbine Fuel

UNSE proposed an adjustment of $266,198, to include the cost of fuel to operate its Valencia Turbines. RUCO witness Marylee Diaz Cortez testified that data responses received from UNSE indicated that the Valencia fuel costs were included in the test year Purchased Power Fuel Adjustor Clause ("PPFAC"), but the Company proposes to transfer recovery of these fuel costs to base rates on a pro forma basis. Ms. Diaz Cortez contends that the proposed treatment would result in a double recovery because UNSE is seeking to increase base rates for recovery while, at the same time, passing the Valencia fuel costs through the PPFAC (RUCO Ex. 10, at 29-30). RUCO therefore recommends removal of $266,198 from the Company's pro forma operating expenses.

UNSE witness Dallas Dukes claims that there would be no double recovery under the Company's proposal. According to Mr. Dukes, the ultimate actual cost of providing energy to customers is all that will be passed on to customers, and the addition of Valencia fuel costs to test year expense would more accurately reflect the base cost of fuel, purchased power and purchased energy on a going-forward basis (Ex. A-24, at 26). He added that UNSE's proposal is intended only to set the base cost, but ultimately the actual cost would go into a deferred regulatory account and customers would be charged only the approved base rate of fuel, purchased power and purchased transmission, and any applicable PPFAC charges in the future, and no double recovery would occur (*Id.*). Staff did not oppose the Company's proposed adjustment.

We agree that the UNSE's proposal would not result in a double recovery of fuel expenses from customers because, as explained by Mr. Dukes, only the known and measurable amount incurred during the test year would be used to establish a representative base power supply rate, and only the actual Valencia fuel costs would be recovered from ratepayers (Ex. A-25, at 15-16). RUCO's proposal on this issue is therefore denied.

M.A.R.C. Training

RUCO proposed removal of $14,251 related to costs incurred by UNSE during the test year for a Management Associated Results Company ("M.A.R.C.") training. RUCO witness Moore stated that these training expenses were for a one-time only training program for union employees, and should therefore be disallowed (RUCO Ex. 7, at 17). At the hearing, Mr. Moore indicated that if the

Company provided a late-filed exhibit showing that such training expenses are recurring, RUCO would agree not to make its proposed adjustment (Tr. 899).

UNSE responded by presenting an exhibit at the hearing showing when M.A.R.C. training took place, and when it is scheduled to take place in the future (Ex. A-59; Tr. 1358). In its reply brief, RUCO stated that it is withdrawing its proposed adjustment related to the training (RUCO Reply Brief, at 9).

Outside Services for Demand Side Management ("DSM") Program

RUCO witness Diaz Cortez testified that, during the test year, UNSE paid ECOS Consulting ("ECOS") $49,920 to develop the Residential New Construction DSM Program (Energy Smart Homes). She indicated that, because future DSM costs will be recovered through a DSM adjustor surcharge, the amount paid to ECOS should disallowed (RUCO Ex. 8, at 30).

UNSE witness Dukes agreed that $49,920 should be removed from test year expenses. However, he stated that $32,865 had previously been eliminated from the Company's expenses and, therefore, an additional reduction of only $17,055 is necessary (Ex. A-24, at 27). In his rejoinder testimony, Mr. Dukes offered additional details regarding this issue, and provided RUCO with supporting workpapers (Ex. A-25, at 16-18).

In its brief, RUCO agreed that, after reviewing the workpapers provided by the Company, the appropriate adjustment should be limited to $17,055 (RUCO Initial Brief, at 20).

Depreciation and Amortization Expense

In its application, UNSE proposed a positive pro forma adjustment of $582,986 to depreciation and amortization expense. Staff witness Ralph Smith recommended a downward adjustment to this amount of $63,105, for a net pro forma depreciation and amortization adjustment of $519,881 (Ex. S-60, Sched. C-15).

In her rebuttal testimony, Ms. Kissinger acknowledged that Staff's adjustment was appropriate to reconcile an error in the Company's depreciation study with respect to transportation equipment (Ex. A-12, at 2). She added, however, that an additional adjustment proposed by RUCO should not be adopted because it did not recognize that a portion of transportation depreciation is capitalized (*Id.*).

In his surrebuttal testimony, RUCO witness Rodney Moore stated that "RUCO agrees with the Company to accept Staff's adjustment" (RUCO Ex. 7, at 11). Despite RUCO's concession prior to the start of the hearing, UNSE argues on brief that "RUCO's proposed adjustment is incorrect and should not be adopted" based on Ms. Kissinger's prior rebuttal testimony (UNSE Initial Brief, at 38)[11]. Despite UNSE's request to deny RUCO's recommendation, we assume the Company does not oppose RUCO's revised position.

Property Tax Expense

Both Staff and RUCO recommended setting allowable expenses for property tax based on a rate of 23.5 percent. Staff witness Ralph Smith testified that Staff's recommendation is based on the known and measurable assessment for 2008, pursuant to legislation passed by the Arizona State Legislature that reduces property tax assessments from a rate of 25 percent in 2005, by 0.5 percent in each successive year, until a rate of 20 percent is achieved in 2015 (Ex. S-56, at 31-33). Mr. Smith stated that the Company's initial proposal fails to recognize the impact of the known tax change. He also indicated that Staff's recommendation is consistent with the recent Southwest Gas rate case (which had a test year ending August 31, 2004), wherein Southwest Gas, Staff, and RUCO agreed that a 24.5 percent assessment for the 2006 rate was appropriate for the calculation of property tax expense (*Id.*)[12]. RUCO witness Rodney Moore also proposed use of a 23.5 percent assessment rate for UNSE in this case, based on the same rationale described by Mr. Smith (RUCO Ex. 7, at 12).

UNSE initially proposed the use of a property tax rate of 24.0 percent but subsequently agreed that the 23.5 percent rate that became effective January 1, 2008 should be used for setting rates in this proceeding (Ex. A-12, at 2-3).

We agree with the parties that the property tax expense allowance in this case should be based on the known and measurable assessment rate currently in effect. The rate for 2008 is 23.5 percent, and the rate will continue to decline in subsequent years while the rates established in this case are in effect.

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[11] It appears that the Company's brief failed to recognize responsive testimony filed after that of its own witness, which responsive testimony expressed agreement with the Company's position. Indeed, RUCO did not address this issue in its brief, presumably because RUCO properly assumed that the issue was resolved.

[12] The recent UNS Gas Decision set the property tax rate at 24.0 percent to reflect the rate in place when the Decision became effective (Decision No. 70011, November 27, 2007, at 32).

Income Tax Expense

UNSE proposed allowance of income tax expense of approximately $4.8 million based on the Company's recommended revenue requirement. Company witness Kissinger stated that UNSE's computation of pro forma income tax expense for current and deferred portions identifies all book-tax accounting differences, because non-cash deferred income taxes are shown separately from current income taxes in the Company's lead-lag study for working capital. She indicated that the Company's treatment of income taxes also ensures that all IRS normalization requirements are met (Ex. A-12, at 11-12).

RUCO witness Diaz Cortez disagreed with UNSE's methodology for calculating income tax expense, stating that it is standard practice in ratemaking to account for income tax expense on a current basis, because the accounting for tax timing differences is reflected for ratemaking purposes in the Company's rate base (RUCO Ex. 10, at 18). According to Ms. Diaz Cortez, tax timing differences that are assets are reflected as rate base additions, while timing differences that are liabilities are treated as reductions to rate base. RUCO therefore disagrees with the Company's proposal on this issue (*Id.*).

In her rejoinder testimony, Ms. Kissinger responded that RUCO's proposed methodology does not accurately describe the ratemaking process, because revenue requirements are based on an income tax expense component that includes both current and deferred elements and some of the most contentious ratemaking issues involve determination of the deferred component of income tax expense. Ms. Kissinger claims that Section 168(i)(9)(B) of the Internal Revenue Code states that normalization requirements are violated if a procedure or adjustment that is inconsistent with the normalization requirements is used for ratemaking (Ex. A-13, at 3-4).

We believe the Company's explanation of the basis for its income tax expense methodology is reasonable. Ms. Kissinger explained that it is necessary to account separately for current and deferred components of the expense for ratemaking purposes to establish a proper revenue requirement, and that the IRS requires consistency with the ratemaking normalization procedures in order to comply with the requirements of the Internal Revenue Code. We therefore reject RUCO's proposed adjustment on this issue.

Interest Synchronization

There does not appear to be any dispute that an interest synchronization adjustment is necessary to coordinate the income tax calculation with rate base and cost of capital. As set forth in Staff witness Ralph Smith's testimony, this adjustment decreases income tax expense and increases the Company's achieved operating income by a similar amount (Ex. S-56; Ex. S-60, Sched. C-14).

New Depreciation Rates

Staff witness Ralph Smith indicated that Staff is in agreement with the Company's proposed new depreciation rates (Ex. S-56 at 68). However, Mr. Smith recommended that each of the new depreciation rates proposed by UNSE should be clearly broken out by a service life and a net salvage rate. He indicated that this would allow the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates to be tracked and accounted for by plant account (*Id.*). There does not appear to be a dispute regarding the new depreciation rates to be employed by UNSE. Further, the Company did not oppose Mr. Smith's suggestions for separating the depreciation rates for service life and net salvage. Staff's recommendation is therefore adopted.

Net Operating Income

Consistent with the foregoing discussion, we find adjusted test year operating expenses were $149,205,544, which based on test year revenues of $158,539,827, resulted in test year adjusted operating income of $9,334,283, a 5.57 percent rate of return on FVRB.

COST OF CAPITAL

UNSE recommends that the Commission determine the Company's cost of common equity to be 11.80 percent, with an overall weighted cost of capital recommendation of 9.89 percent (UNSE Final Schedules, Sched. D-1). Staff recommends a cost of common equity of 10.0 percent, with an overall weighted cost of capital determination of 8.99 percent (Ex. S-60). RUCO proposes adoption of a cost of common equity of 9.30 percent, with an overall weighted cost of capital of 8.67 percent (RUCO Ex. 13 at 6).

Capital Structure and Cost of Debt

As explained by Staff witness David Parcell, a regulated utility company's capital structure (the ratio of debt and equity) is important in setting rates based on an estimate of the company's total

cost of capital. He stated that the regulator must determine whether the given utility's capital structure is appropriate relative to its level of risk and relative to other utilities (Ex. S-52, at 15)

In this case, UNSE proposes using a capital structure consisting of 47.18 percent long-term debt, 3.97 percent short-term debt, and 48.85 percent equity (Ex. A-34 at 8) which, according to Staff, represents the Company's actual capital structure as of June 30, 2007. Staff, however, recommends using the actual end of test year capital structure (June 30, 2006) which is comprised of 48.83 percent common equity, 47.21 percent long-term debt, and 3.96 percent short-term debt (Ex. S-52, at 17-18, Ex. DCP-1). Staff further recommends a cost of long-term debt of 8.16 percent and a cost of short-term debt of 6.36 percent (*Id.*). The Company's proposed rates are 8.22 percent for long-term debt and 6.36 percent short-term debt (Ex. A-52, at 3).

The slight difference between the UNSE and Staff recommendations is due to the time at which the snapshot of actual capital structure is taken. Based on the testimony and evidence presented, we believe the Company's proposal to use the capital structure as of June 30, 2007 is appropriate because it provides a more accurate measurement of the capital structure at the time the rates set in this proceeding will be in effect. We therefore adopt a capital structure consisting of 47.18 percent long-term debt, 3.97 percent short-term debt, and 48.85 percent equity, with rates of 8.22 percent for long-term debt and 6.36 percent short-term debt.

Cost of Common Equity

Determining a company's cost of common equity for purposes of setting its overall cost of capital requires an estimate based on a number of factors. As is seen in the discussion below, determining a regulated entity's cost of common equity is as much an art as a science, and requires a feat of prognostication that would likely cause even the Oracle of Delphi to shudder with trepidation. There is no fool-proof methodology for making this determination, and the expert witnesses rely on various analyses to support their respective recommendations.

UNSE

UNSE witness Kentton Grant based his common equity cost recommendation of 11.80 percent on the results of his common equity models, namely the Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM"). Mr. Grant also examined the risk profile of UNSE relative

to a comparable company group to determine a point in the range produced by those models. The estimated cost of equity produced by this analysis was then compared to the allowed returns for other electric utilities in the United States to confirm the reasonableness of the Company's estimate. As a final matter, Mr. Grant examined the financial impact of the recommended return on equity ("ROE") and the overall rate request to assess the Company's ability to attract capital on reasonable terms (Ex. A-52 at 9).

Mr. Grant claims that it was appropriate to use a comparable group of electric companies in his analysis because the assets of UNSE's parent company, UniSource Energy, are heavily weighted toward TEP, which has a much larger investment in facilities and has a case pending before the Commission regarding the deregulated status of those facilities (*Id.* at 10). Therefore, according to Mr. Grant, the cost of equity capital for UniSource Energy or TEP may not be representative of the cost of equity for UNSE (*Id.*). Mr. Grant's comparable group was based on approximately 60 electric companies evaluated by *Value Line Investment Survey* ("*Value Line*"), from which 8 companies were selected based on several criteria that Mr. Grant believes make them comparable to UNSE (*Id.*).

Mr. Grant explained that the DCF methodology is based on the theory that the price of a share of stock is equal to the present value of all future dividends. As described by Mr. Grant, the constant growth form of the DCF model recognizes that the return to shareholders consists of both dividend yield and growth. He stated that the constant growth form of the model should not be used for companies with near-term growth rates that are significantly higher or lower than their long-term growth potential. For such companies, Mr. Grant claims that a multi-stage DCF model should be used to incorporate the various growth rates that are expected over time (*Id.* at 11-13).

According to Mr. Grant, an annual long-term growth rate of 6.5 percent represents a reasonable estimate of investor expectations for earnings and dividends, which he claims is consistent with the 6.0 to 7.5 percent growth rate range in earnings per share ("EPS") for his comparable company group published by *Value Line*, as well as a five-year estimate of EPS growth reported by *Reuters and Zacks* of 8.0 and 8.6 percent, respectively, for the electric utility industry (*Id.* at 15). Based on his application of a multi-stage DCF model, the estimated cost of equity for the sample

companies produced a range of 9.7 percent to 10.5 percent, with a median value of 10.4 percent (*Id.* at 16).

Mr. Grant stated that use of the CAPM is premised on the concept that capital markets are highly efficient and that investors attempt to optimize their risk/return profiles through diversification. He indicated that the CAPM assumes that risk is comprised of systematic risk (which is unavoidable) and unsystematic risk (which is company-specific and can theoretically be eliminated through portfolio diversification). As a result, Mr. Grant explained that the CAPM is based on the theory that investors should be compensated only for systematic risk (*Id.* at 17). Applying the CAPM produced a result of 9.8 percent to 11.2 percent. Based on his comparison of the DCF and CAPM results, Mr. Grant selected a range of 9.7 percent to 11.2 percent as the Company's estimate of the cost of equity for the comparable company group (*Id.* at 19).

The next step in the Company's analysis was to determine the appropriate return on equity in this proceeding for UNSE, based on a comparison of the "risk profiles" of UNSE and the comparable companies. Mr. Grant asserts that an equity investment in UNSE is "decidedly riskier" than an equity investment in the comparable companies due to several factors, including UNSE's smaller size, a higher customer growth rate, the $60 million maturity of long-term debt in 2008, and the need to procure a new power supply by mid-2008. Based on these relative risk factors, Mr. Grant proposes that a 60 basis point equity risk premium should be applied to UNSE, resulting in a cost of equity range of 10.3 to 11.8 percent. He stated that the ROE for UNSE should be set at the top of the range for comparable companies, and that the Commission should award a ROE of 11.80 percent in this proceeding (*Id.* at 20-23).

UNSE criticizes Staff's and RUCO's ROE recommendations based on the Company's claim that the results fail a basic test of reasonableness. UNSE contends that Staff's (10.0 percent ROE) and RUCO's (9.30 percent ROE) recommendations are below ROEs approved by other state commissions and that UNSE bears much greater risk than comparable companies due to the factors cited in Mr. Grant's testimony. Based on the Company's higher risk assertion, it claims it must be awarded a higher ROE commensurate with that risk.

UNSE is also critical of Staff's use of a geometric means in calculating the market risk premium. UNSE argues that an arithmetic means is supported by academics and financial professionals. The Company also contends that RUCO's analysis placed too much emphasis on near-term analyst growth forecasts, a methodology that UNSE contends has been rejected by the Commission in two recent cases. UNSE is also critical of RUCO's use of a single-stage DCF model, which assumes that company growth rates will continue in perpetuity, and of RUCO's over-reliance on analyst forecasts.

RUCO

RUCO witness William Rigsby proposes adoption of a ROE of 9.30 percent based on his analysis using DCF and CAPM methodologies (RUCO Ex. 13, at 8). As noted above, Mr. Rigsby employed a single-stage DCF analysis, as opposed to the multi-stage version used by UNSE.

RUCO is critical of Company witness Grant's DCF model, which RUCO claims assumes a long-term growth rate that would be comparable to an inflation-adjusted growth rate for all goods and services produced by labor and property in the United States in perpetuity. According to Mr. Rigsby, a valid argument could be made that regulated utility company growth rates may not be comparable to national Gross Domestic Product ("GDP") growth rates, and therefore, the multi-stage DCF advocated by UNSE is inappropriate (RUCO Ex. 14, at 11-12). Mr. Rigsby also stated that the multi-stage DCF used by the FERC requires more weight to be given to short-term growth expectations rather than inflation-adjusted estimates of future GDP growth (*Id.*). Mr. Rigsby pointed out that FERC's reasoning is based on the theory that short-term estimates, similar to those employed by Mr. Rigsby's single-stage DCF model, are more predictable and warrant more weight than the estimates derived from the Company's unweighted multi-stage DCF model (*Id.*).

RUCO also disagrees with UNSE regarding the effect that customer growth should have on the Company's return on equity. Contrary to the Company's claim that high growth presents additional risk that must be reflected through a higher authorized return, RUCO argues that high growth in Arizona is a positive factor that should be a selling point to UniSource investors. RUCO cites to UniSource's 2005 Annual Report, in which its Chairman touted the company's customer growth rate as a positive factor (*Id.* at Attach. C). RUCO also notes that UniSource's stock price has

increased since its acquisition of Citizens which, according to Mr. Rigsby, shows that investors do not regard high growth service areas as a negative factor (*Id.* at 14).

Staff

Staff witness David Parcell presented Staff's ROE recommendation in this case. In developing his recommendation, Mr. Parcell utilized DCF, CAPM, and Comparable Earnings Method ("CEM") analyses. He indicated that, because UNSE is not publicly traded, it is not possible to directly apply cost of equity models. In his analysis, Mr. Parcell employed 2 comparable groups of companies as a proxy for UNSE Gas (Ex. S-52, at 18-19). The first sample group was comprised of a group of nine combination gas and electric companies and the second group consisted of the same 8 electric companies used by the Company's witness.

Mr. Parcell's DCF analysis produced a range of 9.50 percent to 10.5 percent for the proxy groups' cost of equity. His CAPM model produced a cost of equity range of approximately 10.0 percent to 10.50 percent for the sample groups (*Id.* at 26). Mr. Parcell also utilized a CEM analysis, which he described as a method designed to measure the returns expected to be earned on the original cost book value of similar risk companies. According to Mr. Parcell, his CEM analysis was based on market data using market-to-book ratios, and is therefore a market test that should not be subject to criticisms leveled at other analyses that are based on past earned returns. He also claims that the CEM uses prospective returns and is therefore not backward-looking (*Id.* at 26-30). Using the CEM, Mr. Parcell concluded that the cost of equity for the proxy companies is "no more than 10 percent" (*Id.* at 29).

Based on the results of the three methodologies, Mr. Parcell found an overall range of 9.5 percent to 10.5 percent ROE for the proxy companies. He indicated that the range of mid-points for the three methodologies is 10.0 percent to 10.25 percent. Mr. Parcell concluded that the appropriate cost of equity rate for UNSE is in the range of 9.5 percent to 10.5 percent. He recommended that the Commission adopt the mid-point of the range (10.0 percent) as the ROE in this case (*Id.* at 30).

With respect to the arguments raised by the Company, Staff asserts that UNSE failed to give any weight to its own DCF analysis and relied exclusively on its excessive CAPM results. Staff contends that UNSE's CAPM analysis is flawed because it is based on a result of 9.8 percent to 11.2

percent, but only one company in the sample group, UIL Holdings, had a CAPM result in excess of 11 percent. Staff contends that not only did Mr. Grant choose the highest point of the CAPM group in determining his result, he added 60 basis points to that result to support his 11.80 percent ROE recommendation.

In response to the Company's criticism of Staff's use of geometric means in its analysis, Staff cites to Mr. Parcell's surrebuttal testimony, wherein he indicated that investors have access to both arithmetic and geometric returns in making investment decisions and that many mutual fund investors rely on geometric returns in evaluating historic and prospective returns of funds (Ex. S-53 at 2-3). Staff also criticized the Company's use of an inappropriate equity risk premium of 7.1 percent, which is based exclusively on the arithmetic means of common stock and bond returns from 1926 to 2005 (*Id.* at 32). Staff points to Mr. Parcell's testimony indicating that *Value Line* reports show historic returns based on a geometric or compound growth rate basis (*Id.* at 33).

Conclusion on Cost of Equity

Having considered the testimony, exhibits, and arguments, we believe that Staff's recommended cost of equity capital produces a reasonable result and should be adopted. Staff witness Parcell's proposed 10.0 percent cost of equity provides a reasonable balance between the Company's attempt to place the ROE at the very top of the range produced by the Company's analysis and the results achieved through the methodologies employed by Staff and RUCO.

As noted above, Mr. Parcell's DCF analysis produced a range of 9.5 percent to 10.5 percent for the proxy groups' cost of equity, his CAPM model produced a cost of equity range of 10.0 percent to 10.5 percent for the sample groups, and his CEM analysis produced a result for the proxy companies of no more than 10 percent. Based on his conclusion that UNSE has an estimated ROE of 9.5 to 10.5 percent, Mr. Parcell recommended awarding the Company a ROE at the mid-point of the range, or 10.0 percent.

We agree with Staff that it is appropriate to consider the geometric returns in calculating a comparable company CAPM because to do otherwise would fail to give recognition to the fact that many investors have access to such information for purposes of making investment decisions.

Although there continues to be disagreement regarding the risk effect from high customer growth, we believe that high growth has the potential for providing benefits through increased revenues.

Accordingly, we adopt Staff's recommended 10.0 percent ROE in this proceeding for UNSE, which results in an overall weighted average cost of capital of 9.02 percent.

	Percentage	Cost	Avg.Weighted Cost
Common Equity	48.85%	10.0%	4.89%
Long-Term Debt	47.18%	8.22%	3.88%
Short-Term Debt	3.97%	6.36%	.25%
			9.02%

Chaparral City Decision and Fair Value Rate Base

In its application, UNSE proposed that the weighted average cost of capital ("WACC") should be applied to its original cost rate base to determine the required operating income in this case (Ex. A-1, Sched. A-1). However, in the rebuttal testimony submitted by UNSE witness Grant, the Company made the claim that its WACC should be applied to FVRB. UNSE claims that its change of position was based on its understanding of a recent Memorandum Decision issued by the Arizona Court of Appeals in *Chaparral City Water Co. v. Ariz. Corp. Comm'n*, 1 CA-CC 05-0002 (Ariz. App. Feb. 13, 2007) ("*Chaparral City*"). According to Mr. Grant's rebuttal testimony, UNSE is not requesting that its change of position result in a revenue requirement finding that would exceed the amount originally requested by the Company (Ex. A-35 at 33).

UNSE argues that in the Chaparral City case before the Commission, the Commission adopted Staff's recommendation to calculate the revenue requirement by multiplying OCRB by the cost of capital (Decision No. 68179, at 26-28). UNSE claims that only after this exercise was completed did Staff calculate the FVRB for Chaparral City, which resulted in what UNSE contends is a "backing-in" approach because the FVRB calculation is a meaningless exercise that flows from the OCRB and cost of capital equation. UNSE witness Grant asserted that the approach advocated by Staff in this case is mathematically equivalent to the methodology used in the Chaparral City case and rejected by the Court of Appeals (Ex. A-35, at 33).

In support of its argument, UNSE cites to Article 15, §14 of the Arizona Constitution, which states in part that "[t]he Corporation Commission shall, to aid it in the proper discharge of its duties,

ascertain the fair value of the property within the State of every public service corporation doing business therein..." UNSE cites several cases[13] in support of its argument that the Commission is required to determine a company's fair value rate base and use that rate base in establishing the company's rates. UNSE concedes that its proposal to apply the WACC to FVRB is not the only possible approach to setting rates, but suggests that it is the only approach presented in this case that complies with the Arizona Constitution. The Company claims that other permissible methods may be developed in future cases but, for now, the UNSE methodology is the only available choice for the Commission to apply.

Staff argues that the Company's reliance on the unpublished *Chaparral City* decision is misplaced. Staff contends that the Court of Appeals specifically indicated that the Commission was not required to apply the WACC to FVRB in order to set rates, and that the methodology proposed by Mr. Grant would result in an unreasonable and excessive return on equity for UNSE. Staff cites to Mr. Parcell's testimony addressing the Company's proposal, wherein he testified that, under UNSE's proposal, the link between rate base and capital structure would be broken because the "excess" of fair value rate base over original cost rate base is not financed with investor-supplied funds, and therefore the cost of capital cannot be applied to the fair value rate base because there is no financial link between the two concepts (Ex. S-52 at 37). Mr. Parcell's proposed solution is to recognize that the difference between FVRB and OCRB is not financed with investor funds by attributing no cost to the excess between the two. He stated that this recommendation would provide for a return being earned on all investor-supplied funds, which is consistent with sound financial and regulatory standards (*Id.* at 38).

Staff contends that there is no evidence that investors expect such an excess return and that the record supports an opposite conclusion. Staff asserts that the difference between applying the return to OCRB and FVRB would be, in effect, a windfall on unrealized paper profits. Staff claims that Mr. Parcell's proposal to assign no cost to the "excess" between OCRB and FVRB is logical and

[13] *U.S. West Communications, Inc. v. Ariz. Corp. Comm'n*, 201 Ariz. 242, 246, 34 P.3d 351, 355 (2001); *Simms v. Round Valley Light & Power Co.*, 80 Ariz. 145, 151, 294 P.2d 378, 382 (1956); *Scates v. Ariz. Corp. Comm'n*, 118 Ariz. 531, 533-534, 578 P.2d 612, 614-615 (App. 1979); *Phelps Dodge Corp. v. Arizona Electric Power Co-op*, 207 Ariz. 95, 83 P.3d 573, 586 (App. 2004).

consistent with investor expectations. Staff argues that, to the extent that investors may expect a return on the so-called paper profits, such a return is already incorporated into the cost of capital models employed by the experts in this case.

In Decision No. 70011 (at pages 45-51) we cited several decisions rendered in other states which recognized the problem of applying the cost of capital to fair value rate base[14]. Consistent with the problems identified by Mr. Parcell, application of modern cost of capital models, such as DCF and CAPM, directly to FVRB would create redundancies and double counting. In the UNS Gas Order, we cited to the case of *Railroad Commission of Texas v. Entex, Inc.*, 599 S.W.2d 292 (Tx. 1980), in which the Texas Supreme Court discussed the so-called "backing-in" method of determining fair value rate of return. In that case, the court stated that "[i]n a fair value jurisdiction the rate of return multiplied by the rate base usually resulted in a higher return to the book common equity than in an original cost jurisdiction because of the inclusion of the reproduction cost new factor." (*Id.* at 298). In rejecting the "backing-in" argument presented by the utility company, the Texas Supreme Court observed that, in fair value jurisdictions, the return to book common equity is used as a performance indicator by investors, and that fact could not be ignored by blindly applying a rate of return to fair value rate base without recognizing the consequences of such a rate of return on the elements of the company's capital structure. The court also stated:

> [T]he fairness of the rate base or the rate of return can be measured by the cash requirements of the utility. All are interdependent and ultimately need to be reconciled....*a return to book common equity which is out of proportion...cannot be ignored since it is more than necessary to attract capital, and therefore, unfair to the ratepayer.* (*Id.* at 299, emphasis added).

Further, as recognized in the *Entex* case quoted above, the question that must properly be addressed is whether investors expect an additional return in excess of the return resulting from application of the financial models used for calculating the appropriate authorized return.

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[14] In *Re Harbour Water Corporation*, 2001 WL 170550 (Indiana Utility Regulatory Commission); *Gary-Hobart Water Corp. v. Indiana Utility Regulatory Comm'n*, 591 N.E.2d 649, 653 (Ind. App. 1992); *State of North Carolina ex rel. Utilities Commission et al. v. Duke Power Co.*, 285 N.C. 377, 397, 206 S.E.2d 269, 294 (N.C. 1974); *State of North Carolina ex rel. Utilities Commission et al. v. Virginia Electric and Power*, 285 N.C. 398, 206 S.E.2d 283 (N.C. 1974).

UNSE attempts to portray its amended proposal as an innocuous placeholder, by claiming that there is no harm due to its willingness to be limited only to the revenue requirement set forth in its original application. However, the underlying premise of the Company's argument is fallacious unless the Commission were to agree with every revenue requirement position advocated by the Company. As discussed above, we have rejected a number of the arguments raised by UNSE. As a result, the Company's revised position regarding application of FVRB, if it were adopted, would have a substantial impact on the rates that are established in this Decision.

Moreover, the purpose of the Company's reliance on the cases it cites is unclear, given that no party disputes the concept that fair value rate base must be determined and applied in setting rates. The cases cited by UNSE do not, however, stand for the proposition espoused by the Company (*i.e.*, that the Commission *must* apply the Company's WACC to FVRB to determine just and reasonable rates). In fact, those cases make clear that the Commission, although required to ascertain a company's fair value rate base and use that fair value rate base in determining rates, has broad discretion in how the rate-setting formula should be applied.

Even if we were inclined to consider the Company's proposal, its arguments are premature at best. Through his rebuttal testimony, UNSE witness Grant suggests that the Commission must apply the WACC to fair value rate base pursuant to the *Chaparral City* decision (Ex. A-35 at 33). However, Mr. Grant's proposal ignores the explicit language of the Court's decision, which states: "the Commission asserts that it was not bound to use the weighted average cost of capital as the rate of return to be applied to the FVRB. The Commission is correct....[t]he Commission has the discretion to determine the appropriate methodology." (*Chaparral City, supra,* at p. 13, ¶17). Despite this unambiguous explanation, UNSE would have us employ the very methodology the Court of Appeals specifically stated the Commission was not required to apply in setting rates.

Aside from the disingenuousness of the Company's argument, the current posture of the *Chaparral City* case is that it has been remanded to the Commission for further consideration. At this point, the Commission has not rendered a decision on the issue remanded by the Court. Once the Commission issues a subsequent order in the remanded case, the Commission's decision may, or may not, be appealed to the Court of Appeals for a determination of compliance with the Court's remand.

Thus, entirely aside from the inappropriateness of citing the unpublished *Chaparral City* decision as precedent, using it as the foundation for requiring a specific methodology in another unrelated case is clearly improper given that the Commission has been given an opportunity to cure the perceived defects in the *Chaparral City* case. Until that case has been decided under the Court's remand order, it is premature for UNSE (or any other company) to suggest that the Commission must apply a particular methodology, especially a methodology that the Court specifically stated the Commission is not required to adopt.

We also believe that Staff has raised a number of relevant concerns with the Company's attempt to apply the WACC to FVRB without further modification. As Staff points out, there is no logical basis for applying such a methodology because investors have no expectation that they will earn a return on the excess between OCRB, which represents investor supplied funds, and FVRB, which represents unrealized paper profits. If the Company's proposal were to be adopted, the underlying basis of the cost of capital analysis would be called into question and would likely require substantial modification to avoid a result that grants excessive windfall returns to investors at the expense of ratepayers. We note that UNSE states in its brief that, pursuant to the holding in *Ariz. Corp. Comm'n v. Arizona Water Co.*, 85 Ariz. 198, 203, 335 P.2d 412, 415 (1959), the Commission may not consider the argument raised by Staff regarding investor-supplied funds. The *Arizona Water* case is clearly distinguishable from the instant case, however, given the fact that the Court in *Arizona Water* was asked to consider only whether a recent purchase price paid for the utility company could be used by the Commission as the fair value of the utility for setting rates. No such set of facts is presented in this proceeding, and we do not believe the *Arizona Water* holding is applicable to the arguments presented by Staff.

For all of these reasons, after considering all of the relevant arguments, evidence and factors presented in this proceeding, in accordance with our discretion regarding such matters, and consistent with our Decision in the recent UNS Gas case, we reject the Company's proposal on this issue and find that a rate of return of 7.03 percent on FVRB is reasonable and appropriate for UNSE, at this time.

. . .

AUTHORIZED INCREASE

Based on our findings herein, we determine that UNSE is entitled to a gross revenue increase of $4,018,678.

Fair Value Rate Base	$167,551,067
Adjusted Operating Income	9,334,283
Required Rate of Return	7.03%
Required Operating Income	11,792,753
Operating Income Deficiency	2,458,469
Gross Revenue Conversion Factor	1.63463
Gross Revenue Increase	$4,018,678

RATE DESIGN

Minimum Customer Charge

UNSE proposed an increase to the monthly residential customer charge from $6.50 to $7.70, and an increase in the customer charge for small general service customers from $10.00 to $12.00 per month. The Company contends that its proposal is supported by its cost of service study and that the minimum monthly charge increase is a "bare bones" approach in that the charge would recover only the Company's undisputed fixed customer service costs, for items such as metering, meter reading, billing and the service drop (Ex. A-18, at 2-6). RUCO does not oppose the Company's proposal (RUCO Ex. 10, at 18).

Staff witness Frank Radigan generally agreed that the Company's cost of service study supports an increase to the customer charge, and he recommended an increase that is only slightly less than that proposed by the Company ($7.50) (Ex. S-61, at 1-2). He also agreed with the Company's other proposed customer charge increases of $12.00 for small general service, $15.50 for large general service, $365 for large power service (less than 69 kV), and $400 for large power service (69 kV and above).

There is no dispute that UNSE's cost of service study justifies increasing the current customer charges. However, we agree with Staff's witness that the residential customer charge should only be increased to $7.50 per month, with the accompanying commodity charges based on Staff's rate design flowing from the revenue requirement established in this Order. Based on the revenue requirement established above, the "base rate" volumetric charge would be set for residential

customers at $0.089248 per kWh for the first 400 kWh, and $0.09926 per kWh for usage over 400 kWh, for customers in both Mohave and Santa Cruz Counties. The volumetric "base rates" reflect the consolidation of rates for Mohave and Santa Cruz customers and the inverted block rate structure (see discussion below). However, these volumetric rates do not include the additional PPFAC charge, which is being set initially at $0.014746 per kWh for all usage.

For a residential customer in Mohave County, with average monthly usage of 894 kWh, the overall bill (including the PPFAC charge) would increase from $89.82 to $105.42, or approximately 17.4 percent. For a residential customer in Santa Cruz County, with average monthly usage of 719 kWh, the overall bill (including the PPFAC charge) would increase from $76.65 to $85.44, or approximately 11.5 percent.

Mandatory Time-of-Use Rates

UNSE proposed implementation of mandatory time-of-use ("TOU") rates as a means of reducing peak demand by shifting consumption to off-peak periods. According to Company witness Erdwurm, shifting of demand would enable UNSE to reduce spot market energy purchases during peak, resulting in savings for the Company and its customers (Ex. A-17, at 17).

Under the Company's proposal, all new residential, new small general service, and new and existing large general service customers (Greater than 1,000 kW) would be placed on TOU rate plans. During winter months (November through April), UNSE's TOU plan would impose higher rates from 6 a.m. to 10 a.m., and again from 5 p.m. to 9 p.m. In the summer months (May through October), peak rates would apply from 2 p.m. to 6 p.m., with "shoulder" rates from 12 p.m. to 2 p.m. and 6 p.m. to 8 p.m., and off-peak rates the remainder of the day (*Id.* at 17-19).

UNSE contends that voluntary TOU rates have failed to produce the desired peak shifting because relatively few customers currently participate. Although the Company concedes that TOU meters are more costly than non-TOU meters, Mr. Erdwurm stated that the long-term benefits will outweigh the short-term costs, especially as the cost of storing information declines and TOU meters become less costly (Ex. A-18, at 12-13).

Mr. Magruder agrees with the Company's proposed mandatory TOU rates, but suggests UNSE should pay the cost of new TOU meters for existing customers that switch to a TOU rate. For new customers, he proposes that the customer be responsible for the cost of the TOU meter.

Although RUCO agrees with UNSE's TOU plan, Staff opposes making TOU rates mandatory instead of continuing TOU as a voluntary option. Staff witness Frank Radigan stated that the annual incremental cost of a new TOU meter would amount to approximately $30 per customer, requiring a residential customer to move 400 kWh of energy from peak to off-peak per month during the summer to break even or achieve a benefit (Ex. S-61, at 9). He indicated that, because 30 percent of customers use less than 400 kWh, and 92 percent of bills are for usage less than 2,000 kWh per month, "it is very doubtful that the customers could move enough energy from the on-peak period to the off-peak period to justify the meter expense" (*Id.*).

Mr. Radigan testified that some customers would realize a benefit from TOU rates. For example, approximately 8 percent of residential customers have usage over 2,000 kWh per month, but those customers account for more than 25 percent of the Company's sales to the residential class. Because those customers would benefit from TOU rates, Mr. Radigan recommended a "vigorous customer education" program to prompt such customers to move to TOU rates (*Id.*). He noted that the same benefit would be realized for the small general service customers, for which 16 percent of bills are in excess of 2,000 kWh, which accounts for 49 percent of all usage in that service classification.

We understand UNSE's frustration with the lack of customer participation in the current voluntary TOU program. However, we agree with Staff that the plan should not be made mandatory, at this time, because the vast majority of residential customers would not benefit from participation. We agree with Staff that the more equitable solution to increasing participation in the TOU plan is to educate customers that may benefit from TOU rates through an aggressive educational campaign. We therefore direct UNSE to file, within 60 days of the effective date of this Decision, a proposal for increasing customer awareness of TOU rates and the benefits that may result from participation.

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Inverted (Inclining) Block Rate Structure

UNSE proposed implementation of an inclining block rate structure as a means of encouraging conservation. For residential and small general service customers, the Company's proposal would apply a one cent per kWh discount for the first 400 kWh of usage, compared to the second block for all usage over 400 kWh. RUCO agrees with the Company's inclining block rate structure.

Mr. Magruder agrees with UNSE's inverted block proposal. He asserts that such a rate structure may help reduce the Company's overall demand.

Although Staff agrees with the inclining block structure, in principle, Staff witness Radigan stated that it should not be implemented, at this time, due to the relatively small rate increase requested in this case, which could cause some customers to receive rate decreases, thereby leading to increased consumption and customer confusion (Ex. S-61, at 13). Mr. Radigan acknowledged at the rate case hearing that the customer confusion about which he is concerned may be alleviated through the Company's customer education efforts. Mr. Radigan also testified that most of the rate increase was captured within the increase in the customer charge and it was difficult to design rates with a one cent declining block rate without decreasing rates for come customers (Tr. 1268-69).

We agree with the parties that an inverted block rate structure sends a strong and important price signal to customers to conserve energy. While we recognize Staff's concern that some customers will receive a rate decrease while other customers receive a rate increase, the public policy behind incenting conservation outweighs the concerns raised by Staff. We will approve UNSE's inverted block rate design as supported by all parties but Staff.

Consolidation of Rates for Mohave and Santa Cruz

UNSE's customers in Mohave and Santa Cruz counties currently have separate rate structures. Although minimum monthly charges are the same in both areas, Mohave customers' kWh rates for residential and small general service customers are lower than in Santa Cruz. The Company proposes to consolidate these rates into a single rate structure that would result in a larger percentage increase for Mohave customers compared to Santa Cruz (Ex. A-17, at 20). UNSE claims that due to the relatively small increase being requested in this proceeding, the rate consolidation is appropriate. Mr.

Erdwurm states that the Santa Cruz customers have been paying too much relative to Mohave customers, and this case presents an opportunity to remedy the inequity (Ex. A-18, at 15). RUCO agrees with the Company's proposal to consolidate the Mohave and Santa Cruz rates. Staff witness Radigan opposes UNSE's request and recommends, instead, that consolidation of rates be accomplished over two rate cases. Mr. Radigan claims that, under current rates, the absolute dollar differential between customer bills is minor, and consolidating the rates at this time would send the wrong price signal to Santa Cruz customers, who would experience a rate decrease at the same time the Company's costs are increasing (Ex. S-61, at 14-15). He proposes that, in this case, the customer charge be increased for both Mohave and Santa Cruz from the current $6.50 to $7.50 per month, but that Santa Cruz customers receive a lower commodity charge increase to move rates in the two areas closer. Mr. Radigan suggested that, in the Company's next case, the commodity rates would be fully merged into a single rate (*Id.*).

Mr. Magruder proposes that residential and small business rates in both the Mohave and Santa Cruz areas should be combined into a single rate. Mr. Magruder claims that there is no valid basis for continuing separate rates and states that customers in Santa Cruz County have been paying higher rates than those customers in Mohave County for many years.

We find the Company's proposal to consolidate the Mohave and Santa Cruz rates is reasonable and should be approved. Mr. Radigan's arguments on this subject are unconvincing. The evidence that UNSE is running the two operations as one system is undisputed. Given that the Company's operations are combined, it is inequitable for Santa Cruz customers to have a higher rate than Mohave customers. This inequity should be corrected now and not put off until some future rate case.

Demand Charge Differential

UNSE proposed a reduction to the differential between the demand charge for service taken at less than 69 kV ($24.75) and service taken at 69kV ($16.10). The Company believes the differential ($8.65), which should represent the cost for transformation service to reduce voltage below 69 kV, is too high and imposes a significant cost on low load factor customers taking service at lower voltage

(Ex. A-18, at 15). Company witness Erdwurm testified that, based on his experience, the differential was too large absent any uniqueness of the service provider (Tr. 468).

Staff witness Radigan stated that UNSE's cost of service study does not provide a breakdown of costs for providing service at or below 69 kV and, absent supporting documentation, the Company's request should be denied (Ex. S-61, at 17). Although Mr. Erdwurm amended the Company's request in his rebuttal testimony (to narrow the differential from the current $8.65 to $7.00), Mr. Radigan testified that there is no basis to support the Company's proposal. He indicated that the UNSE system transforms power down to a variety of different voltages and, without a study, it is impossible to determine at which of the lower voltages the majority of large commercial customers are taking power (Ex. S-62, at 4).

We agree with Staff that, absent a study showing the costs of serving respective large commercial customers at various voltages, it is difficult to modify a demand rate to accurately reflect the costs of serving such customers. As Mr. Radigan points out, a large commercial customer could take service from a 13.8 kV line and such a customer should be required to pay for both the transformation of power and the distribution of power over miles of distribution lines (*Id.* at 4-5). Without an accurate cost of service study, it is virtually impossible to determine how much equipment on the other side of the step down transformer is being utilized by large commercial customers. For these reasons, we adopt Staff's recommendation on this issue.

CARES Discount

UNSE proposed year-round flat discounts of $8.00 per month for CARES customers and $10.00 per month for CARES-Medical customers. Under the current CARES program, a declining percentage discount is applied to customer bills as usage increases, with a flat discount of $8.00 applied to customers with usage over a 1,000 kWh threshold and over a 2,000 kWh threshold for CARES-Medical customers. The Company argues that the current program discourages conservation because the flat discount does not apply until customers reach a minimum usage threshold (Ex. A-18, at 15-16). RUCO supports UNSE's proposal to implement the flat discounts (RUCO Ex. 10, at 18).

Staff contends that the current program should remain intact. Staff witness Julie McNeely-Kirwan testified that, under the current CARES program, customers using the least amount of energy

receive the highest percentage discount (30 percent) on their entire bills, while customers using progressively higher amounts of energy receive lower percentage discounts (*i.e.*, 20 percent, 10 percent, or flat $8.00 discount once usage exceeds 1,000 kWh, or 2,000 kWh for CARES-Medical). Ms. McNeely-Kirwan points out that the current rate structure provides a built-in incentive to conserve, in order to receive the highest possible discount (Ex. S-66, at 2). She also notes that the $8.00 discount that is achieved, once a threshold is reached, amounts to less than a 1 percent discount (*Id.*).

We agree with Staff that the current CARES rate structure should be continued. Contrary to the Company's claims, the current structure promotes conservation by offering a 30 percent discount to the total customer bill for the lowest usage. As usage increases, CARES customers receive progressively lower discounts on their bills, thereby providing customers with a price signal that encourages such customers to limit their energy use.

We also agree with Staff that UNSE should clarify the language on its website to more clearly describe the CARES discounts that are available, especially to inform customers that the discount is applicable to the entire customer bill, based on total monthly usage (*i.e.*, usage of 300, 600 or 1,000 kWh for CARES and 600, 1,200 or 2,000 kWh for CARES-Medical would trigger progressively smaller discounts). In addition, UNSE should be required to separately report Cares-Medical participation in its CARES report, in accordance with Staff's recommendation (Ex. S-67, at 3-4). The Company should modify the language on its website, in a form acceptable to Staff, within 60 days of the effective date of this Decision.

Low-Income Customer Issues

In its brief, UNSE states that it is committed to making several improvements to service provided to low-income customers. The Company indicated that it has proposed the addition of a Warm Spirits program, similar to that offered by UNS Gas, that would be a voluntary customer-funded program that provides emergency bill payment assistance to low-income customers. The Company stated that it would match customer donations, dollar-for-dollar, up to $25,000 per year, and would also move $20,000 for Emergency Bill Assistance from the Low-Income Weatherization ("LIW") program into Warm Spirits. An additional commitment made by UNSE is to increase LIW

funding from $70,000 to $105,000 annually, and increase the maximum per house expenditure from $1,600 to $2,000. Finally, UNSE indicated that it plans to offer its customers a more convenient way to pay their bills in cash, as an alternative to payday loan businesses (Tr. 517) (UNSE Initial Brief, at 62).

Mr. Magruder recommended that the Company be required to cease using payday loan companies within 60 days of this Decision unless the Company meets certain requirements recommended by the Consumer Law Center.

On February 22, 2008, UNS Gas filed (in Docket No. G-04204A-06-0463 et al.) "Notice of Filing of Payment Alternatives in Compliance with Decision No. 70011." In its filing, UNS Gas stated that it has developed an alternative to requiring cash payments to be made at payday loan stores. According to UNS Gas, it is in the process of developing a cash payment option called PayScan™ that would enable customers to make cash payments at all Circle K stores in Arizona for a service fee of $1.50. UNS Gas expects the new program to be implemented by the second quarter of 2008 and, upon implementation, will notify customers of the option by bill inserts, website updates, and signs posted at cash payment sites.

We believe UNSE's low-income customer commitments are reasonable and should be approved. With respect to the Warm Spirits program, in addition to other educational materials it provides customers, the Company should also, within 60 days of the effective date of this Decision, place a section on customer bill payment stubs that allows customers to check a box to indicate they would like to make a contribution at the time they write their payment checks. This requirement is consistent with the practice followed by APS, Southwest Gas and UNS Gas for similar programs. Regarding the PayScan™ program, we direct the Company to file in this docket, within 60 days of the effective date of this Decision, an updated report regarding implementation of the program for UNSE.

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Demand-Side Management Adjustor Mechanism

In this case, UNSE seeks approval of a Demand-Side Management ("DSM") adjustor mechanism to recover a portion of the costs of its DSM programs[15]. The Company agreed with Staff witness Jerry Anderson's recommendation (Ex. S-63, at 15-16) to fund 100 percent of its expanded LIW program costs, and 25 percent of the other DSM program costs, through the adjustor mechanism (Ex. A-6, at 6). UNSE claims that the initial adjustor charge is expected to support this level of funding, and the adjustor mechanism would be reset annually to ensure the proper level of funding (Ex. S-63, at 13-17). UNSE, Staff and RUCO are in agreement regarding the Company's DSM adjustor mechanism proposal.

Mr. Magruder made observations and recommendations regarding the Company's individual DSM programs. He also proposed that the DSM, Renewable Energy Standard ("RES") and PPFAC adjustors should be reset collectively on the same date each year.

We believe the DSM Docket is the appropriate place to address the details of the Company's specific DSM programs. Mr. Magruder's concerns regarding those programs can be taken into consideration by Staff during its analysis in that docket. The adjustor approved herein will be set initially at $0.000583 per kWh and adjusted annually on June 1 of each year, beginning on June 1, 2009, in accordance with Staff's recommendation.

EPS/REST Adjustor Mechanism

According to Staff witness Jerry Anderson, UNSE is currently required to meet the Environmental Portfolio Standards ("EPS") set forth in A.A.C. R14-2-1618. However, the Commission subsequently adopted in Decision No. 69127 (November 14, 2006), Renewable Energy Standard and Tariff ("REST") rules that are intended to replace the EPS rules (Ex. S-63, at 17-18).

UNSE currently recovers its renewable costs through an EPS surcharge that was approved on an interim basis for Citizens Utilities Company in Decision No. 63360 (February 8, 2001). In this proceeding, Staff recommended that the EPS surcharge be converted to an adjustor mechanism, in

[15] UNSE originally filed in this docket a request for approval of new and enhanced DSM programs but subsequently filed an application in Docket No. E-04204A-07-0365 ("DSM Docket") for approval of its comprehensive DSM portfolio. The DSM Docket application is pending before the Commission.

accordance with the REST rules requirements, with the same EPS rate currently in effect (Ex. S-63, at 19).

On October 12, 2007, UNSE filed an application for approval of its proposed RES Implementation Plan and Associated Tariff (Docket No. E-04204-07-0593). That application requested, among other things, that the Company be released from all obligations under the EPS rules (A.A.C. R14-2-1618), that the remaining EPS funds could be used for REST program expenses, and an effective date and reset date for the REST adjustor charge (UNSE Reply Brief, at 34).

At its April 9, 2008, Open Meeting, the Commission addressed UNSE's REST Plan and adopted Staff's recommendations regarding the Company's application (Docket No. E-04204-07-0593). In the Order discussed at the April 9, 2008, Open Meeting, the Commission, among other things: stated the REST rules superseded the EPS rules; released UNSE from the EPS rule requirements, and directed that any remaining EPS funds be applied to the REST program; directed that UNSE no longer charge the EPS surcharge and no longer file the annual EPS surcharge report; established REST tariff rates[16]; and deferred establishment of the REST adjustor mechanism to this rate case.

We agree with Staff's recommendation to approve a REST adjustor mechanism in accordance with the REST rules. Consistent with the Commission's discussion at the April 9, 2008, Open Meeting, the new REST adjustor would replace the EPS surcharge and any remaining EPS funds would be applied to the REST program. As described by Mr. Anderson, the Company would be entitled to file an application to change the adjustor rate and caps, subject to Staff review and Commission approval or modification. The adjustor charge will continue to be listed on customer bills as a separate line item.

Outages for Customers on Life Support Equipment

Mr. Magruder proposed that UNSE be required to identify all customers that have life support equipment, its type and battery capabilities, and provide that information to local law enforcement

[16] The approved REST rates are as follows: $0.004988 per kWh, with a monthly cap of $2.00, for residential customers; $39.00 for non-residential customers; and $500.00 for non-residential customers with demands of 3 MW or greater (Recommended Order, at page 9, in Docket No. E-04204-07-0593, approved at April 9, 2008, Open Meeting).

offices so that public safety agencies would be able to check on such customers during power outages.

UNSE responded that it is opposed to sharing customer information with third parties but, even if it could share such information, the Company is not able to reliably track where specific customers are located on its system (Ex. A-22, at 6). UNSE claims that it uses outage status recordings to inform customers, but the Company has no way of knowing whether every specific customer has a sufficient backup supply for a certain period of outage. However, UNSE witness James Pignatelli stated that the Company is willing to work with safety response agencies regarding this issue (Tr. 71-72).

Although we do not believe Mr. Magruder's suggested remedies are necessarily the best way to address the issue he raises, given Mr. Pignatelli's commitment to work with appropriate agencies, we direct the Company to file within 90 days of the effective date of this Decision a statement regarding suggested changes to its procedures that may address the concerns raised by Mr. Magruder on this issue.

Nogales/Citizens 1999 Settlement Agreement

Mr. Magruder claims that UNSE, as the successor to Citizens Utilities, has failed to comply with certain provisions of a Settlement Agreement between the City of Nogales and Citizens that was approved by the Commission in Decision No. 61793 (June 29, 1999). The items cited by Mr. Magruder include the alleged failure by UNSE to fund interest-free college loans for students in Santa Cruz County, the assertion that UNSE failed to undertake 20 above-ground pole replacements and 12 underground cable projects, and the need for re-establishment of a Citizens Advisory Council in Santa Cruz County.

During the hearing, the Administrative Law Judge directed UNSE to contact Mr. Magruder to discuss his concerns regarding these matters. In its reply brief, the Company claims that a Company representative met with Mr. Magruder on October 16, 2007, and, although UNSE believes it has complied with the terms of the prior settlement agreement, the company will continue to work with Mr. Magruder to address his concerns (UNSE Reply Brief, at 35-36).

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Magruder Proposed Rate Base Adjustment

Intervenor Marshall Magruder recommended that the Commission disallow from UNSE's rate base $15,561,520 due to the Company's alleged failure to comply with prior Commission Orders related to improvements to the UNSE system in Santa Cruz County. Mr. Magruder claims that UNSE's predecessor, Citizens Utilities, submitted a Plan of Action ("POA") in 1999 to make improvements to its system in Santa Cruz County due to quality of service concerns. According to Mr. Magruder, a Settlement Agreement between Staff and Citizens was approved by Decision No. 62011 (November 2, 1999), which Agreement required Citizens to undertake 20 utility pole replacement projects and 12 underground cable replacement projects in Santa Cruz County. Mr. Magruder contends that the Citizens POA included annual budgets of $15,561,520 for these projects. He stated that some of the projects were over budget by early 1999, some were never started, and others are unknown (Ex. M-23, at 30-31). Mr. Magruder also seeks to reduce the Company's rate base by $282,440 based on his claim that pole and underground cable replacements in that amount were completed by Citizens prior to the UNSE acquisition in 2003 (*Id.* at 34). Mr. Magruder therefore requests that UNSE's rate base be reduced by these amounts.

The Company claims that Mr. Magruder provided no supporting evidence justifying his proposed disallowances, and the Settlement Agreement between Nogales and Citizens contains no provision regarding pole replacements. UNSE argues that it had the discretion to determine which, if any, pole replacements were needed based on existing circumstances. The Company contends that it has researched and engineered needed pole replacements, and has completed any needed replacements. UNSE asserts that it is providing reliable service, a point with which Staff agrees (Ex. S-55, at 6-7).

It is unclear from the record whether there are uncompleted requirements related to the Citizens POA, as Mr. Magruder claims. However, we do not necessarily agree that the remedy proposed by Mr. Magruder is appropriate, and we believe additional information is needed before any further action is taken. We will therefore direct UNSE to file a detailed response to Mr. Magruder's allegations on this issue, within 60 days of the effective date of this Decision. Replies to the Company's response shall be filed by Mr. Magruder, Staff, and RUCO within 30 days thereafter.

Student Loans and Scholarships

With respect to the interest-free student loans, UNSE states in its reply brief that, consistent with Mr. Pignatelli's testimony at the hearing (Tr. 55), the Company awarded 7 scholarships to Nogales High School students from 1999 to 2003 through the Nogales Educational Foundation, and will provide additional scholarships if required by the settlement agreement. The Company added that it has also committed to fund additional scholarships over the next four years for students at Nogales High School and Rio Rico High School (UNSE Reply Brief, at 35).

On December 27, 2007, Mr. Magruder filed a document entitled Notice and Filing of Late-Filed Exhibits[17]. Mr. Magruder claims that his filing "summarizes information from the new information that came to light" in UNSE's reply brief, regarding student scholarships, a Citizens Advisory Council, and the pole and cable replacement projects (Magruder December 27, 2007 Filing, at 3). Mr. Magruder essentially restates his prior arguments from the hearing, claiming that UNSE has not complied with the requirements of the Nogales/Citizens Settlement Agreement regarding these issues. Mr. Magruder contends that all of the scholarships cited by Mr. Pignatelli were awarded before UNSE acquired Citizens, and that the Settlement Agreement requires the Company to fund $3,000 annually of interest-free loans for students attending Arizona colleges, if the students receiving the loans agree to return to Santa Cruz County for two years following graduation. Mr. Magruder argues that the Company's commitment to two scholarships per year, rather than the annual loan requirement, "is as ungenerous to complying with the 'annual' requirement as UNSE could make to this third-world County" [i.e., Santa Cruz County] (Magruder Reply, at 1, emphasis original). Mr. Magruder also reiterates his claim that UNSE deliberately failed to replace known defective underground cables and utility poles, and that the Citizens Advisory Council, although required by the Settlement Agreement, has not met in over 7 years.

It is not entirely clear from the evidentiary record, or the extra-record, late-filed exhibits submitted by Mr. Magruder, whether UNSE is in compliance with its obligations under the prior Settlement Agreement between the City of Nogales and Citizens. Mr. Magruder contends that UNSE

[17] UNSE filed a Response on January 9, 2008, and Mr. Magruder filed a Reply to the Company's Response on January 15, 2008.

is deficient regarding several matters, while the Company maintains that it has complied fully with its responsibilities. No other party has alleged that UNSE is not in compliance with the Commission Order cited by Mr. Magruder. Given that some of the information upon which Mr. Magruder relies was not available at the time of the hearing, we believe the most efficient means of addressing his concerns is to direct UNSE to meet with Mr. Magruder and, if necessary, request that Staff be included in the discussions to provide an objective perspective regarding these issues. Therefore, UNSE should initiate a meeting with Mr. Magruder within 30 days of the effective date of this Decision, and file within 90 days of the effective date of this Decision a statement regarding suggested resolution of the concerns raised by Mr. Magruder on this issue.

Proposed Changes to Rules and Regulations

UNSE proposed several changes to its existing Rules and Regulations governing service. Among those proposed changes is a reduction in the free footage allowed for line extensions, a service connection contribution fee for new service meters, and a proposal to reduce the period, from 15 days to 10 days, that customers have to pay their bills before the bills are considered past due.

Line Extension Policies and Service Connection Contribution

UNSE currently provides an overhead line, or underground service line in areas served by underground lines, up to 150 feet with no more than one carryover pole for each residential customer, without charge (Ex. A-54). The Company proposed elimination of 50 feet of that amount, and one carryover pole, from its overhead line connection (Ex. A-55). Because UNSE's current line extension policy also allows for 400 feet of free footage (Ex. A-56), the total free footage allowance would drop from 550 feet, and one carryover pole, to 500 feet and no carryover pole (Ex. A-21, at 9).

Staff proposes that the free footage allowance be eliminated entirely to increase the likelihood of growth paying for growth (Ex. S-64, at 4-5). Staff witness Bing Young stated that eliminating free footage would lessen the financial strain on UNSE to extend service to new customers in a growing service area. Mr. Young testified that adoption of Staff's recommendation "would significantly improve [UNSE's] ability to recover its distribution costs associated with this growth" (*Id.*). The Company opposes Staff's recommendation on the basis that such a change would have an adverse impact on development in Mohave and Santa Cruz counties (Ex. A-21, at 9-10).

In response to questions from Commissioner Mayes, UNSE proposed at the hearing a Service Connection Contribution ("SCC") fee of $250 that would be required of each new customer[18]. The $250 fee would be treated as a non-refundable contribution to offset construction costs for new service line connections (Ex. A-46). Company witness Grant testified at the hearing that the proposed fee would be similar to a "hook-up fee" except the SCC would not strictly offset construction costs for off-site backbone facilities (Tr. 1064-66). Mr. Grant testified that the SCC would bring in as much as $1.5 million annually, assuming 6,000 new connections per year, but the Company prefers not to implement this proposal until after the pending generic hook-up fee docket has been concluded (Docket Nos. E-00000K-07-0052 and G-00000E-07-0052) (Tr. 960-61). Staff opposes implementation of the SCC in this proceeding and recommends that the issue of hook-up fees be addressed in the generic docket.

We agree with Staff's recommendation to eliminate the free footage allowance currently in effect for UNSE. As noted above, UNSE has advocated the need for CWIP and other rate relief mechanisms to mitigate the financial pressures associated with extending service to new customers in a growing service area. The elimination of free footage will help mitigate UNSE's required capital costs in dealing with customer growth and will also help ensure that the costs of serving growth are paid for by the customers that cause those costs. We also agree with Staff that UNSE's proposed SCC should not be adopted in this proceeding. The issue of hook-up fees for UNSE would, at least at this time, be better addressed in the generic docket where all relevant factors can be considered, including the income tax implications for companies that implement hook-up fees.

Bill Payment Due Date

As set forth in A.A.C. R14-2-210(C), "all bills for utility services are due and payable no later than 15 days from the date of the bill," and "[a]ny payment not received within this time-frame shall be considered delinquent and could incur a late payment charge."

UNSE proposes to modify its billing terms in its tariffs by reducing from 15 days to 10 days (from the time the bill is rendered) the time for customers to pay bills before the bills are considered

[18] The SCC would be waived for customers that build a home in compliance with the Company's "Energy Smart Homes" efficiency standards (Tr. 1066).

"past due." The Company's proposed change would make its billing practices consistent with the tariffs approved for UNS Gas in Decision No. 70011[19]. UNSE witness Thomas Ferry contends that even under the proposed billing change, customers would have plenty of time to pay bills before late payment charges would apply or termination of service would be implemented (Ex. A-21 at 2). According to Mr. Ferry, after the 10-day payment period, customers would have an additional 15 days before a reminder notice would be sent, for a total of 26 days. At that point, the bill would be considered delinquent, and late charges would apply, but termination-of-service procedures (*i.e.*, notice of termination) would not commence for an additional 5 days (*Id.*). Mr. Ferry also indicated that the Company would continue its current practice of working with customers that request or are in need of payment extensions (*Id.*).

Although RUCO witness Diaz Cortez initially opposed the Company's proposed changes to billing dates, based on her apparent understanding that bills would be considered delinquent in a shorter period of time than currently exists, but RUCO did not address this issue in its brief so it is not clear if RUCO was persuaded by the explanation in Mr. Ferry's rebuttal testimony. Staff argues on brief that UNSE's proposal does not comply with the Commission's rules, based on its reading of the rule stating that bills shall not be considered "past due" for at least 15 days after the bill is rendered.

We agree with UNSE that the proposed billing changes are reasonable. We believe the billing changes are consistent with the Commission's Rules, which require only that payments not be considered "delinquent" (and therefore subject to late charges) sooner than 15 days after the bill is rendered. As explained above, the Company's proposal would not consider payments delinquent until at least 25 days after issuance, and the termination timeline would remain unchanged. As we indicated in Decision No. 70011 (at page 74), the proposed change would allow the customer call center representatives to have a single set of rules in place for all of the UniSource affiliates, which should minimize potential errors that may occur when information regarding delinquent bills and/or

[19] The rule for gas companies (A.A.C. R14-2-310(C)) provides that payments not received within 10 days are considered "past due" while the rule for electric companies (A.A.C. R14-2-210(C)) states that payments received more than 15 days after the bill is issued are considered "delinquent." It is unclear whether this difference in terminology is intentional or due to an oversight.

termination of service is provided to customers. In addition, as the UNSE witness pointed out, a bill would not be subject to a late payment charge until at least 25 days after the bill is rendered, and a termination of service notice for nonpayment could not occur sooner than 30 days following issuance of a bill. We believe that these timeframes provide an adequate period for customers to either pay a bill or seek alternative payment arrangements prior to being subjected to a penalty or termination of service. We therefore approve the Company's proposed changes to its billing tariffs. However, in accordance with the UNS Gas Order, we direct UNSE not to implement the approved billing change for a period of six months following the effective date of this Decision in order to allow a transition for customers to the revised billing rule.

Bill Estimation

As described in the testimony of Staff witness Bing Young, UNSE's tariffs do not provide an explanation of its bill estimation methodology. Mr. Young recommended that the Company be required to submit a separate tariff setting forth its estimation methods, within 30 days of the effective date of this Decision (Ex. S-64, at 7-9). Mr. Young also listed the specific parameters that should be included in the Company's bill estimation tariff (*Id.*).

UNSE witness Ferry stated that he is not aware of any customer confusion regarding bill estimation, but indicated that the Company is open to reviewing its policies when TOU billing is offered to a larger customer base.

Given our rejection of UNSE's mandatory TOU proposal, it is not clear whether the Company's conditional concession on this issue means that it does not oppose Staff's recommendation. In any event, we agree with Staff that UNSE should provide more detail in its tariffs regarding the methodology it employs for bill estimations. The greater level of detail will allow more transparency for customers, as well as Commission Staff in fielding calls from customers regarding the issue. UNSE should therefore submit a revised bill estimation tariff, for Commission approval, in accordance with the criteria set forth in Mr. Young's testimony, within 30 days of the effective date of this Decision.

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Magruder Suggestions Regarding UNSE Tariffs

Mr. Magruder proposed that UNSE should be directed to: rewrite its rules and regulations in plain English and Spanish in order to improve customer understanding; provide key portions of the rules and regulations to all customers; facilitate understanding of billing collection schedules and collection, deposits, service termination and complaint handling; absorb credit and debit card fees as a business expense; and reformat its billing statements to improve customer understanding.

UNSE responded that its proposed rules are in full compliance with all Commission rules and regulations, and much of the language in its tariffs comes directly from, and is organized in a manner similar to, the Commission's rules. The Company claims that it already provides a copy of the applicable rules for customers requiring line extensions, and that being required to provide copies of rules to customers would be burdensome and unnecessary, given the fact that they are available online. However, UNSE states that it does not object to translating its tariffs into Spanish and making that version available online.

We find no basis for requiring the Company to undertake the efforts proposed by Mr. Magruder. As UNSE points out, its tariffs, and the proposed changes to those tariffs, comply with the Commission's rules and regulations and, in most instances, are identical or similar to the Commission's rules. The Company has agreed to translate its tariffs into Spanish and post that version online, which should address one of Mr. Magruder's biggest concerns.

OTHER ISSUES

Purchased Power and Fuel Adjustment Clause ("PPFAC")

UNSE currently obtains all of its power supply through a fixed price, full requirements agreement with Pinnacle West. The Pinnacle West contract expires May 31, 2008, and the Company must obtain a new supply of power prior to that date. UNSE witness Michael DeConcini testified that the current fixed price contract will be replaced by new sources of power that include short-term wholesale purchases. As a result, the Company contends that a modified PPFAC is needed that will enable UNSE to recover its actual costs of purchased power and fuel (Ex. A-14, at 19).

UNSE initially proposed a cost recovery mechanism that would automatically adjust based on a 12-month rolling average cost for fuel and purchased power. However, Staff recommended a

PPFAC that is comparable to the Power Supply Adjustor ("PSA") approved for APS in Decision No. 69663 (June 28, 2007), adjusted for UNSE's specific circumstances (Ex. S-56, at 80-85). In his rebuttal testimony, Mr. DeConcini agreed to Staff's proposed PPFAC mechanism, along with a proposed Plan of Administration ("POA") to operate the PPFAC (Ex. A-15, at 8, 16).

The PPFAC agreed upon by UNSE and Staff provides for an effective date of June 1, 2008, when the Company's new power supply agreements will take effect. Prior to that date, the base cost of fuel and purchased power would be set at a level that reflects costs under the current contract and, therefore, the PPFAC rate would be set at zero (until June 1, 2008) (Ex. A-17, at 21; Ex. A-15, at 8-9). Under the terms of the POA, the PPFAC would have a "forward component" and a "true-up component." The forward component would be based on forecasted fuel and purchased power costs, and the true-up component would compare actual fuel and purchased power costs with the amounts collected through base rates and the PPFAC rate in the prior year (Ex. A-15, at 9-12). The POA also provides that the true-up component would reconcile actual and forecast fuel and purchased power costs, and the true-up would be incorporated into the following year's PPFAC rate (*Id.*). In addition, under the POA agreed upon by UNSE and Staff, the PPFAC would run from June 1 through May 31 of the following year; the Company would be required to file by December 31 information and calculations showing the following year's forward and true-up components; Staff would have until February 15 to issue initial comments, or recommended adjustments, regarding the Company's December 31 filing; and the Company would be required to file updated information and calculations regarding the true-up component by April 1, with a Staff response to the updated information required by April 15 (*Id.*). The POA does not contemplate that the Commission would approve each new year's PPFAC, but the Commission could suspend the PPFAC or take other action prior to June 1. The POA further provides that, if an extraordinary event occurs that dramatically affects fuel and energy prices, UNSE would be permitted to seek a modification of the forward component to mitigate the chance that the subsequent true-up would result in an excessive increase (*Id.* at 12-14).

RUCO opposes the PPFAC advocated by the Company and Staff, and has proposed its own adjustor mechanism. RUCO's recommendation is described below.

Although the Company and Staff are in general agreement regarding the PPFAC and POA, the following two operational issues remain in dispute: "other allowable costs" recoverable under the PPFAC and a "cap" on the PPFAC to mitigate the potential for rate shock due to wide swings in the price of natural gas.

"Other" Allowable Costs in PPFAC

UNSE seeks the ability to include "other" costs (*e.g.*, broker's fees, credit costs, and legal fees) through the PPFAC because such costs are not currently recovered through the Company's base rates due to its current full requirements contract (Ex. A-15, at 15; Tr. 339-42). UNSE claims that it has not previously incurred procurement scheduling and management costs related to power acquisition because of the long-standing contract with Pinnacle West. As a result, the Company claims that such costs are not included in its current base rates and, without recovery through the PPFAC, it would not have an opportunity to recover the "other" costs.

UNSE witness DeConcini stated that these costs are directly related to fuel and purchased power procurement, the costs are likely to vary from year to year and, as such, are especially appropriate for inclusion in the PPFAC (Ex. A-16, at 3-4). As an alternative, Mr. DeConcini proposed that the Commission approve forecasted procurement, scheduling and management fees allocated to UNSE from TEP's Wholesale Energy Group (*Id.*).

Staff opposes inclusion of an open-ended category of "other" costs in the PPFAC. Staff argues that such costs should be recovered through base rates, just as other operating expenses are treated (ex. S-58, at 54-56). Staff claims that no other utilities in Arizona have been permitted to recover these types of costs through a PPFAC, and that a recent request by APS to include broker's fees in its PSA was specifically rejected by the Commission in Decision No. 69663 (June 28, 2007, at 107-8). Staff witness Ralph Smith testified that UNSE's PPFAC should be limited to expenses recorded in FERC Accounts 501, 547, 555 and 565, and that Section 9-B of the POA, labeled "Other Allowable Costs," should contain the statement "None without pre-approval from the Commission in an Order" (*Id.* at 56-57).

We agree with Staff that UNSE's request for recovery of "other" expenses through the PPFAC should be denied. We believe Staff properly recommended that only fuel and purchased

power costs recorded in FERC Accounts 501, 547, 555 and 565 should be flowed through the PPFAC, and no other costs should be included in the PPFAC unless the costs are approved by a Commission Order. No other utility company has been permitted to recover such expenses through an automatic adjustor mechanism and we see no valid basis to depart from that precedent. If "other" costs become a significant burden on the Company's operations, it may seek recovery through base rates, where all of its expenses and revenues are considered. We believe that the PPFAC mechanism and accompanying POA proposed by Staff provide UNSE an opportunity to timely recover its fuel and purchased power expenses, without the added guarantee that all "other" related expenses would be automatically recovered through an adjustor outside of a base rate case.

PPFAC "Cap"

In his pre-filed testimony, Staff witness Smith did not support imposing a "cap" on UNSE's PPFAC, agreeing with the Company that (1) because UNSE is in the process of acquiring and developing its resource requirements, it would not be appropriate to cap the PPFAC rate in this period of flux; (2) an inappropriately narrow cap could encourage short-term rate stability at the expense of serving the long-term interests of customers; and (3) short-term rate stability through imposition of caps that are too narrow could lead to large deferrals that negatively impact both the Company and customers (Ex. S-58, at 54).

Near the end of the evidentiary hearing, Staff recalled Mr. Smith to testify regarding Staff Exhibit 68, a proposal filed by Staff to impose an annual cap on the PPFAC rate in order "to address the potential of PPFAC rate shock given new information presented by UNSE" (Ex. S-68). Mr. Smith testified that Staff supports imposition of a "cap" on the forward component of the PPFAC, but no cap on the true-up component (Tr. 1398-1401). Staff contends that its new PPFAC cap recommendation was the result of Staff's analysis of documents (Exs. A-43 and A-44) that were received from the Company at a relatively late stage in the hearing, after Staff's surrebuttal testimony was filed. Staff argues that, upon review of the largely confidential documents received from UNSE, Staff felt the need to inform the Commission of the real potential of PPFAC rate shock in the event of sudden large increases in natural gas prices, and to offer a recommendation for addressing such a situation.

UNSE argues that Staff's PPFAC cap recommendation could impose a substantial hardship on the Company. Company witness Grant estimated that, if gas prices reach $9.00 MMBtu, the annual PPFAC deferral would be approximately $23 million, an amount that would have to be financed by UNSE. Mr. Grant stated that it is uncertain whether the Company's existing credit facility is sufficient to finance that level of deferrals, or if additional financing would be available (Tr. 1411-12).

UNSE also contends that, even if sufficient financing were available for such deferrals, the proposed interest on under-collected balances would not be sufficient to cover the Company's actual financing costs because its borrowing rate on the revolving credit facility is based on LIBOR plus 1 percent, while Staff recommends maintaining the POA interest rate at the applicable one-year Nominal Treasury Constant Maturities. The Company requests that no cap be placed on the forward component at this time but, if such a cap is imposed, the Commission should set the POA interest rate at LIBOR plus 1, and approve a "circuit breaker" mechanism that would allow a forward component price adjustment if the deferral balance reaches more than 5 percent of the Company's total capitalization.

Staff asserts that, according to UNSE Exhibit 43, the Company's estimated total rates (based on projected purchased fuel and purchased power costs from June 2008 through May 2009), including the forward component rates, would increase dramatically in the event of increases in the price of natural gas supplies. For example, according to Staff, UNSE Exhibit 43 shows the forward component of the PPFAC alone would range from 0.48 cents/kWh ($6.00 MMBtu gas), to 1.73 cents/kWh ($7.50 MMBtu gas), to 2.98 cents/kWh ($9.00 MMBtu gas). Based on these natural gas price assumptions, the projected rate increases compared to current rates (including the UNSE proposed base rate increase) would be 8.8 percent with $6.00 MMBtu gas, 21.5 percent with $7.50 MMBtu gas, and 34.2 percent with $9.00 MMBtu gas. Staff therefore believes a cap is appropriate to mitigate potential rate shock.

Based on UNSE's base forecast of power costs (assuming gas at $7.50 MMBtu), Staff recommended a cap of 1.73 cents per kWh for the forward component, which could not be exceeded without a Commission Order. Staff claims that if the cap were implemented, as it recommends, the

total rate increase (including base rates) would be no more than 21.5 percent. Staff argues that, although APS's PSA contains an annual cap of 4 mils, the same type of cap would not be appropriate for UNSE, because UNSE does not own any base load generation and its power costs are therefore subject to a greater degree of volatility. According to Staff, a cap on PPFAC rates based on natural gas price increases would be more appropriate for UNSE.

Staff's recommended 1.73 cents per kWh cap, although introduced late in the hearing process, was based on documents provided after Staff's final testimony was filed, and which documents raised very real concerns by Staff regarding the possible magnitude of sudden and dramatic fuel and purchased power increases that could be experienced by customers. We believe Staff's cap recommendation provides an appropriate balance between the need to protect customers from potential rate shock with the Company's need to recover fuel and purchased power costs in a timely manner. The initial PPFAC rate, effective June 1, 2008, shall be set at 1.4746 cents per kWh.

Finally, we disagree with the Company's alternative interest rate and circuit breaker proposals. In Decision No. 70011, we rejected a proposal by UNS Gas for approval of an interest rate of LIBOR plus 1 percent on the company's PGA bank balance, based on Staff's explanation of the history of how adjustor mechanism interest rates were established and the interest rates in effect for APS and Southwest Gas (Decision No. 70011, at 77-80). We do not believe UNSE has presented a sufficient basis for departing from the PPFAC interest rate proposed by Staff, which is based on the one-year Nominal Treasury Constant Maturities rate and is comparable to the rate approved for APS's PSA that currently exists. In addition, as we noted in the UNS Gas case, "granting a higher interest rate could provide a disincentive for the Company to reduce bank balances and could cause it to become less focused on taking all possible measures to reduce the cost of gas for its customers" (*Id.* at 80).

RUCO's Proposed PPFAC

RUCO opposes the PPFAC proposal supported by UNSE and Staff. Ms. Diaz Cortez proposes a PPFAC structure that would automatically adjust on a monthly basis, based on a 12-month rolling average of purchased power and fuel costs. RUCO's proposal would also include a 6 mils per year cap and a 90/10 sharing mechanism (RUCO Ex. 8, at 10-14). Ms. Diaz Cortez contends that a

rolling average adjustor would send appropriate price signals to customers as fuel costs increase or decrease, while also smoothing out wide fluctuations in fuel costs. She also stated that RUCO's cap proposal would provide protection for customers from sudden large increases, and that the 90/10 sharing mechanism would provide an incentive for the Company to better control its fuel and purchased power costs (RUCO Ex. 10, at 7-8).

Staff and the Company oppose the RUCO PPFAC proposal. Staff witness Smith stated that Staff prefers a forward mechanism that adjusts only once a year, and that a rolling average based adjustor could reduce regulatory scrutiny, increase the level of deferrals, and cause customer confusion due to frequent rate changes (Ex. S-56, at 79-80). On the witness stand, Mr. Smith also expressed concern with the 6 mil cap mechanism proposed by RUCO because the cap is too low for UNSE and could result in significant deferrals (Tr. 1392-93).

Company witness DeConcini stated that RUCO's proposed sharing mechanism is inappropriate for UNSE because, unlike APS, UNSE has no current baseload generation and is in the process of acquiring new power resources (Ex. A-15, at 14). He added that a sharing mechanism would expose the Company to volatility in the short-term power markets and could lead to a confiscatory rate policy, because short-term resource costs are largely beyond the Company's control (*Id.*).

As stated above, we believe Staff's PPFAC recommendations are reasonable and should be adopted. Both the Staff and Company witnesses pointed out potential problems with the adjustor mechanism advocated by RUCO, including the possibility that significant deferrals could be experienced by UNSE under a rolling average structure, the diminished regulatory oversight with such a mechanism, and that it could cause confusion and customer dissatisfaction from frequent rate adjustments. The witnesses also stated the reasons why a sharing mechanism is not appropriate for UNSE, at this time, because of the potential volatility that would likely be experienced by the Company at a time when it is acquiring new sources of power to replace its long-standing full requirements contract.

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Purchased Power Allocation

UNSE witness Erdwurm initially proposed allocating purchased power costs using an "average and peaks" methodology that, as Staff witness Radigan stated, is comprised of an average demand component and a peak demand component (Ex. A-18, at 6-7; Ex. S-62, at 2). UNSE's original proposal would have allocated 100 percent of Accounts 555 and 565 based on average and peaks. However, in his rebuttal testimony, Mr. Erdwurm modified the Company's proposal to a 40 percent average and peaks and 60 percent energy allocation, based on his claim that the UNSE system has a lower load factor than TEP (which he estimated would be allocated at 50 percent of production costs based on average and peaks and 50 percent of production costs based on energy).

Staff witness Radigan testified that purchased power should be allocated with a 100 percent energy component in accordance with the Pinnacle West contract, which has no provision for demand charges or segregation of charges by time of day, month or season (Ex. S-62, at 2). He stated that the Company has provided no credible evidence that the average and peaks method should be used in this case (*Id.*).

We agree with Staff that UNSE's proposed imposition of a purely hypothetical allocation methodology in this case should be rejected. As Mr. Radigan pointed out, "[h]owever much Mr. Erdwurm tries to reverse engineer this energy charge into demand and energy components, the simple fact remains that the purchased power charge is purely volumetric." (*Id.*). We will therefore adopt Staff's purchased power allocation recommendation.

Black Mountain Generating Station

According to UNSE witness DeConcini, the Company has a base demand of 200 to 250 MW, with a peak demand of 450 MW (Ex. A-14, at 1). As stated above, UNSE currently obtains all of its power through a full requirements contract with Pinnacle West, which contract expires May 31, 2008. As a result, the Company is pursuing alternative sources to replace the expiring agreement, including the possibility of purchasing a 90 MW peaking facility called the Black Mountain Generating Station ("BMGS") that is planned to be constructed near Kingman, Arizona by an affiliate company, UniSource Energy Development Company ("UED").

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UNSE

UNSE projects that the BMGS will have a total cost of $60 to $65 million and, to date, all costs have been incurred by UED (Tr. 89). The Company seeks to include only up to $60 million of the plant costs in this case. In order to acquire the BMGS, UNSE proposed a novel ratemaking treatment that would recognize post-test year rate base treatment of the facility before the plant is completed or owned by UNSE. UNSE claims that acquisition of the BMGS would provide operational and financial benefits for the Company, and is a unique opportunity that would allow UNSE to diversify its power supply portfolio. The Company claims that if rate base treatment of the plant is denied in this case, the opportunity to acquire the BMGS would be lost or delayed.

According to Mr. DeConcini, UED has agreed to sell the plant to UNSE at cost, and UNSE has agreed to limit rate recovery to the amount of UED's actual cost of construction, as well as submitting to a subsequent prudence evaluation of the plant's costs (Ex. A-14, at 9; Ex. A-15, at 4). UNSE claims that the $60 million rate base addition would increase the Company's revenue requirement in this case by approximately $10 million.

Operational benefits of the acquisition cited by the Company include: having operational flexibility to meet required reserves and ancillary services, and economic dispatch capabilities; UNSE would have full control over maintenance and operation of the plant; generation would be owned by UNSE to meet reserve needs; and generation would be available in a location where transmission costs can be minimized, and would provide necessary must-run energy and allow for connection to dual systems for redundancy (Ex. A-15, at 6-7).

The primary advantage cited by UNSE for inclusion of the BMGS in rate base is the discounted cost of the plant due to the affiliate relationship with UED. UNSE claims that UED acquired two 2003 vintage LM6000 turbines in 2006 at a discount of approximately 25 percent compared to current prices (Ex. A-14, at 11-14). UNSE also claims that acquisition of the plant would provide long-term financial benefits to customers compared to purchasing wholesale power. Company witness Larson estimated that the cost of owning the BMGS would be approximately $12 million less than purchasing wholesale power, on a net present value basis over 30 years (Ex. A-10, at 2). He also contends that having an additional $10 million in non-fuel revenues would add

approximately $6 million to the Company's cash flows, and $3 million to net income, and provide UNSE a reasonable opportunity to earn a return on the BMGS (Ex. A-8, at 3, 10).

Mr. Larson stated that, given the looming maturity of all $60 million of UNSE's long-term debt in August 2008, the only realistic chance for UNSE to acquire the BMGS is to be allowed to implement a post-test year adjustment to rate base, and a corresponding rate reclassification when the plant becomes operational (Ex. A-9, at 6). The Company also asserts that the BMGS must be accorded rate base treatment in this case, because the deferred accounting treatment recommended by Staff would not provide the Company with sufficient cash flows to support the estimated cost of acquiring the plant (*Id.*). Mr. Larson claims that adoption of Staff's deferral proposal would leave UNSE no choice but to file another rate case as soon as this proceeding is concluded, because the Company would likely not have the ability to attract the capital needed to finance the plant acquisition without certainty of rate recovery through rates in this case (*Id.* at 7).

Staff

Staff opposes inclusion of $60 million in rate base for the BMGS. Staff witness Ralph Smith testified that such rate base inclusion would violate the traditional test year matching concept, and would not be consistent with sound ratemaking principles (Ex. S-56, at 89-92; Ex. S-58, at 64-65). Mr. Smith indicated that UNSE should consider filing an application to seek deferred accounting treatment for the plant as a means of recovering plant costs in its next rate case. He stated that such a process would more closely synchronize the timing of plant operations with rate recovery (Ex. S-56, at 90-91).

Staff cites a host of concerns with approving rate base treatment of the BMGS in this case, including the fact that the plant is not expected to be operational until May or June of 2008, dates that are well beyond the test year, the hearing, and even the expected effective date of this Decision. Staff also points out that the plant is being constructed in its entirety by UED and, therefore, UNSE has not been subjected to cash flow issues associated with the plant's construction. Staff also claims that there is ongoing uncertainty regarding: the eventual total cost of the plant; whether ultimate ownership will rest with UNSE or UED; the plant's operational and maintenance costs; whether the plant's costs are prudent; and whether it would be more economical for the Company to purchase the

plant, or to purchase power on the open market. Staff argues that, given these uncertainties, the BMGS should not be included in the Company's rate base at this time.

RUCO

RUCO similarly opposes inclusion in rate base for the BMGS. RUCO argues that neither the capital costs nor the operating costs of the plant are known, at this time, and it is therefore premature to grant approval before the plant is even finished. Although the Company has agreed to a post-rate base inclusion prudence review, RUCO is concerned that customers would be required to begin paying for a plant before it is completed and prior to analysis in a rate case regarding prudence of the plant costs. RUCO claims that such action by the Commission would set an inappropriate precedent.

RUCO witness Diaz Cortez also stated that adoption of UNSE's proposal would violate the ratemaking matching principle because customer counts at the time of the plant's completion would be different than the customer counts used in this case for setting rates. She indicated that there is no way for the Commission to know the incremental costs, or cost savings, between the test year and the post-test year in-service date for the BMGS, thereby resulting in piecemeal ratemaking (RUCO Ex. 10, at 5). Ms. Diaz Cortez also testified that approval of the Company's request would violate the ratemaking principle that only "used and useful" plant should be accorded rate recognition. Finally, she questioned the lack of opportunity for greater scrutiny of a transaction between affiliated entities under UNSE's proposal (RUCO Ex. 8, at 7).

Conclusion

For the reasons they cite, we agree with Staff and RUCO that the BMGS should not be included in rate base at this time. However, the temporal coincidence of two circumstances specific to this case, expiration of UNSE's contract with Pinnacle West two weeks from now and imminent commercial operation of the plant[20], is a compelling basis on which to encourage UNSE's acquisition of the BMGS. To provide such encouragement, we will authorize UNSE to implement an accounting order to record any and all of the Company's financial activities associated with the BMGS, as if the

[20] UNSE's May 5, 2008 Exceptions at page 4, lines 6-9: "As of May 1, 2008, both gas combustion turbines of the BMGS have been in operation and have synchronized with the grid, *producing power*. Performance testing is planned for the next two weeks and *commercial operation is scheduled for mid-May 2008.*" (emphases added)

BMGS were in rate base as of June 1, 2008. Unless otherwise ordered by the Commission, this accounting order would remain in effect until the effective conclusion of UNSE's next rate case.

Financing Approval for the BMGS

Concurrent with its request for rate base treatment of the BMGS, UNSE seeks approval of a financing request that would enable the Company to issue up to $40 million of new debt securities, and receive up to $40 million of additional equity contributions from UniSource Energy. Mr. Larson indicated that the Company would also require some flexibility regarding the mix of debt and equity in order to best take advantage of market conditions (Ex. A-8, at 15-17). Mr. Larson stated that the requested debt issuance would be in addition to that approved in Decision No. 69395 (March 22, 2007), and that long-term debt would be secured by the BMGS assets or other UNSE assets. Under the Company's proposal, short-term debt issuances (up to 5 years maturity) could be secured or unsecured, with either fixed or variable rates (*Id.*).

Regarding the equity infusion component of the request, UNSE seeks authority to receive from UniSource Energy up to $40 million in additional equity, over and above any contributions that would otherwise be allowed under Commission rules or Orders. Mr. Larson claims that this equity infusion would enable UNSE to purchase the BMGS and provide the Company an opportunity to maintain a balanced capital structure (*Id.*). The Company contends that, absent approval of its combined debt and equity financing proposal, it would not be able to finance the purchase of the BMGS.

Staff recommended approval of the requested financing authority subject to certain conditions, which were subsequently agreed to by the Company. Staff witness Alexander Igwe testified that the financing request should be approved subject to the following conditions:

1) The $40 million of new debt financing and $40 million in new equity should be used for the sole purpose of acquiring the BMGS;

2) The $40 million of new debt financing may be comprised of long-term debt and short-term to intermediate-term debt;

3) UNSE should be permitted to refinance any of the short-term or intermediate-term debt approved by this docket, to long-term debt, without further Commission approval;

4) UNSE should be authorized to issue guarantees and to grant liens on some or all of its assets, including the BMGS, and any other assets acquired subsequent to acquisition of the BMGS, to secure its obligations under the proposed debt issuance and to secure other obligations at the time such liens are granted;

5) UNSE should be authorized to engage in any transactions to execute, or cause to be executed, any documents necessary to effectuate the requested authorizations;

6) UNSE should be required to file a report with Docket Control, within 60 days from the close of each transaction, demonstrating that it had a debt service coverage ("DSC") ratio and times interest earned ratio ("TIER") equal to or greater than 1.0 at the time of the new debt issuances; and

7) UNSE should be required to file a report with Docket Control, within 60 days of the close of each financing package, describing the transaction and demonstrating that the terms are consistent with those generally available to comparable entities (Ex. S-54, at 5-7).

Mr. Igwe indicated that the grant of the Company's financing proposal would not have a material impact on Staff witness Parcell's recommended capital structure, but the exact impact of the financing secured by UNSE on its capital structure could not be determined, at this time, given the Company's need for flexibility regarding the mix of debt and equity it ultimately achieves to finance the BMGS acquisition.

With respect to the requested financing, we agree with Staff that UNSE's requests for approval of up to $40 million of new debt financing, and up to $40 million of equity infusion from UniSource Energy, are measures that should be approved subject to the parameters outlined by Staff. The Company's proposal for securing financing for the purpose of acquiring the BMGS is reasonable, and is therefore approved in accordance with Staff's recommendations, as outlined above. However, approval of the financing set forth herein does not constitute or imply approval or disapproval by the Commission of any particular expenditure of the proceeds derived thereby for purposes of establishing just and reasonable rates.

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Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. On December 15, 2006, UNSE filed an application with the Commission in the above-captioned docket for an increase in its rates throughout its service area in the State of Arizona.

2. On January 12, 2007, Staff filed a Letter of Sufficiency indicating that the Company's application, as supplemented by additional information filed on January11, 2007, met the sufficiency requirements outlined in A.A.C. R14-2-103, and classifying the Company as a Class A utility.

3. On February 1, 2007, a Procedural Order was issued scheduling a hearing for September 10, 2007; directing UNSE to publish notice of the application; and setting various other procedural deadlines.

4. Intervention was granted to RUCO, APS, and Marshall Magruder.

5. With its application in the Rate Case, UNSE filed its required schedules in support of the application, and the direct testimony of various witnesses.

6. On June 28, 2007, Staff, RUCO, and Mr. Magruder filed direct testimony in accordance with the previously established procedural schedule. Staff, RUCO and Mr. Magruder filed additional direct testimony on July 12, 2007.

7. On August 14, 2007, UNSE filed the rebuttal testimony of various witnesses in response to Staff and intervenor testimony.

8. Surrebuttal testimony was filed by Staff, RUCO, and Mr. Magruder on August 24, 2007.

9. On August 31, 2007, UNSE filed the rejoinder testimony of several witnesses in response to the surrebuttal testimony of Staff and intervenor witnesses.

10. The evidentiary hearing commenced as scheduled on September 10, 2007, and additional hearing days were held on September 11, 12, 13, 14, 20 and 21, 2007, and on October 2, 2007.

11. Final Schedules were filed on October 11, 2007, October 16, 2007 and October 17, 2007, respectively, by UNSE, Staff and RUCO.

12. Initial Post-Hearing Briefs were filed on November 5, 2007, by UNSE, Staff, and RUCO, and on November 6, 2007, by Mr. Magruder.

13. Reply Briefs were filed on November 14, 2007, by RUCO, on November 16, 2007, by Mr. Magruder, and on November 19, 2007, by UNSE and Staff.

14. On December 27, 2007, Mr. Magruder filed late-filed exhibits in response to UNSE's reply brief.

15. On January 9, 2008, UNSE filed a response to Mr. Magruder's late-filed exhibits.

16. On January 15, 2008, Mr. Magruder filed a reply to UNSE's response.

17. According to the Company's application, as modified, in the test year ended June 30, 2006, UNSE had adjusted operating income of $8,770,016 on an adjusted OCRB of $141,036,562, for a 6.22 percent rate of return.

18. UNSE requests a revenue increase of $8,468,638; Staff recommends a revenue increase of $3,687,885; and RUCO recommends a revenue increase of $1,282,144.

19. For purposes of this proceeding, we determine that UNSE has an OCRB of $130,740,050 and a FVRB of $167,551,067.

20. A rate of return on FVRB of 7.03 percent is reasonable and appropriate.

21. The Company's attempt to interject the issue of the *Chaparral City* decision through its rebuttal testimony, and its attempt to apply the weighted average cost of capital to FVRB is not reasonable and is not supported by the testimony and evidence in the record.

22. UNSE is entitled to a gross revenue increase of $4,018,678.

23. The class responsibility for the revenue requirement should be allocated using the methodology of Staff's rate design expert witness.

24. For residential customers, the basic monthly customer charge should be increased from $6.50 to $7.50, with a volumetric "base rate" charge of $0.089248 per kWh for the first 400 kWh, and $0.09926 per kWh for usage over 400 kWh, for customers in both Mohave and Santa Cruz Counties. The volumetric "base rates" reflect the consolidation of rates for Mohave and Santa Cruz customers and the inverted block rate structure (see discussion below). However, these volumetric rates do not include the additional PPFAC charge, which is being set initially at $0.014746 per kWh

for all usage.

25. The rates for Mohave and Santa Cruz Counties should be consolidated into a single rate structure.

26. For CARES customers, the current discount applicable to the entire bill should be retained, based on total monthly usage (*i.e.*, usage of 300, 600 or 1,000 kWh for CARES and 600, 1,200 or 2,000 kWh for CARES-Medical would trigger progressively smaller discounts).

27. The rates for other customer classes should be set based on Staff's rate design recommendation, with the customer charges for each class established at the level recommended by Staff and with volumetric charges based on the revenue requirement determined herein. The only exception shall be that residential and small general service customers shall use UNSE's inverted block rate design based on the revenue requirement determined herein.

28. The billing determinants proposed by the Company should be employed for setting rates in this proceeding.

29. Staff's recommendation to set the DSM adjustor surcharge at an initial level of $0.000583, is reasonable. In addition, it is reasonable to require UNSE to file semi-annual reports for the DSM programs, to shift the adjustor filing date to April 1 (with an Adjustor date of June 1), and that the appropriate forum for a full review of the specific DSM programs is in the separate docket in which there is an application currently pending.

30. DSM programs should be funded at the level recommended by Staff: 100 percent of expanded LIW program costs, and 25 percent of the other DSM program costs, funded through the adjustor mechanism.

31. With respect to the Company's PPFAC mechanism, we adopt Staff's recommendations, including limitation of expenses to those recorded in FERC Accounts 501, 547, 555 and 565, and implementation of an annual PPFAC cap of 1.73 cents per kWh on the forward component of the PPFAC.

32. The interest rate for the Company's PPFAC bank balance should be retained, based on one-year Nominal Treasury Constant Maturities, in accordance with Staff's recommendation.

33. Staff's purchased power allocation recommendation is reasonable and should be

adopted.

34. Staff's recommendation to approve a REST adjustor mechanism, in accordance with the REST rules, is reasonable and should be approved. The new REST adjustor will replace the EPS surcharge and any remaining EPS funds would be applied to the REST program.

35. With respect to the use of payday loan stores for acceptance of customer payments, Company should file, within 60 days of the effective date of this Decision, an updated report regarding implementation of the PayScan™ program.

36. The Company's line extension policies should be amended to eliminate the free footage allowance currently in effect. However, the Company's proposed $250 Service Connection Charge should not be adopted.

37. UNSE's proposed billing change, to reduce from 15 days to 10 days, the date for customers to pay bills before the bills are considered past due, is reasonable, subject to the condition that payments would not be considered delinquent, and therefore subject to late charges, until at least 25 days after issuance of the bill, and the service termination timeline would remain unchanged. However, in accordance with the Decision No. 70011, UNSE should not implement the approved billing change for at least six months following the effective date of this Decision.

38. The Company's proposal to include the Black Mountain Generating Station in base rates should not be approved because, among other things, the plant was not operational during the test year, and is therefore not used and useful for ratemaking purposes; UNSE does not yet have ownership of the plant; the plant costs have not been determined to be prudent by the Commission; and the final cost of the plant is unknown since it has not been completed.

39. UNSE's financing request, for approval of up to $40 million of new debt financing, and up to $40 million of equity infusion from UniSource Energy, are measures that should be approved subject to the parameters outlined by Staff. The Company's proposal for securing financing for the purpose of acquiring the BMGS is reasonable, and should therefore be approved in accordance with Staff's recommendations.

40. UNSE proposed to revise the Rules and Regulations provisions in its tariffs, specifically Section 12, which addresses Termination of Service, to add "EFTs or other financial

instruments" to a provision that allows the Company to disconnect electric service without notice under the condition when NSF checks have not been made good. We believe that the customer should be given notice so as to have an opportunity to make good on the check, EFT, or other financial instrument. Therefore, the condition of NSF checks, EFTs, or other financial instruments that have not been made good should be included with the conditions under which service can be terminated with notice and should be deleted from the conditions under which service can be terminated without notice.

41. In view of the expiration of UNSE's power supply contract with Pinnacle West on May 31, 2008, and imminent commercial operation of the BMGS, it is in the public interest to authorize UNSE to implement an accounting order to record UNSE's financial activities associated with the BMGS, as if the BMGS were in rate base as of June 1, 2008. UNSE may use the accounting order to seek recovery of BMGS-related costs in the Company's next rate case.

CONCLUSIONS OF LAW

1. UNS Electric is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§40-250, 40-251, and 40-367.

2. The Commission has jurisdiction over UNSE and the subject matter of the above-captioned application.

3. The fair value of UNSE's rate base is $167,551,067, and applying a 7.03 percent rate of return on this fair value rate base produces rates and charges that are just and reasonable.

4. The rates, charges, approvals, and conditions of service established herein are just and reasonable and in the public interest.

5. The deferral authorization granted herein does not constitute a finding or determination that the deferred costs are reasonable, appropriate, or prudent.

6. It is in the public interest to authorize UNSE to record UNSE's financial activities associated with the BMGS, as if the BMGS were in rate base as of June 1, 2008, and UNSE may use the accounting order to seek recovery of BMGS-related costs in the Company's next rate case.

7. With the conditions imposed herein, the financing approved herein is for lawful purposes within UNSE's corporate powers, is compatible with the public interest, with sound financial

practices, and with the proper performance by UNSE of service as a public service corporation, and will not impair UNSE's ability to perform that service.

8. The financing approved herein is for the purposes stated in the application and is reasonably necessary for those purposes, and is not reasonably chargeable to operating expenses or income.

9. It is reasonable and in the public interest to authorize UNSE to issue debt and receive equity subject to the conditions recommended by Staff.

ORDER

IT IS THEREFORE ORDERED that UNS Electric, Inc., is hereby authorized and directed to file with the Commission, on or before May 31, 2008, revised schedules of rates and charges consistent with the discussion herein and a proof of revenues showing that, based on the adjusted test year level of sales, the revised rates will produce no more than the authorized increase in gross revenues.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after June 1, 2008.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall notify its customers of the revised schedules of rates and charges authorized herein by means of an insert, in a form acceptable to Staff, included in its next regularly scheduled billing.

IT IS FURTHER ORDERED that UNS Electric, Inc. shall file as a compliance item, within 20 days of the effective date of this Decision, a voluntary time of use tariff, for Commission approval.

IT IS FURTHER ORDERED that UNS Electric, Inc. may implement an accounting order to record UNSE's financial activities associated with the BMGS, as if the BMGS were in rate base as of June 1, 2008.

IT IS FURTHER ORDERED that UNS Electric, Inc. may use the accounting order authorized herein to seek recovery of BMGS-related costs in the Company's next rate case.

IT IS FURTHER ORDERED that the deferral authorization granted to UNS Electric, Inc., herein does not constitute a finding or determination that the deferred costs are reasonable,

appropriate, or prudent; and this Decision shall not be construed as providing any relief through rates with respect to the ultimate recovery of the above-authorized deferrals.

IT IS FURTHER ORDERED that, if UNS Electric, Inc., intends to seek future recovery through rates of the deferred costs authorized herein, the Company shall prepare and retain accounting records sufficient to permit detailed review, in a rate proceeding, of all such deferred costs.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall develop a customer education program for its new inverted block rates and shall submit such a program to Docket Control by June 30, 2008, for Commission approval.

IT IS FURTHER ORDERED that UNS Electric, Inc., is hereby authorized to incur up to $40 million of new debt financing, in either long-term and/or short to intermediate-term debt, for the purpose of acquiring the Black Mountain Generating Station, and is authorized to refinance any short-term or intermediate-term debt into long-term debt, without further Order of the Commission, as a means of taking advantage of prevailing market conditions.

IT IS FURTHER ORDERED that UNS Electric, Inc., is authorized to receive up to $40 million of equity from UniSource Energy for the purpose of acquiring the Black Mountain Generating Station.

IT IS FURTHER ORDERED that UNS Electric, Inc., is authorized to issue guarantees and grant liens on some or all of its assets, including the Black Mountain Generating Station, and any other assets acquired subsequent to the acquisition of the Black Mountain Generating Station, to secure its obligations under the proposed debt issuance and to secure other obligations at the time such liens are granted.

IT IS FURTHER ORDERED that UNS Electric, Inc., is authorized to engage in any transactions to execute, or cause to be executed, any documents necessary to effectuate the requested authorizations.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall file a report with Docket Control, within 60 days from the close of each transaction, demonstrating that it had a debt service coverage ratio and times interest earned ratio equal to or greater than 1.0 at the time of the new debt issuances.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall file a report with Docket Control, within 60 days of the close of each financing package, describing the transaction and demonstrating that the terms are consistent with those generally available to comparable entities.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall use the financing approved herein for the purposes set forth in the application.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall file, as a compliance item with Docket Control, within 90 days of the funding of any new debt under this authorization, copies of the executed loan documents.

IT IS FURTHER ORDERED that approval of the financing set forth herein does not constitute or imply approval or disapproval by the Commission of any particular expenditure of the proceeds derived thereby for purposes of establishing just and reasonable rates.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall set the DSM adjustor surcharge at an initial level of $0.000583 per kWh, adjusted annually on June 1 of each year, beginning June 1, 2009, and shall make its DSM adjustor filing by April 1 of each year, beginning April 1, 2009.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall file semi-annual reports for its DSM programs in accordance with Staff's recommendations.

IT IS FURTHER ORDERED that the depreciation rates proposed by UNS Electric, Inc., with Staff's recommended treatment, are approved.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall file a detailed response to Mr. Magruder's allegations regarding the poles and underground cables under the 1999 Nogales/Citizens Settlement Agreement, within 60 days of the effective date of this Decision. Replies to the Company's response shall be filed by Mr. Magruder, Staff, and RUCO within 30 days thereafter.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall, within 60 days of the effective date of this Decision, in a form acceptable to Staff, clarify the language on its website to more clearly describe the CARES discounts that are available, especially to delineate that the discount applicable to the entire bill is based on total monthly usage (*i.e.*, usage of 300, 600 or 1,000 kWh for CARES and 600, 1,200 or 2,000 kWh for CARES-Medical would trigger progressively smaller discounts). In addition, UNSE shall separately report Cares-Medical participation in its CARES report, in

accordance with Staff's recommendation.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall, within 60 days of the effective date of this Decision, place a section on customer bill payment stubs that allows customers to check a box to indicate they would like to make a contribution to the Warm Spirits program.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall file, within 60 days of the effective date of this Decision, an updated report regarding implementation of the PayScan™ program.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall initiate a meeting with Mr. Magruder, within 30 days of the effective date of this Decision, and file within 90 days of the effective date of this Decision, a statement regarding suggested resolution of the concerns raised by Mr. Magruder with respect to the student loans and scholarships issue.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall file, within 30 days of the effective date of this Decision, a revised line extension tariff consistent with the discussion hereinabove, including a transition plan, for Commission approval.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall not implement the approved billing changes regarding payment due dates for 6 months following the effective date of this Decision.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall file with Docket Control, within 30 days of the effective date of this Decision, a revised bill estimation tariff, in accordance with Staff's recommendations for Commission approval.

IT IS FURTHER ORDERED that Staff's recommendation to approve a REST adjustor mechanism, in accordance with the REST rules, shall be approved. The new REST adjustor will replace the EPS surcharge and any remaining EPS funds would be applied to the REST program.

IT IS FURTHER ORDERED that Staff's recommended revisions to the Company's PPFAC mechanism is approved, including limitation of expenses to those recorded in FERC Accounts 501, 547, 555 and 565, and implementation of an annual PPFAC cap of 1.73 cents per kWh on the forward component of the PPFAC.

IT IS FURTHER ORDERED that UNS Electric, Inc. shall file, within 30 days of the effective

date of this Decision, a revised POA in accordance with the discussion hereinabove.

IT IS FURTHER ORDERED that UNS Electric, Inc. shall set the initial PPFAC rate, effective June 1, 2008, at 1.4746 cents per kWh.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall consolidate the rates for customers in Mohave and Santa Cruz Counties into a single rate structure.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall revise its tariffs in accordance with Finding of Fact No. 40 so that NSF checks, EFTs, or other financial instruments that have not been made good are included as conditions under which service can be terminated with notice.

IT IS FURTHER ORDERED that UNS Electric, Inc., shall file to file, within 90 days of the effective date of this Decision, a statement regarding suggested changes to its procedures that may address the concerns raised by Mr. Magruder customers on life support equipment.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN | COMMISSIONER

COMMISSIONER | COMMISSIONER | COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 27th day of May, 2008.

BRIAN C. McNEIL
EXECUTIVE DIRECTOR

DISSENT _____

DISSENT _____

SERVICE LIST FOR: UNS ELECTRIC, INC.

DOCKET NO.: E-04204A-06-0783

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EXHIBIT
RUCO-2
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

Arizona Corporation Commission
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RUCO
By 6:57am

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR 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 GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831 DECISION NO. 70011 **OPINION AND ORDER**

DATES OF HEARING: April 16, 17, 18, 19, 20, 24, and 25, 2007.

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Dwight D. Nodes

IN ATTENDANCE: Mike Gleason, Chairman
Kristin K. Mayes, Commissioner

APPEARANCES:

Mr. Michael W. Patten and Mr. Timothy Sabo, ROSHKA, DEWULF & PATTEN, P.L.C. and Ms. Michelle Livengood, UNISOURCE ENERGY SERVICES, on behalf of Applicant;

Mr. Scott S. Wakefield, Chief Counsel, on behalf of the Residential Utility Consumer Office;

Ms. Cynthia Zwick, Executive Director, Arizona Community Action Association;

Mr. Marshall Magruder, in propria persona; and

Mr. Keith Layton and Ms. Maureen Scott, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

TABLE OF CONTENTS

Rate Application 4
REVENUE REQUIREMENT 5
Rate Base Issues 5
Construction Work in Progress 5
Post-Test-Year Plant 7
Deduction of Customer Advances 8
Geographic Information System 10
Plant in Service 11
Test Year Accumulated Depreciation 13
Working Capital 14
Accumulated Deferred Income Tax 15
Summary of Rate Base Adjustments 16
Operating Income Issues 17
Revenues 17
Customer Annualization 17
Weather Normalization 19
Expenses 20
Legal Expenses Related to FERC Rate Case 20
Rate Case Expense 20
Customer Call Center Expenses 22
Miscellaneous "Unnecessary" Expenses 24
Performance Enhancement Program 26
Supplemental Executive Retirement Plan 27
Fleet Fuel Expense 29
Bad Debt Expense 30
Postage Expense 30
Depreciation and Property Taxes for CWIP 31
Overtime Payroll Expense 31
Payroll Tax Expense 32
Property Tax Expense 32
Membership and Industry Association Dues 32
Interest Synchronization 34
CARES Related Amortization 34
Nonrecurring Severance Payment 34
Nonrecurring Union Training 35
New Depreciation Rates 36
Net Operating Income 36
COST OF CAPITAL 36
Capital Structure 36
Cost of Debt 39
Cost of Common Equity 39
UNS Gas 39

RUCO 42
Staff 43
Conclusion on Cost of Equity 44
Chaparral City Decision and Fair Value Rate Base 45
AUTHORIZED INCREASE 51
RATE DESIGN ISSUES 51
Customer Charge and Seasonal Rates 51
UNS Gas 51
Mr. Magruder 53
RUCO 53
Staff 54
Conclusion 56
Throughput Adjustment Mechanism 57
UNS Gas 57
RUCO 59
Mr. Magruder 60
Staff 60
Conclusion 61
Demand-Side Management Programs 62
UNS Gas 62
Mr. Magruder 63
Staff 63
Conclusion 64
Low-Income Customer Programs 64
CARES Program 65
Warm Spirits Program 66
Payments at Payday Loan Stores 68
Proposed Changes to Rules and Regulations 70
Line and Main Extension Policies 70
Reduction of Bill Payment Due Date 72
Prudence of Gas Procurement Practices and Policies 74
Price Stabilization Policy 75
Purchased Gas Adjustor 77
PGA Bank Interest Rate 78
Expansion of Bandwidth 80
FINDINGS OF FACT 82
CONCLUSIONS OF LAW 86
ORDER 86

BY THE COMMISSION:

On November 10, 2005, the Arizona Corporation Commission ("Commission") opened an inquiry (Docket No. G-04204A-05-0831) into the prudence of the gas procurement practices of UNS Gas, Inc. ("UNS" "UNS Gas" or "Company") ("Prudence Case").

On January 10, 2006, UNS filed an application (Docket No. G-04204A-06-0013) with the Commission seeking review and revision of the Company's Purchased Gas Adjustor ("PGA Case").

On July 13, 2006, UNS filed an application with the Commission (Docket No. G-04204A-06-0463) for an increase in its rates throughout the State of Arizona ("Rate Case").

On July 20, 2006, UNS filed separate Motions to Consolidate in each of the above-captioned dockets.

On August 14, 2006, the Commission's Utilities Division Staff ("Staff") filed a Letter of Sufficiency indicating that the Company's Rate Case application met the sufficiency requirements outlined in A.A.C. R14-2-103, and classifying the Company as a Class A utility.

On August 18, 2006, the Residential Utility Consumer Office ("RUCO") filed an Application to Intervene.

On September 8, 2006, a Procedural Order was issued consolidating the Prudence, PGA, and Rate Case dockets; scheduling a hearing for April 16, 2007; setting various other procedural deadlines; directing UNS to publish notice of the applications and hearing date; and granting RUCO's request for intervention.

On September 20, 2006, Arizona Community Action Association ("ACAA") filed a Motion to Intervene.

By Procedural Order issued November 15, 2006, ACAA's Motion to Intervene was granted.

On November 17, 2006, Marshall Magruder filed a Motion to Intervene on his own behalf.

By Procedural Order issued January 10, 2007, Mr. Magruder's request to intervene was granted.

With its rate application, UNS filed its required schedules in support of the application, as well as the direct testimony of James Pignatelli, David Hutchens, Kentton Grant, Dallas Dukes, Karen Kissinger, Gary Smith, Ronald White, and Tobin Voge.

On February 9, 2007, Staff filed the direct testimony of Ralph Smith, David Parcell, Robert Gray, Julie McNeely-Kirwan, and George Wennerlyn; RUCO filed the direct testimony of William Rigsby, Marylee Diaz Cortez, and Rodney Moore; ACAA filed the direct testimony of Miquelle Scheier; and Mr. Magruder filed his direct testimony.

On February 9, 2007, Staff filed a Request for Extension of Time to file the direct testimony of two of its witnesses.

On February 15, 2007, a Procedural Order was issued granting Staff's extension request, and revising the dates for responsive testimony for the other parties.

On February 16, 2007, Staff filed the direct testimony of Jerry Mendl.

On February 23, 2007, Staff filed the direct testimony of Steven Ruback.

On March 1, 2007, a Procedural Order was issued rescheduling the prehearing conference to April 13, 2007.

On March 16, 2007, UNS filed the rebuttal testimony of D. Bentley Erdwurm, Mr. Grant, Mr. Dukes, Ms. Kissinger, Mr. Hutchens, Mr. Pignatelli, Gary Smith, and Denise Smith.

On March 30, 2007, ACAA filed the surrebuttal testimony of Ms. Scheier.

On April 4, 2007, Staff filed the surrebuttal testimony of Mr. Gray, Ms. McNeely-Kirwan, Mr. Parcell, Mr. Ruback, Mr. Mendl, and Ralph Smith; RUCO filed the surrebuttal testimony of Mr. Rigsby, Mr. Moore, and Ms. Diaz Cortez; and Mr. Magruder filed his surrebuttal testimony.

On April 11, 2007, UNS filed the rejoinder testimony of Denise Smith, Gary Smith, Mr. Pignatelli, Ms. Kissinger, Mr. Dukes, and Mr. Erdwurm.

On April 13, 2007, a prehearing procedural conference was conducted to address the order of witnesses and exhibits.

The evidentiary hearing commenced as scheduled on April 16, 2007, and additional hearing days were held on April 17, 18, 19, 20, 24, and 25, 2007. At the close of the hearing, a briefing schedule was established, with initial briefs due on May 31, 2007, and reply briefs due on June 14, 2007.

On May 30, 2007, Staff filed a Request for Extension of Time to File Initial Brief.

On May 31, 2007, a Procedural Order was issued granting Staff's extension request and

directing initial and reply briefs to be filed by June 5 and June 19, 2007, respectively.

Initial briefs were filed on June 5, 2007, by UNS, Staff, RUCO, and Mr. Magruder. Final Schedules were also filed on June 5, 2007, by UNS and RUCO.

On June 6, 2007, Staff filed a Notice of Errata and Revised Initial Brief.

Reply Briefs were filed on June 19, 2007, by UNS, Staff, RUCO, and Mr. Magruder.

On June 21, 2007, Staff filed a Notice of Errata and Additional Authority.

Rate Application

According to the Company's application, as modified, in the test year ended December 31, 2005, UNS had adjusted operating income of $8,506,168,[1] on an adjusted Original Cost Rate Base ("OCRB") of $162,358,856, for a 5.24 percent rate of return. UNS requests a revenue increase of $9,459,023; Staff recommends a revenue increase of $4,312,354; and RUCO recommends an increase of $2,734,443. A summary of the parties' positions follows.

	Company Proposed	Staff Proposed	RUCO Proposed
ORIGINAL COST			
Adjusted Rate Base	$162,358,856	$154,547,272	$144,646,160
Rate of Return	8.80%	8.12%	8.22%
Req'd Operating Inc.	14,284,546	12,549,238	11,889,914
Op. Income Available	8,506,168	9,900,380	10,219,499
Operating Inc. Def.	5,778,378	2,648,858	1,670,416
Rev.Conver. Factor	1.6370	1.6370	1.6370
Gross Rev. Increase	9,459,023	4,336,098	2,734,443
FAIR VALUE			
Adjusted Rate Base	$191,875,209	$184,063,625	$171,189,139
Rate of Return	7.44%	6.81%	6.95%
Req'd Operating Inc.	14,284,546	12,534,733	11,889,914
Op. Income Available	8,506,168	9,900,380	10,219,499
Operating Inc. Def.	5,778,378	2,634,353	1,670,416
Rev.Conver. Factor	1.6370	1.6370	1.6370
Gross Rev. Increase	9,459,023	4,312,354[2]	2,734,443

[1] The Company's "Final Schedules," which were submitted at the time UNS' initial brief was filed, are inconsistent with the revenue requirement recommendations set forth in the Company's brief (compare, *e.g.*, UNS Initial Brief at 5-6 and Final Schedule A-1). No subsequent filings were submitted to explain the differences between these documents and the reason for the discrepancy is unknown. For purposes of this Decision, we have used the Company's "Revised Schedules," (admitted at the hearing as Ex. A-10), and as set forth in its brief.

[2] Staff's gross revenue increase was calculated by applying a zero cost value to the "excess" between OCRB and FVRB.

REVENUE REQUIREMENT

Rate Base Issues

UNS proposed an OCRB of $162,358,856; Staff recommends an OCRB of $154,547,272; and RUCO proposed an OCRB of $144,646,160. Each of the disputed issues regarding rate base items is discussed below.

Construction Work in Progress

Construction work in progress ("CWIP") is a regulatory concept under which, in limited circumstances, a regulatory body allows recovery in a company's rate base of plant that was under construction during the test year but not used and useful for purposes of serving customers. In this proceeding, UNS Gas seeks inclusion of approximately $7.2 million of CWIP (which would provide the Company with approximately $1.5 million in additional annual revenues). In support of its position, UNS argues that CWIP is an accepted aspect of ratemaking that has been used in many states and that the Arizona Supreme Court previously upheld the allowance of CWIP, citing *Arizona Community Action Assoc. v. Arizona Corp. Comm'n*, 123 Ariz. 228, 230, 599 P.2d 184, 186 (1979). In that case, the Arizona Supreme Court stated that allowing CWIP "appears to be in the public interest to have stability in the rate structure within the bounds of fairness and equity rather than a constant series of rate hearings." (*Id.*).

UNS contends that it will not be able to earn its authorized rate of return even if its full rate request is granted in this case, due to the high rate of growth in its service area, which requires higher levels of capital investment to serve new customers. According to Company witness Kentton Grant, because investment in new plant creates additional fixed costs and because growth leads to capital requirements in excess of the Company's internal cash flow, the impact of regulatory lag on UNS Gas is more severe than for many other utilities (Co. Ex. 28 at 9; Co. Ex. 27 at 28). Mr. Grant testified that in 2006 UNS added $17 million in net plant, which resulted in an additional $3 million in fixed costs (*e.g.*, depreciation, property taxes), but new customers added in 2006 provided only $1.8 million in new revenues, resulting in a net loss of $1.2 million for UNS associated with serving growth in 2006 (Co. Ex. 28 at 10, Attach. KCG-10).

Staff and RUCO oppose inclusion of CWIP in the Company's rate base. Staff witness Ralph Smith stated that, although the Commission has previously allowed CWIP in rate base, the Commission's general practice has been not to allow CWIP. In support of Staff's disallowance recommendation, Mr. Smith claims that absent compelling reasons, which have not been shown by UNS in this case, there is no valid reason to grant CWIP. Mr. Smith asserts that the Company has not demonstrated that its test year CWIP balance was for non-revenue-producing and non-expense-reducing plant. He testified that much of the construction appears to be for mains, services, and meters related to serving customer growth, which plant is therefore revenue producing. Mr. Smith stated that, although test year revenues have been annualized to (2005) year-end customer levels, revenues have not been extended beyond the test year to correspond to customer growth. Thus, according to Mr. Smith, inclusion of CWIP in rate base, without recognition of the incremental revenue the plant supports, would cause a mismatch for regulatory purposes (Ex. S-25 at 9-10).

RUCO witness Marylee Diaz Cortez also recommends disallowance of CWIP for many of the same reasons cited by Staff witness Ralph Smith. Ms. Diaz Cortez stated that the Commission has previously allowed CWIP only in extraordinary circumstances, which she claims are not present in this case. She claims that recovery of earnings on CWIP plant balances prior to the plant becoming used and useful is accomplished through an Allowance for Funds Used During Construction ("AFUDC"), through which the Company may accrue interest on the CWIP balances. The AFUDC accruals are ultimately recovered over the life of the plant through depreciation expense once the asset becomes used and useful in provision of utility service (RUCO Ex. 5, at 7-9). Ms. Diaz Cortez testified that regulatory lag has always been a characteristic of rate of return regulation and that such lag may also provide a benefit to the Company, to the extent that plant retirements, accumulated depreciation, and expired amortizations allow it to earn a return on those items between rate cases. She also stated that the growth phenomenon in the UNS service area has a positive aspect due to the increase of revenues associated with serving new customers (*Id.* at 9-10).

We agree with Staff and RUCO that the request for CWIP in this case is not supported by the record. As the Staff and RUCO witnesses indicated, UNS is not faced with an extraordinary situation that would justify inclusion of CWIP in rate base because the plant required to serve new customers

will help produce revenues; UNS has a means, through accrual of AFUDC, to mitigate the effect of the CWIP investment; allowance of CWIP would undermine the balancing of test year revenues and expenses; and the regulatory lag inherent in utility regulation may provide benefits to the extent that items such as plant retirements and accumulated depreciation occur between test periods and thereby help to mitigate periods of higher plant investment associated with customer growth.

As Staff points out in its brief, one of the few instances in which the Commission previously allowed inclusion of CWIP in rate base occurred in 1984 in a case involving Arizona Public Service Company ("APS"). In that case, the Commission addressed the need for a CWIP allowance due to extraordinary circumstances involving the Palo Verde nuclear plant. The Commission allowed approximately $200 million of APS's $600 million CWIP balance as a means of addressing a critical cash-flow deficiency, and as a means to lessen the severe rate shock that would be experienced by customers if the entirety of the nuclear plant were placed in rate base at one time.[3] Staff argues that UNS is not faced with a comparable cash-flow crisis, and that the $7 million of CWIP requested by the Company does not present a rate shock concern that would justify inclusion of CWIP in this case. We therefore decline the Company's request for rate base recognition of CWIP in this proceeding.

Post-Test-Year Plant

UNS proposes that, if its request for CWIP is denied, the Commission should alternatively allow inclusion of post-test-year plant in rate base. The Company argues that the Commission has approved post-test-year plant in a number of recent cases, and UNS faces faster growth than many other utilities in Arizona. Therefore, UNS argues that, absent inclusion of CWIP, the Commission should recognize inclusion of post-test-year plant.

Staff opposes the Company's proposal for reasons similar to the arguments raised on the CWIP issue. Staff witness Ralph Smith testified that the post-test-year plant arguments suffer from the same flaws as the request for inclusion of CWIP. He stated his belief that recognition of post-test-year plant would be imbalanced because it fails to capture post-test-year revenue growth and decreases in maintenance costs associated with the new plant (Ex. S-27 at 14-15).

[3] *Arizona Public Service Co.*, Decision No. 54247 (November 28, 1984), at 19-20.

We agree with Staff that post-test-year plant should not be included in rate base for the same reasons stated above with respect to the Company's request for CWIP. Although the Commission has allowed post-test-year plant in several prior cases involving water companies, it appears that the issue was developed on the record in those proceedings in a manner that afforded assurance that a mismatch of revenues did not occur. For example, in Decision No. 66849 (March 19, 2004), we stated that "we do not believe that adoption of this method would result in a mismatch because the post-test-year plant additions are revenue neutral (*i.e.*, not funded by CIAC or AIAC)" (*Id.* at 5). In the instant case, however, the Company's request appears to be simply a fallback to its CWIP position, and there is no development of the record to support inclusion of the post-test-year plant. The entirety of UNS's argument consists of two questions in Mr. Grant's direct testimony, which essentially provided that: the Commission has approved post-test-year plant in some prior cases, UNS is experiencing a high customer growth rate, and therefore the Company is entitled to inclusion of post-test-year plant if the Commission denies CWIP (Ex. A-27 at 28-29). Even if we were inclined to recognize post-test-year plant in this case, there is not a sufficient basis upon which to evaluate the reasonableness of the request (*i.e.*, whether a mismatch would exist). We therefore deny the Company's proposal on this issue.

Deduction of Customer Advances

The final issue raised in UNS's trilogy of CWIP-related issues is its plea that the Commission should not reduce rate base to recognize funds received for customer advances, if the Commission rejects UNS's request for CWIP or, alternatively, for post-test-year plant. The Company concedes that such advances are typically deducted from rate base because they represent customer-supplied capital. However, UNS contends that it has received approximately $4 million in customer advances related to the $7 million in CWIP plant investment (Ex. A-28 at 27). Thus, according to UNS, the net impact on rates (if the requested $7 million of CWIP were to be included in rate base) is $3 million, based on the net of the $7 million offset by $4 million in advances.

UNS argues that it is inherently unfair to exclude the advances from rate base if the plant associated with those advances is not yet in service and not included in rate base. UNS claims that the purpose of deducting advances (*i.e.*, recognizing customer-supplied capital) is not furthered when

the plant is not in service. The Company also contends that the deduction of advances in this case would discourage utilities from seeking advances to offset infrastructure capital costs.

Both Staff and RUCO oppose the Company's recommendation. Staff witness Ralph Smith states that because advances represent non-investor-supplied capital, they should be reflected as a deduction to rate base. He stated that Staff is not aware of any instance in which CWIP was excluded for a major utility in Arizona and customer advances were not reflected as a deduction to rate base. Mr. Smith also cites to A.A.C. R14-2-103, Appendix B, Schedule B-1, which he claims requires companies to reflect advances as a deduction from rate base (Ex. S-27 at 15-16).

RUCO witness Marylee Diaz Cortez agreed with Staff's recommendation regarding advances. She testified that the Commission has historically excluded CWIP from rate base and recognized contributions (advances) as a deduction from rate base and that UNS is being afforded (under RUCO's and Staff's recommendations) the same rate base treatment as every other utility in Arizona (RUCO Ex. 6 at 8). Ms. Diaz Cortez claims that it is only the Company's proposal to include CWIP which creates a mismatch, because UNS failed to include the additional revenues the construction projects generate (*Id.* at 8-9).

We agree with Staff and RUCO that advances represent customer-supplied funds that are properly deducted from the Company's rate base. Indeed, the Commission's own rules contemplate that such a deduction is required, as Staff witness Smith testified. Had UNS not requested the inclusion of CWIP in rate base, a ratemaking treatment that is only afforded under extraordinary circumstances (and apparently has not occurred for more than 20 years), there would presumably not have been an issue raised by the Company with respect to an alleged "mismatch" between exclusion of CWIP and deducting advances from rate base. The Company's attempt to frame this issue as one in which it is being treated in a discriminatory manner is unpersuasive.

As we have stated in prior cases, regulated utility companies control the timing of their rate case filings and should not be heard to complain when their chosen test periods do not coincide with the completion of plant that may be considered used and useful and therefore properly included in rate base. We believe our conclusions regarding UNS's CWIP-related proposals are entirely

consistent with the treatment that has been afforded to other utility companies regulated by the Commission and provide a result that is fair to both the Company and its customers.

Geographic Information System

UNS seeks to include in rate base $897,068 for expenses incurred during 2003 and 2004 to install a Geographic Information System ("GIS"). The GIS is a global positioning system that allows UNS to locate existing service lines. UNS witness Gary Smith testified that the Company installed the GIS in response to a Commission Pipeline Safety audit that recommended a complete mapping of the UNS system. He described several benefits of the GIS, including improved response times, better informed decisions regarding adding system infrastructure, and increased accuracy for field staff (Ex. A-15 at 6-7).

According to Staff witness Ralph Smith, the GIS costs should not be included in rate base because they were non-recurring expenses that were largely incurred outside of the test year. He explained that, according to internal Company memos, UNS initially decided to treat the GIS as a capitalized investment, but later determined that capitalization of the costs was inappropriate under Generally Accepted Accounting Principles ("GAAP"). Mr. Smith stated that, under GAAP, the GIS costs were required to be expensed during the period in which they were incurred and, since they were incurred prior to the test year, are not properly includable in rates (Ex. S-27 at 16-18).

RUCO also opposes inclusion of the GIS expenses in rates. RUCO witness Marylee Diaz Cortez stated that because UNS failed to obtain from the Commission an accounting order to treat the GIS expenses as a regulatory asset, which would be eligible for future rate recovery consideration, the Company is not entitled to recover those costs in this rate proceeding (RUCO Ex. 5 at 11-12; RUCO Ex. 6 at 9-10). RUCO argues that regardless of the Company's increased productivity claims, its failure to properly account for the GIS costs precludes recovery in UNS's rate base.

We agree with Staff and RUCO that the GIS costs are not properly recoverable as a regulatory asset in this proceeding. As described by Staff witness Ralph Smith, the GIS costs were required by GAAP to be expensed, and the vast majority of those costs were incurred prior to the test year and are non-recurring in nature (Ex. S-25 at 12-17). Further, the Company's failure to seek an accounting order from the Commission when the costs were incurred renders them unrecoverable as a regulatory

asset. As Mr. Smith points out, it is not unusual for investors to be responsible for expenses incurred between test years, just as the utility's investors may benefit from cost decreases and increased revenues during the same period (Ex. S-27 at 16-19). As both Staff and RUCO contend, there is nothing inherently unfair about the treatment afforded to the GIS costs in this case because costs and revenues are ever changing, and moreover, the improved efficiencies touted by UNS as a result of the GIS inure to the benefit of the Company's investors at least as much as to ratepayers. Finally, any blame for UNS's inability to recover those costs through rates lies with the Company's prior failure to properly account for the costs under GAAP accounting standards.

Plant in Service

Although Staff did not challenge the Company's proposed plant-in-service amounts, RUCO recommends the disallowance of approximately $3.1 million in plant that it considers unsubstantiated. UNS claims that it provided adequate documentation for the plant, but RUCO contends that the Company failed to provide records supporting increased plant balances recorded on the books of Citizens Utilities between the end of the last test year (December 31, 2001) and the date the Company acquired the system from Citizens (August 11, 2003).

According to RUCO, Citizens' gas plant in service was approximately $234 million at the end of 2001, and UNS has records to support $10.7 million of additional plant in service between the end of 2001 and June 30, 2003 (Ex. A-8 at 2; RUCO Ex. 1). RUCO claims that UNS has no records to support additional plant in service as of the date of the transfer, yet the Company booked approximately $248 million of plant in service as of the acquisition date of August 11, 2003 (Tr. at 192-93). UNS witness Karen Kissinger testified that certain electronic files provided to RUCO supported the higher plant value, but conceded that those files do not provide a means of reconciling the plant balances claimed as of the acquisition date (*i.e.*, $248 million) (Tr. at 194-95, 214). RUCO also disputes the Company's argument that the higher plant balances were approved by the Federal Energy Regulatory Commission ("FERC"), based on Ms. Kissinger's concession that the submission to FERC was not a request for approval of the specific plant amounts, but simply a request for confirmation from FERC that the amounts are recorded to the proper FERC accounts (Tr. at 198). Based on the evidence presented, RUCO requests a decrease of $3,133,264 in the Company's

proposed plant in service and a corresponding increase in accumulated depreciation of $3,857,413, (RUCO Ex. 3 at 12).

UNS contends that it provided adequate documentation to support its claimed plant-in-service balances for the period in question. The Company argues that, because Citizens was scrambling to wrap up its accounting for the final months at the time the sale was being finalized, it is not surprising that Citizens' records from that period were less extensive than normal (Tr. at 194-97). UNS relies on the electronic files provided to RUCO to support its position. The Company also points to testimony by RUCO witness Rodney Moore, who agreed that "records from Citizens are notoriously inadequate for a determination of the actual value of the pre-acquisition gross plant and accumulated depreciation" (RUCO Ex. 4 at 4). UNS asserts that other companies seeking post-acquisition approval of plant values based on Citizens' inadequate records have not been subject to downward adjustments[4], and that imposing downward adjustments on UNS would be inequitable. UNS also claims that the Commission's order approving the sale of the Citizens gas system assets to UNS did not include record retention requirements, although such requirements had been included in prior Commission Orders such as those related to the sale of Southern Union Gas Company's assets to Citizens (Ex. A-7 at 6).[5] Another argument raised by UNS is that it directly transferred the final plant-in-service values from Citizens' books to its own at the time of the acquisition. The Company contends that FERC's approval of UNS's accounting procedures and a subsequent audit of the Company's financial statements further support its claim that its proposed plant-in-service value is appropriate.

We find that UNS has explained adequately the basis for its plant-in service-proposal. As UNS witness Kissinger indicated in her rebuttal testimony, the acquisition of the Citizens assets was accounted for by UNS in accordance with applicable accounting standards, and the Company obtained a clean audit opinion regarding its financial statements from PricewaterhouseCoopers for the applicable period following the acquisition (Ex. A-7 at 2; Ex. A-6, Attach. KGK-1). The Company's accounting treatment was also approved by the accounting entries associated with the

[4] *See, e.g., Arizona –American Water Co.*, Decision No. 67093 (June 30, 2004).
[5] Decision No. 57647 (December 2, 1991), at 14.

acquired plant (Ex. A-7 at 4). UNS Gas provided sufficient documentation to support the amount of plant in service transferred from Citizens, and we therefore reject RUCO's proposed adjustment to plant in service.

Test Year Accumulated Depreciation

RUCO has also proposed increasing the Company's accumulated depreciation by approximately $2,855,454, due to RUCO's assertion that UNS improperly applied depreciation rates that were requested in the last rate case (Docket No. G-01032A-02-0598). That case was later suspended and combined with a joint application between UNS and Citizens for acquisition of the Citizens assets by UNS. The consolidated dockets ultimately resulted in a settlement agreement that was approved in Decision No. 66028 (July 3, 2003). RUCO argues that, because the settlement approved in Decision No. 66028 did not specifically mention new depreciation or amortization rates, UNS should apply the depreciation rates approved in the prior Citizens gas rate case in Decision No. 58664 (June 16, 1994). RUCO witness Moore cited to A.A.C. R14-2-102(C)(4), which states that changed depreciation rates shall not become effective until the Commission authorizes such changes. (RUCO Ex. 3 at 13-14). Accordingly, Mr. Moore proposed that test year accumulated depreciation should have been calculated as approved in the prior Citizens rate case, resulting in a reduction to the Company's OCRB of $2,855,454 (*Id.* at 14).

UNS argues that RUCO's recommendation fails to recognize that the Commission approved new depreciation rates in Decision No. 66028 which, as noted above, approved the sale of Citizens' gas system assets to UNS and approved a rate increase pursuant to the terms of a settlement agreement. Although the Commission did not explicitly approve new depreciation rates in Decision No. 66028, UNS contends that the settlement agreement contained a specific schedule showing how the revenue requirement was calculated. UNS witness Kissinger testified that the depreciation rates that formed the basis of the settlement were approved by the Commission and that no party objected to the depreciation rates in that case (Ex. A-7 at 9). Ms. Kissinger also attached to her testimony the schedule that formed the basis of the revenue requirement and explained on cross-examination that the updated depreciation expense adjustment was subsumed within operating expenses in the settlement agreement schedule (*Id.* at Attach. KGK-11; Tr. at 201-03).

We agree with UNS that the depreciation rates contained within the revenue requirement schedules, and attached to the settlement agreement, were implicitly approved in Decision No. 66028. Although Decision No. 66028 approved a "black box" settlement, in the sense that the specific revenue requirement issues were not discussed individually, the basis of the underlying revenue requirement was attached to the settlement agreement, and no party objected to the individual components of that revenue requirement. Accordingly, it was reasonable for UNS to apply the accumulated depreciation rates that were a component of the settlement. Indeed, RUCO witness Diaz Cortez admitted that the prior Citizens rate case order (Decision No. 58664) contained a specific discussion of only 2 of the 28 depreciation accounts and that it would thus be necessary to refer to the underlying application even in that case to ascertain the specific depreciation rates that were approved by the Commission in that order (Tr. at 673-74). We therefore reject RUCO's recommendation on test year accumulated depreciation.

Working Capital

As described by UNS witness Karen Kissinger, working capital is generally defined as "investor funding in excess of the balance of net utility plant reflected in rate base that is required for the provision of utility service" (Ex. A-6 at 10). The components of working capital include materials and supplies, prepayments, and cash working capital. The amounts for materials and supplies, and prepayments, are determined based on test year recorded balances, whereas the cash working capital component was determined by UNS based on a lead-lag study (*Id.* at 10-11).

Staff witness Ralph Smith summarized the concept of cash working capital as follows:

> Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation, a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds (Ex. S-25 at 18-19).

Based on Staff's proposed adjustments, Mr. Smith proposed a corresponding adjustment to the Company's cash working capital requirements. Staff's recommendation results in a cash working capital requirement of negative $268,272, in accordance with Staff's other recommendations in this case (Ex. S-27 at 20, Attach. RCS-2S).

In its initial brief, UNS points out that a number of ratemaking adjustments will have an effect on the Company's working capital requirement. UNS also contends that RUCO's proposed working capital proposal should be rejected because RUCO failed to use a simultaneous equation to compute two elements of cash working capital: synchronized interest and current income taxes (Ex. A-7 at 12).

In its reply brief, RUCO responded that its schedules did account for synchronized interest in both the working capital and income tax calculations. RUCO cites to Mr. Moore's schedules to support its claim (RUCO Ex. 3, Sched. RLM-3, Line 15; Sched. RLM-14, Lines 3, 8, and 18; and Sched. RLM-6, Line 8).

It does not appear from the record that the parties are in disagreement with regard to the underlying working capital requirements, subject to the various adjustments that necessarily flow from the revenue requirement established in this Decision. The working capital requirement has been determined in accordance with the revenue requirement established in this Order.

Accumulated Deferred Income Tax

Based on its recommendations in this case, Staff adjusted rate base by $195,336 to account for removal of accumulated deferred income tax ("ADIT") related to the GIS deferral issue, removal of ADIT related to the Supplemental Executive Retirement Plan, and removal of 50 percent of the ADIT related to incentive compensation (Ex. S-25 at 19). Staff claims that UNS did not contest these ADIT adjustments, which Staff asserts are necessary to reconcile rate base with the components of operating income adjustments.

In its brief, UNS does not address the ADIT issues raised by Staff, which are reconciliation adjustments flowing through from several operating income issues and are addressed below. However, the Company does take issue with RUCO's alleged failure to make corresponding adjustments to ADIT and deferred income tax expense (Ex. A-7 at 11-12). Because RUCO did not address this issue in its briefs, presumably, it does not oppose the Company's position.

Based on the record before us, we agree that the appropriate reconciliation adjustments should be made to reflect the effect on ADIT and income tax expense in accordance with this Decision.

Summary of Rate Base Adjustments

Based on the foregoing discussion, we adopt an adjusted OCRB of $154,604,408 and a Fair Value Rate Base ("FVRB") of $184,120,761.

	Commission Approved
ORIGINAL COST:	
Gas Plant in Service	$271,980,463
Less: Accumulated Depreciation	(72,006,708)
Net Plant in Service	199,973,755
Citizens Acquisition Discount	(30,709,738)
Less: Accum. Amort. – Citizens Acq. Disc.	(1,876,981)
Net Citizens Acq. Discount	(28,832,757)
Total Net Utility Plant	171,140,998
Deductions:	
CIAC	(7,283,595)
Customer Deposits	(3,040,484)
Accum. Deferred Income Taxes	(6,289,473)
Allowance for Working Capital	(211,136)
Regulatory Liabilities	(19,721)
Total Deductions	(16,844,409)
Additions:	
Regulatory Assets	307,819
Total OCRB	$154,604,408
RCND[6] RATE BASE:	
Gas Plant in Service	$367,054,190
Less: Accumulated Depreciation	(97,114,865)
Net Plant in Service	269,939,325
Citizens Acquisition Discount	(41,822,562)
Less: Accum. Amort. – Citizens Acq. Disc.	(2,560,308)
Net Citizens Acq. Discount	(39,262,254)
Total Net Utility Plant	230,677,071
Deductions:	
CIAC	(7,786,962)
Customer Deposits	(3,040,484)
Accum. Deferred Income Taxes	(6,289,473)
Allowance for Working Capital	(211,136)
Regulatory Liabilities	(19,721)

[6] Reconstruction New (less) Depreciation

Total Deductions	(17,347,326)
Additions:	
Regulatory Assets	307,819
Total RCND	$213,637,114
FAIR VALUE RATE BASE:	
Gas Plant in Service	$319,517,327
Less: Accumulated Depreciation	(84,560,787)
Net Plant in Service	234,956,540
Citizens Acquisition Discount	(36,266,150)
Less: Accum. Amort. – Citizens Acq. Disc.	2,218,645
Net Citizens Acq. Discount	(34,047,505)
Total Net Utility Plant	200,909,035
Deductions:	
CIAC	(7,535,279)
Customer Deposits	(3,040,484)
Accum. Deferred Income Taxes	(6,289,473)
Allowance for Working Capital	(211,136)
Regulatory Liabilities	(19,721)
Total Deductions	(17,096,093)
Additions:	
Regulatory Assets	307,819
Total FVRB	$184,120,761

Operating Income Issues

In the test year, the Company's reported operating revenues were $47,169,528, with reported adjusted test year operating expenses of $38,740,547, and test year net operating income of $8,428,981. As reported in its Surrebuttal Schedules, Staff's proposed adjusted test year operating revenues were $47,273,923, with adjusted test year operating expenses of $37,373,543, resulting in test year net operating income of $9,900,380. RUCO's Final Schedules show proposed adjusted test year operating revenues of $50,014,877, with adjusted test year operating expenses of $38,124,962, yielding test year net operating income of $11,889,914. The disputed expense adjustments are discussed below.

Revenues

Customer Annualization

UNS has proposed in this case to calculate customer revenue annualization based on a cyclical growth pattern, which the Company contends more accurately reflects its actual experience

in its service territory. Company witness D. Bentley Erdwurm described the traditional approach of customer annualization as a comparison of customer counts in each month of the test year to the end of test year level of customers. Under this approach, the additional customers attributable to each month are multiplied by the average revenue per customer for each month to obtain the additional revenue attributable to the additional customers (Ex. A-20 at 2). Mr. Erdwurm testified that the traditional method works well when growth is steady and additional customers are similar in size to existing customers, but breaks down when a company, such as UNS, experiences cyclical seasonal growth (*Id.*). He conceded that the Commission has never before adopted a revenue annualization method such as the one advocated by UNS. However, he contends that the Company's proposed methodology is appropriate in this case because "in cases of cyclical growth, the mathematics break down and...[the traditional method] will often give you a totally counterintuitive result, where you would actually have a negative customer adjustment on a growing system" (Tr. at 447).

Staff and RUCO oppose adoption of the Company's annualization proposal. RUCO argues that although the Company's customer levels are somewhat seasonal, they do not exhibit a degree of seasonality or produce an aberrational result that would make the traditional method inappropriate. Ms. Diaz Cortez pointed out that the customer base for UNS's largest rate schedule, R10, increased from month to month for every month except April, May, and July, and that the decreases in those months ranged from .09 percent to .28 percent (RUCO Ex. 6 at 12, Sched. MDC-1). RUCO asserts that these changes do not exhibit an extreme level of seasonality that would justify departure from the traditional method advocated by RUCO and Staff.

Staff witness Ralph Smith testified that the traditional method of customer annualization has been effective in coordinating the revenue element of the ratemaking formula with other components, such as rate base, and that many of the Company's arguments are without merit (Ex. S-27 at 19-21). According to Mr. Smith, any method for determining an annualization adjustment should be transparent and straightforward to allow replication and verification of the results. He contends that while the traditional method satisfies these criteria, UNS's proposal to apply percentage growth factors instead of customer bill counts is difficult to follow and replicate and actually appeared to understate growth (*Id.* at 24).

We agree with Staff and RUCO that UNS has not presented a valid case for departing from the traditional method of calculating customer revenue annualization. Although the Company's arguments may have some validity in a theoretical sense, adoption of the cyclical methodology is not warranted in this proceeding. RUCO and Staff highlighted some of the flaws inherent in the Company's proposal, including the lack of any significant demonstrated seasonality, the complexity of the formula, lack of transparency, and the claim by the Staff witness that the methodology may actually result in an understatement of revenues. We therefore decline to adopt UNS's revenue annualization proposal.

Weather Normalization

Staff witness Ralph Smith stated that Staff's weather normalization adjustment increases retail revenue by $1,962, compared to UNS's proposal, because, in Staff's annualization, the weighted average number of customers exceeded the level reflected in the Company's corresponding annualization. Mr. Smith claims that both the Staff and UNS weather normalization adjustments reflect an increase to revenue due to warmer than normal temperatures during the test year (Ex. S-27 at 25).

In its brief, UNS states that the weather normalization adjustment should reflect the other positions taken herein, including the customer annualization adjustment proposed by the Company.

Although RUCO accepts the Company's proposed weather normalization, it proposes a further adjustment of $900 related to the additional customers/revenue the Company proposes be recognized as a result of its customer annualization proposal (RUCO Ex. 6 at 16).

It is not entirely clear whether the weather normalization issue remains in dispute given our determination above that the Company's customer annualization recommendation should not be adopted. To the extent that there is any remaining disagreement on this issue, we adopt Staff's weather normalization recommendation in accordance with the discussion above regarding customer annualization.

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Expenses

Legal Expenses Related to FERC Rate Case

During the 2005 test year, UNS incurred legal expenses of $311,051 related to settlement discussions involving an El Paso Natural Gas Company ("El Paso") FERC rate case. The El Paso case eventually settled, and due to the non-recurring nature of those legal expenses, both Staff and RUCO recommended removal of that amount from allowable expenses in this case (Ex. S-15 at 30; RUCO Ex. 5 at 21).

UNS witness Dallas Dukes testified that Staff's and RUCO's recommendations would set the Company's legal expenses at an amount well below the expected ongoing level (Ex. A-13 at 17). As an alternative, he proposed an allowance of $430,777 (pre-tax), which represents a two-year average of legal expenses actually incurred by UNS for 2004 and 2005 (*Id.* at 18). Mr. Dukes stated that the actual legal expenses incurred by UNS were $373,174 for 2004, $488,380 for 2005, and $425,540 for 2006, and that its projected legal expenses for 2007 are $425,208 (*Id.*; Ex. A-14 at 9).

We believe that the Company's allowable legal expenses should be set at a level that reflects more accurately its actual experience, both historical and anticipated. Staff and RUCO make a valid argument that the legal expenses incurred during 2005 were higher than normal due to the Company's participation in the El Paso rate case and that such expenses are likely non-recurring in nature. However, the RUCO and Staff recommendations fail to recognize that even after completion of the El Paso case, UNS incurred legal expenses of more than $400,000 in 2006 and is expected to do so again in 2007, legal expenses of in each year. Thus, even if 2005 is removed as an anomaly, actual legal expenses for 2004 and 2006 and projected legal expenses for 2007 produce an average of slightly more than $400,000 per year. We therefore believe it is reasonable, based on the record, to allow legal expenses of $400,000 to UNS in this case.

Rate Case Expense

UNS initially requested inclusion of $600,000 for rate case expense, amortized over three years. However, in his rebuttal testimony, Mr. Dukes amended the request to $900,000, amortized over three years, based on the Company's claim that UNS had already incurred almost $800,000 in costs related to pursuing its rate case (Ex. A-13 at 34-35). UNS contends that the proposals offered

by Staff and RUCO ($255,000 and $251,000, respectively), which are based primarily on comparisons to the recent Southwest Gas rate case (Decision No. 68487), are deficient because they fail to recognize that Southwest Gas used internal personnel and support services, internal costs that are built into Southwest Gas' rate base. In comparison, UNS does not have in-house legal or rate departments, but instead relies heavily on the rate and legal personnel of Tucson Electric Power Company ("TEP") to prosecute its rate cases. Mr. Dukes testified that an allocation from TEP for such costs ensures that TEP customers do not subsidize UNS operations (*Id.*; Ex. A-14 at 9-11). Mr. Dukes added that UNS Gas received more than twice as many data requests as did Southwest Gas (Tr. at 632).

RUCO witness Moore stated that RUCO's recommendation in this case is appropriate based on a comparison to the recent Southwest Gas rate case, in which the approved rates included an allowance for $235,000 allocated over three years (RUCO Ex. 3 at 25-26). RUCO contends that the UNS case shares similar characteristics with the Southwest Gas case in that both companies extensively used in-house staff, both companies requested approval of a decoupling mechanism and PGA revisions, and both cases covered a comparable number of hearing days (*Id.*; Tr. at 655). RUCO therefore recommends a rate case expense allowance of $251,000, amortized over three years.

As indicated above, Staff recommends a rate case expense allowance of $255,000, amortized over three years, based on Staff's view that the Southwest Gas case raised many of the same issues addressed in this proceeding. Staff witness Ralph Smith disputed the rationale offered by UNS for its proposed rate case expense. Mr. Smith stated that although this may be the first rate case for this gas company under its current ownership, the Company had a number of prior periodic rate cases when it was owned by Citizens Utilities. He contends that the transfer of ownership to UNS should not be used as a basis for imposing "excessive" rate case costs (Ex. S-27 at 42-43). Mr. Smith also testified that because the UNS rate case presents many issues that are similar to those considered in the Southwest Gas case (such as a proposed decoupling mechanism and revisions to the PGA), the rate case expense allowed in that case is a useful benchmark for the UNS case (*Id.*). On cross-examination, Mr. Smith also expressed a concern with the overall allocation methodology used by TEP for UNS expenses. He testified that the direct allocation methodology used by TEP may result

in a double recovery, to the extent that the same personnel are used for different companies, because "it could potentially result in loading a disproportionate amount of their cost onto each utility to their rate case they are working on" (Tr. at 896-97). He conceded that the Commission should allow an appropriate level of rate case costs, but indicated that "this is a potential cost here that can get totally out of control if some limits aren't placed on it" (Tr. at 898).

We agree with Staff and RUCO that the Company's proposed rate case expense of $900,000 is excessive and should be reduced significantly. As both Staff and RUCO suggest, the recent Southwest Gas case presented many of the same issues that were raised in this case, and the Southwest Gas case is an appropriate measure of comparison for UNS. In response to the Company's claim that Southwest Gas employed a different method of allocating such costs, and was therefore not comparable to UNS, Staff witness Smith pointed out potential problems with the method used by TEP to allocate costs such as rate case expense. We believe that proposed rate case expense of $900,000 is excessive when compared with similar rate case expense allowances in a long line of cases before the Commission. Although Staff and RUCO present strong arguments in support of their recommendations, given that this is the first UNS Gas rate case since the acquisition of the Citizens assets, and that UNS was required to respond to a substantially higher number of data requests than was Southwest Gas, we allow rate case expense of $300,000, amortized over three years.

Customer Call Center Expenses

During the test year, on May 1, 2005, UNS changed its method of responding to customer calls by implementing a consolidated call center operated by TEP, with a level of costs allocated to UNS. RUCO witness Moore stated that prior to May 1, 2005, UNS Gas operated its call center separately, using 6 customer service representatives at a cost of $17,636 per month (RUCO Ex. 3 at 20). After consolidation of the call center, UNS began to incur allocated costs of $76,227 per month (*Id.*). The Company also subsequently closed walk-in customer service offices in Prescott,

Cottonwood, Flagstaff, and Show Low, thereby requiring customers in those areas to use "payday loan"[7] stores if they want to pay their bills in person (Tr. at 418).

UNS witness Dallas Dukes stated that the consolidated call center provides a higher level of service to customers and indicated that the prior individualized system would have required a significant investment in new systems to respond to rapid growth in the Company's service area. Mr. Dukes cited a number of benefits of the consolidated operations, including the ability to handle increased call traffic, which has nearly doubled since the prior individual operations were in place; expanded service hours; a credit card payment option; call volume tracking ability; and one number availability for gas and electric customers in Mohave and Santa Cruz counties (Ex. A-13 at 29-30). In response to RUCO's claims that customer complaints have increased since the new call center was put in place, Mr. Dukes stated that the primary driver of the increased call volumes was higher gas costs that flowed through to customers. He reiterated that the former individual office format could not have handled the increased volume of calls and that the old system would have required increased staffing and investment to keep up with service demands (Ex. A-14 at 16).

RUCO witness Moore disagrees with the Company's contention that the consolidated call center provides increased customer service. He claims that in 2004, prior to the call center consolidation, 13 percent of the 178 total complaints against the Company related to customer service; in 2005, when the new call center was introduced, 22 percent of the 172 total complaints related to customer service; and in 2006, 17 percent of the 143 total complaints[8] related to customer service (RUCO Ex. 4 at 11; Tr. at 614-15). Based on this data, RUCO argues that UNS is providing worse customer service under the new call center format, despite a 432 percent increase in costs. Accordingly, RUCO recommends that the Company's customer service costs should be reduced to the level incurred prior to the introduction of the consolidated call center.

We do not believe that the record supports the disallowance sought by RUCO on this issue. RUCO's analysis is based on a simple comparison of complaint data and system costs, but does not

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[7] The payday loan store issue is discussed in detail below. UNS currently retains walk-in company offices in Nogales, Kingman, and Lake Havasu.

[8] Mr. Dukes claims that the Company's records reflect 120 UNS Gas complaints in 2005 and 149 complaints in 2006 (Ex. A-14 at 16).

consider the underlying reasons why consolidation to a modernized call center was necessary. The Company's witness cited a number of advantages associated with the new call center operations and pointed out that RUCO's proposal fails to account for the doubling of call volume since the new system was put in place and does not include recognition of the additional investment that would have been required to update the prior decentralized system of customer service. Although we believe that the consolidated call center costs should be allowed in the Company's expenses in this case, we have ongoing concerns regarding UNS's decision to close a number of local offices and farm out its customer service obligations to payday loan stores, as discussed below.

Miscellaneous "Unnecessary" Expenses

RUCO witness Rodney Moore presented testimony requesting that the Company's test year expenses should be reduced by $233,347 for expenses that were "questionable, inappropriate and/or unnecessary" (RUCO Ex. 3 at 22). Mr. Moore claims that his proposed adjustment is related to payments made to chambers of commerce and non-profit organizations and for donations; club memberships; gifts; awards; extravagant corporate events; advertising, and various meals, lodging and refreshments (*Id.*). He cites a sampling of the 1,995 questionable expenses, which include $1,200 for two people to play in a Flagstaff golf tournament, $5,750 for an employee appreciation dinner, $1,000 for Toys for Tots, $3,058 for the Flagstaff Chamber of Commerce, and $1,246 for a chartered air flight (*Id.* at 23).

In response to RUCO's claims, UNS witness Gary Smith testified that most of the expenses related to travel for "regulatory-mandated functions such as leak surveys, safety audits, and training"; that other expenses included "participation in the annual mandatory Commission Pipeline Safety audit and required operator qualification training, welder qualification training, and emergency response testing"; and that many of the remaining expenses are for "small tools that are necessary for maintaining the pipeline system" (Ex. A-16 at 5-6). UNS argues that Mr. Moore did not respond to Mr. Smith's explanation but, instead, attacked Mr. Dukes' suggestion that RUCO should limit its audit to material items because 90 percent of the challenged expenses are under $200 and 65 percent under $50 (Tr. at 636). The Company asserts that RUCO's demand for a specific explanation of why each claimed expense is reasonable is "profoundly unreasonable," (UNS Initial Brief at 25), because

RUCO did not consider the cost of preparing such a response and could have pursued alternate means of verification during discovery. However, in an attempt to appease RUCO, UNS witness Smith stated in his rejoinder testimony that the Company would agree to a disallowance of $27,968 (Ex. A-17 at 3).

This issue is eerily similar to the position taken by Southwest Gas in its last rate case, wherein its witness attempted to deflect the burden of proving the reasonableness of Southwest Gas's claimed expenses for a number of "small ticket" items including jeep tours, balloon rides, club memberships, charitable donations, sports events, barbecues, flowers, and various food and drinks expenses. In that case, the Southwest Gas witness agreed to exclude what she perceived to be clearly inappropriate miscellaneous expenses, but indicated that many of the expenses were too small for even the company to determine whether they should be included in cost of service. Southwest Gas's witness therefore concluded that RUCO had not presented sufficient evidence to support its proposed disallowance. Here, UNS makes an almost identical argument, claiming that because the costs individually are too small to track, RUCO's recommendation must fail. In the Southwest Gas Decision (Decision No. 68487 at 19-21), we rejected that argument, finding that Southwest Gas had not met its burden of proof. As we stated in Decision No. 68487, "[i]t is curious that Southwest Gas seeks to cast the burden of proving the unreasonableness of expenses on RUCO, especially once RUCO has provided some evidence that certain claimed expenses are inappropriate and which evidence, by the Company's own admission, should result in additional exclusions" (*Id.* at 21).

Consistent with the Southwest Gas Decision, we find that a portion of the claimed expenses in this "miscellaneous" category should be disallowed because UNS failed to meet its burden of proof as to their validity. Recognizing that many of the expenses appear to be legitimate expenses related to training, safety, and maintenance, however, we disallow half of RUCO's proposed disallowance ($233,347 x 50% = $116,674). While it may seem unfair for a utility company to be required to come forward with supporting evidence regarding the reasonableness of even small expenses, when the Company is seeking to place the burden of such expenses exclusively on the backs of its customers, it is required to prove that the expenses were reasonably necessary for the provision of service to those customers. If we were to adopt UNS's rationale regarding these relatively small,

miscellaneous expenses, it would be akin to proclaiming the acceptability of the proverbial "death by 1,000 cuts."

Performance Enhancement Program

UNS allows its non-union employees to participate in its parent company's Performance Enhancement Program ("PEP"), which provides eligible employees compensation above their base pay for meeting financial targets (30 percent), cost containment goals (30 percent), and customer service goals (40 percent) (Ex. A-13 at 8-9). Company witness Dukes claims that the PEP is an integral part of its compensation package for employees and that UNS would be required to increase base salaries to attract and retain qualified employees if the program were eliminated (*Id.*).

Staff proposes to adjust the PEP expenses by 50 percent, based on Staff's claim that incentive compensation programs benefit both ratepayers and shareholders. Staff cites to the Southwest Gas Decision to support its position. In that case, the Commission adopted Staff's recommendation to disallow 50 percent of a similar program's costs, based on a finding that the Southwest Gas management incentive program benefited both customers and shareholders. Staff witness Ralph Smith stated that there is no relevant distinction between the UNS and Southwest Gas incentive programs and that the 50/50 sharing of costs is equally appropriate in this case (Ex. S-25 at 29).

RUCO proposes a complete disallowance of the PEP costs, based on its claim that it is not clear that the program is necessary to achieve the PEP's goals. RUCO witness Moore testified that during the test year (2005), no PEP payments were made because UniSource did not meet the program's financial goals. However, the UniSource Board of Directors authorized payment of a Special Recognition Award ("SRA") in 2005 to the employees eligible for the PEP. As a result, UNS is seeking in this proceeding to recover the average of the 2004 PEP payments and the 2005 SRA costs. Mr. Moore contends that the SRA is unique and does not meet the criteria of a typical and recurring test year expense for which rate recovery should be granted (RUCO Ex. 3 at 16-17). He also stated that 60 percent of the PEP payments are related to financial performance and cost containment, which are goals that primarily benefit shareholders. Finally, Mr. Moore asserts that because the PEP does not apply to 60 percent of its employees (*i.e.*, union employees), it is not clear that the program is necessary or will achieve the stated goals (*Id.*; RUCO Ex. 4 at 8).

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. However, 40 percent 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. For the same reasons, we also adopt Staff's recommendation to disallow 50 percent of the Officer's Long-Term Incentive Program (Ex. S-25 at 26).

Although we believe, on balance, that the 50/50 sharing is reasonable, we share RUCO's concerns that the SRA offered to employees in 2005 may have the effect of undermining the very goals the PEP is intended to achieve (*i.e.*, providing an incentive for participating employees to improve performance and thereby benefit both the Company and its customers). As described by Mr. Moore, despite failing to meet the PEP goals, the UniSource Board of Directors decided nonetheless to provide the affected employees with a surrogate means of compensation. It appears that the SRA sends a signal to employees that they will be compensated regardless of performance, which places the entire premise of the PEP at issue. We expect the program to be scrutinized in the Company's next rate case to determine the appropriateness of providing incentive compensation above base salaries to employees.

Supplemental Executive Retirement Plan

UNS Gas allows select executives to participate in a Supplemental Executive Retirement Plan ("SERP"). The SERP provides to eligible executives retirement benefits in excess of the limits allowed under Internal Revenue Service ("IRS") regulations for salaries in excess of specified amounts. UNS contends that the SERP costs are reasonable and that neither Staff nor RUCO have shown that the Company's overall executive compensation costs are excessive or out of line with industry standards.

Staff and RUCO recommend disallowance of the SERP costs ($93,075), in accordance with the Commission's Decision in the Southwest Gas case (Decision No. 68487, at 18-19). In that case, we disallowed Southwest Gas's SERP costs, finding:

> [T]he provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. (*Id.* at 19).

We disagree with the Company's argument that disallowance of the SERP costs effectively allows the IRS to dictate what compensation costs should be recovered. As was clearly stated in the passage cited above, the issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case,[9] and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

More disturbing than the Company's advocacy on the relative merits of the SERP is the statement in its initial brief that "[h]ad UNS Gas been notified that SERP costs would not be allowed, it could have restructured its executive compensation package to take that into account. It would not be fair to hold UNS Gas to this new, unexpected standard." (UNS Initial Brief at 28.) Implicit in the Company's argument is the concept that "if we don't recover fully what we believe are our reasonable costs in our preferred manner, we'll simply shift those costs to another account to disguise the costs and ultimately ensure recovery." The approach to rate recovery seemingly advocated by UNS can serve only to increase the cynicism often expressed by ratepayers regarding the reasonableness of a given utility company's proposed rates and, if allowed, would at its essence turn the ratemaking process into a veritable regulatory version of "Three-Card Monte." We trust that in

[9] *See also Arizona Public Service Co.*, Decision No. 69663, at 27 (June 28, 2007), wherein SERP costs were excluded in their entirety.

future rate applications, Staff and RUCO will explore thoroughly the merits of individual expenses sought by UNS, as well as other companies, to ensure that customers are paying rates that include only the costs necessary to provide quality service.

Fleet Fuel Expense

UNS witness Dukes proposed that the Company's fleet fuel expense be established based on an average gasoline cost of $2.48 per gallon (Ex. A-13 at 19). Mr. Dukes stated that the average fuel price used by UNS reflects the Company's actual costs and that lower cost recommendations made by Staff and RUCO should be rejected. He testified that it is not surprising that UNS would have slightly higher fuel costs than some other utilities because the UNS Gas service area is farther from large metropolitan areas like Phoenix and Tucson and covers a larger number of square miles given its more rural location (*Id.*). In response to a proposed disallowance made by Staff witness Ralph Smith, Mr. Dukes reduced the Company's request by $12,657 (pre-tax) (*Id.* at 23-24).

In his surrebuttal testimony, Staff witness Smith agreed with Mr. Dukes' proposed reduction to fleet fuel expense (Ex. S-27 at 39). Although Staff appears to have reconciled its recommendation with the Company on this issue, UNS's brief continues to advocate rejection of Staff's position (UNS Initial Brief at 29-30). We assume that the Company failed to notice Mr. Smith's surrebuttal testimony agreeing with Mr. Dukes' rebuttal testimony, and we believe that there is no remaining dispute between UNS and Staff.

RUCO agrees that it is appropriate for UNS to annualize its fuel expense to reflect additional employees included in its payroll annualization adjustment. However, RUCO witness Diaz Cortez stated that because gasoline prices were abnormally high in early 2006, the Company's calculation inflated the annualized level of fuel expenses (RUCO Ex. 5 at 14-15). Instead of the proposal to base fuel expenses on an average of $2.48, RUCO recommends using $2.43 per gallon as the average cost (*Id.* at Sched. MDC-3). In addition, RUCO claims that UNS understated the actual miles per gallon (10.28 mpg) achieved by the UNS fleet (*Id.* at 15). On cross-examination, Mr. Dukes admitted that the Company did not respond to the second part of RUCO's recommendation (*i.e.*, the UNS fleet miles per gallon) (Tr. at 241-42). Nor did UNS address the miles per gallon issue in its brief.

We find that the Company has adequately supported the use of $2.48 per gallon as the basis for determining its fleet fuel costs in this proceeding. However, as Ms. Diaz Cortez pointed out, UNS did not respond to the second part of the RUCO recommendation dealing with fleet miles per gallon. We will therefore adopt RUCO's proposal to use the actual 2005 fleet miles per gallon as set forth in Ms. Diaz Cortez's schedules, adjusted by the inclusion of the $2.48 per gallon gasoline price recommended by UNS and Staff.

Bad Debt Expense

In its initial brief, UNS states that although the Company and Staff are in agreement as to the appropriate level of bad debt expense, RUCO's proposal to disallow $100,000 is based on a mismatch and should be rejected (UNS Initial Brief at 29). Ms. Diaz Cortez agreed in her surrebuttal testimony that "the numerator and the denominator of the bad debt ratio would have to be adjusted to remove the NSP and Griffith Plant" (RUCO Ex. 6 at 13). It appears that UNS failed to recognize RUCO's surrebuttal testimony on this issue and, as a result, continues to advocate rejection of a position RUCO conceded before the commencement of the hearing. Since there is no remaining disputed issue, we adopt the Company's recommendation on this issue.

Postage Expense

UNS proposed inclusion in operating expenses of $529,380 for postage costs, based on a two-year average (2005 and 2006) and including acknowledgement of a postal increase that became effective May 14, 2007 (from $.39 to $.41) (Ex. A-13 at 19-21).

In his surrebuttal testimony, Staff witness Ralph Smith modified an earlier adjustment and agreed with UNS that the postage expense starting point of $445,171 is appropriate, which produces an annualized postage expense of $476,960 to reflect a January 8, 2006 postage increase as well as customer growth that occurred during the test year. In addition, Mr. Smith agreed that the May 14, 2007, increase should be recognized, resulting in an overall postage allowance of $503,356 (Ex. S-27, at 39-40). The difference of $26,024 between the UNS and Staff recommendations relates to the Company's proposal to reflect the impact of 2006 postage expense. Mr. Smith stated that customer growth should only be reflected through the 2005 test year because inclusion of customer growth in

2006, without considering the commensurate growth in revenues, would result in an inappropriate mismatch (*Id.*).

RUCO witness Rodney Moore proposed an adjustment comparable to that proposed by Staff (RUCO Ex. 4 at 9). Like that of Staff, RUCO's adjustment is based on the use of historic test year levels, annualized for increases in customer levels and adjusted for known and measurable postal rate increases. As reflected in its final schedules (Final Sched. RLM-9), RUCO's recommendation is for an allowance of $502,018.

It is not clear whether the UNS initial brief recognized the adjustments made by Staff and RUCO in their surrebuttal testimonies, because the UNS brief states that the Staff and RUCO positions should be rejected due to "several errors" (UNS Initial Brief at 30). As described above, both Staff and RUCO eventually agreed with all of the Company's arguments on this issue except one: whether customer growth beyond the test year should be recognized in establishing postage expense. UNS did not address in its reply brief the arguments made in the Staff and RUCO initial briefs, so it is possible the Company is now in agreement with the Staff and RUCO recommendations on this issue. We agree with Staff and RUCO that customer growth should be recognized only through the end of the test year because to do otherwise would result in a clear mismatch between expenses and revenues under the Company's proposal. Although the Staff and RUCO recommendations result in slightly different amounts ($1,338 difference), the reason for the difference is not clear. We therefore adopt Staff's postage expense recommendation of $503,356.

Depreciation and Property Taxes for CWIP

Staff made adjustments to remove the Company's proposed pro forma amounts for depreciation and property taxes related to the request to include CWIP or, alternatively, post-test-year plant (Ex. S-27 at 26). Given our denial of the CWIP and post-test year plant proposals, Staff's adjustments are adopted.

Overtime Payroll Expense

Staff witness Ralph Smith recommended an adjustment to reduce the Company's proposed test year overtime payroll expense by $123,010 (Ex. S-25 at 28). The adjustment relates to Staff's normalization of the overtime payroll expenses (*Id.*). In his Rebuttal testimony, UNS witness Dukes

agreed with Staff's proposal, conceding that Staff's recommendation is more reflective of expected overtime levels (Ex. A-13 at 17). Staff's recommendation is adopted.

Payroll Tax Expense

Staff witness Ralph Smith proposed a reduction to the Company's pro forma payroll tax expense by $9,348 to reflect Staff's adjustments to overtime payroll and incentive compensation expenses (Ex. S-27 at 34). Consistent with Staff's recommendations on the overtime payroll and incentive compensation issues, Staff's payroll tax expense adjustment is adopted accordingly.

Property Tax Expense

UNS proposed the use of a property tax rate of 24.5 percent (Ex. A-13, Attach. DJD-1). Both Staff and RUCO recommend setting allowable expenses for property tax based on a rate of 24.0 percent. Staff witness Ralph Smith testified that Staff's recommendation is based on the known and measurable assessment for 2007, pursuant to legislation passed by the Arizona State Legislature that reduces property tax assessments from a rate of 25 percent in 2005 by .5 percent in each successive year until a rate of 20 percent is achieved in 2015 (Ex. S-27 at 35-36). Mr. Smith stated that the Company's proposal fails to recognize the impact of the known tax change. He also indicated that Staff's recommendation is consistent with the recent Southwest Gas rate case (which had a test year ending August 31, 2004), wherein Southwest Gas, Staff, and RUCO agreed that a 24.5 percent assessment for the 2006 rate was appropriate for the calculation of property tax expense (*Id.*). RUCO witness Rodney Moore also proposed use of a 24.0 percent assessment rate for UNS in this case, based on the same rationale described by Mr. Smith (RUCO Ex. 4 at 14).

We agree with Staff and RUCO that the property tax expense allowance in this case should be based on the known and measurable assessment rate currently in effect. The rate for 2007 is currently 24.0 percent, and the rate will continue to decline in subsequent years while the rates established in this case are in effect. The Staff and RUCO recommendations are therefore adopted.

Membership and Industry Association Dues

UNS initially included $41,854 for dues paid to the American Gas Association ("AGA"). In his direct testimony, RUCO witness Moore recommended a partial disallowance of $1,523 of the

AGA dues based on an AGA/NARUC[10] Oversight Committee Report indicating that 1.54 percent of AGA dues are used for marketing and that 2.10 percent of dues are allocated for lobbying activities (RUCO Ex. 3 at 26-29). In his Rebuttal testimony, UNS witness Dukes agreed with Mr. Moore's proposed adjustment and revised the Company's proposed expenses in accordance with RUCO's recommendation (Ex. A-13, at 18-19).

Staff witness Ralph Smith recommended a larger percentage disallowance of the AGA dues and also proposed eliminating dues paid by the Company to a number of other organizations (primarily for dues to a number of local Chambers of Commerce within the UNS service area) (Ex. S-27 at 37-39; Sched. C-14). Mr. Smith stated that Staff's more aggressive disallowance proposal is based on language in the Southwest Gas Order, (Decision No. 68487, at 14), which admonished Southwest Gas in its next rate case to "provide a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the Company and its Arizona Ratepayers." Mr. Smith acknowledged that the Southwest Gas Order disallowed only the marketing and lobbying portions of the AGA dues (3.64 percent), consistent with RUCO's recommendation in this proceeding. However, he believes UNS should have been on notice to provide additional details regarding AGA activities, which the Company failed to supply. Mr. Smith based his 40 percent disallowance on 1999 and 2000 NARUC audit reports of AGA expenditures (which appear to indicate that approximately 40 percent of AGA dues are used for marketing and lobbying efforts) and on a decision issued by the Florida Public Service Commission disallowing 40 percent of AGA dues from expenses (Ex. S-25 at 34-37, Sched. RCS-3; Ex. S-27 at 37-39).

Mr. Smith raises a valid point regarding the nature of AGA dues and whether a higher percentage of such dues should be disallowed as related to activities that are not necessary for the provision of service to UNS customers. However, we believe it is reasonable, in this case, to allow $40,331 ($41,854 - $1,523), in accordance with RUCO's recommendation. As we indicated in the Southwest Gas Order, however, we expect UNS in its next rate case to provide more detailed support

[10] National Association of Regulatory Commissioners

for allowance of AGA dues and how the AGA's activities benefit the Company's customers aside from marketing and lobbying efforts.

With respect to Mr. Smith's proposal to disallow a number of smaller dues to Chambers of Commerce and similar organizations, we believe these types of expenses are encompassed within RUCO's recommendation regarding so-called "unnecessary" expenses, which are addressed in a prior section of this Order. Given that we disallowed 50 percent of those expenses, it is likely that an additional disallowance under Staff's recommendation would represent a double counting of the types of expenses identified by RUCO. We therefore decline to adopt Staff's recommendation on this issue.

Interest Synchronization

There does not appear to be any dispute that an interest synchronization adjustment is necessary to coordinate the income tax calculation with rate base and cost of capital. As set forth in Staff witness Ralph Smith's testimony, this adjustment decreases income tax expense and increases the Company's achieved operating income by a similar amount (Ex. S-27, Attach. RCS-2S, Sched. C-17).

CARES Related Amortization

Staff recommended that UNS cease deferral of costs related to the Customer Assistance Residential Energy Support ("CARES") program upon approval of the new rates established in this case. According to Staff witness Ralph Smith, Staff has recognized CARES program discounts in Staff's proposed rate design, and Staff recognizes UNS has accumulated some deferred costs related to the program (Ex. S-27 at 44). Based on Staff witness McNeely-Kirwan's recommendation regarding the ratemaking treatment for the accumulated deferred CARES costs, Mr. Smith reduced operating expenses by $441,511 (*Id.*, Sched. C-20). Given our adoption of staff's recommendation regarding the CARES program (see discussion below), Staff's proposed adjustment to operating income is appropriate.

Nonrecurring Severance Payment

Staff witness Ralph Smith initially proposed an adjustment to remove a nonrecurring severance payment for an employee who was dismissed in 2004, but whose severance payment was

made in 2005 (Ex. S-25 at 27-28). UNS witness Dukes opposed Staff's recommendation, stating in his rebuttal testimony that because there was never an offsetting expense for this payment posted to the Company's books in 2005, payroll expense was understated by approximately $52,000 (Ex. A-13 at 15). In his surrebuttal testimony, Mr. Smith stated that Staff's prior adjustment was unnecessary because the item "was effectively adjusted to zero in the UNS Gas filing" (Ex. S-27 at 33).

In its Initial Brief, Staff contends that it disagrees with the attempt by Mr. Dukes "to revise its filing to add this nonrecurring severance expense back twice" (Staff Initial Brief at 15). UNS did not address this issue in either of its Briefs, but it appears from reading Mr. Smith's testimony that the issue was resolved prior to the hearing, considering Mr. Smith's statement that the prior Staff adjustment was unnecessary.

Nonrecurring Union Training

RUCO witness Moore recommended disallowance of $2,584 related to M.A.R.C. (Union) Training that, according to Mr. Moore, UNS had described as "a one-time only instructional session to acquaint Company personnel with working in a unionized environment" (RUCO Ex. 4 at 16). Mr. Moore claims that the expense is nonrecurring and should therefore be disallowed (*Id.*).

UNS witness Gary Smith stated that while the M.A.R.C. training was a one-time event, training is an ongoing activity that is required to comply with regulatory mandates. He claims that, since the end of the test year, another mandatory training program has been established for gas distribution companies to provide training to both the public and employees (Ex. A-17, at 4). The Company therefore requests that RUCO's recommendation be rejected. On cross-examination, Mr. Smith admitted that the M.A.R.C. training was a one-time event and that RUCO had not proposed to disallow any other training expenses incurred by the Company (Tr. at 416-17).

We agree with RUCO that the specific expense item identified by Mr. Moore is related to a one-time training cost that will not occur in the future. No other training costs are recommended for disallowance, and although the Company may face increasing training costs in the future, those costs will be addressed in a future rate case where all relevant test year revenues and expenses will be evaluated for inclusion in rates. We therefore adopt RUCO's recommendation on this issue.

New Depreciation Rates

Staff witness Ralph Smith indicated that Staff is in agreement with the Company's proposed new depreciation rates (Ex. S-25 at 63). However, Mr. Smith recommended that each of the new depreciation rates proposed by UNS should be clearly broken out by a service life and a net salvage rate. He indicated that this would allow the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates to be tracked and accounted for by plant account (*Id.*). There does not appear to be a dispute regarding the new depreciation rates to be employed by UNS. Further, the Company did not oppose Mr. Smith's suggestions for separating the depreciation rates for service life and net salvage. Staff's recommendation is therefore adopted.

Net Operating Income

Consistent with the foregoing discussion, we will allow adjusted test year operating expenses of $37,652,416, which based on test year revenues of $47,273,923, results in test year adjusted operating income of $9,621,507, a 5.30 percent rate of return on FVRB.

COST OF CAPITAL

UNS Gas recommends that the Commission determine the Company's cost of common equity to be 11.0 percent, with an overall weighted cost of capital recommendation of 8.80 percent. Staff recommends a cost of common equity of 10.0 percent, with an overall weighted cost of capital determination of 8.12 percent. RUCO proposes adoption of a cost of common equity of 9.84 percent, with an overall weighted cost of capital of 8.22 percent (RUCO Ex. 8 at 2).

Capital Structure

At the end of the test year, UNS had a capital structure consisting of 55.33 percent long-term debt and 44.67 percent equity (Ex. A-27 at 8). UNS proposes using a hypothetical capital structure of 50 percent debt and 50 percent equity because it is striving to increase its equity ratio to 50 percent and believes that the rates set in this case should reflect the capital structure that would exist when the rates set in this case are in effect (Tr. 964).

According to UNS witness Kentton Grant, "it is reasonable for the Company to target a higher common equity ratio due to the Company's small size, large capital spending needs and limited borrowing capacity" (Ex. A-27 at 8-9). He claims that UNS forecasts achieving a 50 percent equity

ratio by the end of 2008 (*Id.*). In support of the Company's improving equity ratio, Mr. Grant points out that UNS Gas has improved its equity ratio from 33 percent in August of 2003 to 45 percent at the end of 2005. He stated that this improvement has been achieved by UNS Gas's retaining 100 percent of its annual earnings and through additional equity investments from its parent, UniSource Energy. Mr. Grant testified that despite the absence of any dividends being paid by UNS to UniSource over the past several years, UniSource has invested an additional $16 million of equity capital in UNS Gas (*Id.*).

UNS cites to the most recent Southwest Gas Order to support its request for employing a hypothetical capital structure (Decision No. 68487, at 23-25). In that case, the Commission agreed with Staff's request to use a hypothetical capital structure of 40 percent equity, but rejected Southwest Gas' request to use 42 percent equity in the capital structure. During the test year in that case, Southwest Gas had an average actual capital structure of 34.5 percent equity, 5.3 percent preferred stock, and 60.2 percent long-term debt (*Id.* at 23). In this case, Mr. Grant indicated that using the Company's recommended hypothetical capital structure would help alleviate the current weakness in earnings and cash flow in order to offset the negative credit impact of weak cash flows (*Id.* at 10).

RUCO supports the Company's request to use a 50/50 hypothetical capital structure to establish UNS's cost of capital in this proceeding. RUCO witness William Rigsby stated that UNS's capital structure is more heavily weighted with debt than the average of the companies used in his comparable company analysis. He also indicated that the other local gas distribution companies ("LDCs") in his sample group had an average of 48 percent debt and 52 percent equity, compared to UNS at approximately 55 percent and 45 percent, respectively (RUCO Ex. 7 at 43). As a result, Mr. Rigsby suggested, the LDCs in his proxy group would have a lower level of financial risk compared to UNS. As discussed below, Mr. Rigsby did not make an adjustment to his cost of equity analysis to account for a higher level of financial risk but, instead, testified that his hypothetical capital structure recommendation gives recognition to this higher risk (*Id.* at 44).

Although UNS and RUCO are in agreement on the employment of a 50/50 capital structure, Staff contends that a hypothetical capital structure is not appropriate in this case. Staff witness David

Parcell testified that both UNS Gas and UNS Electric currently have higher equity ratios than either TEP or UniSource Energy, and the actual UNS equity ratio is comparable to those of other electric and combination gas and electric utilities (Ex. S-36 at 19-20). Mr. Parcell stated that using a hypothetical capital structure would have the effect of "increasing the actual return on equity to a level exceeding that intentionally approved by the Commission" (*Id.* at 20). According to Mr. Parcell, adopting the Company's proposed 50/50 capital structure would have the net effect of increasing the actual authorized return on equity by 50 basis points, or 0.50 percent (*Id.* at 21).

With respect to the Commission's use of hypothetical capital structures in prior cases, Staff argues that the circumstances are different for UNS. Staff cites to a recent Arizona-American Water Company (Mohave) case in which the Commission adopted a hypothetical capital structure of 40 percent equity and 60 percent debt, although the company's actual structure consisted of 37.2 percent equity and 62.8 percent debt (Decision No. 69440, at 13). Staff asserts that the Commission's Decision in that case was based on its concern that Arizona-American was more highly leveraged than its comparable companies. According to Staff, UNS's capital structure is in line with other comparable companies, so no similar concern exists. Staff contends that the same reasoning holds true with respect to Southwest Gas, which had a highly leveraged capital structure, with more than 60 percent long-term debt during the test year. Staff argues that a hypothetical capital structure should be employed only where a company's actual capital structure is out of line with comparable companies, or where the actual capital structure contains higher cost equity capital, which would be unduly expensive to ratepayers.

Although we understand and appreciate Staff's concerns, we believe the hypothetical capital structure recommendation recommended by UNS and RUCO is reasonable in this case. We believe the Company's efforts to improve its equity ratio over the past several years, through retained earnings and additional equity investment by its parent, should be recognized and encouraged. As indicated by UNS witness Grant, the Company's equity ratio has improved steadily since 2003, and UNS anticipates achieving a 50 percent equity ratio by the end of 2008.

While we recognize that, from a capital structure standpoint, UNS is situated differently from Southwest Gas, we believe it is necessary to express the same concern that was indicated in the

Southwest Gas case regarding ongoing use of a hypothetical capital structure for establishing a company's cost of capital and the rates that flow from that determination. As stated therein, "[a]t some point, we must send Southwest Gas a signal that it must improve its capital structure up to the hypothetical level that has been employed for many years or it must live with the results of its actual capital structure" (Decision No. 68487, at 25). Given the historical and anticipated progress of UNS in improving its equity ratio, we believe it is likely that use of the Company's actual capital structure in future cases would produce a reasonable cost of capital result. In this case, however, we find that the record supports use of the Company's 50/50 capital structure.

Cost of Debt

All parties in the case agreed that the Company's cost of debt was 6.60 percent during the test year. Since there is no dispute regarding this issue, we will adopt a cost of debt of 6.60 percent for purposes of establishing UNS Gas's weighted cost of capital in this proceeding.

Cost of Common Equity

Determining a company's cost of common equity for purposes of setting its overall cost of capital requires an estimate based on a number of factors. There is no fool-proof methodology for making this determination, and the expert witnesses rely on various analyses to support their respective recommendations.

UNS Gas

UNS witness Kentton Grant based his common equity cost recommendation of 11.0 percent on the results of his common equity models, namely the Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM"). Mr. Grant also examined the risk profile of UNS Gas relative to a comparable company group to determine a point in the range produced by those models. The estimated cost of equity produced by this analysis was then compared to the allowed returns for other LDCs in the United States to confirm the reasonableness of the Company's estimate. As a final matter, Mr. Grant examined the financial impact of the recommended return on equity ("ROE") and the overall rate request to assess the Company's ability to attract capital on reasonable terms (Ex. A-27 at 10-11).

Mr. Grant claims that it was appropriate to use a comparable group of LDCs in his analysis because the cost of equity capital for UNS Gas's parent company, UniSource Energy, which is heavily weighted toward the electric industry, may not be representative of the cost of equity capital for UNS Gas. Mr. Grant's comparable group was based on all 16 LDCs evaluated by *Value Line Investment Survey* ("*Value Line*"), from which 11 companies were selected based on several criteria that Mr. Grant believes make them comparable to UNS Gas (*Id.* at 12).

Mr. Grant explained that the DCF methodology is based on the theory that the price of a share of stock is equal to the present value of all future dividends. As described by Mr. Grant, the constant growth form of the DCF model recognizes that the return to shareholders consists of both dividend yield and growth. He stated that the constant growth form of the model should not be used for companies with near-term growth rates that are significantly higher or lower than their long-term growth potential. For such companies, Mr. Grant claims that a multi-stage DCF model should be used to incorporate the various growth rates that are expected over time (*Id.* at 13).

According to Mr. Grant, an annual long-term growth rate of 6 percent represents a reasonable estimate of investor expectations for earnings and dividends, which he claims is consistent with the 6.1 percent median growth rate in earnings per share ("EPS") for his comparable company group published by *Value Line*, as well as a five-year estimate of EPS growth reported by *Thomson Financial* of 5.6 percent for the gas utility industry and 6.4 percent for the broader utilities sector (*Id.* at 16). Based on his application of a multi-stage DCF model, the estimated cost of equity for the sample companies produced a range of 9.1 percent to 10.5 percent, with a median value of 9.9 percent (*Id.* at 18).

Mr. Grant stated that use of the CAPM is premised on the concept that capital markets are highly efficient and that investors attempt to optimize their risk/return profiles through diversification. He indicated that the CAPM assumes that risk is comprised of systematic risk (which is unavoidable) and unsystematic risk (which is company-specific and can theoretically be eliminated through portfolio diversification). As a result, Mr. Grant explained that the CAPM is based on the theory that investors should be compensated only for systematic risk (*Id.*). Applying the CAPM produced a result of 9.9 percent to 11.0 percent. Based on his comparison of the DCF and CAPM

results, Mr. Grant selected a range of 9.5 percent to 11.0 percent as the Company's estimate of the cost of equity for the comparable company group (*Id.* at 20).

The next step in the Company's analysis was to determine the appropriate return on equity ("ROE") in this proceeding for UNS Gas, based on a comparison of the "risk profiles" of UNS and the comparable companies. Mr. Grant asserts that an equity investment in UNS Gas is "decidedly riskier" than an equity investment in the comparable companies due to several factors, including UNS Gas's smaller size, a higher growth rate in net plant investment, the lack of a decoupling mechanism, and lower credit ratings for UNS Gas than for most of the comparable companies. Based on these relative risk factors, Mr. Grant proposes that the ROE for UNS Gas be set at the top of the range for comparable companies and that the Commission award a ROE of 11.0 percent in this proceeding (*Id.* at 21-23).

UNS is critical of the ROE recommendations of both Staff and RUCO based on the Company's claim that Staff and RUCO's use of a geometric means in calculating the market risk premium of their CAPM models is contrary to sound financial theories. UNS argues that an arithmetic means is supported by academics and financial professionals. The Company also contends that RUCO's analysis placed too much emphasis on near-term analyst growth forecasts, a methodology that UNS contends has been rejected by the Commission in two recent cases. UNS is also critical of RUCO's use of a single-stage DCF model, which assumes that company growth rates will continue in perpetuity, and of RUCO's over-reliance on analyst forecasts.

Finally, UNS criticizes Staff's and RUCO's ROE recommendations based on the Company's claim that the results fail a basic test of reasonableness. UNS contends that Staff's (10.0 percent ROE) and RUCO's (9.64 percent ROE)[11] recommendations are below ROEs approved by other state commissions and that UNS Gas bears much greater risk than comparable LDCs due to the factors cited in Mr. Grant's testimony (UNS Initial Brief at 37-38). Based on the Company's higher risk assertion, it claims, it must be awarded a higher ROE commensurate with that risk.

[11] UNS apparently failed to observe that RUCO made an upward adjustment in its ROE recommendation (to 9.84 percent) through Mr. Rigsby's surrebuttal testimony filed on April 4, 2007 (RUCO Ex. 8, at 2).

RUCO

RUCO witness William Rigsby proposes adoption of a ROE of 9.84 percent based on his analysis using DCF and CAPM methodologies (RUCO Ex. 8 at 2). As noted above, Mr. Rigsby employed a single-stage DCF analysis, as opposed to the multi-stage version used by UNS. RUCO contends that Mr. Rigsby's DCF analysis is appropriate because it takes into consideration both short-term and long-term growth projections that are specific to the LDCs used in Mr. Rigsby's proxy group (RUCO Ex. 7 at 46).

RUCO is critical of Company witness Grant's DCF model, which RUCO claims assumes a long-term growth rate for LDCs that would be comparable to an inflation-adjusted growth rate for all goods and services produced by labor and property in the United States in perpetuity. According to Mr. Rigsby, a valid argument could be made that regulated utility company growth rates may not be comparable to national Gross Domestic Product ("GDP") growth rates, and therefore, the multi-stage DCF advocated by UNS is inappropriate (*Id.*). Mr. Rigsby also stated that the multi-stage DCF used by the FERC requires more weight to be given to short-term growth expectations rather than inflation-adjusted estimates of future GDP growth (RUCO Ex. 8 at 9). Mr. Rigsby pointed out that if the Company's DCF inputs (excluding Cascade Natural Gas – which RUCO claims has a stock price that is affected by a merger proposal) were applied to RUCO's single-stage DCF model, the resulting mean average would be significantly less than even Mr. Rigsby's DCF estimate (RUCO Ex. 7 at 47).

With respect to its CAPM analysis, RUCO asserts that the use of both geometric and arithmetic means of historical returns is more reasonable than the Company's exclusive reliance on arithmetic returns (*Id.* at 28). Similar to the arguments made by Staff (see below), RUCO contends that it is appropriate to use both means in the CAPM analysis, because investors have access to both forms of information regarding historical returns. Mr. Rigsby added that he believes the geometric mean provides "a truer picture of the effects of compounding on the value of an investment when return variability exists" (RUCO Ex. 8 at 12).

RUCO also disagrees with UNS regarding the effect that customer growth should have on the Company's return on equity. Contrary to the Company's claim that high growth presents additional risk that must be reflected through a higher authorized return, RUCO argues that high growth in

Arizona is a positive factor that should be a selling point to UniSource investors. RUCO cites to UniSource's 2005 Annual Report, in which UniSource's Chairman touted the company's customer growth rate in excess of 4 percent as a positive factor (*Id.* at Attach. E). RUCO also notes that a Standard & Poors report attached to Mr. Grant's testimony indicates that high customer growth could produce greater profitability or rate stability for an LDC (Ex. A-28, Attach. KCG-12). RUCO claims that it has not ignored the demand for capital that customer growth places on UNS operations, as reflected by RUCO's support for use of the Company's proposed 50/50 hypothetical capital structure.

Staff

Staff witness David Parcell presented Staff's ROE recommendation in this case. In developing his recommendation, Mr. Parcell utilized DCF, CAPM, and Comparable Earnings Method ("CEM") analyses. He indicated that because UNS Gas is not publicly traded, it is not possible to directly apply cost of equity models. In his analysis, Mr. Parcell employed 2 comparable groups of companies as a proxy for UNS Gas (Ex. S-36, at 21-23). The first sample group was comprised of a group of nine combination gas and electric companies and the second group consisted of the same 11 natural gas companies used by the Company's witness.

Mr. Parcell's DCF analysis produced a range of 9.25 percent to 10.5 percent for the proxy groups' cost of equity. His CAPM model produced a cost of equity range of 9.5 percent to 10.25 percent for the sample groups (*Id.* at 25-28). Mr. Parcell also utilized a CEM analysis, which he described as a method designed to measure the returns expected to be earned on the original cost book value of similar risk companies. According to Mr. Parcell, his CEM analysis was based on market data using market-to-book ratios, and is therefore a market test that should not be subject to criticisms leveled at other analyses that are based on past earned returns. He also claims that the CEM uses prospective returns and is therefore not backward-looking (*Id.* at 31-32). Using the CEM, Mr. Parcell concluded that the cost of equity for the proxy companies is "no more than 10 percent" (*Id.* at 33).

Based on the results of the three methodologies, Mr. Parcell found an overall range of 9.25 percent to 10.5 percent ROE for the proxy companies. He indicated that the range of mid-points for the three methodologies is 9.88 percent to 10.0 percent. Mr. Parcell concluded that the appropriate

cost of equity rate for UNS Gas is in the range of 9.5 percent to 10.5 percent. He recommended that the Commission adopt the mid-point of the range (10.0 percent) as the ROE in this case.

With respect to the arguments raised by the Company, Staff asserts that UNS failed to give any weight to its own DCF analysis and relied exclusively on its excessive CAPM results. Staff contends that UNS's CAPM analysis is flawed because it uses a risk-free rate of 5.3 percent, which Staff claims is outdated and exceeds the current level of U.S. Treasury Bond yields, and the Company used an inappropriate equity risk premium of 7.1 percent, which is based exclusively on the arithmetic means of common stock and bond returns from 1926 to 2005.

In response to the Company's criticism of Staff's use of geometric means in its analysis, Staff cites to Mr. Parcell's surrebuttal testimony, wherein he indicated that investors have access to both arithmetic and geometric returns in making investment decisions and that many mutual fund investors rely on geometric returns in evaluating historic and prospective returns of funds (Ex. S-37 at 3). Staff also points to Mr. Parcell's testimony indicating that *Value Line* reports show historic returns based on a geometric or compound growth rate basis (*Id.*).

Conclusion on Cost of Equity

Having considered the testimony, exhibits, and arguments, we believe that Staff's recommended cost of equity capital produces a reasonable result and should be adopted. Staff witness Parcell's proposed 10.0 percent cost of equity provides a reasonable balance between the Company's attempt to place the ROE at the very top of the range produced by the Company's analysis and the results achieved through the methodologies employed by Staff and RUCO.

As noted above, Mr. Parcell's DCF analysis produced a range of 9.25 percent to 10.5 percent for the proxy groups' cost of equity, his CAPM model produced a cost of equity range of 9.5 percent to 10.25 percent for the sample groups, and his CEM analysis produced a result for the proxy companies of no more than 10 percent. Based on his conclusion that UNS Gas has an estimated ROE of 9.5 to 10.5 percent, Mr. Parcell recommended awarding the Company a ROE at the mid-point of the range, or 10.0 percent.

We agree with the Staff and RUCO witnesses that it is appropriate to consider the geometric returns in calculating a comparable company CAPM because to do otherwise would fail to give

recognition to the fact that many investors have access to such information for purposes of making investment decisions. Although there continues to be disagreement regarding the risk effect from high customer growth, we believe that high growth has the potential for providing benefits through increased revenues. In any event, our adoption of the hypothetical capital structure proposed by UNS and RUCO gives recognition to the short-term capital needs associated with growth.

Accordingly, we adopt Staff's recommended 10.0 percent ROE in this proceeding for UNS Gas, which results in an overall weighted average cost of capital of 8.30 percent.

	Percentage	Cost	Avg.Weighted Cost
Common Equity	50.0%	10.0%	5.00%
Total Debt	50.0%	6.60%	3.30%
			8.30%

Chaparral City Decision and Fair Value Rate Base

In its application, UNS proposed that the weighted average cost of capital ("WACC") should be applied to its original cost rate base to determine the required operating income in this case (Ex. A-10, Sched. A-1). However, in the rebuttal testimony submitted by UNS witness Pignatelli, the Company suddenly made the claim that its WACC should be applied to FVRB. UNS claims that its change of position was based on its understanding of a recent Memorandum Decision issued by the Arizona Court of Appeals in *Chaparral City Water Co. v. Ariz. Corp. Comm'n*, 1 CA-CC 05-0002 (Ariz. App. Feb. 13, 2007) ("*Chaparral City*"). According to Mr. Pignatelli's rebuttal testimony, UNS is not requesting that its change of position result in a revenue requirement finding that would exceed the amount originally requested by the Company (Ex. A-2 at 8).

UNS argues that in the Chaparral City case before the Commission, the Commission adopted Staff's recommendation to calculate the revenue requirement by multiplying OCRB by the cost of capital (Decision No. 68179, at 26-28). UNS claims that only after this exercise was completed did Staff calculate the FVRB for Chaparral City, which resulted in what UNS contends is a "backing-in" approach because the FVRB calculation is a meaningless exercise that flows from the OCRB and cost of capital equation. UNS witness Grant asserted that the approach advocated by Staff in this case is

mathematically equivalent to the methodology used in the Chaparral City case and rejected by the Court of Appeals (Ex. A-29, at 13).

In support of its argument, UNS cites to Article 15, §14 of the Arizona Constitution, which states in part that "[t]he Corporation Commission shall, to aid it in the proper discharge of its duties, ascertain the fair value of the property within the State of every public service corporation doing business therein..." UNS cites several cases[12] in support of its argument that the Commission is required to determine a company's fair value rate base and use that rate base in establishing the company's rates. UNS concedes that its proposal to apply the WACC to FVRB is not the only possible approach to setting rates, but suggests that it is the only approach presented in this case that complies with the Arizona Constitution. The Company claims that other permissible methods may be developed in future cases but, that for now, the UNS methodology is the only available choice for the Commission to apply.

RUCO argues in its brief that application of the WACC to FVRB, rather than to the OCRB initially requested by UNS, could be significant if the Commission adopts any of the positions advocated by Staff or RUCO regarding the Company's rate request. RUCO contends that the Company's change of position was untimely and, for that reason alone, should be rejected. Ms. Diaz Cortez stated in her surrebuttal testimony that, had UNS made its request to apply WACC to FVRB in its original application, RUCO's analysis of the cost of capital would have been entirely different and would likely have produced different results. She indicated that RUCO did not have sufficient time to conduct discovery regarding the change of position between the filing of the Company's rebuttal testimony and the filing of RUCO's surrebuttal testimony, some 13 business days later (RUCO Ex. 6, at 4-5). RUCO also argues that because *Chaparral City* was a Memorandum Decision, it cannot be regarded as precedent or cited. RUCO further asserts, citing Paragraph 17 of the Decision, that the Court confirmed the Commission is not required to apply a WACC to FVRB.

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[12] *U.S. West Communications, Inc. v. Ariz. Corp. Comm'n*, 201 Ariz. 242, 246, 34 P.3d 351, 355 (2001); *Simms v. Round Valley Light & Power Co.*, 80 Ariz. 145, 151, 294 P.2d 378, 382 (1956); *Scates v. Ariz. Corp. Comm'n*, 118 Ariz. 531, 533-534, 578 P.2d 612, 614-615 (App. 1979); *Phelps Dodge Corp. v. Arizona Electric Power Co-op*, 207 Ariz. 95, 83 P.3d 573, 586 (App. 2004).

Staff argues that the Company's reliance on the unpublished *Chaparral City* decision is misplaced. Staff points out that the Court of Appeals specifically indicated that the Commission was not required to apply the WACC to FVRB in order to set rates. Staff contends that it is still reviewing the Court's remand order, but the methodology proposed by Mr. Grant would result in an unreasonable and excessive return on equity for UNS. Staff cites to Mr. Parcell's testimony addressing the Company's amended proposal. Mr. Parcell testified that, under UNS's proposal, the link between rate base and capital structure would be broken because the "excess" of fair value rate base over original cost rate base is not financed with investor-supplied funds, and therefore the cost of capital cannot be applied to the fair value rate base because there is no financial link between the two concepts (Ex. S-37 at 8-9). Mr. Parcell's proposed solution is to recognize that the difference between FVRB and OCRB is not financed with investor funds by attributing no cost to the excess between the two. He stated that this recommendation would provide for a return being earned on all investor-supplied funds, which is consistent with sound financial and regulatory standards (*Id.*).

In support of its proposal, Staff cites to decisions rendered in several other states which recognized the problem of applying the cost of capital to fair value rate base[13]. Staff contends that, consistent with the problems identified by Mr. Parcell, application of modern cost of capital models, such as DCF and CAPM, directly to FVRB would create redundancies and double counting. Staff cites the case of *Railroad Commission of Texas v. Entex, Inc.*, 599 S.W.2d 292 (Tx. 1980), in which the Texas Supreme Court discussed the so-called "backing-in" method of determining fair value rate of return. In that case, the court stated that "[i]n a fair value jurisdiction the rate of return multiplied by the rate base usually resulted in a higher return to the book common equity than in an original cost jurisdiction because of the inclusion of the reproduction cost new factor." (*Id.* at 298). In rejecting the "backing-in" argument presented by the utility company, the Texas Supreme Court observed that, in fair value jurisdictions, the return to book common equity is used as a performance indicator by investors, and that fact could not be ignored by blindly applying a rate of return to fair value rate base

[13] In *Re Harbour Water Corporation*, 2001 WL 170550 (Indiana Utility Regulatory Commission); *Gary-Hobart Water Corp. v. Indiana Utility Regulatory Comm'n*, 591 N.E.2d 649, 653 (Ind. App. 1992); *State of North Carolina ex rel. Utilities Commission et al. v. Duke Power Co.*, 285 N.C. 377, 397, 206 S.E.2d 269, 294 (N.C. 1974); *State of North Carolina ex rel. Utilities Commission et al. v. Virginia Electric and Power*, 285 N.C. 398, 206 S.E.2d 283 (N.C. 1974).

without recognizing the consequences of such a rate of return on the elements of the company's capital structure. The court also stated:

> [T]he fairness of the rate base or the rate of return can be measured by the cash requirements of the utility. All are interdependent and ultimately need to be reconciled....*a return to book common equity which is out of proportion...cannot be ignored since it is more than necessary to attract capital, and therefore, unfair to the ratepayer.* (*Id.* at 299, emphasis added).

Staff argues that, as recognized in the *Entex* case quoted above, the question that must properly be addressed is whether investors expect an additional return in excess of the return resulting from application of the financial models used for calculating the appropriate authorized return. Staff contends that there is no evidence that investors expect such an excess return and that the record supports an opposite conclusion. Staff asserts that the difference between applying the return to OCRB and FVRB would be, in effect, a windfall on unrealized paper profits. Staff claims that Mr. Parcell's proposal to assign no cost to the "excess" between OCRB and FVRB is logical and consistent with investor expectations. Staff argues that, to the extent that investors may expect a return on the so-called paper profits, such a return is already incorporated into the cost of capital models employed by the experts in this case. Staff states that, as an example, forecasted earnings per share and dividends per share would be higher if investors expect a utility's assets to grow in value, and historical EPS and DPS would also incorporate growth between a utility's prior and current rate cases. Staff indicates that it will continue to evaluate how to calculate a fair value rate of return, in accordance with the *Chaparral City* decision, and it is possible that a different mathematical adjustment may be developed in the future. Staff argues that UNS did not present any evidence as to how to adjust the cost of capital models in order to determine an appropriate fair value rate of return and that adopting the Company's request would create excessive returns for UNS.

We find the Company's eleventh-hour proposal to substantially amend its application on this issue to be inappropriate, because it is prejudicial to the other parties. Having prepared discovery based on the original proposal, Staff and RUCO were left with insufficient time to conduct discovery regarding the Company's amended proposal and were therefore prejudiced by having insufficient

time to adequately prepare for hearing in this matter. If UNS wished to amend its application regarding a substantial change in the underlying theory of ratemaking upon which it decided to rely, it should have withdrawn its original application and started the entire process over. Based on the procedural deficiencies of the Company's amendment to its application and the prejudicial impact on the opposing parties, its proposal is unreasonable.

UNS attempts to portray its amended proposal as an innocuous placeholder, by claiming that there is no harm due to its willingness to be limited only to the revenue requirement set forth in its original application. However, as RUCO succinctly points out, the underlying premise of the Company's argument is fallacious unless the Commission were to agree with every revenue requirement position advocated by the Company. As discussed above, we have rejected a number of the arguments raised by UNS. As a result, the Company's revised position regarding application of FVRB, if it were adopted, would have a substantial impact on the rates that are established in this Decision.

The purpose of the Company's reliance on the cases it cites is unclear, given that no party disputes the concept that fair value rate base must be determined and applied in setting rates. The cases cited by UNS do not, however, stand for the proposition espoused by the Company (*i.e.*, that the Commission *must* apply the Company's WACC to FVRB to determine just and reasonable rates). In fact, those cases make clear that the Commission, although required to ascertain a company's fair value rate base and use that fair value rate base in determining rates, has broad discretion in how the rate-setting formula should be applied.

Even if we were inclined to consider the Company's proposal, its arguments are premature at best. Through his rebuttal testimony, UNS witness Grant suggests that the Commission must apply the WACC to fair value rate base pursuant to the *Chaparral City* decision (Ex. A-28 at 28). However, Mr. Grant's proposal ignores the explicit language of the Court's decision, which states: "the Commission asserts that it was not bound to use the weighted average cost of capital as the rate of return to be applied to the FVRB. The Commission is correct....[t]he Commission has the discretion to determine the appropriate methodology." (*Chaparral City, supra,* at p. 13, ¶17). Despite

this unambiguous explanation, UNS would have us employ the very methodology the Court of Appeals specifically stated the Commission was not required to apply in setting rates.

Aside from the disingenuousness of the Company's argument, the current posture of the *Chaparral City* case is that it has been remanded to the Commission for further consideration. At this point, the Commission has not held hearings on the issue remanded by the Court, and thus no decision has been rendered by the Commission on the issue. Once the Commission issues a subsequent order in the remanded case, the Commission's decision may, or may not, be appealed to the Court of Appeals for a determination of compliance with the Court's remand. Thus, entirely aside from the inappropriateness of citing the unpublished *Chaparral City* decision as precedent, using it as the foundation for requiring a specific methodology in another unrelated case is clearly improper given that the Commission has been given an opportunity to cure the perceived defects in the *Chaparral City* case. Until that case has been decided under the Court's remand order, and the Court of Appeals has determined whether the Commission's Decision on Remand satisfies the Court's prior order, it is premature for UNS (or any other company) to suggest that the Commission must apply a particular methodology, especially a methodology that the Court specifically stated the Commission is not required to adopt.

We also believe that Staff has raised a number of relevant concerns with the Company's attempt to apply the WACC to FVRB without further modification. As Staff points out, there is no logical basis for applying such a methodology because investors have no expectation that they will earn a return on the excess between OCRB, which represents investor supplied funds, and FVRB, which represents unrealized paper profits. If the Company's proposal were to be adopted, the underlying basis of the cost of capital analysis would be called into question and would likely require substantial modification to avoid a result that grants excessive windfall returns to investors at the expense of ratepayers. We note that UNS states in its reply brief that, pursuant to the holding in *Ariz. Corp. Comm'n v. Arizona Water Co.*, 85 Ariz. 198, 203, 335 P.2d 412, 415 (1959), the Commission may not consider the argument raised by Staff regarding investor-supplied funds. The *Arizona Water* case is clearly distinguishable from the instant case, however, given the fact that the Court in *Arizona Water* was asked to consider only whether a recent purchase price paid for the utility company could

be used by the Commission as the fair value of the utility for setting rates. No such set of facts is presented in this proceeding, and we do not believe the *Arizona Water* holding is applicable to the arguments presented by Staff.

For all of these reasons, we reject the Company's proposal on this issue.

AUTHORIZED INCREASE

Based on our findings herein, we determine that UNS Gas is entitled to a gross revenue increase of $5,257,468.

Fair Value Rate Base	$184,120,761
Adjusted Operating Income	9,621,507
Required Rate of Return	6.97%
Required Operating Income	12,833,217
Operating Income Deficiency	3,211,710
Gross Revenue Conversion Factor	1.6370
Gross Revenue Increase	$5,257,468

RATE DESIGN ISSUES

Customer Charge and Seasonal Rates

UNS Gas

UNS proposes in this case to increase the monthly customer charge for its largest customer class (Residential – R10) from $7 to $20 per month during the "summer" months (April through November) and from the current $7 to $11 per month during the "winter" months (December through March). The Company also proposes to decrease the current commodity rate for the R10 class from the current rate of $0.3004 per therm to $0.1862 per therm.[14]

UNS claims that its proposed rate design is intended to mitigate the cross-subsidization that currently exists between customers in colder climates and customers in warmer climates. According to the Company, it incurs approximately $26 per month in fixed costs to serve a customer, yet the residential customer charge is only $7 per month, with the remaining fixed costs being recovered through volumetric charges. UNS witness Tobin Voge stated that, as an example, a customer in Flagstaff pays substantially more towards the Company's fixed costs (through a higher percentage of volumetric charges) compared to a customer in Lake Havasu (Ex. A-18 at 8, Attach. TVL-1).

[14] Although the $0.1862 rate appears in UNS's original schedules (Ex. A-9, Sched. H-4), and in the Company's post-hearing brief, the Company's Final Schedules reflect a per therm rate proposal of $0.1844.

UNS argues that its proposed rate design would allow the Company to recover more of its fixed costs from all customers and would result in a more equitable policy in an environment of higher gas commodity costs. In support of the Company's position, UNS witness Grant cited a 2006 report from Moody's, which indicated that the volumetric approach to cost recovery is a faulty equation for LDCs that should be rectified through ratemaking (Ex. A-29 at 23). UNS also cites an AGA report, which suggests that, under a traditional volumetric rate design, a gas company's profits and earnings will decline if customers use less gas (Ex. A-37 at 2). The Company contends that it is time to address these alleged inequities through approval of higher monthly service charges and decoupling mechanisms (see discussion below regarding the Company's proposed "Throughput Adjustment Mechanism").

Under the Company's proposal, the monthly customer charge would be increased from $7 to an average of $17 per month (subject to the seasonal differences described above), which UNS claims would enable it to recover approximately 60 percent of its costs incurred in serving a residential customer (Tr. at 512). Because Staff and RUCO oppose the Company's seasonal customer charge proposal, UNS indicated that it is willing to accept a year-round customer charge of $17 (UNS Initial Brief at 46).

UNS asserts that the rate design proposals advocated by Staff and RUCO should be rejected. According to the Company, Staff's recommendation to increase the fixed monthly customer charge to $8.50, and RUCO's proposal to increase the customer charge to no more than $8.13, are an inadequate means of moving rates closer to the Company's cost of service. UNS asserts that its proposal to increase the customer charge by $10 over current levels is not drastic, will not result in "rate shock," and does not violate the principle of "gradualism," given the corresponding request to decrease the commodity charge.

UNS witness D. Bentley Erdwurm addressed the inequities between cold weather and warm weather customers and concluded that substantial cross-subsidization by customers in colder climates exists. He testified that the average customer in Flagstaff currently pays $133 more in annual margin costs than an average customer in Lake Havasu City for the same fixed costs (Ex. A-19 at 10). UNS

argues that this inequity is especially unfair because customers in colder areas have little ability to reduce their overall bills due to the need to use natural gas for heating purposes.

With respect to the avoidance of rate shock and compliance with the principle of gradualism, UNS contends that the Staff and RUCO rate design recommendations focus too narrowly on the customer charge and fail to consider the Company's overall rate design proposal. The Company claims that the increase in the customer charge would be offset by the reduction of the commodity charge. UNS also asserts that the concepts of rate shock and gradualism must be balanced against other rate design elements, including rate stability and matching principles.

Finally, UNS argues that its rate design proposal does not eliminate the incentive for customers to conserve (by the proposal to reduce the commodity charge). According to the Company, even if its proposed per therm charge of approximately 18 cents were adopted, when that rate is combined with an estimated PGA charge of 60 cents per therm, the overall volumetric charge would be decreased by approximately 13 percent, which UNS claims is not enough to stifle conservation incentives.

Mr. Magruder

Intervenor Marshall Magruder opposes the Company's request to impose seasonal rates and to collect a higher percentage of rates from customers in warmer climates. Mr. Magruder claims that the Company's proposal would discriminate against customers in warmer areas and he suggests that customers choose whether to live in colder or warmer climates. He also asserts that UNS's proposed rate structure would send the wrong signal by rewarding high usage customers and penalizing low usage customers. He recommends instead that Staff's proposal to increase the customer charge to $8.50 be adopted.

RUCO

RUCO opposes the Company's recommendation to increase the monthly customer charge significantly. RUCO points out that UNS's proposal would shift more revenue to its fixed costs than it is seeking for its entire rate increase. As UNS witness Erdwurm admitted on cross-examination, the Company's entire requested revenue increase is approximately $10 million, yet it is seeking to recover an additional $16.4 million per year through the fixed monthly charge alone. In order to

remedy this imbalance, UNS proposes to reduce the commodity charge by approximately $6.4 million (Tr. at 475-76). As a result, higher usage customers would experience a reduction in their bills, while lower usage customers would see a much higher percentage increase.

RUCO contends that some shifting of costs to the customer charge is appropriate and recommends that the current recovery of approximately 26 percent through the monthly fixed charge should be increased to 36 percent (under RUCO's revenue requirement recommendation) (RUCO Ex. 5 at 34). RUCO also disagrees with the Company's seasonal customer charge proposal. RUCO asserts that the justification offered by UNS in support of this proposal (to levelize customer bills) is not appropriate because the Company's customers already have a voluntary means to levelize their bills through an existing billing program. Ms. Diaz Cortez stated that if the Company believes more customers would benefit from levelized billing, it should make a greater effort to publicize the existing program's availability rather than seeking to impose a Commission-mandated seasonal rate design (*Id.* at 30).

Staff

Staff contends that the Company's rate design proposal in this case is designed to shift almost all of the risk of rate recovery to ratepayers and should therefore be rejected. Staff witness Steven Ruback presented Staff's rate design recommendation and stated that the UNS rate design would result in a "staggering" increase in the fixed customer charge for all classes of service (Ex. S-23 at 3). For the residential class, Mr. Ruback indicated, the Company's proposal would result in a customer charge increase of 185 percent in the summer period and 57 percent in the winter period (*Id.*). Mr. Ruback explained that, although the monthly charge increase would be partially offset by a lower volumetric charge, UNS's proposal presents a "serious front end loading problem, a decoupling issue and gradualism problem" (*Id.* at 4). He testified that it is not surprising that UNS would seek to increase the fixed customer charges and that such an approach is a common means that utilities use to lessen the risk of recovery (*Id.* at 6). Mr. Ruback stated UNS's proposal is unusual in that the Company has proposed to recover all of its increase, and some of the volumetric margin, through fixed charges (*Id.*).

According to Mr. Ruback, the Company's proposal represents a step towards a Straight Fixed Variable ("SFV") rate design, a concept employed by the FERC as a means of rationing pipeline design day capacity by price. Mr. Ruback stated that SFV rate design is inappropriate for retail distribution rate design because there is no need to ration retail distribution capacity. He further testified that UNS's rate design proposal "violates the well-established and long-standing regulatory principle that a utility should have a reasonable opportunity, not a guarantee to earn its allowed rate of return" (*Id.* at 9). Mr. Ruback indicated that he is aware of only one LDC, Atlanta Gas Light Company, that is permitted to employ the SFV rate design method to recover its distribution revenue requirement, and that exception to the general rule is mandated by state legislation that precludes the Georgia Public Service Commission from establishing an alternative rate design. Mr. Ruback stated that "other jurisdictions allow for reasonable fixed customer charges and reasonable fixed demand charges, but require that the bulk of the distribution revenue requirement be recovered over throughput" (*i.e.*, volumetric charges) (*Id.* at 10).

According to Staff witness Ralph Smith, Staff's rate design recommendation is based on the consideration of a number of factors, including cost of service; the desire to encourage energy conservation; the need to use gradualism in cases where rates are being charged, so that customers are not burdened with large rate increases; customer equity issues within and between rate classes; efforts to make rates and bills easier for customers to understand; revenue impacts on the Company; and other policy considerations. He stated that given all of these variables, it is understandable that rate design is considered more of an art than a science (Ex. S-26 at 2).

Under Staff's proposed rate design, the fixed monthly customer charge would be increased from $7 to $8.50 for residential customers, with no seasonal difference in the customer charge. Staff's proposed commodity charge for Rate R10 customers would increase to $0.3217 per therm, under Staff's revenue requirement recommendation (*Id.* at 9). Mr. Smith explained that if Staff's recommended revenue requirement and rate design were adopted, a residential customer (R10) using 100 therms of gas would experience a total bill increase from $115.48 to $119.11 (3.14 percent) (*Id.*). Staff asserts that its proposed rate design is reasonable and should be adopted by the Commission.

Conclusion

Although we understand that UNS would like to recover as much of its margin as possible through monthly customer charges, we do not believe it is reasonable to adopt a rate design that would impose a significant increase on customers based on where they live within the Company's service area. Under the Company's recommendation, residential customers with lower usage (*i.e.*, customers typically located in warmer climates) would bear the brunt of the revenue increase due primarily to the dramatic front-loading increase to the fixed monthly customer charge. As set forth in the UNS Final Schedules (based on UNS's proposed revenue requirement), in the "summer" months (April through November), a residential customer (R10) would experience an increase of 146 percent with 5 therms of usage, 118 percent with 10 therms of usage, and 82 percent with 20 therms of usage. During the "winter" months (December through March), the same customer would incur increases of 40 percent with 5 therms of usage, 28 percent with 10 therms of usage, and 13 percent with 20 therms of usage (UNS Final Schedules, Sched. H-4). While higher usage customers may realize lower increases, or even decreases (depending on usage), we do not believe that a dramatic increase imposed on lower usage customers is appropriate in this case. As we stated in the Southwest Gas Decision in rejecting a similar type of rate design proposal, "[such a] rate design would have the effect of encouraging greater usage of natural gas at a time when, by all accounts, an increase in demand for natural gas is coupled with shortages in supply. We do not believe that it is appropriate to send a signal to customers of 'the more you use, the more you save,'" (Decision No. 68487, at 37).

As discussed by Staff's witnesses, movement towards cost-based rates is just one of the many factors that must be considered in designing rates. The goal of moving closer to cost-based rates must be balanced with competing principles such as gradualism, fairness, and encouragement of conservation. Based on the testimony and evidence presented in the record, and considering the arguments raised regarding competing principles of the rate design equation, we believe that Staff's rate design recommendation appropriately makes significant movement towards cost-based rates and provides a reasonable level of protection for the customers who are affected by this base rate increase. Accordingly, we adopt Staff's recommended monthly charges, as set forth in the

attachments to Exhibit S-27, with the accompanying commodity charges based on Staff's rate design flowing from the revenue requirement established in this Order.

For a residential customer on Rate R10, the fixed monthly customer charge would increase from $7 to $8.50, and the volumetric charge would increase from $0.3004 to $0.3270 per therm. Based on these rates, a residential customer with 20 therms of usage would experience an increase in monthly base rates of 15.6 percent (from $13.01 to $15.04) and an overall monthly increase (including the cost of gas) from $28.70 to $30.73 (7.1 percent). The same customer with typical January consumption (87 therms) would see an increase in base rates of 11.5 percent (from $33.13 to $36.94) and an overall increase (including the cost of gas) from $101.37 to $105.18 (3.8 percent).

Throughput Adjustment Mechanism

UNS Gas

In its application, UNS proposed a Throughput Adjustment Mechanism ("TAM") which would increase or decrease the collection of volumetric revenues to match anticipated levels. The Company claims that the TAM would allow it to implement energy conservation programs without the concern that its revenues would be diminished if the conservation measures were successful. UNS indicated that under its proposed TAM, under-recovery or over-recovery of revenues during any given period would be trued-up in future periods through the use of a volumetric surcharge or credit.

As explained by Company witness Erdwurm, the TAM is a type of decoupling mechanism that has growing support from regulatory and environmental organizations. In his testimony, Mr. Erdwurm stated that organizations such as the Natural Resources Defense Council ("NRDC"), the American Council for an Energy Efficient Economy ("ACE"), and the AGA have expressed support for rate mechanisms that decouple utility retail sales from recovery of fixed costs (Ex. A-19 at 17-18). He claims that a NARUC Resolution encourages state commissions to adopt rate designs that include decoupling mechanisms such as the TAM (*Id.* at 18). The Company also introduced a newsletter issued by the AGA indicating that decoupling mechanisms have been implemented in 10 states (Ex. A-37).

According to UNS, the Company's return is highly dependent on customer usage because of the volumetric nature of its rates. UNS witness Tobin Voge's testimony stated that a warmer than

normal winter will cause customer usage, and thus Company revenues, to decline, thereby rendering UNS unable to collect its full fixed costs (Ex. A-18 at 15). On the other hand, during a colder than normal winter, UNS would experience a surge in revenues. The Company contends that the TAM would make customer bills less volatile by evening out wide fluctuations due to weather.

Mr. Voge's testimony indicates that in order to implement the proposed TAM, a base use per customer ("UPC") must first be established. Under the Company's proposal, a separate base would be established for residential, small volume commercial, and small volume public authority customers. The UPCs would be calculated by dividing calendar year therm sales by average number of customers. The difference between the actual and base UPC would then be multiplied by the 2005 base number of customers, and the margin rate for the customer class, to determine the throughput adjustment in dollars (*Id.* at 12-13).

The Company asserts that, by minimizing the impact of weather on customer bills, the TAM would provide a more equitable rate design that ensures that customers do not pay more for the Company's fixed costs than they would under normal weather conditions (Ex. A-19 at 15). UNS also claims that the TAM would encourage conservation by reducing the conflict between conservation efforts and the Company's financial stake in the volumetric revenues associated with usage (Ex. A-18 at 15).

UNS dismisses the validity of RUCO's arguments that the TAM would eliminate the incentive for customers to conserve. The Company argues that, under its proposal, all customers would receive bills with identical TAM adjustments based on cumulative system usage, not personal household consumption. As a result, UNS claims, each individual customer would continue to benefit from conservation efforts because the individual customer's actions would represent only a small portion of the usage data reflected in future TAM adjustments.

UNS also disputes arguments made by Staff and RUCO that the TAM would remove the Company's risk of revenue recovery. The Company claims that the TAM would not alter the ability or inability to recover base rates established in the rate case, and that rising capital expenditure requirements associated with customer growth would continue. UNS also argues that its proposed TAM differs from the "conservation margin tracker" decoupling mechanism that was rejected in the

Southwest Gas case (Decision No. 68487 at 33-34). According to UNS, the TAM differs from the decoupling mechanism proposed by Southwest Gas in the following ways: the TAM would cover all small volume customers, not just residential customers; UNS has provided examples of the calculations needed to implement the TAM; and UNS is willing to consider the creation of a deferred adjustment account (Ex. A-18 at 14). Finally, UNS claims that it has pledged to continue supporting demand-side management ("DSM") programs, regardless of adoption of the TAM. The Company argues, therefore, that it cannot be accused of attempting to use its TAM proposal as leverage for its continued support for DSM.

RUCO

RUCO witness Marylee Diaz Cortez testified regarding the reasons for RUCO's opposition to the proposed TAM. She stated that the TAM would cause customers to pay for a fixed amount of consumption regardless of their actual usage and would remove any risk to the Company associated with revenue recovery (RUCO Ex. 5 at 30-31). Ms. Diaz Cortez testified that variations in consumption are already addressed by the rate case process based on weather normalization of revenues (Tr. at 706).

RUCO argues that it is not appropriate for the Commission to provide a guarantee of a certain stream of revenues because the regulatory process is intended to provide only the opportunity for a company to recover its revenue requirement. Ms. Diaz Cortez stated that UNS already has an exclusive service territory and a captive customer base, giving it a low business risk. She also indicated that the authorized rate of return set by the Commission compensates the Company for any business risk that may exist (RUCO Ex. 5 at 31).

RUCO next argues that approval of the TAM would present a departure from the historic test year concept, which RUCO claims is required under the Commission's rules and the Arizona Constitution. Finally, RUCO contends that Southwest Gas experiences greater decreases in consumption due to conservation than does UNS Gas, yet the Commission previously rejected Southwest Gas' decoupling mechanism proposal. RUCO points out that the Commission expressed concern that the decoupling mechanism proposed by Southwest Gas could have resulted in

disincentives for customers to conserve (Decision No. 68287 at 34), and the same concern exists with respect to UNS Gas's proposed TAM.

Mr. Magruder

Mr. Magruder opposes adoption of the Company's proposed TAM for many of the same reasons identified by Staff and RUCO. He argues that UNS should not be insulated from risk and that customers should not have to pay for gas they have not used.

Staff

Staff witness Steven Ruback expressed several concerns with the Company's proposed TAM. Mr. Ruback stated that the TAM is essentially an automatic adjustment clause and that such adjustors traditionally are intended to recover volatile costs that, if left unrecovered, could jeopardize a company's financial health. He indicated three requirements for the types of costs generally allowed to be recovered through adjustor mechanisms: the costs must be large enough to jeopardize the utility's financial health, they must be volatile, and they must be substantially beyond a company's control. He claims that the TAM does not meet these tests because traditional ratemaking has not left UNS in poor financial condition, non-gas costs are not extremely volatile, and non-gas costs are within management's control (Ex. S-23 at 16).

Mr. Ruback also asserts that UNS already has in place two types of revenue decoupling mechanisms - the fixed customer charge, which is independent of throughput, and the PGA, which protects the Company from volatile spikes in the cost of gas (*Id.* at 16-17). At the hearing, Mr. Ruback testified that, in his opinion, "the TAM is overly broad because it compensates for reduced sales from anything – from weather variation, from economic activity, to loss of costs, to high commodity charges." (Tr. at 796). He conceded that it is not just UNS Gas's proposal he dislikes, stating, "I haven't seen a TAM I liked yet." (*Id.*) However, Mr. Ruback contends that adoption of the TAM would represent "piecemeal ratemaking" because there is no commensurate opportunity in the mechanism to consider offsetting adjustments related to cost of service reductions, cost of capital changes, and changes in customer allocation factors (Ex. A-23 at 14).

Finally, Staff points to the Southwest Gas rate case, in which the Commission rejected a similar proposal. Staff acknowledged that the Commission directed Southwest Gas and interested

stakeholders to examine further decoupling mechanisms, and Staff indicated that it is willing to engage in discussions outside of this case regarding such mechanisms. However, Staff argues that UNS's proposal should be rejected based on the record in this case.

Conclusion

We do not believe the record supports adoption of UNS Gas's proposed decoupling mechanism in this case. In the Southwest Gas case, we cited a number of concerns with a decoupling mechanism that was similar to the TAM proposed by UNS Gas in this proceeding. We pointed out in the Southwest Gas Order that decoupling mechanisms require "customers [to] provide a guaranteed method of recovering authorized revenues, thereby virtually eliminating the Company's attendant risk." (Decision No. 68487 at 34) We also noted that, under such a mechanism, customers would "be required to pay for gas that they have not used in prior years, a phenomenon that could result in disincentives for such customers to undertake conservation efforts...[and would be] faced with a surcharge for not using 'enough' gas the prior year." (*Id.*) We therefore directed Southwest Gas to find rate design alternatives that truly encourage conservation and to engage in discussions with affected stakeholders to pursue implementation of a decoupling mechanism through the DSM policy process or through a proposal in Southwest Gas's next rate case (*Id.*).

Although the Company attempts to distinguish its TAM from the mechanism rejected in the Southwest Gas case, the differences are insignificant compared to the overall similarities between the proposals. The first difference cited by the Company, that it is willing to apply the TAM to all small volume customers, is not persuasive given Southwest Gas's concession that it was also willing to extend its decoupling mechanism to a broader base of customers (*Id.* at 31). The next difference claimed by UNS is essentially that its proposal provided a greater level of detail, by including examples of calculations that would be used to implement the TAM, than did that of Southwest Gas. As indicated in the passages quoted above, our primary concern with the Southwest Gas proposal was not specifically with the lack of implementation details, but rather with a concept that would provide the utility with a level of risk insulation, while possibly discouraging conservation efforts through imposition of a surcharge on an entire class of customers if that class did not use "enough" gas the preceding year. The final difference claimed by UNS is its offer "to consider the creation of a

deferred throughput adjustment account." (Ex. A-18, at 14) Again, the distinction identified by UNS is not substantive in nature but instead provides an alternative means of accounting for the proposed surcharge. The Company's alternative accounting technique does not, however, address the underlying concerns clearly expressed regarding the Southwest Gas decoupling mechanism. We see no reason, based on the record in this proceeding, to depart from our finding in the Southwest Gas Decision regarding a proposed decoupling mechanism.

Having rejected UNS Gas's TAM proposal, we encourage the Company to engage in discussions with other stakeholders affected by this issue; to participate in the ongoing DSM workshops before the Commission; and, if possible, to develop a decoupling mechanism that does not suffer from the types of deficiencies identified by the parties in this case.

Demand-Side Management Programs

UNS Gas

UNS Gas proposes to implement several new DSM programs, including a residential furnace retrofit program, residential new construction home program, commercial HVAC retrofit program, and commercial gas-cooking efficiency program. The Company claims that these four new programs will require funding of $916,616 and that a proposed expansion of its low-income weatherization ("LIW") program will cost an additional $135,000, for a total annual DSM portfolio expense of $1,051,616 (Ex. A-15 at 13-15).

UNS states that it is largely in agreement with Staff's DSM recommendations, specifically with respect to submission of the programs for review by Staff. UNS witness Denise Smith testified that the Company prefers to have the new programs approved in this case so that they may be implemented as soon as possible (Tr. at 518). On May 4, 2007, the Company filed its DSM program proposals in a separate docket for Staff's review (Docket No. G-04204A-07-0274).

Ms. Smith indicated that the Company has agreed to use Staff's recommended Societal Cost Test to determine the effectiveness of the DSM programs, despite her reservations regarding how that test would be applied (Ex. A-21 at 4, 7; Ex. A-22 at 2). However, Ms. Smith stated that the other DSM tests - including the Participant Test, Program Administrator Cost Test, Total Resource Cost Test, and Rate Impact Measure Test - should also be utilized, to provide a full analysis of program

effectiveness (Ex. A-21 at 7). Ms. Smith also agreed that the Company would continue to provide semi-annual reports to the Commission, but stated that the Company would seek at a later time to move to an annual reporting requirement (Ex. A-22 at 14).

With respect to calculation of the DSM adjustor mechanism, Ms. Smith indicated that UNS agrees initially to limit recovery to 25 percent of the new program costs ($230,000) and LIW program costs ($113,400), plus the cost of the baseline study that is needed to evaluate thoroughly the effectiveness of the programs ($82,000). The total amount of $425,400 would translate to a DSM adjustor surcharge of $0.0031 per therm, when divided by total test year therms of 138,223,864 (*Id.* at 3).

Mr. Magruder

Mr. Magruder indicates that he is a proponent of DSM programs but believes that additional review of the Company's programs is necessary prior to approval. However, he suggested that all the necessary information regarding the programs should be submitted to Staff as soon as possible so that the programs could be addressed in the Recommended Opinion and Order in this case, to allow the parties an opportunity to comment regarding the findings determined therein. He also suggested that an integration of the UNS Gas and UNS Electric DSM programs could be consolidated in the pending electric rate case for UNS. At the same time, however, Mr. Magruder recommended that UNS Gas's DSM programs should not be funded until after public hearings are held on those programs. He proposed that the Energy Smart Home ("ESH") program should include training of local city/county building inspectors to meet Energy Star requirements, using RESNET personnel. Finally, Mr. Magruder recommended that in-home energy audits should be continued due to their value (Magruder Brief at 38-41).

Staff

Staff witness Julie McNeely-Kirwan presented Staff's position regarding the Company's proposed DSM programs. She recommended that the LIW funding ($113,400) and 25 percent of the new program costs ($229,154) should be included in the initial DSM surcharge, but that UNS Gas's portion of the baseline study costs ($82,000) should not be included in the surcharge initially (Ex. S-

40 at 1-2, 8). Based on this recommendation, Staff calculated an initial DSM surcharge of $0.0025 which it recommends be established in this case (*Id.*).

Ms. McNeely-Kirwan also agreed with UNS that the DSM adjustor reset date should require a filing by April 1 of each year, with an adjustment date of June 1. As indicated above, UNS agreed with Staff's recommendation to require semi-annual DSM reports. In her direct testimony, Ms. McNeely-Kirwan recommended that the Company file a comprehensive DSM portfolio, which UNS has apparently provided through an attachment to Denise Smith's testimony (Ex. A-23), as well as in the separate docket cited above. However, Staff opposes approval of specific programs in this proceeding and recommends approval in a separate docket, consistent with past practice for other companies (Tr. at 1141).

Conclusion

We agree with Staff's recommendation to set the DSM adjustor surcharge at an initial level of $0.0025, which reflects exclusion of the baseline cost study. As indicated in Staff's recommendation, the costs of the baseline study may be included in a subsequent reset of the adjustor once sufficient justification of the allocated costs has been submitted for Staff's review. UNS agreed with Staff's proposal to shift the adjustor filing date to April 1, with an adjustor date of June 1, as well as with Staff's recommendation that semi-annual reports be required for the DSM programs. We also agree with Staff that the appropriate forum for a full review of the specific DSM programs is in the separate docket in which there is an application currently pending. This approach is consistent with that required for other companies, including APS and Southwest Gas (*See, e.g.*, Decision No. 68487, at 61-63).

Low-Income Customer Programs

UNS Gas currently offers several low-income assistance programs. The Customer Assistance Residential Energy Support ("CARES") program (Rate Schedule R12) provides a per therm discount to customers meeting eligibility requirements during the months of November through April. Warm Spirits is an emergency bill assistance program offered to eligible low-income customers. As discussed above, UNS also offers the LIW program, the costs of which would now be recovered through the DSM adjustor mechanism.

UNS Gas states that, in addition to offering these specific programs, it will continue to work with the ACAA on low-income customer issues. The Company contends that it is committed to automatically enrolling customers eligible for the Low-Income Home Energy Assistance Program ("LIHEAP") into the CARES program (Ex. A-16 at 8) and will continue to expand its outreach efforts. Those outreach efforts include distribution of CARES applications to local assistance agencies, public libraries, and municipal buildings and promotion of the program through residential bill inserts (Ex. A-17 at 4). UNS also contends that it is willing to explore opportunities to increase the marketing of low-income programs and to increase LIW funds to low-income agencies.

Miquelle Scheier testified on behalf of ACAA regarding various low-income customer issues, including CARES customers (ACAA Ex. 1). Ms. Scheier opposed the Company's proposal to increase the customer charge for low-income customers; urged the Commission to increase marketing efforts for the R12 tariff; requested the Commission to require automatic enrollment of LIHEAP customers into the CARES program; sought the elimination of payday loan offices as payment centers for cash-paying customers; requested that bill assistance money be increased from $21,500 to $50,000; asked that LIW funding be increased to $200,000, and that $20,000 of that amount be directed to community volunteer weatherization efforts; and requested that the proposal to reduce the due date for bills be denied (*Id.* at 2).

CARES Program

Customers receiving service under the CARES program currently pay the same basic monthly charge of $7 as do other residential customers, but CARES customers receive a per therm discount of $0.15 on the first 100 therms of usage during the months of November through April. As described above in the rate design section of the Order, UNS proposed a seasonal monthly charge increase to $20 from December through March and to $11 from April through November. The Company also proposed to decrease the volumetric charge applicable to all customers. For CARES customers, UNS proposed a year-round customer charge discount of $6.50 per month, along with the reduction of the commodity charge discussed previously. Under the Company's recommendation, CARES customers' fixed monthly charge would increase from $7 to $13.50 from April through November,

but would decrease to $4.50 per month from December through March. The same volumetric charges would apply to all residential customers.

The Company claims that its proposal would increase CARES customers' bills modestly, with an increase of $1.12 per month during winter months (assuming100 therms of usage), and $4.21 per month during summer months (assuming 20 therms of usage) (Ex. A-9, Sched. H-4). UNS contends that some higher usage CARES customers may actually see a rate decrease due to the Company's proposed commodity charge reduction.

Staff recommends that the current monthly charge of $7 be retained for CARES customers and that they continue to receive the current $0.15 per therm discount for the first 100 therms of usage during the months of November through April (Ex. S-40 at 2). Staff contends that its recommendation provides a price signal that would encourage conservation by CARES customers during winter months, because usage over 100 therms during those months would incur a substantial increase. Staff witness McNeely-Kirwan stated that the Company's rate design proposal would provide a disincentive for conservation, given UNS's recommendation to decrease the volumetric charge for all therms of usage (*Id.* at 3).

Given our prior rejection of UNS's seasonal customer charge and across-the-board volumetric rate reduction recommendation, the application of the Company's proposal to CARES customers is effectively a moot point. We agree with Staff that keeping the current customer charge in effect for CARES customers, and retaining the current winter volumetric discount for the first 100 therms, will help mitigate the effects of the rate increase approved in this case and will continue to provide a rate structure for the low-income customers enrolled in the program that offers an opportunity to reduce their overall bills through conservation efforts. We therefore adopt Staff's recommendation on this issue.

Warm Spirits Program

Warm Spirits is a program, funded by customer contributions, that provides emergency bill payment assistance to low-income customers. UNS witness Gary Smith testified that UniSource Energy promotes the program through bill inserts and bill messages encouraging customers to contribute to the program (Ex. A-15 at 10-11). The proceeds of the contributions are distributed to

local service agencies, which assist qualified low-income customers in paying their bills, most often during the winter heating season. Mr. Smith stated that UNS Gas matches customer donations dollar-for-dollar with funds provided by UniSource shareholders. He indicated that UniSource made a one-time donation of $50,000 to the program in 2004 and that UNS matched $24,000 in donations in 2005. Mr. Smith testified that the Company would continue to match customer contributions on a dollar-for-dollar basis (*Id.*). As indicated above, ACAA proposes that the Commission require UNS to provide funding for Warm Spirits in the amount of $50,000 per year (ACAA Ex. 1 at 2).

The Company originally proposed that the Low-Income Weatherization Program include $21,600 in emergency bill assistance, separately and in addition to that already available through Warm Spirits. The $21,600 would have been part of the UNS Gas DSM portfolio and funded through the DSM adjustor. Staff objected because emergency bill assistance is not DSM and should not be funded as DSM. Staff proposed, and the Company agreed, that the $21,600 be moved into Warm Spirits and funded though base rates. We agree that the $21,600 in additional emergency bill assistance should not be funded through the DSM adjustor and that this amount should be moved into Warm Spirits and funded through base rates.

We believe that the Company's matching contributions to the Warm Spirits program, which currently amount to approximately $20,000 to $25,000 per year, are a reasonable commitment at this time. However, we encourage the Company to continue to promote the existence of the program and the ability for customers to make voluntary contributions.

It is not clear in the record whether UNS Gas currently has a section on customer bill payment stubs that allows customers to check a box to indicate that they would like to make a contribution at the time they write out their payment checks. This issue was raised in the Southwest Gas case, wherein we directed Southwest Gas to modify its billing statements to allow voluntary contributions (Decision No, 68487, at 59-60). In that Order, we pointed out that a contribution line is offered to APS customers and that "inclusion of a line on customer bills is preferable to [relying solely] on a bill insert, which may be discarded when customers open their bills." (*Id.* at 60) Therefore, if UNS Gas does not currently have in place a bill statement contribution option, it shall implement the change within 60 days of the effective date of this Decision.

Payments at Payday Loan Stores

In 2006, UNS closed local offices in Prescott, Cottonwood, Flagstaff, and Show Low[15] (Tr. at 434-35). These closings coincided with the Company's consolidation of its Tucson call center operations for all of the UniSource operating affiliates, which UNS claims was intended to improve customer service while at the same time cutting the Company's operating costs (Tr. at 436-40). At the time these offices were being closed, customers were notified that future payments could be made at various ACE Cash Express locations and other specified "cash only" stores (Ex. A-16, Attach. GAS-3). For payments made at these so-called "payday loan" stores in areas where UNS does not have a local office, UNS pays the fee charged by the payday loan stores, but customers who pay at such stores in an area that has a local office (*i.e.*, Kingman, Lake Havasu, and Nogales) must pay a $1 fee in order to make a payment at the payday loan stores (*Id.* at 8).

ACAA witness Scheier expressed concern that cash paying customers, especially low-income customers, could be vulnerable to predatory lending practices at the payday loan stores. She testified that ACAA objects to the use of such stores because "it places already vulnerable customers in a more vulnerable situation." (ACAA Ex. 1 at 13) Ms. Scheier also stated that she did not understand why the Company could not place "ATM-like kiosks" that accept cash payments in local areas (*Id.*). She further claimed that some low-income clients had been encouraged to take out loans when they made payments at the payday loan stores (ACAA Ex. 2, at 2).

Mr. Magruder also opposes use of payday loan stores for taking payments. He suggested that other payment agents should be found by the Company or, alternatively, that a Company employee may need to be on-location at the payday loan stores during weekdays (Magruder Brief at 37).

UNS witness James Pignatelli testified that UNS does not send customers to predatory lenders by its acceptance of payments at payday loan stores. He indicated that customers could obtain loans from payday loan stores even if the Company had not closed its local offices or had in place ATM-like kiosks (Ex. A-3 at 1). Mr. Pignatelli stated that the decision to close some branch offices and

[15] UNS continues to operate local offices in Kingman, Lake Havasu, and Nogales.

offer alternative locations for cash-paying customers was made to keep down costs for all customers, including low-income customers (*Id.*).

UNS witness Gary Smith claims that Ms. Scheier's comments regarding customers' being encouraged to take out loans from the payday loan stores is not consistent with information the Company has received from payday loan store managers (Ex. A-17 at 5). He contends that UNS is not encouraging customers to utilize payday loan services at these locations (Ex. A-16 at 9). During the hearing, Mr. Smith testified that APS also utilizes payday loan stores for acceptance of cash payments, as does Citizens Frontier Communications (Tr. at 343). He indicated that UNS contacted grocery stores and local banks in the Prescott and Chino Valley areas about their willingness to accept payments, but was turned down. Mr. Smith stated that UNS was looking into a joint arrangement with APS under which a payday loan store in Flagstaff would have a dedicated window available for payment of utility bills, separate from the store's main counter. He also testified that the Company was discussing with APS the possibility of using a non-payday loan store site for acceptance of payments (Tr. at 344-47).

Although we encourage UNS to seek out cost-cutting opportunities, we are concerned when those efforts result in the diminution of service to customers. We understand the Company's call center consolidation decision was intended to provide consistency between the UniSource affiliates and to reduce costs in the long-term. On cross-examination, the Company's witness sought to justify the office closings on the basis that not enough people used the local offices to justify their continuation, and that more customers use the payday loan stores due to their convenience (Tr. at 342-43). However, the closing of a number of local offices, especially in northern Arizona, represents not just the elimination of a nearby location for making payments, but also the loss of an office where customers could talk to a representative of the Company face-to-face to work out payment arrangements or receive assistance in signing up for available programs.

We believe that additional efforts should be undertaken by UNS to explore fully all available alternatives for the provision of service to customers. We therefore direct the Company to make every reasonable effort to determine whether other payment locations may be utilized either in addition to, or in lieu of, the payday loan stores currently used by UNS. These efforts should include,

but not be limited to, joining with other utilities to enlist alternative agents, such as banks or grocery stores, to accept cash payments and to explore of opening joint local offices to offset costs and any other alternatives that may enhance customer service without exposing customers to the potential of being solicited by predatory lenders in the course of making a utility payment. UNS shall file a copy of its recommendations consistent with this directive within 90 days of the effective date of this Decision.

Proposed Changes to Rules and Regulations

UNS proposed a number of changes to its existing Rules and Regulations governing service. Among those proposed changes are increases to charges for service lines and main extensions and a proposal to reduce the period, from 15 days to 10 days, that customers have to pay their bills before the bills are considered past due.

Line and Main Extension Policies

UNS proposes amendments to its Rules and Regulations (*i.e.*, tariffs) that it claims would ensure that developers and new customers pay a fair cost for infrastructure associated with connecting new developments to the UNS Gas system (Ex. A-15 at 19-20). As described by UNS witness Gary Smith, the Company proposes changes to both its service line and main extension policies (*Id.* at Sched. GAS-2). The Company's proposals, as set forth in its brief, are as follows:

1. For a new gas service line, the customer would be required to reimburse the Company at a rate of $16 per foot on the customer's property (the current rate is $8 per foot). For customers who provide the trench for the service line, the rate would be $12 per foot (*Id.* at 19).
2. Under the Company's proposal, there would be no free footage, so developers would pay the entire amount up front (subject to refund) (Tr. at 386-87).
3. In its effort to comply with A.A.C. R14-2-307, UNS prepared an incremental contribution study ("ICS") to determine an estimate of the costs and benefits of adding a customer to the system. Under the Company's proposal, the ICS component would be modified to reduce the credit applied to new customers or developers per service line or main extension (thereby increasing the required advances from new customers and developers). According to the Company, this change would ensure that the cost burden is initially placed on new customers and developers for main extensions or line extensions, subject to refund over a five-year period (Tr. at 384-87, 919; Ex. A-35).
4. For line extensions over $500,000, UNS would add a gross-up amount equal to the Company's estimated federal, state, and local income tax liability in advance (Ex. A-15, Sched. GAS-2).

UNS estimated that the changes described above would result in an additional $3.6 to $3.8 million per year in contributions, on average (Ex. A-30; Tr. at 915). The changes would result in an increased contribution from new customers/developers, from the current amount of approximately $300 to more than $500 per connection (*Id.*). In response to questions from Commissioner Mayes, UNS later offered the following two additional alternative proposals[16]:

1. Eliminating of the ICS and retaining tariff language requiring new customers to pay for the entire length of the new service line to their property, resulting in an additional estimated $1.2 million in contributions (Ex. A-31; Tr. at 916); and
2. Requiring that new customers/developers pay for excess flow valves (approximately $250 each), which will become a mandatory requirement for new service lines beginning in July 2008 (Ex. A-32; Tr. at 1067).

UNS points out that Staff witness Ralph Smith testified that the Company's line extension and main extension proposals (not including the alternatives) appear to be reasonably supported by the Company (Ex. S-25 at 64-67; Ex. S-27 at 44). Mr. Smith indicated that the Company's proposal appears to provide a feasibility study in compliance with Commission requirements (Tr. at 869-71). Therefore, Staff does not oppose the Company's tariff change requests on these issues. UNS also argues that its proposed ICS helps the Company specifically tailor a new customer's or developer's up-front contribution requirement rather than imposing a flat one-size-fits-all contribution requirement. UNS adds that because not all developments become fully built-out within the allotted five-year term of advance refunds, the balance of advances would become contributions after that five-year period (Tr. at 1055). UNS asserts that its proposals seek to hold developers and new customers responsible for a fair share of costs associated with serving growth.

We find that the Company's line and main extension proposals are a reasonable means of increasing the up-front contributions required from new customers and developers to connect to the UNS Gas system. However, we also believe that one of the alternatives suggested by the Company,

[16] UNS witness Gary Smith testified that the Company does not advocate adoption of these alternatives because he believes the Company's proposal, if combined with the alternatives, would require a significant increase in contributions by new customers and developers, from the current average of approximately $310 per connection to nearly $1,000 per connection. He stated that requiring substantial increases in required contributions could put UNS Gas at a competitive disadvantage, relative to the construction of homes using all electric or propane, and thereby lessen the Company's ability to add new service connections (Tr. at 1069-72).

the charge for excess flow valve installation, should be implemented by UNS to further increase the amount required for system connections. Since the excess flow valves will become mandatory in 2008, it is reasonable that the costs to install those devices should be included in the contributions, i.e. non-refundable, required from new customers/developers.

As set forth in Exhibit A-30, it is estimated that institution of these combined measures would cause the average contribution per service line to increase from the current amount of approximately $300 to $383 in 2007, $635 in 2008, and $760 in 2009 and beyond. The net result is that new customer/developer contributions would more than double within the next year and would continue to increase in the following year. Although the contributions are actually advances that are refundable within the first five years, to the extent a development is not built out within that five-year period, the balance of the up-front contributions would become nonrefundable and would not be includable in rate base.

We believe that our finding on this issue achieves a result that is consistent with the rate design concept of gradualism because, although it represents a significant increase in the up-front contribution required to be financed by new customers/developers, it keeps intact the ability of developers to recapture all or part of the initial investment. At the same time, as described by the Company's witnesses, approval of this modified proposal avoids the potential competitive disadvantage that would be faced by UNS Gas if a fully nonrefundable hook-up fee were to be implemented suddenly. We recognize that, over the long-term, increasing the number of customers on the system and the revenues associated with those customers should provide a benefit to all customers. While we believe the extension measures approved in this Order are reasonable at this time, we direct UNS Gas to investigate fully the issue of developer contributions and present in its next rate case viable alternatives to the proposal adopted herein, including but not limited to nonrefundable hook-up fees and other measures that would hold harmless existing customers and require greater contributions to ensure that growth pays for itself.

Reduction of Bill Payment Due Date

UNS proposes to modify its billing terms in its tariffs by reducing from 15 days to 10 days (from the time the bill is rendered) the time for customers to pay bills before the bills are considered

past due. The Company's proposed change would make its billing practices consistent with the requirements of the Commission's Rules, as set forth in A.A.C. R14-2-310(C). UNS witness Gary Smith contends that even under the proposed billing change, customers would have plenty of time to pay bills before late payment charges would apply or termination of service would be implemented (Ex. A-16 at 4). According to Mr. Smith, after the 10-day payment period, customers would have an additional 15 days before a late payment charge would be imposed, for a total of 25 days. At that point, the bill would be considered delinquent, but termination-of-service procedures (*i.e.*, notice of termination) would not commence for an additional 5 days, and several additional days would likely pass before actual termination occurred. Mr. Smith indicated that the Company would be able to waive the late fee if a customer presented good cause for late payment (*Id.*).

RUCO, ACAA, and Mr. Magruder oppose the Company's proposal to reduce the time to pay a bill. RUCO argues that, although the Company's proposal is consistent with the minimum requirements of the Commission's Rules, the only advantage identified by UNS is that the proposed tariff change would bring consistency to the three affiliated utility companies that are served by the UniSource consolidated call center (Tr. at 355). RUCO claims that the proposed payment dates are so short that a customer could go on vacation and return home to find the gas service shut off (RUCO Ex. 5 at 35). RUCO witness Diaz Cortez stated that RUCO has received calls from customers opposing the proposed changes and that a more flexible payment schedule should be retained. Ms. Diaz Cortez stated that the Company is already compensated, through the working capital calculation, for the delay that exists between the rendering of bills and the receipt of payment from customers (*Id.* at 36). RUCO also contends that the call center consistency rationale offered by the Company does not support the proposed changes because the call center representatives must be trained regarding gas-specific issues anyway. RUCO asserts that the payment schedule change would provide only a minimal benefit to the Company, but customers would bear the burden of the proposed changes.

Staff did not oppose the Company's proposal, but recommended a six-month waiver of the late payment penalty charge. Staff argues that during this initial six-month period, the penalty should be waived from day 10 to alleviate the hardship on customers from the proposed billing change.

According to UNS witness Gary Smith, the Company agrees with Staff's recommended six-month waiver period before the billing changes go into effect (Ex. A-16 at 3-4).

We agree with UNS that the proposed billing changes are reasonable. The billing changes would make the Company's tariffs consistent with the Commission's Rules and would remove an inconsistency among the billing tariffs currently in effect for the UniSource affiliates. The proposed change would also allow the customer call center representatives to have a single set of rules in place for all of the UniSource affiliates, which should minimize potential errors that may occur when information regarding delinquent bills and/or termination of service is provided to customers. In addition, as the UNS witness pointed out, a bill would not be subject to a late payment charge until at least 25 days after the bill is rendered, and a termination of service notice for nonpayment could not occur sooner than 30 days following issuance of a bill. We believe that these timeframes provide an adequate period for customers to either pay a bill or seek alternative payment arrangements prior to being subjected to a penalty or termination of service. We therefore approve the Company's proposed changes to its billing tariffs. However, in accordance with the Company's agreement to abide by Staff's six-month waiver recommendation, we direct UNS Gas not to implement the approved billing change for a period of six months following the effective date of this Decision.

Prudence of Gas Procurement Practices and Policies

As described above, this consolidated proceeding includes Docket No. G-04204A-05-0831 (the Prudence Case), which relates to an audit conducted by Staff of UNS Gas's natural gas procurement practices and policies during the period of September 2003 through December 2005 (Tr. at 761). Staff retained Jerry Mendl, President of MSB Energy Associates, Inc., and George Wennerlyn, President of Select Energy Consulting, LLC, to conduct the Prudence Case audit.

Based on his review of the Company's procurement practices during the audit period, Mr. Mendl concluded that the Company's procurement strategy during the audit period was reasonable (Ex. S-20 at 1). He reiterated at the hearing that "[UNS Gas's] natural gas procurement strategy that was set forth in the price stabilization policies was reasonable over the review period." (Tr. at 761)

Mr. Wennerlyn reached the same conclusion regarding the Company's practices during the 2003-2005 audit period. He stated that the Company's gas procurement practices and policies during

that period "achieved appropriate objectives of a purchasing strategy which balances reliability, cost, and price stability. The purchases were reasonable and prudent." (Ex. S-18 at 4-5)

There is no dispute on the issue of prudence during the identified audit period. We therefore agree that the Company's natural gas procurement practices and policies during the audit period of September 2003 through December 2005 are deemed prudent.

Price Stabilization Policy

This piece of the prudence equation relates to the request by UNS Gas for the Commission to approve its current "Price Stabilization Policy" ("PSP"). The basis for UNS Gas's request for what is effectively prudence pre-approval was described as follows by Company witness David Hutchens as follows:

> We believe that instead of the Commission attempting to second guess, after the fact, the individual acts that UNS Gas transacted in connection with gas procurement and hedging, it is more productive and beneficial to customers that the Commission review the policies and approve them prospectively. That way the Company will know the clear direction of the Commission and act accordingly. If the Company acts within the approved policies, its transactions will be conclusively prudent (Ex. A-4, at 7).

In his rebuttal testimony, Mr. Hutchens responded to Staff's concern that approval of the PSP in this case would put the Company on "autopilot" with respect to its procurement practices by indicating that such a practice would be inconsistent with the Company's past behavior and with the PSP itself (Ex. A-5 at 10). Mr. Pignatelli testified at the hearing that UNS sought the PSP approval in this case in order to avoid second-guessing during "the heat of a rate case three or four years after the fact" (Tr. at 106). He indicated that while the Company would keep adequate documentation of its procurement practices, he feared "a political decision down the road" (Tr. at 122).

Staff opposes the Company's request for approval of the PSP, arguing that approval of UNS Gas's hedging policy would insulate 45 percent of its gas purchases from a subsequent prudence review and is not necessary if the Company retains adequate documentation. Staff argues that UNS Gas and Staff have a fundamental disagreement regarding the purpose of the hedging plan. Staff claims that, as indicated by Mr. Hutchens, UNS views the hedging policy only as a means of reducing

the volatility of natural gas prices (Tr. at 129, 157), whereas Staff believes that hedging policies ensure price stability, reliability, and competitiveness to achieve the lowest possible cost (Tr. at 744-45). Staff asserts that elimination of traditional prudence reviews in favor of the "compliance review" process sought by the Company would deprive Staff of the ability to properly employ its three-prong standard.

Staff witness Mendl also expressed concern with the higher burden of proof that would exist for Staff under the Company's proposal. He stated that if pre-approval of a particular plan is given, the Company may seek to abide by that plan instead of responding to market conditions, because adherence to the prior plan would be deemed presumptively reasonable (Tr. at 772). Staff argues that pre-approval is not necessary because, as pointed out by Mr. Mendl, prudence is judged based on what was known at the time decisions were made, not on a retrospective analysis (*Id.*). Staff contends that UNS can protect itself from future prudence disallowances by maintaining proper documentation regarding the decisions that were made and that the Company has not presented any evidence that the current standard is unfair.

We agree with Staff that the Company's request is simply unnecessary because there has been no evidence presented to suggest that the current process is unfair or unreasonable. Indeed, Mr. Hutchens conceded that there has been no indication that "there would be some unfair or biased after-the-fact analysis based on ...[the] Staff recommendations" (Tr. at 140). Mr. Hutchens also admitted that the only benefits to be gained from granting UNS's request are to the Company and that the purpose of seeking the Commission's approval of the PSP is to insulate the Company from risk (Tr. at 778). As Staff indicates, UNS Gas can avoid future prudence disallowances by properly documenting its procurement practices and policies. Moreover, in spite of Mr. Pignatelli's cynical assertion that pre-approval is necessary to avoid politically based decisions in the future, the record suggests that just the opposite is true. As discussed above, two outside Staff consultants conducted a comprehensive audit of the Company's procurement practices from September 2003 through 2005 and found that UNS Gas's practices and policies were prudent. We agree with Staff's recommendations. We do not believe that UNS Gas has presented a sufficient justification for approval of the PSP, and we therefore deny its request.

Purchased Gas Adjustor

In Docket No. G-04204A-06-0013 (the PGA Case), which was previously consolidated in the above-captioned proceeding, UNS Gas filed an application seeking approval to revise its current Purchased Gas Adjustor ("PGA"). UNS witness Hutchens testified that the current volatile natural gas market has exposed weaknesses in the Company's existing PGA mechanism, which cause delays in cost recovery, and that such delays impact customer decisions based on the lack of timely price information and impact the Company's cash flows (Ex. A-4 at 7). Mr. Hutchens stated that the deficiencies in the current PGA include: 1) inappropriate price signals to customers, 2) the potential for large bank balances to accumulate 3) a below-market interest allowance earned on bank balances; 4) an inappropriately narrow bandwidth, and 5) a potentially adverse impact on the Company's ability to devote capital to necessary investments to serve customers (*Id.* at 7-8).

Based on these claimed deficiencies, Mr. Hutchens made the following recommendations in his direct testimony to improve the Company's PGA mechanism:

1. Bandwidth – The bandwidth should be eliminated or, in the alternative, increased to $0.25 per therm for an interim period of time and then eliminated.
2. Base Cost of Gas – The base cost of gas should be set at zero, and the entire cost of gas reflected in the PGA.
3. PGA Bank Interest – The interest earned on the PGA bank balance should reflect UNS Gas's actual cost of new debt, which is the London Inter-Bank Offering Rate ("LIBOR") plus 1.5 percent.
4. Bank Balance Thresholds – The new threshold level for under-collected bank balances established in Decision No. 68325 ($6,240,000) should also be adopted as the threshold level for over-collected bank balances.
5. Capital Structure – To the extent the PGA bank balances result in long-term financing, that debt should be excluded from the cost of capital calculation in rate case proceedings.
6. Surcharges – When surcharges are required, the Commission should approve a surcharge large enough to eliminate the bank balance in a reasonable time period and allow for timely recovery (*Id.* at 8).

In his direct testimony, Staff witness Robert Gray offered seven recommendations regarding the Company's PGA proposals. He stated as follows:

1. The base cost of gas should be set at zero.

2. UNS should provide specific customer education materials to explain the change (setting the cost to zero), and should represent the cost of gas as a specific and separate line item on customer bills, noting in a footnote any temporary PGA surcharge or credit in effect.
3. During the first 12 months the new PGA bandwidth is in effect, UNS should provide a comparison of the new monthly PGA rate to the sum of the base cost of gas and the monthly PGA rate in prior months.
4. The bandwidth on the monthly PGA rate should be expanded to $0.15 per therm.
5. The threshold on the PGA bank balance for *under-collected* balances should be eliminated.
6. The threshold on the PGA bank balance for *over-collected* balances should be set at $10 million.
7. The currently applicable interest rate for the PGA bank balance should be retained.

UNS claims that the parties are in agreement regarding most of the PGA issues. The Company points out that all parties agree that the entire cost of gas should be reflected in the PGA and that the base cost of gas should be set at zero in order to send proper price signals regarding the actual cost of gas. UNS also contends that all parties have agreed that some widening of the current bandwidth is appropriate, although Staff continues to disagree with the requested level of the widening. In his rebuttal testimony, Mr. Hutchens agreed with Staff's recommendation that the under-collection threshold for requesting a PGA surcharge should be eliminated and that the over-collection threshold should be set at $10 million (Ex. A-5 at 4). The two remaining disputed PGA issues are the appropriate bandwidth level and the PGA bank interest rate.

PGA Bank Interest Rate

UNS witness Hutchens testified that the Company is requesting that it be allowed to recover through the PGA one of two rates, depending on the size of the PGA bank balance. For balances below twice the PGA threshold (currently $6.24 million), UNS seeks to earn the interest rate based on LIBOR plus 1.0 percent.[17] For balances that exceed twice the PGA bank balance threshold, UNS seeks to recover a "carrying cost at a rate equal to UNS Gas' authorized rate weighted average cost of capital as determined in this proceeding" (Ex. A-4 at 14).[18]

[17] UNS initially sought interest rate recovery based on LIBOR plus 1.5 percent, but amended the request to LIBOR plus 1.0 percent through Mr. Hutchens's rebuttal testimony, due to a lowering of the interest rate on the Company's short-term revolving credit facility (Ex. A-5 at 5).

[18] As discussed above, the WACC established in this proceeding is 8.30 percent, compared to the LIBOR plus 1.0 percent rate, which was 5.53 percent at the end of May 2007 (See Ex. A-4 at 13).

Although RUCO agreed to the LIBOR plus 1.5 percent rate (and would presumably also agree to the modified LIBOR plus 1.0 percent rate), RUCO opposes allowing the WACC rate to be applied to the higher balances requested by UNS (RUCO Ex. 5 at 24-25). RUCO contends that, given its agreement with the Company's proposal to double the current bandwidth and to provide for timely recovery of necessary surcharges, the higher interest rate would not be necessary because UNS would no longer be burdened with large under-collected balances. Ms. Diaz Cortez added that it would be inappropriate to predetermine outside of a rate case the ratemaking treatment to be afforded to the specific debt (*Id.* at 25-26).

Staff also opposes the Company's request to apply the WACC to higher PGA bank balances. Staff witness Robert Gray testified that interest rates for PGA bank balances were originally set in a generic docket (Decision No. 61225, issued October 30, 1998) and applied uniformly to all Arizona LDCs as a result of the consensus of a working group that included LDCs, Staff, and RUCO (Ex. S-41 at 13). The uniform interest established in that generic docket was the monthly three-month commercial *non-financial* paper rate, as established by the Federal Reserve (*Id.*). Mr. Gray stated that the interest rate was later changed in a subsequent generic proceeding (Decision No. 68600, issued March 23, 2006), only because the Federal Reserve was no longer publishing the previously established rate. Therefore, the current generic interest rate for PGA bank balances is the monthly three-month commercial *financial* paper rate published by the Federal Reserve. The rates are similar, although the current rate is slightly higher, on average, than the prior rate (*Id.*).

According to Mr. Gray, the Company's request should be rejected by the Commission for several reasons. He stated that the UNS proposal is unnecessary because it would add a level of administrative complexity to the process in making the calculations and because the PGA bank balances do not always trend upwards (*Id.* at 14). Mr. Gray testified that it was unclear which LIBOR rate the Company was proposing to use, that it appears the LIBOR itself would be very close to the interest rate currently in effect, and that it is only the application of an add-on component to the LIBOR rate (*i.e.*, the LIBOR plus 1.0 percent proposed by UNS) that raises the rate above the current rate by a substantial amount (*Id.* at 14-15). Mr. Gray indicated that the PGA interest rate approved recently for Southwest Gas was the one-year nominal Treasury constant maturities rate, which is

comparable to the rate currently in effect for UNS Gas. The same rate is in effect for APS, and Mr. Gray asserts that UNS has not presented any justification for a different treatment (*Id.* at 15).

Mr. Gray also stated that Staff's recommendations to expand the PGA bandwidth (see discussion below) and to expand and eliminate the bank balance thresholds would reduce the likelihood of UNS Gas's incurring substantial bank balances for long periods of time (*Id.* at 16). He therefore recommended that the existing interest rate continue to be applied to UNS's PGA bank balances or, as an alternative, that the same interest rate applicable to both Southwest Gas and APS (the one-year nominal Treasury constant maturities rate) be applied (*Id.*). Finally, Mr. Gray recommended that if the applicable interest rate becomes unavailable (*i.e.*, unpublished) for one or more months, the prior month's interest rate apply. If the interest rate becomes unavailable on a recurrent basis, he recommends that UNS file a request to change to a comparable rate (*Id.* at 17).

We agree with Staff that UNS has not presented a sufficient basis for altering the PGA bank balance interest rate that currently exists. As Mr. Gray points out, a similar rate is in effect for Southwest Gas and APS, and we see no reason why UNS should be treated differently from those companies. In addition, granting a higher interest rate could provide a disincentive for the Company to reduce bank balances and could cause it to become less focused on taking all possible measures to reduce the cost of gas for its customers (*Id.* at 15-16). We therefore adopt Staff's recommendation to retain the current interest rate for UNS's PGA bank balances.

Expansion of Bandwidth

Under its current configuration, the Company's PGA bandwidth limits the movement of the monthly PGA rate over a 12-month period. The current bandwidth is $0.10 per therm, which means that when a new PGA rate is calculated each month, the new monthly rate cannot be more than $0.10 per therm different than the monthly PGA rate for any of the previous 12 months (Ex. S-41 at 5). Mr. Gray explained that the PGA bandwidth was initially established in 1999 at a rate of $0.07 per therm for Arizona LDCs during a period of relatively stable gas prices. As prices became more volatile, that bandwidth level often limited the movement of monthly PGA rates for periods of time. In Decision No. 62994 (November 3, 2000), UNS's predecessor was granted a bandwidth increase to $0.10 per therm (*Id.*). Mr. Gray testified that recent bandwidth adjustments were approved for

Southwest Gas (to $0.13 per therm) and for Duncan Rural (could change up to $1.20 per therm per year). However, he indicated that the Commission granted the significant expansion to Duncan Rural due to that company's small size and considerable financial constraints (*Id.* at 6).

In its application, UNS Gas initially requested that the PGA bandwidth be eliminated or, alternatively, set at $0.25 per therm for a period of time before being eventually eliminated (Ex. A-4 at 11-12). In his rebuttal testimony, UNS witness Hutchens agreed with RUCO's proposal to increase the current bandwidth to $0.20 per therm (Ex. A-5 at 3-4). Mr. Hutchens stated that setting the bandwidth at an inappropriately low level would fail to send proper price signals to customers regarding the actual cost of the gas being consumed (Ex. A-4 at 12).

Staff witness Gray recommended that the bandwidth be increased to $0.15 per therm. He stated that this bandwidth increase would provide the Company with significant additional room for movement of the monthly PGA rate, while providing a reasonable limit on the exposure of UNS customers to automatic adjustments without Commission review. Mr. Gray also indicated that Staff remains open to consideration of further changes to the PGA mechanism, if such changes are warranted (Ex. S-41 at 7-8). He explained in his surrebuttal testimony that setting a proper bandwidth level requires a balancing of several policy goals, including "timely recovery of gas costs by the utility, reduction of price volatility for ratepayers, and the Commission's interest in reviewing significant changes in rates before they are passed along to ratepayers." (Ex. S-42, at 2) He conceded that employing a bandwidth could result in the Company's accumulating large bank balances that must eventually be paid by customers (Tr. at 1133). However, he reiterated that the various policy goals, including protection of ratepayer interests, must be balanced in setting the bandwidth (*Id.*).

We agree with Staff's recommendations regarding the PGA issues, including increasing the Company's bandwidth to $0.15 per therm. The $0.15 per therm bandwidth is higher than the $0.13 bandwidth approved recently for Southwest Gas, and we believe it is reasonable under the facts of this case. Although UNS attempts to use the Duncan Rural case as a basis for seeking a greater increase in the bandwidth, Mr. Gray explained that Duncan is a very small natural gas cooperative with only 80 customers and that it has significant financial issues. UNS Gas is not in a comparable situation, and we do not believe a comparison with Duncan Rural is relevant for purposes of setting

an appropriate bandwidth in this proceeding. Indeed, the 50 percent increase over UNS's current bandwidth is significant and properly balances the policy goals identified in Staff's testimony. The rate of $0.15 per therm will provide UNS Gas with a greater degree of flexibility in maintaining its PGA bank balances at a reasonable level, while also offering to customers a measure of protection from sudden automatic PGA increases outside of the Commission's purview.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. On November 10, 2005, the Arizona Corporation Commission opened an inquiry (Docket No. G-04204A-05-0831) into the prudence of the gas procurement policies and practices of UNS Gas Inc. (the Prudence Case).

2. On January 10, 2006, UNS Gas filed an application (Docket No. G-04204A-06-0013) with the Commission seeking review and revision of the Company's Purchased Gas Adjustor (the PGA Case).

3. On July 13, 2006, UNS Gas filed an application with the Commission (Docket No. G-04204A-06-0463) for an increase in its rates throughout the State of Arizona (the Rate Case).

4. On August 14, 2006, Staff filed a Letter of Sufficiency indicating that the Company's Rate Case application met the sufficiency requirements outlined in A.A.C. R14-2-103 and classifying the Company as a Class A utility.

5. On September 8, 2006, a Procedural Order was issued consolidating the Prudence Case, PGA Case, and Rate Case dockets; scheduling a hearing for April 16, 2007; and setting various other procedural deadlines.

6. Intervention was granted to RUCO, ACAA, and Marshall Magruder.

7. With its application in the Rate Case, UNS filed its required schedules in support of the application, and the direct testimony of various witnesses.

8. On February 9, 2007, Staff, RUCO, ACAA, and Mr. Magruder filed direct testimony in accordance with the previously established procedural schedule. Staff filed additional direct

testimony on February 16 and February 23, 2007.

9. On March 16, 2007, UNS filed the rebuttal testimony of various witnesses in response to Staff and intervenor testimony.

10. Surrebuttal testimony was filed by ACAA on March 30, 2007; and by Staff, RUCO, and Mr. Magruder on April 4, 2007.

11. On April 11, 2007, UNS filed the rejoinder testimony of several witnesses in response to the surrebuttal testimony of Staff and intervenor witnesses.

12. The evidentiary hearing commenced as scheduled on April 16, 2007, and additional hearing days were held on April 17, 18, 19, 20, 24, and 25, 2007.

13. Initial Post-Hearing Briefs were filed on June 5, 2007, by UNS, Staff, RUCO, and Mr. Magruder. Final Schedules were also filed on June 5, 2007, by UNS and RUCO. On June 6, 2007, Staff filed a Notice of Errata and revised Initial Brief.

14. Reply Briefs were filed on June 19, 2007, by UNS, Staff, RUCO, and Mr. Magruder.

15. On June 21, 2007, Staff filed a Notice of Errata and Additional Authority.

16. According to the Company's application, as modified, in the test year ended December 31, 2005, UNS had adjusted operating income of $8,506,168 on an adjusted OCRB of $162,358,856, for a 5.24 percent rate of return.

17. UNS requests a revenue increase of $9,459,023, Staff recommends a revenue increase of $4,312,354, and RUCO recommends a revenue increase of $2,734,443.

18. For purposes of this proceeding, we determine that UNS Gas has an OCRB of $154,604,408 and a FVRB of $184,120,761.

19. A rate of return on FVRB of 6.97 percent is reasonable and appropriate.

20. The Company's attempt to interject the issue of the *Chaparral City* decision through its rebuttal testimony was untimely, prejudicial to the other parties, and its late attempt to apply the weighted average cost of capital to FVRB is not reasonable and is not supported by the testimony and evidence in the record.

21. UNS Gas is entitled to a gross revenue increase of $5,257,468.

22. The Company's proposed decoupling mechanism proposal, the Throughput

Adjustment Mechanism, is not adopted in this proceeding.

23. The class responsibility for the revenue requirement should be allocated using the methodology of Staff's rate design expert witness.

24. For residential customers under Schedule R10, the basic monthly customer charge should be increased from $7.00 to $8.50, with a commodity charge increase to $0.3270 per therm, based on the revenue requirement established herein.

25. For CARES customers (Schedule R12), the current customer charge of $7.00 should remain in place, with a commodity charge increase to $0.3270 per therm, based on the revenue requirement established herein.

26. The rates for other customer classes should be set based on Staff's rate design recommendation, with the customer charges for each class established at the level recommended by Staff and with volumetric charges based on the revenue requirement determined herein.

27. The billing determinants proposed by the Company should be employed for setting rates in this proceeding.

28. Staff's recommendation to set the DSM adjustor surcharge at an initial level of $0.0025, which reflects exclusion of the baseline cost study, is reasonable. In addition, it is reasonable to require UNS to file semi-annual reports for the DSM programs, to shift the adjustor filing date to April 1 (with an Adjustor date of June 1), and that the appropriate forum for a full review of the specific DSM programs is in the separate docket in which there is an application currently pending.

29. In the event that UNS Gas does not currently have in place a bill statement contribution option, the Company should implement the change within 60 days of the effective date of this Decision.

30. The Company's natural gas procurement practices and policies during the audit period of September 2003 through December 2005 are deemed prudent.

31. UNS Gas has not presented a sufficient justification for approval of the Price Stabilization Plan.

32. With respect to the Company's Purchased Gas Adjustor mechanism, we adopt Staff's

recommendations, including setting the base cost of gas at zero and increasing the current $0.10 per therm adjustment band to $0.15 per therm.

33. The interest rate for the Company's PGA bank balance should remain in place (monthly three-month commercial financial paper rate published by the Federal Reserve), in accordance with Staff's recommendation.

34. DSM programs should be funded at the level recommended by Staff: LIW funding ($113,400) and 25 percent of the new program costs ($229,154) should be included in the initial DSM surcharge, but UNS Gas's portion of the baseline study costs ($82,000) should not be included in the surcharge initially. Staff's proposed initial DSM surcharge of $0.0025 is therefore adopted.

35. With respect to the use of payday loan stores for acceptance of customer payments, the Company should make every reasonable effort to determine whether other payment locations may be utilized either in addition to, or in lieu of, the payday loan stores currently used by UNS, and the Company should file a copy of its recommendations consistent with this directive within 90 days of the effective date of this Decision.

36. The Company's line and main extension proposals are a reasonable means of increasing the up-front contributions required from new customers and developers to connect to the UNS Gas system, subject to inclusion of the addition of a charge for excess flow valve installation, and subject to the additional requirement that UNS Gas investigate fully the issue of developer contributions and present in its next rate case viable alternatives to the proposal adopted herein, including but not limited to nonrefundable hook-up fees and other measures that would hold harmless existing customers and require greater contributions to ensure that growth pays for itself.

37. UNS Gas's proposed billing change, to reduce from 15 days to 10 days, the date for customers to pay bills before the bills are considered past due, is a reasonable modification that will make the Company's tariffs consistent with the Commission's Rules and would remove an inconsistency among the billing tariffs currently in effect for the other UniSource affiliates. However, in accordance with the Company's agreement to abide by Staff's six-month waiver recommendation, UNS Gas should not implement the approved billing change for at least six months following the effective date of this Decision.

CONCLUSIONS OF LAW

1. UNS Gas is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§40-250, 40-251, and 40-367.

2. The Commission has jurisdiction over UNS Gas and the subject matter of the above-captioned Rate Case, Prudence Case, and PGA Case.

3. The fair value of UNS Gas's rate base is $184,120,761, and applying a 6.97 percent rate of return on this fair value rate base produces rates and charges that are just and reasonable.

4. The rates, charges, approvals, and conditions of service established herein are just and reasonable and in the public interest.

ORDER

IT IS THEREFORE ORDERED that UNS Gas, Inc., is hereby authorized and directed to file with the Commission, on or before November 30, 2007, revised schedules of rates and charges consistent with the discussion herein and a proof of revenues showing that, based on the adjusted test year level of sales, the revised rates will produce no more than the authorized increase in gross revenues.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after December 1, 2007.

IT IS FURTHER ORDERED that UNS Gas, Inc., shall notify its customers of the revised schedules of rates and charges authorized herein by means of an insert, in a form acceptable to Staff, included in its next regularly scheduled billing,.

IT IS FURTHER ORDERED that UNS Gas, Inc., shall file in its next rate case more detailed support for allowance of AGA dues and an explanation of how the AGA's activities, aside from marketing and lobbying efforts, benefit the Company's customers.

IT IS FURTHER ORDERED that UNS Gas, Inc., should engage in discussions with other stakeholders affected by this issue, participate in the ongoing DSM workshops before the Commission, and, if possible, attempt to develop a decoupling mechanism that does not suffer from the types of deficiencies identified by the parties in this case.

IT IS FURTHER ORDERED that if UNS Gas, Inc., does not currently have in place a bill

statement contribution option, it shall implement such a change within 60 days of the effective date of this Decision.

IT IS FURTHER ORDERED that UNS Gas, Inc., shall set the DSM adjustor surcharge at an initial level of $0.0025, and shall make its DSM adjustor filing by April 1 of each year.

IT IS FURTHER ORDERED that UNS Gas, Inc., shall file semi-annual reports for its DSM programs in accordance with Staff's recommendations.

IT IS FURTHER ORDERED that UNS Gas, Inc., shall file a copy of its recommendations regarding available alternatives for payment and service center locations within 90 days of the effective date of this Decision.

IT IS FURTHER ORDERED that UNS Gas, Inc. shall submit, within 30 days of this Decision, a revised Excess Flow Valve Installation tariff indicating that all new customers/developers shall pay the full cost of installation and the payment shall be a contribution (i.e. non-refundable).

IT IS FURTHER ORDERED that UNS Gas, Inc., shall investigate fully the issue of developer contributions and present in its next rate case viable alternatives to the proposal adopted herein, including but not limited to nonrefundable hook-up fees and other measures that would hold harmless existing customers and require greater contributions to ensure that growth pays for itself.

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IT IS FURTHER ORDERED that UNS Gas, Inc., shall not implement the approved billing change to reduce the payment due date, for six months following the effective date of this Decision.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN

COMMISSIONER

COMMISSIONER

COMMISSIONER

COMMISSIONER

IN WITNESS WHEREOF, I, DEAN S. MILLER, Interim Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 27th day of Nov., 2007.

DEAN S. MILLER
INTERIM EXECUTIVE DIRECTOR

DISSENT

DISSENT

SERVICE LIST FOR: UNS GAS, INC.

DOCKET NOS.: G-04204A-06-0463, G-04204A-06-0013 and G-04204A-05-0831

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BEFORE THE ARIZONA CORPORATION COMMI

Arizona Corporation Commission
DOCKETED

FEB 23 2006

DOCKETED BY

EXHIBIT
RUCO-3
ADMITTED

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. G-01551A-04-0876

DECISION NO. 68487

OPINION AND ORDER

DATES OF HEARING: October 3, 4, 5, 6, 7 and 11, 2005

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Dwight D. Nodes

IN ATTENDANCE: William A. Mundell, Commissioner
Marc Spitzer, Commissioner
Kristin K. Mayes, Commissioner

APPEARANCES: Mr. Andrew W. Bettwy, Ms. Karen S. Haller and Mr. Justin Lee Brown, on behalf of Southwest Gas Corporation;

Mr. Scott S. Wakefield, on behalf of the Residential Utility Consumer Office;

Mr. Walter Meek, on behalf of the Arizona Utility Investors Association;

Mr. Peter Q. Nyce, Jr., on behalf of the United States Department of Defense;

Mr. Timothy M. Hogan, Arizona Center for Law in the Public Interest, on behalf of Southwest Energy Efficiency Project and Natural Resources Defense Council;

Ms. Laura Sixkiller, ROSHKA, DEWULF & PATTEN, PLC, on behalf of Tucson Electric Power Company; and

Mr. Jason Gellman and Ms. Diane Targovnik, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

We agree with Staff that the 2005 wage increase expense should be allowed because it is a known and measurable expense that is being incurred by the Company on a going-forward basis. Because the post-test year wage increase has been applied only to employees who were employed during the test year, there is no resulting mismatch of revenue and expenses.

American Gas Association Dues

The American Gas Association ("AGA") is a national trade association for natural gas distribution and transmission companies. During 2004, Southwest Gas paid dues to the AGA (Arizona portion) of $211,934 (RUCO Ex. 5, RLM-9). The AGA provides services to its members in the following categories: Public Affairs; Communications; Corporate Affairs and International; General Counsel and Corporate Secretary; Regulatory Affairs; Marketing Development; Operating & Engineering Services; Policy & Analysis; Industry Finance & Administrative Programs; and General & Administrative Expense (Ex. A-30, RLA-3).

Although Southwest Gas claims that it has removed the amount of the dues that are attributable to the AGA's Marketing and Lobbying functions (1.54 percent and 2.10 percent, respectively), RUCO seeks an additional 39.09 percent disallowance ($75,385) for the Public Affairs and Communications functions performed by the AGA (RUCO Ex. 5, RLM-9). According to RUCO witness Moore, the Communications category of AGA operations promotes the use of gas over other fuels, while the Public Affairs category provides members with information on legislative and regulatory developments, provides testimony, comments, and filings regarding legislative and regulatory activities, and lobbies on behalf of the industry (*Id.* at 21-22).

Southwest Gas witness Aldridge countered that the Communications and Public Affairs categories are appropriate AGA functions that should be recovered in test year expenses because the Company removed the amounts specifically associated with marketing and lobbying. Ms. Aldridge testified that the Communications function of the AGA includes developing informational materials for member companies and consumers and coordinating all media activity (Tr. 550). With respect to the Public Affairs function, the AGA described its activities as follows: "The [AGA] monitored and represented the activities of Congress and Federal agencies that affected issues of importance to the natural gas industry and its customers. This division also monitored state and local legislative and

its management's compensation at risk. According to Southwest Gas, if the Company put these amounts in the employees' base salary, Staff and RUCO would not claim that there should be a disallowance.

In Decision No. 64172, 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 Staff's equal sharing recommendation to be a reasonable resolution.

Supplemental Executive Retirement Plan

Southwest Gas offers a Supplemental Executive Retirement Plan ("SERP") to the Company's officers. Company witness Mashas testified that the SERP is necessary "to ensure that the retirement and deferred compensation portions of [the officers'] total compensation are on parity with all other employees of Southwest whose retirement distribution is not impacted by certain IRS regulations" (Ex. A-33, at 3). Mr. Mashas claims that recovery of the SERP costs is reasonable due to restrictions on these employees' basic retirement plan ("BRP"), exclusion of deferred compensation from the BRP calculation, and the need to ensure attraction and retention of qualified employees. Mr. Mashas explained that IRS regulations place limits on pension plan calculations for salaries exceeding $165,000 and thus salaries in excess of that level are not included in the pension calculation. Mr. Mashas stated that the SERP provides officers with a retirement benefit equal to 50 percent of the average of the last three years salary provided that they are at least 60 years old and have at least 20 years of service (*Id.* at 5-6). In addition, IRS regulations place restrictions on the Company's 401(k) contributions to the extent that "maximum contribution levels represent a significantly smaller percentage of an officer's salary compared to other employees" (*Id.* at 4-5).

RUCO witness Moore proposed a reduction in test year expenses of approximately $2.7

million associated with the SERP. Mr. Moore stated the cost of these supplemental retirement benefits for select executives is not a necessary cost of providing gas service to customers because the Company's officers are already fairly compensated with a wide array of benefits, including a retirement plan. Mr. Moore cited to the Company's most recent rate case before the Nevada Public Utilities Commission[3] where Southwest Gas' SERP expenses were excluded from the Company's operating expenses (RUCO Ex. 5, at 28-29).

We agree with RUCO's position on this issue. Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

Miscellaneous Expenses

Through her Direct testimony, Company witness Aldridge indicated that the application included an adjustment to remove certain miscellaneous expenses for items such as gym memberships, donations and meals (Ex. A-29, at 23).

Based on his review of data requests, RUCO witness Moore proposed an additional adjustment to remove from test year expenses "payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events and for various meals, lodging and refreshments, which are not necessary in the provisioning of gas service" (RUCO Ex. 5, at 25).

[3] *Application of Southwest Gas Corporation for Increase in Rates*, Public Utilities Commission of Nevada, Order in Docket No. 04-3011 (August 30, 2004), at 41.

EXHIBIT
RUCO-4
ADMITTED

0000092983

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

Arizona Corporation Commission
DOCKETED
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IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA.

DOCKET NO. G-01551A-07-0504

DECISION NO. 70665

OPINION AND ORDER

DATES OF HEARING: June 13, 2008 (Procedural Conference); June 16, 17, 18, 20, 24, 25 and 26, 2008.

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Dwight D. Nodes

IN ATTENDANCE: Mike Gleason, Chairman
Jeff Hatch-Miller, Commissioner
Kristin K. Mayes, Commissioner

APPEARANCES: Ms. Karen S. Haller, Mr. Justin Lee Brown, and Ms. Meridith J. Strand, on behalf of Southwest Gas Corporation;

Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office;

Mr. Michael Grant, GALLAGHER & KENNEDY, P.A., on behalf of the Arizona Investment Council;

Mr. Timothy Hogan, Arizona Center For Law In The Public Interest, on behalf of Southwest Energy Efficiency Project; and

Ms. Maureen Scott, Senior Staff Counsel, and Mr. Charles Hains and Mr. Kevin Torrey, Staff Attorneys, Legal Division, on behalf of the Arizona Corporation Commission.

TABLE OF CONTENTS

INTRODUCTION 2
Rate Application 4
REVENUE REQUIREMENT 5
Rate Base Issues 5
Yuma manors Pipeline Replacement 5
Summary of Rate Base Adjustments 8
Operating Income Issues 9
Revenues 9
Operating Expenses 9
2008 Wage Increase 9
American Gas Association Dues 10
Injuries and Damages Expenses 12
Management Incentive Program 14
Supplemental Executive Retirement Plan 16
Miscellaneous "Unnecessary" Expenses 18
Southwest Gas Legal Arguments 20
Summary of Operating Expense Adjustments 20
Net Operating Income 20
COST OF CAPITAL 21
Cost of Debt and Preferred Stock 21
Cost of Common Equity 21
Southwest Gas 21
RUCO 23
Staff 23
Conclusion on Cost of Equity 25
Capital Structure 26
Chaparral City Decision and Fair Value Rate of Return 29
Conclusion on Fair Value Rate Base Issue 31
AUTHORIZED INCREASE 33
RATE DESIGN ISSUES 34
Proposed Decoupling Mechanism 34
Southwest Gas 34
AIC 36
SWEEP 37
RUCO 38
Staff 39
Resolution 40
Volumetric Rate Design 41
Basic Service Charge 43
Southwest Gas 43
SWEEP 44
RUCO 44

Operating Expenses

2008 Wage Increase

In this proceeding, Southwest Gas has included in proposed test year expenses a 3 percent general wage increase that was given to employees in 2008, in addition to a wage increase given in 2007. Staff does not oppose recognition of the 2008 wage increase because it is a known and measurable post-test-year event. RUCO does not object to inclusion of the 2007 wage increases that became effective in May and June 2007 (after the end of the test year), but proposes to disallow the 2008 increases on the basis that they are too far removed from the end of the test year and would create a mismatch between rate base, revenues, and expenses at the end of the test year. (RUCO Ex. 3 at 23.)

Company witness Randi Aldridge testified that, contrary to RUCO's assertion, the Company included only wage increases for employees who were employed as of the end of the test year, to avoid a mismatch. (Ex. A-10 at 6-7.) She stated that the 2008 wage increase did not apply to any employee hired after the end of the test year (April 30, 2007); therefore, the number of employees at the end of the test year is synchronized with customers served during the test year. (*Id.* at 7.)

We agree with the Company and Staff that the 2008 wage increase expense should be allowed because it is a known and measurable expense that is being incurred by Southwest Gas on a going-forward basis. Because the post-test-year wage increase has been applied only to employees who were employed during the test year, there is no resulting mismatch of revenues and expenses. Our conclusion is consistent with the treatment accorded this issue in the Company's prior rate case. (*See* Decision No. 68487 at 12-13.)

American Gas Association Dues

The American Gas Association ("AGA") is a national trade association for natural gas distribution and transmission companies. During 2007, Southwest Gas paid to the AGA dues of $401,795, with the Arizona jurisdictional amount being 56.70 percent of the total ($227,920). (Staff Final Sched. C-6.) The AGA provides services to its members in the following categories: Advertising; Public Affairs; Corporate Affairs; General Counsel; General & Administrative Expense; Policy, Planning and Regulatory Affairs; Operations & Engineering Management; Policy & Analysis;

and Industry Finance & Administrative Programs. (Ex. A-11, RLA-2.)

In the Company's last rate case, Southwest Gas requested recovery of 96.36 percent of the AGA dues, excluding 3.64 percent of the dues related to the AGA's marketing and lobbying functions. In that case, Staff did not oppose the Company's request, but RUCO proposed disallowance of 39.09 percent of the AGA dues, to exclude the Communications and Public Affairs expense categories. The Commission rejected RUCO's proposed disallowance and adopted the Company's inclusion of 96.36 percent of the AGA dues, finding that "[a]lthough the descriptions of AGA activities provided by the Company [were] somewhat nebulous," Southwest Gas had satisfied its burden of showing that the AGA functions provide a benefit to the Company and its customers. (Decision No. 68487 at 14.) However, the Commission directed Southwest Gas to provide in its next rate case filing "a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the Company and its Arizona customers." (*Id.*)

In this case, Southwest Gas seeks recovery of 94.52 percent of its AGA dues, excluding 5.48 percent of the dues as related to marketing and lobbying functions. To satisfy the Commission's directive in the prior Decision, Company witness Aldridge provided testimony describing the AGA's functions, as well as several attachments extolling the virtues of various AGA activities. (Ex. A-10 at 21-24; Ex. A-11, RLA-1 and RLA-2.) The Company contends that it has provided ample support for the functions provided by the AGA and the benefits that accrue to the Company and its ratepayers as a result of the AGA's activities. Southwest Gas argues that the documentation provided comes directly from the AGA and that there is no better source of information for analyzing the appropriateness of the AGA's activities. The Company cites to the testimony of Ms. Aldridge who claimed that AGA member benefits amounted to $479 million, compared to only $18 million in total membership dues. (Ex. A-11 at 9.)

RUCO did not oppose the Company's proposed recovery of AGA dues in this proceeding. However, Staff recommends disallowance of 40 percent of AGA dues on the basis that Southwest Gas has not demonstrated how the AGA's activities provide specific benefits to ratepayers. Staff witness Ralph Smith stated that Southwest Gas failed to substantiate its claims that AGA membership resulted in $479 million in member savings in 2006, and that it is not clear if the claimed benefits

have ever been audited or verified. (Ex. S-12 at 40; Ex. S-13 at 33.) Mr. Smith testified that the Company failed to demonstrate why ratepayers should fund activities through membership in an industry organization that would likely be disallowed if they were performed by the Company itself. (*Id.*) Staff's 40-percent disallowance recommendation is based on decisions by other state regulatory commissions and audits of the AGA by the National Association of Regulatory Utility Commissioners ("NARUC"). Mr. Smith cited to orders issued by other commissions in which AGA dues were disallowed in the following percentages: Michigan (16.17 percent), California (25 percent), and Florida (40 percent). (*See* Ex. S-12 at 41-45.) He also cited a 1999 NARUC-sponsored audit of AGA expenditures that stated, "these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit." (*Id.* at 43.)

Staff claims that its recommended 40-percent disallowance is consistent with a March 2005 NARUC Audit Report that quantified AGA function categories that Staff believes should not be paid by ratepayers. The categories cited by Staff are: Public Affairs (24.13 percent); Corporate Affairs and International (10.54 percent); half of General Counsel and Corporate Secretary (2.6 percent); and Marketing (2.37 percent). (*Id.* at RCS-2, Sched. C-6.) Staff contends that the 39.64-percent total represented by these activities supports its recommended disallowance. Moreover, according to Mr. Smith, based on the 2007 and 2008 AGA budgets, the recommended dues disallowance would be 43.29 percent and 46.19 percent, respectively (*Id.*; Ex. S-14 at 33-34.)

We find that Staff's recommended disallowance of 40 percent of AGA dues represents a reasonable approximation of the amount for which ratepayers receive no supportable benefit. The documentation offered by the Company to justify the AGA dues, including the alleged monetary savings to members, consists primarily of information provided by the AGA itself and must be viewed in that context. As Staff witness Ralph Smith indicated, several other states have disallowed AGA dues in substantially higher amounts than the amount proposed by Southwest Gas. Mr. Smith also pointed out that Staff's recommended disallowance is approximately the same percentage as that attained by totaling up AGA activities for Public Affairs, Corporate Affairs, half of General Counsel expenses, and marketing under a 2005 NARUC audit. Further, application of the 2007 and 2008

AGA dues would result in even greater disallowances under these categories. We therefore adopt Staff's recommendation to disallow 40 percent of the Company's AGA dues.

Injuries and Damages Expenses

Southwest Gas and Staff continue to dispute the appropriate amount to be allocated for injuries and damages expenses. The Company has proposed an increase in this expense of approximately $2,490,000, for a total of $8,169,000. Staff recommends reducing the Company's proposed increase to $1,638,000, for a total injuries and damages expense allowance of $7,317,000.

Southwest Gas contends that its proposal is consistent with the methodology agreed to by the parties, and adopted by the Commission, in the Company's last rate case. The Company's proposal utilizes claims in all jurisdictions over a 10-year period and includes recognition of a change in the Company's self-insurance limits during that period. Company witness Mashas testified that from January 1998 through July 2004, the Company's insurance policies provided that Southwest Gas was self-insured for up to $1 million of expenses related to a single claim. From August 2004 through July 2005, the Company provided self-insurance for the first $1 million per claim, and also for *aggregate* claims up to $10 million. In August 2005, Southwest Gas acquired an additional policy that covers aggregate claims for amounts between $5 million and $10 million. (Ex. A-16 at 3-4.)

According to Mr. Mashas, Southwest Gas has experienced only one incident since August 2004 in which the claim exceeded the $1 million per incident self-insured amount. The incident in question occurred in May 2005 when a leaking gas fire in Tucson caused several people to be severely burned, and Southwest Gas paid $10 million in a settlement of claims related to the incident. Southwest Gas argues that Staff's removal of this amount from its 10-year average is inappropriate because prior to August 2004, injuries and damages claims over $1 million would have been indemnified by the Company's insurer and would therefore not have been recorded on the Company's books. (*Id.* at 5.) Mr. Mashas claims that Staff's 10-year average is therefore skewed and is inconsistent with the treatment afforded injuries and damages expenses in the last rate case. Southwest Gas argues that Staff's exclusion of the $10 million claim does not reflect the level of self-insurance that the Company expects to experience during the period rates from this case are in effect.

Staff asserts that the $10 million payment related to the 2005 incident should be excluded

RUCO proposes disallowing 50 percent of MIP costs to recognize that both shareholders and customers receive a benefit from the performance goals included in the MIP. (RUCO Ex. 3 at 29.)

In the last Southwest Gas rate case, as well as several subsequent cases,[3] 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 No. 68487 at 18.) In that Decision, we stated:

> In Decision No. 64172, 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 Staff's 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.[4]

Supplemental Executive Retirement Plan

Southwest Gas also offers a Supplemental Executive Retirement Plan ("SERP") to select executives. The SERP provides supplemental benefits for high-ranking employees in excess of the limits placed by Internal Revenue Service ("IRS") regulations on pension plan calculations for salaries above specified amounts. (Ex. S-12 at 30-31.) We explained in the last Southwest Gas case:

> IRS regulations place limits on pension plan calculations for salaries exceeding $165,000 and thus salaries in excess of that level are not included in the pension calculation. Mr. Mashas stated that the SERP

[3] *See UNS Gas, Inc.*, Decision No. 70011 (November 27, 2007) at 27; *Arizona Public Service Co.*, Decision No. 69663 (June 28, 2007) at 27; and *UNS Electric, Inc.*, Decision No. 70360 (May 27, 2008) at 21.

[4] On the same basis, we will also disallow 100 percent of the Southwest Gas stock incentive plan ("SIP"). The costs related to similar incentive plans were recently rejected for APS and UNS Electric. (*See* Ex. S-12 at 32-34.) As was noted in the APS case, stock performance incentive goals have the potential to negatively affect customer service, and ratepayers should not be required to pay executive compensation that is based on the performance of the Company's stock price. (Decision No. 69663 at 36.)

> provides officers with a retirement benefit equal to 50 percent of the average of the last three years salary provided that they are at least 60 years old and have at least 20 years of service. In addition, IRS regulations place restrictions on the Company's 401(k) contributions to the extent that "maximum contribution levels represent a significantly smaller percentage of an officer's salary compared to other employees."

[Decision No. 68487 at 18 (citations omitted).]

Company witness Hobbs testified that the MIP, SIP and SERP are "key components of [the Company's] prudently managed total executive compensation expense and are vital to the Company's attraction and retention of highly-skilled employees, which ultimately benefits customers." (Ex. A-8 at 7-8.) She explained that the SERP is an "unqualified plan," and therefore payments are not guaranteed. She also stated that contrary to the testimony provided by Staff and RUCO, virtually every other gas and electric utility offers such employees a SERP, and the costs of the SERP are reasonable. (*Id.*)

Staff witness Smith and RUCO witness Moore recommend a total disallowance of SERP expenses. Mr. Smith cites to the prior Southwest Gas rate case, as well as the subsequent UNS Gas, APS, and UNS Electric cases, wherein the Commission disallowed SERP costs. Mr. Moore stated that SERP costs are not a necessary cost for providing service and indicated that the high-ranking officers covered by the SERP are already fairly compensated for their work and are provided a comprehensive array of benefits in addition to salaries. (RUCO Ex. 3 at 30.)

We agree with Staff and RUCO that the SERP expenses sought by Southwest Gas should once again be disallowed. We do not believe any material factual difference exists in this case that would require a result that differs from the Company's prior case. In that case, we stated:

> [W]e believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives "whole" in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden

on ratepayers.

(Decision No. 68487 at 19.)

In the recent UNS Gas, APS, and UNS Electric cases, we followed the rationale cited above in disallowing SERP expenses. In Decision No. 70011, we indicated that SERP costs should not be recoverable and indicated:

> [T]he issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case, and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

[*Id.* at 28, (footnote omitted).] For these reasons, we agree with the recommendations of Staff and RUCO that the request for inclusion in rates of SERP expenses should be denied. We therefore adopt the recommendations of Staff and RUCO on this issue.

Miscellaneous "Unnecessary" Expenses

Based on his review of data requests, RUCO witness Rodney Moore proposed a disallowance of $185,210 from test year expenses for various miscellaneous expenses that RUCO deems unnecessary for the provision of service to the Company's customers. Mr. Moore testified that RUCO adjusted the Company's proposed operating expenses to remove payments to chambers of commerce and non-profit organizations; donations; club memberships; gifts; awards; extravagant corporate events; advertising; and various meals, lodging, and refreshments. (RUCO Ex. 3 at 27.) In his Surrebuttal Testimony, Mr. Moore cites the following specific miscellaneous expenses as examples of items that should not be recoverable: (1) massages ($2,160); (2) gift certificates to theaters, restaurants, and shopping malls ($18,230); (3) water, ice, coffee, beverages and refreshments for Company offices ($66,422); (4) breakfast, lunch, and dinner for meetings ($71,358); (5) off-site management meetings at various resorts ($8,835); and (6) a Board of Directors meeting at a golf course ($5,365). (*Id.* at 28; RUCO Ex. 6 at 7.)

Through her testimony, Company witness Randi Aldridge stated that RUCO had failed to

BEFORE THE ARIZONA CORPORATION CC

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

Arizona Corporation Commission
DOCKETED
JUN 28 2007

DOCKETED BY nR

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827 DECISION NO. 69663 **OPINION AND ORDER**

DATES OF HEARING: October 5, (Pre-Hearing Conference), December 6, (Procedural Conference), October 10, 11, 12, 13, 16, 19, 20, 23, 24, 25, 26, 30, November 3, 6, 7, 8, 9, 20, 27, 28, 30, December 1, 4, 5, 6, 11, 12, 13, and 15, 2006.

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Lyn Farmer

IN ATTENDANCE: Jeff Hatch-Miller, Chairman
Mike Gleason, Commissioner
Kristin K. Mayes, Commissioner
William A. Mundell, Commissioner
Barry Wong, Commissioner

APPEARANCES: Mr. Thomas L. Mumaw, PINNACLE WEST CAPITAL CORPORATION, Ms. Deborah R. Scott, SNELL & WILMER, LLP, and Mr. William Maledon, OSBORN MALEDON, P.A., on behalf of Arizona Public Service

Company;

Mr. Scott Wakefield, Chief Counsel, and Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office;

Mr. Bill Murphy, MURPHY CONSULTING, on behalf of Distributed Energy Association of Arizona;

Ms. Laura Sixkiller, ROSHKA, DeWULF & PATTEN, PLC, on behalf of UniSource Energy Services;

Mr. Timothy Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST, on behalf of Southwest Energy Efficiency Project and Western Resource Advocates;

Mr. Gary L. Nakarado, on behalf of Vote Solar and Arizona Solar Energy Industry;

Mr. Michael Grant, GALLAGHER & KENNEDY, P.A., on behalf of Arizona Utility Investors Association;

Mr. Kurt J. Boehm, BOEHM, JURTZ & LOWRY, on behalf of the Kroger Company;

Mr. C. Webb Crockett, FENNEMORE CRAIG, P.C., on behalf of the Arizonans for Electric Choice and Competition and Phelps Dodge Mining Company;

Lieutenant Colonel Karen S. White, on behalf of the Federal Executive Agencies;

Mr. Jay I. Moyes, MOYES STOREY, on behalf of Az-Ag Group;

Mr. Andrew W. Bettwy, on behalf of Southwest Gas Corporation;

Mr. Douglas V. Fant, on behalf of the Interwest Energy Alliance and Distributed Energy Association of Arizona;

Mr. Lawrence V. Robertson, Jr., MUNGER CHADWICK, on behalf of Southwestern Power Group II, LLC, Bowie Power Station, LLC and Mesquite Power, LLC.

Mr. Christopher Kempley, Chief Counsel, Ms. Janet F. Wagner, Senior Staff Attorney, and Mr. Charles Hains, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

We agree with Staff that it is disturbing that APS was not complying with USOA in recording its lobbying costs. When APS is concerned about timely recovery of its costs, and the time necessary to process its rate cases, it certainly does not speed up the process or instill confidence in APS' filings when the Commission learns that Staff auditors must expend extra time and effort to make sure all costs have been appropriately accounted for by the Company. Although APS now says that it agrees with Staff that all future lobbying expenses should be recorded below-the-line and that any recovery should in the future be expressed as a pro forma adjustment, and that it has made this change to its accounting system on a going-forward basis, we will order the Company to comply and expect Staff and other parties to monitor the Company's continued compliance with this requirement.

We agree with RUCO's adjustment to reduce lobbying expense by $785,654. APS did demonstrate some customer benefits that resulted from its lobbying activities, and with the APS allocated below-the-line costs together with those excluded in the RUCO adjustment, we find that the remaining costs are reasonable. However, we agree with Staff that it is not desirable to have to distinguish between "good" and "bad" lobbying activities. To the extent that in future rate cases APS proposes pro forma adjustments to recover its below-the-line lobbying expenses, APS must provide the itemized lobbying costs associated with each benefit it alleges resulted from the specific lobbying activity. Accordingly, we will reduce operating expense by removing $785,654 of lobbying expenses.

l. Incentive Compensation

1. Stock-Based Incentive Compensation

APS requests $4.8 million in TY operating expense related to its employee stock incentive program, which it asserts is integral in attracting and retaining high quality management personnel. Staff recommended eliminating costs associated with APS' stock-based incentive plans, but allowing recovery of TY expenses for APS' cash-based incentive compensation, approximately $17.8 million. Staff recommends the costs of the stock-based incentive plan not be included in rates because that compensation program is driven by the financial performance of Pinnacle West Capital Corporation

("Pinnacle West"), rather than the operational performance of APS as a public utility.[26] Staff recommends the costs of the cash-based incentive plan be included in rates because the TY level of those costs was tied to performance measures that benefit APS' customers.

APS argues that the issue is whether APS compensation, including incentives, is reasonable. APS does not believe that the Commission should look at how that compensation is determined or its individual components, but rather should just look at the total compensation. The Company argues that the interests of investors and consumers are not in fundamental conflict over the issue of financial performance, because both want the Company to be able to attract needed capital at a reasonable cost.

We agree with Staff that APS' stock-based based incentive compensation expense should not be included in the cost of service used to set rates. Contrary to APS' argument that we should not look at how compensation is determined, we do not believe rates paid by ratepayers should include costs of a program where an employee has an incentive to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate. As testified to by Staff witness Dittmer and set out in Staff's Initial Brief, "[e]nhanced earnings levels can sometimes be achieved by short-term management decisions that may not encourage the development of safe and reliable utility service at the lowest long-term cost. . . . For example, some maintenance can be temporarily deferred, thereby boosting earnings.. . . But delaying maintenance can lead to safety concerns or higher subsequent 'catch-up' costs." (Staff Initial Brief, pp. 31-31) To the extent that Pinnacle West shareholders wish to compensate APS management for its enhanced earnings, they may do so, but it is not appropriate for the utility's ratepayers to provide such incentive and compensation. Accordingly, we will reduce operating expense by $4,487,657.[27]

2. Cash-Based Incentive Compensation

APS incurred approximately $17.8 million of cash-based (variable) incentive expense during

[26] "Awards are based on the Company's compound annual growth rate in Earnings Per Share over a three-year performance period relative to the S&P Electric Utilities Super Composite EPS growth rate over the same period." APS Exhibit No. 51, Gordon Rebuttal, p. 21.

[27] ACC Jurisdictional amount, Staff Initial Brief, Revised Joint Accounting Schedule, Schedule C-13.

the TY.[28] APS' variable incentive program is an "at risk" pay program where a part of an employee's annual cash compensation is put at risk and expectations are established for the employee at the start of the year. If certain performance results are achieved, a predictable award will be earned based upon objective criteria. The actual amount of the award depends upon the achieved results. The intent of the plan is to: link pay with business performance and personal contributions to results; motivate participants to achieve higher levels of performance; communicate and focus on critical success measures; reinforce desired business behaviors, as well as results; and to reinforce an employee ownership culture. (APS Exhibit No. 51, Gordon Rebuttal, p. 8) Staff did not oppose inclusion of the TY variable incentive expense in cost of service, noting that although corporate earnings serve as a threshold or precondition to the payout, the TY level of expense is tied primarily to performance measures that directly benefit APS customers. (Staff Exhibit No. 43, Dittmer Direct, p. 110)

RUCO proposed an adjustment reducing APS' cash-based incentive program expense by approximately 20 percent, or $4,563,000. The adjustment is based on a policy recommendation that ratepayers should not be expected to shoulder the entire incentive program that allows APS employees to earn additional compensation when APS ratepayers have experienced repeated rate increases over the past two years. APS opposes RUCO's adjustment as arbitrary and without analysis or justification. In its Reply Brief, RUCO indicates that it is not recommending adoption of both the RUCO and the Staff adjustment to incentive pay, and that Commission adoption of either one would be appropriate. We adopted the Staff adjustment for the reasons set forth above, and believe that adjustment will reflect an appropriate level of incentive compensation. Therefore we will not adopt RUCO's adjustment.

2. Uncontested Operating Adjustments

a. Spent Fuel Storage

No party has disputed APS' final adjustment to increase purchased power and fuel costs by $10,653,000 to reflect the Company's ongoing ACC Jurisdictional costs for interim storage of spent

[28] Total expense was $21,727,033, but the Company voluntarily eliminated Officers' cash-based compensation in the amount of $3,895,147, leaving $17,831,886 in the proposed TY cost of service. Staff Exhibit S-34, Dittmer Direct p. 107, footnote 31.

EXHIBIT
RUCO-6
ADMITTED

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-09-0206

DIRECT TESTIMONY

OF

BEN JOHNSON, Ph.D.

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 6, 2009

TABLE OF CONTENTS

Introduction 1

I. Background 3

II. UNSE Financial Situation and Credit Metrics 4

III. UNSE's Filing: An Overview 10

IV. Black Mountain Generating Station 15

V. Rate Base Adjustments 21

VI. Income Adjustments 28

VII. Fair Value Rate of Return 45

VII. Conclusions and Recommendations 59

Appendix A: Qualifications

TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of

The Residential Utility Consumer Office

Before the

Arizona Corporation Commission

Docket No. E-04204A-09-0206

Introduction

Q. Would you please state your name and address?

A. Ben Johnson, 3854-2 Killearn Court, Tallahassee, Florida.

Q. What is your present occupation?

A. I am a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation.

Q. Have you prepared an appendix that describes your qualifications in regulatory and utility economics?

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

Q. Have you prepared any schedules to be filed with your testimony?

A. Yes, I have prepared Schedules BJ-1 through BJ-10. These schedules were prepared under my supervision and are attached to my testimony.

Q. What is your purpose in making your appearance at this hearing?

A. Our firm has been retained by the Residential Utility Consumer Office ("RUCO") to assist with RUCO's evaluation of UNS Electric, Inc.'s (UNSE's) Application for a rate increase. The purpose of my testimony is to present RUCO's revenue requirement recommendation for UNSE in this proceeding, taking into account my analysis, as well as that of RUCO's rate of return witness Bill Rigsby.

Following this introduction, my testimony has eight sections. In the first section, I briefly summarize the background of this proceeding. In the second section, I discuss UNSE's financial condition and UNSE's credit ratings. In the third section I briefly summarize and discuss UNSE's revenue requirement filing in general terms. In the fourth section, I discuss UNSE's proposal to add the Black Mountain Generating Station to rate base. In the fifth section, I discuss the rate base adjustments proposed by UNSE and I present RUCO's recommendations with respect to each proposed adjustment. In the sixth section, I discuss the income adjustments proposed by the Company and I present RUCO's recommendations with respect to each proposed adjustment. In the seventh section, I discuss the appropriate rate of return to be applied to a fair value rate base. In the eighth and final section, I summarize my conclusions and recommendations.

I. Background

Q. Can you briefly discuss UNSE's most recent rate case?

A. Yes. On December 15, 2006, UNSE filed an application requesting an increase in rates and approval of financing for the purchase of the Black Mountain Generating Station. UNSE requested a revenue increase of $8,468,638, and proposed an adjusted original cost rate base ("OCRB") of $141,036,562 and a fair value rate base of $177,847,579 [Decision 70360, p. 5] Staff and RUCO recommended revenue increases of $3,687,855 and $1,282,144, respectively. [Id.] Staff proposed an OCRB of $130,740,050, and a fair value rate base (FVRB) of $167,551,067. [Id.] RUCO proposed an OCRB of $128,795,088, and a FVRB of $161,635,350. [Id.] The evidentiary hearing was held on 8 days from September 10, 2007 through October 2, 2007. The Commission determined that UNSE had an OCRB of $130,740,050 and a FVRB of $167,551,057. [Id., p. 80] The Commission further determined that the Company was entitled to a revenue increase of $4,018,678, or 2.5% over adjusted test year revenues.[1] [Id.] The Commission ordered the new rates to become effective June 1, 2008. [Id., p. 84]

Q. Can you now briefly discuss the procedural background of this case?

A. Yes. UNSE's initial application for a rate increase was filed with the Commission on April 30, 2009. On May 26, 2009, UNSE filed an Amendment which updated certain financial information in its Application. On May 29, 2009, Staff filed a Letter of Sufficiency in the docket indicating that UNS' application had meet the sufficiency requirements of the Arizona Administrative Code. A Procedural Order was issued on June 18, 2009, setting an evidentiary hearing for February 4, 2010, establishing dates for testimony, and setting a deadline for motions to intervene. On September 1, 2009, RUCO's motion to intervene was granted. On

1 The Commission determined UNSE's adjusted test year revenues to be $158,539,827. [Id., p. 37]

October 1, 2009, the Arizona School Boards Association and the Arizona Association of School Business Officials' motion to intervene was granted.

II. UNSE Financial Situation and Credit Metrics

Q. What information does UNSE provide regarding its financial condition?

A. The Company notes that in the prior rate case, the Commission authorized a return on equity (ROE) of 10%. [UNSE Application, p. 2] The Company claims, however, that in 2008 it earned a ROE of 4.6%, and that it is projected to earn an ROE of only 4.0% in 2009. [Id.] "[I]t is readily apparent that UNS Electric has been under-earning its cost of capital by a wide margin and will continue to do so until appropriate rate relief is granted". [Grant Direct, p. 17] According to UNSE, if the Company is not allowed to earn its cost of capital, UniSoruce Energy (UNSE's parent company) would have no incentive to increase its equity investment, which in turn would force UNSE to become more dependent on debt financing, and could lead to a series of back to back rate cases. [Grant Direct, pp. 19-20] According to the Company, such a scenario would jeopardize its creditworthiness, and increase costs to everyone, including customers. [Id.] "[E]ven a modest decline in financial performance could cause a downgrading of the Company's credit rating to junk bond status". [Grant Direct, p. 9]

Q. Is UNSE's recent financial performance problematic?

A. While there is no expectation that earnings will exactly match the allowed rate of return, it is not in the public interest for the Company to achieve earnings that are far below its cost of capital – particularly if this pattern were to be sustained for several more years into the future.

Q. What rating agencies cover UNSE's debt?

A. According to the Company, a revolving credit facility it shares with UNS Gas, and its senior unsecured debt are both rated by Moody's.

Q. Can you explain how Moody's rates the Company's credit?

A. Yes. As shown below, Moody's has established a series of tiers designated by alphanumeric codes to rate corporate securities.

Moody's Credit Ratings

Investment Grade	Speculative Grade	In Default
Aaa	Ba1	Ca
Aa1	Ba2	C
Aa2	Ba3	
Aa3	B1	
A1	B2	
A2	B3	
A3	Caa1	
Baa1	Caa2	
Baa2	Caa3	
Baa3		

Q. Where does UNSE currently fall within this range?

A. The Company's debt obligations are rated Baa3. [Pritz Direct, p. 3] The credit facility rating was assigned in July 2008 and the rating on the senior notes was assigned in August 2008. [Id.] As you can see in the table above, UNSE is rated on the lowest tier of "investment grade" credit by Moody's. Fortunately, Moody's has assigned a "stable" outlook for the Company. [Id.]

Q. Has Moody's provided any explanation of its rating for UNSE?

A. Yes. Moody's provides the following "ratings rationale":

> The Baa3 rating for the shared guaranteed credit facility is driven by the relatively stable and predictable nature of UNSE's and UNSG's regulated cash flows, as well as their strong combined financial profile which provide the basis of the UES guarantee. For the past several years, cash flow credit metrics at both UNSE and USE have been at or above the ranges demonstrated by electric utilities rated within the Baa range. The rating also considers the traditionally challenging regulatory environment in Arizona, but contemplates recent decisions which appear intended to provide more timely recovery of certain costs.
>
> The rating assumes UNSE and UNSG will be reasonably successful in managing their regulatory relationships with an objective of achieving more timely recovery and an opportunity to earn a fair return. The rating also incorporates an expectation that increasing capital expenditures will be financed in a manner consistent with maintaining current financial strength. [UNSE Exhibit MBP-2]

Moody's provides the following explanation for its rating outlook:

> The stable outlook reflects the relatively stable cash flows anticipated to be generated by UNSE and UNSG and Moody's assumption that increases in the cost of fuel and purchased power will, in fact, be recovered on a relatively timely basis. [Id.]

Q. To what extent does Moody's look at UniSource Energy and UNSE's corporate structure when issuing its rating?

A. That is an issue considered by the agency. Moody's states:

> The rating also recognizes the position of UNSE and UNSG as indirect subsidiaries of UNS through UES. UES is an intermediate holding company with no operations or debt. Debt at UNSE and UNSG is guaranteed by UES, which creates cross-support. UES has not historically received any dividend payments from its utility subsidiaries, and none are anticipated for the foreseeable future. Between 2005 and 2007, UNS contributed approximately $40 million of equity to these subsidiaries in support of their capital programs and to strengthen their balance sheets. [Id.]

Q. What does Moody's say regarding UNSE's credit metrics?

A. Those obviously play a large part in determining a company's rating. For UNSE, Moody's states:

> UNSEs cash flow credit metrics have historically been strong; generally at or above the upper end of the ranges indicated in Moody's rating methodology for electric utilities rated Baa. For example, the ratio of cash from operations excluding changes in working capital (CFO - Pre WC) to Debt (adjusted in accordance with Moody's standard analytical adjustments), has been above 20% for the past several years. Credit metrics are expected to decline somewhat over the next few years, with CFO - Pre WC / Debt moving into the upper teens. The anticipated weakening in metrics reflects the impact of the termination of UNS Electric's full requirements power supply agreement with Pinnacle as well as its continuing growing capital expenditure program. Rating Level of Business Risk
>
> UNSG's credit metrics have also historically remained reasonably stable and generally within the ranges indicated for regulated gas distribution utilities rated Baa in Moody's regulated gas distribution methodology. Metrics are expected to improve modestly if reasonable rate relief occurs in the near-term. [Id.]

Q. Should the Commission be concerned about UNSE's bond rating and credit metrics?

A. Yes, this is a legitimate concern, particularly since the UNSE ratings are currently near the low end of the industry range, and any substantial further degradation could put the Company below the "investment grade" categories. The most obvious reason for concern is the impact of any further downgrading on the interest rates which would be paid by the Company when it needs to raise additional debt capital. As ratings decrease, the required interest on new issuances increases. These increased debt costs lead to higher costs for customers over the life cycle of the debt issuance.

Q. Can you elaborate on the potential adverse impact of an UNSE downgrade?

A. Yes. To fully understand the potential problems, it is helpful to review a few basic facts. First, the market for newly issued junk-rated debt is limited. While there are many junk bonds on the market, many of these were originally issued with higher ratings, and were subsequently downgraded when problems were subsequently encountered by the issuer. While it is possible to issue new debt with a low bond rating, provided the issuer is willing to pay a high enough interest rate, in practice the market for such debt is relatively thin and uncertain, and the cost could actually exceed the cost of equity.

As well, if UNSE were to assume the burden of paying inordinately high interest rates on newly issued debt, it would further reduce the amount of protection offered to its existing creditors, thereby increasing the risk of default or bankruptcy. In turn, this would increase the risk facing stockholders, which would lead to an increase in the cost of equity, making it more difficult to tap the equity markets, and result in a higher allowed return on fair value. Simply stated, a substantial further downgrading could lead to a series of undesirable ripple effects that are difficult to predict in advance, but are not in the best interests of either shareholders or customers, and which should certainly be of concern to the Commission.

Q. Are there aspects of the financial "crisis" which began in September 2008 which ought to be considered in evaluating the potential impact of an UNSE downgrade?

A. Yes. We have recently seen extreme swings in credit markets, triggered by relatively minor changes in the underlying facts. Once perceptions of the credit-worthiness of major institutions like Lehman Brothers or Wachovia turned a bit negative, the shift in perceptions began to feed on itself, leading to rapidly escalating atmosphere of fear and uncertainty, which in turn had very real consequences for these firms and others.

During a financial crisis or tight credit environment, even firms with an investment

grade bond rating may find it more difficult than normal to issue additional debt or equity. Having a debt rating toward the low end of the utility industry, the Company may find it difficult to fully fund its planned capital construction program – bearing in mind that merely offering to pay higher than normal interest rates wouldn't necessarily solve the problem, since the very need to offer such high rates could be perceived as a sign of weakness, pushing away more risk-averse investors and making it harder to raise capital in the future.

Absent the ability to access the debt market on a routine basis at attractive interest rates, UNSE would be left with relatively limited and unattractive options. UNSE could slow, or halt, all but the most urgently needed construction projects, but if this were to continue for very long, it could result in a reduction in service reliability, or require extraordinary measures to maintain reliability, such as rolling brownouts during peak hours, or a temporary moratorium on new service connections .

Q. You've painted a rather bleak picture of the potential consequences if a bond downgrading were to occur. Are you suggesting that these risks should dominate the Commission's analysis of the issues in this case?

A. No, not at all. But I wanted to make clear that RUCO recognizes the importance of maintaining a reasonable debt rating, notwithstanding various differences of opinion that may exist concerning the most appropriate resolution of specific issues. That said, I am not by any stretch of the imagination suggesting that the Commission should throw all other concerns overboard or to accept every one of the Company's requests in this case, no matter how excessive or unreasonable, in a misplaced effort to minimize the risk of a downgrading. I believe a vigilant regulatory regime, which forces stockholders to absorb imprudent costs encourages greater efficiency and is ultimately in everyone's best interest.

Arizona has constitutional requirements that require fairness to both consumers and

stockholders. As a result, it is certainly possible that the regulatory system may be somewhat less favorable to investors than one that is solely the creation of a legislature that is subjected to intense lobbying by the industries that are regulated. But, this is something the Commission should treat as a given. For regulation to work as intended, management of monopolies cannot be given a blanket promise of immediate, full recovery of any and all costs they have incurred, or anticipate incurring. Instead, it is appropriate to closely scrutinize the Company's application to identify a normalized level of reasonable, prudently incurred costs which are appropriate for consideration in determining rates to be paid by customers.

III. UNS Electric's Filing: An Overview

Q. Can you now summarize UNSE's overall revenue request?

A. Yes. UNSE requests a $13.5 million rate increase, or approximately 7.5% over test year revenues. [Application, p. 2] The requested increase is based in part on adjusted test year sales and expenses during the 2008 test year. However, it also reflects certain post-test year adjustments.

UNSE is also requesting two modifications to its current Purchased Power and Fuel Adjustment Clause ("PPFAC"). First, UNSE is requesting an increase to the interest it is allowed to collect when its PPFAC collections are less than actual purchased power and fuel costs. [Id.] Second, UNSE requests that credit-related costs to support the procurement of wholesale power and natural gas be included in its PPFAC. [Id.]

Finally, UNSE is requesting a post-test year adjustment to include the Black Mountain Generation Station ("BMGS") in rate base. [Id.] An affiliate, UniSource Energy Development Company, currently owns BMGS. The Company is requesting a related rate reclassification that

results in an increase in its non-fuel base rate and a corresponding decrease in its power supply base rate; these offsetting rate changes are intended to cancel out, so the impact on the Company's revenues and customer bills will be neutral. [Id., p. 6]

Q. Has UNSE proposed various adjustments to its actual test year results?

A. Yes. UNSE has proposed several adjustments to its test year rate base. The largest adjustment is the proposed inclusion of BMGS in rate base. This adjustment would result in a $61.4 million increase in rate base. [BMGS Schedule B-2] In its "base" filing (i.e., excluding requests related to BMGS), UNSE is proposing certain other adjustments that collectively result in a $11.1 million increase in the rate base. [Schedule B-2] Total adjustments inclusive of BMGS result in a $72.5 million increase in rate base. Similarly, UNSE has proposed numerous adjustments to the actual test year operating income. In its base filing, these adjustments collectively result in a $216,965 net increase to its operating income above the actual level experienced during the test year. [Schedule C-1]

Q. Can you explain the concept of pro forma adjustments, in general terms?

A. Yes. Although terminology can vary, test year adjustments can be classified into various groups, based on the underlying purpose or theoretical basis for making the adjustment. Company witness Kissinger speaks of three major types: normalizations, annualizations and eliminations. He describes normalizing adjustments as follows:

> Normalization adjustments reflect that the recorded test year operating revenues and expenses may not be representative of a normal level for ratemaking purposes. Certain events may have affected recorded transactions in an atypical manner. Moreover, some transactions eligible for reflection in revenue requirements are incurred at intervals less frequent than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amounts recorded in the test year may not be viewed as "normal," thus

> requiring a restatement for ratemaking purposes. [Kissenger Direct, p. 3]

Mr. Kissinger describes annualization adjustments as follows:

> Annualization adjustments are made to reflect the full, 12-month revenue or expense level of certain components of operating income. Annualization adjustments are typically computed using end-of-test-year quantities, and the most current known and measurable prices and rates. [Id.]

He describes eliminations as follows:

> Elimination adjustments are made to remove out-of-period or non-recurring transactions, or items that are not costs or revenues related to the provision of utility service. Thus, they are not eligible for reflection in revenue requirements. [Id.]

Many of the Company's proposed "annualization" adjustments are designed to bring costs and revenue to an end-of-test year basis, while others update costs beyond the test year, to reflect the impact of additional investment, inflation and cost changes which didn't occur until after the test year. While making "annualization" adjustments for "known and measurable" cost increases is a popular method for dealing with the closely related problems of inflation and regulatory lag, this method tends to be arbitrary and controversial, particularly when attempts are made to select a cut-off date or annualization data that goes beyond the end of the test year. Regardless of how well known or measurable a particular cost change may be, it is difficult to achieve internal consistency and an appropriate "matching" of revenues and costs when the adjustments go beyond the test year.

RUCO believes the Commission should continue to use an historical test year, and it should generally reject ad hoc adjustments stretching well beyond the test year. Even if the Commission were persuaded that a particular utility's financial situation warrants extraordinary measures that go beyond its traditional historical test year approach, I don't believe the best solution is to accept more and more adjustments for "known and measurable" changes, or to

extend the cut off date for cost increases farther and farther beyond the end of the test year while leaving revenues frozen at the level which occurred during, or at the end of, the test year.

While it has long been accepted by this Commission and many other regulators, trying to solve a potential problem with inflation by adopting adjustments for "known and measurable" changes to the historic test year is an inherently difficult and controversial process. Should the Commission only consider changes which occurred during the test year? Or, should the Commission go a few weeks, or perhaps 6 months beyond the test year? While it is understandable why the Commission will sometimes go somewhat beyond the end of the test year, in my opinion, this is not the preferred solution to dealing with inflation and attrition. Among other problems, as adjustments stretch farther and farther beyond the test year, it becomes increasingly arbitrary to select a cutoff date; as well, the mismatch between revenues and expenses tends to become increasingly severe, and it becomes harder to ensure that the adjustments are both known and accurately measurable, and that the final result is a realistic and representative snapshot of the Company's operations.

To its credit, in the Company's filing, it mostly focuses on the test year. However, it makes a handful of exceptions in which it proposes adjustments that are calculated with different dates that go well past the end of the test year. No overarching principle has been put forward to justify the particular mix of adjustments and dates, and in my view the end result is not an improvement over an analysis which focuses on the Company's actual operating experience during the test year. There is no assurance that the end result of a series of inconsistent adjustments will be reasonable, or representative of actual conditions that can reasonably be anticipated in the future.

While I will readily concede that at first blush it seems reasonable to extend the cut-off date for known and measurable adjustments to go as far as possible past the end of the test year, this is not a good solution to an inflation or attrition problem, even assuming one exists

(something which hasn't been proved in this case). Extending adjustments farther and farther beyond the test year tends to degenerate into an arbitrary, ad hoc, and ultimately unsound process of picking and choosing items to be included in the adjustment process, as well as picking and choosing the dates to be used in developing each of the adjustments. There is no sound theoretical basis for deciding exactly how far to go beyond the test year, yet it is clear that the farther one goes past the test year, the less the Commission will be relying on actual experience, and the more it will be relying on a hypothetical version of what might possibly occur in the future.

As well, the more one goes beyond the actual test year experience, the less confidence can be placed in the underlying premise that the test year represents a realistic, representative snapshot of the Company's actual revenues, costs, and income. By limiting the adjustment process to only consider revenue increases through December 2008, while including a range of cost increases stretching well beyond that date, the Company is proposing a mis-match of revenues and costs with no assurance that the final end result of this mis-matching process is in any way reasonable or accurate.

Rather than debating the merits of each of these adjustments in isolation, one-by-one, or attempting to put forward a different ad hoc mixture of adjustments, my general approach has been to start with a specific cut-off date, and then to remove all of the adjustments that are inconsistent with that cut-off date. More specifically, I recommend using a December 31, 2008 (or January 1, 2009) cut off date (these dates are essentially identical, in my view).

I realize that the Commission might feel some deviation from a strict historical test year may be warranted – e.g. by accepting some of the adjustments related to the first 6 or 9 months beyond the test year. However, rather than pursuing that sort of ad hoc solution, I would recommend the Commission instead use a simpler, more explicit approach. For instance, if the Commission were convinced that the Company's recent weak earnings merit some sort of

additional compensation beyond that provided in prior cases, I don't believe ad hoc post-test year adjustments are an appropriate response. Instead, I would suggest using a simpler, more explicit approach, by allowing a slightly higher return on the fair value rate base than would otherwise be approved.

IV. Black Mountain Generating Station

Q. Can you now briefly discuss the Black Mountain Generating Station?

A. Yes. Black Mountain Generating Station (BMGS) is a 90 MW gas turbine generating facility in Northern Arizona. BMGS was recently developed, and is still owned, by UniSource Energy Development Company ("UED"), an affiliate of UNSE. The generating station consists of two LM6000 45 MW combustion turbines. [McKenna Direct, p. 13] These turbines were purchased by UED at a "discounted" price from another utility, which had never used them. [Application, p. 9] BMGS entered service on May 30,2008. [McKenna Direct, p. 13]

In June 2008, UED and UNSE entered into a 5-year Power Purchase Agreement (PPA) under which UED sells all the output of BMGS to UNS Electric. [Exhibit KGK-1, p. 15] Under the terms of the PPA, UNSE pays UED a fixed Capacity Charge of ***CONFIDENTIAL $855,000 CONFIDENTIAL*** per month. [See, UED-UNSE PPA, provided on response to Staff DR 1-9] UNSE receives a credit of ***CONFIDENTIAL $9.50 CONFIDENTIAL*** for each kW that falls below 90 MW in any month. [Id.] The costs associated with the PPA are recoverable through UNSE's PPFAC.

Q. What does UNSE propose regarding the BMGS??

A. UNSE proposes that UED transfer BMGS to the Company at a cost equaling $62 million, and

that this value be added to rate base. [McKenna Direct, p. 16]

> This is the actual current book cost for BMGS and is not a "capped cost" that the Company proposed in its last rate case. UNS Electric proposes to use this actual cost of $62 million as the rate base value of BMGS, if it is included in rate base. [Id.]

UNS Electric proposes that the Commission approve a post-test-year adjustment to rate base and a revenue-neutral-rate reclassification that "reflects the completed cost of this facility upon the transfer of ownership to UNS Electric". [DeConcini Direct, p. 14] UNS Electric would finance the acquisition under the conditions approved by the Commission in UNSE's previous rate case. UNS Electric is authorized to incur up to $40 million of new debt financing and to receive up to $40 million in equity from UniSource Energy, to acquire BMGS. UNS Electric is proposing a rate reclassification that would result in an increase to the Company's non-fuel base rates and a corresponding decrease to UNSE's base power supply rate. [Id.]

Q. Did UNSE make a similar proposal in its last rate case?

A. Yes. UNSE proposed adding BMGS to rate base in Docket No. E-04204A-06-0783. Agreeing with RUCO and Staff, the Commission rejected that proposal as premature. [See, Decision 70360, p. 76] Like Staff, RUCO opposed including BMGS in rate base at that time, because: 1) neither the capital costs nor the operating costs of the plant were known; 2) adoption of the proposal would violate the ratemaking matching principle because customer counts at the time of the plant's completion would be different than the customer counts used in that case for setting rates; 3) the Company's request would violate the ratemaking principle that only "used and useful" plant should be accorded rate recognition; and, 4) there was not sufficient opportunity for close scrutiny of a transaction between affiliated entities. [See, Id.] However, the Commission concluded that there was "a compelling basis on which to encourage UNSE's acquisition of the BMGS". [Id.]

> To provide such encouragement, we will authorize UNSE to implement an accounting order to record any and all of the Company's financial activities associated with the BMGS, as if the BMGS were in rate base as of June 1, 2008. Unless otherwise ordered by the Commission, this accounting order would remain in effect until the effective conclusion of UNSE's next rate case. [Id., p. 76-77]

Q. Why has UNSE not already acquired the BMGS, in response to that encouragement?

A. The Company explains that it has not yet acquired BMGS because it does not have the financial strength to do so in the absence of some greater assurance from the Commission that the cost of the plant will be recovered from customers. It states that it "could simply not acquire an asset as large as BMGS without a commensurate increase in earnings and cash flow." [DeConcini Direct, p. 15] According to the Company, the deferred accounting treatment for BMGS approved by the Commission did not provide enough cash flow relief to "cover the interim cash costs that UNSE Electric would have had to incur to finance the BMGS acquisition". [Id.] Therefore, argues the Company, obtaining financing for the transaction would have been difficult. [Id.] Further, UNSE claims it would have "experienced a substantial decline" in key credit metrics during the interim period between the date when it acquired title to the plant, and the date when its base rates are increased to provide for recovery of the cost of the plant (rather than through the PPAC). [Id.]

Q. Where does BMGS fit into UNSE's overall mix of generation sources?

A. UNSE acquires most of its power through power supply contracts, including the contract for BMGS. The exception is its Valencia generating plant, which has 65 MW of combustion turbine peaking capacity. [McKenna Direct, p. 6] These sources collectively provide

> 70 to 100% of the approximate 475 MW of peak capacity required through May 31, 2010. For the summer (June through September) period of 2009, UNS Electric has 90 to 100% of its peak capacity hedged. The remaining capacity necessary to serve daily peak loads will be purchased

through the short-term daily and real-time markets. [Id.]

If it acquires ownership of BMGS, the Company will more than double the portion of its peak requirements which it meets with its own capacity; however, the majority of its peak requirements will still be met through power supply contracts, and an even larger majority of its energy needs will continue to be acquired through wholesale transactions (neither Valencia nor BMGS are base load plants).

Q. What are the benefits of owning BMGS when compared to purchasing power and peaking capacity on the wholesale market?

A. UNS points primarily to operational benefits, claiming greater flexibility, reliability and efficiency and a superior location. [McKenna, p. 17] Flexibility includes the ability to "utilize its instantaneous, load following and emergency dispatch capabilities". [Id.] Ownership also allows UNSE to address the "intermittency issues of certain types of renewable energy facilities that will be providing power to UNS Electric customers in the future." [Id., p. 18]

Ownership increases reliability, because the Company will have "complete discretion and control over maintenance and operation of the facility for the long term." [Id.] Owning BMGS increases efficiency, by allowing UNSE to "obtain the exact type of unit it needs to meet its requirements" and "better meet its peaking capacity and reserve needs of its supply portfolio on a long-term basis". [Id.] Finally, "because BMGS is located in UNS Electric's load area, it can help to minimize transmission costs and enhance system reliability". [Id.]

Q. What do you recommend regarding UNSE's BMGS request?

A. I recommend the Commission approve this aspect of the Company's filing, for several reasons. First and foremost, UNSE is highly depended on purchased power, with very little of its own generating capacity; this acquisition will improve UNSE's resource mix, making it less subject

to the inherent risks associated with nearly exclusive reliance on wholesale markets. The only generating facility currently owned by the Company is the 65 MW gas turbine Valencia unit. The remainder of its 475 MW of peak capacity requirements is served by purchased power, either through purchased power agreements or on the spot market.

Second, the BMGS Combustion Turbines appear to have been acquired at a reasonable cost. In 2006, UED purchased the two LM6000 combustion turbines from Consolidated Edison in New York. The turbines were 2003 vintage units that had never been placed in service. According to UNSE, the purchase price of these units was 50% less than the cost of purchasing two new LM6OOO's from the manufacturer, General Electric. [McKenna Direct, p. 14] While I have not conducted an in-depth prudence analysis, I am not aware of any allegation of imprudence, or any claim that it would not be cost effective, over the life cycle of the plant, for UNSE to own this resource, rather than continuing to purchase power on the wholesale market.

Third, the Company's request for advance approval of the ownership transfer from the affiliate that built the plant is a reasonable one under the current circumstances – considering its small size and limited financial strength, and particularly given the Company's assurance that the ownership transfer will not increase current customer rates. By waiting to transfer ownership until it receives a Commission order granting rate base treatment, a potential problem with regulatory lag is avoided, eliminating a potential burden on stockholders, yet this would be accomplished without unduly burdening customers.

The Company and its affiliates will achieve continuous recovery of the cost of the plant; it currently receives cost recovery through the PPFAC; that treatment will end and base rate treatment will begin at the same time. Providing advanced authorization for this changeover at the time when title is transferred avoids a potentially serious problem with regulatory lag, which is particularly helpful in this situation, given the large size of the investment relative to the Company's small current capitalization. The $62 million cost of the plant is substantial, relative

to the Company's $192 million existing total capitalization. [See, Grant Direct, p. 9]

Absent advance approval, the Company might have difficulty borrowing a portion of the funds needed to pay for the plant; similarly, a failure to grant approval of the ownership transfer now that the plant is operating and serving UNSE's customers could reasonably be interpreted by the Company as a possible indication of Commission displeasure or disapproval of the plant. Under those circumstances, it would not be unreasonable for the parent company to decline to make the necessary equity investment required to support the plant – preferring to keep its equity investment, and legal title to the plant, within an unregulated affiliate where it will have the maximum flexibility to decide whether to continue to sell the power to UNSE, to sell power on the open market, or to sell the plant to another owner.

Fourth, adding BMGS to rate base in this proceeding will not harm, and could possibly improve, the Company's credit metrics – something that is in the long term best interests of customers. UNSE's current credit rating from Moody's is Baa3, the lowest investment grade rating assigned by that rating agency. [Id.] Avoiding junk bond status is in the interests of ratepayers. Absent a special effort to overcome the regulatory lag problem, and assurance that the investment will be deemed prudent by the Commission, acquisition of the BMGS plant could jeopardize the Company's investment grade rating. However, acquisition of the BMGS plant will reduce the Company's risk exposure to the wholesale power market, providing it with a more balanced power supply mix, thereby improving its business risk profile, which will be beneficial to its credit outlook over the long term.

As well, the near term acquisition of this plant offers the long term potential for improved financial metrics, which could eventually lead to an improvement in its bond rating. The infusion of as much as $40 million of additional equity capital to support the BMGS investment (which has already been authorized by the Commission) would expand the

Company's balance sheet, ameliorating the impact of the additional debt needed to help finance the plant, and making the Company's financial metrics less susceptible to short term fluctuations in operating expenses. Significantly, the acquisition could improve UNSE's cash flow picture, since customers will continue to pay the full cost of the plant, but a portion of this cost will be reclassified as depreciation. As well, depreciation is a non-cash item, so a portion of the amounts currently being paid by customers will no longer be paid out for purchased power expense; the net result is likely to be an increase in funds from operations, as computed by financial analysts in future years.

V. Rate Base Adjustments

Q. Can you briefly describe the Company's first proposed rate base adjustment - the Acquisition Discount Adjustment?

A. Yes. In August, 2003, UniSource Energy purchased Citizens Communications Company's Arizona electric utility assets. UniSource paid less than book value for the assets, resulting in a "acquisition discount", or "negative acquisition premium". According to witness Dukes, Unisource paid $104.3 million less than the original cost of Citizen's electric assets. [Dukes Direct, p. 10] GAAP accounting requires this amount to be shown on the Company's books as a negative acquisition adjustment. However, when reviewing the proposed acquisition, the Commission approved a settlement agreement that included a negative acquisition adjustment of just $93.6 million, which is roughly 10% less than the actual amount booked. [See, Decision 66028, p. 8] The Acquisition Discount Adjustment

> takes the GAAP discount and reduces it to the value of the discount authorized by the Commission. Put another way, the GAAP discount must be eliminated for ratemaking purposes, thus increasing its original

> cost rate base. This increased rate base must then be reduced by the value of the agreed upon discount. Overall, this adjustment results in a net increase to rate base. [Dukes Direct, pp. 10-11]

Q. Did UNSE request a similar adjustment in its last rate case?

A. Yes. UNSE proposed an acquisition adjustment, which was not opposed by any party. [See, Decision 70360, p. 14]

Q. What is your conclusion with regard to the Acquisition Discount Adjustment?

A. I recommend approving this adjustment. As a general rule, assets are appropriately put into the original cost rate base at the amount expended when the asset was originally devoted to public service (less accumulated depreciation). It is reasonable to make an exception in this case, since the Company voluntarily agreed to less favorable regulatory treatment as part of a Settlement. I would also point out that the public interest is well served by adjusting the rate base downward by less than the full amount of the negative acquisition adjustment. This regulatory treatment effectively rewards the Company's stockholders for negotiating a favorable acquisition price – a result that greatly benefits customers relative to paying the full depreciated original cost, or an even greater amount, as is more typically the case.

Q. Can you now discuss the Company's second rate base adjustment - the Post Test Year Non-Revenue Plant in Service?

A. Yes. UNSE proposes to include 85 items in rate base that had not been placed into service by the end of the test year. [See, UNSE response to Staff DR 4.9] However, according to UNSE, the Company invested "every single dollar in this adjustment" before the end of the test year. [Dukes Direct, pp. 11-12] "These investments were not in service by the end of the test year, but will be in service when rates established in this case go into effect". [Id., p. 12]

Q. Did the Company propose any post test year adjustments to rate base in its last rate case?

A. Yes. In its 2007 rate case, UNSE requested the inclusion of construction work in progress (CWIP) in rate base. Alternatively, the Company requested the inclusion of post test year plant in rate base. [See, Decision 7360, p. 9] In that proceeding, UNSE argued that the majority of the CWIP expenditures "will not produce new revenue or reduce the Company's expenses but, instead, will improve service reliability for both new and existing customers". [Id., p. 6] The Commission noted that the few times CWIP had been allowed in rate base involved extraordinary circumstances, and concluded that "UNSE is not faced with an extraordinary situation that would justify inclusion of CWIP in rate base because the plant required to serve new customers will help produce revenues". [Id., p. 8]

The Commission further concluded that the Company could mitigate the effect of the CWIP investment through the accrual of AFUDC; allowing CWIP would undermine the balancing of test year revenues and expenses; and, regulatory lag can be both a benefit and determent to UNSE. [Id.] With regard to the Company's post test-year plant request, the Commission concluded that "post-test-year plant should not be included in rate base for the same reasons stated above with respect to the Company's request for CWIP". [Id., p. 9] The Commission further explained:

> This issue is virtually identical to that raised in the UNS Gas case (Decision No. 7001 1 , at 7-8). As we stated in that Decision, "although the Commission has allowed post-test-year plant in several prior cases involving water companies, it appears that the issue was developed on the record in those proceedings in a manner that afforded assurance that a mismatch of revenues did not occur" (Id.) For example, in Decision No. 66849 (March 19, 2004), we stated that "we do not believe that adoption of this method would result in a mismatch because the post-test-year plant additions are revenue neutral (i.e., not funded by CIAC or AIAC)" (Id. at 5). In the instant case, however, the Company's request appears to

> be simply a fallback to its CWIP position, and there is no development of the record to support inclusion of the post-test-year plant. ... Even if we were inclined to recognize post-test-year plant in this case, there is not a sufficient basis upon which to evaluate the reasonableness of the request (i.e., whether a mismatch would exist). We therefore deny the Company's proposal on this issue. [Id.]

Q. Can you describe the post-test year investments UNSE hopes to include in rate base in this proceeding?

A. Essentially, it is requesting rate base treatment for the portion of UNSE's CWIP balance, as of the end of the test year, which UNSE considers "non-revenue producing". [See, attachment provided by UNSE in response to Staff DR 4.9] It includes investments in intangibles, as well as transmission, distribution and general plant assets. [Id.]

Q. What is UNSE's basis for including these investments in its proposed rate base?

A. UNSE contends that, given anticipated future rate cases, "UNS Electric would not begin recovering its investment for over 3.5 years after the investments were made to serve existing customers. " [Dukes Direct, p. 12] Further, UNSE claims that it's request is reasonable because it is limited to "revenue neutral plant". [Id., p. 13]

Q. Do you agree with UNSE's proposal to include these investments in rate base, or this "revenue neutral" characterization?

A. No. First, it isn't clear what is meant by the term "revenue neutral" in this context. The effect of including these items in rate base certainly is not revenue neutral – it increases the rate base, and if it were approved, this proposal would increase revenues received by the Company and the bills paid by customers. Furthermore, there is nothing extraordinary about these investments; aside from being labeled "revenue-neutral" (whatever that means), these assets are

not unlike many other assets that are routinely acquired by utilities in the ordinary course of business, benefiting both existing and future customers.

They include investments that should improve the Company's efficiency and help reduce operating expenses (e.g., "Project to replace existing work order, facilities data base & facilities mapping system with improved GPS based work order and mapping system"). They include investments that are necessary to accommodate growth (e.g., "Blanket account for line & service extensions to commercial businesses"), which will presumably be accompanied by future growth in revenues as well. They even include investments that may be reimbursed by third parties (e.g., "Damage to company facilities for which repair or replacement cost is billed to outside entities who cause the damage."). The list of proposed post-test year assets includes investments that are quite ordinary (e.g., "Specific project to construct a new warehouse with provisions for offices and material storage".

It is not a question of whether these investments are worthwhile, but whether they require extraordinary post-test year treatment. I see no evidence that special treatment is warranted in this case. The Commission should bear in mind that the Company will ultimately receive reimbursement for the cost of all of these investments from its customers. In fact, many of these investments will be paid for using internally generated cash flows received from customers through the allowance for depreciation which is included in existing rates. As well, even if an investment is financed with externally acquired funds, the cost of financing those investments will often be paid for through growth in revenues from increases in the sale of energy to existing customers as well as increases in the number of customers. To the extent any investments are not sufficiently offset through growth, depreciation, or reduced operating expenses, any resulting shortfall that might arise will be short lived, since they will be included in the rate base developed in future rate cases.

Second, as a matter of sound public policy, RUCO believes the Commission should

1 continue to use an historical test year, and it should reject proposals to include in rate base a
2 long list of investments which were not placed into service until well beyond the test year.
3 UNSE claims that all of these investments will be in service by the time new rates will likely go
4 into effect, but that is not a valid criteria for judging the merit of this proposal, since it is not
5 proposing to adjust for growth in revenues that occurred after the end of the test year.
6 Third, it is inappropriate to modify the test year for some, but not all, of the impacts of
7 post-test year events. For instance, it is impossible to know precisely how these assets will
8 impact the Company's operating costs. In some cases, there may be additional maintenance and
9 other costs; in other cases, costs may actually decline as a result of these investments, as older
10 equipment is reinforced with new additions that increase reliability, or reduce the need to incur
11 extraordinary labor costs to provide reliable service as the existing facilities near overload
12 conditions, or it becomes feasible to operate more efficiently using better capital equipment and
13 facilities.
14 In general, as new transmission and distribution facilities are added to the system it
15 becomes feasible to serve load growth, which allows the Company to earn additional revenues.
16 Yet, the Company has not made any adjustments for increased revenues associated with
17 customer and sales growth which will be accommodated by, or occur contemporaneously with
18 completion of these various projects. There is no justification for violating the matching
19 principle by reaching well beyond the test year to the cost of these various projects while
20 ignoring the accumulation of additional depreciation after the test year, as well as the offsetting
21 benefit of operating cost decreases and revenue increases which will occur during
22 contemporaneously with completion of these various projects. I believe it is preferable to adopt
23 a uniform, consistent cut-off date as of the end of the test year.
24
25 **Q. Can you now discuss the Company's third proposed rate base adjustment - Accumulated**

Deferred Income Taxes?

A. UNSE reduced rate base by $684,777 to account for Accumulated Deferred Income Taxes. [Schedule B-2, p. 2] Company witness Kissinger explains this adjustment:

> The adjustment reduces rate base for the computed balance of Accumulated Deferred Income Taxes, a source of non-investor capital, based on adjusted test year rate base and operating results and the Company's existing income tax ratemaking authority. ... This reflects the ADIT associated with assets owned by UNS Electric at the end of the test year, and the results of operations for the test year. There are no incremental effects included for any potential future events. [Kissinger Direct, pp. 4-7]

I have included this adjustment in the $2,028,227 deferred taxes amount shown on line 10 of BJ-2.

Q. Can you now discuss the Company's fourth proposed rate base adjustment - Working Capital?

A. The Company reduced its rate base by $3.8 million as an allowance for negative working capital. [Schedule B-2, p. 2] Company witness Dukes explains this adjustment:

> The Working Capital adjustment was computed in two pieces. First, as indicated on page2 of Schedule B-5, the recorded end-of-test-year balances for Materials and Supplies, and Prepayments are adjusted to reflect the 13-month average monthly balances, in recognition of the variability in the monthly balances of the accounts. This is consistent with the treatment of such accounts in prior rate cases. Second, Working Capital is adjusted for the reflection in rate base of a measure of Cash Working Capital, developed through the preparation of a comprehensive lead-lag study. [Dukes Direct, p. 14]

While I have not undertaken a detailed, independent review of the Company's working capital needs, the Company's working capital allowance appears reasonable, and I have included it on line 12 of BJ-2, along with an amount related to BMGS, as shown on line 12 of BJ-3.

VI. Income Adjustments

Q. Let's discuss UNSE's proposed income adjustments. Can you begin by commenting on UNSE's first income adjustment?

A. UNSE's first income adjustment, "Retail Revenue and Purchased Power Annualization" is intended to adjust the test year revenues and expenses to reflect the impact of current rates, which went into effect mid-year 2008. This $11.7 million adjustment to operating income includes a $10.7 million increase in electric sales revenue, and a $956,469 decrease in purchased power expenses. [See, Schedule C]

Absent the revenue adjustment, the test year results would reflect a mixture of the previously approved rates and those that were in effect prior to the last rate case, making it difficult to compute the amount of any rate increase that might be warranted in this case, relative to current rates.

UNSE explains the purchased power expense adjustment as follows:

> It is necessary to maintain the operating income neutrality of the PPFAC process. The PPFAC process allows for recovery of all eligible fuel, purchased power and purchased transmission cost ("PPFAC eligible cost") without profit. The amount included in revenue in the form of base power supply charges and PPFAC charges must be equal to the amount of PPFAC eligible cost reflected within expenses. Thus when we annualize the revenue to reflect the PPFAC rate as of June 1, 2008, we must also annualize the PPFAC eligible cost to be equivalent. [Dukes Direct, p. 17]

Q. What is your conclusion regarding this adjustment?

A. As with many of the proposed adjustments, I primarily focused on the ratemaking theory underlying the Company's proposal. I concluded that it is reasonable to make an adjustment of this type, in order to keep the base rates and PPFAC rates in synch, and to maintain an

appropriate matching between revenues and expenses. Accordingly, I have included this adjustment in my recommended revenue requirements, as shown on BJ-7, page 1 in column (B). As with other proposed adjustments that I accepted for purposes of developing my revenue requirement recommendations, I am not vouching for the Company's calculations, and I reserve the right to comment further on those calculations, at a later point in the proceeding.

Q. Can you now discuss UNSE's second income adjustment - Wholesale Revenue and Purchased Power?

A. This adjustment includes a $10.1 million decrease to Sales for Resale revenue, and a corresponding $10.1 million decrease to Fuel and Purchased power expenses. [Schedule C] This adjustment is designed to ensure that any profits on wholesale transactions are credited to customers through the PPFAC. UNSE explains:

> For book purposes the revenue associated with wholesale sales is recorded and 100% of that is also booked as a PPFAC regulatory liability (ultimately to credit customers through the PPFAC). There are also expenses associated with producing those revenues and those are expensed as incurred. Without adjustment the profit on those sales would flow through the income statement. Therefore an adjustment is made to the Company's actual books to bring the expenses up to the revenue level. By making that adjustment, there is no operating income from wholesale transactions. That "profit" is maintained in the PPFAC regulatory liability, which is then credited to customers through the PPFAC. So, the PPFAC rate reflects any profit in wholesale transactions and reduces the ultimate cost to customers. Therefore, we take the cost and the revenue out of the test year (which zero themselves out) because the profit on wholesale transactions is already reflected in the PPFAC rates... [Dukes Direct, p. 18]

Q. What do you conclude regarding this adjustment?

A. This adjustment also appears to be appropriate and consistent with the Commission's past policy. Accordingly, I have included it on BJ-7, page 1 in column (C).

Q. Can you now discuss UNSE's third income adjustment - Weather Normalization?

A. This adjustment is intended to restate the test year results as if perfectly normal weather conditions had occurred. UNSE's analysis indicates that during the test year weather was slightly hotter than normal, resulting in sales that were slightly greater than normal. [Erdwurm Direct, p. 9] Accordingly, UNSE made negative adjustments to revenues and expenses, for a net $186,687 reduction in operating income. [Schedule C]

Q. What do you conclude regarding the weather adjustment?

A. A similar adjustment was unopposed and accepted by the Commission in UNSE's last rate case. This type of adjustment is consistent with the underlying purpose of using a historical test year, which is simply a device for analyzing the normal level of revenues and costs which can be expected in the future. Therefore, I have included this adjustment in developing my recommended revenue requirements, as shown on BJ-7, page 1 in column (D).

Q. Can you now discuss UNSE's fourth income adjustment - Customer Energy Annualization & Customer Demand Normalization?

A. This adjustment restates test year bills and volumes "to be consistent with the number of customers on the system at the end of the test year". [Erdwurm Direct, p. 10] UNSE's customer count adjustment results in a 11,151,325 reduction in kWh. [Id., p. 11] This 0.7% reduction in kWh results in a $1.7 million decrease in operating income. [Schedule C-2]

Q. What do you conclude regarding this adjustment?

A. A similar adjustment was unopposed and accepted by the Commission in UNSE's last rate case. As well, this type of adjustment is appropriate if the Commission is going to use an end-of-year rate base, as has been its typical practice. Hence, in developing my recommended revenue

requirement, I have incorporated the adjustment amount proposed by the Company, as shown on BJ-7, page 1 in column (E).

Q. Can you now discuss UNSE's fifth income adjustment - Normalization of Revenues and Expenses for Fuel and PPFAC?

A. This adjustment normalizes test year PPFAC-eligible costs and revenues to the average rate included in UNSE's April 1, 2009 PPFAC submission.

> That submission results in an overall system average recovery rate for fuel, purchased power and purchased transmission cost at $0.067738 per kWh of sold energy when applied to test year billing determinants. This is 21% less than the overall system average rate of $0.086191 billed within rates from January lst, 2008 through December 31st, 2008. [Dukes Direct, p. 19]

The adjustment modifies test year operations to reflect the Company's most recent estimation of fuel, purchased power and purchased transmission expenses, with the intent of synchronizing the base rate calculations with the PPFAC rate calculations. The result is a $10.2 million reduction in operating income. [Schedule C] UNSE explains that the net result of all its PPFAC adjustments is "income neutral".

> Adjusted retail revenues for customer charges and delivery charges reflect the most recent rates that went into effect June 1, 2008 applied to the customer levels at the end of the test year and usage levels adjusted for normal weather. And the PPFAC eligible revenues and PPFAC eligible cost are based on the overall average rate effective June 1,2009, applied to the test year adjusted customer and consumption levels. Thus the PPFAC eligible revenue and PPFAC eligible cost have "zero" impact on operating income (no rate increase impact), but establish an overall base cost of fuel, purchased power and purchased transmission of $0.067738 per kWh - which is our best estimate of the cost at this point in time. [Dukes Direct, p. 19]

Q. What do you conclude regarding this adjustment?

A. As I understand it, this adjustment will have no net impact on customer bills, and is designed to

synchronize the base rates with the most recent PPFAC submission by the Company. This adjustment appears to be consistent with past Commission practice, and I have included it in my recommended revenue requirements, as shown on BJ-7, page 1 in column (F).

Q. Can you now discuss UNSE's sixth income adjustment - CARES Discounts?

A. According to the Company, this normalization adjustment is required because "subscription to the CARES program is increasing". [Erdwurm Direct, p. 18] The $61,797 adjustment increases the test year level of discount to $752,265, which "better approximates discounts that will prevail when rates are in effect". [Id.]

Q. What do you conclude regarding this adjustment?

A. Although the process by which UNSE calculated this adjustment is not entirely clear to me, it appears that Company has estimated an increase in the CARES discount based on an increase in the number of customers who were receiving the benefit of this discount as of the end of the year. Assuming I have interpreted the calculations correctlty, the adjustment does not go beyond the end of the test year, and it appears reasonable. Accordingly, I have included it in my recommended revenue requirements, as shown on BJ-7, page 1 in column (G).

Q. Can you now discuss UNSE's sixth income adjustment - Demand Side Management (DSM) Revenues and Expense?

A. In the Company's last rate case, it proposed a Demand-Side Management ("DSM') adjustor mechanism to recover costs of its DSM programs. UNSE and Staff agreed that the mechanism would be used to fund 100 percent of its expanded Low Income Weatherization ("LIW") program costs, and 25 percent of the other DSM program costs. [See, Decision 70360, p. 57] The Commission initially set the DSM adjustor at $0.000583 per kWh, and decided the amount

would be adjusted annually on June 1 of each year. [p. 57]

In this proceeding, UNSE has adjusted revenues and expenses for a net $168,787 increase in operating revenues. The Company explains: "This adjustment excludes from test year revenue and expenses the activity directly related to the DSM adjustor mechanism approved in Commission Decision No. 70360". [Dukes Direct, p. 20]

Q. What do you conclude regarding the DSM adjustment?

A. This adjustment appears reasonable, and I have included it in developing my recommended revenue requirements, as shown on BJ-7, page 1 in column (F).

Q. Can you now discuss UNSE's seventh income adjustment - Payroll Expense?

A. This adjustment consists of a $220,252 increase to operating expenses. [Schedule C] In calculating this adjustment, UNSE used end of test-year employee levels, and a mixture of 2009 and estimated 2010 wage levels.

> The Payroll Expense adjustment is intended to reflect in operating expenses an annualized level of salaries and wages based on current rates of pay and the number of employees on the UNS Electric payroll at the end of the test-year. That annualized level is then adjusted for the known pay rate increase that will go into effect January 1, 2009 and the estimated pay rate increase that will go into effect January 1,2010. [Dukes Direct, pp. 20-21]

Q. What is your conclusion regarding this adjustment?

A. I disagree with the portion of this adjustment that includes estimated pay increases that won't go into effect until far beyond the end of the test year. I do not object to including the January 1, 2009 pay increase, since this helps synchronize this cost with other aspects of the test year calculations, but it is not appropriate to include the second portion of the adjustment.

Accordingly, I have incorporated a similar adjustment in my revenue requirement analysis, but it uses the December 31, 2008 employee levels in conjunction with wage levels that went into effect the next day, on January 1, 2009. This modified adjustment results in a $79,628 increase to operating expenses, as shown on BJ-7, page 2 in column (I), rather than the $220,252 increase proposed by the Company.

Q. Can you now discuss UNSE's eighth income adjustment - Payroll Tax Expense?

A. UNSE explains:

> The Payroll Tax Expense adjustment was computed in a manner similar to, and consistent with, the payroll adjustment. An annualized level of payroll taxes was computed using current payroll tax rates, the same end-of-test-year employee levels and current salary rates that were used in the payroll adjustment. [Dukes Direct, p. 21]

The proposed adjustment consists of a $55,054 increase to operating expenses. [Schedule C]

Q. What is your conclusion regarding this adjustment?

A. I don't dispute the underlying premise of this adjustment, but have modified it to be consistent with my modifications to the payroll expenses adjustment. In other words, I used December 31, 2008 employees levels, and the wage levels that went into effect in January, 2009. This modified adjustment results in a $35,430 increase to operating expenses, as shown on BJ-7, page 2 in column (J).

Q. Can you now discuss UNSE's ninth income adjustment - Pension and Benefits?

A. This adjustment is "intended to reflect in operating expenses a level of pension and benefits expense reflecting the end-of-test-year work force, current pension and benefit actuarial expense level, and a normal level of business activity". [Dukes Direct, p. 22] The adjustment includes pensions, the Company's share of contributions to the employees' 401(k) plan, and

current medical costs. [Id.] The adjustment consists of a $220,252 increase to expenses. [Schedule C]

The adjustment was calculated as the difference between actual test year expense, and the level of expense estimated for 2009. [See, Income - Pension & Benefits 12-08.xls provided in response to Staff's second set of data requests] Essentially, UNSE has replaced actual 2008 expenses with anticipated 2009 expenses.

Q. What is your conclusion regarding this adjustment?

A. I recommend against this adjustment. It is reasonable to rely on the actual pensions and benefits expenses during the test year, and it isn't appropriate to estimate the level of costs that will be incurred during 2009.

Q. Can you now discuss UNSE's tenth income adjustment - Post Retirement Medical?

A. Witness Dukes explains: "The Post Retirement Medical adjustment is intended to reflect in operating expenses a level of post retirement medical payments reflecting the end-of-test-year work force level.". [Dukes Direct, p. 22] The adjustment consists of a $161,929 increase to expenses. [Schedule C]

Q. What is your conclusion regarding this adjustment?

A. This adjustment appears reasonable and consistent with past Commission practice, and I have included it in developing my recommended revenue requirements, as shown on BJ-7, page 2 in column (L).

Q. Can you now discuss UNSE's eleventh income adjustment - Rate Case Expense?

A. The adjustment consists of a $138,890 increase to expenses. [Schedule C] UNSE explains:

> The Rate Case Expense adjustment addresses the outside costs already incurred, and expected to be incurred, in connection with this rate case. This amount is an estimate of the anticipated final cost and will be updated before this proceeding concludes. The adjustment amortizes the balance to expense over three years. This is the approximate time period between when UNS Electric filed this rate case and when the next rate case will likely occur. The adjustment also reflects the collection of the anticipated remaining balance of rate case expense allowed to be recovered in the last UNS Electric Rate Order. That remaining balance will also be amortized over the anticipated life of rates in this case. [Dukes Direct, p. 23]

To calculate this adjustment, UNSE assumes $500,000 in rate case expenses annualized over 3 years, for an annual expense of $166,667. [See, Income - Rate Case Expense 12-08.xls provided in response to Staff's 2nd set of data requests] UNSE then adds $30,556 as the remaining amount of rate case expense approved in the last rate case, and subtracts $58,333 as the amount of rate case expense approved in the last rate case which had already been collected during the test year. [Id.] The net result is the $138,890 decrease in operating income.

Q. What is your conclusion regarding this adjustment?

A. In the prior rate case, UNSE calculated rate case expenses based on an assumed $600,000 cost. The Commission concluded that was an excessive amount of assumed rate case expense, and approved an adjustment that assumed $300,000 in rate case expenses instead. [Decision 70360, p. 24] This rate case was filed just 2 years after the prior rate case filing. This proceeding involves many of the same company witnesses, and many of the same issues. Given the commonality of witnesses and issues, I see no reason why the Company's rate case expenses should increase sharply above the level found reasonable in the prior case. Accordingly, I have used the Company's methodology, but have assumed a lower level of rate case expense of $300,000. To the extent the Company chooses to spend more than this amount, the excess amount should be the responsibility of the stockholders, and not borne by customers. As shown on BJ-7, page 2 in column (M), this results in a $72,223 increase to operating expenses.

Q. Can you now discuss UNSE's twelfth income adjustment - Bad Debt Expense?

A. Yes. This adjustment consists of a $436,441 decrease to operating expenses. Consistent with the methodology approved in the last rate case, UNSE developed a bad debt expense ratio based on the average annual bad debt expense for the years 2006-2008, and average annual unadjusted retail revenues for 2006-2008. UNSE then applies this ratio to test year revenues adjusted for revenue annualization, customer annualization, weather normalization, the PPFAC revenue adjustment, and CARES discounts. [See, Income - Bad Debt Expense 12-08.xls provided in response to Staff's 2nd set of data requests] Since actual bad debt expense was significantly greater in 2008 than 2006 and 2007, the averaging method results in a downward adjustment to test year expenses.

Q. What is your conclusion regarding this adjustment?

A. The adjustment is reasonable, and appears to be calculated in a manner consistent with the Commission's order in the prior rate case. Bad debt expense increased during 2008, as the economy turned down and more customers had trouble paying their bills. Hopefully, this problem will be short lived, and as the economy stabilizes bad debt expense will return to a more normal level. In any event, it is reasonable to normalize this expense to eliminate the impact of short term fluctuations, just as revenues are normalized to eliminate the impact of weather fluctuations. Accordingly, I included this adjustment on BJ-7, page 2 in column (N).

Q. Can you now discuss UNSE's thirteenth income adjustment - Interest on Customer Deposits?

A. This adjustment consists of a $145,701 decrease to operating expenses. [Schedule C] This is described as a normalizing adjustment "to reflect the currently applicable interest rate and

balance of customer deposits as of the end of the test year." [Dukes Direct, p. 24]

Q. What is your conclusion regarding this adjustment?

A. This type of adjustment is appropriate, in order to synchronize the level of interest on customer deposits with the end of the test-year rate base, and other adjustments that are tied to this cut off date. Accordingly, I recommend the Commission approve this adjustment. I have incorporated this adjustment into BJ-7, page 2 in column (O).adjst

Q. Can you now discuss UNSE's fourteenth income adjustment - Workers Compensation?

A. Yes. This adjustment consists of a $115,528 decrease to operating expenses. [Schedule C] It is designed to "to normalize the workers compensation expense level within the test year to an expected recurring level". [Dukes Direct, p. 24] UNSE further explains:

> This adjustment reduces the test year level to reflect a three year average for the expense which has fluctuated between a credit of $4 thousand in one of those years and as much as $212 thousand in expense in another. [Id.]

Q. What is your conclusion regarding this adjustment?

A. This adjustment appears to be calculated in a manner consistent with the approach approved by the Commission in the previous rate case, and I have included it in developing my recommended revenue requirements, as shown on BJ-7, page 2 in column (P).

Q. Can you now discuss UNSE's sixteenth income adjustment- Miscellaneous Expenses?

A. Yes. This adjustment consists of a $342,454 decrease to operating expenses. [Schedule C]

This adjustment removes test-year expenses that should not be included

> in revenue requirements because they are for out-of-period activity, not reflective of test-year activity and/or should not be recovered from customers. Also included in this adjustment is an increase to test year postage expense to reflect the postage rate increases that went into effect May 12, 2008 and May 11, 2009. Additionally, the normalization of outside legal cost is contained within this adjustment. [Dukes Direct, p. 25]

Outside legal costs were normalized to reflect a three-year average. [Id.] UNSE explains:

> In this case, the test year activity did not fairly reflect a normal and recurring level, prior to adjustment, the test year contained $141 thousand in outside legal costs related to the last UNS Electric rate case filing that were disallowed recovery of and thus written off within the test year. Once that adjustment is made the test year level is only $28 thousand, which is not reflective of normal and recurring levels. In 2005, 2006 and 2007 the Company spent $128, $106 and $181 thousand respectively, on outside legal costs, excluding UNS Electric rate case activity. That results in a three-year average of $138 thousand which is reflective of normal and recurring levels and is consistent with expected spending levels. [Id.]

This adjustment also excludes a portion of certain organizational dues. Specifically, UNSE removes 1% of USWAG dues, and 16% of EEI dues.

Q. What is your conclusion regarding this adjustment?

A. While the general thrust of the adjustment is reasonable, I disagree with the amount.

To begin with, I disagree with UNSE's exclusion of just 1% of USWAG does and 16% of EEI dues. Neither exclusion is sufficient, in my opinion. I say this for two primary reasons. First, a large, but indeterminate, portion of these organizations' activities are designed to influence government policy, both directly (supporting industry lobbying and public relations efforts with respect to Congress and various State and Federal agencies) and indirectly (through various types of policy studies and research which support those efforts). The Company has

focused on a narrow subset of this overall range of activities – those which are most directly related to influencing legislation, but the entire range of activities is primarily the responsibility of, and for the benefit of, stockholders.

Second, these organization's activities would continue whether or not UNSE or any other Arizona utility belongs to the organization, or contributes to the budget for these activities. Thus, it is hard to say these costs are necessary for the Company to incur, or that membership offers any significant benefits to the Company's ratepayers. Taking both of these problems into account, I recommend that ratepayers be required to bear no more than a reasonable portion of these dues. While the specific split between stockholders and ratepayers is a matter of discretion for the Commission, in preparing my recommendations I have excluded 40% of the cost, consistent with RUCO's position in the pending UNS Gas rate case.

With regard to the adjustment for legal costs, I agree it is reasonable to use a "normalized" level of legal expense, and I don't object to using a relatively brief, recent period to develop an estimate of the ongoing, normal level of cost. However, the Company used a 3 year average that excluded the test year. In my view, it would be more appropriate to use an average that includes the recent 2008 level of legal expenses, and it would be appropriate to exclude the cost of the prior rate case. More specifically, I recommend using an average of the Company's 2006, 2007 and 2008 legal expenses, excluding costs associated with the prior rate case, which are being dealt with separately.

I have also modified the postage portion of this adjustment. My revised postage calculations include the portion related to the postage rate increase that went into effect during the test year, but I have excluded the portion related to the May 2009 postage increase, since this went into effect well beyond the end of the test year. My recommended adjustment is shown on BJ-7, page 2 in column (Q).

Q. Can you now discuss UNSE's seventeenth income adjustment- A&G Expense Capitalized?

A. Yes. This adjustment consists of a $229,429 decrease to operating expenses. [Schedule C] UNSE states that the adjustment is necessary to "normalize the level of administrative and general charges capitalized during the test year". [Dukes Direct, p. 25]

> The charges capitalized are for services performed by personnel in support areas like Information Services, Plant Accounting, and Operational Systems Support. A study was performed during the test year to evaluate the time spent by these service areas in support of capital activities. A new capitalization rate was determined and put into effect in the first quarter of 2009. This new rate was used to normalize test year activity and more properly reflect the known capitalization rate going forward. [Id., pp. 25-26]

Q. What is your conclusion regarding this adjustment?

A. This adjustment appears reasonable. I have included it in my recommended revenue requirements, as shown on BJ-7, page 3 in column (R).

Q. Can you now discuss UNSE's eighteenth income adjustment- Depreciation and Property Tax for Post Test Year Non-Revenue Producing Plant in Service?

A. This adjustment consists of a $442,526 increase to operating expenses. [Schedule C] UNSE does not provide a discussion of this adjustment. However, it appears to be directly related to the supposedly "non-revenue producing" plant investment the Company proposes to add to rate base, which was not in service during the test year. I recommend the Commission disallow this adjustment, consistent with my recommendation regarding rejection of the proposed addition to rate base.

Q. Can you now discuss UNSE's nineteenth income adjustment- Depreciation & Amortization Annualization?

A. This adjustment consists of a $507,792 decrease to operating expenses. [Schedule C] UNSE

explains:

> The Depreciation Expense adjustment is computed to reflect in pro forma operating expense an annual depreciation amount based on depreciable plant in service as of the end of the test year and book depreciation rates as presented in detail in the testimony of witness Dr. Ronald E. White. The calculation of the adjustment properly considers the effects of depreciation associated with vehicles that are charged to clearing accounts or expense categories other than depreciation. This adjustment does not include any amounts related to BMGS. The depreciation expense requested for BMGS is presented separately. [Kissinger Direct, p. 7]

Q. What do you conclude regarding this adjustment?

A. This adjustment appears reasonable, and I recommend the Commission accept it. I have included it in my recommended revenue requirements, as shown on BJ-7, page 3 in column (T).

Q. Can you now discuss UNSE's twentieth income adjustment- Property Tax Expense?

A. Yes. This adjustment consists of a $7,358 decrease to operating expenses. [Schedule C] The adjustment is based in part on the assessment ratio that won't go into effect until January 1, 2010. [Kissinger Direct, p. 8]

Q. What do you conclude regarding this adjustment?

A. By using the 2010 assessment ratio, this adjustment goes too far beyond the test year. I have developed an alternative adjustment, as shown on BJ-7, page 3 in column (U), which uses the 22% assessment ratio, which is applicable "from and after December 31, 2008 through December 31, 2009". [See, page 20 of Income - Property Tax Expense 12-08_bates.pdf, provided in response to Staff's 2nd set of data requests]

Q. Can you now discuss UNSE's final income adjustment- Income Taxes?

A. This adjustment is intended to reflect the Company's final adjusted operating revenues, expenses and rate base. The Company explains that it is computed in two parts.

> The first part is pro forma current income tax expense, the tax liability computed as though an actual income tax return was being prepared on final adjusted test year taxable operating income. For this purpose, it was necessary to identify all operating book-tax differences ("Schedule M items"), both timing and permanent, and then recompute based on adjusted test year operating revenues and expenses, if necessary. The tax deduction for interest was computed using a synchronization methodology reflecting final adjusted rate base and the weighted cost of debt in the capital structure. The second part of the income tax calculation is deferred income tax expense. Deferred income taxes are computed on the Schedule M items representing timing differences for which the Company has obtained normalization ratemaking authority from the Commission as previously described in my testimony. [Kissinger Direct, p. 8]

Q. What do you conclude regarding this adjustment?

A. The basic approach the Company is using seems reasonable. I have used a similar approach in computing my income tax adjustment, on BJ-7, page 3 in column (V), modified to be consistent with my other recommendations.

Q. Are there any other expense related adjustments you would like to discuss?

A. Yes. First, while I have not quantified specific adjustments related to Incentive Compensation, Stock-Based Compensation, and the Supplemental Executive Retirement Plan (SERP), RUCO's position on these expenses is well known to the Commission. As a matter of sound public policy, RUCO continues to urge the Commission to disallow all Stock-Based Compensation Expenses and SERP expenses, and to disallow 50% of Incentive Compensation Expenses. The effect of this policy is to place responsibility for these costs on stockholders, rather than

ratepayers. The rationale for this policy is set forth in detail in the testimony of Ralph Smith, filed on behalf of RUCO in the pending UNS Gas rate case.

Second, RUCO believes it would appropriate, again as a matter of sound public policy, to exclude a portion of purchased power and fuel related costs from the Company's PPFAC, in order to provide an incentive for management to aggressively control these costs, and to manage its power and fuel acquisition process as efficiently as possible. Historically, the Company has acquired nearly all of its energy from a single supplier (Arizona Public Service Company), and so arguably there was not a great need for an incentive mechanism in the PPFAC. However, the Company plans to begin purchasing more power on the wholesale market, and it plans to produce more of its power using its own generating facilities. Accordingly, I recommend adopting a 90/10 sharing mechanism for UNSE that is like the one utilized by APS.

VII. Fair Value Rate of Return

Q. The Commission's traditional method of calculating a rate of return for application to a fair value rate base was recently addressed by the Arizona courts. Can you briefly explain that proceeding, and how it relates to this case?

A. On September 30, 2005 the Commission issued Decision No. 68176 granting a rate increase to Chaparral City Water Company. ("Chaparral") In accordance with longstanding precedent, the Commission multiplied the weighted average cost of capital (WACC) by the original cost rate base (OCRB) to estimate the needed operating income. [Decision 68176, pp. 26-28] The Commission then divided that required level of operating income by the fair value rate base (FVRB) to arrive at a fair rate of return. [Id., p. 28] The fair rate of return was then applied to

the FVRB to determine operating income for rate making purposes. Chaparral subsequently filed an appeal with the Arizona Court of Appeals that, among other things, has resulted in the Commission rethinking its approach to developing the rate of return it applies to the FVRB.

Q. Did the Court of Appeals address the methodology for determining a fair rate of return?

A. Yes. First, the court recognized that the Arizona Constitution gives the Commission "exclusive and plenary" authority to prescribe rates for public utilities within the state. [Chaparral City Water Company v. ACC, 1 CA-CC 05-0002, Memorandum Decision, p. 5] However, the court also noted that the state Constitution specifically requires the Commission to ascertain the "fair value" of the utility's property. [Id., p. 6]. Article 15, Section 14 of the Arizona Constitution states:

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

The court stated that this provision has been interpreted as requiring the Commission to determine the fair value of the utility's property, and to use that finding as the rate base in setting rates. [Id., citing Simms v. Round Valley Light & Power Co., 294 P. 2nd at 382] The court noted that the Arizona Constitution does not define fair value, but stated that it is "generally recognized as being based on both original cost and reproduction cost". [Id., p. 4, f.n. 4]

On appeal, Chaparral argued that operating income should be determined by multiplying the FVRB by the rate of return, and that "the rate of return is generally equal to a utility's weighted cost of capital". [See, Id., p. 7] The Commission responded by asserting that it was not bound to use the weighted average cost of capital as the rate of return to be applied to

FVRB. The court agreed, stating:

> If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology. [Id., p. 13]

The court also noted that "rates of return vary, depending upon the type of rate base used". [Id., p. 7, f.n. 5] However, the Court of Appeals found that the Commission's method for determining operating income ignored fair value rate base, in violation of the Arizona Constitution.

> Here, the Commission determined Chaparral City's operating income based on the OCRB and then mathematically calculated a corresponding rate of return had the income been based on the FVRB. Under this method, Chaparral City's operating income, and therefore its revenue requirements and rates, were based not on the fair value of its property, but on its OCRB, which does not comport with the Arizona Constitution. [Id., p. 12]

Accordingly, the court remanded the matter to the Commission for further determination.

Q. What did the Commission decide on remand?

A. On July 28, 2008, the Commission issued Decision No. 70441, in which it stated:

> Our previous method was a shorthand method of ensuring that inflation would only influence one piece of the ratemaking formula - the rate of return. However, the Court of Appeals has made it clear that, under our constitution, the "inflation component" belongs in the FVRB. Accordingly, in order to avoid over-counting the effect of inflation, it is necessary for us to ensure that the rate of return does not also carry an inflation component. [Decision No. 70441, p. 33]

The Commission noted that there are many methods that could be used to determine an appropriate FVROR, including the methods advocated by Staff and RUCO in the Chaparral

case. [Id., p. 34] Staff's method "adjusts the cost of capital to reflect the cost of the portion of the capital structure that is funded by neither debt nor equity, but exists due to inflation". [Id.] RUCO's method "analyzes the inflation contained in the estimates of cost of equity and adjusts the cost of capital to eliminate the inflation component". [Id.] Ultimately, the Commission used a method similar to the one I recommended on behalf of RUCO, but with a significant modification, which limited its scope. [Id.]

Q. Are there other methods available for the Commission to deal with this issue in this proceeding?

A. Yes. The Commission has several methods to choose from, including: the method I recommended on behalf of RUCO in the Chaparral remand proceeding; the modified method that was subsequently adopted by the Commission in the Chaparral remand proceeding; and three other methods, which have been advocated by Staff in various proceedings.

Q. Can you describe the method that was recommended by RUCO in the Chaparral remand case?

A. Yes. As I explained in that proceeding, in jurisdictions where the rate base is entirely based on original cost data, it is common practice to apply a rate of return which is based upon the weighted average cost of capital, derived in large part using accounting data (e.g. debt and equity amounts; embedded interest rates). In contrast, where the rate of return will be applied to the current value of the utility's property, a lower return is appropriate – one that provides the utility with an opportunity to recover its actual capital costs, without overcompensating for inflation.

A rate of return that is fair to both customers and stockholders can be derived from the weighted average cost of capital by simply subtracting an amount related to the rate of inflation,

thereby preventing a double counting of compensation for inflation. For example, assume the weighted average cost of capital is 7.50%, and the relevant inflation rate is 2.5%, then a fair return on the fair value rate base would be 5.00%, or thereabouts.

Q. Why is it appropriate to remove inflation from the rate of return?

A. A typical cost of capital, which includes inflation, cannot be applied to the fair value rate base because this would result in a double counting of inflation. A fair value valuation of the rate base tends to be higher than an original cost valuation, because it also reflects the impact of inflation and other factors which tend to contribute to an upward growth in value over time. Economists have long recognized that inflation and other factors which increase the value of an investment will significantly impact an investment's expected return. In turn, these factors affect the present value of the investment. To fully understand this relationship, it is necessary to realize that growth in the value of an investment is a component of the total return achieved by the investor. Indeed, for many so-called growth stocks which pay little or no dividends, virtually the entire return received by the investor results from growth in the market value of the stock (capital gains). The same principle applies to the value of rental property in areas where real estate prices (and/or rents) are escalating – investors will take into account the anticipated growth in the value of their investment – similar to the way growth stocks are evaluated.

Similarly, if the income being generated by a particular investment is expected to grow over time (e.g. rents are increasing), that will tend to push up the current market value of an investment. Investors will accept a lower current return from an investment, if they have reason to believe the return will increase over time.

The current market value of an investment is determined by the net effect of multiple factors, including the current annual income or return (in dollars), expected changes in that

income or return, and expected changes in the value of the investment. Thus, real estate investors in areas where demand is growing will often purchase property with an extremely low or negative current cash return, because they anticipate profiting from future growth. Similarly, investors might construct a new office building, despite the fact that the rent payments during the first few years will actually be less than their direct expenses (interest, utilities, taxes, etc.), indicating a negative current level of return – if they expect rents, and/or the value of the property, to increase sufficiently in the future. Investors take into account all aspects of anticipated returns, including past and future trends in market rents, as well as anticipated growth in the value of the building. If the growth expectations are strong enough, investors will accept extremely low or negative returns during the early years, because they anticipate earning an adequate return over the entire life cycle of their investment.

Since the dollar magnitude of the fair value rate base is larger than an original cost rate base, reflecting past growth in the value of the utility's property, and since the future income stream can reasonably be expected to increase in the future, due to inflation and other factors which tend to push up property values as time passes, a 5.00% return on fair value is likely to provide investors with as large a total return (over time) as a 7.50% return applied to an original cost rate base. The exact amounts received by investors may differ somewhat, and they certainly will differ during any specific year, but the key point is that investors will have as strong an opportunity to recover their capital costs and to earn a competitive return through the application of a 5.00% return on an escalating estimate of fair value as with a 7.50% return on the original cost. The regulatory goal of simulating the effects of competitive markets, and compensating investors for the impact of inflation, can be achieved either way.

Q. Can you explain in greater detail why a fair rate of return applied to a fair value rate base is less than the percentage return which would normally be applied to an original cost rate

base?

A. Yes. If the return is going to be fair to customers as well as to stockholders, it must be lower than the weighted average cost of capital. The same percentage figure cannot be appropriate for application to both the original cost and to the replacement cost of the utility's property, unless these two cost measures happen to be nearly the same.

Another way of seeing why this conclusion is valid is to start with the competitive market result, which is widely accepted as the appropriate standard for utility regulation in nearly all jurisdictions, regardless of whether they use original cost or fair value in developing their rate base calculations. Utilities in Arizona and other states are all competing for investment capital that is being provided in a national market. If the same percentage rates of return were applied to fair value rate bases in Arizona as are applied to original cost rate bases in all other jurisdictions, it is self evident that Arizona investors would be overcompensated.

If the same cost of capital were applied to a fair value rate base as is applied to original cost rate bases in other jurisdictions, Arizona utilities would be provided with an opportunity to earn windfall profits, in comparison with the treatment of utilities in other states, where firms are only given the opportunity to earn a normal, competitive return.

While the Arizona Constitution requires use of a fair value rate base, and that may influence the specific rate of compensation provided to any specific utility during any specific year, it is not necessary or appropriate to provide Arizona utilities with earnings that consistently exceed those earned, on average, by utilities in other states (or which consistently exceed the earnings of the average unregulated firm which operates in competitive markets, adjusted for differences in risk). Yet just such a consistent differential would occur if the same rate of return were applied to fair value in Arizona and to original cost in other jurisdictions.

Aside from differences in risk, the long term average compensation provided to utility investors in Arizona should be roughly equivalent to that paid to investors in other enterprises –

assuming comparable levels of risk. Investors in Arizona and in other states should all be given a reasonable opportunity to earn a normal return – a return which is consistent with competitive market levels.

I made that last statement in terms of the long term average, because there could be differences in timing, due to differences in the rate base valuation methodology. The return on investment provided in a fair value rate jurisdiction might be somewhat lower in the initial years, and higher in the later years of any given investment, relative to the timing of the returns received in an original cost jurisdiction, just as investors in growth stocks receive more of their return in later years, as dividends increase, or upon sale of the stock. While the year-to-year pattern of cash flows might differ somewhat depending on the specific rate base methodology, the overall long term average level of compensation paid to investors should be very similar, regardless of whether the rate base is based upon original cost, or fair value.

Consistent with this line of reasoning, it is clear that the appropriate magnitude of the difference between the appropriate rate of return in an original cost jurisdiction and the fair rate of return in a fair value jurisdiction is closely related to the rate of growth in the utility's fair value rate base relative to the original cost of its property. The more rapidly fair value is growing relative to original cost, the less need there is to immediately provide a high level of current income in the form of high percentage return for application to the fair value rate base. This is exactly what we observe in the stock market, where investors are satisfied with relatively lower levels of current income and dividends in growth industries, where the value of the stock and the anticipated future level of dividends are expected to grow over time.

Q. Can you now describe the modified method the Commission used in the Chaparral case?

A. The Commission held:

> Although we believe that the cost of debt may reflect the effects of

> inflation, we are not convinced that the evidence presented in this proceeding is developed sufficiently to make that determination with certainty. Accordingly, while we agree with RUCO that the WACC should be adjusted to remove the inflation component, we believe that the appropriate adjustment in this case is to adjust only the cost of equity component of the WACC. [Id., pp. 36-37]

The Commission used a "conservative" inflation estimate of 2.00%, but it only removed the inflation component from the cost of equity component of the WACC. [Id., p. 37]

Q. Can you now describe some other methods that can be used in developing a fair rate of return to apply to the fair value rate base?

A. Yes. In the Chaparral remand proceeding, Staff recommended developing a "fair value capital structure", and assigning cost rates to the various components. Staff recommended assigning a zero cost to the "fair value increment" (The amount by which fair value exceeds OCRB) [See, Decision 70441, p. 14] Staff explained that since this portion was not financed by investors, a zero cost would be appropriate. [Id.]

Staff presented a second alternative on October 3rd, 2008 through Staff witness Gordon Fox, who presented testimony in the most recent Chaparral rate case. Mr. Fox noted that on remand in the Chaparral case, the Commission did not reduce the cost of debt for inflation "due to inadequacies in the record". [Fox Direct, Docket W-02113A-07-0551, p. 5] Mr. Fox concludes (correctly) that inflation is a component of the cost of debt (interest rates tend to increase as inflationary expectations increase). "Accordingly, Staff recommends a FVROR that includes an adjustment to remove the inflation component, i.e., an "accretion return" from the cost of debt". [Id.] However, Staff only removed half of the inflation component from capital costs, because FVRB is computed by averaging OCRB and RCND.

> The OCRB includes no inflation factor. Thus, if the inflation adjustment is made for the entire inflation component of capital costs, the downward

> adjustment to the FVROR will be greater than the upward inflation recognized in the FVRB for reasons other than market forces. As a result of this lack of symmetry, when the FVROR is multiplied by the FVRB to compute operating income, the calculation will be skewed downward. Removing only half of the inflation component from the equity and debt costs maintains symmetry between the FVROR and the FVRB. [Id., p. 8]

A third method advocated by Staff is similar to its first method described above, except that rather than assigning a zero cost rate to the fair value increment, Staff would assign a cost equal to half the rate of inflation.

Q. Several of the methods described above include an inflation component. To the extent inflation is going to be considered, what inflation factor would you suggest using?

A. This is a matter of judgment; the Commission can exercise sound discretion in determining the most appropriate inflation factor to subtract from the weighted average cost of capital. Numerous data series are available as indicators of historical inflation rates, including the data published by the Bureau of Labor Statistics for the annual rate of change in the Gross Domestic Product Deflator, as well as annual changes in consumer prices and various measures of producer prices. Expected future inflation rates are obviously of vital importance in this context, so it is appropriate to consider a forward looking view of inflation. However, it is also reasonable to consider historical inflation, since this contributed to increases in the current fair value of the utility's property. A useful measure of investor inflation expectations can be derived by comparing yields on Treasury Inflation-Protected Securities (TIPS) and other securities issued by the Treasury Department with similar liquidity and duration. TIPS are bonds issued by the U.S. Treasury which are sometimes called "linkers", because they are "linked" to the actual rate of inflation.

TIPS are issued twice a year, in January and July. The principal amount that is paid

back to the holder upon maturity is periodically increased, based on the CPI-All Consumer Items. Like most government bonds, the TIPS coupon rate (percentage return) is constant, but these particular securities are unique because they generate an increasing flow of interest payments. TIPs pay interest twice a year, based upon a fixed rate that is multiplied by the inflation-adjusted principal. The end result is that investors are protected against inflation both with respect to the value of their investment, and with respect to the income they receive.

Thus, for example, if the interest rate on a TIP Security is 5%, its cost is $100, and cumulative total amount of inflation from the time of issuance until maturity is 20%, the value of the investment would increase to $120 at maturity. The 5% interest rate would be applied to the increasing principal amount, eventually reaching the level of 5% of $120 – approximately 20% more than the initial payment level.

At maturity, the securities are redeemed at the greater of their inflation-adjusted principal or the original par amount at the time they were issued. TIPS provide yet another example that illustrates one of the key points in my testimony – that the percentage rate of return earned by an investment that grows in value over time will normally be lower than the analogous return paid on an investment that does not grow over time. The fact that these securities offer significantly different percentage returns is further proof of this fundamental point. But, these securities are also of interest because they provide useful insights into investor expectations concerning inflation.

It is well established in the academic literature that the difference between the yield on a TIP and the yield on a comparable government security that is not linked to inflation can be used to estimate investors' future inflation expectations. In fact, UNSE uses such an approach to estimate inflation in this proceeding.

Q. What inflation rate did UNSE calculate?

A. UNSE developed an estimate of long term inflation of 2.1%. [Pritz Direct, p. 11] This estimate was derived from several data series published by the Federal Reserve Bank of Cleveland: 20-year TIPS Derived Expected Inflation; 10-year TIPs Derived Expected Inflation; and, Adjusted 10-year TIPs Derived Expected Inflation. [Id., pp. 10-11; STF Pritz adjusted tips inflation 2006 to 2009.xls] The last series includes an adjustment to account for the liquidity differences between TIPs treasuries and other treasuries, but it was discontinued by the Federal Reserve Bank of Cleveland in October, 2008 because the "extreme rush to liquidity" was affecting the accuracy of the series. http://www.clevelandfed.org/research/data/tips/index.cfm]

In developing its estimate, UNSE relied on an average of recent Adjusted 10-year TIPs Derived Expected Inflation rates, and a single recent 20-year TIPS Derived Expected Inflation rate for its estimate of the long term inflation rate.

> In light of the current uncertainty in the financial markets, I recommend averaging two figures to arrive at an estimate of long-term inflation expectations. The first figure is the average adjusted implied inflation rate for the period from January 2007 through August 2008, representative of expectations prior to the disruption in the financial markets. That figure is 2.68%. The second figure is the February 2009 unadjusted implied inflation based on 20-year treasuries, 1.52%. The average of these two figures is 2.1%. [Pritz Direct, p. 11]

Q. What is your recommendation concerning the appropriate inflation rate to use in developing the fair rate of return?

A. In my opinion, it would be reasonable to use a 2.1% inflation rate. However, I don't think the rate should be based purely on forward looking expectations, as the Company has done. Under the current circumstances, there isn't a great difference between historic inflation and forward looking inflation estimates, but as a matter of theory, I believe it is appropriate to give some weight to both views of inflation. While I agree the 2.1% inflation rate is reasonable, I have a fundamental disagreement with slashing the rate in half, as the Company suggests, and the Commission staff has proposed in the recent Chaparral proceeding.

The Company doesn't provide any explanation or justification for cutting the inflation rate in half, but from my reading of the Staff's testimony in the recent Chaparral case, I get the impression this method is based, at least in part, on the fact that reproduction costs are only given half weight in the fair value rate base calculations, while original cost (which does not escalate with inflation) is also given half weight. In my view, this does not provide adequate justification for simply slashing the inflation rate in half.

While it is true that reproduction cost is only given half weight in developing the FVRB, reproduction cost does not escalate at the inflation rate; to the contrary, reproduction costs tend to grow faster than the rate of inflation, because they don't fully consider the favorable impact of technological changes, increasing economies of scale, and other sources of increased efficiency and cost savings – factors which tend to hold back the pace at which prices escalate over time.

Technological improvements and other sources of cost savings are one of the reasons why the Commission doesn't rely entirely on reproduction cost in developing fair value, and instead weights reproduction cost with original cost. As well, it's important to realize that technological improvements and other sources of cost savings are considered in developing the GDP deflator and most other measures of inflation. In other words, the 2.1% inflation rate developed by the Company is a relatively low percentage figure, because it takes into account the beneficial effects of technological changes and other sources of cost savings which ameliorate or offset other factors which tend to push up reproduction costs. Since the 2.1% inflation rate is relatively modest, it isn't necessary to cut this rate in half in order to develop an appropriate net figure for use in this context.

Q. What fair value rate of return is the Company proposing?

A. Company witness Grant recommends a 6.88% rate of return to be applied to UNSE's fair value

rate base. [Grant Direct, p. 13] The primary explanation provided regarding the development of this rate is the following:

> This ROR, when applied to the Company's FVRB of $265 million, produces an overall rate increase that would provide UNS Electric with a reasonable opportunity to earn its cost of capital, to support its creditworthiness and to attract capital on reasonable terms. [Id.]

Elsewhere in the Company's testimony, it explained that this 6.88% figure is less than the percentage figure that would be developed by starting with its estimate of the WACC and adopting the method adopted by the Commission in the Chaparral remand case (which it estimates works out to 8.08%), or the alternative method proposed by the Staff in the more recent Chaparral case, cutting the inflation rate in half, (which it estimates works out to a FVROR of 7.99%).

Q. Have you prepared an analysis of the five methods you described above in comparison with RUCO's estimate of the weighted average cost of capital and the requested rate of return proposed by the Company?

A. Yes. This analysis is shown on my schedule BJ-10. Under "Method 1" I show the impact of using the 9.25% cost of equity and other WACC inputs presented in the testimony of RUCO witness Bill Rigsby, and subtracting an inflation rate of 2.1%. The result of this methodology, which is the one I presented in the Chaparral remand proceeding, results in a fair value rate of return of 5.96%.

"Method 2" shows the effect of using the procedure adopted by the Commission in that proceeding, in which the inflation rate is only subtracted from the equity cost component; it results in a fair value rate of return of 7.10%.

The other three approaches I discuss above, which have been proposed by the Staff in

various contexts, are shown as Methods 3, 4 and 5 of BJ-10. These three methods result in a fair value rates of return of 5.39%, 5.80%, and 7.01%, respectively.

Q. What do you recommend concerning the fair return on fair value in this proceeding?

A. I recommend the Commission begin by evaluating all of the methods presented on BJ-10. The Commission can use its discretion to set a fair return on fair value, provided that it reasonably b balances the interests of both ratepayers and customers, and in so doing it gives the Company a reasonable opportunity to recover its cost of capital, and earn a reasonable return on its invested capital. These various methods result in returns on fair value ranging from 5.39% to 7.01%, with a midpoint of 6.20% and an average of 6.25%. The greatest weight should be given to Method 1, because it is the most theoretically sound approach. I recognize that the Commission has discretion in adopting the allowed return on fair value, and it may want to give at some limited consideration to other methods, resulting in a slightly higher or lower return. But, using Method 1, as I recommend, with Mr. Rigsby's recommended weighted average cost of capital, a fair return on fair value is computed to be 5.96%, as shown on BJ-10.

VIII. Conclusions and Recommendations

Q. Can you now please briefly summarize your recommendations?

A. Yes. The effect of my recommendations, as well as Bill Rigsby's cost of capital analysis, is set forth on Schedule BJ-1 of my exhibit. If the Commission were to accept all of my recommendations, the original cost rate base would be approximately $229.9 million; similarly the RCND rate base would be approximately $411.4 million. The fair value rate base would be approximately $320.7 million, assuming the Commission follows its traditional 50/50 weighting of original cost and RCND. These figures compare to the Company's rate base

proposals of $237.2 million, $418.7 million, and $327.9 million, for original cost, RCND and fair value, respectively.

If the Commission were to accept all of my recommendations, after taking into account my recommended pro forma adjustments, the test year operating income would be $16.3 million, which compares to the Company's proposed operating income of $15.7 million. If the Commission were to adopt RUCO witness Rigsby's 9.25% estimate of the cost of equity and his overall weighted average cost of capital of 8.06%, applying my recommended 5.96% fair rate of return to a fair value rate base of approximately $320.7 million, the required operating income is approximately $19.1 million. This analysis suggests a test year operating income deficiency of $2.8 million. This compares to the Company's calculated income deficiency of $8.3 million.

Q. What increase in revenues is implied by this income deficiency calculation?

A. Applying the Company's gross revenue conversion factor to this test year income deficiency results in a base rate revenue increase of approximately $4.5 million. This compares to the Company's proposed revenue increase of $13.5 million.

Q. Does this conclude your testimony, prefiled on November 6, 2009?

A. Yes, it does.

Appendix A

Qualifications

Present Occupation

Q. What is your present occupation?

A. I am a consulting economist and President of Ben Johnson Associates, Inc.®, a firm of economic and analytic consultants specializing in the area of public utility regulation.

Educational Background

Q. What is your educational background?

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. The title of my Master's Thesis is a "A Critique of Economic Theory as Applied to the Regulated Firm." Finally, I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics. The title of my doctoral dissertation is "Executive Compensation, Size, Profit, and Cost in the Electric Utility Industry."

Clients

Q. What types of clients employ your firm?

A Much of our work is performed on behalf of public agencies at every level of government involved in utility regulation. These agencies include state regulatory

commissions, public counsels, attorneys general, and local governments, among others. We are also employed by various private organizations and firms, both regulated and unregulated. The diversity of our clientele is illustrated below.

Regulatory Commissions

Alabama Public Service Commission—Public Staff for Utility Consumer Protection
Alaska Public Utilities Commission
Arizona Corporation Commission
Arkansas Public Service Commission
Connecticut Department of Public Utility Control
District of Columbia Public Service Commission
Idaho Public Utilities Commission
Idaho State Tax Commission
Iowa Department of Revenue and Finance
Kansas State Corporation Commission
Maine Public Utilities Commission
Minnesota Department of Public Service
Missouri Public Service Commission
National Association of State Utility Consumer Advocates
Nevada Public Service Commission
New Hampshire Public Utilities Commission
North Carolina Utilities Commission—Public Staff
Oklahoma Corporation Commission
Ontario Ministry of Culture and Communications
Staff of the Delaware Public Service Commission
Staff of the Georgia Public Service Commission
Texas Public Utilities Commission
Virginia State Corporation Commission
Washington Utilities and Transportation Commission

West Virginia Public Service Commission—Division of Consumer Advocate

Wisconsin Public Service Commission

Wyoming Public Service Commission

Public Counsels

Arizona Residential Utility Consumers Office

Colorado Office of Consumer Counsel

Colorado Office of Consumer Services

Connecticut Consumer Counsel

District of Columbia Office of People's Counsel

Florida Public Counsel

Georgia Consumers' Utility Counsel

Hawaii Division of Consumer Advocacy

Illinois Small Business Utility Advocate Office

Indiana Office of the Utility Consumer Counselor

Iowa Consumer Advocate

Maryland Office of People's Counsel

Minnesota Office of Consumer Services

Missouri Public Counsel

New Hampshire Consumer Counsel

Ohio Consumer Counsel

Pennsylvania Office of Consumer Advocate

Utah Department of Business Regulation—Committee of Consumer Services

Attorneys General

Arkansas Attorney General

Florida Attorney General—Antitrust Division

Idaho Attorney General

Kentucky Attorney General

Michigan Attorney General

Minnesota Attorney General

Nevada Attorney General's Office of Advocate for Customers of Public Utilities

South Carolina Attorney General

Utah Attorney General

Virginia Attorney General

Washington Attorney General

Local Governments

City of Austin, TX

City of Corpus Christi, TX

City of Dallas, TX

City of El Paso, TX

City of Galveston, TX

City of Norfolk, VA

City of Phoenix, AZ

City of Richmond, VA

City of San Antonio, TX

City of Tucson, AZ

County of Augusta, VA

County of Henrico, VA

County of York, VA

Town of Ashland, VA

Town of Blacksburg, VA

Town of Pecos City, TX

1 Other Government Agencies

2

3 Canada—Department of Communications
4 Hillsborough County Property Appraiser
5 Provincial Governments of Canada
6 Sarasota County Property Appraiser
7 State of Florida—Department of General Services
8 United States Department of Justice—Antitrust Division
9 Utah State Tax Commission

10

11 Regulated Firms

12

13 Alabama Power Company
14 Americall LDC, Inc.
15 BC Rail
16 CommuniGroup
17 Florida Association of Concerned Telephone Companies, Inc.
18 LDDS Communications, Inc.
19 Louisiana/Mississippi Resellers Association
20 Madison County Telephone Company
21 Montana Power Company
22 Mountain View Telephone Company
23 Nevada Power Company
24 Network I, Inc.
25 North Carolina Long Distance Association
26 Northern Lights Public Utility
27 Otter Tail Power Company
28 Pan-Alberta Gas, Ltd.
29 Resort Village Utility, Inc.
30 South Carolina Long Distance Association

Stanton Telephone
Teleconnect Company
Tennessee Resellers' Association
Westel Telecommunications
Yelcot Telephone Company, Inc.

Other Private Organizations

Arizona Center for Law in the Public Interest
Black United Fund of New Jersey
Casco Bank and Trust
Coalition of Boise Water Customers
Colorado Energy Advocacy Office
East Maine Medical Center
Georgia Legal Services Program
Harris Corporation
Helca Mining Company
Idaho Small Timber Companies
Independent Energy Producers of Idaho
Interstate Securities Corporation
J.R. Simplot Company
Merrill Trust Company
MICRON Semiconductor, Inc.
Native American Rights Fund
PenBay Memorial Hospital
Rosebud Enterprises, Inc.
Skokomish Indian Tribe
State Farm Insurance Company
Twin Falls Canal Company
World Center for Birds of Prey

1 ***Prior Experience***

2

3 **Q. Before becoming a consultant, what was your employment experience?**

4 A. From August 1975 to September 1977, I held the position of Senior Utility Analyst
5 with Office of Public Counsel in Florida. From September 1974 until August 1975, I
6 held the position of Economic Analyst with the same office. Prior to that time, I was
7 employed by the law firm of Holland and Knight as a corporate legal assistant.

8

9 **Q. In how many formal utility regulatory proceedings have you been involved?**

10 A. As a result of my experience with the Florida Public Counsel and my work as a
11 consulting economist, I have been actively involved in approximately 400 different
12 formal regulatory proceedings concerning electric, telephone, natural gas, railroad, and
13 water and sewer utilities.

14

15 **Q. Have you done any independent research and analysis in the field of regulatory**
16 **economics?**

17 A. Yes, I have undertaken extensive research and analysis of various aspects of utility
18 regulation. Many of the resulting reports were prepared for the internal use of the
19 Florida Public Counsel. Others were prepared for use by the staff of the Florida
20 Legislature and for submission to the Arizona Corporation Commission, the Florida
21 Public Service Commission, the Canadian Department of Communications, and the
22 Provincial Governments of Canada, among others. In addition, as I already mentioned,
23 my Master's thesis concerned the theory of the regulated firm.

24

Q. Have you testified previously as an expert witness in the area of public utility regulation?

A. Yes. I have provided expert testimony on more than 250 occasions in proceedings before state courts, federal courts, and regulatory commissions throughout the United States and in Canada. I have presented or have pending expert testimony before 35 state commissions, the Interstate Commerce Commission, the Federal Communications Commission, the District of Columbia Public Service Commission, the Alberta, Canada Public Utilities Board, and the Ontario Ministry of Culture and Communication.

Q. What types of companies have you analyzed?

A. My work has involved more than 425 different telephone companies, covering the entire spectrum from AT&T Communications to Stanton Telephone, and more than 55 different electric utilities ranging in size from Texas Utilities Company to Savannah Electric and Power Company. I have also analyzed more than 30 other regulated firms, including water, sewer, natural gas, and railroad companies.

Teaching and Publications

Q. Have you ever lectured on the subject of regulatory economics?

A. Yes, I have lectured to undergraduate classes in economics at Florida State University on various subjects related to public utility regulation and economic theory. I have also addressed conferences and seminars sponsored by such institutions as the National Association of Regulatory Utility Commissioners (NARUC), the Marquette University College of Business Administration, the Utah Division of Public Utilities and the University of Utah, the Competitive Telecommunications Association (COMPTEL), the

International Association of Assessing Officers (IAAO), the Michigan State University Institute of Public Utilities, the National Association of State Utility Consumer Advocates (NASUCA), the Rural Electrification Administration (REA), North Carolina State University, and the National Society of Rate of Return Analysts.

Q. Have you published any articles concerning public utility regulation?

A. Yes, I have authored or co-authored the following articles and comments:

"Attrition: A Problem for Public Utilities—Comment." *Public Utilities Fortnightly*, March 2, 1978, pp. 32-33.

"The Attrition Problem: Underlying Causes and Regulatory Solutions." *Public Utilities Fortnightly*, March 2, 1978, pp. 17-20.

"The Dilemma in Mixing Competition with Regulation." *Public Utilities Fortnightly,* February 15, 1979, pp. 15-19.

"Cost Allocations: Limits, Problems, and Alternatives." *Public Utilities Fortnightly,* December 4, 1980, pp. 33-36.

"AT&T is Wrong." *The New York Times,* February 13, 1982, p. 19.

"Deregulation and Divestiture in a Changing Telecommunications Industry," with Sharon D. Thomas. *Public Utilities Fortnightly*, October 14, 1982, pp. 17-22.

"Is the Debt-Equity Spread Always Positive?" *Public Utilities Fortnightly,* November 25, 1982, pp. 7-8.

"Working Capital: An Evaluation of Alternative Approaches." *Electric Rate-Making,* December 1982/January 1983, pp. 36-39.

"The Staggers Rail Act of 1980: Deregulation Gone Awry," with Sharon D. Thomas. *West Virginia Law Review,* Coal Issue 1983, pp. 725-738.

"Bypassing the FCC: An Alternative Approach to Access Charges." *Public Utilities Fortnightly*, March 7, 1985, pp. 18-23.

"On the Results of the Telephone Network's Demise—Comment," with Sharon D. Thomas. *Public Utilities Fortnightly*, May 1, 1986, pp. 6-7.

"Universal Local Access Service Tariffs: An Alternative Approach to Access Charges." In *Public Utility Regulation in an Environment of Change,* edited by Patrick C. Mann and Harry M. Trebing, pp. 63-75. Proceedings of the Institute of Public Utilities Seventeenth Annual Conference. East Lansing, Michigan: Michigan State University Public Utilities Institute, 1987.

With E. Ray Canterbery. Review of *The Economics of Telecommunications: Theory and Policy* by John T. Wenders. *Southern Economic Journal* 54.2 (October 1987).

"The Marginal Costs of Subscriber Loops," A Paper Published in the Proceedings of the Symposia on Marginal Cost Techniques for Telephone Services. The National Regulatory Research Institute, July 15-19, 1990 and August 12-16, 1990.

With E. Ray Canterbery and Don Reading. "Cost Savings from Nuclear Regulatory Reform: An Econometric Model." *Southern Economic Journal,* January 1996.

Professional Memberships

Q. Do you belong to any professional societies?

A. Yes. I am a member of the American Economic Association.

UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206
TABLE OF CONTENTS TO BJ SCHEDULES

SCHEDULE #	
BJ - 1	ACC JURISDICTIONAL REVENUE REQUIREMENTS
BJ - 2	ORIGINAL COST RATE BASE
BJ – 3	ORIGINAL COST RATE BASE ADJUSTMENTS: TOTAL COMPANY
BJ – 4	RCND RATE BASE
BJ – 5	RCND RATE BASE ADJUSTMENTS: ACC
BJ – 6	OPERATING INCOME
BJ – 7	OPERATING INCOME ADJUSTMENTS: TOTAL COMPANY
BJ – 8	COST OF CAPITAL
BJ – 9	OPERATING INCOME ADJUSTMENT: SYNCHRONIZE INCOME TAXES
BJ – 10	FAIR VALUE RATE OF RETURN CALCULATIONS

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
ACC JURISDICTIONAL REVENUE REQUIREMENTS

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-1

LINE NO.	DESCRIPTION	(A) RUCO ORIGINAL COST	(B) RUCO RCND	(C) RUCO FAIR VALUE
1	ADJUSTED RATE BASE	$229,945,361	$411,422,319	$320,683,840
2	ADJUSTED OPERATING INCOME	16,335,782	16,335,782	16,335,782
3	CURRENT RATE OF RETURN (L2 / L1)	7.10%	3.97%	5.09%
4	REQUIRED OPERATING INCOME (L5 * L1)	18,533,596		19,112,757
5	REQUIRED RATE OF RETURN	8.06%		5.96%
6	OPERATING INCOME DEFICIENCY (L4 - L2)	2,197,814		2,776,974
7	GROSS REVENUE CONVERSION FACTOR	1.6363		1.6363
8	REVENUE REQUIREMENT	$3,596,283		**$4,543,963**

REFERENCES:
COLUMN (A): RUCO SCHEDULES BJ-2, BJ-7, BMGS SCHEDULE A1
COLUMN (B): RUCO SCHEDULES BJ-4, BMGS SCHEDULE A1
COLUMN (C): JOHNSON TESTIMONY, BMGS SCHEDULE A1

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
ORIGINAL COST RATE BASE

DOCKET NO. E-04204A
SCHEDULE BJ-2

LINE NO.	DESCRIPTION	(A) AS FILED TOTAL COMPANY	(B) RUCO ADJUSTMENTS TOTAL COMPANY	(C) RUCO AS ADJUSTED TOTAL COMPANY
1	GROSS UTILITY PLANT IN SERVICE	$454,177,170	$55,716,067	$509,893,237
2	Less: Accumulated depreciation & amortization	193,348,359	1,009,199	194,357,558
3	NET UTILITY PLANT IN SERVICE	**$260,828,811**	**$54,706,868**	**$315,535,679**
	CITIZENS ACQUISITION ADJUSTMENT			
4	Citizens Acquisition Discount	$(93,273,341)		(93,273,341)
5	Less: Accum. Amort. - Citizens Acq. Discount	$(20,876,317)		(20,876,317)
6	NET CITIZENS ACQUISITION DISCOUNT	**(72,397,024)**		**(72,397,024)**
7	TOTAL NET UTILITY PLANT	**188,431,787**	**61,970,352**	**250,402,139**
	DEDUCTIONS:			
8	Customer advances for construction	(12,605,744)		(12,605,744)
9	Customer deposits	(4,064,671)		(4,064,671)
10	Accumulated Deferred Income Taxes	(2,028,227)		(2,028,227)
11	TOTAL DEDUCTIONS	**$(18,698,642)**		(18,698,642)
	ADDITIONS:			
12	Allowance for working capital	$6,085,768	$(580,420)	$5,505,348
13	Regulatory assets			
14	Regulatory Liabilities			
15	TOTAL ADDITIONS	6,085,768	(580,420)	5,505,348
16	TOTAL ORGINAL COST RATE BASE	**$175,818,913**	**$54,126,448**	**$229,945,361**

REFERENCES:
COLUMN (A): RUCO SCHEDULE BJ-3
COLUMN (B): RUCO SCHEDULE BJ-3
COLUMN (C): RUCO SCHEDULE BJ-3

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
ORIGINAL COST RATE BASE ADJUSTMENTS: TOTAL COMPANY

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-3

LINE NO.	DESCRIPTION	(A) Adjusted (Original) at End of Test Period	(B) BMGS Adjustments (a)	(C) BMGS Adjusted At End of Test Period	(D) OTHER RUCO ADJUSTMENTS	(E) RUCO ADJUSTED
1	GROSS UTILITY PLANT IN SERVICE	$454,177,170	$62,979,551	$517,156,721	$(7,263,484)	$509,893,237
2	Less: Accumulated depreciation & amortization	193,348,359	1,009,199	194,357,558	-	194,357,558
3	NET UTILITY PLANT IN SERVICE	**$260,828,811**	**$61,970,352**	**$322,799,163**	**$(7,263,484)**	**$315,535,679**
	CITIZENS ACQUISITION ADJUSTMENT					
4	Citizens Acquisition Discount	(93,273,341)		(93,273,341)		(93,273,341)
5	Less: Accum. Amort. - Citizens Acq. Discount	(20,876,317)		(20,876,317)		(20,876,317)
6	NET CITIZENS ACQUISITION DISCOUNT	**(72,397,024)**		**(72,397,024)**		**(72,397,024)**
7	TOTAL NET UTILITY PLANT	**188,431,787**	**61,970,352**	**250,402,139**		**250,402,139**
	DEDUCTIONS:					
8	Customer advances for construction	(12,605,744)		(12,605,744)		(12,605,744)
9	Customer deposits	(4,064,671)		(4,064,671)		(4,064,671)
10	Accumulated Deferred Income Taxes	(2,028,227)		(2,028,227)		(2,028,227)
11	TOTAL DEDUCTIONS	**(18,698,642)**		**(18,698,642)**		**(18,698,642)**
	ADDITIONS:					
12	Allowance for working capital	6,085,768	(580,420)	5,505,348		5,505,348
13	Regulatory assets	-				
14	Regulatory Liabilities	-				
15	TOTAL ADDITIONS	6,085,768	(580,420)	5,505,348		5,505,348
15	TOTAL ORGINAL COST RATE BASE	**$175,818,913**	**$61,389,932**	**$237,208,845**	**$(7,263,484)**	**$229,945,361**

REFERENCES:
COLUMN (A): COMPANY BMGS SCHEDULE B2 P1
COLUMN (B): COMPANY BMGS SCHEDULE B2 P1
COLUMN (C): (A)+(B)

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
RCND RATE BASE

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-4

LINE NO.	DESCRIPTION	(A) ADJUSTED RCND RATE BASE	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED
1	GROSS UTILITY PLANT IN SERVICE	$844,301,155	$58,572,449	$902,873,604
2	Less: Accumulated depreciation & amortization	$367,590,759	$1,054,932	$368,645,691
3	NET UTILITY PLANT IN SERVICE	$476,710,396	$57,517,517	$534,227,913
	CITIZENS ACQUISITION ADJUSTMENT			
4	Citizens Acquisition Discount	$(130,469,005)		$(130,469,005)
5	Less: Accum. Amort. - Citizens Acq. Discount	$(27,773,948)		$(27,773,948)
6	NET CITIZENS ACQUISITION DISCOUNT	$(102,695,057)		$(102,695,057)
7				
8	TOTAL NET UTILITY PLANT	$374,015,339	$64,781,001	$438,796,340
9				
10	DEDUCTIONS:			
11	Customer advances for construction	$(17,555,056)		$(35,110,112)
12	Customer deposits	$(4,064,671)		$(8,129,342)
	Accumulated Deferred Income Taxes	$(3,996,158)		$(7,992,316)
13				
	TOTAL DEDUCTIONS	$(25,615,885)		$(25,615,885)
14	ADDITIONS:			
15	Allowance for working capital	$6,085,768	$(580,420)	$5,505,348
16	Regulatory assets			
17	Regulatory Liabilities			
18	TOTAL ADDITIONS	6,085,768	(580,420)	5,505,348
19	TOTAL RCND RATE BASE	**$354,485,222**	**$56,937,097**	**$411,422,319**

REFERENCES:
COLUMN (A): BMGS COMPANY SCHEDULE B1
COLUMN (B): BJ-3
COLUMN (C): COLUMN (A) + COLUMN (B)

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
RCND RATE BASE ADJUSTMENTS: ACC

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-5

LINE NO.	DESCRIPTION	(A) RCND Adjusted (Original) at End of Test Period (a) (b)	(B) BMGS Adjustments (c)	(C) BMGS Adjusted At End of Test Period	(D) OTHER RUCO ADJUSTMENTS	(E) RUCO AS ADJUSTED
1	GROSS UTILITY PLANT IN SERVICE	$844,301,155	$65,835,933	$910,137,088	$(7,263,484)	$902,873,604
2	Less: Accumulated depreciation & amortization	367,590,759	1,054,932	368,645,691		368,645,691
3	NET UTILITY PLANT IN SERVICE	**$476,710,396**	**$64,781,001**	**$541,491,397**	**$(7,263,484)**	**$534,227,913**
	CITIZENS ACQUISITION ADJUSTMENT					
4	Citizens Acquisition Discount	(130,469,005)		(130,469,005)		(130,469,005)
5	Less: Accum. Amort. - Citizens Acq. Discount	(27,773,948)		(27,773,948)		(27,773,948)
6	NET CITIZENS ACQUISITION DISCOUNT	**(102,695,057)**		**(102,695,057)**		**(102,695,057)**
7						
8	TOTAL NET UTILITY PLANT	**374,015,339**	**64,781,001**	**438,796,340**		**438,796,340**
9						
10	DEDUCTIONS:					
11	Customer advances for construction	(17,555,056)		(17,555,056)		(35,110,112)
12	Customer deposits	(4,064,671)		(4,064,671)		(8,129,342)
	Accumulated Deferred Income Taxes	(3,996,158)		(3,996,158)		(7,992,316)
13						
	TOTAL DEDUCTIONS	**$(25,615,885)**		**$(25,615,885)**		**$(25,615,885)**
14	ADDITIONS:					
15	Allowance for working capital	6,085,768	(580,420)	5,505,348		5,505,348
16	Regulatory assets					-
17	Regulatory Liabilities					-
18	TOTAL ADDITIONS	**$6,085,768**	**$(580,420)**	**$5,505,348**	**$-**	**$5,505,348**
19	TOTAL RCND RATE BASE	**$354,485,222**	**$64,200,581**	**$418,685,803**	**$(7,263,484)**	**$411,422,319**

REFERENCES:
COLUMN (A): COMPANY BMGS SCHEDULE B3 P1, COLUMN (a) (b)
COLUMN (B): COMPANY BMGS SCHEDULE B3 P1, COLUMN (c)
COLUMN (C): COMPANY BMGS SCHEDULE B3 P1
COLUMN (D): Post Test Year Adjustment Staff DR 4.9
COLUMN (E): (C)+(D)

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
OPERATING INCOME

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-6

LINE NO.	DESCRIPTION	(A) AS FILED TOTAL COMPANY	(B) RUCO ADJUSTMENTS TOTAL COMPANY	A+B (C) RUCO AS ADJUSTED TOTAL COMPANY
	ELECTRIC OPERATING REVENUES			
0	Electric Retail Revenues	$181,638,915	$(22,358,469)	$159,280,446
2	Sales for Resale	10,168,115	(10,168,115)	
3	Other Operating Revenue	3,103,658	(1,458,039)	1,645,619
4	Total Operating Revenues	**$194,910,688**	**$(33,984,623)**	**$160,926,065**
	OPERATING EXPENSES:			
5	Fuel, Purchased Power & Transmission	$143,362,723	$(43,019,937)	$100,342,786
6	Other Operations and Maintenance Expense	21,569,849	(1,469,430)	20,100,419
7	Depreciation and Amortization	14,429,415	1,141,704	15,571,119
8	Taxes Other than Income Taxes	3,680,634	579,459	4,260,093
9	Income Taxes	2,081,685	2,234,181	4,315,866
10	Total Operating Expenses	**$185,124,306**	**$(40,534,023)**	**$144,590,283**
11	OPERATING INCOME	**$9,786,382**	**$6,549,400**	**$16,335,782**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE C1, UNADJUSTED
COLUMN (B): BJ-7, P3 (AB)
COLUMN (C): COLUMN (A) + COLUMN (B)

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
OPERATING INCOME ADJUSTMENTS: TOTAL COMPANY

LINE NO.	DESCRIPTION	(A) AS FILED TOTAL COMPANY	Retail Revenue & Purchased Power Annualization (B)	Wholesale Rev & Purch Power (C)	Weather Normalization (D)	Customer Energy Annualization & Customer Demand Normalization (E)	Normalization of Rev & Exp for Fuel and PPFAC (F)	CARES Discounts (G)	DSM & Renewables Revenue & Expense (H)	Payroll Expense (I)
	ELECTRIC OPERATING REVENUES									
0	Electric Retail Revenues	$181,638,915	$10,733,456		$(1,017,300)	$(2,820,565)	$(29,192,263)	(61,797)		
2	Sales for Resale	10,168,115		(10,168,115)						
3	Other Operating Revenue	3,103,658							(1,458,039)	
4	Total Operating Revenues	$194,910,688	$10,733,456	$(10,168,115)	$(1,017,300)	$(2,820,565)	$(29,192,263)	$(61,797)	$(1,458,039)	$-
	OPERATING EXPENSES:									
5	Fuel, Purchased Power & Transmission	$143,362,723	(956,469)	(10,168,115)	(830,613)	(1,079,814)	(19,024,147)			
6	Other Operations and Maintenance Expense	21,569,849							(1,617,113)	79,628
7	Depreciation and Amortization	14,429,415								
8	Taxes Other than Income Taxes	3,680,634							(9,713)	
9	Income Taxes	2,081,685								
10	Total Operating Expenses	$185,124,306	$(956,469)	$(10,168,115)	$(830,613)	$(1,079,814)	$(19,024,147)	$-	$(1,626,826)	$79,628
11	OPERATING INCOME	$9,786,382	$11,689,925	$-	$(186,687)	$(1,740,751)	$(10,168,116)	$(61,797)	$168,787	$(79,628)

REFERENCES:
COLUMN (A): COMPANY SCHEDULE C1, COLUMN (a)
COLUMN (B): COMPANY SCHEDULE C2 P1
COLUMN (C): COMPANY SCHEDULE C2 P1
COLUMN (D): COMPANY SCHEDULE C2 P1
COLUMN (E): COMPANY SCHEDULE C2 P1
COLUMN (F): COMPANY SCHEDULE C2 P1
COLUMN (G): COMPANY SCHEDULE C2 P1
COLUMN (H): COMPANY SCHEDULE C2 P2
COLUMN (I): COMPANY WORKPAPER "Income – Payroll Expenses 12-08.xls"
RUCO adjustment eliminates the 3% factor associated with the expected 2010 pay increases.

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
SUMMARY OF OPERATING ADJUSTMENTS (000'S)

LINE NO.	DESCRIPTION	Payroll Tax Expense (J)	Pension & Benefits (K)	Post Retirement Medical (L)	Rate Case Expense (M)	Bad Debt Expense (N)	Interest on Customer Deposits (O)	Workers Compensation (P)	Miscellaneous Expenses (Q)
	ELECTRIC OPERATING REVENUES								
1	Revenues from Base Rates								
2	Revenues from Surcharges								
3	Other Electric Revenues								
4	Total Electric Operating Revenues								
	OPERATING EXPENSES:								
5	Fuel, Purchased Power & Transmission								
6	Other Operations and Maintenance Expense			161,929	72,223	(436,441)	(145,701)	(115,528)	(397,462)
7	Depreciation and Amortization								
8	Taxes Other than Income Taxes	35,430							(10,495)
9	Income Taxes								
10	Total Operating Expenses	$35,430	$-	$161,929	$72,223	$(436,441)	$(145,701)	$(115,528)	$(407,957)
11	OPERATING INCOME	$(35,430)	$-	$(161,929)	$(72,223)	$436,441	$145,701	$115,528	$407,957

REFERENCES:
COLUMN (J): COMPANY WORKPAPER "Income – Payroll Tax Expenses 12-08.xls"
RUCO adjustment uses payroll expenses which excludes the 3% factor associated with the expected 2010 pay increases.
COLUMN (K): DENY
COLUMN (L): COMPANY SCHEDULE C2 P2
COLUMN (M): COMPANY WORKPAPER "Income – Rate Case Expenses 12-08.xls"
RUCO adjustment assumes rate case expenses of $300,000
COLUMN (N): COMPANY SCHEDULE C2 P3
COLUMN (O): COMPANY SCHEDULE C2 P3
COLUMN (P): COMPANY SCHEDULE C2 P3
COLUMN (Q): COMPANY SCHEDULE C2 P3 AND SUPPORTING WORKPAPERS
RUCO adjustment eliminates 40% of USWAG and EEI dues; normalizes legal expenses based actual 2006-2008 expenses; and eliminates the 5/12/09 postage increase

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
SUMMARY OF OPERATING ADJUSTMENTS (000'S)

LINE NO.	DESCRIPTION	A&G Expense Capitalized (R)	Depr & Property Tax for Post TY Non-Rev. Plant in Service (S)	Depr & Amort Expense Annualization (T)	Property Tax Expense (U)	Income Taxes (V)	BMGS PPA Adjustment (W)	BGMS O&M Expense (X)	BMGS Depr & Amort Expense Annalization (Y)	BMGS Property Tax Expense (Z)	BMGS Income Taxes (AA)	Synchronize Income Taxes (AB)	SUM OF BJ7, PAGES 1 THROUGH 3 (AC) RUCO ADJUSTED TOTAL COMPANY
	ELECTRIC OPERATING REVENUES												
0	Revenues from Base Rates												(22,358,469)
2	Revenues from Surcharges												(10,168,115)
3	Other Electric Revenues												(1,458,039)
4	Total Electric Operating Revenues												$(33,984,623)
	OPERATING EXPENSES:												
5	Fuel, Purchased Power & Transmission						(10,960,779)						(43,019,937)
6	Other Operations and Maintenance Expense	(229,429)						1,158,464					(1,469,430)
7	Depreciation and Amortization			(507,792)					1,649,496				1,141,704
8	Taxes Other than Income Taxes				144,026					420,211			579,459
9	Income Taxes					39,582					2,079,821	114,778	2,234,181
10	Total Operating Expenses	$(229,429)	$-	$(507,792)	$144,026	$39,582	$(10,960,779)	$1,158,464	$1,649,496	$420,211	$2,079,821	$114,778	$(40,534,023)
11	OPERATING INCOME	$229,429	$-	$507,792	$(144,026)	$(39,582)	$10,960,779	$(1,158,464)	$(1,649,496)	$(420,211)	$(2,079,821)	$(114,778)	$6,549,400

REFERENCES:
COLUMN (R): COMPANY SCHEDULE C2 P3
COLUMN (S): DENY
COLUMN (T): COMPANY SCHEDULE C2 P3
COLUMN (U): COMPANY WORKPAPER "Income – Property Tax Expense 12-08.xls"
RUCO adjustment uses 22% assessment ratio effective 1/1/09
COLUMN (V): COMPANY SCHEDULE C2 P3
COLUMN (W): COMPANY BMGS SCHEDULE C2 P1
COLUMN (X): COMPANY BMGS SCHEDULE C2 P1
COLUMN (Y): COMPANY BMGS SCHEDULE C2 P1
COLUMN (Z): COMPANY WORKPAPER "Income – Property Tax Expense 12-08.xls"
RUCO adjustment uses 22% assessment ratio effective 1/1/09
COLUMN (AA): COMPANY BMGS SCHEDULE C2 P1
COLUMN (AB): SUM BJ 7 PAGES 1 THROUGH 3

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
COST OF CAPITAL

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-8

LINE NO.	TYPE OF CAPITAL	(A) PERCENT	(B) COST RATE	(C) WEIGHTED AVG. COST RATE
1	COMMON EQUITY	45.76%	9.25%	4.23%
2	TOTAL DEBT	54.24%	7.05%	3.82%
3	TOTALS	100.00%		8.06%

REFERENCES:
WAR-1

.ECTRIC, INC.
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
.TING INCOME ADJUSTMENT: SYNCHRONIZE INCOME TAXES

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-9

DESCRIPTION	TOTAL COMPANY AMOUNT	REFERENCE
FEDERAL INCOME TAXES:		
OPERATING INCOME BEFORE INCOME TAXES	$20,651,648	SCHEDULE BJ-6, LINE 4 – (LINES 5 THROUGH 8)
LESS:		
ARIZONA STATE TAX	826,316	LINE 11
INTEREST EXPENSE	8,792,927	NOTE (a)
FEDERAL TAXABLE INCOME	11,032,406	LINE 1 - LINES 2 & 3
FEDERAL INCOME TAX RATE	31.630%	BMSG SCHEDULE C3
FEDERAL INCOME TAX EXPENSE	3,489,550	LINE 4 X LINE 5
STATE INCOME TAXES:		
OPERATING INCOME BEFORE INCOME TAXES	20,651,648	LINE 1
LESS:		
INTEREST EXPENSE	8,792,927	LINE 17
STATE TAXABLE INCOME	11,858,721	LINE 7 - LINE 8
STATE TAX RATE	6.968%	BMSG SCHEDULE C3
STATE INCOME TAX EXPENSE	826,316	LINE 9 X LINE 10
TOTAL INCOME TAXES	4,315,866	LINE 6 + LINE 11
INCOME TAXES PER COMPANY	4,201,088	COMPANY SCHEDULE. C-1
ADJUSTMENT	$114,778	LINE 12 - LINE 13

NOTE (a)
INTEREST SYCHRONIZATION

ADJUSTED RATE BASE	$229,945,361	BJ-2
WEIGHTED COST OF DEBT	3.82%	BJ-8
INTEREST EXPENSE	$8,792,927	

UNS ELECTRIC, INC.
FVROR CALCULATIONS

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-10

Method 1

LINE NO.	TYPE OF CAPITAL	(A) CAPITALIZATION	(B) PERCENT	(C) COST RATE	(D) INFLATION COMPONENT	(E) MODIFIED COST RATE	(F) WEIGHTED AVG. COST RATE
1	COMMON EQUITY	83,755,000	45.76%	9.25%	2.10%	7.15%	3.27%
2	TOTAL DEBT	99,272,000	54.24%	7.05%	2.10%	4.95%	2.68%
3	TOTALS	183,027,000	100.00%				5.96%

Method 2

LINE NO.	TYPE OF CAPITAL	(A) CAPITALIZATION	(B) PERCENT	(C) COST RATE	(D) INFLATION COMPONENT	(E) MODIFIED COST RATE	(F) WEIGHTED AVG. COST RATE
4	COMMON EQUITY	83,755,000	45.76%	9.25%	2.10%	7.15%	3.27%
5	TOTAL DEBT	99,272,000	54.24%	7.05%	0.00%	7.05%	3.82%
6	TOTALS	183,027,000	100.00%				7.10%

Method 3

LINE NO.	TYPE OF CAPITAL	(A) CAPITALIZATION	(B) PERCENT	(C) COST RATE	(D) INFLATION COMPONENT	(E) MODIFIED COST RATE	(F) WEIGHTED AVG. COST RATE
7	COMMON EQUITY	83,755,000	30.59%	9.25%	0.00%	9.25%	2.83%
8	TOTAL DEBT	99,272,000	36.26%	7.05%	0.00%	7.05%	2.56%
9	FVRB INCREMENT	90,738,479	33.14%	0.00%	0.00%	0.00%	0.00%
10	TOTALS	273,765,479	100.00%				5.39%

Method 4

LINE NO.	TYPE OF CAPITAL	(A) CAPITALIZATION	(B) PERCENT	(C) COST RATE	(D) INFLATION COMPONENT	(E) MODIFIED COST RATE	(F) WEIGHTED AVG. COST RATE
11	COMMON EQUITY	83,755,000	30.59%	9.25%	0.00%	9.25%	2.83%
12	TOTAL DEBT	99,272,000	36.26%	7.05%	0.00%	7.05%	2.56%
13	FVRB INCREMENT	90,738,479	33.14%	1.25%	0.00%	1.25%	0.41%
14	TOTALS	273,765,479	100.00%				5.80%

Method 5

LINE NO.	TYPE OF CAPITAL	(A) CAPITALIZATION	(B) PERCENT	(C) COST RATE	(D) INFLATION COMPONENT	(E) MODIFIED COST RATE	(F) WEIGHTED AVG. COST RATE
15	COMMON EQUITY	83,755,000	45.76%	9.25%	1.05%	8.20%	3.75%
16	TOTAL DEBT	99,272,000	54.24%	7.05%	1.05%	6.00%	3.25%
17	TOTALS	183,027,000	100.00%				7.01%

EXHIBIT
RUCO-7
ADMITTED

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-09-0206

DIRECT RATE DESIGN TESTIMONY

OF

BEN JOHNSON, Ph.D.

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 13, 2009

TABLE OF CONTENTS

Introduction 1

I. Background 2

II. UNSE's Cost of Service and Rate Design Proposals.....3

III. Fully Allocated Embedded Costs.....6

IV. Revenue Distribution.....12

V. Residential Rate Design and Miscellaneous Tariff Issues.....17

TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of

The Residential Utility Consumer Office

Before the

Arizona Corporation Commission

Docket No. E-04204A-09-0206

Introduction

Q. Would you please state your name and address?

A. Ben Johnson, 3854-2 Killearn Court, Tallahassee, Florida.

Q. What is your present occupation?

A. I am a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation.

Q. Have you prepared an appendix that describes your qualifications in regulatory and utility economics?

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

Q. Are you the same Ben Johnson that filed revenue requirements testimony on November 6th, 2009?

A. Yes, I am.

Q. Have you prepared any schedules to be filed with your testimony?

A. Yes, Schedules BJ-11 through BJ-13, which are attached to my testimony, were prepared under my supervision.

Q. What is the nature of this testimony?

A. Our firm has been retained by the Residential Utility Consumer Office ("RUCO") to assist with RUCO's evaluation of UNS Electric, Inc.'s (UNSE's) Application for a rate increase. The purpose of this testimony is to present RUCO's rate design recommendations.

Following this introduction, my testimony has five sections. In the first section, I briefly discuss the background of the rate design phase of the proceeding. In the second section, I summarize UNSE's cost of service methodology and rate design proposals. In the third section, I discuss fully allocated cost of service studies, focusing on the Company's Average and Peaks methodology. In the fourth section, I discuss the Company's proposed revenue distribution and offer some suggestions for an alternative approach. In the fifth section, I critique the Company's current and proposed residential rates, and recommend some changes to the Company's proposed rate design.

I. Background

Q. Can you briefly discuss UNSE's most recent rate case?

A. Yes. On December 15, 2006, UNSE filed an application requesting a revenue increase of

$8,468,638. The Commission determined that the Company was entitled to a revenue increase of $4,018,678, or 2.5% over adjusted test year revenues. [Decision 70360, p. 80] The Commission rejected UNSE class allocation approach, and instead determined that the class responsibility for the revenue requirement should be allocated using the methodology of Staff's rate design expert witness. [Id.] Among other things, the Commission also: approved increases in customer charges, but not to the extent requested by the Company; approved an inverted block rate design for residential and small general service customers; approved an additional purchased power and fuel adjustment charge; rejected mandatory time of use rates; rejected a proposal to modify existing volumetric discounts for CAREs customers; and, approved certain low income customer commitments.

II. UNSE's Cost of Service and Rate Design Proposals

Q. Can you briefly summarize UNSE's proposals in this phase of the proceeding, beginning with its cost of service study?

A. Yes. UNSE's cost study methodology is a multi-step process. First, costs were "functionalized" by grouping costs with similar purposes or functions. [Erdwurm Direct, p. 11] The functionalized costs were then classified into demand-related, energy-related or customer-related costs. [Id.] Finally, the functionalized and classified costs were allocated to service classes using various allocation factors. [Id.]

Q. Can you expain the "functionalization", "classification" and "allocation" steps in a little more detail?

A. Yes. Examples of functions include transmission, distribution-primary lines, and metering. In total, UNSE identified over 20 different functions in its Class Cost of Service Study (CCOSS).

Certain of these costs were classified as demand, on the theory that these costs are most affected by the level of kW demand. [Id., p. 12] In general, these costs are viewed as being incurred on either a coincident basis (occurring at the same time) or non-coincident (varying as a function of peak demands within specific portions of the system, which could potentially vary with respect to the time when those individual peaks occur).

> Coincident demands tend to be more correlated with cost at the production level. In other words, coincident demands address whether there is purchased power and generation capacity for UNS Electric's entire system needs. Consequently, non-coincident demands become more correlated with cost as we move downstream though the distribution system to the end-users. [Id.]

Costs classified as energy are most affected by kWh by class. Some of these costs can vary by time-of-day. Costs that were viewed as being customer-related were assumed to vary based on class customer counts, weighted by relative levels of costs imposed by different types of customers, or in some cases on a uniform (non-weighted) basis. [Id.]

"Allocation" involves applying factors (e.g., peak demand contribution, energy or customers) to spread the costs to particular customer classes and rate schedules. Allocation factors can be external or internal. "External allocation factors are determined independent of the magnitude of specific costs in the CCOSS". [Id., p. 13] For example, "distribution stations-demand sub-transmission" costs are allocated based on non-coincident peak demands. [Id., pp. 13-14] Internal allocation factor are based upon cost components within the cost of service model. For example, Deferred Taxes and Tax Credits are allocated based on Total Plant in Service. [Id., p. 15]

Q. Can you provide a few examples of how UNSE applies allocation factors to costs?

A. UNSE used the Average and Peaks Method to allocate production costs. [Id., p. 14] This factor is made up of two components: an average demand component (with a percentage weight of the

system load factor) and a peak demand component (with a percentage weight of one minus the system load factor). [Id., p. 15]

> The average demand component was calculated by dividing the number of hours in the test-year into the loss-adjusted energy. The peak demand component was calculated as a combination of coincident peak demands (time of system peak) from June, July, August, and September of the test-year. [Id.]

UNSE uses its "EFUEL" allocation factor to allocate purchased power costs. This factor is based on energy, and has no peak component. [Id., p. 14] The Company explains:

> In the last general rate case, the Commission's order indicated that all purchased power expenses should be based on energy. The Company's preferred method is to allocate a portion of purchased power costs using the Average and Peaks Method; however the Company is not proposing this method in this proceeding. In the last case, Staff argued that purchased power was billed to the Company entirely on an energy basis, and therefore energy should be used to allocate it. While the Company believes that the use of Average and Peaks is more appropriate for at least a portion of purchased power, the Company's rate design proposal would remain unchanged regardless of how purchased power is allocated. The allocation of the proposed rate increase is based more on customer impact than cost allocation, so the argument of whether to use Average and Peaks or energy becomes purely academic, and inconsequential from a practical standpoint. The customer impact issue is especially important in this case, given current economic conditions. The Company may again propose the Average and Peak method to allocate a portion of purchased power in the future, in a case where class cost causation is given more emphasis relative to customer impact. [Id.]

UNSE also uses the Average and Peaks method to allocate transmission and subtransmission costs. [Id., p. 15-16]

Q. Can you now summarize UNSE's rate design methodology?

A. In designing its proposed rates, UNSE considered the impact on customers and the "benefits of moving to cost-based rates". [Id., p. 18]

> The Company's approach promotes "gradualism." It avoids large percentage differences in class revenue increases. In other words, we balanced the future need to move each class towards rates that are more reflective of cost of service while recognizing that such a move must be tempered with other factors like gradualism, and the avoidance of "rate shock". [Id.]

UNSE's proposes to increase all classes by a uniform percentage amount of 9.21%, except Residential CARES, which is -9.41%, when compared to the adjusted test year revenues (taking into account weather normalization and the rate changes approved in the last rate case). When compared to unadjusted test-year revenue, there are minor differences in the percentage increases, as shown in the following chart. [Schedule H-1]

Class	Change in Unadjusted Revenues	Change in Adjusted Revenues
Residential:	7.98%	9.21%
Residential CARES:	-9.04%	-9.41%
Small General Service:	8.36%	9.21%
Large General Service:	8.03%	9.21%
Large Power Service:	7.95%	9.21%
Interruptible Power Service:	10.06%	9.21%
Lighting:	8.39%	9.21%

III. Fully Allocated Embedded Costs

Q. Let's turn to the next section of your testimony. Can you provide a brief description of fully allocated embedded cost studies, and explain what they measure?

A. Certainly. Fully allocated cost of service studies divide total test-year revenues, rate base, and operating expenses among the various customer classes to estimate the rate of return earned

from each class. Many of these costs are either joint or common costs not directly attributable to any one customer class; therefore, they must be allocated by a formula. This opens the door to subjective judgments, and the results of the study tend to depend heavily on the particular allocation formulas chosen by the analyst.

Because they are based upon embedded costs, these studies do not report direct cause-and-effect relationships between the consumption decisions of the class members and the costs incurred by the utility. Thus a "cost" is not necessarily the actual expense that a particular group of customers imposes on the system. Nevertheless, cost of service studies have long been used by this Commission and other regulators as a tool that can assist with the process of developing electric and gas rates. As long as their limitations are recognized, and reasonable allocation formulas are employed, fully allocated cost studies can help the Commission in determining an appropriate revenue distribution.

Q. Can the judgment and arbitrariness be eliminated, if the analyst is completely unbiased and if sufficient effort is applied to the task?

A. No. The problem lies neither with the people performing the studies nor with the amount of effort and resources devoted to the analysis. Rather, it is inherent in the very concept of allocating embedded costs. To a large degree, these costs are the result of management and engineering decisions which reflect many different considerations, are completely outside the control of individual customers or customer classes, and thus cannot be unambiguously traced to customers. While the goal may be to insure that each customer class pays the costs that it causes, it simply isn't possible to achieve this result by allocating historical accounting costs.

Even when the actions of particular customer classes do influence such decisions, the linkage is largely indirect, and is obscured by the passage of time. For instance, customers influence the transmission costs incurred during the test year; but these influences are almost

entirely traceable to customer actions (and subsequent management decisions) that occurred years ago, when the transmission lines serving today's customers were originally planned and constructed. Hence, the cause and effect links between today's customers (or customers present during the test year) and test year costs are inherently impossible to measure through the techniques used in developing an embedded cost of service study. All of the various alternative allocation formulas rely upon statistics relating to the test year, and none of them can possibly reflect with exactness the historic relationships of cause and effect that explain the embedded accounting costs reflected in the test year data.

This problem is particularly severe in this case, because UNSE obtains most of its energy through power purchase contracts, rather than generating the power itself. While these contractual arrangements are structured around per-KWH charges, it is reasonable to surmise that various other factors besides energy consumption (e.g. coincident peak demand or the UNSE average system load factor) have some influence on the price that is charged for these purchases, at least to some degree. For these and other reasons, there is no "perfect" formula for allocating most, if not all, of the costs incurred by UNSE, including the cost of transmission and distribution. Some cost allocation experts will sometimes imply their approach is the "true" answer, and that any significantly different approach is a heresy not to be condoned. I disagree with that viewpoint. There is no "correct" method for allocating joint and common costs, and any attempt to locate it will ultimately prove fruitless.

Embedded cost allocation studies are simply a technique for evaluating the relative fractions of the total revenue requirement that can reasonably be recovered from each class. At best, these studies provide a yardstick for judging whether or not each customer class is paying an appropriate share of the joint and common costs. The real question is whether the yardstick is reasonably straight and true, or whether it is bent to favor particular classes at the expense of others.

Aside from the long lags that typically occur between when costs are planned, contracted, and incurred and when those costs are recovered through rates, there is another fundamental problem. Most of the Company's embedded costs are not caused by the actions of particular customers or customer classes; rather they are incurred by management based upon an evaluation of the needs of the system as a whole. Thus it isn't feasible, or meaningful, to rely entirely on an evaluation of causal relationships in deciding on the most reasonable allocation method.

Consider, for example, an investment in which 10% of the cost can be meaningfully traced to customer classes and the remaining 90% is attributable to factors like fluctuations in the weather and fundamental characteristics of the geography of the Company's service territory. It is not necessarily reasonable to allocate 100% of the investment solely on the basis of the 10% that is logically traceable to customers. Furthermore, given the impossibility of identifying and measuring causative factors precisely, even this 10% of the total cost might be misinterpreted and traced to the wrong classes.

In evaluating the relative merits of different approaches, I believe it is important for the Commission to give adequate recognition to the basic product being sold by UNSE: electrical energy. Any allocation method that slights the importance of the most fundamental measure of the Company's output (kilowatt hours of electricity) should be viewed with skepticism. Where there is no clear cause-and-effect relationship between customer actions and costs, kWh sales provides a reasonable basis for allocation, because they closely reflect the benefits received by each class from the investments and expenses in question.

Q. Would you briefly explain the Average and Peaks allocation approach?

A. Yes. There are several ways this approach can be implemented, but in general it gives partial weight to the "average" level of demand, and some weight to a measure of "peak" demand.

Consider a simplified system consisting of four classes. As shown on Schedule BJ-15, Class A has a 50 kW load that runs at all times. Class B has a maximum load of 100 kW, and a load factor of 50%; it does not operate during the system coincident peak hours. Class C is similar, with a maximum load of 100 kW, and a load factor of 50%; however, 75kW of its load is present when the system coincident peaks occur. Finally, Class D has a 25% load factor; its coincident peak load is 150kW, and its non-coincident peak (NCP) is 200kW. The system CP demand in this example equals 275 kW and the sum of the NCP demands equals 450 kW. The average demand would equal 50 kW in each case, with the system average demand totaling 200kW.

There are several different versions of the coincident peak component. All of these methods allocate costs based on participation in system-wide coincident peaks. That is, during the hours when the system reaches its greatest demand, each load's portion of that demand is determined, and this becomes the basis for allocation. One method focuses on the hour during each month in which the maximum level of demand is experienced, then averages the results of these 12 different hours. This is sometimes referred to as a "12 CP" method. When this logic is taken to the extreme, it focuses on the single hour during the year when the highest CP is experienced. This is called the "1 CP" method. Anther variant is the "2 CP" method, which typically focuses on the maximum summer hour, and the maximum winter hour, whenever those happen to occur. UNSE uses the 4CP method, which is similar to the 1 CP method, except that it focuses exclusively on the four summer months, rather than the single hottest month; no consideration is given to peak characteristics during any other months of the year.

From an economic standpoint it is apparent a utility does not design its generating system or negotiate purchased power contracts merely to meet the coincident peak demand, regardless of whether one focuses on 1, 2, 3, 4, or 12 hours of each year. Yet, this is the underlying basis of the various CP allocation methods. In reality, when designing the system or

negotiating power purchases, management is also concerned with system reliability, fuel costs, and the ability to obtain all of the energy required to meet its customers' needs, as well as the riskiness and cost-effectiveness of the method used to acquire the needed power, including questions of fuel diversity, transmission costs required to move power from the point of generation to the point of consumption, and related geographic characteristics.

Q. Do you agree with the Company's use of the Average and Peaks method?

A. In general, this is a far better approach than a purely peak-oriented methodology, as is sometimes advocated by other parties. The Average and Peaks method recognizes that the primary purpose of a utility's production plant is to provide energy used by its customers, and thus it gives considerable weight to energy (average demand). However, the Average and Peaks approach also recognizes that it is less costly to serve customers with high load factors (their use of energy occurs fairly uniformly throughout the day, 365 days a year), and customers who consume little or no energy during times when energy use is at a peak (e.g. street lighting, which occurs in the evening). These types of customers are allocated a relatively small share of the cost of production plant, while customers with loads that fluctuate in synch with the system are allocated a somewhat higher share. Logically, both average demand and UNSE's system coincident peak would both be factors considered in determining the price paid by UNSE for purchased power – regardless of whether the price of that power is stated purely on a per-KWH basis.

To the extent a cost allocation method is supposed to reflect the factors which "cause" costs, it makes sense to give some consideration to coincident peak data, as well as average demand, or energy. Nevertheless, it is also fair to say that the inherent problems with cost allocation studies are particularly acute in this case, where very little of UNSE's power is self generated. While pricing of the power purchase contracts may provide some insight into the

underlying cost patterns, they are not fully determinative. For instance, prices can be stated on a flat per-KWH basis, yet the stated price per KWH may be influenced, in part, by the Company's average load factor, as historically observed and expected to occur in the future.

IV. Revenue Distribution

Q. Let's turn to the fourth section of your testimony. What factors do you think should be considered in developing the interclass revenue distribution?

A. I recommend giving some consideration to the cost of service results. However, I think other factors are also important in developing a fair and reasonable revenue distribution, including historical rate relationships, ability to pay, relative risk, and demand or market conditions (including the extent of any retail competition that might exist).

It is sometimes argued that the revenue burden should be distributed among the classes based entirely upon the results of a particular class cost-of-service study, at least as a goal. This argument has grown in popularity as "cost-based" ratemaking has come into vogue. However, I fundamentally disagree with this philosophy, particularly when it is tied to a single embedded cost allocation study. Valid cost-of-service studies can provide a useful starting point in developing the overall revenue distribution; but even if the cost study itself isn't controversial, the ultimate determination of rate spread should be tempered by consideration of other factors, such as the ones I just enumerated.

Any proposal to move away from the existing rate relationships should be implemented gradually. This is particularly important in a case like the present one, where the cost allocation methods are a matter of controversy, changes in the allocation methods are being proposed by

various parties, and there is relatively little information available to evaluate how the various allocation methods react to changing weather and economic conditions, and thus little is known about how the various class returns react to changing conditions in the future.

In any event, the revenue distribution should not be designed merely to track the results of a particular cost-of-service study. Instead, thought should be given from the outset to the potential hardships imposed on particular classes, historical relationships among the classes, and other elements of interclass equity. Moreover, the Commission should recognize that efforts to achieve uniform class rates of return are mostly fruitless. Even if a consistent COS methodology is employed from case to case, minor fluctuations in weather, economic conditions, and other variables can easily produce absolute fluctuations in the class rates of return of 1%-4% or even more, defeating such an attempt at uniformity. If an above-average increase is imposed in one case (because a class appears to earning less than the average return), a below-average increase may appear appropriate in the very next case, simply because of minor fluctuations in weather or usage patterns – even if the underlying methodology is not changing. Of course, where changes in the costing methodology are involved, the class returns can fluctuate by even wider margins, due simply to differences in allocation techniques.

Given the inherent instability and subjectivity of the various allocations, the goal of absolute uniformity in class rates of return can probably never be achieved. Such an effort is an attempt to hit a moving target, and that very effort can potentially conflict with important policy objectives, like rate continuity, gradualism and stability.

Q. How has the Company proposed to distribute its proposed revenue increase among the various customer classes?

A. The Company explains that the goal of its cost of service study

> is to confirm the extent to which present and proposed rates generate

> revenue that recovers costs and provides for a reasonable return on investment per customer class. ... If the proposed rates produce class revenues resulting in each class earning its required return on invested capital, we say that "parity" has been reached.". [Id., pp. 17-18]

Of course, this goal of "parity" or uniformity is mathematically dependent on the specific allocation procedures used in the cost study. If different allocations were used, the proposed revenue distribution would also likely change.

Q. Did the Company seek to achieve parity in its rate design?

A. No. UNSE explains:

> The impact on customers must be weighed against the benefits of moving to costbased rates. The Company's approach promotes "gradualism." It avoids large percentage differences in class revenue increases. In other words, we balanced the future need to move each class towards rates that are more reflective of cost of service while recognizing that such a move must be tempered with other factors like gradualism, and the avoidance of "rate shock". [Id., p. 18]

The following table shows UNSE's estimated rates of return by customer class associated with the Company's current rates and proposed rates, based on the Company's proposed revenue requirement analysis, and proposed cost allocations, and assuming BMGS is added to rate base. Also shown are the proposed revenue changes as a percentage of adjusted test year revenues. Returns under proposed rates range from a low of -26.25% for the Lighting class to a high of 17.15% for the Large General Service class.

Class	Return Present Rates	Return Proposed Rates	Revenue Change
Residential:	3.43%	4.45%	7.75%
Small General Service:	7.35%	12.04%	9.21%
Large General Service:	10.19%	17.15%	9.21%
Large Power Service:	-1.40%	-2.25%	9.21%
Interruptible Power Service:	1.19%	3.22%	9.21%
Lighting:	-14.14%	-26.25%	9.21%
Total:	4.77%	7.29%	8.48%

Source: Schedules BMGS G-1, G-2, H-1
Note: Residential revenue change includes reduced CAREs revenues

Q. What is your reaction to UNSE's proposed revenue distribution?

A. The Company has essentially proposed a uniform across-the-board percentage increase in rates. In my view this is a reasonable approach to use. Nevertheless, moderate deviations from the average increase would also be reasonable, and consistent with the principle of rate stability and gradualism.

For the reasons I stated earlier, I don't believe the Company's cost allocation should be the sole consideration in developing rates; but, neither do I think it needs to be completely ignored. Instead, it would be reasonable to give modest weight to the cost study results – particularly when the class return is far above or below the system average.

The Company's cost allocation study shows three classes have significantly below-average returns: Large Power Service, Interruptible Power Service, and Lighting. The study indicates one class – Large General Service – has a significantly above-average return. Neither of the other classes have returns that deviate greatly from the system average. The Residential class return is a little below the average, while the Small General Service return is a little above the average. In this regard, it's important to realize that the Residential return includes the full impact of the CARES discount, which distorts the result. This discount is appropriately

considered a cost to be borne by all customer classes – not just the Residential class, as assumed in the Company's study.

Q. Have you developed an alternative revenue distribution approach which you are recommending for the Commission to consider?

A. Yes. I have developed an alternative methodology which gives considerable weight to historic rate relationships, while also giving some consideration to the Company's cost of service results.

Specifically, starting with the results of the Company's cost of service study, I looked at the classes with rates of return significantly above or below the system average. In order to avoid inter-class inequities, and in recognition of the fact that cost allocation studies are not perfectly precise, I believe that none of the classes should receive percentage rate increases that differ dramatically from the overall system average. Instead, I recommend increasing the rates paid by these classes by slightly more, or less, than the system average (as appropriate), thereby moving the class returns toward the average, without making futile attempt to move toward complete uniformity of returns. My specific recommendations are as follows:

First, I recommend giving an above-increase to the following rate schedules, which all have returns that are substantially lower than the system average (4.77%): Large Power Service (-1.40%), Interruptible Power Service (1.19%), and Lighting (-14.14%). In all of these cases, the Company's cost allocation study confirms these rate schedules are generating below-average returns (although the extent of the discrepancy isn't necessarily the same in each case). More specifically, I recommend increasing Large Power Service, Interruptible Power Service and Lighting by 1.0% more than the Residential and Small General Service classes.

Second, Large General Power has a return that is substantially higher than the system average; I recommend increasing the rates paid by this class by 1.0% less than the Residential

and Small General Service classes.

Third, the Residential and Small General Service classes have returns that are relatively similar to the system average, and thus there is no need to take steps to either increase or decrease their overall position in the COSS. While I have not developed exact calculations, I estimate that these classes would receive an increase of approximately 3.4% if RUCO's revenue requirement were adopted, while Large Power Service, Interruptible Power Service and Lighting would increase by approximately 4.4% and Large General Power would increase by approximately 2.4%.

V.Residential Rate Design and Miscellaneous Tariff Issues

Q. Let's turn to the last section of your testimony. What other rate design issues do you wish to discuss?

A. I would like to comment on the Company's proposals regarding customer charges, time of use (TOU) rates, and rates for low income customers. Also, I would like to address UNSE's inclining block energy charges.

Q. Let's discuss customer charges. Can you describe the existing charges?

A. The current customer charge for residential customers is $7.50. Customer charges for other customer classes range from $4.12 for Lighting, to $400.00 for Large Power Service >69KV.

Q. What is UNSE proposing with regard these charges?

A. The Company is proposing to increase these charges for all classes (excluding CAREs) "to levels closer to the cost-based levels indicated in the Class Cost of Service Study". [Erdwurm Direct, p. 20] As shown in the table below, the increases range from 1.75% for Large Power

Service >69KV, to 10.07% for Lighting. Residential customers would see a 6.67% increase in their customer charge.

Class	Current Customer Charge	Proposed Customer Charge	Percent Change
Residential:	$7.50	$8.00	6.67%
Residential CARES:	$7.50	$3.50	-53.33%
Small General Service:	$12.00	$12.50	4.17%
Large General Service:	$15.50	$16.00	3.23%
Large General Service TOU:	$20.40	$20.90	2.45%
Large Power Service (<69KV):	$365.00	$372.00	1.92%
Large Power Service (>69KV):	$400.00	$407.00	1.75%
Interruptible Power Service:	$15.50	$16.00	3.23%
Lighting:	$4.12	$4.54	10.07%

Source: Schedule H-3

Q. What is the basis for these increases?

A. As I mentioned, the primary justification for this proposal is UNSE's belief that this will move rates closer to the costs indicated by its cost of service study. Consistent with this reasoning, according to the Company, the increases will also

> reduce how much high-use customers subsidize lower-use customers for the costs of metering, meter reading, billing, and other customer-specific equipment installed on the customers' premises.... [and move] a step towards providing more incentive for encouraging energy efficiency programs because the revenue requirement is less dependent on customers consuming electricity. [Id.]

Q. Do you agree with UNSE's customer charge proposal?

A. No. Many of the customer charges are already higher than appropriate; no further increases are warranted, and it would be preferable to shift away from this revenue source toward higher kWh rates. When customer charges are set at reasonable levels, they are an acceptable rate-

design tool for recovering a portion of a regulated utility's costs. However, the Company's proposed customer charges are excessive. The proposed charges are not justified by cost considerations, and approving them would be inconsistent with such important policy objectives as economic efficiency, energy conservation, and equity.

I find several problems with the Company's proposal. First, holding all else constant, raising customer charges will tend to encourage kWh consumption and discourage energy conservation, while lowering customer charges will discourage energy usage and encourage greater energy efficiency.

Second, the proposed changes would place a heavier burden on low use customers, for whom this is a major element of their electric bill, including those who do not own a large number of appliances, those who set the thermostat at a high level during the summer, or otherwise find ways to use relatively little electricity.

Third, the Company's proposal is based upon a cost allocation approach which allocates substantial portions of the Company's distribution investment and operating expenses on the basis of customers, regardless of whether or not these items directly vary in response to decisions by customers to join or leave the system. Even if one were to assume that there is no better way to assign some of these costs that doesn't mean the resulting allocated cost figures are a valid justification for determining what portion of the revenue requirement should be recovered through a fixed monthly charge, and what portion should be recovered through the kWh rates. Allocation techniques acceptable for interclass purposes are not necessarily optimal for intraclass rate design purposes.

Q. Would you elaborate on your first point?

A. Yes. Customer charges have a negative effect similar to that of declining block rates, in which rates drop as the level of usage increases. In general, such rate structures make small-volume

users pay a higher average rate per kWh than large-volume users and tend to present customers with a relatively low kWh rate for increased usage. This has several undesirable effects: it imposes excessive rates on low-volume users, including those who are most successful in limiting their energy usage, and it tends to discourage energy conservation. A relatively high customer charge translates into relatively low kWh rates; as a result, it sends price signals that make it appear less costly to consume additional energy, providing relatively little reward for those customers who buy more efficient light bulbs or appliances, install additional insulation, adjust the thermostat to higher levels in the summer, or take other steps to reduce their consumption of electricity.

Although the Company's inclining block rates for energy charges ameliorates this problem, high customer charges tend to offset some of the benefits of the inclining block design. The following example in the table below illustrates this point. The costs are based on the Company's proposed residential rates, which include an $8.00 customer charge, an energy charge of $0.026115 per kWh for the first 400 kWhs and $0.036129 for each additional kWh, and a base power supply charge of $0.0687657 per kWh.

	200 kWh	500 kWh	1000 kWh
Customer Charge	$8.00	$8.00	$8.00
Energy Charge	3.22	14.06	32.12
Base Charge	13.75	34.38	68.77
Total	$24.97	$56.44	$108.89
Total per kWh	$0.125	$0.113	$0.109

Source: Schedule H-3-BMGS

As shown, a customer using 200 kWh during a given month would incur a total bill of $24.97 under the proposed rates. Thus, he would pay an average of about 12.5 cents per kWh. In comparison, a customer who uses 500 kWh would pay an average price of approximately 11.3

cents per kWh, or roughly 10% less than the rate per kWh paid by the smaller customer – just the opposite of what one would expect considering the inclining block rate design alone. Similarly, the customer using 1,000 kWh will actually pay less per kWh than the customer using 500 kWh, notwithstanding the use of an inclining block rate structure. In essence, a high customer charge tends to create an effective discount on the average rate per kWh paid by large-volume users relative to the rate paid by low volume users, and it confronts customers with a marginal price which is lower than would be the case if a lower customer charge were applied. In my view, this pricing pattern runs directly counter to the policy goal of encouraging energy conservation, and this disadvantage outweighs any putative benefit of better tracking allocating costs.

Q. Have you analyzed the methods by which the Company allocates costs to the customer charge?

A. Yes. I have reviewed the Company's cost of service study, and concluded that most of the costs allocated to this rate are not focused on the variable or marginal costs that are actually attributable to the decision of customers to join or leave the system. The customer charge should primarily collect the variable costs of metering, billing, and collecting the monthly bill. Other so called "customer costs" can and should be recovered through per kWh rates.

Q. Have you provided an alternative estimate of customer-related costs?

A. Yes. As shown on BJ-11, I have used the information provided in UNSE Schedules G-4 and H-2 to develop an alternative estimate of the costs that can form the basis of a more appropriate customer charge. I started with the group of expense accounts that the Company labels as "Customer Accounts" and "Customer Service & Info Exp" in its cost of service study, as listed

on page 5 of BMGS Schedule G-4. Then, I removed certain accounts that clearly do not vary with the number of customers on the system each month. Specifically, I excluded the expenses in accounts 904 - "Uncollectible Accounts" and 431 - "Customer Deposit Interest"; the former account would more appropriately be allocated in proportion to revenue, or it could be directly assigned to individual classes in proportion to their actual uncollectible experience. The latter account is more appropriately allocated on a composite basis, in proportion to net plant or some other aggregate measure of the Company's investment, since customer deposits are a source of funding which can be used for general corporate purposes, like short term debt.

After removing these two accounts, the remaining expenses were then divided by the weighted number of customers, as developed by the Company on BMGS Schedule H-2, and the quotient was divided by 12 to arrive at a per-month cost. I'm not suggesting that rates need to be set exactly equal to this measure of costs, but I recommend the Commission start reducing the customer charges, rather than increasing them. The cost estimates set forth on BJ-11 can be used as an initial guide in making this transition. For example, the monthly customer cost for residential customers is $3.63, and I recommend reducing the customer charge for residential customers from the current level of $7.50, to $5.00 per month. The reduction in revenue resulting from this reduction in the customer charge would be offset by an increase in revenue from higher per-kWh rates. I plan to provide the Commission with a chart showing the effect of this proposal on some typical customer bills prior to the hearing in this case.

Q. Even if the Commission were to accept UNSE's cost allocations, which include an allocation of various investment-related costs, do you nevertheless oppose recovery of those costs through monthly customer charges?

A. Yes. Neither economics nor public policy requires that electric rates be tied directly to the results of fully allocated cost-of-service studies. Such studies are useful primarily as a tool

which can assist regulators in determining the appropriate distribution of revenues among customer classes. Even in that context, factors other than the cost study results should be considered. Furthermore, in designing rates within the various rate classes, fully allocated embedded cost studies are of relatively little value.

Class cost of service studies are too imprecise to accurately reflect cost differences between individual customers, or between customers with different demographic, usage and other characteristics. Furthermore, attempts to design rates based upon the results of an embedded cost study can conflict with important public policy objectives. Two long-recognized policy goals pertinent to electricity rate design are the promotion of economic efficiency and the encouragement of energy conservation. The former objective implies that consumers should pay rates that reflect the costs they impose on society for the electricity they consume. Viewed strictly from the Company's perspective, these costs would include any production, transmission, distribution, and other costs (including fuel) that vary as a function of consumption.

A fully-allocated cost study does not produce that kind of cost result, because it includes not only costs that vary with consumption, but also all of the fixed costs incurred by the Company regardless of what customers (and potential customers) do. Thus these studies do not show the cost caused by a customer's decision to join or remain on the grid, nor do they show the costs which are caused by the customer's decisions regarding how much electricity to consume during a particular month, nor do they accurately reflect the costs which determined by the customers decisions concerning when to consume power (e.g. during peak hours). To the extent the Commission is persuaded that cost data may be helpful in advancing goals like economic efficiency and energy conservation, fully allocated embedded costs are not particularly useful.

In fact, a marginal cost study better isolates costs which are directly affected by

consumer decisions, and marginal cost data is much more useful in evaluating the Company's current and proposed rates against the goal of economic efficiency. Of course, rates set equal to marginal costs may result in overrecovery or underrecovery of a utility's revenue requirement, and I am not suggesting that marginal cost studies are a panacea. My point is simply to emphasize that fully-allocated costs are not the same as marginal costs, and designing prices to track such costs will not necessarily promote economic efficiency, because allocated embedded costs are not directly related to specific production and consumption decisions.

Likewise, rates tied directly to the results of fully allocated class cost-of-service studies may not promote the longstanding goal of energy conservation. Strictly speaking, conservation will be encouraged by setting a relatively high price per kWh – even if that means setting a customer charge which is below the level of customer costs. More generally, energy conservation is encouraged when customers are sent a price signal which reflects the relatively high cost of adding new generating and transmission capacity, and which reflects the relatively high cost of producing electricity without harming the environment. Price signals of this sort are not likely to be derived from an embedded cost of service study, which gives great weight to various fixed and sunk costs, and gives relatively little weight to the forward looking costs to society which are of such concern to environmentalists, and others who advocate energy conservation.

In this case, the Company's proposed increases to the fixed monthly component of its rates results in a reduction in the level of kWh rates which would otherwise be applicable. Decreases in the energy charge which are offset by increases in the customer charge tend to encourage energy consumption rather than promote energy conservation. Hence, regardless of how one feels about the use of embedded cost analyses, the Company's proposed customer charge increases are inconsistent with valid public policy objectives, and should not be accepted.

Q. Let's discuss time of use rates. Can you please describe the Company's existing rates?

A. UNSE has five voluntary TOU plans:

- Residential Weekends Off-peak - RES-01 -TOU-A
- Small General Service - SGS-10 TOU
- Large Power Service - LPS-TOU
- Large General Service - LGS-TOU-N; and
- Interruptible Power Service - IPS-TOU

Each of these TOU plans has Summer on-peak, shoulder and off-peak pricing, and winter on-peak and off-peak pricing. For residential customers, all weekend hours (and all hours for six selected holidays) are Off-peak. [Erdwurm Direct, p. 21]

Q. What changes is the Company proposing with regard to its TOU rates?

A. First, UNSE proposes to redesign its TOU rates by greatly increasing the rate differential between the on and off-peak time-periods. BJ-12 shows the On-Peak, Shoulder, and Off-Peak Summer rates, and the On-Peak and Off-Peak Winter rates for each TOU plan. As shown, current Summer Off-Peak rates are approximately 79-84% of Summer On-Peak rates. Winter Off-Peak rates are approximately 76-81% of Winter On-Peak rates. Under the Company's proposal, the differentials would be dramatically widened, so that Summer Off-Peak rates would be just 31-39% of Summer On-Peak rates, and Winter Off-Peak rates would be approximately 23-24% of Winter On-Peak rates. For residential customers specifically, Summer Off-Peak rates would go from 83.73% to 31.43% of the Summer On-Peak rates, and Winter Off-Peak rates would go from 81.45% to 23.42% of the Winter On-Peak rates.

The Summer On-Peak period is 2:OO p.m. to 6:OO p.m. and Summer Shoulder Periods are Noon (12:OO p.m.) to 2:OO p.m. and 6:OO p.m. to 8:OO p.m. The Winter On-Peak Periods are 6:OO a.m. to 1O:OO a.m. and 5:OO p.m. to 9:00 p.m. All other Summer hours are Off-peak. Weekend and holiday hours are also off-peak for residential customers. For other

customer classes, the TOU hour designation applies every day. [Id.] UNSE claims two benefits to the increased differentials. First,

> [L]arger price differentials between On-Peak, Shoulder-Peak and Off-peak periods mean customers will see a bigger gap between the price they pay for On-Peak power as compared to Shoulder-Peak or Off-peak power. This will provide an enhanced incentive to shift load to off-peak periods. In other words, larger differentials increase the relative price of on-peak service and decrease the price of off-peak service. This should lead to more customers using less energy at peak times, and "shifting" the demand or load to other times in the day. By shifting load to off-peak periods, this helps reduce the need for UNS Electric to find capacity during peak times when that capacity is most expensive and is also in the shortest supply. So, larger differentials should ease the burden on the Company to acquire the most costly power during these peak periods. [Id., p. 23]

UNSE also claims that current TOU customers can save even more money under these increased differentials, and offers the following example:

> Consider, for example, an average residential customer who is able to shift 30% of summer peak usage to summer shoulder, 25% of summer shoulder to summer off-peak, and 20% of winter peak usage to winter off-peak. This customer would save 5.1% annually under the proposed time-of-use design. That is over 2.5 times more than the 1.9% annual savings to be realized under the current TOU tariffs. [Id.]

Second, UNSE proposes to implement Super-Peak Demand Response rates for residential customers, and for general service customers with demands less than 3MW. [Id., p. 26] This rate design applies a significantly higher rate for 1 hour each day (excluding weekends and selected holidays) during the summer, with lower rates during the remaining hours. UNSE's proposed Super Peak rates are shown on BJ-13.

Q. What is your response to the Company's residential TOU proposals?

A. In general, the Company is to be commended for offering customers TOU rate options, and I am

sympathetic with its desire to increase participation on these schedules. As well, I'm sympathetic to its proposal to increase the time period differentials, which will encourage customers to reduce their on-peak consumption. However, further thought needs to be given to the appropriate differentials. The Company has offered very little evidence in support of the specific percentage differentials it is proposing, and due to time constraints I have not had the opportunity to evaluate this aspect of its proposals in depth.

Similarly, I believe the Company's "super-peak" proposal has merit, but I have some concerns regarding the specifics. I agree with the general philosophy behind these proposals; to the extent certain customers are willing to reduce their usage during peak hours, the Company will be able to avoid the high costs associated with purchasing power on the spot market to meet peak loads, and it will reduce the need to add peaking capacity in the future. As well, improvements in the Company's system load factor may enable it to reduce the price it pays for purchased power, even when that power is purchased on a uniform price per kWh basis. In general, it is economically efficient to provide customers with price signals that recognize that on peak consumption is considerably more costly than off-peak consumption.

However, I have some concerns that the "super peak" pricing proposal doesn't seem to go far enough in aligning price signals with actual costs. For instance, the Company appears to be proposing to apply the higher price every Summer weekday, regardless of the weather, and regardless of whether or not unusually high costs will be incurred during that particular day. The UNSE proposal is somewhat ambiguous, simply stating: "The single hour chosen will start at either 2:OO p.m., 3:OO p.m., 4:OO p.m. or 5:OO p.m. for summer months". [Id., p. 25] It isn't entirely clear when this hour will be chosen, or by whom. If customers have the freedom to select the hour when they can most easily reduce their load, and to specify this choice when they sign up for the service, this approach may be quite appealing to customers. Yet, I'm not sure if this is the Company's intent, since it needs to be concerned about adverse selection and a

lack of load diversity amongst the super peak customers – particularly if large numbers of customers opt into this rate. It wouldn't be desirable to have large numbers of customers all selecting the same exact hour, leading to load reductions during one particular peak hour, without reducing load in any of the adjacent hours.

If the Company wants to limit the number of customers who can sign up for any specific super peak hour, additional tariff language will be needed to ensure that customers are given an opportunity to join a waiting list for their preferred hour, and to ensure that any decision by the Company to assign customers to an hour other than their preferred choice will be made in a reasonable and non-discriminatory manner.

Q. Do you have any other suggestions for a more precisely targeted version of the Super Peak pricing concept?

A. Yes. I recommend the Company develop, and the Commission approve as a pilot program an alternative approach to super peak pricing which is more precisely targeted. In this pilot program, the Company would have considerable flexibility to identify super peak hours based on actual load conditions on a day to day basis throughout the hot Summer months. In return, customers would receive a deeper discount on their off-peak consumption. The goal would be to more precisely target the actual peak hour, based on anticipated weather and load conditions of each specific day.

To be fully effective, of course, customers would need to be informed of each "super peak" pricing period before it occurs, so that they have an opportunity to adjust their thermostats, avoid running their dishwasher or doing their laundry, or take other actions to reduce their load during the peak time period. While it is potentially difficult to contact a large number of customers on short notice, with today's technologies, it doesn't have to be costly to do this. If customers are contacted using a combination of emails, text messages and "robo-

calls" (recordings sent to the customer's telephone), a high percentage will receive advance notification of the peak period each day, and the per-customer cost would be minimal.

This alternative approach would make it possible to more narrowly focus the super-peak pricing period on specific hours and days when the Company incurs the highest costs - the particular hours when the system is expected to experience unusually high loads, limited generating capacity, or both. Most obviously, the super-peak price should apply during the hottest hours of the hottest days of each summer. Since weather is variable, it is impossible to predict these hours much more than 36 hours in advance; traditional time-of-day pricing is greatly over-simplified, since it applies the same high price during all of the summer afternoon hours, regardless of the actual weather. Similarly, the Company should have the flexibility to send the higher price signal during hours when its costs are unusually high because one of its peaking plants is unavoidably off-line, even if the weather isn't unusually hot.

Consistent with this reasoning, under this alternative approach, it would not be necessary to apply the "super peak" price to a specific hour of every single day of the entire summer. Instead, the higher rate would be limited to no more than 60 hours each summer, and no more than 2 hours during any single day, while the Company would have flexibility in choosing specific hours and days on a case-by-case basis.

Under this alternative approach, as I envision it, the Company would not be required to charge every customer the higher super peak price during the exact same hour each time. Instead, it would have the flexibility to maximize system benefits and cost savings, by adjusting the super peak hour on a case-by-case basis, while offering a larger off-peak discount, to ensure the plan is still attractive to customers. For instance, on unusually high-cost days, the Company could apply the higher price from 2pm until 4pm for one group of customers (the "A" group), while applying the higher price from 3pm until 5pm for a second group of customers (the "B" group). This would significantly increase the overall load reduction throughout that entire 3

hour period, with the maximum reduction occurring during the hour with the highest anticipated peak. The idea is to provide the Company with greater flexibility to focus the price signal during the specific days of each year when it receive the greatest benefit from the load reduction, while still providing reasonable limits on the frequency with which the higher rate would apply (no more than two hours per day and no more than 60 hours per year), thereby making the rate attractive to customers.

Q. Can you now explain the Company's low income proposals?

A. First, UNSE proposes to shield the majority of CAREs customers from the rate increase proposed in this case.

> CARES customers with monthly usage of 945 kWh will receive the full benefit of the bill reductions attributable to the June 1,2009 downward adjustment in the PPFAC rate, but will not see increases attributable to UNS Electric's proposed rate increase in this case. The 945 kWh threshold exceeds CARES median use of 621 kWh per month and CARES average use of 772 kWh per month. ... As a CARES customer's usage passes 945 kWh and continues to grow, this customer will face relatively more exposure to the rate increase, which is appropriate given the Company's conservation objectives.[Erdwurm Direct, pp. 4-5]

UNSE proposes to accomplish this through the combination of several rate proposals.

> This has been accomplished by lowering the CARES customer charge (before any applicable percentage discount) to $3.50 per month from the current level of $7.50 per month. Additionally, CARES customers will pay a reduced base power supply rate, and the PPFAC forward and true-up components will be set to zero and frozen for CARES customers upon implementation of new rates. CARES customers will also still receive the additional percentage discounts (30% for 0-300 kWh; 20% for 301-600 kWh, and 10% for 601-1000 kWh) and the flat $8.00 per month discount for customers with monthly usage in excess of 1,000 kWh. [Id., p. 28]

Q. Do you agree with this aspect of the Company's rate design proposals?

A. I agree with the general goal of ameliorating the impact of any rate increase on CAREs customers. Needless to say, I also agree with the proposal to reduce the CAREs customer charge, since I am recommending this rate element be reduced for other customers, as well. As I explained above, I developed an estimate of $3.63 per month for customer costs, and recommend reducing the customer charge from $7.50 to $5.00. Consistent with that recommendation, it would be reasonable to further reduce the customer charge paid by CAREs customers to $2.50. However, some of the other proposals, like modifying the base power supply rate and PPFAC true-up mechanism, seem unnecessarily complicated.

Instead, I would recommend increasing the usage-based discounts; this is a simpler approach, which still ameliorates the impact on CAREs customers, yet it also makes it easier to balance the policy tradeoffs related to energy conservation. By focusing on the discount percentages, the Commission can adjust how much of the CAREs rate relief benefits low usage customers, and how much benefits higher usage customers. By increasing the discount applicable to the customer charge and low kWh blocks, it is feasible to provide substantial rate relief to CAREs customers, without reducing the incentive for these customers to conserve energy.

Q. What else is the Company proposing with regard to CAREs customers?

A. UNSE proposes to expand the range of qualifying customers, but only if the costs are borne by other customers. Currently eligible customers include those within 150% of the poverty threshold.

> UNS Electric encourages the Commission to offer a program that provides discounts to customers falling between the 150% and the

> 200% of poverty thresholds. However, UNS Electric's support of an expanded program is contingent upon the program costs being fully recovered from other retail customers. [Id., p. 29]

Q. Do you agree with this proposal?

A. No. Any income cut-off for inclusion in the CAREs plan is necessarily somewhat arbitrary. No justification has been provided for increasing the cut-off above the current level. Already, we have a situation where customers at 160% of the poverty level (and those customers who are unaware of the CAREs program, or decline to participate) are subsidizing those below 150% of the poverty level who are taking advantage of this discount. While expanding coverage to include customers at 160% of the poverty level eliminates this potential inequity for those customers, it exacerbates the problem for those above 200% of the poverty level. Why should customers at 200 to 250% of the poverty level subsidize those who are below 200% of the poverty level? By definition, neither the group of customers paying the subsidy, nor those receiving it, are poverty stricken, and neither group is as needy as those below 150% of the poverty level.

I am troubled by the lack of any solid justification for increasing the cutoff to 200%, but I am also deeply concerned by the practical implications of this proposal, however well-intentioned. As the cutoff is increased farther and farther above the poverty level, a larger and larger number of customers will become eligible for the subsidy – which will significantly increase the burden on other customers, who will have to pay a subsidy to a substantially larger number of customers. In this regard, it is important to realize that the current difficult economic difficulties have had adversely affected many different types of customers, including middle class, two earner families where one of the family members has lost their job, but remain above 200% of the poverty line. It is not at all clear that

someone who is undergoing genuine hardship during these difficult economic times should subsidize someone else, merely because the latter customer happens to have an income level falling between 150% and 200% of the poverty level. Finally, I would note that the 150% cutoff has been used by many, if not all, of the other utilities in Arizona, and no evidence has been offered suggesting that this cutoff has not been a reasonable and successful solution to the difficult policy tradeoffs that I mentioned a moment ago.

Q. Finally, can you briefly discuss the Company's "inclining block" energy charges?

A. Yes. In its prior rate case, UNSE proposed an inclining block rate structure for residential and small general service customers. [See, Decision 70360, p. 52] The Company proposed to apply a one cent per kWh discount for the first 400 kWh of usage, compared to the second block for all usage over 400 kWh. [Id.] The Commission held:

> We agree with the parties that an inverted block rate structure sends a strong and important price signal to customers to conserve energy. While we recognize Staffs concern that some customers will receive a rate decrease while other customers receive a rate increase, the public policy behind incenting conservation outweighs the concerns raised by Staff. We will approve UNSE's inverted block rate design as supported by all parties but Staff. [Id.]

Q. Is the Company proposing any changes to this rate structure?

A. No. However, I believe it would be appropriate to make some changes, to build upon the progress that was made in the last case. More specifically, I suggest adopting a block structure like the one that is currently included in APS's tariff. APS currently has rate blocks: the first 400 kWh has the lowest rate; the second 400 kWh has a higher rate; and, all additional kWh have a still higher rate. Consistent with that pattern, and as a logical extension of the policy adopted in the prior rate case, I recommend charging the lowest rate for the first 400 kWh;

charging one cent more for usage in the second 400 kWh block; and, charging one cent more (two cents higher than the first block) for all additional kWh.

Q. Does this conclude your rate design testimony pre-filed on November 13, 2009?

A. Yes, it does.

Appendix A

Qualifications

Present Occupation

Q. What is your present occupation?

A. I am a consulting economist and President of Ben Johnson Associates, Inc.®, a firm of economic and analytic consultants specializing in the area of public utility regulation.

Educational Background

Q. What is your educational background?

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. The title of my Master's Thesis is a "A Critique of Economic Theory as Applied to the Regulated Firm." Finally, I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics. The title of my doctoral dissertation is "Executive Compensation, Size, Profit, and Cost in the Electric Utility Industry."

Clients

Q. What types of clients employ your firm?

A Much of our work is performed on behalf of public agencies at every level of government involved in utility regulation. These agencies include state regulatory

commissions, public counsels, attorneys general, and local governments, among others. We are also employed by various private organizations and firms, both regulated and unregulated. The diversity of our clientele is illustrated below.

Regulatory Commissions

Alabama Public Service Commission—Public Staff for Utility Consumer Protection
Alaska Public Utilities Commission
Arizona Corporation Commission
Arkansas Public Service Commission
Connecticut Department of Public Utility Control
District of Columbia Public Service Commission
Idaho Public Utilities Commission
Idaho State Tax Commission
Iowa Department of Revenue and Finance
Kansas State Corporation Commission
Maine Public Utilities Commission
Minnesota Department of Public Service
Missouri Public Service Commission
National Association of State Utility Consumer Advocates
Nevada Public Service Commission
New Hampshire Public Utilities Commission
North Carolina Utilities Commission—Public Staff
Oklahoma Corporation Commission
Ontario Ministry of Culture and Communications
Staff of the Delaware Public Service Commission
Staff of the Georgia Public Service Commission
Texas Public Utilities Commission
Virginia State Corporation Commission
Washington Utilities and Transportation Commission

West Virginia Public Service Commission—Division of Consumer Advocate

Wisconsin Public Service Commission

Wyoming Public Service Commission

Public Counsels

Arizona Residential Utility Consumers Office

Colorado Office of Consumer Counsel

Colorado Office of Consumer Services

Connecticut Consumer Counsel

District of Columbia Office of People's Counsel

Florida Public Counsel

Georgia Consumers' Utility Counsel

Hawaii Division of Consumer Advocacy

Illinois Small Business Utility Advocate Office

Indiana Office of the Utility Consumer Counselor

Iowa Consumer Advocate

Maryland Office of People's Counsel

Minnesota Office of Consumer Services

Missouri Public Counsel

New Hampshire Consumer Counsel

Ohio Consumer Counsel

Pennsylvania Office of Consumer Advocate

Utah Department of Business Regulation—Committee of Consumer Services

Attorneys General

Arkansas Attorney General

Florida Attorney General—Antitrust Division

Idaho Attorney General

Kentucky Attorney General

Michigan Attorney General

Minnesota Attorney General

Nevada Attorney General's Office of Advocate for Customers of Public Utilities

South Carolina Attorney General

Utah Attorney General

Virginia Attorney General

Washington Attorney General

Local Governments

City of Austin, TX

City of Corpus Christi, TX

City of Dallas, TX

City of El Paso, TX

City of Galveston, TX

City of Norfolk, VA

City of Phoenix, AZ

City of Richmond, VA

City of San Antonio, TX

City of Tucson, AZ

County of Augusta, VA

County of Henrico, VA

County of York, VA

Town of Ashland, VA

Town of Blacksburg, VA

Town of Pecos City, TX

1 Other Government Agencies

2

3 Canada—Department of Communications
4 Hillsborough County Property Appraiser
5 Provincial Governments of Canada
6 Sarasota County Property Appraiser
7 State of Florida—Department of General Services
8 United States Department of Justice—Antitrust Division
9 Utah State Tax Commission

10

11 Regulated Firms

12

13 Alabama Power Company
14 Americall LDC, Inc.
15 BC Rail
16 CommuniGroup
17 Florida Association of Concerned Telephone Companies, Inc.
18 LDDS Communications, Inc.
19 Louisiana/Mississippi Resellers Association
20 Madison County Telephone Company
21 Montana Power Company
22 Mountain View Telephone Company
23 Nevada Power Company
24 Network I, Inc.
25 North Carolina Long Distance Association
26 Northern Lights Public Utility
27 Otter Tail Power Company
28 Pan-Alberta Gas, Ltd.
29 Resort Village Utility, Inc.
30 South Carolina Long Distance Association

1 Stanton Telephone
2 Teleconnect Company
3 Tennessee Resellers' Association
4 Westel Telecommunications
5 Yelcot Telephone Company, Inc.
6
7 Other Private Organizations
8
9 Arizona Center for Law in the Public Interest
10 Black United Fund of New Jersey
11 Casco Bank and Trust
12 Coalition of Boise Water Customers
13 Colorado Energy Advocacy Office
14 East Maine Medical Center
15 Georgia Legal Services Program
16 Harris Corporation
17 Helca Mining Company
18 Idaho Small Timber Companies
19 Independent Energy Producers of Idaho
20 Interstate Securities Corporation
21 J.R. Simplot Company
22 Merrill Trust Company
23 MICRON Semiconductor, Inc.
24 Native American Rights Fund
25 PenBay Memorial Hospital
26 Rosebud Enterprises, Inc.
27 Skokomish Indian Tribe
28 State Farm Insurance Company
29 Twin Falls Canal Company
30 World Center for Birds of Prey
31

Prior Experience

Q. Before becoming a consultant, what was your employment experience?

A. From August 1975 to September 1977, I held the position of Senior Utility Analyst with Office of Public Counsel in Florida. From September 1974 until August 1975, I held the position of Economic Analyst with the same office. Prior to that time, I was employed by the law firm of Holland and Knight as a corporate legal assistant.

Q. In how many formal utility regulatory proceedings have you been involved?

A. As a result of my experience with the Florida Public Counsel and my work as a consulting economist, I have been actively involved in approximately 400 different formal regulatory proceedings concerning electric, telephone, natural gas, railroad, and water and sewer utilities.

Q. Have you done any independent research and analysis in the field of regulatory economics?

A. Yes, I have undertaken extensive research and analysis of various aspects of utility regulation. Many of the resulting reports were prepared for the internal use of the Florida Public Counsel. Others were prepared for use by the staff of the Florida Legislature and for submission to the Arizona Corporation Commission, the Florida Public Service Commission, the Canadian Department of Communications, and the Provincial Governments of Canada, among others. In addition, as I already mentioned, my Master's thesis concerned the theory of the regulated firm.

Q. Have you testified previously as an expert witness in the area of public utility regulation?

A. Yes. I have provided expert testimony on more than 250 occasions in proceedings before state courts, federal courts, and regulatory commissions throughout the United States and in Canada. I have presented or have pending expert testimony before 35 state commissions, the Interstate Commerce Commission, the Federal Communications Commission, the District of Columbia Public Service Commission, the Alberta, Canada Public Utilities Board, and the Ontario Ministry of Culture and Communication.

Q. What types of companies have you analyzed?

A. My work has involved more than 425 different telephone companies, covering the entire spectrum from AT&T Communications to Stanton Telephone, and more than 55 different electric utilities ranging in size from Texas Utilities Company to Savannah Electric and Power Company. I have also analyzed more than 30 other regulated firms, including water, sewer, natural gas, and railroad companies.

Teaching and Publications

Q. Have you ever lectured on the subject of regulatory economics?

A. Yes, I have lectured to undergraduate classes in economics at Florida State University on various subjects related to public utility regulation and economic theory. I have also addressed conferences and seminars sponsored by such institutions as the National Association of Regulatory Utility Commissioners (NARUC), the Marquette University College of Business Administration, the Utah Division of Public Utilities and the University of Utah, the Competitive Telecommunications Association (COMPTEL), the

International Association of Assessing Officers (IAAO), the Michigan State University Institute of Public Utilities, the National Association of State Utility Consumer Advocates (NASUCA), the Rural Electrification Administration (REA), North Carolina State University, and the National Society of Rate of Return Analysts.

Q. Have you published any articles concerning public utility regulation?

A. Yes, I have authored or co-authored the following articles and comments:

"Attrition: A Problem for Public Utilities—Comment." *Public Utilities Fortnightly*, March 2, 1978, pp. 32-33.

"The Attrition Problem: Underlying Causes and Regulatory Solutions." *Public Utilities Fortnightly*, March 2, 1978, pp. 17-20.

"The Dilemma in Mixing Competition with Regulation." *Public Utilities Fortnightly,* February 15, 1979, pp. 15-19.

"Cost Allocations: Limits, Problems, and Alternatives." *Public Utilities Fortnightly,* December 4, 1980, pp. 33-36.

"AT&T is Wrong." *The New York Times,* February 13, 1982, p. 19.

"Deregulation and Divestiture in a Changing Telecommunications Industry," with Sharon D. Thomas. *Public Utilities Fortnightly*, October 14, 1982, pp. 17-22.

"Is the Debt-Equity Spread Always Positive?" *Public Utilities Fortnightly,* November 25, 1982, pp. 7-8.

"Working Capital: An Evaluation of Alternative Approaches." *Electric Rate-Making,* December 1982/January 1983, pp. 36-39.

"The Staggers Rail Act of 1980: Deregulation Gone Awry," with Sharon D. Thomas. *West Virginia Law Review,* Coal Issue 1983, pp. 725-738.

"Bypassing the FCC: An Alternative Approach to Access Charges." *Public Utilities Fortnightly*, March 7, 1985, pp. 18-23.

"On the Results of the Telephone Network's Demise—Comment," with Sharon D. Thomas. *Public Utilities Fortnightly*, May 1, 1986, pp. 6-7.

"Universal Local Access Service Tariffs: An Alternative Approach to Access Charges." In *Public Utility Regulation in an Environment of Change,* edited by Patrick C. Mann and Harry M. Trebing, pp. 63-75. Proceedings of the Institute of Public Utilities Seventeenth Annual Conference. East Lansing, Michigan: Michigan State University Public Utilities Institute, 1987.

With E. Ray Canterbery. Review of *The Economics of Telecommunications: Theory and Policy* by John T. Wenders. *Southern Economic Journal* 54.2 (October 1987).

"The Marginal Costs of Subscriber Loops," A Paper Published in the Proceedings of the Symposia on Marginal Cost Techniques for Telephone Services. The National Regulatory Research Institute, July 15-19, 1990 and August 12-16, 1990.

With E. Ray Canterbery and Don Reading. "Cost Savings from Nuclear Regulatory Reform: An Econometric Model." *Southern Economic Journal,* January 1996.

Professional Memberships

Q. Do you belong to any professional societies?

A. Yes. I am a member of the American Economic Association.

UNS ELECTRIC, INC.
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TABLE OF CONTENTS TO BJ SCHEDULES

SCHEDULE #	
BJ – 11	ALTERNATIVE CUSTOMER CHARGE CALCULATIONS
BJ – 12	PROPOSED TOU RATES
BJ – 13	PROPOSED SUPER PEAK TOU RATES

UNS ELECTRIC, INC.
ALTERNATIVE CUSTOMER CHARGE CALCULATIONS

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-11

LINE NO.		(A) TOTAL	(B) RESIDENTIAL	(C) SGS	(D) LGS	(E) LPS	(F) INTERRUPTIBLE	(G) STREET LIGHTING
	CUSTOMER ACCOUNTS EXPENSES							
1	901-Supervision	$260,950	$198,177	$33,541	$15,296	$9,470	$259	$4,207
2	902-Meter Reading Expense	915,625	706,293	119,540	54,515	34,354	922	0
3	903-Cust Records & Coll Exp	3,070,993	2,327,967	394,009	179,683	113,233	3,039	53,063
4	905-Misc Cust Accts Exp	39,451	31,033	5,252	2,395	23	41	707
5	Total Customer Accts Expense	$4,287,019	$3,263,469	$552,343	$251,889	$157,080	$4,261	$57,977
	CUSTOMER SERVICE & INFO EXP							
6	908-Customer Assistance Exp	94,671	75,830	12,834	5,853	55	99	0
7	909-Info & Instruct Exp	49,423	39,587	6,700	3,055	29	52	0
8	910-Mlisc Cust Serv & Iinfo Exp	31,336	25,100	4,248	1,937	18	33	0
9	Total Cust Service & Iinfo Expense	$175,431	$140,517	$23,782	$10,846	$103	$183	$0
10	Customer Costs	$4,462,450	$3,403,986	$576,125	$262,735	$157,182	$4,444	$57,977
11	Adjusted Average Number of Customers	89,746	78,124	7,778	2,010	19	34	1,781
12	Customer Charge (Line 10/Line 11)/12	$4.14	$3.63	$6.17	$10.89	$689.40	$10.89	$2.71

REFERENCES:
UNSE BMGS Schedules H-2; G-4

UNS ELECTRIC, INC.
PROPOSED TOU RATES

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-12

LINE NO.		(A) Existing Rate	(B) Percent of On Peak	(C) Proposed Rate	(D) Percent of On Peak
	Residential TOU				
1	Summer on-peak	$0.092183	100.00%	$0.153093	100.00%
2	Summer Shoulder	$0.081803	88.74%	$0.068767	44.92%
3	Summer off-peak	$0.077183	83.73%	$0.048113	31.43%
4	Winter on-peak	$0.080873	100.00%	$0.153093	100.00%
5	Winter off-peak	$0.065873	81.45%	$0.035849	23.42%
	Small General Service TOU				
6	Summer on-peak	$0.090348	100.00%	$0.130888	100.00%
7	Summer Shoulder	$0.079658	88.17%	$0.066778	51.02%
8	Summer off-peak	$0.075348	83.40%	$0.040888	31.24%
9	Winter on-peak	$0.079448	100.00%	$0.130888	100.00%
10	Winter off-peak	$0.064448	81.12%	$0.032668	24.96%
	Large General Service TOU				
11	Summer on-peak	$0.082832	100.00%	$0.116024	100.00%
12	Summer Shoulder	$0.071452	86.26%	$0.059129	50.96%
13	Summer off-peak	$0.067832	81.89%	$0.041024	35.36%
14	Winter on-peak	$0.071072	100.00%	$0.116024	100.00%
15	Winter off-peak	$0.056072	78.89%	$0.027306	23.53%
	Large Power Service TOU				
16	Summer on-peak	$0.070170	100.00%	$0.094919	100.00%
17	Summer Shoulder	$0.058180	82.91%	$0.046959	49.47%
18	Summer off-peak	$0.055170	78.62%	$0.034919	36.79%
19	Winter on-peak	$0.058170	100.00%	$0.094919	100.00%
20	Winter off-peak	$0.043170	74.21%	$0.022905	24.13%
	Interruptible Power Service TOU				
21	Summer on-peak	$0.071861	100.00%	$0.097611	100.00%
22	Summer Shoulder	$0.059691	83.06%	$0.048927	50.12%
23	Summer off-peak	$0.056861	79.13%	$0.037611	38.53%
24	Winter on-peak	$0.059411	100.00%	$0.097611	100.00%
25	Winter off-peak	$0.044411	74.75%	$0.022479	23.03%

Hours:
Summer on-peak: 2:00 p.m. To 6:00 p.m.
Summer Shoulder Peak: 12:00 p.m. To 2:00 p.m. And 6:00 p.m. To 8:00 p.m.
Summer Off Peak: 12:00 a.m. To 12:00 p.m. And 8:00 p.m. To 12:00 a.m.
Winter On-Peak: 6:00 a.m. To 10:00 a.m. And 5:00 p.m. To 9:00 p.m.
Winter Off Peak: 12:00 a.m. To 6:00 a.m., 10:00 a.m. To 5:00 p.m., and 9:00 p.m. To 12:00 a.m.

REFERENCES:
UNSE Schedule H-3

UNS ELECTRIC, INC.
PROPOSED SUPER PEAK TOU RATES

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-13

LINE NO.		(A) Proposed Rate	(B) Percent of Super Peak
	Residential Super Peak		
1	Summer Super-peak	$0.482730	100.00%
2	Summer Shoulder	$0.068767	14.25%
3	Summer off-peak	$0.048113	9.97%
4	Winter on-peak	$0.153093	100.00%
5	Winter off-peak	$0.035849	23.42%
	Small General Service Super Peak		
6	Summer Super-peak	$0.417820	100.00%
7	Summer Shoulder	$0.066778	15.98%
8	Summer off-peak	$0.040888	9.79%
9	Winter on-peak	$0.130888	100.00%
10	Winter off-peak	$0.032668	24.96%
	Large General Service Super Peak		
11	Summer Super-peak	$0.358480	100.00%
12	Summer Shoulder	$0.059129	16.49%
13	Summer off-peak	$0.041024	11.44%
14	Winter on-peak	$0.116024	100.00%
15	Winter off-peak	$0.027306	23.53%

Hours:
Summer Super- Peak:
Version A: 2:OO p.m. to 3:OO p.m.;
Version B: 3:OO p.m. to 4:OO p.m.;
Version C: 4:OO p.m. to 5:OO p.m.; or
Version D: 5:OO p.m. to 6:OO p.m.

Summer Shoulder-Peak:
Version A: 3:OO p.m. to 6:OO p.m.;
Version B: 2:OO p.m. to 3:OO p.m. and 4:OO p.m. to 6:OO p.m.;
Version C: 2:OO p.m. to 4:OO p.m. and 5:OO p.m. to 6:OO p.m.; or
Version D: 2:OO p.m. to 5:OO p.m.

Summer Off -Peak:
12:OO a.m. (midnight) to 2 p.m. and 6:OO p.m. to 12:OO a.m. (midnight)

Winter On-Peak: 6:00 a.m. To 10:00 a.m. And 5:00 p.m. To 9:00 p.m.
Winter Off Peak: 12:00 a.m. To 6:00 a.m., 10:00 a.m. To 5:00 p.m., and 9:00 p.m. To 12:00 a.m.

REFERENCES:
Exhibit DBE-3A

EXHIBIT
RUCO-8
ADMITTED

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-09-0206

SURREBUTTAL TESTIMONY

OF

BEN JOHNSON, PH.D.

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 15, 2010

SURREBUTTAL TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of

The Residential Utility Consumer Office

Before the

Arizona Corporation Commission

Docket No. E-04204A-09-0206

Introduction

Q. Would you please state your name and address?

A. Ben Johnson, 3854-2 Killearn Court, Tallahassee, Florida.

Q. Are you the same Ben Johnson that earlier filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the scope of your surrebuttal testimony?

A. I will respond to certain comments made by UNS Electric witnesses concerning my testimony on the following issues: the appropriate rate of return to be applied to a fair value rate base; various adjustments to operating income; and, residential rate design. Further, as alluded to in my direct testimony, I will provide some calculations that illustrate the potential impacts of my

customer charge and inclining block rate recommendations.

Q. What does UNS have to say about calculating an appropriate rate of return to be applied to a fair value rate base?

A. UNS continues to argue that if the rate of return is reduced to reflect the impact of inflation, only half the actual rate of inflation should be subtracted from the rate of return, since half the FVRB (The OCRB portion) does not include inflation. UNS argues that such a methodology is required by the Commission's most recent decision in the Chaparral rate case.

> As recognized by the Commission in Decision No. 71308, RCND is impacted by inflation, whereas OCRB is stated in original nominal dollar terms. Since only 50% of FVRB is impacted by inflation, the Commission determined that the ROR on FVRB should be determined by subtracting only 50% of an inflation rate from the weighted average cost of capital. If the full rate of inflation were deducted from the weighted cost of capital, as advocated by Dr. Johnson, this method would result in an adjustment that overstates the impact of inflation on capital costs and would produce an unreasonably low ROR on FVRB. [Grant Rebuttal, pp. 16-17]

Q. Does the Commission's recent Chaparral decision require application of the same methodology in this case?

A. No. Nothing in that decision indicates that the Commission intended to adopt a specific methodology for application to all future cases. If the Commission were interested in doing that, it could easily have provided some indication of its intent in that case, and initiated a rulemaking proceeding – which would be the best way to go about investigating the pros and cons of adopting a uniform methodology to apply in all cases, regardless of the facts brought forward in each specific proceeding.

As well, I would note that while the Commission applied a methodology recommended by its Staff, the Commission did not discuss the pros and cons of that particular methodology at

length in its final order. When describing Staff's methodology, the Commission stated:

> Because one half of the FVRB includes OCRB, which does not include inflation, Staff adjusted the 2.4 percent inflation factor by one-half, resulting in an inflation adjustment to the WACC of 1.2 percent. [Decision 71308, pp. 43-44]

However, this passage is merely descriptive of the Staff's rationale for using this particular methodology in this case, rather than one of the other methodologies that have been put forward by the Staff in various other proceedings. Importantly, when the Commission discussed it's own conclusions, it did not discuss this line of reasoning in detail, nor did it explicitly adopt this reasoning. The Commission simply concluded that FVRB includes an inflation component, it is appropriate to make a corresponding downward adjustment to the FVROR, and that adjustment should not be limited to the portion of the rate base that is funded with equity (as it had done in a prior proceeding). For example, the Commission states:

> Because there is an inflation component in the Company's FVRB, all inflation must be removed from the rate of return, whether in debt or equity. [Id., p. 49]

This conclusion is fully consistent with my recommended approach. Further, the Commission seems to realize that this issue is far from settled, given its controversial nature and recent history of litigation, and there is no indication in the order that it is unwilling to hear further evidence concerning the best approach to use. To the contrary, the Commission stated that further refinements to the inflation methodology are "possible" and were "encouraged" [Id.]

Q. Do you agree that because half the FVRB is comprised by the OCRB, that the WACC must be reduced by only half the rate of inflation?

A. No. As I explained in my direct testimony, the fact that OCRB is part of the fair value process

does not provide an adequate justification for slashing the inflation rate in half. I will concede that OCRB is given half weight in developing the FVRB, and OCRB does not increase with inflation. However, half weight is being given to RCND, and reproduction costs tend to grow faster than the actual rate of inflation. RCND does not fully consider the favorable impact of technological changes, increasing economies of scale, the beneficial impact of making input substitutions to increase reliance on inputs that are decreasing in cost, have been more favorably affected by technological change, or have experienced relatively mild increases in price levels. These factors are taken into consideration in developing inflation statistics, and thus the rate of inflation that is reported for the Consumer Price Index, the GDP Deflator, and similar data series reflects the beneficial (ameliorating) impact of these phenomena – whereas RCND has a tendency to grow faster than the overall rate of inflation, because these ameliorating factors are not adequately reflected in the development of reproduction costs.

FVRB reflects the Commission's estimate of the current fair value of the utility's property and equipment; if the Commission were to rely exclusively on RCND, it would greatly overstate the current value, which would not be fair to consumers. In my opinion, while the Commission certainly has discretion in deciding on a fair return that is appropriate to apply to the fair value rate base, there is no logical reason to slash the inflation rate in half – much less adopt a rule that mandates this approach in all cases, regardless of the underlying factual circumstances (e.g. the manner in which the RCND estimates were developed, or the extent to which those estimates have been growing at a pace that is faster than the overall rate of inflation).

Q. Can you now discuss the Company's criticisms of your income and expense adjustments?

A. Given time and resource contraints, I will not respond to every point made by the Company; the absence of a comment in this surrebuttal should not be interpreted as agreement with the

Company's criticisms. One of the most significant, and fundamental points of disagreement relates to the appropriate application of the historical test year. The Company disagrees with many of my adjustments (or my decision to not adopt certain adjustments proposed by UNS), because it disagrees with my recommended cut-off date for the inclusion of changes to circumstances that were observed after the end of the test year. In my direct testimony, I recommended the Commission should continue to use an historical test year, and it should generally reject ad hoc adjustments for changes that occurred, or will occur, beyond the end of the test year. The Company disagrees with my use of a traditional historical test year approach, for two reasons. First, it argues that the Commission has sometimes allowed post test year adjustments in utility rate cases. Second, it contends that the Comission's rules and regulations do not specifically prohibit post test year adjustments. [See, Dukes Rebuttal, p. 6]

Q. Do you continue to believe that the Commission should generally follow a strict historical test year approach?

A. Yes. As I explained in my direct testimony, making adjustments for "known and measurable" cost increases is a popular method for dealing with the closely related problems of inflation and regulatory lag. However, despite its popularity, this approach tends to be arbitrary and controversial. Regardless of how well known or measurable a particular cost change may be, it is difficult to achieve internal consistency and an appropriate "matching" of revenues and costs when the adjustments go beyond the test year. If the Commission concludes that the financial situation of a particular utility calls for measures that go beyond a traditional historical test year approach, I don't believe the best response is to accept more and more adjustments for "known and measurable" changes, or to extend the cut off date for cost increases farther and farther beyond the end of the test year, while leaving revenues frozen at the level which occurred during, or at the end of, the test year. As adjustments stretch farther and farther beyond the test

year, the computed revenue requirement tends to get larger and larger. While this makes it easy to justify higher and higher rates, this approach has little theoretical merit. To the contrary, the farther beyond the test year one ventures, the more difficult and arbitrary it becomes to select a cutoff date, and the less confidence one can have in the final result of the test year calculations. The farther one goes beyond the test year – particularly if expenses are adjusted more aggressively than revenues – the more severe the mismatch that occurs between revenues and expenses. As the misaligment of revenues and expenses becomes increasingly severe, it becomes harder to ensure that the adjustments are known and accurately measurable, and that the final result of the process is a realistic and representative snapshot of the Company's operations. For this reason, I would urge the Commission to adopt a strict application of the historical test year approach, and to the extent it decides to grant a larger rate increase than is justified by the historical test year data, in order to help maintain the Company's financial integrity or for some other valid reason, I recommend that it be explicit about that decision, the reasoning behind the decision, and the basis for determining the magnitude of the additional increase in rates beyond that which would be justified by the actual results of operations during the test year.

Q. Are there other issues related to specific adjustments that you would like to briefly address?

A. Yes. I would like to respond to the Company's discussion of my treatment of its pension and benefit (P&B) loading rate, and its property tax adjustment. In my direct testimony, I explained that the P&B adjustment includes pensions, the Company's share of contributions to the employees' 401(k) plan, and current medical costs. The adjustment essentially replaced actual 2008 expenses with anticipated 2009 expenses. I recommended against this adjustment, arguing that it is reasonable to rely on the actual pensions and benefits expenses during the test year,

rather than estimating the level of costs that will be incurred during 2009. However, in its rebuttal, the Company explained that the P&B loading rate used by UNS in its rate filing went into effect on January 1, 2009, which is essentially equivalent to going into effect at the end of the 2008 test year. Accordingly, I would concede that this is a reasonable adjustment, which is consistent with the use of a historical test year, as well as my recommended treatment of the wage rate increase that went into effect on January 1, 2009. Hence, I am revising my position, to recommend that the Company's P&B adjustment be approved.

A somewhat similar situation applies to the Company's property tax adjustment. The Company proposed making an adjustment to property taxes to reflect the assessment ratio that will go into effect on January 1, 2010. I recommended making an adjustment based upon the assessment ratio that went into effect on January 1, 2009. In its surrebuttal testimony, UNS points out that the lien date for the 2009 property tax year is January 1, 2008, and that the lien date for the 2010 tax year is January 1, 2009. [See, Kissenger Rebuttal, p. 3] I continue to believe the approach I recommended in my direct testimony is a reasonable one, which is fully consistent with the strict application of a historical test year. However, in reviewing the Company's rebuttal testimony on this point, and thinking more about this issue, I can see that this is a grey area. Because there is such a long lag in the property taxation process, one can make a plausible argument that use of the assessment ratio that will go into effect on January 1, 2010 is consistent with a 2008 test year, since the assessment ratio is based on data that was gathered during 2008, and is being computed "as of" January 1, 2009 – essentially the end of the test year. Accordingly, while I still believe the approach I recommended in my direct testimony is the best approach, I will concede it is a close call, and that the Company's approach can also be fairly characterized as being somewhat consistent with a 2008 test year.

Q. Can you now discuss UNS' criticisms of your residential rate design recommendations?

A. Yes. In my direct testimony I recommended reducing Residential customer charges to $5.00 per month, rather than increasing them to $8.00 per month, as the Company proposes. I also recommended adding another block, or tier, to the Company's inclining block rate structure. More specifically, for residential customers I recommend applying the lowest rate to the first 400 kWh per month; charging a higher rate for the next 400 kWh per month, and charging a still higher rate for all additional kWh.

In response, UNS claims that I have proposed to "radically" shift cost recovery away from the customer charge to the energy charge.

> In doing so, he significantly understates the residential customer charge. This results in a mismatch between revenue collection and cost causation. Shifting customer-related costs to energy (per kWh) charges leads to the Company under-recovering when sales are relatively low, regardless of whether low sales are attributable to weather, the economy, conservation and energy efficiency or other factors. Likewise, over-recoveries result when sales are relatively high. [Erdwurm Rebuttal, p. 6]

Mr. Erdwurm admits that my proposed rate design will provide customers a greater incentive to conserve engery. However, he believes that it will preclude the Company from having a reasonable opportunity to earn its allowed return, becasue certain costs "will go unrecovered if kWh sales levels are below the test-year levels used to design rates". [Id., p. 7]

Q. Do you agree with Mr. Erdwurm?

A. No, I do not. As I explained in my direct testimony, we have a fundamental disagreement about the most appropriate way to analyze costs; from my perspective, the Residential customer charges are already higher than appropriate (a similar problem probably exists with other rate schedules, but I have not studied those in as much depth). The Company's proposal is not based upon a valid analysis of economic costs. Rather it is based on an embedded cost allocation

approach which allocates substantial portions of the Company's distribution investment and operating expenses on the basis of customers, regardless of whether or not these items directly vary in response to decisions by customers to join or leave the system. Most of the costs allocated to this rate are not focused on the variable costs that are directly attributable to the decision of customers to join or leave the system, and none of the computations are based on a forward looking, marginal cost analysis. The customer charge should primarily collect the variable costs of metering, billing, and collecting the monthly bill. Other so called "customer costs," including costs of the distribution system, which are largely determined by the configuration of the Company's service territory, the need to stand ready to provide service to all customers; and the need to be able to deliver energy to customers as and when they need it. These costs do not vary from month to month, with changes in the number of customers on the system, and it is reasonable to recover these costs through the service that is sold to consumers – just as the cost of a grocery store's parking lot is recovered through the price of groceries, rather than through a per-customer fee for the privilege of shopping at the store.

Furthermore, setting customer charges at relatively high levels (as the Company prefers) tends to encourage kWh consumption and discourage energy conservation – both of which are contrary to the public interest. Although the Company's inclining block rate structure ameliorates part of this problem, it does not completely eliminate it. As I explained in my direct testimony, the high customer charges proposed by the Company tend to result in customer bills that decrease on a per-total-kWh basis as usage increases, despite the inclining block structure. By proposing to further increase customer charges above levels which are already higher than necessary, the Company is proposing to place an even heavier burden on low use customers and losing an opportunity to encourage energy conservation.

Q. Does the Company have other complaints about your recommended reductions in the customer charge and increases in per kWh rates paid by high usage customers?

A. Yes. It complains that these changes will increase revenue and income volatility, and make it more difficult for it to achieve its approved rate of return, as explained by Company witness Erdwurm:

> The Company appreciates Dr. Johnson's acknowledgement that progress has been made in promoting conservation in rates. Dr. Johnson, however, has not adequately considered the adverse potential impact of his proposals on UNS Electric's financial condition.
>
> ...Dr. Johnson seeks to radically shift recovery away from the customer charge to the energy charge. ...This results in a mismatch between revenue collection and cost causation. Shifting customer-related costs to energy (per kWh) charges leads to the Company under-recovering when sales are relatively low, regardless of whether low sales are attributable to weather, the economy, conservation and energy efficiency or other factors. ...a cost-based residential customer charge – like the one proposed by UNS Electric – helps mitigate periodic swings in revenue because of volatility in usage. In short, it is important that a rate design that promotes conservation also gives some measure of revenue stability for the Company. [Id., pp. 6-7]

Furthermore, setting customer charges at relatively high levels (as the Company prefers) tends to encourage kWh consumption and discourage energy conservation – both of which are contrary to the public interest. Although the Company's inclining block rate structure ameliorates part of this problem, it does not completely eliminate it. Mr. Erdwurm concedes that my suggested revisions to the Company's rate design will provide customers with a greater incentive to conserve, and he seems to realize that as a result of these stronger incentives, over time growth in kWh will gradually be slowed, as customers choose more energy-efficient light bulbs, come to accept higher thermostat settings, acquire more energy-efficient appliances, and so forth. However, he doesn't focus on the long term benefits of the gradual change in consumer behavior in response to these changed price signals, which will reduce the need to

install costly new facilities, reducing the need for future rate increases in order to pass through the cost of these facilities, he instead focuses on potential adverse effects on the Company's earnings and revenue volatility in the short run:

> ...his rate design proposal will also preclude providing UNS Electric a reasonable opportunity to earn its approved return. UNS Electric's proposed residential rate design provides a balance between the conservation goal and providing the Company a fair opportunity to recover its costs. Dr. Johnson's residential rate design proposal, in contrast, ignores customer-related costs that the Company incurs for every customer that receives service from UNS Electric. I believe Dr. Johnson's rate design is confiscatory in its approach. [Id., p. 6]

Q. How do you respond?

A. It was certainly not my intent to be "radical" in any of my recommendations, nor do I think anything I proposed fits this characterization. Take the recommended reduction in customer charges, for example. I proposed reducing the customer charge for residential customers from the current level of $7.50, to $5.00 per month. Stated as a percentage, this reduction would be fairly dramatic – a decline of one-third. However, the reduction in revenue resulting from this reduction in the customer charge would be offset by an increase in revenue from higher per-kWh rates, so the net impact on a typical customer bill would be much less dramatic.

The following tables compare the Company's proposed rates with directly analogous rates that would result from retaining the existing $7.50 customer charge, reducing it to $6.50, or reducing it to $5.00 (as I recommend), while adjusting the per kWh rate in each case by an offsetting amount to provide the same total revenues. As shown, the impact on customer bills is relatively mild:

UNS Rate Proposal, including a $8.00 customer charge				
	100 kWh	500 kWh	1000 kWh	1500 kWh
Customer Charge	$8.00	$8.00	$8.00	$8.00
Energy Charge	2.61	14.06	32.12	50.19
Base Charge	6.88	34.38	68.77	103.15
Total	$17.49	$56.44	$108.89	$161.34
Total per kWh	0.175	0.113	0.109	0.108
UNS Rate Proposal except using a $7.50 Customer Charge				
	100 kWh	500 kWh	1000 kWh	1500 kWh
Customer Charge	$7.50	$7.50	$7.50	$7.50
Energy Charge	2.67	14.35	32.7	51.05
Base Charge	6.88	34.38	68.77	103.15
Total	$17.05	$56.23	$108.96	$161.70
Total per kWh	0.170	0.112	0.109	0.108
UNS Rate Proposal except using a $6.50 Customer Charge				
	100 kWh	500 kWh	1000 kWh	1500 kWh
Customer Charge	$6.50	$6.50	$6.50	$6.50
Energy Charge	2.78	14.92	33.84	52.76
Base Charge	6.88	34.38	68.77	103.15
Total	$16.16	$55.80	$109.11	$162.41
Total per kWh	0.162	0.112	0.109	0.108
UNS Rate Proposal except using a $5.00 Customer Charge				
	100 kWh	500 kWh	1000 kWh	1500 kWh
Customer Charge	$5.00	$5.00	$5.00	$5.00
Energy Charge	2.95	15.78	35.56	55.34
Base Charge	6.88	34.38	68.77	103.15
Total	$14.83	$55.16	$109.32	$163.49
Total per kWh	0.148	0.110	0.109	0.109

Similarly, the impact on the Company's revenues and net income will also be relatively mild. For instance, if the Residential customer charge is increased to $8.00, as the Company proposes, it will generate approximately $424,000 more per year than the current rate. Conversely, reducing the rate to $5.00 would generate $2,542,000 less than the current rate. In both cases, however, this change would be offset the an change in revenues from the per kWh

rates of a similar total magnitude, initially leaving total revenues and net income largely unchanged. (Over time, revenues would grow more with the higher per kWh rates, and thus net income would also tend to grow more, over the long term). I find it hard to understand why the Company views this recommended shift in revenues from the fixed monthly rate category to the per kWh rate category "radical." To put these numbers into perspective, this recommended shift in revenues between categories of $2,542,000 per year is equivalent to just 8.5% of the Company's proposed revenues from Residential customers excluding revenues derived from Base Power Supply Charges, and just 3.1% of the analogous total including Base Power Supply Charges. Bearing in mind that this is merely a change in category – not an actual change in revenues – it is hard to see why the Company views such a modest change as too "radical."

In any event, the Commission can decide how far, and how fast, it wants to move toward encouraging energy conservation, and how quickly it wants to better align rates with marginal cost. If the Commission agrees with the approach I am recommending, but wants to move more gradually, it could adopt a more gradual change in rates, by reducing the customer charge to a lesser degree than I have recommended. A reduction in customer charges to $6.50 would represent a categorical shift in revenues of about 1.6%, yet it would still be a worthwhile step in the right direction.

Q. Does this conclude your surrebuttal testimony pre-filed on January 15, 2010?

A. Yes, it does.

EXHIBIT
RUCO-9
ADMITTED

Cost-of-Service Rates Manual

Federal Energy Regulatory Commission
888 North Capitol Street, N.E.
Washington, D.C. 20426
United States of America
www.ferc.gov

June 1999

Table of Contents

Introduction 1

Step 1: Computing the Cost-of-Service 6
- **The Cost-of-Service Formula** 6
- **Test Period** 7
- **Rate Base** 8
  - **Gross Plant** 9
    - **Allowance For Funds Used During Construction (AFUDC)** 9
  - **Accumulated Reserve for Depreciation** 10
    - **Management Fee** 10
  - **Accumulated Deferred Income Taxes (ADIT)** 11
  - **Working Capital** 12
    - Cash working capital 12
    - Materials and Supplies, and Prepayments 13
- **Cost-of-Service** 13
  - **Return** 13
    - **Capitalization or Capital Structure** 15
    - **Cost of Debt** 16
    - **Return on Equity** 16
    - **Pretax Return** 17
  - **Operation and Maintenance Expenses** 18
  - **Administrative and General Expenses** 19
  - **Depreciation Expense** 19
  - **Federal and State Income Taxes** 20
    - **AFUDC** 21
    - **Effective Tax Rate** 22
    - **Limited Liability Companies** 22
  - **Non-Income Taxes** 22
  - **Credits to the Cost-of-Service** 23

Step 2: Computing a Functionalized Cost-of-Service 23
- **K-N Method** 24

Step 3: Cost Classification 28
- **Classification of Costs Between Fixed and Variable** 28
- **Classification of Costs Between Demand and Commodity** 29
  - Volumetric 30
  - Fixed-Variable 30
  - Seaboard 30
  - United 31
  - Modified Fixed-Variable 32
  - Straight Fixed-Variable 32

Step 4: Cost Allocation 33
- **Mcf's and Dth's** 34

$159,602,000, is equity financed. This means that the owners of Pipeline U.S.A. used their own funds to finance this portion of their investment.

** Pipeline U.S.A. issues its own debt which is not guaranteed by its parent, has its own bond rating and its capital structure is comparable to other equity capitalizations approved by the Commission. Therefore, Pipeline U.S.A. meets the Commission's criteria for using its own capital structure for setting its rates.*

Cost of Debt: This refers to the cost of long term debt incurred by the pipeline to construct or expand the pipeline. For ongoing pipelines that have been issuing debt, we use the actual imbedded cost of debt in the capital structure. The actual imbedded cost of debt is the weighted average of all the debt issued and the cost at which the debt was issued. For new pipelines that have indicated that they would issue debt to finance their investment, but have not yet actually issued the debt, we compute the cost of debt based on a projection, or recent historical debt cost such as historical average Baa utility bonds (Moody's Bond Survey), which is the most prevalent rating for utilities. We also use Moody's to compute the cost of debt if we decide use of a hypothetical capital structure is appropriate.

A-8, column 3, shows the cost of debt of Pipeline U.S.A. of 8.25%. The cost of debt represents a return to Pipeline U.S.A.'s bondholders. The debt return dollars appearing in Column 5 represents the cost to Pipeline U.S.A. to pay the interest on the debt to its bondholders. This debt return, or interest on debt, of $30,723,000 as shown in column (5) is included in the Return component of the cost-of-service.

Return on Equity or Cost of Equity: This is the pipeline's actual profit, or return on its investment. The return on equity is derived from a range of equity returns developed using a Discounted Cash Flow

(DCF) analysis of a proxy group of publicly held natural gas companies. The Commission currently uses a two-stage Discounted Cash Flow (DCF) methodology. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short term growth estimates and the other long term growth estimates. These estimates are then weighted, two-thirds for the short-term growth projection and one-third on the long-term growth, and utilized in determining a range of reasonable equity returns. Two-thirds is used for the short-term growth rate on the theory that short-term growth rates are more predictable, and thus deserve a higher weighting than long term growth rate projections. An equity return is then selected within this zone based on an analysis of the company's risk. It is assumed, that most pipelines face risks that would place them in the middle of the zone of reasonableness. However, a case could be made depending on the facts of the specific pipeline that the return on equity should be outside the zone. As an example, a pipeline with a high debt capitalization ratio is usually considered more risky and thus, a higher return on equity would be expected.

We have determined that a reasonable return on equity for Pipeline U.S.A. is 14.00%. This return was at the high end of our range of equity returns because Pipeline U.S.A. is a relatively new pipeline company with a high debt capitalization ratio. The equity portion of the return permitted to be collected in rates is $22,344,000 shown in column (5) of A-8.

Pretax Return. Pretax return is the amount earned by a pipeline before income taxes and debt interest payments. Pretax return is often calculated for pipelines and used to further settlement negotiations. Using a pretax return figure can avoid the lengthy discussions and debates that surround the issues of capitalization ratios and ROE calculations and analyses. Use of a pretax return reduces these issues down to one number, a pretax percentage that can easily be compared to other pipeline's pretax returns. The pretax return figure

EXHIBIT
RUCO-10
ADMITTED

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-09-0206

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 6, 2009

1 TABLE OF CONTENTS

2 INTRODUCTION 1
3 SUMMARY OF TESTIMONY AND RECOMMENDATIONS 4
4 COST OF EQUITY CAPITAL 10
5 Discounted Cash Flow (DCF) Method 10
6 Capital Asset Pricing Model (CAPM) Method 26
7 Current Economic Environment 33
8 COST OF DEBT 48
9 CAPITAL STRUCTURE 48
10 WEIGHTED COST OF CAPITAL 50
11 COMMENTS ON UNSG'S COST OF EQUITY CAPITAL TESTIMONY 52
12 DCF Comparison 53
13 CAPM Comparison 55
14 Final Cost of Equity Estimate 59
15
16 APPENDIX 1
17 ATTACHMENT A
18 ATTACHMENT B
19 ATTACHMENT C
20 SCHEDULES WAR-1 THROUGH WAR-9
21

INTRODUCTION

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

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utilities regulation and your educational background.

A. I have been involved with utilities regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have also been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to this testimony, further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of UNS Electric, Inc.'s ("UNSE" or "Company") application for a permanent rate increase ("Application") for the Company's electric distribution operations in Mohave and Santa Cruz Counties. UNSE filed the Application with the ACC on April 30, 2009. The Company has chosen the operating period ending December 31, 2008 for the test year in this proceeding.

Q. Briefly describe UNSE.

A. UNSE is a wholly owned subsidiary of UniSource Energy Services, which is owned by UniSource Energy Corporation ("UniSource" or "Parent"), an Arizona corporation, based in Tucson, that is publicly traded on the New York Stock Exchange ("NYSE")'. UniSource is also the parent company of Tucson Electric Power, the second largest investor owned electric utility in the state. In addition to the electric distribution operations of UNS, UniSource also provides electric utilities distribution service through its other subsidiary UNS Gas, Inc., to customers in Northern Arizona and Santa Cruz County.

Q. Please explain your role in RUCO's analysis of UNSE's Application.

A. I reviewed UNSE's Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In

addition to my recommended capital structure, my direct testimony will present my recommended costs of common equity and my recommended cost of long-term debt (the Company has no short-term debt or preferred stock). The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Company's Application and from market-based research that I conducted during my analysis.

Q. Is this your first case involving UNSE?

A. No. In 2003 I was involved with UniSource's acquisition of UniSource Energy Corporation's gas and electric assets from Citizens' Utilities Company. The UNSE entity was the result of that acquisition. I also provided cost of capital testimony in the Company's most recent rate case proceeding which resulted in Decision No. 70360, dated May 27, 2008. UNSE's present rates were established in that Decision.

Q. Were you also responsible for conducting an analysis of the Company's proposed revenue level, rate base and rate design?

A. No. Those aspects of the case were handled by Ben Johnson, Ph.D. of Ben Johnson Associates, Inc. Dr. Johnson will provide testimony on RUCO's recommended level of required revenue (based on his adjustments to Company-proposed levels of rate base and operating expense). Dr. Johnson will also provide testimony on his recommended

methodology to develop a fair value rate of return to be applied to UNSE's fair value rate base.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into seven sections. First, the introduction I have just presented and second, the summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow ("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of returns for utilities that operate in the Arizona jurisdiction. In this second section I will also provide a brief overview of the economic climate that UNSE is currently operating in. Fourth, I will discuss my recommended cost of debt. Fifth, I will compare my

recommended capital structure with the Company-proposed capital structure. Sixth, I will explain my weighted cost of capital recommendation and seventh, I will comment on UNSE's cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

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

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

Original Cost of Equity Capital – I am recommending a 9.25 percent original cost of equity capital. This 9.25 percent original cost figure is based on the range of results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies. My recommended 9.25 percent figure is 215 basis points lower than the Company-proposed cost of equity capital of 11.40 percent.

Cost of Debt – Based on my review of the costs associated with UNSE's various debt instruments, I am recommending that the Company-proposed 7.05 percent cost of debt be adopted by the Commission.

Capital Structure – I am recommending that the Company-proposed capital structure, which is comprised of 54.24 percent long-term debt and 45.76 percent common equity, be adopted by the Commission.

Original Cost Rate of Return – Based on the results of my recommended capital structure, original cost of equity capital, and debt analyses, I am recommending an 8.06 percent original cost rate of return ("OCROR") for UNSE. This figure represents the weighted average cost of my recommended 9.25 percent original cost of equity capital and my 7.05 percent recommended cost of debt. My recommended 8.06 percent OCROR is 98 basis points lower than the Company-proposed unadjusted 9.04 percent weighted average cost of capital.

Fair Value Rate of Return – As explained in the direct testimony of RUCO witness Dr. Johnson, RUCO is recommending a 5.96 percent fair value rate of return ("FVROR") which is 210 basis points lower than my recommended 8.06 percent OCROR. In arriving at this 5.96 percent FVROR figure RUCO considered several different methods to determine an appropriate rate of return to apply to the Company's fair value rate base. The method that RUCO used to arrive at its recommended 5.96 percent FVROR comports with the provisions of Decision No. 70441,

dated July 28, 2008, which resulted from a prior remand proceeding which involved Chaparral City Water Company.[1]

Q. Please explain why RUCO is recommending two different rates of return in this case?

A. UNSE has chosen to use an average of the Company's original cost rate base ("OCRB"), which is based on the original book value of plant assets, and a rate base derived from a reconstruction cost new study ("RCND"), which takes general inflation into consideration, to arrive at a fair value rate base ("FVRB") which reflects the current dollar value of UNSE's original cost rate base. Because general inflation is also reflected in my OCROR figure, it is inappropriate to apply it to an OCRB. To do so would result in a double counting of inflation. For this reason Dr. Johnson has derived a FVROR which reduces my recommended OCROR by an inflation factor of 210 basis points.

Q. Can you explain further why it is necessary to determine an inflation factor adjustment to arrive at an OCROR?

A. Yes. Unless a utility elects to forego an RCND study that restates the value of the OCRB in current dollars, and agrees to use its OCRB as its FVRB, the utility's FVRB is calculated by averaging its OCRB and its RCND rate bases. Because an RCND study restates the OCRB in current

[1] Chaparral City Water Company has appealed that Decision. The appeal is currently pending before the Arizona Court of Appeals.

dollars (through the use of engineering indexes that contain certain inflation factors to calculate an RCND rate base), it is inappropriate to apply an OCROR to a FVRB. This is because the OCROR, like the FVRB, contains an inflation component in it. Consequently, the application of the OCRB rate of return to a FVRB (calculated using the average of an OCRB and the RCND rate base) produces an inappropriate level of operating income which reflects an over-counting of the effects of inflation. As a result, a utility's investors would earn additional operating income on the effects of inflation, as opposed to only earning a return on actual investor supplied capital. To remedy this situation, the OCROR is adjusted downward by removing the inflation expectation that is embedded in it.[2] This is the same rationale that the Commission relied on in Decision No. 70441.

Q. Why do you believe that RUCO's recommended 5.96 percent FVROR is an appropriate rate of return for UNSE to earn on its invested capital?

A. The FVROR that RUCO is recommending meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled

[2] In a case where there is deflation, an upward adjustment would be made to account for a level of deflation.

to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as UNSE, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

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

A. Based on the results of my DCF and CAPM analyses, which ranged from 6.15 percent to 9.55 percent for a sample of electric utility companies, I am recommending a 9.25 percent original cost of equity capital for UNSE. My recommended original cost of equity capital figure falls on the higher end of an acceptable range of results obtained from my DCF and CAPM analyses, which utilized a sample of publicly traded electric utility companies.

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate UNSE's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e. the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = \frac{D_1}{P_0} + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$\frac{D_1}{P_0}$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth

This formula is the basis for the standard growth valuation model that I used to determine UNSE's cost of equity capital.

Q. In determining the rate of future dividend growth for UNSE, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as $g = b \times r$.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[3]

[3] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity,

and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as g = b x r, is also referred to as the internal or sustainable growth rate.

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[4] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six

[4] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

percent.[5] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rate for earnings and dividends, displayed in the last column, is 16.20 percent. If this rate was to be used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change in only the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the

[5] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new

shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[6] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

[6] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

$$g = (br) + (sv)$$

where: g = DCF expected growth rate,

b = the earnings retention ratio,

r = the return on common equity,

s = the fraction of new common stock sold that accrues to a current shareholder, and

v = funds raised from the sale of stock as a fraction of existing equity.

and $v = 1 - [(BV) \div (MP)]$

where: BV = book value per share of common stock, and

MP = the market price per share of common stock.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

...

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M ÷ B) + 1] ÷ 2.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M ÷ B) + 1] ÷ 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In a prior Southwest Gas Corporation rate case[7], the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case, Mr. Hill used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

[7] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on a proxy group consisting of ten electric utility companies that have similar operating characteristics to UNS.

Q. Why did you use a proxy group methodology as opposed to a direct analysis of UNSE?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company, as is the case with UNSE itself. Consequently it was necessary to create a proxy by analyzing publicly traded electric utilities with similar risk characteristics.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

...

Q. What criteria did you use in selecting the companies that make up your proxy for UNSE?

A. All of the electric utilities in my sample are publicly traded on the NYSE and are followed by The Value Line Investment Survey's ("Value Line") electric utility industry segment. All of the companies in the proxy are engaged in the provision of regulated electric services. Attachment A of my testimony contains Value Line's most recent evaluation of the ten electric utilities that I used for my cost of common equity analysis.

Q. What companies are included your proxy?

A. The ten electric utility companies included in my proxy (and their NYSE ticker symbols) are ALLETE, Inc. ("ALE"), Black Hills Corporation ("BKH"), CH Energy Group,, Inc. ("CHG"), Empire District Electric Company ("EDE"), Hawaiian Electric Industries, Inc. ("HE"), MGE Energy, Inc. ("MGEE"), Northeast Utilities ("NU"), NSTAR ("NST") Otter Tail Corporation ("OTTR"), and UIL Holdings. ("UIL").

Q. Did the Company's witness also perform a similar analysis using electric utilities?

A. Yes, the Company's witness, Martha B. Pritz, performed a similar analysis of publicly traded electric utilities.

Q. Does your sample of electric utilities include all of the same electric utility companies that Ms. Pritz included in her sample?

A. No. My sample includes eight of the sample electric utility companies that Ms. Pritz selected for her sample.

Q. Please explain the difference in your samples.

A. In addition to the eight companies that our samples have in common, Ms. Pritz also included Northwestern Corporation and Portland General Electric Company. I decided not to include those two utilities because of a lack of Value Line information on them. In the case of Northwestern Corporation, the utility is covered in Value Line's Small and Mid-Cap Edition which does not provide projections extending into the 2014 time frame which I rely on in my DCF analysis. While Value Line does provide such projections on Portland General Electric Company, the utility did not have a full five years of historical data that I also rely on in my DCF model. Consequently, I substituted these two utilities with two other electrics: Black Hills Corporation ("BKH") and Otter Tail Corporation ("OTTR").

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the utilities included in the

sample for the historical observation period 2004 to 2008. Schedule WAR-5 also includes Value Line's projected 2009, 2010 and 2012-14 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding for the electric utilities in my sample.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use ALLETE, Inc., (NYSE symbol ALE) as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described on page 18) to multiply ALE's earned return on common equity by its earnings retention ratio for each year during the 2004 to 2008 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, Page 1, ALE's sustainable internal growth rate increased from 4.74 percent in 2004 to 5.60 percent in 2005. The company's growth rates experienced a pattern of decline during the remainder of the observation period, which resulted in a 5.06 percent average over the 2004 to 2008 time frame. Value Line's analysts are

forecasting this trend to continue through 2009 before growth climbs steadily to 2.72 percent through the 2012-14 period. Based on these estimates I believe a 2.75 percent rate of internal growth is possible for AGL (Schedule WAR-4, Page 1, Column A, Line 1).

Q. Please continue with the external growth rate "s x v" component portion of your analysis.

A. Schedule WAR-5 demonstrates that ALE's share growth averaged just 2.36 percent over the observation period. Value Line expects future outstanding shares to increase from 32.60 million in 2008 to 41.00 million by the end of 2014. Taking this data into consideration, I am estimating a 5.00 percent rate of share growth for ALE's (Schedule WAR-4, Page 2, Column A, Line 1). I used this estimate to calculate the s x v component of the DCF dividend growth rate (which is 0.77 percent for ALE). My final dividend growth rate estimate for ALE is 3.52 percent (2.75 percent internal growth + 0.77 percent external growth) and is shown on Page 1 of Schedule WAR-4.

Q. What is your average dividend growth rate estimate using the DCF model for the electric utilities?

A. Based on the DCF model, my average dividend growth rate estimate is 4.15 percent, which is also displayed on page 1 of Schedule WAR-4.

Q. How do your average dividend growth rate estimates compare with the growth rate data published by Value Line and other analysts?

A. The average dividend growth rate estimate that I've calculated falls between the projections of the securities analysts I've relied on. My 4.15 percent estimate is 229 basis points lower than the 6.44 percent consensus EPS projections published by Zacks Investment Research ("Zacks"), exhibited in my Attachment B, and 42 basis points higher than Value Line's 3.73 percent projected estimates. As can also be seen on Schedule WAR-6, the 4.15 percent estimate that I have calculated is 166 basis points higher than the 2.49 percent five-year historical average of Value Line data (on EPS, DPS and BVPS) and is 78 basis point higher than the 3.37 percent average of the 5-year EPS means provided by Zacks, and the aforementioned percent five-year historical average of Value Line data. In fact, my 4.15 percent estimate is 56 basis points higher than the 3.59 percent Value Line 5-year compound history that is also displayed on Schedule WAR-6. Based on the information presented in Schedule WAR-6, I would say that my 4.15 percent estimate, which falls between Zack's and Value Line's projections, is a fair representation of the growth estimates presented by securities analysts at this point in time.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's August 7, August 28 and September 25,

2009 Ratings and Reports Electric Utility Industry updates for electric utilities located in the western, eastern and central regions of the U.S. I then divided those figures by the eight-week average price per share of the appropriate utility's common stock. The eight-week average price is based on the daily closing stock prices for each of the companies in my proxies for the period August 17, 2009 to October 10, 2009.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the electric utilities included in your sample?

A. As shown in Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 9.55 percent.

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind CAPM and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[8], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and

[8] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

risk as measured by beta.[9] In this regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification. Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

[9] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

where: k = the expected return of a given security,

r_f = risk-free rate of return,

$ß$ = beta coefficient, a statistical measurement of a security's systematic risk,

r_m = average market return (e.g. S&P 500), and

$r_m - r_f$ = market risk premium.

Q. What types of financial instruments are generally used as a proxy for the risk-free rate of return in the CAPM model?

A. Generally speaking, the yields of U.S. Treasury instruments are used by analysts as a proxy for the risk-free rate of return component.

Q. Please explain why U.S. Treasury instruments are regarded as a suitable proxy for the risk-free rate of return?

A. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of various Treasury instruments will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[10] a real rate

[10] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the real rate of interest, an inflationary expectation, and a risk

of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the real rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my testimony, this compensation translates into higher rates of returns to the investor.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used an eight-week average of the yields on a 5-year U.S. Treasury instrument. The yields were published in Value Line's Selection and Opinion publication dated August 21, 2009 through October 9, 2009 (Attachment C). This resulted in a risk-free (r_f) rate of return of 2.41 percent.

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premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

Q. Why did you use the yield on a 5-year year U.S. Treasury instrument as opposed to a short-term T-Bill?

A. While a shorter term instrument, such as a 91-day T-Bill, presents the lowest possible total risk to an investor, a good argument can be made that the yield on an instrument that matches the investment period of the asset being analyzed in the CAPM model should be used as the risk-free rate of return. Since utilities in Arizona generally file for rates every three to five years, the yield on a 5-year U.S. Treasury Instrument closely matches the investment period or, in the case of regulated utilities, the period that new rates will be in effect.

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both the 9.60 percent geometric mean and the 11.70 percent arithmetic mean of the historical total returns on the S&P 500 index from 1926 to 2008 as the proxy for the market rate of return (r_m). For the risk-free portion of the risk premium component (r_f), I used the geometric mean of the total returns of intermediate-term government bonds for the same eighty-two year period. The market risk premium (r_m - r_f) that results by using these inputs is 4.20 percent (9.60% - 5.40% = <u>4.20%</u>). The market risk premium that results by using the arithmetic mean calculation is 6.10 percent (11.70% - 5.60% = <u>6.10%</u>).

Q. How did you select the beta coefficients that were used in your CAPM analysis?

A. The beta coefficients (ß), for the individual utilities used in both my proxies, were calculated by Value Line and were current as of October 9, 2009. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the electric utilities included in my sample ranged from 0.65 to 0.90 with an average beta of 0.73.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean to calculate the risk premium results in an average expected return of 5.46 percent. My calculation using an arithmetic mean results in an average expected return of 6.83 percent.

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	9.55%
CAPM	5.46% – 6.83%

Based on these results, my best estimate of an appropriate range for an original cost of equity capital for UNSE is 5.46 percent to 9.55 percent. My final recommended original cost of equity capital figure is 9.25 percent.

Q How did you arrive at your recommended original cost of equity capital figure of 9.25 percent?

A. My recommended original cost of equity capital figure of 9.25 percent falls on the high end of the range of estimates produced by my DCF and CAPM results and is based on my analysis of projected returns of the electric utilities included in my sample.

Q. How does your recommended original cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 11.40 percent cost of equity capital proposed by the Company is 215 basis points higher than the 9.25 percent original cost of equity capital that I am recommending.

Current Economic Environment

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. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a brief review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board

("Federal Reserve" or "Fed"), then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[11] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

[11] This is the interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

Q. Did the Federal Reserve achieve its goals during this period?

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000.

Q. What has been the state of the economy since 2001?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower

growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including Value Line, believed that the Federal Reserve was cutting rates in the hope of avoiding a recession.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates – moves which indicated that the worst may be over and that the recession might have bottomed out during the last quarter of 2001 – a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in forty-five years.

Even though some signs of economic strength, mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC announced "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.'[12]

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent.

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief.

[12] Wolk, Martin, "Fed holds interest rates steady," MSNBC, January 28, 2004.

As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the federal funds rate to a level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates.

Q. What was the reaction in the financial community to the Fed's decision not to raise interest rates?

A. As in the past, banks followed the Fed's lead once again and held the prime rate to a level of 8.25 percent, or 300 basis points higher than the federal funds rate of 5.25 percent established on June 29, 2006.

Q. How did analysts view the Fed's actions between January 2001 and August 2006?

A. According to an article that appeared in the December 2, 2004 edition of The Wall Street Journal, the FOMC's decision to begin raising rates two years ago was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy.[13] In other words, the Fed was

[13] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

trying to head off inflation *before* it became a problem. During the period following the August 8, 2006 FOMC meeting, the Fed's decisions not to raise rates were viewed as a gamble that a slower U.S. economy would help to cap growing inflationary pressures.[14]

Q. Was the Fed attempting to engineer another "soft landing", as it did in the mid-nineties, by holding interest rates steady?

A. Yes, however, as pointed out in an August 2006 article in The Wall Street Journal by E.S. Browning, soft landings – like the one that the Fed managed to pull off during the 1994-95 time frame, in which a recession or a bear market were avoided – rarely happen[15]. Since it began increasing the federal funds rate in June 2004, the Fed had assured investors that it would increase rates at a "measured" pace. Many analysts and economists interpreted this language to mean that former Chairman Greenspan would be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates contributed to the bankruptcy of Orange County, California

[14] Ip, Greg, "Fed Holds Interest Rates Steady As Slowdown Outweighs Inflation," The Wall Street Journal Online Edition, August 8, 2006.

[15] Browning, E.S, "Not Too Fast, Not Too Slow…," The Wall Street Journal Online Edition, August 21, 2006.

and the Mexican peso crisis[16]. According to Mr. Browning, at the time that his article was published, the hope was that Chairman Bernanke would succeed in slowing the economy "just enough to prevent serious inflation, but not enough to choke off growth." In other words, "a 'Goldilocks economy,' in which growth is not too hot and not too cold."

Q. Was the Fed's attempt to engineer a soft landing successful during the period that followed the August 8, 2006 FOMC meeting?

A. It would appear so. Articles published in the mainstream financial press were generally upbeat on the economy during that period. An example of this is an article written by Nell Henderson that appeared in the January 30, 2007 edition of The Washington Post. According to Ms. Henderson, "a year into [Fed Chairman] Bernanke's tenure, the [economic] picture has turned considerably brighter. Inflation is falling; unemployment is low; wages are rising; and the economy, despite continued problems in housing, is growing at a brisk clip."[17]

Q. What has been the state of the economy over the past two years?

A. Reports in the mainstream financial press during the majority of 2007 reflected the view that the U.S. economy was slowing as a result of a worsening situation in the housing market and higher oil prices. The

[16] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

[17] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

overall outlook for the economy was one of only moderate growth at best. Also during this period the Fed's key measure of inflation began to exceed the rate setting body's comfort level.

On August 7, 2007, the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate unchanged at 5.25 percent.[18] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation would fail to moderate. However, during this same period, evidence of an even slower economy and a possible recession was beginning to surface. Within days of the Fed's decision to stand pat on rates, a borrowing crisis rooted in a deterioration of the market for subprime mortgages and securities linked to them, forced the Fed to inject $24 billion in funds (raised through open market operations) into the credit markets.[19] By Friday, August 17, 2007, after a turbulent week on Wall Street, the Fed made the decision to lower its discount rate (i.e. the rate charged on direct loans to banks) by 50 basis points, from 6.25 percent to 5.75 percent, and took steps to encourage banks to borrow from the Fed's discount window in order to provide liquidity to lenders. According to an article that appeared in the August 18, 2007 edition of The Wall Street Journal, [20] the Fed had used all of its tools to

[18] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

[19] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

[20] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall

restore normalcy to the financial markets. If the markets failed to settle down, the Fed's only weapon left was to cut the Federal Funds rate – possibly before the next FOMC meeting scheduled on September 18, 2007.

Q. Did the Fed cut rates as a result of the subprime mortgage borrowing crises?

A. Yes. At its regularly scheduled meeting on September 18, 2007, the FOMC surprised the investment community and cut both the federal funds rate and the discount rate by 50 basis points (25 basis points more than what was anticipated). This brought the federal funds rate down to a level of 4.75 percent. The Fed's action was seen as an effort to curb the aforementioned slowdown in the economy. Over the course of the next four months, the FOMC reduced the Federal funds rate by a total 175 basis points to a level of 3.00 percent – mainly as a result of concerns that the economy was slipping into a recession. This included a 75 basis point reduction that occurred one week prior to the FOMC's meeting on January 29, 2008.

...

Street Journal, August 9, 2007

Q. What actions has the Fed taken in regard to interest rates since the beginning of 2008?

A. The Fed made two more rate cuts which included a 75 basis point reduction in the federal funds rate on March 18, 2008 and an additional 25 basis point reduction on April 30, 2008. The Fed's decision to cut rates was based on its belief that the slowing economy was a greater concern than the current rate of inflation (which the majority of FOMC members believed would moderate during the economic slowdown).[21] As a result of the Fed's actions, the federal funds rate was reduced to a level of 2.00 percent. From April 30, 2008 through September 16, 2008, the Fed took no further action on its key interest rate. However, the days before and after the Fed's September 16, 2008 meeting saw longstanding Wall Street firms such as Lehman Brothers, Merrill Lynch and AIG failing as a result of their subprime holdings. By the end of the week, the Bush administration had announced plans to deal with the deteriorating financial condition which had now become a worldwide crisis. The administrations actions included former Treasury Secretary Henry Paulson's request to Congress for $700 billion to buy distressed assets as part of a plan to halt what has been described as the worst financial crisis since the 1930's[22]. Amidst this turmoil, the Fed made the decision to cut the federal funds rate by another

[21] Ip, Greg, "Credit Worries Ease as Fed Cuts, Hints at More Relief" The Wall Street Journal, March 19, 2008

[22] Soloman, Deborah, Michael R. Crittenden and Damian Paletta, "U.S. Bailout Plan Calms Markets, But Struggle Looms Over Details" The Wall Street Journal, September 20, 2008

50 basis points in a coordinated move with foreign central banks on October 8, 2008. This was followed by another 50 basis point cut during the regular FOMC meeting on October 29, 2008. At the time of this writing, the federal funds target rate now stands at 0.25 percent, the result of a 75 basis point cut announced on December 16, 2008. After FOMC meetings in January, March April, June, August and September of 2009, the Fed elected not to make any changes in the federal funds rate, stating in January that the rate would remain low "for some time."[23] Presently, the Fed's discount rate is at 0.50 percent, a level not seen since the 1940s.[24] Based on data released during the early part of December 2008, the U.S. has officially been in a recession since December of 2007.

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected benchmark rates?

A. U.S. Treasury instruments are for the most part still at historically low levels. As can be seen on the first page of Attachment C, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has fallen to 0.50 percent from 1.75 percent in 2008.

[23] Hilsenrath, Jon and Liz Rappaport, "Fed Weighs Idea of Buying Treasurys as Focus Shifts" The Wall Street Journal, January 29, 2009

[24] Hilsenrath, Jon, "Fed Cuts Rates Near Zero to Battle Slump" The Wall Street Journal, December 17, 2008

Q. What has been the trend in other leading interest rates over the last year?

A. All of the leading interest rates have dropped from levels that existed a year ago (Attachment C, Value Line Selection & Opinion page 3277, dated October 9, 2009). The prime rate has fallen from 5.00 percent a year ago to 3.25 percent. The benchmark federal funds rate, just discussed, has decreased from 2.00 percent, in October 2008, to a level of 0.00 - 0.25 percent (as a result of the December 16, 2008 rate cut discussed above). The yields on all of the non-inflation protected maturities of U.S. Treasury instruments (exhibited in Attachment C) have also decreased over the past year. A previous trend, described by former Chairman Greenspan as a "conundrum"[25], in which long-term rates fell as short-term rates increased, thus creating a somewhat inverted yield curve that existed as late as June 2007, is completely reversed and a more traditional yield curve (one where yields increase as maturity dates lengthen) presently exists (Attachment C). The 5-year Treasury yield, used in my CAPM analysis, has fallen from 2.86 percent, in October 2008, to 2.31 percent. The 30-Year Treasury constant maturity rate also decreased from 4.22 percent over the past year to 4.05 percent as has the 30-year zero rate which has dropped from 4.22 percent to 4.13 percent. These current yields are considerably lower than corresponding yields that existed during the early nineties and at the beginning of the current decade (as can be seen on Schedule WAR-8).

[25] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005

Q. What is the current outlook for the economy?

A. Value Line's analysts have become increasingly optimistic in their outlook on the economy as of late and had this to say on the housing situation in the October 9, 2009 edition of Value Line's Selection and Opinion publication:

> **The unfolding housing recovery is likely to be a drawn out affair**, as the nation strives to rebound from the worst slump in this sector in decades. For the most part, housing has shown steady improvement, since seemingly bottoming out earlier in 2009, as data on housing starts and sales of new homes and existing residences have mostly trended higher. However, the latest figures point up the fragility of this recovery, as sales of existing homes fell 2.7% in August—after four straight monthly increases—while new home sales were basically flat with a month earlier. Home prices continue to be soft, meantime, with prices near their lows for the past few years, as the massive inventories of unsold houses are depressing home values across much of the country.

Value Line's analysts went on to state

> **Elsewhere, the picture is mixed as well.** For example, weekly jobless claims have been trending lower for the most part in recent weeks, but key industrial sectors (notably the capital goods arena) are exhibiting some lingering weakness. We think the economy will continue to press forward in uneven increments for the balance of this year and into 2010.

Q. How are Value Lines analysts viewing electric utilities as an investment opportunity?

A. Value Line's analysts are recommending electric utilities as a relatively safe investment. In the August 28, 2009 Value Line Electric Utility (East) Industry update, analyst Michael Ratty had this to say:

> During these challenging economic times, utility stocks are still sought after due to their relative stability and attractive dividend yields. With several stocks yielding over 7%, income-oriented investors should have little trouble finding appeal in this industry. All told, we believe this might be a good time to increase your portfolio's electric-utility exposure.

In the September 25, 2009 Value Line Electric Utility (Central) Industry update, analyst Paul E. Debbas, CFA stated the following:

> Electric utility stocks have not participated in the partial recovery that the market has made so far this year after the horrible showing in 2008. To date, the Value Line Composite Average is up over 25%, but the Value Line Utility Average has hardly budged. Thus, this group's valuation has become relatively more attractive. The industry's average yield of 5% is more than twice the market mean. Many of these equities offer attractive yields that are above the industry average, plus some dividend-growth potential. Investors should be cautious about most stocks with a well above-average yield, however, due to the possibility of a dividend cut. We show a split dividend at the top of the page if we believe that there is a chance of a reduction.

Q. After weighing the economic information that you've just discussed, do you believe that the cost of equity that you have estimated is reasonable for UNSE?

A. I believe that my recommended cost of equity will provide UNSE with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are still low by historical standards) and a low and stable outlook for inflation are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my cost of capital analysis has produced such a return.

COST OF DEBT

Q. Have you reviewed UNSE's testimony on the Company-proposed cost of long-term debt?

A. Yes, I have reviewed the testimony prepared by Ms. Pritz.

Q. Do you agree with Ms. Pritz's inclusion of the amortized debt discount and expenses and losses attributed to reacquired debt and the credit facility fees to arrive at her cost of debt figure of 7.05 percent?

A. Yes.

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

A. I am recommending that the Commission adopt the Company proposed cost of debt of 7.05 percent.

CAPITAL STRUCTURE

Q. Have you reviewed UNSE's testimony regarding the Company's proposed capital structure?

A. Yes.

Q. Please describe the Company's proposed capital structure.

A. The Company is proposing a capital structure comprised of 54.24 percent long-term debt and 45.76 percent common equity.

Q. What capital structure are you proposing for UNSE?

A. I am recommending that the Commission adopt the Company-proposed capital structure.

Q. Is UNSE's actual capital structure in line with industry averages?

A. No. UNSE's capital structure is higher in debt than the average capital structure of the electric utilities. As can be seen in Schedule WAR-9, the capital structures for those utilities averaged approximately 48 percent for debt and 52 percent for equity (51.6 percent common equity + 0.4 percent preferred equity). UNSE would be viewed by investors as having more financial risk (i.e. the risk of not being able to service debt instruments) and would expect a slightly higher return on equity.

Q. Have you made an upward adjustment to your cost of common equity that was derived from the sample electric utilities that exhibited lower financial risk?

A. No. As explained in the testimony of RUCO witness Dr. Johnson, RUCO's recommended FVROR will provide UNSE with adequate operating income to mitigate concerns regarding the level of debt in the Company's capital structure.

WEIGHTED COST OF CAPITAL

Q. How does the Company's proposed weighted average cost of capital compare with your recommendation?

A. The Company has proposed an unadjusted weighted average cost of capital of 9.04 percent. This composite figure is the result of a weighted average of UNSE's proposed 7.05 percent cost of long-term debt and 11.40 percent cost of common equity. The Company-proposed 9.04 percent OCRB weighted cost of capital is 98 basis points higher than the 8.06 percent OCRB weighted cost that I am recommending, which is the weighted cost of my recommended 7.05 percent cost of long-term debt and my recommended 9.25 percent cost of common equity. In its Application, the Company makes a 134 basis point upward adjustment to the aforementioned 9.04 percent weighted average cost of capital in order to arrive at a 10.38 percent OCROR that produces the same level of operating income as the Company-proposed 6.88 percent FVROR does.

Q. How does the Company's proposed FVROR of 6.88 percent compare with RUCO's recommendation?

A. The Company-proposed FVROR of 6.88 percent is 92 basis points higher than the 5.96 percent FVROR that RUCO witness Dr. Johnson is recommending.

Q. Why is RUCO recommending a FVROR that is lower than the OCROR that was derived from the results of your DCF and CAPM analyses?

A. As I explained earlier in my testimony, the lower FVROR removes an inflation expectation that is embedded in the OCROR. The method that RUCO has relied on to arrive at its recommended 596 percent FVROR is consistent with the provisions contained in Decision No. 70441 which established a FVROR for Chaparral City Water Company ("Remand Proceeding"). During the Remand Proceeding, the Commission was required to develop an appropriate rate of return on Chaparral's FVRB under a remand order from the Arizona Court of Appeals. In doing so, the Commission adopted, in part, a methodology that was proposed by Dr. Johnson who testified on behalf of RUCO on the FVRB rate of return issue that was central to that proceeding.[26]

Q. What did Dr. Johnson recommend in the Remand Proceeding?

A. Dr. Johnson recommended that a 200 basis point adjustment be made to the original weighted average cost of capital in order to remove the effects of general inflation from Chaparrals FVRRB. His recommendation was based on the low end of a range of figures that represented the difference

[26] On September 30, 2005, the Commission issued Decision No. 68176 which granted a permanent rate increase to Chaparral. Following the Commission's decision on the matter, the Company filed an application for rehearing on which the Commission took no action. Chaparral subsequently filed an appeal with the Arizona Court of Appeals, Division One ("Court of Appeals"). The Company's appeal claimed that Chaparral was denied a fair rate of return on its invested capital as a result of the Commission's established method of calculating a level of operating income based on the Company's fair value rate base ("FVRB"). On February 13, 2007, the Court of Appeals issued a Memorandum Decision which affirmed in part, vacated, and remanded Decision No. 68176 to the Commission for further determination.

between Treasury Inflation-Protected Securities ("TIPS") and U.S. Treasury bonds with similar liquidity and maturity characteristics.

Q. Did the Commission adopt Dr. Johnson's recommendation?

A. In part, yes. The Commission adopted a FVROR that was derived from a an inflation adjustment that reduced the cost of common equity by 200 basis points as opposed to Dr. Johnson's recommendation to reduce the original weighted average cost of capital by 200 basis points.

COMMENTS ON UNSE'S COST OF EQUITY CAPITAL TESTIMONY

Q. What methods did Ms. Pritz use to arrive at her cost of common equity for UNSE?

A. Ms. Pritz used a DCF methodology and a CAPM methodology to estimate UNSE's cost of common equity. She also relied on a bond yield plus risk premium approach to estimating the cost of common equity which is somewhat similar to the CAPM methodology.

Q. Did you conduct a bond yield plus risk premium approach to estimating your recommended cost of common equity?

A. No. I believe that the CAPM is a better model for the risk positioning type of methodology that the risk premium approach employs.

Q. Can you provide a comparison of the results derived from your respective DCF and CAPM models?

A. Yes.

DCF Comparison

Q. Were there any differences in the way that you conducted your DCF analysis and the way that Ms. Pritz conducted hers?

A. Yes, Ms. Pritz relied on the results of a multi-stage DCF model, using her proxy of ten electric utilities that I described earlier in my testimony, as opposed to the single-stage constant growth model that I relied on.

Q. Do you agree with Ms. Pritz's reliance on the multi-stage DCF model?

A. No. The 6.50 percent long-term growth rate that Ms. Pritz uses in the second stage of her multi-stage DCF model is the median value of her growth rate estimate that relied on five year-growth rate estimates from analysts from Value Line, Zacks, and SNL. The multi-stage model calculates this additional 6.50 percent rate of growth into perpetuity. Her multi-stage DCF model produces an average estimated cost of equity of 12.10 percent for her sample group of electric utilities.

...

Q. Does Ms. Pritz give equal weight to the near-term and long-term growth estimates in her multi-stage model?

A. Yes Ms. Pritz gives equal weight to both her near-term and long-term multi-stage inputs. A good argument can be made that more emphasis should be placed on the near-term component of Ms. Pritz's 's multi-stage DCF model as opposed to the long-term growth rate that is carried out into perpetuity.

Q. Why didn't you conduct a multi-stage DCF analysis like the one conducted by Ms. Pritz?

A. Given the fact that the single-stage model is a constant growth model, I saw no need to rely on a model which calculates a second growth rate estimate into perpetuity. The five-year growth rate projections that I rely on in for the single-stage DCF model is also consistent with the use of a 5-year treasury instrument as the risk free rate of return in my CAPM model. This 5-year investment horizon is very close to the 3 to 5-year periods that utilities in Arizona apply for rate relief.

Q. What is the difference between Ms. Pritz's DCF estimate and your DCF estimate?

A. As I noted earlier, Ms. Pritz's multi-stage DCF produced an estimate of 12.10 percent which is 255 basis points higher than the 9.55 percent cost

of common equity derived from my DCF analysis which is a mean average of the DCF estimates of the ten electric utilities in my proxy.

Q. Does Ms. Pritz provide an estimate that is based on the single-stage model that you employed?

A. Not directly, however the exhibits in her testimony contain inputs and estimates used in her multi-stage model that can also be used in the single-stage model. Using the inputs and estimates that appear in Ms. Pritz's exhibits, a single-stage model would produce a mean average estimate of 11.40 percent or 185 basis points higher than my 9.55 percent DCF estimate.

Q. What is the main reason for the difference between your single-stage DCF results and the single stage results obtained from Ms. Pritz's data?

A. The main difference is her higher growth rate estimate of 5.62 percent, which was based on EPS estimates only, as opposed to my 4.15 percent estimate. There is not much difference in our average dividend yields.

CAPM Comparison

Q. Please describe the differences in the way that you conducted your CAPM analysis and the way that Ms. Pritz conducted hers?

A. The main differences between Ms. Pritz's CAPM analysis and mine are her use of a 20-year Treasury instrument for the risk free rate of return (as

opposed to my use of a 5-year instrument) and her upwardly adjusted market risk premium. In regard to her market risk premium, Ms. Pritz relied solely on an arithmetic mean average of the difference between 20-year Treasury returns and the historical returns of large company stocks from 1926 to 2008 to derive a market risk premium of 6.50 percent. She then added an additional 2.29 percent to arrive at her market risk premium of 8.79 percent.

Q. What does the 2.29 percent adjustment to Ms. Pritz's market risk premium represent?

A. On page 14 of her direct testimony, Ms. Pritz states that the 2.29 percent upward adjustment is the observed increase between yields on Baa/BBB-rated bonds and the yields on 30-year U.S. Treasury bonds since August 2008 when the credit markets began to deteriorate.

Q. Do you agree with the upward adjustment Ms. Pritz has made to the historical average return on the market obtained from Morningstar's 2009 SBBI Yearbook?

A. No I do not agree with her upward adjustment. On the one hand she has chosen a twenty-year treasury instrument to derive the historical market risk premium but then wants to adjust an 82 year average of market results upward based on the spread between a 30-year treasury

instrument and Baa/BBB-rated debt that only occurred over a brief period of time.

Q. Why has Ms. Pritz made her adjustment to the historical market risk premium obtained from Morningstar?

A. Ms. Pritz stated that the reason for it is because the CAPM is producing "illogical results" given the current economic environment.

Q. Do you agree with Ms. Pritz's rationale?

A. No. I believe that the CAPM is producing expected returns that are reflective of the current economic environment. I am unaware of any time during the late nineties or prior to the current recession that analysts, testifying before the Commission, made downward adjustments to the market risk premium in the CAPM because it was producing "illogical results" during a robust period of economic growth.

Q. What is the difference between Ms. Pritz's adjusted market risk premium and your recommended market risk premiums that relied on arithmetic and geometric means?

A. There is a 40 basis point difference between her higher unadjusted market risk premium of 6.50 percent (which is the arithmetic mean of historical returns on the market minus the historical yields on a 20-year Treasury instrument) and my arithmetic mean market risk premium of 6.10 percent.

The difference between her higher unadjusted market risk premium of 6.50 percent and my geometric mean market risk premium of 4.20 percent is 230 basis points.

Q. What financial instrument did Ms. Pritz use as a proxy for the risk free (i.e. r_f) rate in her CAPM model?

A. Ms. Pritz used the average yield on a 20-year U.S. Treasury instrument during February 2009, which was 3.83 percent over that period, as opposed to my 5-year treasury instrument yield of 2.41 percent.

Q. What is the difference in the average beta that you used in your CAPM models?

A. Ms. Pritz's sample of electric utilities had an average beta of 0.71 as opposed to my average beta of 0.73.

Q. Has there been a change in the betas since Ms. Pritz filed her direct testimony?

A. Yes. The current average beta for her sample is 0.70. However, I need to point out that this includes only nine of the electric utilities included in her sample since Value Line is currently unable to calculate a meaningful beta for Northwestern Corporation. This was one of the two utilities that I excluded from my sample.

Q. What is the difference between Ms. Pritz's CAPM estimate and your CAPM estimate?

A. Ms. Pritz's CAPM estimate, derived from her arithmetic mean model, of 10.10 percent is 327 basis points higher than the 6.83 percent cost of common equity derived from my arithmetic mean CAPM analysis and 464 basis points higher than my 5.46 percent cost of common equity derived from my geometric mean CAPM analysis.

Q. What expected return would Ms. Pritz's CAPM produce if her inputs were updated with her unadjusted market risk premium of 6.5 percent?

A. Updating Ms. Pritz's risk free rate of return to a more recent yield of 4.14 percent (the average for the month of September 2009) and a beta of 0.70 would produce an expected return of 8.69 percent, which is 131 basis points lower than the 10.10 percent figure presented in her testimony, and is 56 basis points lower than my recommended cost of common equity of 9.25 percent.

Final Cost of Equity Estimate

Q. How did Ms. Pritz arrive at her proposed 11.40 percent cost of common equity for UNSE?

A. Ms. Pritz averaged the results of her DCF, CAPM and risk premium analyses to arrive at her proposed 11.40 percent cost of common equity.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Ms. Pritz, Mr. Grant or any other witness for UNSE constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on UNSE?

A. Yes, it does.

Appendix 1

Qualifications of William A. Rigsby, CRRA

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Society of Utility and Regulatory Financial Analysts
38th Annual Financial Forum and CRRA Examination
Georgetown University Conference Center, Washington D.C.
Awarded the Certified Rate of Return Analyst designation
after successfully completing SURFA's CRRA examination.

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
Phoenix, Arizona
July 1991 – October 1994

Appendix 1

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Tucson Electric Power	E-01933A-04-0408	Rate Review
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase
Black Mountain Sewer Corporation	SW-02361A-05-0657	Rate Increase
Far West Water & Sewer Company	WS-03478A-05-0801	Rate Increase
Gold Canyon Sewer Company	SW-02519A-06-0015	Rate Increase
Arizona Public Service Company	E-01345A-05-0816	Rate Increase
Arizona-American Water Company	W-01303A-06-0014	Rate Increase
Arizona-American Water Company	W-01303A-05-0718	Transaction Approval
Arizona-American Water Company	W-01303A-05-0405	ACRM Filing
UNS Gas, Inc.	G-04204A-06-0463	Rate Increase
Arizona-American Water Company	W-01303A-07-0209	Rate Increase
Tucson Electric Power	E-01933A-07-0402	Rate Increase
Southwest Gas Corporation	G-01551A-07-0504	Rate Increase
Chaparral City Water Company	W-02113A-07-0551	Rate Increase
Arizona-American Water Company	W-01303A-08-0227 et al.	Rate Increase
Far West Water & Sewer Company	WS-03478A-08-0608	Interim Rate Increase
Johnson Utilities, LLC	WS-02987A-08-0180	Rate Increase
UNS Gas, Inc.	G-04204A-08-0571	Rate Increase
Arizona Water Company	W-01445A-08-0440	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Black Mountain Sewer Corporation	SW-02361A-08-0609	Rate Increase
Global Utilities	SW-02445A-09-0077 et al.	Rate Increase
Litchfield Park Service Company	SW-01428A-09-0104 et al.	Rate Increase

ATTACHMENT A

All the major utilities in the eastern region of the United States are reviewed in this Issue. Those serving the central region will be found in Issue 5. All of the western providers are covered in Issue 11.

During the second quarter, utility stocks significantly underperformed the major market averages. As other, more sensitive economic sectors rebounded strongly off bear-market lows, the utility group lagged a bit. The group's 9.1% quarterly return ranked toward the bottom of all industries, topping only the Telecommunications group. This came as little surprise however, as utility companies suffered considerably less during last year's broad market selloff, attributable to their more conservative, stable business models. Utilities historically rebound at a much slower pace.

Lower Demand for Electricity

During the first half of 2009, the demand for electricity declined roughly 4%, marking a rare occurrence for the generally stable industry. As a result, several utilities have scaled back their 2009 earnings outlooks to reflect lower usage.

Coal vs. Alternative Fuel Sources

Coal remains the most popular fuel source in the United States (responsible for roughly 50% of domestic power) due to its abundance and low cost. However, its share of total output has been on a downward trend. In fact, on a year-over-year basis, coal generation has declined over 10% in the United States. This can be attributed to stricter curbs on CO2 emissions, but more notably, the increased popularity in alternative energy sources, such as wind (up 29%) and solar power (up 3%). Government incentive programs coupled with public concern over environmental issues are the main drivers of this development. Long-term, we look for this trend to continue based primarily on a recently passed congressional bill. The bill requires 20% of electricity sales in 2021 to come from renewable resources. This in turn would create a cap and trade program to reduce greenhouse gas emissions by 17% below 2005 levels by 2020, and 83% by 2050.

INDUSTRY TIMELINESS: 66 (of 98)

Dividends

Utility dividends have continued to increase during the first half of 2009 supported by reduced dividend tax rates. Currently, the average yield among the utilities group is about 5%, more than double the median of all dividend-paying stocks under our coverage. Leaders in issue 1 include, *Pepco Holdings* (7.7%), *UIL Holdings* (6.8%), *Duke Energy* (6.4%), *Progress Energy* (6.4%), *TECO Energy* (6.2%) and *Con Edison* (6.0%).

The American Recovery and Reinvestment Act

In February 2009, Congress passed this act in an attempt to provide a stimulus to the struggling U.S. economy. Of the $787 billion included in the package, the Department of Energy (DOE) is responsible for implementing roughly $40 billion. Of the DOE total, $4.5 billion is alotted to the Office of Electricity Delivery and Energy Reliability (OE). These funds will be geared towards the modernization of the nation's energy and communication infrastructure. The OE is awarding 50% matching grants to utilities and other organizations that promote investments associated with this cause. We believe the majority of these grants will likely support the advancement of *Smart Grid* programs. This technology enables real time monitoring of energy usage and automated adaption of energy flow. Customers will be able to better monitor consumption, which will ultimately lead to reduced costs for utility companies. Over the past three months, several utilities in this issue have submitted applications to invest in *Smart Grid* technology, including Washington DC.-based *Pepco Holdings* ($142 million), North Carolina-based *Progress Energy* ($200 million), New York-based *Con Edison* ($172 million), and Connecticut-based *UIL Holdings* ($38 million).

Conclusion

During these challenging economic times, utility stocks are still sought after due to their relative stability and attractive dividend yields. With several stocks yielding over 7%, income-oriented investors should have little trouble finding appeal in this industry. All told, we believe this might be a good time to increase your portfolio's electric-utility exposure.

Michael Ratty

Composite Statistics: Electric Utility Industry

2005	2006	2007	2008	2009	2010		12-14
304.7	325.7	343.2	365.3	***355***	***375***	Revenues ($bill)	***440***
21.4	25.3	27.7	28.1	***27.5***	***30.5***	Net Profit ($bill)	***38.0***
29.1%	31.4%	33.2%	33.5%	***34.0%***	***34.0%***	Income Tax Rate	***34.0%***
4.6%	4.8%	6.1%	7.7%	***10.0%***	***7.0%***	AFUDC % to Net Profit	***6.0%***
54.8%	51.8%	51.0%	53.7%	***52.5%***	***51.5%***	Long-Term Debt Ratio	***50.0%***
44.0%	47.1%	47.9%	45.3%	***47.0%***	***47.5%***	Common Equity Ratio	***49.5%***
405.6	468.3	471.7	518.4	***505***	***535***	Total Capital ($bill)	***635***
426.0	491.9	509.6	559.1	***555***	***595***	Net Plant ($bill)	***710***
7.1%	7.0%	7.5%	7.0%	***6.5%***	***7.0%***	Return on Total Cap'l	***7.0%***
11.7%	11.2%	12.0%	11.7%	***10.5%***	***11.0%***	Return on Shr. Equity	***11.0%***
11.9%	11.4%	12.1%	11.8%	***10.5%***	***11.0%***	Return on Com Equity	***11.5%***
5.1%	5.6%	5.6%	5.0%	***4.5%***	***5.0%***	Retained to Com Eq	***5.5%***
57%	52%	54%	58%	***63%***	***59%***	All Div'ds to Net Prof	***66%***
16.1	14.8	17.0	15.4	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	***13.5***
.86	.80	.90	.93			Relative P/E Ratio	***.90***
3.5%	3.5%	3.2%	3.7%			Avg Ann'l Div'd Yield	***4.3%***

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2005	2006	2007
% Change Retail Sales (kwh)	+5.4	+1.3	+2.2
Average Indust. Use (mwh)	1568	1578	1571
Avg. Indust. Revs. per kwh (¢)	5.73	6.10	6.35
Regulated Cap. at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+1.2	+1.7	+.7
Fixed Charge Coverage (%)	253	265	289

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

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All of the major electric utilities located in the western region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 5.

We present our rankings of states' regulatory climates. There have been some changes since our last report on regulatory climates.

Electric utility stocks have not participated in the stock market's partial recovery in 2009. Even so, many issues are appealing for income-oriented investors.

INDUSTRY TIMELINESS: 64 (of 98)

Ranking The Regulators

From time to time, we run a list showing each state's regulatory climate, along with that of the District of Columbia and the Federal Energy Regulatory Commission (FERC). This is important because, even in states that have had partial deregulation of the electric utility industry, the power distribution function is still regulated by a state commission. Regulation is becoming more significant because many utilities have large capital projects under way or on the drawing board. Moreover, kilowatt-hour sales are declining in many regions due to the recession, and this lessens a utility's ability to earn its allowed return on equity. Most of the companies in this Issue have rate cases pending or have just concluded them. Finally, regulation can come into play even for utilities that don't have distribution operations in a particular state. For example, *Entergy* wants to spin off its nonregulated nuclear assets into a separate company but cannot do so until the commissions in New York and Vermont grant their permission.

In some states, the governor appoints the commissioners; in others, this is an elected office. But a state's regulatory climate entails more than just the commission. The executive, legislative, and judicial branches of the state government play a part and are considered in our rankings.

Note that seven states are excluded from the list below, either because of an absence of investor-owned electric utilities or because we do not cover any companies that have a significant presence in the state. The states are Alaska, Kentucky, Maine, Nebraska, Rhode Island, Tennessee, and Utah.

• *Above Average:* Alabama, California, Colorado, Florida, Idaho, Indiana, Massachusetts, Ohio, South Dakota, Wisconsin, FERC.

• *Average:* Arizona, Delaware, District of Columbia, Georgia, Hawaii, Iowa, Kansas, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, North Carolina, North Dakota, Oklahoma, Pennsylvania, South Carolina, Texas, Virginia, Washington, Wyoming.

• *Below Average:* Arkansas, Connecticut, Illinois, Maryland, New York, Oregon, Vermont, West Virginia.

Since we ran this list in May of this year, we have made four changes. We raised Michigan and New Hampshire from Below Average to Average; lowered Hawaii from Above Average to Average; and lowered Maryland from Average to Below Average. Michigan passed a law last year that will result in more timely rate relief for utilities. New Hampshire (served by a subsidiary of Northeast Utilities) has generally been providing reasonable regulatory treatment in recent years—a far cry from the time when Public Service of New Hampshire filed for bankruptcy protection. The utilities of Hawaiian Electric Industries are underearning their allowed ROEs due, in part, to regulatory lag. Maryland forced Constellation Energy to give back some money it would have kept as a result of a shift to market-based pricing, and has ruled that it had the grounds to review an asset sale, contrary to what Constellation contends.

Conclusion

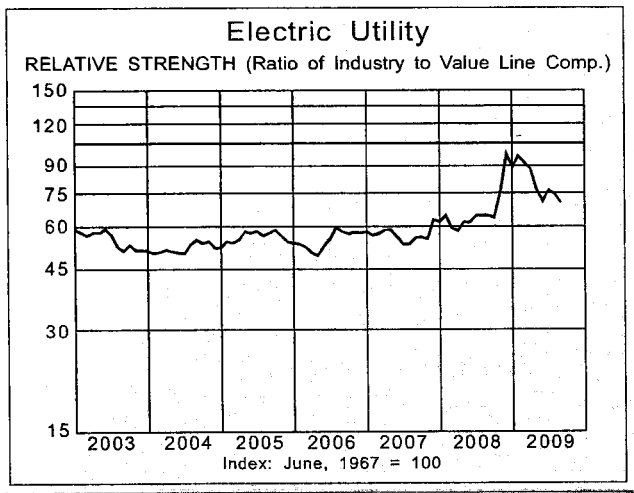
Electric utility stocks have not participated in the partial recovery that the market has made so far this year after the horrible showing in 2008. To date, the Value Line Composite Average is up over 25%, but the Value Line Utility Average has hardly budged. Thus, this group's valuation has become relatively more attractive. The industry's average yield of 5% is more than twice the market mean. Many of these equities offer attractive yields that are above the industry average, plus some dividend-growth potential. Investors should be cautious about most stocks with a well above-average yield, however, due to the possibility of a dividend cut. We show a split dividend at the top of the page if we believe that there is a chance of a reduction.

Paul E. Debbas, CFA

Composite Statistics: Electric Utility Industry

2005	2006	2007	2008	2009	2010		12-14
304.7	325.7	343.2	365.3	**335**	**355**	Revenues ($bill)	**420**
21.4	25.3	27.7	28.1	**27.0**	**30.0**	Net Profit ($bill)	**38.0**
29.1%	31.4%	33.2%	33.5%	**34.5%**	**34.0%**	Income Tax Rate	**34.5%**
4.6%	4.8%	6.1%	7.7%	**10.0%**	**7.0%**	AFUDC % to Net Profit	**6.0%**
54.8%	51.8%	51.0%	53.7%	**52.5%**	**52.0%**	Long-Term Debt Ratio	**50.0%**
44.0%	47.1%	47.9%	45.3%	**46.5%**	**47.5%**	Common Equity Ratio	**49.0%**
405.6	468.3	471.7	518.4	**510**	**535**	Total Capital ($bill)	**635**
426.0	491.9	509.6	559.1	**560**	**595**	Net Plant ($bill)	**700**
7.1%	7.0%	7.5%	7.0%	**6.5%**	**7.0%**	Return on Total Cap'l	**7.0%**
11.7%	11.2%	12.0%	11.7%	**10.5%**	**11.0%**	Return on Shr. Equity	**11.0%**
11.9%	11.4%	12.1%	11.8%	**10.5%**	**11.0%**	Return on Com Equity	**11.0%**
5.1%	5.6%	5.6%	5.0%	**4.5%**	**5.0%**	Retained to Com Eq	**5.0%**
57%	52%	54%	58%	**65%**	**60%**	All Div'ds to Net Prof	**56%**
16.1	14.8	17.0	15.4			Avg Ann'l P/E Ratio	**13.5**
.86	.80	.90	.92			Relative P/E Ratio	**.90**
3.5%	3.5%	3.2%	3.7%			Avg Ann'l Div'd Yield	**4.3%**

Bold figures are Value Line estimates



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All of the major electric utilities located in the western region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 5.

Oil prices have been extremely volatile for well over a year. We examine the effect that oil prices have on electric utilities.

Electric utilities are continuing to feel the effects of the recession.

Currently, there is no merger and acquisition activity in this industry.

The underperformance of this sector has made electric utility stocks relatively more attractive.

How Oil Prices Affect Utilities

Contrary to what some people believe, oil is not widely used to generate electricity in the United States. According to the federal government's Energy Information Association, in the past three years only 1% of the nation's electricity was generated from oil. In fact, the only investor-owned utilities that use oil to produce a significant proportion of their power are the three utilities that are part of *Hawaiian Electric Industries*, which used oil to generate 60% of its electricity in 2008. The most important fuel source is coal, at slightly under 50%. Natural gas and nuclear fuel each have around a 20% share.

Utilities that have gas and oil exploration and production subsidiaries stand to benefit from higher oil prices. *Black Hills Corporation* is one such company. However, the gas portion of its E&P business is far greater than the oil portion, so the effects of weak gas prices are outweighing the benefits of high (compared with the level in early 2009) oil prices.

The Recession Is Affecting Electric Sales

Although electric utilities are somewhat resistant to the state of the economy—sales to residential customers are influenced more by the weather than the economy—there is no doubt that the recession is hurting these companies. Some companies have seen their customer growth rates drop significantly from the levels experienced just a few years ago. This is especially true for *Pinnacle West*, *NV Energy*, and *UniSource Energy*, which operate in states hit hard by the housing slump.

INDUSTRY TIMELINESS: 57 (of 98)

Others are experiencing worse-than-expected sales. This was one reason why *Portland General Electric* sharply reduced its earnings expectation for 2009. *El Paso Electric* is another utility that has reduced its guidance as sales have fallen short of expectations.

Utilities were already facing a tough comparison for kilowatt-hour sales simply because 2008 was a leap year and thus had one extra day. Although this might seem trivial, it really does affect the year-to-year sales comparisons for utilities.

A Lack Of Merger And Acquisition Activity

Last month, Exelon terminated its hostile takeover bid for NRG Energy (an independent power producer that is covered in Issue 6) after its slate of nominees to NRG's board failed to win enough support. Accordingly, there is no current merger and acquisition activity in this industry that involves entire companies (as opposed to asset sales).

The credit crisis that began last September lessened many companies' ability to obtain capital at attractive terms. Although the crisis has become less severe since then, many utilities are still taking a cautious stance. Another factor is that obtaining regulatory approval for utility mergers and acquisitions is frequently lengthy and difficult. (The CEO of a utility that was involved in a proposed merger that fell through lamented that the time to close utility deals is measured in years, not months.) And this industry's track record in mergers and acquisitions is mixed. This is not to say that there won't be any merger announcements anytime soon, but we do not advise investors to purchase utility stocks based on the possibility of a deal. Some investors have held shares of *El Paso Electric* and CH Energy Group for many years, waiting for a takeover bid that has yet to occur.

Conclusion

The Value Line Composite Average is up 18% so far this year, but the Value Line Utility Average is down 1%. This divergent performance has made electric utility equities relatively more attractive. This group's average dividend yield, at about 5%, is more than twice the median of all dividend-paying stocks under our coverage. There are numerous stocks in this industry that offer a high, secure yield and good 3- to 5-year dividend-growth potential.

Paul E. Debbas, CFA

Composite Statistics: ELECTRIC UTILITY INDUSTRY

2005	2006	2007	2008	2009	2010		12-14
304.7	325.7	343.2	365.3	*355*	*375*	Revenues ($bill)	*440*
21.4	25.3	27.7	28.1	*27.5*	*30.5*	Net Profit ($bill)	*38.0*
29.1%	31.4%	33.2%	33.5%	*34.0%*	*34.0%*	Income Tax Rate	*34.0%*
4.6%	4.8%	6.1%	7.7%	*10.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
54.8%	51.8%	51.0%	53.7%	*52.5%*	*51.5%*	Long-Term Debt Ratio	*50.0%*
44.0%	47.1%	47.9%	45.3%	*47.0%*	*47.5%*	Common Equity Ratio	*49.5%*
405.6	468.3	471.7	518.4	*505*	*535*	Total Capital ($bill)	*635*
426.0	491.9	509.6	559.1	*555*	*595*	Net Plant ($bill)	*710*
7.1%	7.0%	7.5%	7.0%	*6.5%*	*7.0%*	Return on Total Cap'l	*7.0%*
11.7%	11.2%	12.0%	11.7%	*10.5%*	*11.0%*	Return on Shr. Equity	*11.0%*
11.9%	11.4%	12.1%	11.8%	*10.5%*	*11.0%*	Return on Com Equity	*11.5%*
5.1%	5.6%	5.6%	5.0%	*4.5%*	*5.0%*	Retained to Com Eq	*5.5%*
57%	52%	54%	58%	*63%*	*59%*	All Div'ds to Net Prof	*66%*
16.1	14.8	17.0	15.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.5*
.86	.80	.90	.93			Relative P/E Ratio	*.90*
3.5%	3.5%	3.2%	3.7%			Avg Ann'l Div'd Yield	*4.3%*

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2005	2006	2007
% Change Retail Sales (kwh)	+5.4	+1.3	+2.2
Average Indust. Use (mwh)	1568	1578	1571
Avg. Indust. Revs. per kwh (¢)	5.73	6.10	6.35
Capacity at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+1.2	+1.7	+.3
Fixed Charge Coverage (%)	254	270	291

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

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ALLETE NYSE-ALE

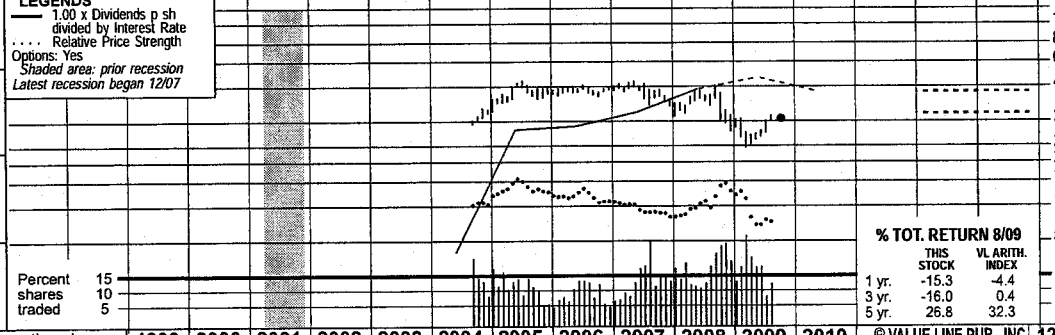
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
33.10	15.8	(Trailing: 13.4 Median: NMF)	0.92	5.4%	VALUE LINE

TIMELINESS 4 Lowered 5/29/09
SAFETY 2 New 10/1/04
TECHNICAL 4 Lowered 9/11/09
BETA .70 (1.00 = Market)

High:						37.5	51.7	49.3	51.3	49.0	34.5	
Low:						30.8	35.7	42.6	38.2	28.3	23.3	

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+35%)	12%
Low	35	(+5%)	7%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	1	0	0	0	1
Options	0	1	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	74	82	80
to Sell	77	61	60
Hld's(000)	17191	17770	19395

Percent shares traded 15 10 5

% TOT. RETURN 8/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-15.3	-4.4
3 yr.	-16.0	0.4
5 yr.	26.8	32.3

ALLETE, in its current configuration, began trading on September 21, 2004, the day after it spun off its automotive services business, ADESA (NYSE: KAR), to shareholders and effected a 1-for-3 reverse stock split. ALLETE shareholders received one share of ADESA for each ALLETE share held. Data for the "old" ALLETE are not shown because they are not comparable.

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
--	--	--	--	--	25.30	24.50	25.23	27.33	24.57	*21.30*	*21.25*	Revenues per sh	*20.50*
--	--	--	--	--	2.97	3.85	4.14	4.42	4.23	*3.55*	*4.00*	"Cash Flow" per sh	*4.50*
--	--	--	--	--	1.35	2.48	2.77	3.08	2.82	*1.95*	*2.30*	Earnings per sh A	*2.75*
--	--	--	--	--	.30	1.25	1.45	1.64	1.72	*1.76*	*1.80*	Div'd Decl'd per sh B ■ †	*1.92*
--	--	--	--	--	2.12	1.95	3.37	6.82	9.24	*8.70*	*8.70*	Cap'l Spending per sh	*6.75*
--	--	--	--	--	21.23	20.03	21.90	24.11	25.37	*25.65*	*26.30*	Book Value per sh C	*28.75*
--	--	--	--	--	29.70	30.10	30.40	30.80	32.60	*34.50*	*36.00*	Common Shs Outst'g D	*41.00*
--	--	--	--	--	25.2	17.9	16.5	14.8	13.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
--	--	--	--	--	1.33	.95	.89	.79	.86	*Value Line*		Relative P/E Ratio	*.95*
--	--	--	--	--	.9%	2.8%	3.2%	3.6%	4.4%	*estimates*		Avg Ann'l Div'd Yield	*4.9%*
--	--	--	--	--	751.4	737.4	767.1	841.7	801.0	*735*	*765*	Revenues ($mill)	*855*
--	--	--	--	--	38.5	68.0	77.3	87.6	82.5	*60.0*	*75.0*	Net Profit ($mill)	*105*
--	--	--	--	--	38.8%	28.4%	37.5%	34.8%	34.3%	*35.0%*	*36.0%*	Income Tax Rate	*35.0%*
--	--	--	--	--	1.8%	.4%	1.4%	6.6%	5.8%	*8.0%*	*7.0%*	AFUDC % to Net Profit	*4.0%*
--	--	--	--	--	38.2%	39.1%	35.1%	35.6%	41.6%	*44.5%*	*46.5%*	Long-Term Debt Ratio	*48.5%*
--	--	--	--	--	61.8%	60.9%	64.9%	64.4%	58.4%	*55.5%*	*53.5%*	Common Equity Ratio	*51.5%*
--	--	--	--	--	1020.7	990.6	1025.6	1153.5	1415.4	*1595*	*1765*	Total Capital ($mill)	*2325*
--	--	--	--	--	883.1	860.4	921.6	1104.5	1387.3	*1625*	*1875*	Net Plant ($mill)	*2325*
--	--	--	--	--	5.1%	8.0%	8.6%	8.6%	6.7%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
--	--	--	--	--	6.1%	11.3%	11.6%	11.8%	10.0%	*7.0%*	*8.0%*	Return on Shr. Equity	*9.0%*
--	--	--	--	--	6.1%	11.3%	11.6%	11.8%	10.0%	*7.0%*	*8.0%*	Return on Com Equity E	*9.0%*
--	--	--	--	--	4.7%	5.2%	5.0%	5.8%	3.9%	*.5%*	*1.5%*	Retained to Com Eq	*2.5%*
--	--	--	--	--	23%	54%	57%	51%	61%	*96%*	*83%*	All Div'ds to Net Prof	*74%*

CAPITAL STRUCTURE as of 6/30/09
Total Debt $646.2 mill. **Due in 5 Yrs** $109.1 mill.
LT Debt $627.2 mill. **LT Interest** $30.7 mill.
(LT interest earned: 5.1x)
Leases, Uncapitalized Annual rentals $8.3 mill.

Pension Assets-12/08 $273.7 mill. **Oblig.** $440.4 mill.

Pfd Stock None

Common Stock 34,100,096 shs.

MARKET CAP: $1.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+1.1	+.3	+1.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.15	4.82	4.73
Capacity at Peak (Mw)	1761	1701	1757
Peak Load, Winter (Mw)	1586	1614	1582
Annual Load Factor (%)	80.0	80.0	80.0
% Change Customers (avg.)	+1.3	+1.3	.7
Fixed Charge Cov. (%)	503	503	438

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	--	--	-3.5%
"Cash Flow"	--	--	1.0%
Earnings	--	--	-1.0%
Dividends	--	--	3.0%
Book Value	--	--	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2006	192.5	178.3	199.1	197.2	767.1
2007	205.3	223.3	200.8	212.3	841.7
2008	213.4	189.8	201.7	196.1	801.0
2009	199.6	164.7	*185*	*185.7*	*735*
2010	*205*	*175*	*195*	*190*	*765*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2006	.68	.49	.78	.82	2.77
2007	.93	.80	.58	.77	3.08
2008	.82	.37	.85	.78	2.82
2009	.55	.29	*.51*	*.60*	*1.95*
2010	*.70*	*.35*	*.60*	*.65*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.30	.315	.315	.315	1.25
2006	.3625	.3625	.3625	.3625	1.45
2007	.41	.41	.41	.41	1.64
2008	.43	.43	.43	.43	1.72
2009	.44	.44	.44		

BUSINESS: ALLETE, Inc. is the parent company of Minnesota Power, which supplies electricity to 142,000 customers in northeastern Minn., and Superior Water, Light & Power in northwestern Wisc. Electric revenue mix, '08: taconite mining/processing, 31%; paper/wood products, 11%; other industrial, 2%; residential, 12%; commercial, 12%; wholesale, 23% other, 9%. Has real estate operation in Florida. Discontinued water-utility ops. in '01. Spun off automotive remarketing ops. in '04. Generating sources, '08: coal & lignite, 65%; hydro, 4%; purchased, 31%. '08 depr. rate: 2.5%. Has 1,500 employees. Chairman & CEO: Donald J. Shippar. President: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's utility subsidiary had a disappointing regulatory outcome this year . . . Although the final order of the Minnesota Public Utilities Commission (MPUC) won't come until the fourth quarter, indications are that it will be far less than the interim rate increase of $41 million that Minnesota Power was granted last year. Accordingly, the utility is taking reserves for the refunding of previously collected revenues to customers. This amounted to $0.34 a share in the first half of 2009 and might total as much as $0.10 a share in the second half of the year. What's more, after the company and some intervenors filed for reconsideration, the MPUC actually trimmed the expected rate increase (originally $21.1 million) to $20.4 million.

. . . so Minnesota Power will file a rate case in late 2009. An interim tariff hike will occur in early 2010, with the final order due in the fourth quarter. The utility has not stated how much it plans to request.

Earnings are headed sharply lower this year. The revenue refunds are the main reason. ALLETE's real estate operation is likely to contribute nothing to the bottom line in 2009, compared with a modest profit a year ago. Finally, interest expense and average shares outstanding are up because the company needs to finance part of its large capital budget. We have lowered our earnings estimate from $2.10 a share to $1.95.

We look for a partial bottom-line recovery in 2010. We assume that Minnesota Power gets some interim rate relief early in the year. Our earnings estimate is $2.30 a share, which we consider on the conservative side. ALLETE has not yet given earnings guidance for 2010, but expects to do so when it reports third-quarter results this fall. If the company's profit expectation for next year is at least as high as our estimate, then we believe that the board of directors will boost the dividend in 2010.

This stock's yield is slightly above the utility average. On the other hand, total return potential to 2012-2014 is somewhat below average, even with our projection of continued dividend growth over that time. Meanwhile, the stock is untimely.

Paul E. Debbas, CFA *September 25, 2009*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢ net; '05, ($1.84); gain (losses) on discontinued operations: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next earnings report due late Oct. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '08: $7.65/sh. (D) In mill. (E) Rate base: Original cost deprec. Rate allowed on com. eq. in '09: 10.74%; earned on avg. com. eq., '08: 10.7%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	65

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BLACK HILLS CORP. NYSE-BKH

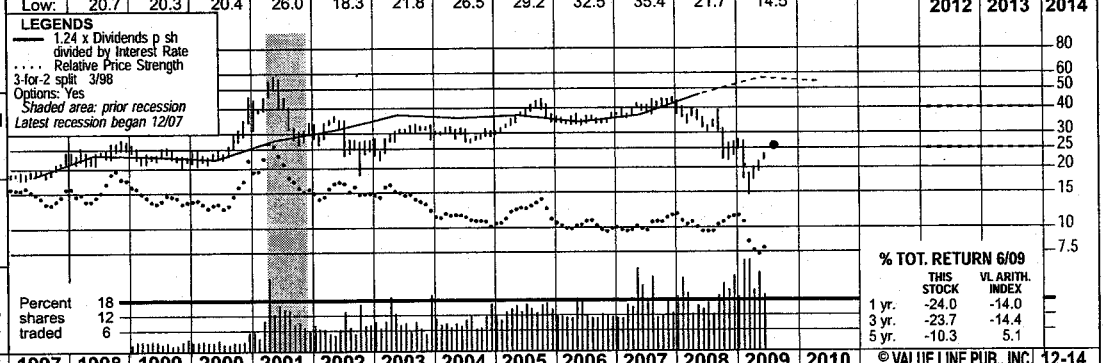
RECENT PRICE 25.79 | P/E RATIO 10.7 (Trailing: 31.8 Median: 15.0) | RELATIVE P/E RATIO 0.66 | DIV'D YLD 5.6% | VALUE LINE

TIMELINESS 3 Raised 11/21/08
SAFETY 3 Lowered 8/15/03
TECHNICAL 4 Lowered 7/24/09
BETA .85 (1.00 = Market)

High:	27.9	26.5	46.1	58.5	36.9	33.5	32.5	44.6	37.9	45.4	44.0	27.8
Low:	20.7	20.3	20.4	26.0	18.3	21.8	26.5	29.2	32.5	35.4	21.7	14.5

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.24 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 3/98
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+55%)	15%
Low	25	(-5%)	5%

Insider Decisions

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

Institutional Decisions

	3Q2008	4Q2008	1Q2009
to Buy	66	73	70
to Sell	83	80	74
Hld's(000)	26962	27542	26204

% TOT. RETURN 6/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-24.0	-14.0
3 yr.	-23.7	-14.4
5 yr.	-10.3	5.1

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
6.51	6.74	6.92	7.50	14.45	31.48	37.05	69.69	57.96	15.74	35.17	34.54	41.97	19.69	18.41	26.03	*40.50*	*42.40*	Revenues per sh	*48.25*
1.82	1.92	2.09	2.45	2.52	2.72	2.88	3.68	5.27	4.93	4.26	4.46	4.81	5.04	5.29	2.95	*5.90*	*5.95*	"Cash Flow" per sh	*7.50*
1.11	1.11	1.19	1.40	1.49	1.60	1.70	2.37	3.42	2.33	1.84	1.74	2.11	2.21	2.68	.18	*2.40*	*2.20*	Earnings per sh A	*3.00*
.85	.88	.89	.92	.95	1.00	1.04	1.08	1.12	1.16	1.20	1.24	1.28	1.32	1.37	1.40	*1.42*	*1.44*	Div'd Decl'd per sh B ■ †	*1.56*
1.88	4.78	2.40	1.13	.98	1.18	4.89	5.79	14.07	8.65	2.80	2.80	4.18	9.24	6.92	8.51	*7.35*	*5.50*	Cap'l Spending per sh	*5.75*
7.85	8.13	8.43	8.91	9.46	9.58	10.14	11.95	18.95	19.66	21.72	22.43	22.29	23.68	25.66	27.19	*27.80*	*28.55*	Book Value per sh C	*32.00*
21.40	21.58	21.64	21.68	21.70	21.58	21.37	23.30	26.89	26.93	32.30	32.48	33.16	33.37	37.80	38.64	*39.00*	*39.25*	Common Shs Outst'g D	*40.00*
15.3	12.4	13.1	11.9	13.0	14.9	13.6	10.9	11.4	12.5	15.9	17.1	17.3	15.8	15.0	NMF	*Bold figures are*		Avg Ann'l P/E Ratio	*11.5*
.90	.81	.88	.75	.75	.77	.78	.71	.58	.68	.91	.90	.92	.85	.80	NMF	*Value Line*		Relative P/E Ratio	*.75*
5.0%	6.4%	5.8%	5.5%	4.9%	4.2%	4.5%	4.2%	2.9%	4.0%	4.1%	4.2%	3.5%	3.8%	3.4%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*

CAPITAL STRUCTURE as of 3/31/09
Total Debt $983.1 mill. **Due in 5 Yrs** $745.1 mill.
LT Debt $471.2 mill. **LT Interest** $31.6 mill.
(Interest not earned.)
Leases, Uncapitalized Annual rentals $3.7 mill.

Pension Assets-12/08 $136.9 mill. **Oblig.** $242.6 mill.
Pfd Stock None

Common Stock 38,798,483 shs.
as of 4/30/09

MARKET CAP: $1.0 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
791.9	1623.8	1558.6	423.9	1136.1	1121.7	1391.6	656.9	695.9	1005.8	*1580*	*1665*	Revenues ($mill)	*1925*
36.5	52.8	88.1	63.2	57.1	57.2	70.3	74.0	100.1	6.8	*95.0*	*90.0*	Net Profit ($mill)	*125*
29.8%	36.5%	36.5%	31.9%	34.4%	31.8%	33.8%	31.3%	31.3%	33.1%	*30.0%*	*33.0%*	Income Tax Rate	*33.0%*
3.3%	3.8%	8.5%	18.2%	.7%	.3%	1.0%	9.7%	14.8%	NMF	*13.0%*	*9.0%*	AFUDC % to Net Profit	*3.0%*
42.6%	52.1%	44.7%	53.6%	55.0%	49.9%	47.6%	44.3%	36.8%	32.3%	*44.5%*	*46.5%*	Long-Term Debt Ratio	*41.0%*
57.4%	47.2%	54.7%	45.9%	44.5%	49.6%	52.4%	55.7%	63.2%	67.7%	*55.5%*	*53.5%*	Common Equity Ratio	*59.0%*
377.3	589.4	931.0	1154.0	1578.2	1469.3	1409.1	1418.4	1534.2	1551.8	*1955*	*2085*	Total Capital ($mill)	*2150*
464.2	794.3	1238.2	1476.3	1442.4	1445.7	1435.4	1646.4	1823.5	2022.2	*2175*	*2245*	Net Plant ($mill)	*2400*
11.4%	10.6%	10.6%	6.6%	4.8%	5.3%	6.6%	6.8%	7.9%	1.6%	*6.0%*	*6.0%*	Return on Total Cap'l	*7.5%*
16.8%	18.7%	17.1%	11.8%	8.0%	7.8%	9.5%	9.4%	10.3%	.7%	*8.5%*	*8.0%*	Return on Shr. Equity	*9.5%*
16.8%	19.0%	17.2%	11.9%	8.1%	7.8%	9.5%	9.4%	10.3%	.7%	*8.5%*	*8.0%*	Return on Com Equity E	*9.5%*
6.4%	10.5%	11.6%	6.0%	2.8%	2.3%	3.8%	3.8%	5.1%	NMF	*3.5%*	*3.0%*	Retained to Com Eq	*5.0%*
62%	45%	33%	50%	65%	71%	60%	59%	50%	NMF	*58%*	*64%*	All Div'ds to Net Prof	*50%*

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+3.1	+2.8	+34.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.78	5.06	5.97
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	570	593	881
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+1.7	+87.6
Fixed Charge Cov. (%)	275	352	238

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	2.0%	-10.0%	*14.5%*
"Cash Flow"	5.5%	-1.5%	*9.0%*
Earnings	1.0%	-8.0%	*10.0%*
Dividends	3.5%	3.5%	*2.5%*
Book Value	10.5%	5.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	171.9	153.8	157.6	173.6	656.9
2007	186.5	163.9	162.4	183.1	695.9
2008	152.8	153.3	291.9	407.8	1005.8
2009	437.9	*350*	*360*	*432.1*	*1580*
2010	*460*	*370*	*380*	*455*	*1665*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.55	.37	.66	.62	2.21
2007	.91	.66	.46	.65	2.68
2008	.31	.34	.51	d.98	.18
2009	.94	*.46*	*.50*	*.50*	*2.40*
2010	*.60*	*.50*	*.55*	*.55*	*2.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.32	.32	.32	.32	1.28
2006	.33	.33	.33	.33	1.32
2007	.34	.34	.34	.35	1.37
2008	.35	.35	.35	.35	1.40
2009	.355	.355			

BUSINESS: Black Hills Corporation is a holding company for utilities that serve 202,000 electric customers in CO, SD, WY, and MT, and 557,000 gas customers in NE, IA, KS, CO, and WY. Electric rev. breakdown, '08: res'l, 26%; comm'l, 33%; ind'l, 11%; wholesale, 25%; other, 5%. Generating sources, '08: coal, 44%; oil & gas, 1%; purchased, 55%. Mines coal & has an oil & gas E&P business. Acq'd Wickford Energy Mktg. 7/97; Mallon Resources 3/03; Cheyenne Light 1/05; utility ops. from Aquila 7/08. Discont. telecom in '05; oil mktg. in '06. Fuel costs: 45% of revs. '08 depr. rate: 4.0%. Has about 2,200 empls. Chairman, Pres. & CEO: David R. Emery. Inc.: SD. Address: P.O. Box 1400, 625 Ninth St., Rapid City, SD 57709. Tel.: 605-721-1700. Internet: www.blackhillscorp.com.

We have raised our 2009 earnings estimate for Black Hills by $0.75 a share, to $2.40. In the March quarter, earnings benefited from $0.25 a share of income from mark-to-market accounting gains associated with an interest rate swap. Also, the company recorded a $3.8 million tax benefit in the period. Finally, the nonutility operations fared better than we expected. We'll continue to include any mark-to-market gains or losses in our presentation, but given their unpredictability, we have not factored any of these in our estimates.

Due to the unusually tough comparison, we now believe that share earnings will decline in 2010, despite the fact that we boosted our estimate from $1.95 to $2.20.

The company is building a coal-fired plant. Black Hills Power will own 75% of the Wygen Unit III, a 110-megawatt facility. The company's share of the cost is an estimated $191 million. The plant should come on line in June of 2010. The utility intends to file rate cases this fall, so that new tariffs can take effect when Wygen III begins commercial operation.

The utility was granted a gas rate increase in Iowa. The rate hike was $10.4 million (5.8%), based on a return of 10.1% on a common-equity ratio of 51.4%. New tariffs went into effect at the end of July.

Black Hills has repaid a bridge loan that it took on in 2008 to buy some utility properties. But this entailed the issuance of $250 million of five-year notes at a lofty interest rate of 9%. Additional debt financing is likely by yearend to help fund the company's capital budget. Even with these additional borrowings, the common-equity ratio will remain healthy.

Black Hills needs more generating capacity in Colorado. The utility was granted permission to build two 100-mw gas-fired units. It will get additional capacity through a competitive bidding process.

This stock has risen more than 30% in price since our May report due likely in part to increased interest by value investors. Even after this advance, the stock offers a yield that is somewhat above the utility mean. Total return potential to 2012-2014 is below average for a utility, however.

Paul E. Debbas, CFA *August 7, 2009*

(A) Dil. EPS. Excl. nonrec. losses: '05, 99¢; '08, $1.55; '09, 28¢; gains (losses) on disc. ops.: '03, 30¢; '04, 2¢; '05, (7¢); '06, 21¢; '07, (4¢). '08, $4.12. '06 EPS don't add due to rounding. Next egs. report due early Nov. (B) Div'ds histor. paid in early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd chgs. In '08: $13.16/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in SD in '99: none specified; earned on avg. com. eq., '08: .7%. Regul. Climate: Above Avg.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	45

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CH ENERGY GROUP NYSE-CHG

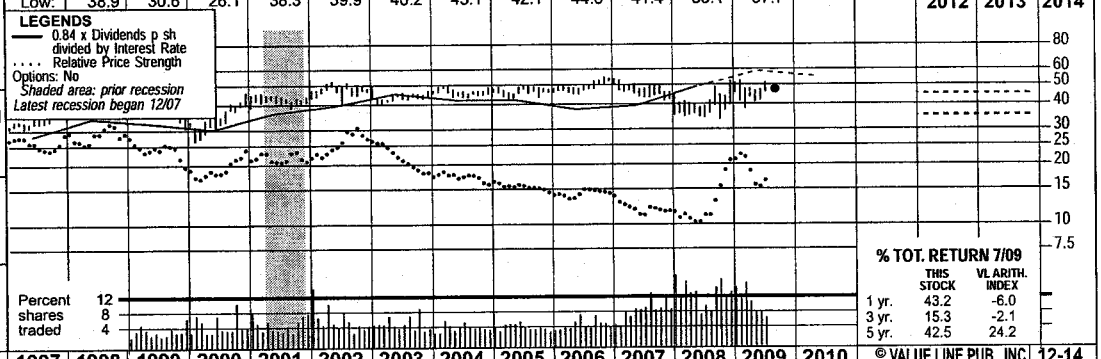
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
47.55	22.2	(Trailing: 21.0 Median: 17.0)	1.40	4.5%	VALUE LINE

TIMELINESS 3 Lowered 7/10/09
SAFETY 1 Raised 12/7/01
TECHNICAL 4 Raised 8/28/09
BETA .65 (1.00 = Market)

High:	47.1	45.0	46.3	45.9	52.4	49.7	49.6	50.2	54.9	53.8	52.4	52.7
Low:	38.9	30.6	26.1	38.3	39.9	40.2	43.1	42.1	44.6	41.4	33.4	37.7

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 0.84 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: No
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(-5%)	3%
Low	35	(-25%)	-2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
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	0	0	0	0	0	0	0

Institutional Decisions

	3Q2008	4Q2008	1Q2009
to Buy	40	69	75
to Sell	47	50	46
Hld's(000)	8521	8358	8543

% TOT. RETURN 7/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	43.2	-6.0
3 yr.	15.3	-2.1
5 yr.	42.5	24.2

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
30.52	29.91	29.28	29.28	30.11	29.86	30.95	45.83	44.52	43.29	51.18	50.22	61.70	63.03	75.93	84.45	*79.10*	*87.00*	Revenues per sh	*100.00*
5.23	5.25	5.33	5.69	5.80	5.83	5.92	6.49	5.50	4.18	5.02	4.89	5.11	4.83	4.98	4.65	*4.80*	*5.20*	"Cash Flow" per sh	*6.15*
2.68	2.68	2.74	2.99	2.97	2.90	2.88	3.05	3.11	2.12	2.78	2.69	2.81	2.56	2.70	2.22	*2.25*	*2.50*	Earnings per sh A	*3.00*
2.05	2.08	2.10	2.12	2.14	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	*2.16*	*2.16*	Div'd Decl'd per sh B ■ †	*2.16*
3.13	3.37	2.87	2.84	2.54	2.71	2.76	3.58	4.14	4.50	3.79	3.98	4.05	4.76	5.37	5.33	*6.30*	*5.70*	Cap'l Spending per sh	*5.65*
24.65	25.33	25.96	26.87	27.61	28.00	28.73	29.38	30.33	30.31	30.80	31.31	31.97	32.54	33.19	33.17	*34.55*	*34.95*	Book Value per sh C	*36.45*
16.95	17.24	17.50	17.56	17.28	16.86	16.86	16.36	16.36	16.06	15.76	15.76	15.76	15.76	15.76	15.78	*15.80*	*15.80*	Common Shs Outst'g D	*16.00*
12.2	10.0	10.2	10.1	11.5	14.6	13.5	11.4	13.6	22.6	15.7	17.2	16.5	19.1	17.5	17.9	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.72	.66	.68	.63	.66	.76	.77	.74	.70	1.23	.90	.91	.88	1.03	.93	1.09	*Value Line*		Relative P/E Ratio	*.90*
6.3%	7.8%	7.5%	7.0%	6.3%	5.1%	5.6%	6.2%	5.1%	4.5%	4.9%	4.7%	4.7%	4.4%	4.6%	5.4%	*estimates*		Avg Ann'l Div'd Yield	*5.3%*

CAPITAL STRUCTURE as of 6/30/09
Total Debt $463.8 mill. **Due in 5 Yrs** $110.0 mill.
LT Debt $463.8 mill. **LT Interest** $20.0 mill.
(LT interest earned: 3.8x)
Leases, Uncapitalized Annual rentals $3.2 mill.
Pension Assets-12/08 $261.3 mill. **Oblig.** $423.5 mill.
Pfd Stock $21.0 mill. **Pfd Div'd** $1.0 mill.
210,300 shs. 4½%-4.96% cum., $100 par, redeemable at $101-$107/sh.

Common Stock 15,790,053 shs.
as of 7/31/09
MARKET CAP: $750 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
521.9	749.9	728.4	695.5	806.7	791.5	972.5	993.4	1196.8	1332.9	*1250*	*1375*	Revenues ($mill)	*1600*
51.8	54.2	54.1	36.6	45.4	43.4	45.3	41.4	43.6	36.1	*35.5*	*39.5*	Net Profit ($mill)	*48.0*
35.8%	41.4%	--	36.6%	40.1%	41.9%	36.3%	36.3%	33.5%	37.6%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
.8%	1.4%	1.4%	2.3%	1.6%	.9%	.9%	1.5%	2.5%	2.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
38.3%	37.4%	28.1%	34.1%	35.5%	38.3%	39.6%	38.8%	42.6%	43.2%	*47.0%*	*47.0%*	Long-Term Debt Ratio	*49.5%*
55.3%	56.1%	64.6%	61.6%	61.8%	59.1%	58.0%	58.8%	55.2%	54.6%	*51.0%*	*51.0%*	Common Equity Ratio	*48.5%*
875.9	857.1	768.5	790.3	785.3	834.4	868.7	871.8	948.1	958.5	*990*	*970*	Total Capital ($mill)	*1050*
921.4	930.9	561.8	601.7	707.5	745.1	779.5	827.1	891.3	945.9	*950*	*1000*	Net Plant ($mill)	*1100*
7.3%	7.7%	8.1%	5.4%	6.5%	5.9%	6.0%	5.7%	5.6%	4.8%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
9.6%	10.1%	9.8%	7.0%	9.0%	8.4%	8.6%	7.7%	8.0%	6.6%	*6.5%*	*7.0%*	Return on Shr. Equity	*8.0%*
10.0%	10.6%	10.2%	7.1%	9.1%	8.6%	8.8%	7.9%	8.1%	6.7%	*6.5%*	*7.0%*	Return on Com Equity E	*8.0%*
2.5%	3.1%	3.1%	NMF	2.0%	1.7%	2.0%	1.2%	1.6%	.4%	*.5%*	*1.0%*	Retained to Com Eq	*2.0%*
77%	73%	71%	102%	78%	81%	77%	85%	80%	95%	*96%*	*86%*	All Div'ds to Net Prof	*73%*

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-4.2	+2.4	+2.5
Avg. Indust. Use (MWH)	1377	1108	1090
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1295	1185	1187
Peak Load, Summer (Mw)	1295	1185	1187
Annual Load Factor (%)	50.0	56.0	55.0
% Change Customers (avg.)	+.9	+1.0	+1.0
Fixed Charge Cov. (%)	328	306	282

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	9.5%	10.0%	*5.0%*
"Cash Flow"	-2.0%	-0.5%	*4.0%*
Earnings	-1.5%	-1.5%	*3.0%*
Dividends	--	--	*Nil*
Book Value	2.0%	1.5%	*1.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	317.2	213.9	239.8	222.5	993.4
2007	343.4	271.0	260.1	322.3	1196.8
2008	409.8	313.6	300.8	308.7	1332.9
2009	378.4	200.2	*320*	*351.4*	*1250*
2010	*380*	*315*	*325*	*355*	*1375*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.16	.26	.55	.60	2.56
2007	1.37	.33	.27	.73	2.70
2008	1.22	.11	.18	.71	2.22
2009	1.46	d.09	*.35*	*.53*	*2.25*
2010	*1.35*	*.25*	*.36*	*.54*	*2.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.54	.54	.54	.54	2.16
2006	.54	.54	.54	.54	2.16
2007	.54	.54	.54	.54	2.16
2008	.54	.54	.54	.54	2.16
2009	.54	.54	.54		

BUSINESS: CH Energy Group, Inc. is a holding company for Central Hudson Gas & Electric, which provides electricity and gas in the Mid-Hudson Valley region of New York State (75% of '08 income). Customers: 300,000 electric, 74,000 gas. Griffith Energy provides gas, oil, electricity, & propane to over 111,000 customers in Northeast (12% of '08 income). Investments were 13% of '08 income. Electric revenue breakdown, '08: residential, 48%; commercial, 28%; industrial, 7%; other, 17%. Generating sources, '08: hydro, 2%; purchased, 98%. Fuel costs: 70% of revenues. '08 reported depreciation rate (utility): 2.8%. Chairman, President & CEO: Steven V. Lant. Inc.: NY. Address: 284 South Ave., Poughkeepsie, NY 12601-4879. Tel.: 845-452-2000. Internet: www.chenergy.com.

CH Energy Group's share earnings performance slipped into the red in the June interim. A revenue gap was to blame for most of the lackluster showing as the rate plan that recently expired did not counter economic headwinds. Consumer conservation and rising uncollectible accounts owing to the recession continue to weigh on the bottom line. Thus, we have trimmed our 2009 share earnings estimate by $0.30, to $2.25.

A new rate agreement went into effect on July 1st. The plans grants a 47% common equity ratio, increased from 45%, and moves up the allowed return on equity from 9.6% to 10%. This may prove to be a challenge to this regional electricity and gas provider as the public service commission (PSC) rejected several large expenses. First, liability insurance for directors and officers and, secondly, variable pay for management were not recognized. On top of that, the PSC implied a $3 million reduction for austerity measures. CHG may be hard-pressed to wring out further cost savings as it has trimmed expense levels in order to help offset slow and nonpaying accounts.

CH Energy has filed a new rate case for the period beginning July 1, 2010. The utility is seeking to increase revenues for delivered electricity by $15.2 million and gas by $3.9 million. Upgrades to its energy grid system, compliance costs, and rising property taxes have necessitated the modest request. CH has built expectations with its request to attempt cost containment, especially of its pension obligations and post-retirement benefits, that should garner close to $15 million in annual savings. But the outcome of the proposed rate increase will not be determined until next June, and the uncertainty of unemployment levels and general economic health may still cause some unpredictability.

Investors ought to stay on the sidelines for now. Most accounts are drawn to the utility sector thanks to above-average dividends. CHG's payout, however, has been stagnant for years and offers an on-par yield. Relative stock price performance in the year ahead is average, and the 3- to 5-year outlook appears negligible since CHG currently trades above our Target Price Range.

Mary Beth Wiedenkeller *August 28, 2009*

(A) Diluted earnings. Excl. nonrecurring gains: '02, 12¢; '06, 17¢; gain from discontinued operation: '02, 29¢. '05 & '06 earnings don't total due to rounding. Next earnings report due late October. (B) Div'ds historically paid in early Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '08: $420.5 mill., $26.65/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '06: 9.6%; earned on avg. com. eq., '07: 8.2%. Regulatory Climate: Below Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	90

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EMPIRE DISTRICT NYSE-EDE

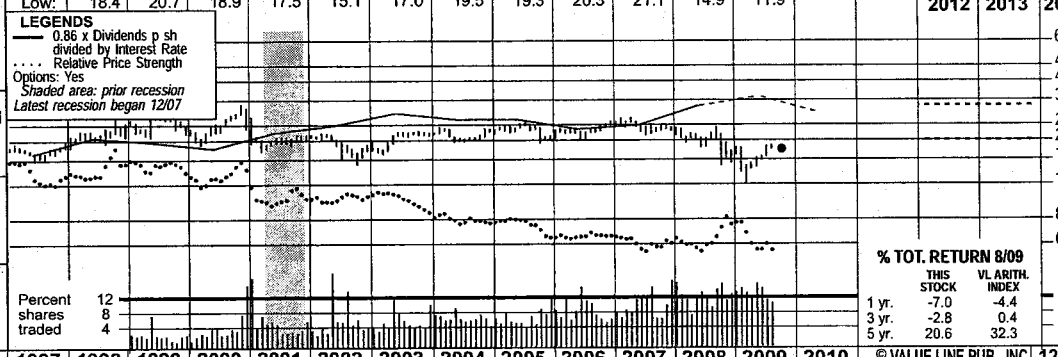
RECENT PRICE 18.09 | P/E RATIO 12.2 (Trailing: 13.3 Median: 20.0) | RELATIVE P/E RATIO 0.71 | DIV'D YLD 7.1% | VALUE LINE

TIMELINESS 3 Lowered 8/10/07
SAFETY 3 Lowered 10/4/02
TECHNICAL 3 Raised 9/18/09
BETA .75 (1.00 = Market)

High:	26.1	26.8	30.8	26.6	22.0	22.5	23.5	25.0	25.1	26.1	23.5	19.0
Low:	18.4	20.7	18.9	17.5	15.1	17.0	19.5	19.3	20.3	21.1	14.9	11.9

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 0.86 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+65%)	18%
Low	20	(+10%)	9%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	2	0	0
to Sell	0	0	0	0	0	0	0	0	2

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	49	67	56
to Sell	55	43	48
Hld's(000)	14026	13650	13254

Percent shares traded 12 8 4

% TOT. RETURN 8/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-7.0	-4.4
3 yr.	-2.8	0.4
5 yr.	20.6	32.3

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
12.41	12.75	12.67	12.53	12.83	14.02	13.94	14.78	13.37	13.56	13.03	12.67	14.80	13.67	14.59	15.25	14.20	14.15	Revenues per sh	15.75
2.49	2.62	2.52	2.67	2.67	2.97	2.89	3.12	2.19	2.43	2.48	2.22	2.45	2.75	2.69	2.91	2.95	3.05	"Cash Flow" per sh	3.50
1.16	1.32	1.18	1.23	1.29	1.53	1.13	1.35	.59	1.19	1.29	.86	.92	1.41	1.09	1.17	1.50	1.55	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	1.28	1.28	1.28	1.28	1.28	1.28	Div'd Decl'd per sh B ■ †	1.35
3.27	5.14	3.34	3.79	3.38	3.03	4.14	7.61	4.02	3.43	2.65	1.64	2.83	3.97	5.46	6.28	4.70	3.00	Cap'l Spending per sh	2.50
12.37	12.47	12.69	12.96	13.06	13.43	13.48	13.65	13.58	14.59	15.17	14.76	15.08	15.49	16.04	15.56	15.80	16.30	Book Value per sh C	17.50
13.57	13.94	15.22	16.44	16.78	17.11	17.37	17.60	19.76	22.57	24.98	25.70	26.08	30.25	33.61	33.98	38.00	40.25	Common Shs Outst'g D	41.00
19.6	13.3	14.9	14.8	13.9	14.0	21.7	17.7	33.9	16.2	15.8	24.8	24.5	15.9	21.7	17.3	Bold figures are		Avg Ann'l P/E Ratio	14.0
1.16	.87	1.00	.93	.80	.73	1.24	1.15	1.74	.88	.90	1.31	1.30	.86	1.15	1.06	Value Line		Relative P/E Ratio	.95
5.6%	7.3%	7.3%	7.0%	7.1%	6.0%	5.2%	5.4%	6.4%	6.6%	6.3%	6.0%	5.7%	5.7%	5.4%	6.3%	estimates		Avg Ann'l Div'd Yield	5.5%
						242.2	260.0	264.3	305.9	325.5	325.5	386.2	413.5	490.2	518.2	540	570	Revenues ($mill)	650
						22.2	23.6	10.4	25.5	29.5	21.8	23.8	39.9	33.2	39.7	52.0	61.0	Net Profit ($mill)	75.0
						41.9%	32.7%	--	34.3%	34.5%	34.1%	33.4%	35.4%	30.3%	32.5%	34.0%	35.5%	Income Tax Rate	35.5%
						5.4%	24.5%	34.7%	2.2%	1.0%	1.0%	2.4%	10.7%	23.1%	31.5%	28.0%	12.0%	AFUDC % to Net Profit	3.0%
						59.6%	57.6%	57.2%	55.5%	52.0%	51.3%	51.0%	49.7%	50.1%	53.6%	54.0%	53.5%	Long-Term Debt Ratio	51.0%
						40.4%	42.4%	42.8%	44.5%	48.0%	48.7%	49.0%	50.3%	49.9%	46.4%	46.0%	46.5%	Common Equity Ratio	49.0%
						580.0	565.8	626.9	740.3	789.2	779.1	803.3	931.0	1081.1	1140.4	1305	1410	Total Capital ($mill)	1475
						616.0	720.3	750.5	794.1	833.9	857.0	896.0	1031.0	1178.9	1342.8	1460	1520	Net Plant ($mill)	1600
						5.5%	6.5%	4.0%	5.4%	5.7%	4.7%	4.7%	5.9%	4.7%	5.2%	5.5%	6.0%	Return on Total Cap'l	7.0%
						9.5%	9.8%	3.9%	7.8%	7.8%	5.8%	6.0%	8.5%	6.2%	7.5%	8.5%	9.5%	Return on Shr. Equity	10.5%
						8.8%	9.8%	3.9%	7.8%	7.8%	5.8%	6.0%	8.5%	6.2%	7.5%	8.5%	9.5%	Return on Com Equity E	10.5%
						NMF	.5%	NMF	NMF	.1%	NMF	NMF	.8%	NMF	NMF	1.0%	1.5%	Retained to Com Eq	3.0%
						107%	95%	NMF	109%	99%	NMF	NMF	90%	117%	109%	88%	83%	All Div'ds to Net Prof	73%

CAPITAL STRUCTURE as of 6/30/09
Total Debt $780.1 mill. **Due in 5 Yrs** $253.6 mill.
LT Debt $637.5 mill. **LT Interest** $44.5 mill.
Incl. $50 mill. 8.5% trust preferred securities.
(LT interest earned: 2.3x)
Leases, Uncapitalized Annual rentals $1.1 mill.
Pension Assets-12/08 $92.7 mill. **Oblig.** $154.3 mill.
Pfd Stock None

Common Stock 34,492,377 shs.
as of 8/1/09

MARKET CAP: $625 million (Small Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+2.6	+1.4	+2.8
Avg. Industrial Use (MWH)	3096	3067	2973
Avg. Industrial Rev/KWH (¢)	5.66	6.10	6.28
Capacity at Peak (Mw)	1262	1255	1255
Peak Load, Summer (Mw)	1159	1173	1152
Annual Load Factor (%)	52.5	53.4	54.3
% Change Customers (avg.)	+2.1	+1.5	+.7
Fixed Charge Cov. (%)	273	203	208

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	1.0%	1.5%	1.5%
"Cash Flow"	--	3.5%	4.0%
Earnings	-1.0%	3.5%	6.0%
Dividends	--	--	1.5%
Book Value	2.0%	1.5%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	84.0	91.7	131.2	106.6	413.5
2007	125.7	107.2	142.5	114.8	490.2
2008	136.9	111.3	138.7	131.3	518.2
2009	136.0	112.2	156.8	135	540
2010	145	120	165	140	570

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.08	.28	.74	.26	1.41
2007	.15	.19	.76	d.01	1.09
2008	.21	.14	.59	.23	1.17
2009	.32	.22	.71	.25	1.50
2010	.30	.20	.75	.30	1.55

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.32	.32	.32	.32	1.28
2006	.32	.32	.32	.32	1.28
2007	.32	.32	.32	.32	1.28
2008	.32	.32	.32	.32	1.28
2009	.32	.32	.32		

BUSINESS: The Empire District Electric Company supplies electricity to 167,000 customers in a 10,000 sq. mi. area in Missouri (89% of '08 retail elec. revs.), Kansas (5%), Oklahoma (3%), & Arkansas (3%). Acq'd Missouri Gas (45,000 customers) 6/06. Supplies water service and has a small fiber-optic operation. Electric revenue breakdown, '08: residential, 40%; commercial, 30%; industrial, 15%; other, 15%. Generating sources, '08: coal, 36%; gas, 24%; hydro, 1%; purchased, 39%. Fuel costs: 48% of revenues. '08 reported deprec. rate: 3.0%. Has 733 employees. Chairman: Myron W. McKinney. President & CEO: William L. Gipson. Inc.: KS. Address: 602 S. Joplin Ave., P.O. Box 127, Joplin, MO 64802-0127. Tel.: 417-625-5100. Internet: www.empiredistrict.com.

We estimate that Empire District Electric's earnings will rise significantly in 2009. The main reason is a full year's benefit of the $22.0 million electric rate increase that took effect last September. If the company attains our $1.50 estimate, this would be its highest share profit since 1998.

Now that the stock price has rebounded, the company is issuing shares under a $60 million "dribble" program. The stock price fell below $12 earlier this year but has recovered to above $18. We believe that Empire District will need additional equity beyond this $60 million, due to its high capital budget (see below). Because average shares outstanding will probably be higher than we thought three months ago, we have lowered our 2010 earnings estimate by $0.15 a share, to $1.55.

Some significant capital projects are under construction. Empire District will own 50 megawatts of a 665-mw coal-fired plant at a cost of $88.0 million and 102 mw of an 850-mw coal-fired facility at a cost of $218 million-$230 million. These plants will probably go into service in the summer of 2010. The utility will file a rate case in Missouri next year in order to place these projects into the rate base.

We believe that the dividend will hold at the current level. Earlier this year, we were concerned that a dividend cut was possible due to the low stock price, which made an equity offering unappealing. Cutting the dividend might have been a necessary but unpleasant alternative to issuing stock at a depressed price. The stock price recovery precludes a dividend cut, in our view. The payout ratio is high, but the board of directors didn't cut the dividend even when the company didn't cover it.

The utility is seeking a gas rate increase. Empire District filed for a boost of $2.9 million (4.9%) based on a return on equity of 11.3%. A rate order is due by early May, but this will come too late for the primary heating season in the first quarter of 2010.

This stock's main attraction is its high yield. It is two percentage points above the utility average. Due to the high payout ratio, however, 3- to 5-year dividend growth potential is now unspectacular.

Paul E. Debbas, CFA *September 25, 2009*

(A) Excl. loss from discontinued operations: '06, 2¢. '06 EPS don't add to full-year total due to change in shares. Next earnings report due late Oct. (B) Dividends historically paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available (3% discount). † Shareholder investment plan available. (C) Incl. intangibles. In '08: $210.7 mill., $6.20/sh. (D) In mill. (E) Rate base: Deprec. original cost. Rate allowed on common equity in MO in '08: 10.8%; earned on avg. com. eq., '08: 7.4%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	65

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HAWAIIAN ELECTRIC NYSE-HE

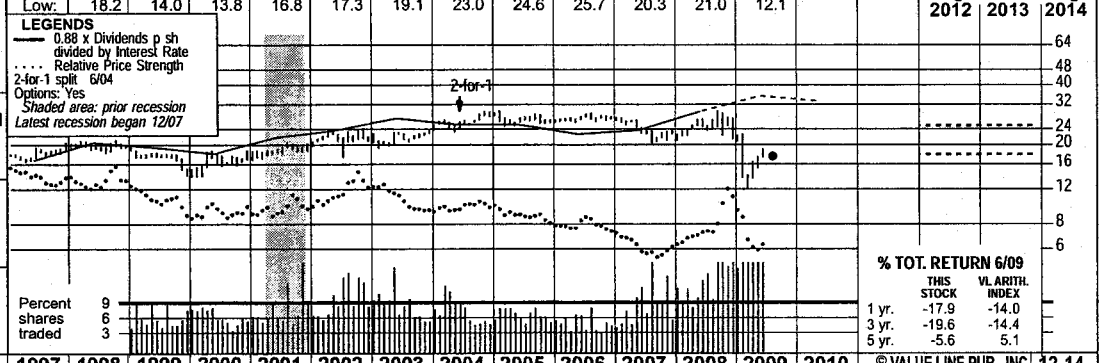
RECENT PRICE **17.63** | P/E RATIO **15.3** (Trailing: 20.0 / Median: 16.0) | RELATIVE P/E RATIO **0.94** | DIV'D YLD 7.0- 4.5 % | VALUE LINE

TIMELINESS 4 Lowered 4/17/09
SAFETY 3 Lowered 5/8/09
TECHNICAL 4 Lowered 7/31/09
BETA .70 (1.00 = Market)

High:	21.3	20.3	19.0	20.6	24.5	24.0	29.5	29.8	28.9	27.5	29.8	22.7
Low:	18.2	14.0	13.8	16.8	17.3	19.1	23.0	24.6	25.7	20.3	21.0	12.1

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 0.88 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 6/04
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+40%)	14%
Low	18	(Nil)	7%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	1	0	0	2	0	1	4	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	1	0	0

Institutional Decisions

	3Q2008	4Q2008	1Q2009
to Buy	100	108	91
to Sell	84	95	101
Hld's(000)	36080	36535	38420

% TOT. RETURN 6/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-17.9	-14.0
3 yr.	-19.6	-14.4
5 yr.	-5.6	5.1

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
20.64	20.74	21.76	22.86	22.95	23.12	23.64	26.05	24.26	22.46	23.49	23.85	27.36	30.21	30.40	35.56	*27.25*	*29.35*	Revenues per sh	*32.00*
2.23	2.52	2.73	2.81	3.01	3.23	3.35	3.08	3.33	3.52	3.54	3.09	3.22	3.19	3.01	2.72	*2.90*	*3.35*	"Cash Flow" per sh	*3.75*
1.19	1.30	1.33	1.30	1.38	1.48	1.45	1.27	1.60	1.62	1.58	1.36	1.46	1.33	1.11	1.07	*1.15*	*1.50*	Earnings per sh A	*1.75*
1.15	1.17	1.19	1.21	1.22	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	*1.24*	*1.24*	Div'd Decl'd per sh B ■ †	*1.24*
4.06	3.50	3.27	3.33	2.31	2.60	2.09	2.04	1.77	1.74	2.15	2.66	2.76	2.58	2.62	3.12	*3.80*	*2.95*	Cap'l Spending per sh	*3.75*
11.62	11.90	12.25	12.52	12.77	12.87	13.16	12.72	13.06	14.21	14.36	15.01	15.02	13.44	15.29	15.35	*15.25*	*15.45*	Book Value per sh C	*16.75*
55.35	57.31	59.55	61.71	63.79	64.23	64.43	65.98	71.20	73.62	75.84	80.69	80.98	81.46	83.43	90.52	*91.75*	*92.00*	Common Shs Outst'g D	*93.50*
15.5	12.5	13.5	13.7	13.2	13.4	12.1	12.9	11.8	13.5	13.8	19.2	18.3	20.3	21.6	23.2	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.92	.82	.90	.86	.76	.70	.69	.84	.60	.74	.79	1.01	.97	1.10	1.15	1.41	*Value Line*		Relative P/E Ratio	*.85*
6.2%	7.2%	6.6%	6.8%	6.7%	6.2%	7.1%	7.5%	6.6%	5.7%	5.7%	4.8%	4.6%	4.6%	5.2%	5.0%	*estimates*		Avg Ann'l Div'd Yield	*5.5%*

CAPITAL STRUCTURE as of 3/31/09
Total Debt $1214.7 mill. **Due in 5 Yrs** $265.0 mill.
LT Debt $1214.7 mill. **LT Interest** $66.8 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 2.7x)
Pension Assets-12/08 $619.1 mill. **Oblig.** $964.3 mill.
Pfd Stock $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100.
Sinking fund ends 2018.
Common Stock 91,533,957 shs.
as of 4/30/09
MARKET CAP: $1.6 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
1523.3	1719.0	1727.3	1653.7	1781.3	1924.1	2215.6	2460.9	2536.4	3218.9	*2500*	*2700*	Revenues ($mill)	*3000*
111.1	84.6	109.8	120.2	120.1	109.6	120.3	109.9	93.6	92.2	*110*	*140*	Net Profit ($mill)	*160*
33.9%	41.6%	34.6%	34.6%	34.9%	45.8%	36.4%	36.5%	35.4%	34.7%	*39.0%*	*40.0%*	Income Tax Rate	*40.0%*
6.1%	9.8%	5.9%	4.8%	5.1%	7.6%	5.9%	8.4%	8.3%	14.2%	*17.0%*	*7.0%*	AFUDC % to Net Profit	*10.0%*
47.2%	58.4%	56.9%	52.0%	48.6%	47.6%	45.2%	49.9%	47.6%	46.0%	*49.0%*	*44.0%*	Long-Term Debt Ratio	*41.0%*
41.4%	39.9%	41.6%	46.5%	49.8%	51.0%	53.3%	48.6%	51.0%	52.7%	*50.0%*	*52.0%*	Common Equity Ratio	*55.0%*
2049.5	2101.2	2235.8	2251.0	2186.9	2375.1	2283.9	2252.7	2501.8	2635.2	*2795*	*2750*	Total Capital ($mill)	*2825*
2066.2	2091.3	2067.5	2079.3	2311.9	2422.3	2542.8	2647.5	2743.4	2907.4	*3095*	*3190*	Net Plant ($mill)	*3650*
6.8%	5.9%	6.7%	7.3%	7.3%	6.0%	6.8%	6.4%	5.2%	4.7%	*5.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
10.3%	9.7%	11.4%	11.1%	10.7%	8.8%	9.6%	9.7%	7.1%	6.5%	*7.5%*	*9.0%*	Return on Shr. Equity	*10.0%*
11.0%	9.8%	11.6%	11.3%	10.8%	8.9%	9.7%	9.9%	7.2%	6.5%	*7.5%*	*9.5%*	Return on Com Equity E	*10.0%*
1.5%	1.7%	4.4%	4.3%	3.9%	1.1%	1.5%	.7%	.8%	.5%	*NMF*	*1.5%*	Retained to Com Eq	*2.5%*
88%	84%	63%	63%	64%	87%	85%	93%	89%	93%	*106%*	*84%*	All Div'ds to Net Prof	*75%*

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+.3	- -	-1.8
Avg. Indust. Use (MWH)	6623	6584	6623
Avg. Indust. Revs. per KWH (¢)	17.38	17.68	25.36
Capacity at Yearend (Mw)	2204	2223	2227
Peak Load, Winter (Mw)	1685	1635	1590
Annual Load Factor (%)	72.5	74.7	75.3
% Change Customers (yr-end)	+1.2	+1.3	+.1
Fixed Charge Cov. (%)	301	262	255

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	3.5%	6.5%	*Nil*
"Cash Flow"	- -	-3.0%	*4.0%*
Earnings	-1.5%	-6.0%	*7.0%*
Dividends	- -	- -	*Nil*
Book Value	1.5%	1.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	574.9	605.0	673.9	607.1	2460.9
2007	554.0	600.8	673.4	708.2	2536.4
2008	729.6	774.1	915.4	799.8	3218.9
2009	543.8	*650*	*650*	*656.2*	*2500*
2010	*650*	*675*	*700*	*675*	*2700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.40	.33	.40	.20	1.33
2007	.17	.21	.24	.49	1.11
2008	.41	.06	.44	.16	1.07
2009	.22	*.22*	*.35*	*.36*	*1.15*
2010	*.37*	*.37*	*.38*	*.38*	*1.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.31	.31	.31	.31	1.24
2006	.31	.31	.31	.31	1.24
2007	.31	.31	.31	.31	1.24
2008	.31	.31	.31	.31	1.24
2009	.31	.31			

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company (HECO) & American Savings Bank (ASB). HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 440,000 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Discontinued int'l power sub. in '01. Elec. rev. breakdown, '08: res'l, 33%; comm'l, 34%; large light & power, 32%; other, 1%. Generating sources, '08: oil, 60%; purchased, 40%. Fuel costs: 60% of revs. '08 reported depr. rate (utility): 3.8%. Has 3,600 employees. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: P.O. Box 730, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Web: www.hei.com.

Hawaiian Electric Industries' largest utility subsidiary has received an interim rate increase. The Public Utilities Commission of Hawaii (PUC) granted Hawaiian Electric Company (HECO) an interim tariff hike that was less than the $79.8 million (6.2%) boost, based on a 10.5% return on equity, agreed upon by the utility and various intervenor groups. HECO believes that the interim order amounts to a $61.1 million (4.7%) increase, but the PUC will have to rule on this, and on the timing of the rate hike. Hearings aren't going to occur until the last week of October. As for the final tariff increase, HECO is requesting $86.8 million (6.7%), based on an 11% return on equity.

The interim rate hike will help HEI's earnings once it is implemented. The company expects a 13% increase in utility operating and maintenance costs this year. Higher utility expenses hurt earnings considerably in the first quarter of 2009, and we expect a similar result in the second period. (Earnings were released shortly after this report went to press.) Another challenge is a decline in kilowatt-hour sales, stemming from the weak economy.

We would not be surprised if HEI's two other utilities file rate cases in the coming months. Like HECO, Hawaii Electric Light Company (HELCO) and Maui Electric Company have been earning ROEs of less than 8%. All three utilities (including HECO) are seeking regulatory mechanisms that will decouple electric volume and electric sales. And HELCO will need to file an application in order to place an 18-megawatt facility (at a cost of $92 million) in the rate base.

American Savings Bank is facing some challenges. The effects of the weak economy have hurt credit quality. Also, the bank is undertaking a cost-cutting program, but expenses aren't likely to reach desired levels until 2010.

We advise investors to look elsewhere. Although the board of directors has held the dividend steady so far, we still do not rule out a cut. That's why we are showing a split dividend at the top of the page. Even if HEI avoids a dividend reduction, a dividend increase is unlikely anytime soon, and total return potential to 2012-2014 is unimpressive.

Paul E. Debbas, CFA *August 7, 2009*

(A) Diluted EPS. Excl. gains (losses) from disc. ops.: '98, (16¢); '99, 6¢; '00, (56¢); '01, (36¢); '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (loss): '05, 11¢; '07, (9¢). Next egs. due early Nov. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinv. plan avail. † Sharehldr. invest. plan avail. (C) Incl. intang. In '08: $6.77/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate all'd on com. eq. in '07: HECO, 10.7% (interim); in '07: HELCO, 10.7%; in '07: MECO, 10.7%; earned on avg. com. eq., '08: 6.8%. Regulatory Climate: Above Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	65

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MGE ENERGY INC. NDQ-MGEE

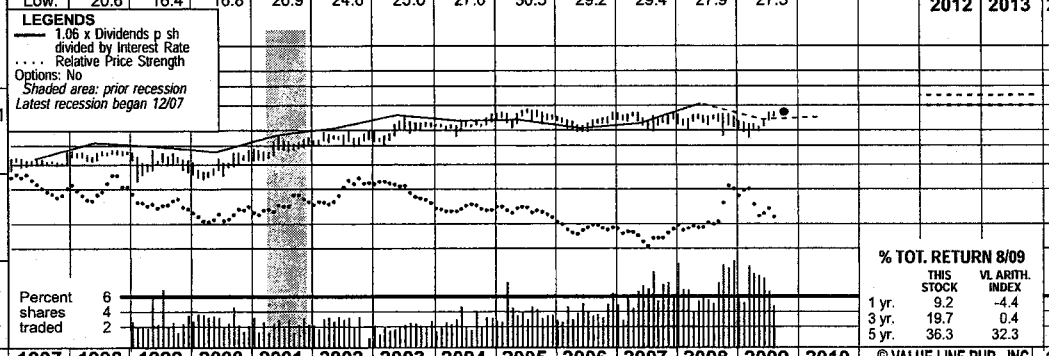
RECENT PRICE **37.12** | P/E RATIO **15.6** (Trailing: 15.8 Median: 15.0) | RELATIVE P/E RATIO **0.91** | DIV'D YLD **4.0%** | VALUE LINE

TIMELINESS 3 Lowered 6/26/09
SAFETY 1 New 1/3/03
TECHNICAL 4 Lowered 8/14/09
BETA .65 (1.00 = Market)

High:	23.8	23.9	23.7	27.8	30.1	35.8	36.4	38.8	37.0	37.2	36.5	37.2
Low:	20.6	16.4	16.8	20.9	24.6	25.0	27.6	30.5	29.2	29.4	27.9	27.3

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.06 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: No
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+20%)	9%
Low	40	(+10%)	6%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	1	0	0	0	3	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	55	47	52
to Sell	38	42	44
Hld's(000)	7627	7435	7661

% TOT. RETURN 8/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	9.2	-4.4
3 yr.	19.7	0.4
5 yr.	36.3	32.3

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
15.18	15.23	15.46	15.75	16.46	15.53	16.96	19.50	19.55	19.75	21.89	20.84	25.10	24.20	24.49	26.02	*24.80*	*25.45*	Revenues per sh	*25.80*
2.86	2.92	3.03	2.41	3.26	3.59	3.81	3.89	3.78	3.33	2.94	2.88	3.00	3.52	3.69	4.02	*3.85*	*3.95*	"Cash Flow" per sh	*4.20*
1.51	1.53	1.49	.82	1.40	1.38	1.48	1.67	1.62	1.69	1.71	1.77	1.57	2.06	2.27	2.38	*2.40*	*2.50*	Earnings per sh A	*2.80*
1.19	1.25	1.26	1.28	1.29	1.30	1.31	1.32	1.33	1.34	1.35	1.36	1.37	1.39	1.41	1.43	*1.45*	*1.47*	Div'd Decl'd per sh B ■	*1.54*
1.47	1.64	1.19	1.36	1.35	1.92	3.16	4.44	2.47	4.45	4.52	4.70	4.19	4.41	6.21	4.62	*2.30*	*2.30*	Cap'l Spending per sh	*2.50*
11.51	11.78	12.01	11.14	11.25	11.34	11.49	12.05	12.67	12.94	14.34	16.59	16.81	17.89	19.49	20.88	*21.85*	*22.85*	Book Value per sh	*21.05*
16.08	16.08	16.08	16.08	16.08	16.08	16.16	16.62	17.07	17.57	18.34	20.39	20.45	20.98	21.95	22.90	*23.20*	*23.20*	Common Shs Outst'g C	*25.00*
15.2	14.3	14.5	28.1	14.5	16.2	14.0	11.7	14.8	16.0	17.5	18.0	22.4	15.9	15.0	14.2	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.90	.94	.97	1.76	.84	.84	.80	.76	.76	.87	1.00	.95	1.19	.86	.80	.87	*Value Line*		Relative P/E Ratio	*1.00*
5.2%	5.7%	5.8%	5.5%	6.3%	5.8%	6.3%	6.7%	5.5%	5.0%	4.5%	4.3%	3.9%	4.3%	4.1%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*

CAPITAL STRUCTURE as of 6/30/09
Total Debt $366.4 mill. **Due in 5 Yrs** $34.6 mill.
LT Debt $272.4 mill. **LT Interest** $12.0 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $2.4 mill.
Pension Assets-12/08 $103.1 mill.
Obligation $191.8 mill.

Pfd Stock None

Common Stock 23,113,638 shs.
as of 7/31/09
MARKET CAP: $850 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
274.0	324.1	333.7	347.1	401.5	424.9	513.4	507.5	537.6	596.0	*575*	*590*	Revenues ($mill)	*645*
23.8	27.4	27.2	29.2	30.6	33.8	32.1	42.4	48.8	52.8	*56.0*	*58.0*	Net Profit ($mill)	*70.0*
36.9%	36.5%	36.9%	39.1%	39.4%	37.9%	38.2%	37.9%	36.3%	35.5%	*36.5%*	*36.5%*	Income Tax Rate	*36.5%*
1.9%	1.9%	2.2%	--	--	--	--	--	2.2%	2.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
44.5%	47.8%	42.2%	45.8%	43.5%	37.4%	39.3%	38.7%	35.2%	36.3%	*36.0%*	*35.5%*	Long-Term Debt Ratio	*35.0%*
55.5%	52.2%	57.8%	54.2%	56.5%	62.6%	60.7%	61.3%	64.8%	63.7%	*64.0%*	*64.5%*	Common Equity Ratio	*65.0%*
334.3	383.7	373.9	419.5	465.3	540.5	566.2	612.6	660.1	750.6	*785*	*815*	Total Capital ($mill)	*940*
260.1	342.8	401.2	451.5	537.5	607.4	667.7	728.4	844.0	901.2	*910*	*965*	Net Plant ($mill)	*1000*
8.8%	8.8%	9.0%	8.1%	7.8%	7.1%	6.6%	7.8%	8.1%	7.7%	*8.5%*	*8.5%*	Return on Total Cap'l	*9.0%*
12.8%	13.7%	12.6%	12.8%	11.6%	10.0%	9.3%	11.3%	11.4%	11.0%	*11.5%*	*11.0%*	Return on Shr. Equity	*12.0%*
12.8%	13.7%	12.6%	12.8%	11.6%	10.0%	9.3%	11.3%	11.4%	11.0%	*11.5%*	*11.0%*	Return on Com Equity D	*12.0%*
1.5%	2.9%	2.3%	2.6%	2.5%	2.3%	1.2%	3.7%	4.3%	4.4%	*5.0%*	*4.5%*	Retained to Com Eq	*5.5%*
89%	79%	82%	79%	79%	77%	87%	67%	62%	60%	*59%*	*58%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-0.7	+2.8	-2.8
Avg. Indust. Use (MWH)	2865	2846	2737
Avg. Indust. Revs. per KWH (¢)	6.20	6.20	7.11
Capacity at Peak (Mw)	780	780	NA
Peak Load, Summer (Mw)	NA	NA	772
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	340	350	350

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	4.5%	4.0%	*.5%*
"Cash Flow"	2.0%	2.0%	*.5%*
Earnings	6.5%	6.0%	*6.0%*
Dividends	1.0%	1.0%	*.5%*
Book Value	5.5%	8.0%	*7.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	158.6	99.7	110.6	138.6	507.5
2007	167.9	110.6	116.3	142.8	537.6
2008	190.0	124.7	125.8	155.5	596.0
2009	181.1	107.6	*125*	*161.3*	*575*
2010	*183*	*114*	*128*	*165*	*590*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.56	.34	.62	.54	2.06
2007	.59	.47	.71	.50	2.27
2008	.63	.48	.78	.49	2.38
2009	.65	.43	*.79*	*.51*	*2.40*
2010	*.65*	*.52*	*.80*	*.53*	*2.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.342	.342	.345	.345	1.37
2006	.345	.345	.348	.348	1.39
2007	.348	.348	.355	.355	1.41
2008	.355	.355	.3617	.3617	1.43
2009	.3617	.3617	.3684		

BUSINESS: MGE Energy Inc. is a holding company for Madison Gas and Electric, which provides electric service to approximately 137,000 customers in a 316-square-mile area of Dane County and gas service to 141,000 customers in 1,630 square miles in seven counties in Wisconsin. Electric revenue breakdown, '08: residential, 34%; commercial, 54%; industrial, 6%; public authorities and other, 6%. Generating sources, '08: coal, 52%; purchased power, 39%; natural gas and other, 9%. Fuel costs: 51% of revenues. '07 reported depreciation rate: electric, 3.4%; gas, 3.3%. Has 750 employees. Chairman, President & CEO: Gary J. Wolter. Inc.: Wisconsin. Address: 133 South Blair St., P.O. Box 1231, Madison, WI 53701-1231. Telephone: 608-252-7000. Internet: www.mge.com.

We've shaved a nickel off our 2009 share-net estimate for MGE Energy. Our revised assessment represents a modest increase over the $2.38 per share that the Wisconsin electric and gas utility earned in 2008. A more conservative stance seems prudent, given generally weak power demand, coinciding with lower overall economic activity in the upper Midwest. The company experienced a 3.4% year-over-year decline in electric utility revenue during the second quarter, reflecting both lower direct sales and fewer resale opportunities. Comparatively, electric revenue increased nearly 4% during last year's June period.

MGE is still well positioned for the long haul, thanks to an attractive service area that includes Dane County and the city of Madison. The population of Dane County is expected to grow faster than any other region in Wisconsin over the next two decades or so. Madison, meanwhile, gets high marks for job and GDP growth. The city is home to a major campus in the state university system, which remains a magnet for residential and commercial activity.

MGE remains a good clean-energy investment play. The company is installing a public network of six electric vehicle-charging stations in its service area. The interconnected system is the first of its kind in the United States. MGE also recently agreed to purchase land development rights for two wind generation sites in northeast Iowa. The sites, located near Wellsburg and Hawkeye, could produce up to 175 megawatts of renewable energy. MGE currently boasts 137 mw of wind capacity through wholly owned and partnership facilities.

MGE recently raised its quarterly common stock dividend by 2%, to 36.84 cents, marking the 33rd straight year that the company has raised its payout. We expect MGE to pay out $34 million in dividends this year, more than seven times 1976's $4.7 million total.

MGE shares are ranked 3 (Average) for year-ahead relative price performance. At the current quotation, long-term appreciation potential doesn't stand out, either. However, the stock may appeal to conservative, income-oriented investors.

Nils C. Van Liew *September 25, 2009*

(A) Excl. nonrecurring loss: '96, 42¢. Next earnings report due late Oct. (B) Dividends historically paid in mid-March, June, September, December. ■ Dvd. reinvestment plan available. (C) In millions. (D) Rate allowed on common equity in '08: 12.9%; earned on average common equity, '08: 13.0%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	85

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NORTHEAST UTILITIES NYSE-NU

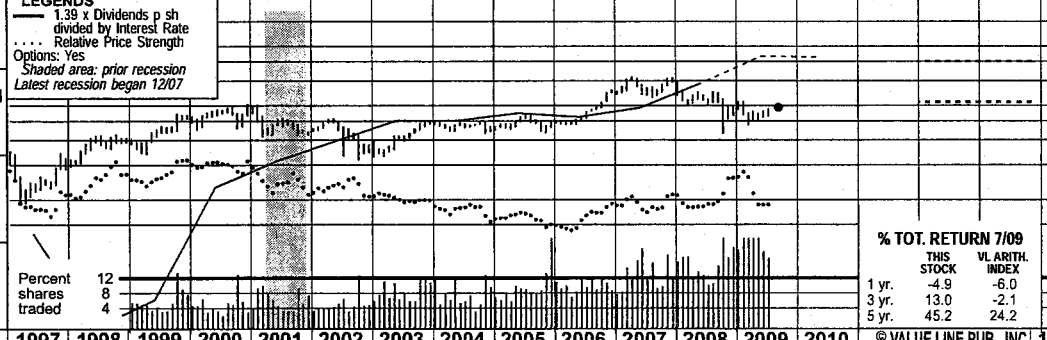
RECENT PRICE 23.55 | P/E RATIO 12.7 (Trailing: 11.8 Median: 19.0) | RELATIVE P/E RATIO 0.80 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Lowered 5/29/09
SAFETY 3 Raised 9/6/02
TECHNICAL 3 Raised 7/17/09
BETA .70 (1.00 = Market)

High:	17.3	22.0	24.6	24.3	20.7	20.3	20.3	22.0	28.9	33.6	31.6	25.3
Low:	11.7	13.6	18.0	16.6	12.7	13.1	17.2	17.3	19.1	26.2	17.2	19.0

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.39 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+70%)	17%
Low	25	(+5%)	5%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	3	0	0	0	0	0	0	0
to Sell	0	3	0	0	0	0	0	0	0

Institutional Decisions

	3Q2008	4Q2008	1Q2009
to Buy	109	124	178
to Sell	112	97	91
Hld's(000)	114850	113282	135401

% TOT. RETURN 7/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-4.9	-6.0
3 yr.	13.0	-2.1
5 yr.	45.2	24.2

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
29.19	29.15	29.51	29.52	29.46	28.77	33.91	40.86	52.82	40.89	47.53	51.82	41.85	44.64	37.27	37.22	**32.40**	**34.65**	Revenues per sh	**33.25**
5.86	6.26	6.02	3.77	2.68	3.73	5.68	3.39	10.48	6.32	5.80	5.00	5.46	3.69	4.82	6.16	**5.15**	**5.50**	"Cash Flow" per sh	**5.75**
1.60	2.30	2.24	.01	d1.05	d.36	d1.14	d.20	1.37	1.08	1.24	.91	.98	.82	1.59	1.86	**1.85**	**1.95**	Earnings per sh A	**2.25**
1.76	1.76	1.76	1.38	.25	--	.10	.40	.45	.53	.58	.63	.68	.73	.78	.83	**.95**	**1.00**	Div'd Decl'd per sh B ■	**1.15**
2.49	2.31	1.97	1.85	1.85	1.79	2.50	2.88	3.40	3.86	4.31	4.85	5.89	5.49	7.14	8.06	**5.35**	**7.25**	Cap'l Spending per sh	**5.75**
17.89	18.48	19.08	17.73	16.34	15.63	15.80	15.43	16.27	17.33	17.73	17.80	18.46	18.14	18.65	19.38	**20.25**	**21.25**	Book Value per sh C	**25.00**
124.33	124.96	127.05	128.44	130.18	130.95	131.87	143.82	130.13	127.56	127.70	129.03	131.59	154.23	156.22	155.83	**176.00**	**176.00**	Common Shs Outst'g D	**210.00**
16.6	10.0	10.3	NMF	--	--	--	--	14.1	16.1	13.4	20.8	19.8	27.1	18.7	13.7	*Bold figures are*		Avg Ann'l P/E Ratio	**14.5**
.98	.66	.69	NMF	--	--	--	--	.72	.88	.76	1.10	1.05	1.46	.99	.82	*Value Line*		Relative P/E Ratio	**.95**
6.6%	7.7%	7.6%	8.9%	2.4%	--	.6%	1.9%	2.3%	3.0%	3.5%	3.3%	3.5%	3.3%	2.6%	3.2%	*estimates*		Avg Ann'l Div'd Yield	**3.5%**

CAPITAL STRUCTURE as of 6/30/09
Total Debt $5536.0 mill. **Due in 5 Yrs** $1129.2 mill.
LT Debt $4909.4 mill. **LT Interest** $294.6 mill.
Incl. $566.2 mill. of rate reduction bonds.
(LT interest earned: 2.3x)
Leases, Uncapitalized Annual rentals $24.6 mill.

Pension Assets-12/08 $1.56 bill. **Oblig.** $2.30 bill.
Pfd Stock $116.2 mill. **Pfd Div'd** $5.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption.
Common Stock 175,281,532 shs.
as of 7/31/09
MARKET CAP: $4.1 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
4471.3	5876.6	6873.8	5216.3	6069.2	6686.7	5507.3	6884.4	5822.2	5800.1	**5700**	**6100**	Revenues ($mill)	**7000**
d127.0	d14.4	186.4	144.2	162.7	122.1	128.5	126.2	251.5	296.2	**320**	**350**	Net Profit ($mill)	**455**
--	--	--	--	32.1%	29.8%	30.8%	--	30.3%	29.7%	**34.0%**	**30.0%**	Income Tax Rate	**30.0%**
--	--	--	9.2%	7.1%	6.8%	17.4%	21.5%	13.9%	15.8%	**9.0%**	**14.0%**	AFUDC % to Net Profit	**14.0%**
49.9%	45.7%	65.9%	64.3%	63.9%	64.2%	63.2%	58.7%	59.2%	60.4%	**59.0%**	**59.0%**	Long-Term Debt Ratio	**55.0%**
42.7%	48.8%	32.4%	33.9%	34.3%	34.0%	35.1%	39.7%	39.2%	38.1%	**40.0%**	**39.5%**	Common Equity Ratio	**44.0%**
4876.0	4546.6	6544.7	6513.2	6591.6	6749.4	6923.2	7052.0	7431.1	7926.2	**8930**	**9445**	Total Capital ($mill)	**11925**
3947.4	3547.2	3822.1	4728.4	5429.9	5864.2	6417.2	6242.2	7229.9	8207.9	**8710**	**9510**	Net Plant ($mill)	**12575**
--	1.9%	4.6%	4.1%	4.2%	2.8%	3.5%	2.9%	5.0%	5.4%	**5.0%**	**5.5%**	Return on Total Cap'l	**5.5%**
NMF	NMF	8.3%	6.2%	6.8%	5.1%	5.0%	4.3%	8.3%	9.4%	**8.5%**	**9.0%**	Return on Shr. Equity	**8.5%**
NMF	NMF	8.5%	6.3%	6.9%	5.1%	5.1%	4.3%	8.4%	9.6%	**9.0%**	**9.5%**	Return on Com Equity E	**8.5%**
NMF	NMF	5.6%	3.2%	3.7%	1.6%	1.5%	.3%	4.3%	5.3%	**4.5%**	**4.5%**	Retained to Com Eq	**4.0%**
NMF	NMF	37%	51%	48%	70%	72%	94%	50%	45%	**51%**	**52%**	All Div'ds to Net Prof	**53%**

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-4.1	+1.5	-3.5
Avg. Indust. Use (MWH)	776	772	NA
Avg. Indust. Revs. per KWH (¢)	7.76	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Capacity Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.2	+.5	NA
Fixed Charge Cov. (%)	NMF	201	215

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	3.0%	-3.5%	-3.0%
"Cash Flow"	3.5%	-8.5%	2.5%
Earnings	--	3.0%	8.0%
Dividends	3.5%	8.5%	6.5%
Book Value	1.0%	2.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	2147	1661	1593	1483	6884.4
2007	1703	1391	1451	1276	5822.2
2008	1520	1325	1506	1447	5800.1
2009	1593	1224	**1433**	**1450**	**5700**
2010	**1600**	**1400**	**1600**	**1500**	**6100**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	d.13	.09	.67	.19	.82
2007	.49	.30	.32	.47	1.59
2008	.57	.37	.47	.46	1.86
2009	.60	.47	**.38**	**.40**	**1.85**
2010	**.60**	**.40**	**.48**	**.47**	**1.95**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.1625	.1625	.175	.175	.68
2006	.175	.175	.1875	.1875	.73
2007	.1875	.1875	.20	.20	.78
2008	.20	.20	.2125	.2125	.83
2009	.2375	.2375			

BUSINESS: Northeast Utilities is the parent of the NU system, which is the largest utility in New England and serves 1.9 million electric and 200,000 gas customers. Connecticut Light & Power (CL&P) provides service to most of CT; Public Service Co. of New Hampshire (PSNH) supplies power to three quarters of NH's population; Western Massachusetts Electric Co. (WMECO) serves the western half of MA. Acq'd Yankee Energy 3/00. Electric rev. breakdown, '08: res'l, 55%; comm'l, 35%; ind'l, 9%; other, 1%. Generating sources not available. Fuel costs: 52% of revs. '08 reported depr. rate: 3.0%. Has 6,200 employees. Chairman, President & CEO: Charles W. Shivery. Inc.: CT. Address: P.O. Box 270, Hartford, CT 06141-0270. Tel.: 800-999-7269. Internet: www.nu.com.

Northeast Utilities' distribution operations are underearning their allowed returns on equity. This situation has persisted for several quarters, but has worsened of late due to declining electric sales, rising operating and maintenance expense, and higher bad-debt expense. For the 12-month period that ended June 30th, the earned ROEs for Connecticut Light & Power, Public Service of New Hampshire, Western Massachusetts Electric, and Yankee Gas were 7.7%, 5%, 7.7%, and 8.1%, respectively. Except for PSNH, these figures are likely to decline by yearend.

Rate cases at each electric utility are pending or upcoming. PSNH filed a request for permanent rate increases of $51 million, based on a 10.5% ROE, effective August 1, 2009 and an additional $17 million effective July 1, 2010. The commission granted the utility a temporary rate hike of $25.6 million that took effect on August 1st. (The final rate order will be retroactive to this date.) CL&P expects to file a rate application in late 2009 or early 2010, and WMECO plans to file one in mid-2010.

The second half of 2009 isn't likely to be as good as the first half. Thus, we expect earnings for the full year to be flattish, despite favorable first-half comparisons. Our estimate of $1.85 a share is at the midpoint of NU's targeted range of $1.80-$1.90. We expect profit growth, to $1.95 a share, in 2010, based on the benefits of rate relief at PSNH and the effects of a better economy on electric sales.

NU's transmission business is faring well. The company is earning an ROE of around 13% on its transmission rate base. NU is requesting siting approval to build three projects in New England at a cost of $1.46 billion from 2009 through 2013. It also has a 75% stake in a joint venture to build a transmission line to Quebec. The federal regulators have approved this project, but other approvals are needed before NU and its partner can begin building the $700 million-$800 million line.

By utility standards, this stock's yield is somewhat below average. Over the 3- to 5-year period, transmission investments should enhance NU's earning power, and dividend growth should be good. The subpar regulatory climate in Connecticut is worrisome, however.

Paul E. Debbas, CFA *August 28, 2009*

(A) Diluted EPS. Excl. nonrec. gains (losses): '99, $1.40; '01, 42¢; '02, 10¢; '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢). '07, '08 EPS don't add due to rounding. Next egs. report due early Nov. (B) Div'd susp. 2Q '97; reinstated 4Q '99. Div'ds historically paid late Mar., June, Sept. & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '08: $24.32/sh. (D) In mill. (E) Rate all'd on com. eq. in MA: '99, 11%; in CT: (elec.) '08, 9.40% (gas) '07, 10.1%; in NH: '97, 11%; earned on avg. com. eq., '08: 9.7%. Regulatory Climate: CT, NH, Below Avg.; MA, Above Avg.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	50

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NSTAR NYSE-NST

RECENT PRICE **31.97** | P/E RATIO **13.4** (Trailing: 14.0 / Median: 14.0) | RELATIVE P/E RATIO **0.84** | DIV'D YLD **4.9%** | VALUE LINE

TIMELINESS 3 Lowered 6/19/09
SAFETY 1 Raised 6/11/99
TECHNICAL 4 Lowered 8/14/09
BETA .65 (1.00 = Market)

High:	22.5	22.3	23.5	22.6	24.1	24.5	27.2	31.5	35.9	37.4	40.0	36.8
Low:	17.5	18.2	18.2	17.0	17.0	19.3	22.7	24.9	26.5	30.8	25.7	27.5

Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

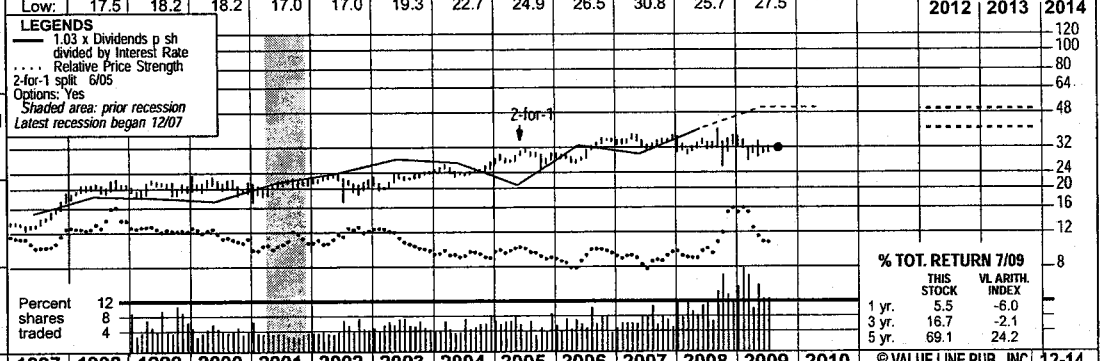
	Price	Gain	Ann'l Total Return
High	50	(+55%)	16%
Low	40	(+25%)	10%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	3	1	1	0	0	0	0
to Sell	0	3	3	3	2	0	0	1	0

Institutional Decisions

	3Q2008	4Q2008	1Q2009
to Buy	91	117	133
to Sell	100	101	96
Hld's(000)	48045	50208	52014



% TOT. RETURN 7/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	5.5	-6.0
3 yr.	16.7	-2.1
5 yr.	69.1	24.2

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
16.42	17.00	16.96	17.17	18.31	17.19	15.94	25.45	30.09	25.64	27.48	27.73	30.36	33.50	30.54	31.32	*30.90*	*33.00*	Revenues per sh	*40.00*
2.98	3.35	3.11	3.65	3.66	3.84	3.04	3.78	3.81	3.95	3.98	4.09	5.00	5.34	5.55	5.84	*6.00*	*6.30*	"Cash Flow" per sh	*7.25*
1.14	1.21	1.04	1.31	1.36	1.38	1.39	1.60	1.64	1.69	1.74	1.76	1.83	1.93	2.07	2.22	*2.35*	*2.55*	Earnings per sh A	*3.25*
.86	.89	.92	.94	.94	.95	.98	1.01	1.04	1.07	1.09	1.13	.87	1.54	1.33	1.43	*1.53*	*1.63*	Div'd Decl'd per sh B ■	*1.95*
2.81	2.42	2.08	2.13	1.23	1.57	1.53	1.78	2.22	3.50	2.94	2.95	3.63	3.99	3.37	3.95	*3.40*	*3.30*	Cap'l Spending per sh	*2.75*
9.71	10.06	10.31	10.54	10.98	11.14	13.29	12.65	11.90	12.25	12.84	13.52	14.37	14.82	15.95	16.74	*17.60*	*18.55*	Book Value per sh C	*22.00*
90.26	91.07	96.01	97.02	97.03	94.37	116.12	106.07	106.07	106.07	106.07	106.55	106.81	106.81	106.81	106.81	*106.81*	*106.81*	Common Shs Outst'g D	*106.81*
13.1	10.7	12.3	9.7	10.6	14.6	14.6	12.9	12.7	12.7	12.8	14.0	15.5	15.9	16.6	14.8	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.77	.70	.82	.61	.61	.76	.83	.84	.65	.69	.73	.74	.83	.86	.88	.89	*Value Line*		Relative P/E Ratio	*.95*
5.8%	6.9%	7.2%	7.4%	6.5%	4.7%	4.8%	4.9%	5.0%	4.9%	4.9%	4.6%	3.1%	5.0%	3.9%	4.3%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 6/30/09
Total Debt $2964.5 mill. **Due in 5 Yrs** $1977.5 mill.
LT Debt $1741.3 mill. **LT Interest** $104.5 mill.
Incl. $252.9 mill. securitized bonds.
(LT interest earned: 3.5x)
Leases, Uncapitalized Annual rentals $17.1 mill.
Pension Assets-12/08 $716.7 mill. **Oblig.** $1.07 bill.
Pfd Stock $43.0 mill. **Pfd Div'd** $2.0 mill.
430,000 shs. 4.25%-4.78%, cumulative, redeemable at $102.80-$103.625.
Common Stock 106,808,376 shs. as of 7/31/09
MARKET CAP: $3.4 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
1851.4	2699.5	3191.8	2719.1	2914.1	2954.3	3243.1	3577.7	3261.8	3345.4	*3300*	*3525*	Revenues ($mill)	*4275*
146.5	181.0	179.1	181.3	188.0	190.4	198.1	208.7	223.5	239.5	*255*	*275*	Net Profit ($mill)	*345*
29.1%	41.6%	41.4%	35.8%	37.5%	38.5%	35.6%	37.8%	37.4%	38.1%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
1.5%	2.5%	2.8%	1.6%	2.4%	.5%	1.9%	3.3%	1.7%	.8%	*Nil*	*Nil*	AFUDC % to Net Profit	*1.0%*
50.0%	59.4%	59.2%	60.9%	58.5%	58.6%	60.4%	59.2%	58.9%	56.1%	*46.5%*	*50.0%*	Long-Term Debt Ratio	*45.0%*
47.2%	39.4%	39.5%	37.8%	40.2%	40.2%	38.6%	39.7%	40.1%	42.8%	*52.5%*	*49.0%*	Common Equity Ratio	*54.0%*
3269.3	3409.8	3197.4	3433.7	3387.1	3585.3	3980.4	3986.3	4248.2	4174.8	*3585*	*4045*	Total Capital ($mill)	*4375*
2550.6	2523.6	2625.4	2847.6	3216.1	3425.0	3701.8	3945.3	4142.3	4398.4	*4525*	*4625*	Net Plant ($mill)	*4725*
6.1%	7.6%	8.1%	7.5%	7.8%	7.4%	7.1%	7.3%	7.1%	7.7%	*9.0%*	*8.0%*	Return on Total Cap'l	*9.5%*
9.0%	13.1%	13.7%	13.5%	13.4%	12.8%	12.6%	12.8%	12.8%	13.1%	*13.0%*	*13.5%*	Return on Shr. Equity	*14.5%*
9.1%	13.0%	13.7%	13.8%	13.7%	13.1%	12.8%	13.1%	13.0%	13.3%	*13.5%*	*14.0%*	Return on Com Equity E	*14.5%*
2.4%	4.8%	5.0%	5.2%	5.1%	4.8%	4.6%	4.9%	4.9%	4.9%	*5.0%*	*5.0%*	Retained to Com Eq	*6.0%*
74%	64%	65%	63%	63%	64%	64%	63%	63%	63%	*65%*	*63%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-1.9	+1.8	--
Avg. Indust. Use (MWH)	1001	983	982
Avg. Indust. Revs. per KWH (¢)	8.40	6.80	7.40
Capacity at Peak (Mw)	NMF	NMF	NA
Peak Load, Summer (Mw)	4959	4555	4562
Annual Load Factor (%)	NMF	NMF	NA
% Change Customers (avg.)	+1.5	+.7	+.4
Fixed Charge Cov. (%)	262	294	296

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	6.0%	3.0%	*4.0%*
"Cash Flow"	4.0%	7.5%	*4.5%*
Earnings	4.5%	4.0%	*8.0%*
Dividends	4.0%	6.0%	*5.5%*
Book Value	4.0%	5.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1034.8	784.6	956.3	802.0	3577.7
2007	984.4	725.1	804.9	747.4	3261.8
2008	895.6	743.7	892.2	813.9	3345.4
2009	947.8	707.5	*850*	*794.7*	*3300*
2010	*975*	*775*	*925*	*850*	*3525*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.41	.43	.72	.38	1.93
2007	.45	.47	.79	.37	2.07
2008	.55	.47	.80	.39	2.22
2009	.57	.53	*.82*	*.43*	*2.35*
2010	*.60*	*.60*	*.90*	*.45*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.29	.29	.29	.29	1.16
2006	.3025	.3025	.3025	.3025	1.21
2007	.325	.325	.325	.325	1.30
2008	.35	.35	.35	.35	1.40
2009	.375	.375	.375		

BUSINESS: NSTAR is a holding company for NSTAR Electric, which distributes electricity to an area of 1,702 sq. mi. in eastern Massachusetts, incl. Boston and 80 surrounding towns and cities, and NSTAR Gas, which distributes gas to an area of 1,067 sq. mi. in 51 communities in central and eastern Massachusetts. Acq'd Commonwealth Energy 8/99. Serves 1.1 mill. electric, 300,000 gas customers. Electric rev. breakdown, '08: residential, 42%; commercial, 53%; industrial, 5%; other, less than 1%. Sold fossil plants in '98, nuclear plant in '99. Fuel costs: 54% of revs. '08 reported deprec. rate: 3.0%. Has 3,250 employees. Chairman, Pres. & CEO: Thomas J. May. Inc.: MA. Address: 800 Boylston St., Boston, MA 02199-8003. Tel.: 617-424-2000. Internet: www.nstar.com.

We have trimmed our 2009 earnings estimate for NSTAR by a nickel a share, to $2.35. Second-quarter profits fell slightly short of our $0.55-a-share estimate due to milder-than-usual weather conditions. The utility's service territory experienced one of the coolest Junes on record. With the mild summer weather continuing as the third quarter began, we decided to lower our third-quarter estimate as well. Our full-year forecast of $2.35 a share is still within NSTAR's targeted range of $2.33-$2.43 and would produce a healthy 6% earnings increase from the 2008 tally.

Earnings should advance steadily through 2012, thanks to a regulatory agreement that provides for annual base rate increases. (Another good feature of the regulatory plan is an allowed return on equity of 12.5%.) Investment in NSTAR's transmission system is also increasing the company's earning power. And the utility is controlling its operating and maintenance costs effectively. We're sticking with our 2010 share-net estimate of $2.55, which is based on a return to normal weather patterns. This would produce earnings growth at the high end of NSTAR's targeted annual range of 6%-8%. The company has an identical goal for annual dividend growth. It has achieved this objective in recent years — the decline shown in the statistical array for 2005 was merely due to the shift of a dividend declaration from the fourth quarter of 2005 to the first period of 2006.

NSTAR and its partner, Northeast Utilities, received a favorable ruling from the Federal Energy Regulatory Commission on the companies' plan to build a transmission line to Quebec. Other approvals will be needed before the companies can break ground, probably in 2011. NSTAR's 25% stake in the project would amount to as much as $200 million. Each of these companies has fared well in recent years when developing transmission projects in New England.

This high-quality stock is an average utility selection. NSTAR is a financially sound company with a good track record of earnings and dividend growth, but these strong points are already reflected in the share price.

Paul E. Debbas, CFA *August 28, 2009*

(A) Diluted EPS. Excl. nonrecurring losses: '01, $1.66 net; '02, 17¢; '03, 4¢. '06, '07 & '08 EPS don't add to full-year total due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid in early Feb., May, Aug., and Nov. There were only 3 div'd declarations in '05, 5 in '06. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '08: $2.5 bill., $23.69/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in '06: 12.5%; earned on avg. com. eq., '08: 13.5%. Regulatory Climate: Above Average.

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

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OTTER TAIL CORP. NDQ-OTTR

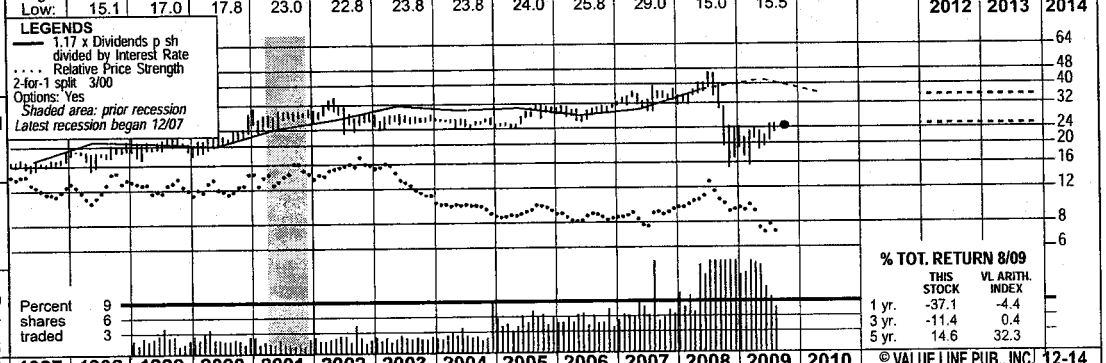
RECENT PRICE **24.54** | P/E RATIO **25.0** (Trailing: 27.6 / Median: 17.0) | RELATIVE P/E RATIO **1.45** | DIV'D YLD **4.9%** | VALUE LINE

TIMELINESS 4 Lowered 11/14/08
SAFETY 2 New 7/27/90
TECHNICAL 3 Lowered 9/25/09
BETA .90 (1.00 = Market)

High:	21.4	22.8	29.0	31.0	34.9	28.9	27.5	32.0	31.9	39.4	46.2	25.2	
Low:	15.1	17.0	17.8	23.0	22.8	23.8	23.8	24.0	25.8	29.0	15.0	15.5	

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.17 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 3/00
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+45%)	12%
Low	25	(Nil)	5%

Insider Decisions

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

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	70	61	54
to Sell	48	43	41
Hld's(000)	16809	16765	16375

Percent shares traded 9 6 3

% TOT. RETURN 8/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-37.1	-4.4
3 yr.	-11.4	0.4
5 yr.	14.6	32.3

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
11.86	12.86	14.70	16.13	16.80	18.14	19.48	23.45	26.53	27.75	29.28	30.45	35.59	37.43	41.50	37.06	*32.20*	*35.15*	Revenues per sh	*40.00*
2.25	2.33	2.47	2.78	2.95	2.75	2.91	3.21	3.40	3.44	3.30	2.88	3.35	3.39	3.55	2.81	*2.85*	*3.25*	"Cash Flow" per sh	*4.40*
1.12	1.17	1.19	1.24	1.29	1.29	1.45	1.60	1.68	1.79	1.51	1.50	1.78	1.69	1.78	1.09	*.90*	*1.20*	Earnings per sh A	*1.90*
.84	.86	.88	.90	.93	.96	.99	1.02	1.04	1.06	1.08	1.10	1.12	1.15	1.17	1.19	*1.19*	*1.22*	Div'd Decl'd per sh B ■	*1.30*
1.38	1.36	1.66	2.85	1.79	1.23	1.37	1.85	2.17	2.95	1.97	1.72	2.04	2.35	5.43	7.51	*3.35*	*4.05*	Cap'l Spending per sh	*5.75*
7.62	7.90	8.24	8.61	8.96	9.47	10.30	10.87	11.33	12.25	12.98	14.81	15.80	16.67	17.55	19.14	*19.45*	*20.25*	Book Value per sh C	*22.50*
22.36	22.36	22.36	22.43	23.46	23.76	23.85	23.85	24.65	25.59	25.72	28.98	29.40	29.52	29.85	35.38	*36.00*	*37.00*	Common Shs Outst'g D	*40.00*
15.6	13.8	14.2	14.0	12.8	14.4	13.9	13.5	16.4	16.0	17.8	17.3	15.4	17.3	19.0	30.1	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.92	.91	.95	.88	.74	.75	.79	.88	.84	.87	1.01	.91	.82	.93	1.01	1.84	*Value Line*		Relative P/E Ratio	*1.00*
4.8%	5.3%	5.2%	5.2%	5.6%	5.2%	4.9%	4.7%	3.8%	3.7%	4.0%	4.2%	4.1%	3.9%	3.5%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*

CAPITAL STRUCTURE as of 6/30/09
Total Debt $533.0 mill. **Due in 5 Yrs** $246.0 mill.
LT Debt $411.8 mill. **LT Interest** $20.0 mill.
(LT interest earned: 2.9x)

Leases, Uncapitalized Annual rentals $46 mill.
Pension Assets-12/08 $127.5 mill. **Oblig.** $182.6 mill.
Pfd Stock $15.5 mill. **Pfd Div'd** $.7 mill.
155,000 shs. $3.60-$6.75, cum., no par ($100 liquidating value).
Common Stock 35,611,789 shs.
as of 7/31/09
MARKET CAP: $875 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
464.6	559.4	654.1	710.1	753.2	882.3	1046.4	1105.0	1238.9	1311.2	*1160*	*1300*	Revenues ($mill)	*1600*
36.9	40.2	43.6	46.1	39.7	40.0	52.9	50.8	54.0	35.1	*32.0*	*45.0*	Net Profit ($mill)	*75.0*
32.2%	30.3%	31.5%	30.3%	27.4%	29.8%	34.6%	34.8%	34.1%	30.0%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
.7%	.8%	3.1%	5.7%	5.0%	2.4%	1.7%	1.9%	4.2%	6.1%	*6.0%*	*8.0%*	AFUDC % to Net Profit	*8.0%*
38.7%	39.5%	43.5%	44.0%	43.2%	37.1%	35.0%	33.5%	38.9%	32.9%	*36.0%*	*32.0%*	Long-Term Debt Ratio	*31.0%*
53.9%	53.5%	53.5%	53.4%	54.3%	60.7%	62.9%	64.5%	59.4%	65.6%	*63.0%*	*67.0%*	Common Equity Ratio	*68.0%*
455.6	484.4	522.2	587.2	614.6	706.5	738.2	763.0	882.1	1032.5	*1110*	*1125*	Total Capital ($mill)	*1310*
503.0	515.9	543.0	587.9	633.3	682.1	697.1	718.6	854.0	1037.6	*1100*	*1200*	Net Plant ($mill)	*1500*
9.7%	9.6%	9.3%	9.0%	7.8%	6.8%	8.3%	7.7%	7.2%	4.3%	*3.5%*	*5.0%*	Return on Total Cap'l	*6.5%*
13.2%	13.7%	14.8%	14.0%	11.4%	9.0%	11.0%	10.0%	10.0%	5.1%	*4.5%*	*6.0%*	Return on Shr. Equity	*8.5%*
14.1%	14.8%	14.9%	14.5%	11.7%	9.1%	11.2%	10.2%	10.2%	5.1%	*4.5%*	*6.0%*	Return on Com Equity E	*8.5%*
4.5%	5.4%	5.8%	6.0%	3.2%	2.5%	4.2%	3.3%	3.5%	NMF	*NMF*	*NMF*	Retained to Com Eq	*2.5%*
70%	65%	63%	60%	73%	73%	63%	68%	66%	108%	*136%*	*102%*	All Div'ds to Net Prof	*70%*

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+2.5	+3.3	+3.0
Avg. Indust. Use (MWH)	30169	31458	32402
Avg. Indust. Revs. per KWH (¢)	5.04	5.20	5.15
Capacity at Peak (Mw)	711	NA	NA
Peak Load, Winter (Mw)	690	705	773
Annual Load Factor (%)	66.2	NA	NA
% Change Customers (yr-end)	+.5	+.2	NA
Fixed Charge Cov. (%)	446	410	257

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	8.5%	7.0%	.5%
"Cash Flow"	1.5%	-1.0%	5.0%
Earnings	2.0%	-1.5%	4.0%
Dividends	2.5%	2.0%	2.0%
Book Value	7.0%	8.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	257.8	279.9	280.6	286.7	1105.0
2007	301.1	305.9	302.2	329.7	1238.9
2008	300.2	323.6	352.9	334.5	1311.2
2009	277.2	246.9	*325*	*310.9*	*1160*
2010	*300*	*310*	*340*	*350*	*1300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.50	.37	.45	.37	1.69
2007	.34	.53	.44	.47	1.78
2008	.27	.12	.31	.39	1.09
2009	.12	.07	*.30*	*.41*	*.90*
2010	*.20*	*.20*	*.35*	*.45*	*1.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.28	.28	.28	.28	1.12
2006	.288	.288	.288	.288	1.15
2007	.293	.293	.293	.293	1.17
2008	.298	.298	.298	.298	1.19
2009	.298	.298	.298		

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to over 129,000 customers in a mainly rural area in Minnesota (50% of retail elec. revs.), North Dakota (41%), and South Dakota (9%). Electric revenue breakdown, '08: residential, 31%; commercial & farms, 36%; industrial, 23%; other, 10%. Fuel costs: 10% of revenues. Has operations in manufacturing, plastics, health services, food ingredients, & others. 2008 reported depreciation rate: 4.3%. Has 4,166 employees. Chairman: John MacFarlane. President & Chief Executive Officer: John D. Erickson. Incorporated: Minnesota. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Telephone: 800-664-1259. Internet: www.ottertail.com.

Otter Tail Corporation reported unfavorable results for the second quarter. The company has been operating in a challenging environment in recent periods. Although the retail business benefited from some improvement on the residential front, OTTR continued to experience weakness in the wholesale power market. Meanwhile, the nonelectric businesses have experienced lower orders from major customers, owing to weakness in the broader economy. Looking forward, higher rates and efforts to control expenses should benefit the company. Still, challenges might well persist in the near term. For full-year 2009, the company has lowered its share earnings guidance to $0.70-$1.10. We concur, and have adjusted our estimate at the midpoint. Performance might improve in 2010, assuming a more-favorable operating climate.

The South Dakota Public Utilities Commission granted the company a rate increase of $2.9 million (roughly 11.7%). The approved rates were implemented in July of 2009. Elsewhere, Otter Tail has requested a revenue increase of $6.1 million (5.1%) in North Dakota. It has been granted an interim annual increase of $4.8 million (4.1%) from January onward. A tentative settlement was filed in June. Regulatory authorities have scheduled a hearing for September 28th to consider the settlement. The company's focus on procuring rate relief is important, as it depends upon such approved revenue increases to help it cope with greater costs.

Otter Tail has completed the transition to a holding company structure, effective July 1, 2009. As part of the arrangement, Otter Tail Corporation now functions as a holding company with two main subsidiaries, Otter Tail Power Company and Varistar Corporation, which operates the nonelectric businesses. This new legal structure should be well-received by the regulatory community, and allow for better execution of debt transactions at Otter Tail Power Company.

This stock is unfavorably ranked for year-ahead performance. Looking further out, we expect increased share net by 2012-2014. From the present quotation, this issue offers decent long-term total return potential, on a risk-adjusted basis.

Michael Napoli, CPA *September 25, 2009*

(A) Diluted earnings. Excl. nonrecurring gains: '98, 7¢; '99, 34¢; gains from discont. operations: '04, 8¢; '05, 33¢; '06, 1¢. Next earnings report due early November. (B) Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '08: $4.02/sh. (D) In mill., adj. for split. (E) Regulatory Climate: MN, ND, Average; SD, Above Average.

Company's Financial Strength	A
Stock's Price Stability	75
Price Growth Persistence	40
Earnings Predictability	70

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UIL HOLDINGS NYSE-UIL

RECENT PRICE **25.52** | P/E RATIO **13.6** (Trailing: 11.8 Median: 17.0) | RELATIVE P/E RATIO **0.86** | DIV'D YLD **6.8%** | VALUE LINE

TIMELINESS 3 Raised 11/16/07
SAFETY 2 Raised 2/29/08
TECHNICAL 5 Lowered 8/7/09
BETA .70 (1.00 = Market)

High:	32.5	32.2	33.6	31.8	35.3	27.6	32.8	33.7	43.8	43.0	37.8	31.2
Low:	25.0	23.3	22.7	26.3	16.9	18.5	25.1	27.4	27.4	27.0	25.1	17.0

Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

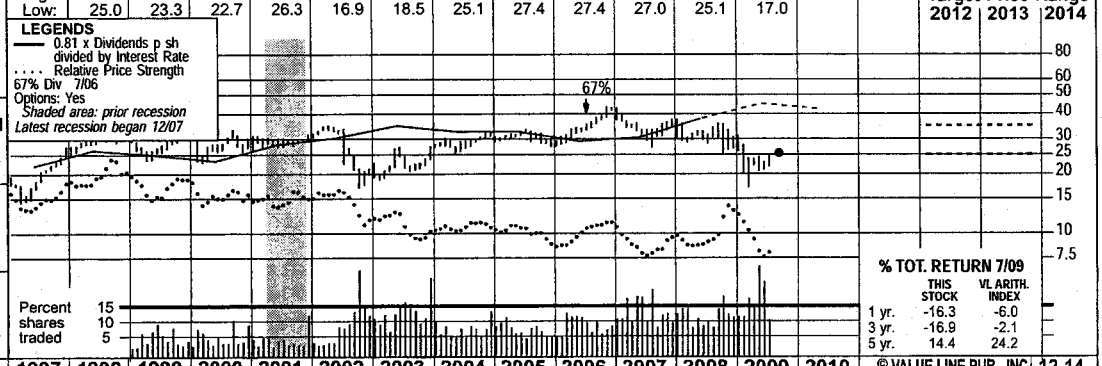
	Price	Gain	Ann'l Total Return
High	35	(+35%)	13%
Low	25	(Nil)	6%

Insider Decisions

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

Institutional Decisions

	3Q2008	4Q2008	1Q2009
to Buy	60	68	55
to Sell	41	43	53
Hld's(000)	12931	11775	11952



% TOT. RETURN 7/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-16.3	-6.0
3 yr.	-16.9	-2.1
5 yr.	14.4	24.2

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
27.82	27.97	29.38	30.89	30.64	29.34	29.01	37.54	46.15	47.55	40.39	45.87	49.88	34.03	39.23	37.69	*32.00*	*33.10*	Revenues per sh	*42.20*
4.90	4.77	4.91	4.81	5.40	5.34	4.67	5.53	6.61	5.89	4.69	4.37	4.13	4.65	5.48	5.93	*5.40*	*5.80*	"Cash Flow" per sh	*6.80*
1.88	1.91	2.18	1.90	1.96	1.80	2.23	2.56	2.53	1.85	1.24	1.54	1.30	1.86	1.87	1.89	*1.90*	*2.00*	Earnings per sh A	*2.25*
1.60	1.66	1.69	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	*1.73*	*1.73*	Div'd Decl'd per sh B ■	*1.73*
4.04	2.69	2.53	2.01	1.44	1.63	1.48	2.31	2.01	2.41	2.19	2.04	2.25	3.09	9.92	8.57	*7.50*	*7.80*	Cap'l Spending per sh	*8.10*
18.03	18.23	18.72	18.72	18.94	19.05	19.55	20.42	21.25	20.28	20.65	22.84	22.39	18.53	18.55	18.85	*19.35*	*19.85*	Book Value per sh C	*21.75*
23.47	23.48	23.50	23.50	23.18	23.39	23.44	23.46	23.53	23.79	23.86	24.01	24.32	24.86	25.03	25.17	*30.00*	*30.20*	Common Shs Outst'g E	*30.80*
13.6	10.5	9.3	11.4	10.1	16.3	12.6	10.8	11.5	15.0	18.0	18.7	23.5	18.7	18.4	16.7	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.80	.69	.62	.71	.58	.85	.72	.70	.59	.82	1.03	.99	1.25	1.01	.98	1.00	*Value Line*		Relative P/E Ratio	*.95*
6.2%	8.2%	8.3%	8.0%	8.8%	5.9%	6.2%	6.2%	5.9%	6.2%	7.7%	6.0%	5.7%	5.0%	5.0%	5.5%	*estimates*		Avg Ann'l Div'd Yield	*5.5%*

CAPITAL STRUCTURE as of 6/30/09
Total Debt $694.3 mill. **Due in 5 Yrs.** $255.0 mill.
LT Debt $594.4 mill. **LT Interest** $30.0 mill.
(LT interest earned: 3.9x)
Leases, Uncapitalized: Ann. rentals $13.1 mill.

Pension Assets-12/08 $212 mill. **Oblig.** $348 mill.

Pfd Stock None

Common Stock 29,929,591 shs.
as of 8/3/09
MARKET CAP: $775 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
680.0	880.9	1085.8	1131.0	963.7	1101.3	1213.1	846.0	982.0	948.7	*960*	*1000*	Revenues ($mill)	*1300*
52.2	59.9	59.4	44.0	29.5	36.9	31.4	45.4	46.7	48.1	*57.0*	*60.5*	Net Profit ($mill)	*69.0*
56.0%	44.5%	44.8%	45.2%	53.1%	45.4%	44.1%	31.2%	39.5%	42.2%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
4.3%	4.4%	3.2%	5.1%	8.5%	1.1%	9.0%	8.0%	8.3%	8.2%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*8.0%*
50.5%	52.2%	49.9%	45.0%	50.1%	47.2%	47.2%	47.0%	50.8%	53.6%	*52.0%*	*52.0%*	Long-Term Debt Ratio	*52.0%*
44.6%	47.8%	50.1%	55.0%	49.9%	52.8%	52.8%	53.0%	49.2%	46.4%	*48.0%*	*48.0%*	Common Equity Ratio	*48.0%*
1026.5	1001.3	998.6	877.8	988.2	1039.6	1031.5	869.2	943.6	1023.6	*1205*	*1250*	Total Capital ($mill)	*1400*
521.5	550.7	546.4	517.1	548.8	563.9	592.1	647.0	878.4	1073.6	*1150*	*1180*	Net Plant ($mill)	*1250*
7.1%	7.9%	8.1%	7.3%	4.3%	4.5%	4.1%	6.5%	6.2%	6.1%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
10.3%	12.5%	11.9%	9.1%	6.0%	6.7%	5.8%	9.9%	10.1%	10.1%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
11.4%	12.5%	11.9%	9.1%	6.0%	6.7%	5.8%	9.9%	10.1%	10.1%	*10.0%*	*10.0%*	Return on Com Equity D	*10.5%*
2.5%	4.0%	3.8%	.6%	NMF	NMF	NMF	NMF	3.1%	1.0%	*1.0%*	*1.5%*	Retained to Com Eq	*2.5%*
78%	68%	68%	93%	NMF	NMF	NMF	NMF	70%	90%	*91%*	*87%*	All Div'ds to Net Prof	*76%*

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-3.1	Nil	-3.2
Avg. Indust. Use (MWH)	657	665	650
Avg. Indust. Revs. per KWH (¢)	10.2	9.9	8.4
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	Nil	+.5	Nil
Fixed Charge Cov. (%)	323	343	322

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	2.0%	-3.5%	*2.0%*
"Cash Flow"	.5%	-1.5%	*4.0%*
Earnings	--	--	*3.0%*
Dividends	--	--	*Nil*
Book Value	--	-2.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	200.3	199.8	261.1	184.8	846.0
2007	274.6	216.7	267.9	222.8	982.0
2008	234.6	216.1	278.7	219.3	948.7
2009	235.5	200.4	*284.1*	*240*	*960*
2010	*240*	*230*	*290*	*240*	*1000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.15	.42	1.21	.08	1.86
2007	.22	.38	.92	.35	1.87
2008	.23	.45	.86	.35	1.89
2009	.48	.51	*.65*	*.26*	*1.90*
2010	*.45*	*.47*	*.75*	*.33*	*2.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.432	.432	.432	.432	1.73
2006	.432	.432	.432	.432	1.73
2007	.432	.432	.432	.432	1.73
2008	.432	.432	.432	.432	1.73
2009	.432	.432	.432		

BUSINESS: UIL Holdings, parent of The United Illuminating Company, provides electricity to 324,000 customers in largely urban and suburban southern Connecticut. Revenue distribution: resid, 40%; commer, 47%; indust, 12%; other, 1%. Largest industrial customers: primary metals, fabricated metal products, transportation equipment. Sold American Payment Systems in 2004. Sold Xcelecom in 2006. Fuel costs: 54% of revenues; labor costs, 14%. 2008 depreciation rate: 4.0%. Has 981 employees. Non-Executive Chairman: F. Patrick McFadden. Chief Executive Officer & President: James P. Torgerson. Incorporated: Connecticut. Address: 157 Church Street, P.O. Box 1564, New Haven, Connecticut 06506-0901. Telephone: 203-499-2394. Internet: www.uil.com.

UIL Holdings posted strong second-quarter results. The Connecticut-based energy provider reported share earnings of $0.51 for the period, up 13% from last year's figure. Performance was primarily driven by increased distribution profits (up 30% year over year), reflecting the recent rate relief in the company's Connecticut service area. Decreased uncollectible expense and lower operating and maintenance costs further aided the bottom-line advance. Meanwhile, transmission operations declined slightly on a year-over-year basis, despite the completion of the Middletown-Norwalk 345-kilovolt project, which came on line in December of last year.

Expansion projects and infrastructure upgrades ought to boost earnings in the years ahead. Last year, the United Illuminating Company (UIL's power distributor) entered into a 50-50 joint venture with NRG Energy to construct the GenConn project. The project consists of two, 200 megawatt peaking generation units, one located in Devon and the other in Middletown. Management indicated that construction of the Devon site is already under way and is scheduled to be in service by June, 2010, while Middletown is scheduled for June, 2011. Upon their completion, we believe these additions will largely improve United Illuminating's generation capabilities, and act as key catalysts down the road.

The company has revised its capital expenditure program. Management indicated it now intends to spend about $125 million in 2009, up from previous the range of $75 million to $90 million. Over the next 10 years, UIL forecasts it will spend $1.7 billion on capital projects, with approximately 70% geared toward distribution, 25% toward transmission, and the remaining 5% for United Illuminating's 50-50 joint venture with NRG Energy (GenConn project).

These neutrally ranked shares may appeal to income-oriented investors. The stock currently offers a yield (6.8%) that is almost two full percentage points above the utility average. However, the high payout ratio indicates that an increase in the dividend is unlikely over the 3- to 5-year pull.

Michael Ratty *August 28, 2009*

(A) EPS basic. Excl. nonrecur. gains (losses): '92, 35¢; '93, (34¢); '94, (6¢); '96, 17¢; '00, 4¢; '03, (26¢); '04, $2.14; '06, ($5.07). Next egs. report due early Nov. (B) Div'ds historically paid in early Jan., early April, early July, and early Oct. ■ Div'd reinvest. plan avail. (C) Incl. deferred chgs. & regul. assets. In '08: $30.77/sh. (D) Rate base: orig. cost. Rate allowed on common equity in '08: 8.75%. Earned on average common equity in '08: 10.0%. Regul. Clim.: Below Average. (E) In millions. Adjust for stock dividends.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	70

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ATTACHMENT B

Proven Ratings, Research & Recommendations

Zacks.com Quotes and Research

ALLETE INC (NYSE)

Scottrade

ALE	33.72	-0.14	(0.42%)	Vol. 81,018	14:52 ET

ALLETE is a multi-services company. ALLETE's holdings include the one of the largest wholesale automobile auction networks in North America; a provider of independent auto dealer inventory financing; one of the largest investor-owned water utilities in Florida and North Carolina; significant real estate holdings in Florida and a low-cost electric utility that serves some of the largest industrial customers in the United States. (Company Press Release)

General Information

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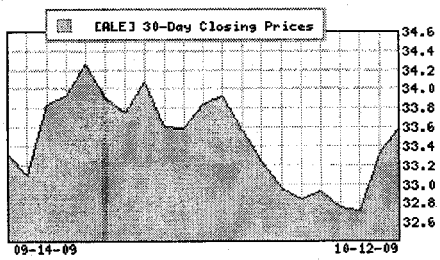
Duluth, MN 55802-2093
Phone: 218-279-5000
Fax: 218-723-3944
Web: www.allete.com
Email: tthorp@allete.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	10/23/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	33.58
52 Week High	41.61
52 Week Low	23.35
Beta	0.70
20 Day Moving Average	188,136.66
Target Price Consensus	36.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	0.78	4 Week	-1.73
12 Week	13.10	12 Week	-0.04
YTD	4.06	YTD	-12.96

Share Information		Dividend Information	
Shares Outstanding (millions)	34.10	Dividend Yield	5.24%
		Annual Dividend	$1.76
Market Capitalization (millions)	1,145.08	Payout Ratio	0.00
Short Ratio	12.77	Change in Payout Ratio	0.00
Last Split Date	09/21/2004	Last Dividend Payout / Amount	08/12/2009 / $0.44

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.52	Current (1=Strong Buy, 5=Strong Sell)	2.00
Current Year EPS Consensus Estimate	2.13	30 Days Ago	2.00
Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	2.25
Next EPS Report Date	10/23/2009	90 Days Ago	2.60

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.79	vs. Previous Year	-21.62%	vs. Previous Year	-13.22%
Trailing 12 Months:	13.02	vs. Previous Quarter	-56.06%	vs. Previous Quarter:	-17.48%
PEG Ratio	3.95				

Price Ratios		ROE		ROA	
Price/Book	1.17	09/30/09	-	09/30/09	-

Price/Cash Flow	7.70	06/30/09	9.25	06/30/09	3.72
Price / Sales	-	03/31/09	9.76	03/31/09	3.99
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	1.59	06/30/09	1.23	06/30/09	10.22
03/31/09	1.78	03/31/09	1.41	03/31/09	10.06
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	14.87	06/30/09	14.87	06/30/09	28.70
03/31/09	14.84	03/31/09	14.84	03/31/09	26.25
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	5.14	06/30/09	0.71	06/30/09	41.48
03/31/09	5.48	03/31/09	0.73	03/31/09	42.22

Zacks.com Quotes and Research

BLACK HILLS CORP (NYSE)

Scottrade

BKH	25.27	▲0.09	(0.36%)	Vol. 195,649	14:57 ET

Black Hills Corp. is an energy company primarily consisting of four principal businesses: electric, coal mining, oil and gas production, and energy marketing. The Company's mission statement is to position the Company nationally to build value for shareholders, offer competitive prices for customers and create opportunities for employees through quality energy products and services.

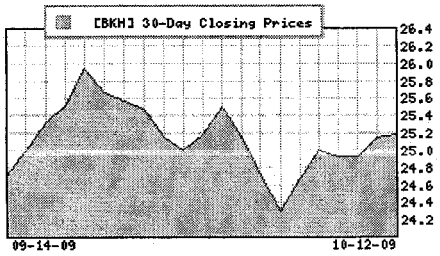
General Information

BLACK HILLS COR
625 Ninth Street
Rapid City, SD 57701
Phone: 605 721-1700
Fax: 605-348-4748
Web: www.blackhillscorp.com
Email: djahr@bh-corp.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	11/04/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	25.18
52 Week High	28.93
52 Week Low	14.54
Beta	1.12
20 Day Moving Average	252,932.75
Target Price Consensus	22.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	1.90	4 Week	-0.64
12 Week	4.70	12 Week	-7.47
YTD	-6.60	YTD	-21.39

Share Information		Dividend Information	
Shares Outstanding (millions)	38.84	Dividend Yield	5.64%
		Annual Dividend	$1.42
Market Capitalization (millions)	978.04	Payout Ratio	0.00
Short Ratio	14.55	Change in Payout Ratio	0.00
Last Split Date	03/11/1998	Last Dividend Payout / Amount	08/14/2009 / $0.35

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.19	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	1.55	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	3.00
Next EPS Report Date	11/04/2009	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.28	vs. Previous Year	-55.88%	vs. Previous Year	67.90%
Trailing 12 Months:	13.47	vs. Previous Quarter	-74.58%	vs. Previous Quarter:	-41.24%
PEG Ratio	2.71				

Price Ratios		ROE		ROA	
Price/Book	0.90	09/30/09	-	09/30/09	-

Price/Cash Flow	5.53	06/30/09	6.63	06/30/09	2.25
Price / Sales	-	03/31/09	7.49	03/31/09	2.57
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	0.71	06/30/09	0.59	06/30/09	5.17
03/31/09	0.55	03/31/09	0.49	03/31/09	6.15
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	-4.26	06/30/09	-4.26	06/30/09	27.84
03/31/09	-6.13	03/31/09	-6.13	03/31/09	27.69
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	8.39	06/30/09	0.67	06/30/09	39.97
03/31/09	6.56	03/31/09	0.44	03/31/09	30.54

Zacks.com Quotes and Research

CH ENERGY GROUP INC (NYSE)

Scottrade

CHG	43.33	-0.34	(-0.78%)	Vol. 19,690	14:47 ET

CENTRAL HUDSON GAS & ELECTRIC generates, purchases and distributes electricity and purchases and distributes gas. The Company, in the opinion of its general counsel, has, with minor exceptions, valid franchises, unlimited in duration, to serve a territory extending about 85 miles along the Hudson River and about 25 to 40 miles east and west from such River. The southern end of the territory is about 25 miles north of New York City, and the northern end is about 10 miles south of the City of Albany.

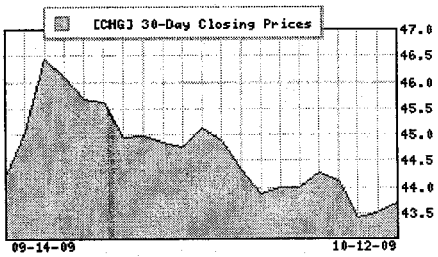
General Information

CH ENERGY GRP
284 South Avenue
Poughkeepsie, NY 12601-4879
Phone: 845 452-2000
Fax: 914 486-5415
Web: www.chenergygroup.com
Email: customerservices@cenhud.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	10/26/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	43.67
52 Week High	52.66
52 Week Low	36.63
Beta	0.38
20 Day Moving Average	41,586.85
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	-1.22	4 Week	-3.69
12 Week	-9.17	12 Week	-19.73
YTD	-15.02	YTD	-28.64

Share Information		Dividend Information	
Shares Outstanding (millions)	15.79	Dividend Yield	4.95%
		Annual Dividend	$2.16
Market Capitalization (millions)	689.55	Payout Ratio	0.00
Short Ratio	15.84	Change in Payout Ratio	0.00
Last Split Date	N/A	Last Dividend Payout / Amount	10/08/2009 / $0.54

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.33	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	2.45	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	3.00
Next EPS Report Date	10/26/2009	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	17.82	vs. Previous Year	-181.82%	vs. Previous Year	-36.16%
Trailing 12 Months:	19.32	vs. Previous Quarter	-106.16%	vs. Previous Quarter:	-47.10%
PEG Ratio	-				

Price Ratios	ROE	ROA

Price/Book	1.30	09/30/09	-	09/30/09	-
Price/Cash Flow	8.87	06/30/09	6.70	06/30/09	2.13
Price / Sales	-	03/31/09	7.30	03/31/09	2.38
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	1.42	06/30/09	1.27	06/30/09	3.01
03/31/09	1.33	03/31/09	1.22	03/31/09	2.99
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	4.99	06/30/09	4.99	06/30/09	33.56
03/31/09	4.94	03/31/09	4.94	03/31/09	35.51
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	22.02	06/30/09	0.88	06/30/09	47.79
03/31/09	24.61	03/31/09	0.74	03/31/09	42.47

Proven Ratings, Research & Recommendations

Zacks.com Quotes and Research

EMPIRE DIST ELEC CO (NYSE)

Scottrade

EDE	18.37	▼-0.20	(-1.08%)	Vol. 64,109	14:52 ET

The Empire District Electric Company is an operating public utility engagedin the generation, purchase, transmission, distribution and sale ofelectricity in parts of Missouri, Kansas, Oklahoma and Arkansas. TheCompany also provides water service to several towns in Missouri.

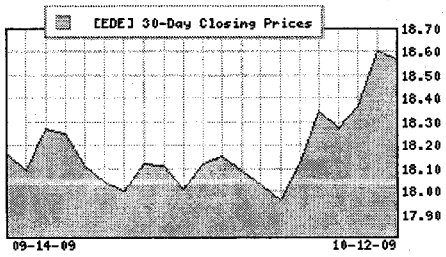
General Information

EMPIRE DISTRICT
602 Joplin Street
Joplin, MO 64801
Phone: 417 625-5100
Fax: 417 625-5173
Web: www.empiredistrict.com
Email: jwatson@empiredistrict.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	10/15/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	18.57
52 Week High	19.68
52 Week Low	11.92
Beta	0.76
20 Day Moving Average	151,225.45
Target Price Consensus	18.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	2.20	4 Week	-0.35
12 Week	6.72	12 Week	-5.68
YTD	5.51	YTD	-10.91

Share Information		Dividend Information	
Shares Outstanding (millions)	34.49	Dividend Yield	6.89%
		Annual Dividend	$1.28
Market Capitalization (millions)	640.52	Payout Ratio	0.00
Short Ratio	7.02	Change in Payout Ratio	0.00
Last Split Date	01/30/1992	Last Dividend Payout / Amount	08/28/2009 / $0.32

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.69	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	1.50	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	3.00
Next EPS Report Date	10/15/2009	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.41	vs. Previous Year	57.14%	vs. Previous Year	0.85%
Trailing 12 Months:	13.56	vs. Previous Quarter	-31.25%	vs. Previous Quarter:	-17.49%
PEG Ratio	-				

Price Ratios		ROE		ROA	
Price/Book	1.20	09/30/09	-	09/30/09	-
Price/Cash Flow		06/30/09		06/30/09	

	6.38		8.73		2.73
Price / Sales	-	03/31/09	8.11	03/31/09	2.63
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	0.59	06/30/09	0.38	06/30/09	-
03/31/09	0.88	03/31/09	0.59	03/31/09	-
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	-	06/30/09	-	06/30/09	15.48
03/31/09	-	03/31/09	-	03/31/09	15.58
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	-	06/30/09	1.21	06/30/09	54.66
03/31/09	-	03/31/09	1.30	03/31/09	56.50

Zacks.com Quotes and Research

HAWAIIAN ELEC INDUSTRIES (NYSE)

Scottrade

HE	18.70	-0.23	(-1.22%)	Vol. 252,604	14:54 ET

Hawaiian Electric Industries, Inc. is a holding company with subsidiaries engaged in the electric utility, savings bank, freight transportation, real estate development and other businesses, primarily in the State of Hawaii, and in the pursuit of independent power projects in Asia and the Pacific.

General Information

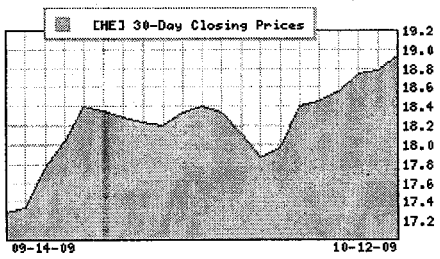
HAWAIIAN ELEC
900 Richards Street
Honolulu, HI 96813
Phone: 808 543-5662
Fax: 808 543-7966
Web: www.hei.com
Email: shollinger@hei.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	11/10/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	18.93
52 Week High	27.55
52 Week Low	12.09
Beta	0.56
20 Day Moving Average	606,279.38
Target Price Consensus	17.65



% Price Change		% Price Change Relative to S&P 500	
4 Week	9.55	4 Week	6.82
12 Week	10.38	12 Week	-2.45
YTD	-14.50	YTD	-28.53

Share Information		Dividend Information	
Shares Outstanding (millions)	91.56	Dividend Yield	6.55%
		Annual Dividend	$1.24
Market Capitalization (millions)	1,733.19	Payout Ratio	0.00
Short Ratio	14.96	Change in Payout Ratio	0.00
Last Split Date	06/14/2004	Last Dividend Payout / Amount	08/20/2009 / $0.31

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.28	Current (1=Strong Buy, 5=Strong Sell)	2.75
Current Year EPS Consensus Estimate	0.94	30 Days Ago	2.75
Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	3.00
Next EPS Report Date	11/10/2009	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	20.21	vs. Previous Year	-64.58%	vs. Previous Year	-32.06%
Trailing 12 Months:	19.12	vs. Previous Quarter	-22.73%	vs. Previous Quarter:	-3.29%
PEG Ratio	3.37				

Price Ratios		ROE		ROA	
Price/Book	1.21	09/30/09	-	09/30/09	-
Price/Cash Flow		06/30/09		06/30/09	

	13.47		6.24		1.20
Price / Sales	-	03/31/09	8.25	03/31/09	1.54
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	0.91	06/30/09	0.91	06/30/09	3.13
03/31/09	0.92	03/31/09	0.92	03/31/09	3.70
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	2.54	06/30/09	2.54	06/30/09	15.69
03/31/09	1.77	03/31/09	1.77	03/31/09	15.87
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	-	06/30/09	0.85	06/30/09	45.83
03/31/09	-	03/31/09	0.84	03/31/09	45.78

Proven Ratings, Research & Recommendations

Zacks.com Quotes and Research

MGE ENERGY INC (NASD)

Scottrade

MGEE	36.20	-0.33	(-0.90%)	Vol. 38,753	14:55 ET

MGE Energy is a public utility holding company. Its principal subsidiary, MGE, generates and distributes electricity to more than 128,000 customers in Dane County, Wisconsin (250 square miles) and purchases, transports and distributes natural gas to nearly 123,000 customers in seven south-central and western Wisconsin counties (1,375 square miles). (Press Release)

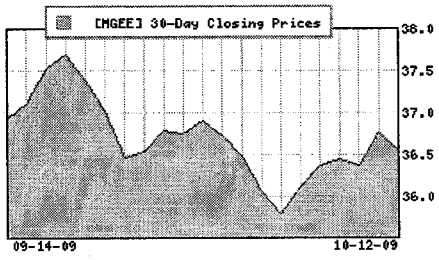
General Information

MGE ENERGY INC
133 South Blair Street
Madison, WI 53703
Phone: 608 252-7000
Fax: 608 252-7098
Web: www.mgeenergy.com
Email: investor@mgeenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	11/04/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	36.53
52 Week High	38.23
52 Week Low	27.27
Beta	0.29
20 Day Moving Average	53,735.85
Target Price Consensus	37



% Price Change		% Price Change Relative to S&P 500	
4 Week	-1.06	4 Week	-3.52
12 Week	4.94	12 Week	-7.25
YTD	10.70	YTD	-6.10

Share Information		Dividend Information	
Shares Outstanding (millions)	23.11	Dividend Yield	4.03%
		Annual Dividend	$1.47
Market Capitalization (millions)	844.35	Payout Ratio	0.00
Short Ratio	7.54	Change in Payout Ratio	0.00
Last Split Date	02/21/1996	Last Dividend Payout / Amount	08/28/2009 / $0.37

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.65	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	2.25	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	3.00
Next EPS Report Date	11/04/2009	90 Days Ago	0.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.24	vs. Previous Year	-10.42%	vs. Previous Year	-13.77%
Trailing 12 Months:	15.55	vs. Previous Quarter	-33.85%	vs. Previous Quarter:	-40.62%
PEG Ratio	3.25				

Price Ratios		ROE		ROA	
Price/Book	1.71	09/30/09	-	09/30/09	-

Price/Cash Flow	8.85	06/30/09	11.11	06/30/09	4.34
Price / Sales	-	03/31/09	11.54	03/31/09	4.49
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	0.93	06/30/09	0.63	06/30/09	9.34
03/31/09	0.96	03/31/09	0.69	03/31/09	9.18
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	14.41	06/30/09	14.41	06/30/09	21.34
03/31/09	14.19	03/31/09	14.19	03/31/09	21.33
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	9.33	06/30/09	0.55	06/30/09	35.61
03/31/09	8.96	03/31/09	0.56	03/31/09	35.77

Zacks.com Quotes and Research

NORTHEAST UTILS (NYSE)

Scottrade

NU	23.29	▼-0.23	(-0.98%)	Vol. 837,579	14:56 ET

Northeast Utilities is the parent company of the Northeast Utilitiessystem. The Northeast Utilities system furnishes franchised retail electric service in Connecticut, New Hampshire and western Massachusetts through three of the company's wholly owned subsidiaries: The Connecticut Light and Power Company; Public Service Company of New Hampshire; and Western Massachusetts Electric Company. It also provides service to a limited number of customers through another wholly owned subsidiary, Holyoke Water Power Company.

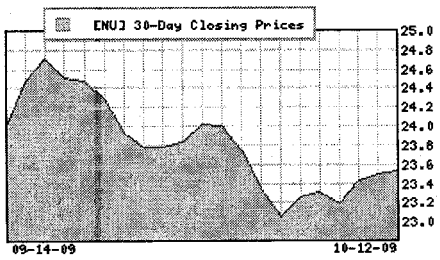
General Information

NORTHEAST UTIL
One Federal Street
Building 111-4
Springfield, MA 01105
Phone: 860-665-5000
Fax: 413-665-3652
Web: www.nu.com
Email: psnhreq@psnh.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	11/09/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	23.52
52 Week High	25.31
52 Week Low	18.82
Beta	0.49
20 Day Moving Average	1,491,480.75
Target Price Consensus	25.94



% Price Change		% Price Change Relative to S&P 500	
4 Week	-2.04	4 Week	-4.48
12 Week	6.57	12 Week	-5.81
YTD	-2.24	YTD	-17.66

Share Information		Dividend Information	
Shares Outstanding (millions)	175.28	Dividend Yield	4.04%
		Annual Dividend	$0.95
Market Capitalization (millions)	4,122.63	Payout Ratio	0.00
		Change in Payout Ratio	0.00
Short Ratio	4.32	Last Dividend Payout / Amount	08/28/2009 / $0.24
Last Split Date	N/A		

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.39	Current (1=Strong Buy, 5=Strong Sell)	1.50
Current Year EPS Consensus Estimate	1.84	30 Days Ago	1.50
Estimated Long-Term EPS Growth Rate	8.50	60 Days Ago	1.44
Next EPS Report Date	11/09/2009	90 Days Ago	1.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.81	vs. Previous Year	27.03%	vs. Previous Year	-7.61%
Trailing 12 Months:	11.76	vs. Previous Quarter	-21.67%	vs. Previous Quarter:	-23.16%
PEG Ratio	1.51				

Price Ratios		ROE		ROA	
Price/Book	1.18	09/30/09	-	09/30/09	-
Price/Cash Flow	3.87	06/30/09	10.01	06/30/09	2.36
Price / Sales	-	03/31/09	9.66	03/31/09	2.24
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	1.23	06/30/09	1.04	06/30/09	5.63
03/31/09	1.26	03/31/09	1.09	03/31/09	5.11
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	8.38	06/30/09	8.38	06/30/09	20.00
03/31/09	7.48	03/31/09	7.48	03/31/09	19.68
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	13.70	06/30/09	1.24	06/30/09	56.01
03/31/09	13.55	03/31/09	1.26	03/31/09	56.39

Proven Ratings, Research & Recommendations

Zacks.com Quotes and Research

NSTAR (NYSE)

Scottrade

NST	31.57	▼-0.19	(-0.60%)	Vol. 341,473	14:57 ET

NSTAR was formed through a merger of BEC Energy and Commonwealth Energy System. The company, headquartered in Boston, Massachusetts provides regulated electric and gas utility services and is also engaged intelecommunications and other non-regulated activities. NSTAR, through its subsidiaries, Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company and Commonwealth Gas Company, serves approximately 1.3 million customers throughout Massachusetts. (Press Release)

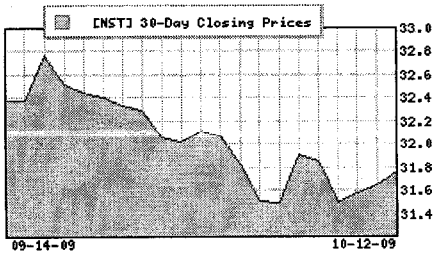
General Information

NSTAR
800 Boylston Street
Boston, MA 02199
Phone: 617 424-2000
Fax: 617 424-4032
Web: www.nstaronline.com
Email: ir@nstar.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	11/05/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	31.76
52 Week High	36.94
52 Week Low	27.17
Beta	0.24
20 Day Moving Average	541,710.31
Target Price Consensus	33.17



% Price Change		% Price Change Relative to S&P 500	
4 Week	-1.91	4 Week	-4.36
12 Week	3.45	12 Week	-8.57
YTD	-12.96	YTD	-26.88

Share Information		Dividend Information	
Shares Outstanding (millions)	106.81	Dividend Yield	4.72%
		Annual Dividend	$1.50
Market Capitalization (millions)	3,392.22	Payout Ratio	0.00
		Change in Payout Ratio	0.00
Short Ratio	10.73	Last Dividend Payout / Amount	10/07/2009 / $0.38
Last Split Date	06/06/2005		

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.83	Current (1=Strong Buy, 5=Strong Sell)	2.33
Current Year EPS Consensus Estimate	2.37	30 Days Ago	1.86
Estimated Long-Term EPS Growth Rate	5.70	60 Days Ago	2.13
Next EPS Report Date	11/05/2009	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.41	vs. Previous Year	12.77%	vs. Previous Year	-4.87%
Trailing 12 Months:	13.87	vs. Previous Quarter	-7.02%	vs. Previous Quarter:	-25.35%
PEG Ratio	2.37				

Price Ratios	ROE	ROA

Price/Book	1.82	09/30/09	-	09/30/09	-
Price/Cash Flow	5.44	06/30/09	13.49	06/30/09	3.05
Price / Sales	-	03/31/09	13.36	03/31/09	3.01
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	0.52	06/30/09	0.49	06/30/09	7.32
03/31/09	0.60	03/31/09	0.57	03/31/09	7.04
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	11.79	06/30/09	11.79	06/30/09	17.45
03/31/09	11.40	03/31/09	11.40	03/31/09	17.35
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	28.12	06/30/09	0.93	06/30/09	48.29
03/31/09	24.77	03/31/09	1.01	03/31/09	50.21

Proven Ratings, Research & Recommendations

Zacks.com Quotes and Research

OTTER TAIL CP (NASD)

Scottrade

OTTR	24.25	-0.03	(-0.12%)	Vol. 53,901	15:02 ET

OTTER TAIL's primary business is the production, transmission, distribution and sale of electric energy. The Company, through its subsidiaries, is also engaged in other businesses which are referred to as Health Services Operations and Diversified Operations.

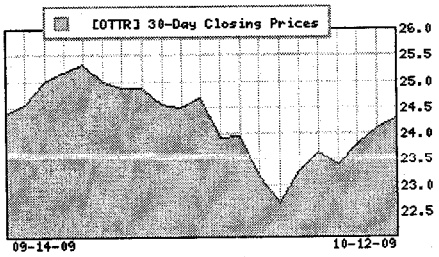
General Information

OTTER TAIL CORP
215 South Cascade Street
Box 496
Fergus Falls, MN 56538-0496
Phone: 218-739-8479
Fax: 218-998-3165
Web: www.ottertail.com
Email: sharesvc@ottertail.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	11/09/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	24.28
52 Week High	25.40
52 Week Low	14.99
Beta	1.13
20 Day Moving Average	137,201.30
Target Price Consensus	22.33



% Price Change		% Price Change Relative to S&P 500	
4 Week	-0.33	4 Week	-2.82
12 Week	3.32	12 Week	-8.69
YTD	4.07	YTD	-12.92

Share Information		Dividend Information	
Shares Outstanding (millions)	35.61	Dividend Yield	4.90%
Market Capitalization (millions)	864.66	Annual Dividend	$1.19
Short Ratio	27.23	Payout Ratio	0.00
Last Split Date	03/16/2000	Change in Payout Ratio	0.00
		Last Dividend Payout / Amount	08/12/2009 / $0.30

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.29	Current (1=Strong Buy, 5=Strong Sell)	4.00
Current Year EPS Consensus Estimate	0.88	30 Days Ago	4.00
Estimated Long-Term EPS Growth Rate	11.70	60 Days Ago	4.00
Next EPS Report Date	11/09/2009	90 Days Ago	4.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	27.59	vs. Previous Year	-36.36%	vs. Previous Year	-23.80%
Trailing 12 Months:	26.11	vs. Previous Quarter	-58.82%	vs. Previous Quarter:	-11.06%
PEG Ratio	2.36				

Price Ratios		ROE		ROA	
Price/Book	1.29	09/30/09	-	09/30/09	-

Price/Cash Flow	8.58	06/30/09	4.80	06/30/09	1.93
Price / Sales	-	03/31/09	5.20	03/31/09	2.02
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	1.30	06/30/09	0.92	06/30/09	2.66
03/31/09	1.29	03/31/09	0.94	03/31/09	2.56
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	3.20	06/30/09	3.20	06/30/09	18.76
03/31/09	3.24	03/31/09	3.24	03/31/09	18.91
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	8.88	06/30/09	0.62	06/30/09	37.76
03/31/09	9.17	03/31/09	0.51	03/31/09	34.68

Proven Ratings, Research & Recommendations

Zacks.com Quotes and Research

UIL HLDG CORP (NYSE)

Scottrade

UIL	26.80	▼-0.16	(-0.59%)	Vol. 32,781	15:02 ET

UIL Holdings Corporation is the holding company for The United Illuminating Company and United Resources. United Illuminating Company is aNew Haven-based regional distribution utility that provides electricity and energy-related services to customers in municipalities in the Greater New Haven and Greater Bridgeport areas.(PR)

General Information

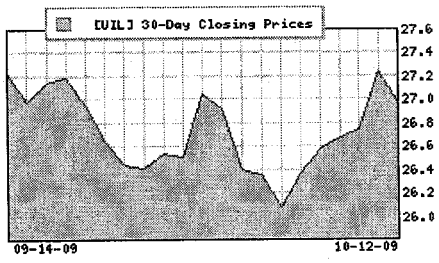
UIL HOLDINGS CP
157 Church Street
New Haven, CT 06506
Phone: 203-499-2000
Fax: 203-499-3626
Web: www.uil.com
Email: Susan.Allen@uinet.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	11/10/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	26.96
52 Week High	34.67
52 Week Low	17.00
Beta	0.73
20 Day Moving Average	96,142.35
Target Price Consensus	26.75



% Price Change		% Price Change Relative to S&P 500	
4 Week	-0.96	4 Week	-3.43
12 Week	15.71	12 Week	2.26
YTD	-10.22	YTD	-23.53

Share Information		Dividend Information	
Shares Outstanding (millions)	29.93	Dividend Yield	6.41%
		Annual Dividend	$1.73
Market Capitalization (millions)	806.91	Payout Ratio	0.00
		Change in Payout Ratio	0.00
Short Ratio	6.61	Last Dividend Payout / Amount	09/15/2009 / $0.43
Last Split Date	07/05/2006		

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.69	Current (1=Strong Buy, 5=Strong Sell)	2.00
Current Year EPS Consensus Estimate	1.93	30 Days Ago	2.00
Estimated Long-Term EPS Growth Rate	4.20	60 Days Ago	2.00
Next EPS Report Date	11/10/2009	90 Days Ago	1.33

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.01	vs. Previous Year	13.33%	vs. Previous Year	-7.29%
Trailing 12 Months:	12.37	vs. Previous Quarter	8.51%	vs. Previous Quarter:	-14.92%
PEG Ratio	3.33				

Price Ratios		ROE		ROA	
Price/Book	1.39	09/30/09	-	09/30/09	-
Price/Cash Flow		06/30/09		06/30/09	

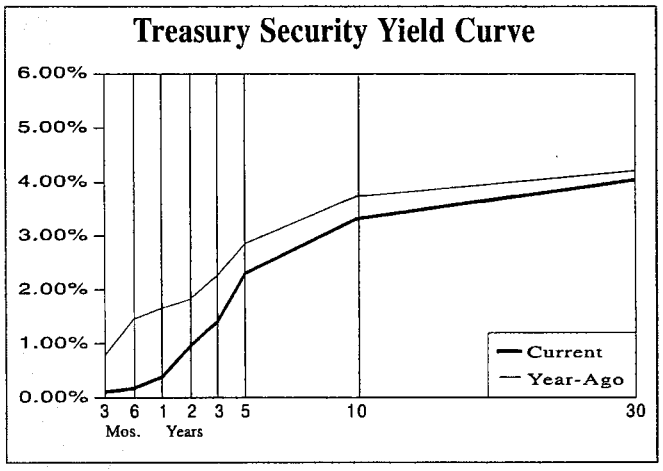
	5.22		11.29		2.73
Price / Sales	-	03/31/09	11.39	03/31/09	2.69
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	1.05	06/30/09	1.03	06/30/09	6.03
03/31/09	0.76	03/31/09	0.75	03/31/09	5.67
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	10.13	06/30/09	10.13	06/30/09	19.44
03/31/09	9.62	03/31/09	9.62	03/31/09	18.87
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	160.84	06/30/09	1.04	06/30/09	51.04
03/31/09	156.24	03/31/09	1.19	03/31/09	54.43

ATTACHMENT C

Selected Yields

	Recent (9/30/09)	3 Months Ago (6/30/09)	Year Ago (10/01/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.18	0.41	3.05
3-month LIBOR	0.29	0.60	4.15
Bank CDs			
6-month	0.40	0.65	1.61
1-year	0.64	0.86	2.14
5-year	2.27	1.92	3.77
U.S. Treasury Securities			
3-month	0.11	0.18	0.80
6-month	0.17	0.34	1.45
1-year	0.38	0.48	1.66
5-year	2.31	2.56	2.86
10-year	3.31	3.53	3.74
10-year (inflation-protected)	1.53	1.80	2.25
30-year	4.05	4.33	4.22
30-year Zero	4.13	4.41	4.22

	Recent (9/30/09)	3 Months Ago (6/30/09)	Year Ago (10/01/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.63	3.77	5.64
FHLMC 6.5% (Gold)	2.82	3.23	5.63
FNMA 6.5%	2.60	3.07	5.54
FNMA ARM	2.62	2.53	3.88
Corporate Bonds			
Financial (10-year) A	5.61	6.87	7.25
Industrial (25/30-year) A	5.31	5.96	6.52
Utility (25/30-year) A	5.40	5.79	6.46
Utility (25/30-year) Baa/BBB	5.73	6.88	6.61
Foreign Bonds (10-Year)			
Canada	3.31	3.36	3.71
Germany	3.22	3.39	4.00
Japan	1.30	1.36	1.51
United Kingdom	3.59	3.69	4.43
Preferred Stocks			
Utility A	5.77	6.10	6.53
Financial A	6.61	7.75	7.78
Financial Adjustable A	5.48	5.48	5.48



	Recent (9/30/09)	3 Months Ago (6/30/09)	Year Ago (10/01/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.04	4.79	5.23
25-Bond Index (Revs)	4.86	5.77	5.56
General Obligation Bonds (GOs)			
1-year Aaa	0.37	0.40	2.10
1-year A	0.80	1.10	2.20
5-year Aaa	1.57	2.07	3.32
5-year A	2.00	3.47	3.37
10-year Aaa	2.57	3.23	4.23
10-year A	2.95	4.75	4.43
25/30-year Aaa	3.92	4.66	5.29
25/30-year A	4.45	6.18	5.67
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.70	6.05	5.45
Electric AA	4.75	6.10	5.40
Housing AA	5.10	6.50	5.90
Hospital AA	5.25	6.45	5.95
Toll Road Aaa	4.75	6.05	5.40

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/23/09	9/9/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	854633	823202	31431	763053	790331	675003
Borrowed Reserves	307300	320295	-12995	347846	444263	518826
Net Free/Borrowed Reserves	547333	502907	44426	415208	346068	156178

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	9/14/09	9/7/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1668.5	1666.8	1.7	3.0%	13.4%	16.7%
M2 (M1+savings+small time deposits)	8303.3	8307.2	-3.9	-3.9%	-1.4%	7.6%

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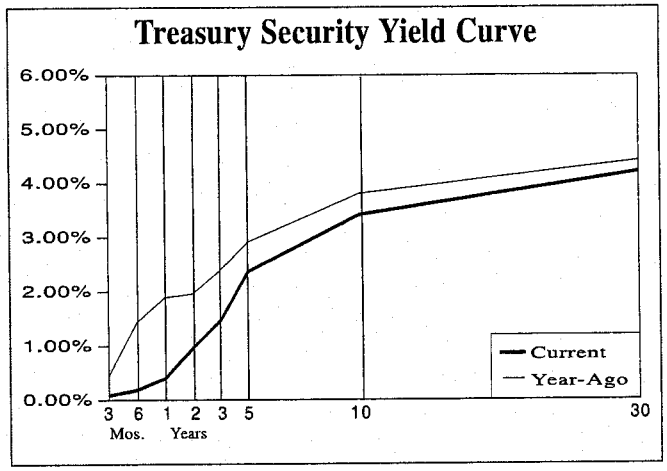
Selected Yields

	Recent (9/23/09)	3 Months Ago (6/24/09)	Year Ago (9/24/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.21	0.44	2.85
3-month LIBOR	0.29	0.60	3.48
Bank CDs			
6-month	0.40	0.65	1.61
1-year	0.64	0.87	2.14
5-year	2.27	1.92	3.77
U.S. Treasury Securities			
3-month	0.09	0.18	0.46
6-month	0.19	0.31	1.43
1-year	0.40	0.46	1.89
5-year	2.37	2.71	2.91
10-year	3.42	3.69	3.81
10-year (inflation-protected)	1.60	1.88	1.99
30-year	4.20	4.43	4.41
30-year Zero	4.30	4.50	4.39

	Recent (9/23/09)	3 Months Ago (6/24/09)	Year Ago (9/24/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.77	3.79	5.56
FHLMC 6.5% (Gold)	2.57	3.28	5.43
FNMA 6.5%	2.36	3.06	5.34
FNMA ARM	2.62	2.53	3.86
Corporate Bonds			
Financial (10-year) A	5.68	6.75	7.14
Industrial (25/30-year) A	5.47	6.07	6.53
Utility (25/30-year) A	5.58	5.89	6.50
Utility (25/30-year) Baa/BBB	6.14	7.30	6.74
Foreign Bonds (10-Year)			
Canada	3.42	3.45	3.66
Germany	3.37	3.42	4.16
Japan	1.35	1.39	1.49
United Kingdom	3.75	3.70	4.57
Preferred Stocks			
Utility A	6.08	6.05	6.85
Financial A	6.55	8.21	8.04
Financial Adjustable A	5.47	5.47	5.47



	Recent (9/23/09)	3 Months Ago (6/24/09)	Year Ago (9/24/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.20	4.86	5.03
25-Bond Index (Revs)	4.98	5.78	5.44
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.40	2.15
1-year A	0.90	0.90	2.25
5-year Aaa	1.61	2.17	3.10
5-year A	3.01	2.60	3.20
10-year Aaa	2.65	3.27	4.02
10-year A	4.15	3.63	4.22
25/30-year Aaa	4.03	4.70	5.13
25/30-year A	5.60	5.15	5.45
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.35	5.80	5.55
Electric AA	5.40	5.90	5.60
Housing AA	5.80	6.10	5.90
Hospital AA	5.80	6.05	5.95
Toll Road Aaa	5.35	5.85	5.65

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/9/09	8/26/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	823201	794546	28655	754077	773683	643434
Borrowed Reserves	320295	327647	-7352	369408	467326	513721
Net Free/Borrowed Reserves	502906	466899	36007	384669	306357	129712

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	9/7/09	8/31/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1667.2	1635.6	31.6	9.2%	11.6%	18.0%
M2 (M1+savings+small time deposits)	8306.2	8293.6	12.6	-3.0%	-0.5%	8.0%

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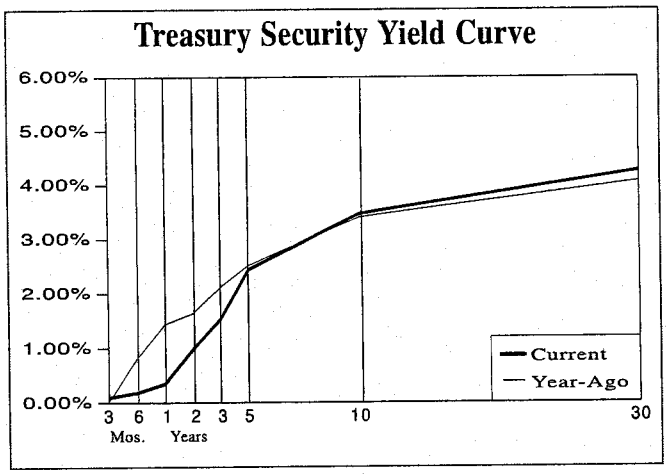
Selected Yields

	Recent (9/16/09)	3 Months Ago (6/17/09)	Year Ago (9/17/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.21	0.42	2.50
3-month LIBOR	0.29	0.61	3.06
Bank CDs			
6-month	0.40	0.66	1.61
1-year	0.65	0.87	2.26
5-year	2.30	1.92	4.10
U.S. Treasury Securities			
3-month	0.10	0.16	0.04
6-month	0.19	0.31	0.81
1-year	0.35	0.47	1.44
5-year	2.44	2.68	2.52
10-year	3.47	3.69	3.41
10-year (inflation-protected)	1.60	1.92	1.74
30-year	4.26	4.51	4.07
30-year Zero	4.37	4.60	4.11

	Recent (9/16/09)	3 Months Ago (6/17/09)	Year Ago (9/17/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.57	4.00	5.43
FHLMC 6.5% (Gold)	2.71	3.13	5.33
FNMA 6.5%	2.47	2.96	5.24
FNMA ARM	2.62	2.53	3.86
Corporate Bonds			
Financial (10-year) A	5.74	6.70	6.79
Industrial (25/30-year) A	5.55	6.13	6.08
Utility (25/30-year) A	5.59	5.95	5.94
Utility (25/30-year) Baa/BBB	6.21	7.54	6.51
Foreign Bonds (10-Year)			
Canada	3.38	3.44	3.44
Germany	3.34	3.48	4.02
Japan	1.33	1.47	1.50
United Kingdom	3.69	3.79	4.41
Preferred Stocks			
Utility A	6.29	5.47	6.56
Financial A	6.73	8.72	8.77
Financial Adjustable A	5.47	5.47	5.47



	Recent (9/16/09)	3 Months Ago (6/17/09)	Year Ago (9/17/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.33	4.86	4.54
25-Bond Index (Revs)	5.33	5.76	5.09
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.40	1.73
1-year A	0.90	1.10	1.83
5-year Aaa	1.71	2.25	2.79
5-year A	2.15	3.65	2.84
10-year Aaa	2.78	3.33	3.59
10-year A	3.15	4.85	3.79
25/30-year Aaa	4.10	4.72	4.94
25/30-year A	4.56	6.24	5.32
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.85	6.30	5.05
Electric AA	4.90	6.35	5.00
Housing AA	5.30	6.65	5.40
Hospital AA	5.35	6.60	5.45
Toll Road Aaa	4.90	6.30	5.00

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/9/09	8/26/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	823201	794546	28655	754077	773683	643434
Borrowed Reserves	320295	327647	-7352	369408	467326	513721
Net Free/Borrowed Reserves	502906	466899	36007	384669	306357	129712

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	8/31/09	8/24/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1635.7	1639.0	-3.3	9.9%	9.6%	17.6%
M2 (M1+savings+small time deposits)	8293.7	8282.4	11.3	-3.4%	0.1%	7.6%

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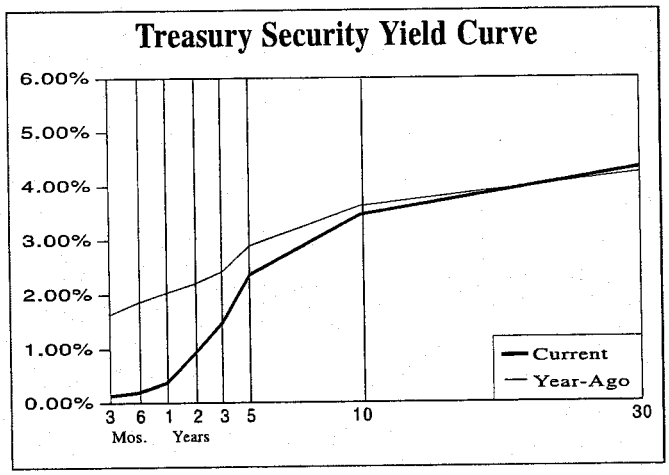
Selected Yields

	Recent (9/02/09)	3 Months Ago (6/10/09)	Year Ago (9/10/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.21	0.34	3.00
3-month LIBOR	0.30	0.64	2.82
Bank CDs			
6-month	0.42	0.66	1.60
1-year	0.72	0.87	2.26
5-year	2.30	1.92	4.15
U.S. Treasury Securities			
3-month	0.14	0.17	1.64
6-month	0.20	0.31	1.86
1-year	0.38	0.53	2.04
5-year	2.37	2.92	2.90
10-year	3.47	3.95	3.63
10-year (inflation-protected)	1.63	1.86	1.61
30-year	4.33	4.76	4.23
30-year Zero	4.46	4.84	4.27
Mortgage-Backed Securities			
GNMA 6.5%	3.77	4.26	5.31
FHLMC 6.5% (Gold)	2.90	3.07	5.36
FNMA 6.5%	2.72	2.91	5.20
FNMA ARM	2.62	2.53	3.86
Corporate Bonds			
Financial (10-year) A	6.04	6.82	6.51
Industrial (25/30-year) A	5.63	6.50	6.08
Utility (25/30-year) A	5.65	6.28	6.04
Utility (25/30-year) Baa/BBB	6.40	7.76	6.49
Foreign Bonds (10-Year)			
Canada	3.42	3.64	3.46
Germany	3.42	3.69	4.07
Japan	1.33	1.55	1.52
United Kingdom	3.76	3.92	4.46
Preferred Stocks			
Utility A	5.84	7.62	6.12
Financial A	6.62	8.63	7.33
Financial Adjustable A	5.54	5.46	5.46
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.37	4.71	4.62
25-Bond Index (Revs)	5.43	5.63	5.15
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.40	1.58
1-year A	1.10	0.90	1.68
5-year Aaa	1.76	2.14	2.69
5-year A	3.16	2.57	2.79
10-year Aaa	2.88	3.21	3.48
10-year A	4.40	3.57	3.68
25/30-year Aaa	4.21	4.72	4.53
25/30-year A	5.75	5.16	4.77
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.50	5.85	4.87
Electric AA	5.55	5.95	4.92
Housing AA	6.05	6.25	5.13
Hospital AA	6.05	6.20	5.15
Toll Road Aaa	5.50	6.00	4.95



Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	8/26/09	8/12/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	794546	708501	86045	756262	762985	613021
Borrowed Reserves	327647	340534	-12887	394750	486512	508084
Net Free/Borrowed Reserves	466899	367967	98932	361513	276473	104936

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	8/24/09	8/17/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1639.0	1656.3	-17.3	9.4%	12.4%	18.0%
M2 (M1+savings+small time deposits)	8282.4	8310.5	-28.1	-4.3%	0.5%	7.6%

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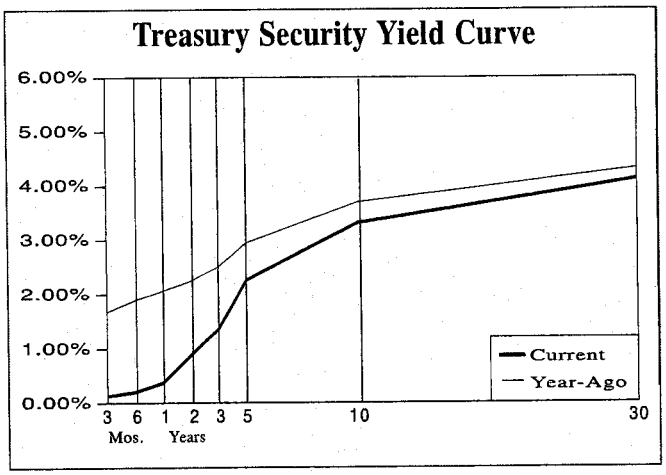
Selected Yields

	Recent (9/02/09)	3 Months Ago (6/3/09)	Year Ago (9/03/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.23	0.28	2.88
3-month LIBOR	0.33	0.64	2.81
Bank CDs			
6-month	0.42	0.70	1.60
1-year	0.72	0.92	2.26
5-year	2.25	1.92	4.15
U.S. Treasury Securities			
3-month	0.13	0.12	1.68
6-month	0.21	0.25	1.90
1-year	0.38	0.44	2.07
5-year	2.27	2.42	2.95
10-year	3.31	3.54	3.70
10-year (inflation-protected)	1.74	1.63	1.64
30-year	4.12	4.45	4.32
30-year Zero	4.22	4.53	4.37

	Recent (9/02/09)	3 Months Ago (6/3/09)	Year Ago (9/03/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.92	3.37	5.60
FHLMC 6.5% (Gold)	3.07	2.89	5.67
FNMA 6.5%	2.85	2.78	5.48
FNMA ARM	2.62	2.53	3.89
Corporate Bonds			
Financial (10-year) A	5.79	6.82	6.69
Industrial (25/30-year) A	5.43	6.35	6.11
Utility (25/30-year) A	5.45	6.17	6.13
Utility (25/30-year) Baa/BBB	6.14	7.83	6.54
Foreign Bonds (10-Year)			
Canada	3.33	3.36	3.48
Germany	3.23	3.57	4.14
Japan	1.32	1.55	1.47
United Kingdom	3.55	3.79	4.50
Preferred Stocks			
Utility A	6.37	6.10	6.16
Financial A	5.94	8.35	6.97
Financial Adjustable A	5.53	5.53	5.53



	Recent (9/02/09)	3 Months Ago (6/3/09)	Year Ago (9/03/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.53	4.61	4.68
25-Bond Index (Revs)	5.99	5.53	5.17
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.40	1.58
1-year A	0.90	1.13	1.68
5-year Aaa	1.80	2.02	2.74
5-year A	2.24	3.45	2.84
10-year Aaa	2.93	3.01	3.55
10-year A	3.30	4.55	3.75
25/30-year Aaa	4.36	4.64	4.69
25/30-year A	4.82	6.16	5.07
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.30	6.20	4.85
Electric AA	5.40	6.25	4.80
Housing AA	5.55	6.55	5.15
Hospital AA	5.60	6.50	5.25
Toll Road Aaa	5.35	6.30	4.80

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	8/26/09	8/12/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	794546	708501	86045	756262	762985	613020
Borrowed Reserves	327647	340534	-12887	394750	486512	508084
Net Free/Borrowed Reserves	466899	367967	98932	361512	276473	104936

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	8/17/09	8/10/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1658.2	1663.6	-5.4	17.9%	13.1%	19.9%
M2 (M1+savings+small time deposits)	8312.4	8318.3	-5.9	-1.5%	1.1%	8.1%

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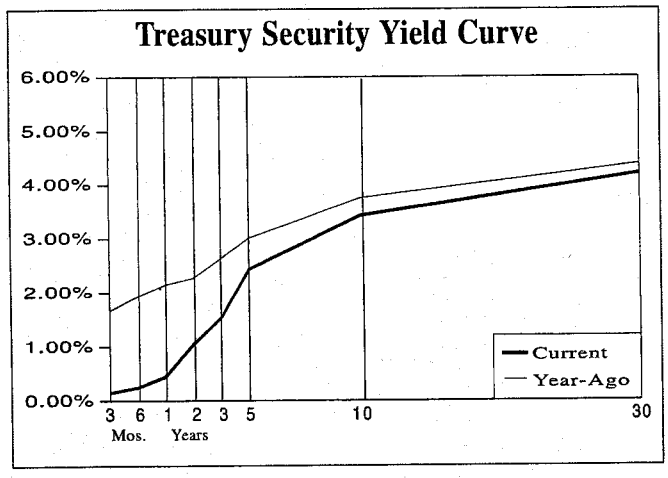
Selected Yields

	Recent (8/26/09)	3 Months Ago (5/27/09)	Year Ago (8/27/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.24	0.31	2.84
3-month LIBOR	0.37	0.67	2.81
Bank CDs			
6-month	0.48	0.69	1.60
1-year	0.72	0.92	2.26
5-year	2.25	1.92	4.15
U.S. Treasury Securities			
3-month	0.15	0.16	1.67
6-month	0.25	0.29	1.94
1-year	0.45	0.47	2.15
5-year	2.44	2.44	3.01
10-year	3.43	3.74	3.76
10-year (inflation-protected)	1.70	1.81	1.51
30-year	4.20	4.63	4.38
30-year Zero	4.29	4.74	4.44

	Recent (8/26/09)	3 Months Ago (5/27/09)	Year Ago (8/27/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.95	3.34	5.62
FHLMC 6.5% (Gold)	2.95	2.61	5.66
FNMA 6.5%	2.73	2.28	5.56
FNMA ARM	2.75	2.78	4.02
Corporate Bonds			
Financial (10-year) A	6.13	7.00	6.60
Industrial (25/30-year) A	5.52	6.61	6.18
Utility (25/30-year) A	5.53	6.44	6.15
Utility (25/30-year) Baa/BBB	6.17	8.01	6.57
Foreign Bonds (10-Year)			
Canada	3.40	3.57	3.53
Germany	3.24	3.63	4.17
Japan	1.32	1.48	1.45
United Kingdom	3.55	3.75	4.51
Preferred Stocks			
Utility A	6.34	6.08	6.16
Financial A	5.99	8.28	7.08
Financial Adjustable A	5.52	5.53	5.53



	Recent (8/26/09)	3 Months Ago (5/27/09)	Year Ago (8/27/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.58	4.44	4.64
25-Bond Index (Revs)	5.62	5.42	5.15
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.42	1.56
1-year A	1.10	1.15	1.66
5-year Aaa	1.81	1.87	2.79
5-year A	3.21	3.29	2.89
10-year Aaa	2.96	2.84	3.60
10-year A	4.48	4.40	3.80
25/30-year Aaa	4.54	4.41	4.71
25/30-year A	6.05	5.89	4.95
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.80	5.94	5.05
Electric AA	5.85	6.04	5.10
Housing AA	6.35	6.34	5.25
Hospital AA	6.35	6.29	5.30
Toll Road Aaa	5.80	6.09	5.10

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	8/12/09	7/29/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	708499	728888	-20389	768051	749904	583661
Borrowed Reserves	340534	347217	-6683	427197	503204	502158
Net Free/Borrowed Reserves	367965	381671	-13706	340854	246700	81504

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	8/10/09	8/3/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1663.8	1677.2	-13.4	17.9%	12.1%	18.7%
M2 (M1+savings+small time deposits)	8318.3	8323.9	-5.6	-0.7%	1.6%	7.9%

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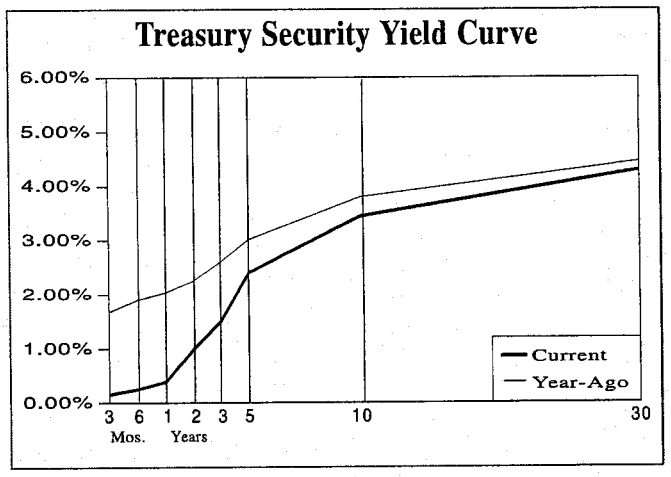
Selected Yields

	Recent (8/19/09)	3 Months Ago (5/20/09)	Year Ago (8/20/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.23	0.26	2.77
3-month LIBOR	0.42	0.72	2.81
Bank CDs			
6-month	0.48	0.72	1.63
1-year	0.72	0.97	2.26
5-year	1.90	1.92	4.16
U.S. Treasury Securities			
3-month	0.16	0.17	1.68
6-month	0.25	0.27	1.90
1-year	0.39	0.42	2.04
5-year	2.41	2.03	3.01
10-year	3.45	3.19	3.80
10-year (inflation-protected)	1.69	1.51	1.54
30-year	4.29	4.14	4.45
30-year Zero	4.42	4.26	4.51

	Recent (8/19/09)	3 Months Ago (5/20/09)	Year Ago (8/20/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.85	3.02	5.63
FHLMC 6.5% (Gold)	2.95	2.27	5.69
FNMA 6.5%	2.73	2.03	5.58
FNMA ARM	2.75	2.78	4.02
Corporate Bonds			
Financial (10-year) A	6.23	6.66	6.46
Industrial (25/30-year) A	5.60	6.21	6.22
Utility (25/30-year) A	5.64	6.01	6.17
Utility (25/30-year) Baa/BBB	6.23	7.59	6.65
Foreign Bonds (10-Year)			
Canada	3.40	3.14	3.58
Germany	3.25	3.43	4.12
Japan	1.35	1.43	1.45
United Kingdom	3.59	3.58	4.56
Preferred Stocks			
Utility A	6.02	6.09	6.18
Financial A	7.10	8.37	7.26
Financial Adjustable A	5.52	5.52	5.52



	Recent (8/19/09)	3 Months Ago (5/20/09)	Year Ago (8/20/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.65	4.61	4.67
25-Bond Index (Revs)	5.66	5.53	5.17
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.43	1.56
1-year A	0.90	1.16	1.66
5-year Aaa	1.73	1.82	2.80
5-year A	2.17	3.25	2.90
10-year Aaa	2.94	2.81	3.58
10-year A	3.30	4.35	3.78
25/30-year Aaa	4.54	4.40	4.66
25/30-year A	5.00	5.92	5.04
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.50	5.97	4.80
Electric AA	5.60	6.02	4.75
Housing AA	5.75	6.32	5.10
Hospital AA	5.85	6.27	5.20
Toll Road Aaa	5.55	6.07	4.75

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	8/12/09	7/29/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	708500	728855	-20355	768047	749902	583660
Borrowed Reserves	340534	347217	-6683	427197	503204	502158
Net Free/Borrowed Reserves	367966	381638	-13672	340849	246697	81502

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	8/3/09	7/27/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1677.5	1647.6	29.9	17.9%	14.1%	18.8%
M2 (M1+savings+small time deposits)	8323.6	8365.6	-42.0	0.1%	2.0%	7.9%

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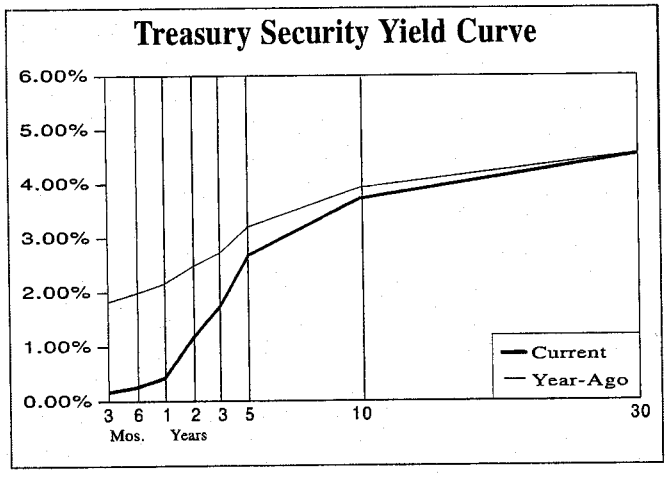
Selected Yields

	Recent (8/12/09)	3 Months Ago (5/13/09)	Year Ago (8/13/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.25	0.32	2.74
3-month LIBOR	0.45	0.88	2.80
Bank CDs			
6-month	0.50	0.73	1.60
1-year	0.73	0.98	2.26
5-year	1.90	1.93	4.16
U.S. Treasury Securities			
3-month	0.17	0.17	1.83
6-month	0.26	0.28	1.99
1-year	0.43	0.50	2.16
5-year	2.68	1.98	3.20
10-year	3.72	3.12	3.93
10-year (inflation-protected)	1.83	1.64	1.68
30-year	4.54	4.10	4.56
30-year Zero	4.65	4.18	4.61

	Recent (8/12/09)	3 Months Ago (5/13/09)	Year Ago (8/13/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.83	3.09	5.84
FHLMC 6.5% (Gold)	3.19	2.38	5.87
FNMA 6.5%	2.91	2.20	5.79
FNMA ARM	2.75	2.78	4.02
Corporate Bonds			
Financial (10-year) A	6.45	6.94	6.20
Industrial (25/30-year) A	5.85	6.19	6.29
Utility (25/30-year) A	5.79	6.01	6.27
Utility (25/30-year) Baa/BBB	6.62	7.57	6.75
Foreign Bonds (10-Year)			
Canada	3.52	3.10	3.61
Germany	3.46	3.34	4.21
Japan	1.43	1.46	1.46
United Kingdom	3.79	3.52	4.60
Preferred Stocks			
Utility A	5.66	6.35	6.27
Financial A	6.06	8.65	7.37
Financial Adjustable A	5.51	5.51	5.51



	Recent (8/12/09)	3 Months Ago (5/13/09)	Year Ago (8/13/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.65	4.63	4.75
25-Bond Index (Revs)	5.68	5.57	5.23
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.43	1.56
1-year A	1.10	1.16	1.66
5-year Aaa	1.69	1.82	2.90
5-year A	3.09	3.24	3.00
10-year Aaa	2.98	2.86	3.68
10-year A	4.50	4.41	3.88
25/30-year Aaa	4.66	4.43	4.75
25/30-year A	6.17	5.91	5.10
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.90	5.96	5.00
Electric AA	5.95	6.06	5.05
Housing AA	6.45	6.36	5.20
Hospital AA	6.45	6.31	5.20
Toll Road Aaa	5.90	6.11	5.10

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	7/29/09	7/15/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	728856	743860	-15004	777896	755940	557494
Borrowed Reserves	347217	387829	-40612	451108	519244	495733
Net Free/Borrowed Reserves	381639	356031	25608	326788	236696	61761

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	7/27/09	7/20/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1647.6	1644.8	2.8	19.0%	13.0%	16.9%
M2 (M1+savings+small time deposits)	8365.7	8341.1	24.6	3.1%	2.3%	8.1%

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UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206
TABLE OF CONTENTS TO SCHEDULES WAR

SCHEDULE #	
WAR - 1	COST OF CAPITAL SUMMARY
WAR - 2	DCF COST OF EQUITY CAPITAL
WAR - 3	DIVIDEND YIELD CALCULATION
WAR - 4	DIVIDEND GROWTH RATE CALCULATION
WAR - 5	DIVIDEND GROWTH COMPONENTS
WAR - 6	GROWTH RATE COMPARISON
WAR - 7	CAPM COST OF EQUITY CAPITAL
WAR - 8	ECONOMIC INDICATORS - 1990 TO PRESENT
WAR - 9	CAPITAL STRUCTURES OF SAMPLE COMPANIES

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
COST OF CAPITAL SUMMARY

DOCKET NO. E-04204A-09-0206
SCHEDULE WAR - 1

ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTED	(C) RUCO ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
2	LONG-TERM DEBT	$ 99,272	$ -	$ 99,272	54.24%	7.05%	3.82%
3	COMMON EQUITY	83,755	-	83,755	45.76%	9.25%	4.23%
4	TOTAL CAPITALIZATION	$ 183,027	$ -	$ 183,027	100.00%		
5	**ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL**						**8.06%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) ÷ COLUMN (C), LINE 4
COLUMN (E): LINE 1 - COMPANY SCHEDULE D-1
COLUMN (E): LINE 2 - TESTIMONY WAR
COLUMN (E): LINE 3 - SCHEDULE WAR-1, PAGE 2 LINE 9
COLUMN (F): COLUMN (D) x COLUMN (E)

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DCF COST OF EQUITY CAPITAL

DOCKET NO. E-04204A-09-0206
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	ALE	ALLETE, INC.	5.25%	+	3.52%	=	8.77%
2	BKH	BLACK HILLS CORPORATION	5.60%	+	6.06%	=	11.66%
3	CHG	CH ENERGY GROUP, INC.	4.79%	+	2.29%	=	7.08%
4	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	7.04%	+	3.00%	=	10.04%
5	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	6.97%	+	2.98%	=	9.95%
6	MGEE	MGE ENERGY, INC.	4.06%	+	5.76%	=	9.82%
7	NU	NORTHEAST UTILITIES	3.99%	+	5.04%	=	9.03%
8	NST	NSTAR	4.74%	+	5.75%	=	10.49%
9	OTTR	OTTER TAIL CORPORATION	4.95%	+	2.97%	=	7.92%
10	UIL	UIL HOLDINGS	6.60%	+	4.16%	=	10.77%
11	**AVERAGE**						**9.55%**

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND YIELD CALCULATION

DOCKET NO. E-04204A-09-0206
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	÷	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	ALE	ALLETE, INC.	$1.76	÷	$33.51	=	5.25%
2	BKH	BLACK HILLS CORPORATION	1.42	÷	25.36	=	5.60%
3	CHG	CH ENERGY GROUP, INC.	2.16	÷	45.12	=	4.79%
4	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	1.28	÷	18.18	=	7.04%
5	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	1.24	÷	17.80	=	6.97%
6	MGEE	MGE ENERGY, INC.	1.47	÷	36.34	=	4.06%
7	NU	NORTHEAST UTILITIES	0.95	÷	23.80	=	3.99%
8	NST	NSTAR	1.50	÷	31.64	=	4.74%
9	OTTR	OTTER TAIL CORPORATION	1.19	÷	24.06	=	4.95%
10	UIL	UIL HOLDINGS	1.73	÷	26.17	=	6.60%
11	**AVERAGE**						**5.40%**

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 08/07/2009, 08/28/2009 & 09/25/2009.
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 08/17/2009 TO 10/09/2009
STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) ÷ COLUMN (B)

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	ALE	ALLETE, INC.	2.75%	+	0.77%	=	3.52%
2	BKH	BLACK HILLS CORPORATION	4.50%	+	1.56%	=	6.06%
3	CHG	CH ENERGY GROUP, INC.	2.25%	+	0.04%	=	2.29%
4	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	2.40%	+	0.60%	=	3.00%
5	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	2.90%	+	0.08%	=	2.98%
6	MGEE	MGE ENERGY, INC.	5.35%	+	0.41%	=	5.76%
7	NU	NORTHEAST UTILITIES	4.25%	+	0.79%	=	5.04%
8	NST	NSTAR	5.75%	+	0.00%	=	5.75%
9	OTTR	OTTER TAIL CORPORATION	2.70%	+	0.27%	=	2.97%
10	UIL	UIL HOLDINGS	2.40%	+	1.76%	=	4.16%
11	**AVERAGE**						**4.15%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH	x	(B) { [((M ÷ B) + 1) ÷ 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
1	ALE	ALLETE, INC.	5.00%	x	{ [((1.31) + 1) ÷ 2] - 1 }	=	0.77%
2	BKH	BLACK HILLS CORPORATION	0.80%	x	{ [((0.91) + 1) ÷ 2] + 1 }	=	1.56%
3	CHG	CH ENERGY GROUP, INC.	0.25%	x	{ [((1.31) + 1) ÷ 2] - 1 }	=	0.04%
4	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	8.00%	x	{ [((1.15) + 1) ÷ 2] - 1 }	=	0.60%
5	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	1.00%	x	{ [((1.17) + 1) ÷ 2] - 1 }	=	0.08%
6	MGEE	MGE ENERGY, INC.	1.25%	x	{ [((1.66) + 1) ÷ 2] - 1 }	=	0.41%
7	NU	NORTHEAST UTILITIES	9.00%	x	{ [((1.18) + 1) ÷ 2] - 1 }	=	0.79%
8	NST	NSTAR	0.01%	x	{ [((1.80) + 1) ÷ 2] - 1 }	=	0.00%
9	OTTR	OTTER TAIL CORPORATION	2.25%	x	{ [((1.24) + 1) ÷ 2] - 1 }	=	0.27%
10	UIL	UIL HOLDINGS	10.00%	x	{ [((1.35) + 1) ÷ 2] - 1 }	=	1.76%
11	**AVERAGE**						**0.63%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 08/07/2009, 08/28/2009 & 09/25/2009
COLUMN (C): COLUMN (A) x COLUMN (B)

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	ALE	ALLETE, INC.	2004	0.7778		6.10%		4.74%	21.23	29.70	
2			2005	0.4960		11.30%		5.60%	20.03	30.10	
3			2006	0.4765		11.60%		5.53%	21.90	30.40	
4			2007	0.4675		11.80%		5.52%	24.11	30.80	
5			2008	0.3901		10.00%		3.90%	25.37	32.60	
6			GROWTH 2004 - 2008					5.06%	-		2.36%
7			2009	0.0974		7.00%		0.68%		34.50	5.83%
8			2010	0.2174		8.00%		1.74%		36.00	5.09%
9			2012-14	0.3018		9.00%		2.72%	3.00%	41.00	4.69%
10											
11	BKH	BLACK HILLS CORPORATION	2004	0.2874		7.80%		2.24%	22.43	32.48	
12			2005	0.3934		9.50%		3.74%	22.29	33.16	
13			2006	0.4027		9.40%		3.79%	23.68	33.37	
14			2007	0.4888		10.30%		5.03%	25.66	37.80	
15			2008	-6.7778		0.70%		NMF	27.19	38.64	
16			GROWTH 2004 - 2008					3.70%	5.00%		4.44%
17			2005	0.4083		8.50%		3.47%		39.00	0.93%
18			2006	0.3455		8.00%		2.76%		39.25	0.79%
19			2007	0.4800		9.50%		4.56%	4.00%	40.00	0.69%
20											
21	CHG	CH ENERGY GROUP, INC.	2004	0.1970		8.60%		1.69%	31.31	15.76	
22			2005	0.2313		8.80%		2.04%	31.97	15.76	
23			2006	0.1563		7.90%		1.23%	32.54	15.76	
24			2007	0.2000		8.10%		1.62%	33.19	15.76	
25			2008	0.0270		6.70%		0.18%	33.17	15.78	
26			GROWTH 2004 - 2008					1.35%	1.50%		0.03%
27			2009	0.0400		6.50%		0.26%		15.80	0.13%
28			2010	0.1360		7.00%		0.95%		15.80	0.06%
29			2012-14	0.2800		8.00%		2.24%	1.50%	16.00	0.28%
30											
31	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	2004	-0.4884		5.80%		NMF	14.76	25.70	
32			2005	-0.3913		6.00%		NMF	15.08	26.08	
33			2006	0.0922		8.50%		0.78%	15.49	30.25	
34			2007	-0.1743		6.20%		NMF	16.04	33.61	
35			2008	-0.0940		7.50%		NMF	15.56	33.98	
36			GROWTH 2004 - 2008					0.78%	1.50%		7.23%
37			2009	0.1467		8.50%		1.25%		38.00	11.83%
38			2010	0.1742		9.50%		1.65%		40.25	8.84%
39			2012-14	0.2286		10.50%		2.40%	2.00%	41.00	3.83%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 08/07/2009, 08/28/2009 AND 09/25/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	2004	0.0882		8.90%		0.79%	15.01	80.69	
2			2005	0.1507		9.70%		1.46%	15.02	80.98	
3			2006	0.0677		9.90%		0.67%	13.44	81.46	
4			2007	-0.1171		7.20%		NMF	15.29	83.43	
5			2008	-0.1589		6.50%		NMF	15.35	90.52	
6			GROWTH 2004 - 2008					0.97%	1.00%		2.92%
7			2009	-0.0783		7.50%		NMF		91.75	1.36%
8			2010	0.1733		9.50%		1.65%		92.00	0.81%
9			2012-14	0.2914		10.00%		2.91%	2.00%	93.50	0.65%
10											
11	MGEE	MGE ENERGY, INC.	2004	0.2316		10.00%		2.32%	16.59	20.39	
12			2005	0.1274		9.30%		1.18%	16.81	20.45	
13			2006	0.3252		11.30%		3.68%	17.89	20.98	
14			2007	0.3789		11.40%		4.32%	19.49	21.95	
15			2008	0.3992		11.00%		4.39%	20.88	22.90	
16			GROWTH 2004 - 2008					3.18%	8.00%		2.94%
17			2009	0.3958		11.50%		4.55%		23.20	1.31%
18			2010	0.4120		11.00%		4.53%		23.20	0.65%
19			2012-14	0.4500		12.00%		5.40%	7.00%	25.00	1.77%
20											
21	NU	NORTHEAST UTILITIES	2004	0.3077		5.10%		1.57%	17.80	129.03	
22			2005	0.3061		5.10%		1.56%	18.46	131.59	
23			2006	0.1098		4.30%		0.47%	18.14	154.23	
24			2007	0.5094		8.40%		4.28%	18.65	156.22	
25			2008	0.5538		9.60%		5.32%	19.38	155.83	
26			GROWTH 2004 - 2008					2.64%	2.00%		4.83%
27			2009	0.4865		9.00%		4.38%		176.00	12.94%
28			2010	0.4872		9.50%		4.63%		176.00	6.27%
29			2012-14	0.4889		8.50%		4.16%	5.00%	210.00	6.15%
30											
31	NST	NSTAR	2004	0.3580		13.10%		4.69%	13.52	106.55	
32			2005	0.5246		12.80%		6.71%	14.37	106.81	
33			2006	0.2021		13.10%		2.65%	14.82	106.81	
34			2007	0.3575		13.00%		4.65%	15.95	106.81	
35			2008	0.3559		13.30%		4.73%	16.74	106.81	
36			GROWTH 2004 - 2008					4.69%	5.00%		0.06%
37			2009	0.3489		13.50%		4.71%		106.81	0.00%
38			2010	0.3608		14.00%		5.05%		106.81	0.00%
39			2012-14	0.4000		14.50%		5.80%	5.50%	106.81	0.00%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 08/07/2009, 08/28/2009 AND 09/25/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	OTTR	OTTER TAIL CORPORATION	2004	0.2667		9.10%		2.43%	14.81	28.98	
2			2005	0.3708		11.20%		4.15%	15.80	29.40	
3			2006	0.3195		10.20%		3.26%	16.67	29.52	
4			2007	0.3427		10.20%		3.50%	17.55	29.85	
5			2008	-0.0917		5.10%		NMF	19.14	35.38	
6			GROWTH 2004 - 2008					3.33%	8.00%		5.12%
7			2009	-0.3222		4.50%		NMF		36.00	1.75%
8			2010	-0.0167		6.00%		NMF		37.00	2.26%
9			2012-14	0.3158		8.50%		2.68%	4.00%	40.00	2.49%
10											
11	UIL	UIL HOLDINGS	2004	-0.1234		6.70%		NMF	22.84	24.01	
12			2005	-0.3308		6.70%		NMF	22.39	24.32	
13			2006	0.0699		9.90%		0.69%	18.53	24.86	
14			2007	0.0749		10.10%		0.76%	18.55	25.03	
15			2008	0.0847		10.10%		0.86%	18.85	25.17	
16			GROWTH 2004 - 2008					0.77%	-2.00%		1.19%
17			2009	0.0895		10.00%		0.89%		30.00	19.19%
18			2010	0.1350		10.00%		1.35%		30.20	9.54%
19			2012-14	0.2311		10.50%		2.43%	2.50%	30.80	4.12%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 08/07/2009, 08/28/2009 AND 09/25/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6 & 16, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
GROWTH RATE COMPARISON

DOCKET NO. E-04204A-09-0206
SCHEDULE WAR - 6

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) VALUE LINE PROJECTED DPS	(C) VALUE LINE PROJECTED BVPS	(D) VALUE LINE HISTORIC EPS	(D) VALUE LINE HISTORIC DPS	(D) VALUE LINE HISTORIC BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) 5 - YEAR COMPOUND HISTORY DPS	(F) 5 - YEAR COMPOUND HISTORY BVPS
1	ALE	3.52%	4.00%	-1.00%	3.00%	3.00%	-	-	-	2.25%	20.22%	54.74%	4.55%
2	BKH	6.06%	-	10.00%	2.50%	4.00%	-8.00%	3.50%	5.00%	2.83%	-43.29%	3.08%	4.93%
3	CHG	2.29%	-	3.00%	NMF	1.50%	-1.50%	-	1.50%	1.13%	-4.69%	0.00%	1.45%
4	EDE	3.00%	-	6.00%	1.50%	2.00%	3.50%	-	1.50%	2.90%	8.00%	0.00%	1.33%
5	HE	2.98%	6.00%	7.00%	NMF	2.00%	-6.00%	-	1.00%	2.00%	-5.82%	0.00%	0.56%
6	MGEE	5.76%	5.00%	6.00%	0.50%	7.00%	6.00%	1.00%	8.00%	4.79%	7.68%	1.26%	5.92%
7	NU	5.04%	8.50%	8.00%	0.00%	5.00%	3.00%	8.50%	2.00%	5.93%	19.57%	7.14%	2.15%
8	NST	5.75%	5.70%	8.00%	5.50%	5.50%	4.00%	6.00%	5.00%	5.67%	5.98%	6.06%	5.49%
9	OTTR	2.97%	11.70%	4.00%	2.00%	4.00%	-1.50%	2.00%	8.00%	4.31%	-7.67%	1.99%	6.62%
10	UIL	4.16%	4.20%	3.00%	NMF	2.50%	-	-	-2.00%	1.93%	5.25%	0.00%	-4.69%
11				5.40%	2.14%	3.65%	-0.06%	4.20%	3.33%		0.52%	7.43%	2.83%
12	AVERAGES	4.15%	6.44%		3.73%			2.49%		3.37%		3.59%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 08/07/2009, 08/28/2009 AND 09/25/2009
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 08/07/2009, 08/28/2009 AND 09/25/2009
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1 THROUGH 17
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 08/07/2009, 08/28/2009 AND 09/25/2009

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
CAPM COST OF EQUITY CAPITAL

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ALE	k	=	2.41%	+ [	0.70	x	(	9.60%	-	5.40%	)]	=	5.35%
2	BKH	k	=	2.41%	+ [	0.85	x	(	9.60%	-	5.40%	)]	=	5.98%
3	CHG	k	=	2.41%	+ [	0.65	x	(	9.60%	-	5.40%	)]	=	5.14%
4	EDE	k	=	2.41%	+ [	0.75	x	(	9.60%	-	5.40%	)]	=	5.56%
5	HE	k	=	2.41%	+ [	0.70	x	(	9.60%	-	5.40%	)]	=	5.35%
6	MGEE	k	=	2.41%	+ [	0.65	x	(	9.60%	-	5.40%	)]	=	5.14%
7	NU	k	=	2.41%	+ [	0.70	x	(	9.60%	-	5.40%	)]	=	5.35%
8	NST	k	=	2.41%	+ [	0.65	x	(	9.60%	-	5.40%	)]	=	5.14%
9	OTTR	k	=	2.41%	+ [	0.90	x	(	9.60%	-	5.40%	)]	=	6.19%
10	UIL	k	=	2.41%	+ [	0.70	x	(	9.60%	-	5.40%	)]	=	5.35%
11	**AVERAGE**					**0.73**								**5.46%**

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 INTERMEDIATE TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 08/21/2009 THROUGH 10/09/2009 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE GEOMETRIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2008 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES OVER THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2009 YEARBOOK.

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
CAPM COST OF EQUITY CAPITAL

DOCKET NO. E-04204A-09-0206
SCHEDULE WAR - 7
PAGE 2 OF 2

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ALE	k	=	2.41%	+ [	0.70	x	(	11.70%	-	5.60%	)]	=	6.68%
2	BKH	k	=	2.41%	+ [	0.85	x	(	11.70%	-	5.60%	)]	=	7.60%
3	CHG	k	=	2.41%	+ [	0.65	x	(	11.70%	-	5.60%	)]	=	6.38%
4	EDE	k	=	2.41%	+ [	0.75	x	(	11.70%	-	5.60%	)]	=	6.99%
5	HE	k	=	2.41%	+ [	0.70	x	(	11.70%	-	5.60%	)]	=	6.68%
6	MGEE	k	=	2.41%	+ [	0.65	x	(	11.70%	-	5.60%	)]	=	6.38%
7	NU	k	=	2.41%	+ [	0.70	x	(	11.70%	-	5.60%	)]	=	6.68%
8	NST	k	=	2.41%	+ [	0.65	x	(	11.70%	-	5.60%	)]	=	6.38%
9	OTTR	k	=	2.41%	+ [	0.90	x	(	11.70%	-	5.60%	)]	=	7.90%
10	UIL	k	=	2.41%	+ [	0.70	x	(	11.70%	-	5.60%	)]	=	6.68%
11	**AVERAGE**					0.73								6.83%

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 INTERMEDIATE TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEYS "SELECTION & OPINIONS" PUBLICATION FROM 08/21/2009 THROUGH 10/09/2009 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE ARITHMETIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2008 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES OVER THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2009 YEARBOOK

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. E-04204A-09-0206
SCHEDULE WAR - 8

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.39%	1.90%	10.01%	6.98%	8.10%	7.50%	7.49%	9.86%	10.06%
2	1991	4.25%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.03%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.96%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.61%	4.00%	7.14%	3.60%	4.21%	4.25%	4.25%	8.31%	8.63%
6	1995	2.81%	2.50%	8.83%	5.21%	5.83%	5.49%	5.49%	7.89%	8.29%
7	1996	2.93%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	2.34%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.55%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.19%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.38%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	2.83%	0.80%	6.92%	3.41%	3.88%	3.40%	5.95%	7.59%	8.02%
13	2002	1.59%	1.60%	4.67%	1.17%	1.67%	1.61%	5.38%	7.41%	7.98%
14	2003	2.27%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	2.68%	3.60%	4.34%	2.34%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.39%	2.90%	6.16%	4.19%	3.22%	3.15%	4.57%	5.38%	5.78%
17	2006	3.24%	2.80%	7.97%	5.96%	4.97%	4.73%	4.91%	5.94%	6.30%
18	2007	2.85%	2.00%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	2008	3.58%	1.30%	5.09%	2.39%	1.92%	1.37%	4.28%	6.34%	6.64%
20	CURRENT	-1.40%	-1.00%	3.25%	0.50%	0.00% - 0.25%	0.11%	4.05%	5.40%	5.73%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (D): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 10/09/2009
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 10/09/2009
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. E-04204A-09-0206
SCHEDULE WAR - 9

LINE NO.		ALE	PCT.	BKH	PCT.	CHG	PCT.	EDE	PCT.	HE	PCT.
1	DEBT	$ 588.3	41.6%	$ 501.3	32.3%	$ 413.9	43.2%	$ 611.6	53.6%	$ 307.0	18.1%
2											
3	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	21.0	2.2%	0.0	0.0%	0.0	0.0%
4											
5	COMMON EQUITY	827.1	58.4%	1,050.5	67.7%	523.5	54.6%	528.9	46.4%	1,389.5	81.9%
6											
7	TOTALS	$ 1,415.4	100%	$ 1,551.8	100%	$ 958.5	100%	$ 1,140.4	100%	$ 1,696.5	100%
8											

		MGEE	PCT.	NU	PCT.	NST	PCT.	OTTR	PCT.	UIL	PCT.
9											
10											
11											
12	DEBT	$ 272.4	36.3%	$ 4,103.2	57.6%	$ 2,343.7	56.1%	$ 339.7	32.9%	$ 549.0	53.6%
13											
14	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	43.0	1.0%	15.5	1.5%	0.0	0.0%
15											
16	COMMON EQUITY	478.2	63.7%	3,020.3	42.4%	1,788.2	42.8%	677.2	65.6%	474.6	46.4%
17											
18	TOTALS	$ 750.6	100%	$ 7,123.5	100%	$ 4,174.8	100%	$ 1,032.5	100%	$1,023.6	100%
19											

		ELECTRIC PROXY AVERAGE	PCT.
20			
21			
22			
23			
24	DEBT	$ 1,003.0	48.1%
25			
26	PREFERRED STOCK	8.0	0.4%
27			
28	COMMON EQUITY	1,075.8	51.6%
29			
30	TOTALS	$ 2,086.8	100%

REFERENCE:
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS

EXHIBIT
RUCO-11
ADMITTED

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-09-0206

SURREBUTTAL TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 15, 2010

TABLE OF CONTENTS

INTRODUCTION 1

SUMMARY OF UNS ELECTRIC, INC.'S REBUTTAL TESTIMONY 2

COMPARISON OF RECOMMENDATIONS 3

COST OF EQUITY CAPITAL 5

Capital Asset Pricing Model (CAPM) 7
Discounted Cash Flow (DCF) 16

ATTACHMENT A – Excerpt of Direct Testimony of Stephen G. Hill

ATTACHMENT B – Value Line Selected Yields

ATTACHMENT C – FERC Cost-of-Service Rates Manual

INTRODUCTION

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

A. My name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office, located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state the purpose of your surrebuttal testimony.

A. The purpose of my surrebuttal testimony is to respond to UNSE's rebuttal testimony on RUCO's recommended rate of return on invested capital (which includes RUCO's recommended cost of debt and cost of common equity) for the Company's electric distribution operations located in Mohave and Santa Cruz Counties.

Q. Have you filed any prior testimony in this case on behalf of RUCO?

A. Yes. On October 30, 2009, I filed direct testimony with the ACC. My direct testimony addressed the cost of capital issues that were raised in UNSE's Application which was filed on April 30, 2009.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony contains four parts: the introduction that I have just presented; a summary of UNSE's rebuttal testimony; a comparison of the cost of capital recommendations being made by the parties to the case; and a section on the cost of equity capital.

Q. Will you address the FVROR issues associated with the case?

A. No. RUCO consultant Ben Johnson, Ph.D. will discuss the FVROR aspects of the case.

SUMMARY OF UNSE ELECTRIC, INC.'S REBUTTAL TESTIMONY

Q. Have you reviewed UNSE'S rebuttal testimony?

A. Yes. I have reviewed the rebuttal testimonies of Company witnesses Michael J. DeConcini, Kentton C. Grant and Martha B. Pritz which were filed on December 11, 2009.

Q. Please summarize Mr. DeConcini's rebuttal testimony.

A. Mr. DeConcini's rebuttal testimony provides an overview of the Company's rebuttal filing and addresses the various points of disagreement that UNSE has with the recommendations and positions of ACC Staff, RUCO, ASBA and AASBO. In regard to cost of capital, Mr. DeConcini expresses his displeasure with the FVROR recommendations of ACC Staff and RUCO.

Q. Please summarize Mr. Grant's rebuttal testimony.

A. Mr. Grant's rebuttal testimony focuses on the Company-proposed purchase of the Black Mountain Generating Station, changes to UNSE's PPFAC and the cost of capital recommendations made by ACC Staff and RUCO. Mr. Grant expresses his belief that the cost of equity

recommendation presented in my direct testimony is too low and that UNSE will only earn an ROE of 6.00 percent if the Commission adopts it.

Q. Please summarize Ms. Pritz's rebuttal testimony.

A. Ms. Pritz's rebuttal testimony expresses her belief that the cost of equity recommendation presented in my direct testimony is too low and is critical of the inputs that I used in both my single stage DCF model and my CAPM model (which used both an arithmetic and geometric mean to arrive at the market risk premium component).

COMPARISON OF RECOMMENDATIONS

Q. Are the parties to the case in agreement on the issue of capital structure?

A. Yes, the parties to the case are in agreement on the issue of capital structure. Both ACC Staff and RUCO are recommending that the Commission adopt the Company-proposed capital structure comprised of 54.24 percent long-term debt and 45.76 percent common equity.

Q. Are ACC Staff and RUCO also in agreement with the Company-proposed 7.05 percent cost of long-term debt?

A. Yes. ACC Staff witness David C. Parcell and I have recommended that the Commission adopt the Company-proposed 7.05 percent cost of long-term debt.

Q. Are UNSE, ACC Staff and RUCO in agreement on a cost of equity capital for the Company?

A. No. As is typical in utility rate cases there is substantial disagreement on a cost of common equity.

Q. Please summarize the costs of common equity and the OCROR's that are being recommended by the parties to the case.

A. In regard to the cost of common equity, the parties to the case are presently recommending the following estimates:

UNSE	11.40%
ACC Staff	10.00%
RUCO	9.25%

As can be seen in the above comparison, the Company-proposed cost of equity capital is 215 basis points higher than my recommended cost of equity capital. The difference between my recommended cost of equity and Mr. Parcell's recommended cost of equity is 75 basis points. The OCROR (i.e. the weighted cost of capital based on the costs of debt and equity noted above) being recommended by the parties to the case are as follows:

UNSE	9.04%
ACC Staff	8.40%
RUCO	8.06%

As can be seen above, there is presently a 98 basis point difference between the Company-proposed 9.04 percent OCROR (before any FVROR adjustment) and RUCO's recommended weighted cost of capital of 8.06 percent. RUCO and ACC Staff's recommended OCROR are within 34 basis points of each other.

Q. What FVROR's are the parties to the case recommending?

A. The parties to the case are recommending the following FVROR's:

UNSE	6.88%
ACC Staff	5.49%
RUCO	5.96%

The above comparison shows a difference of 92 basis points between the Company and RUCO's recommended FVROR's and a difference of 47 basis points between the ACC Staff and RUCO recommendations.

COST OF EQUITY CAPITAL

Q. Has there been any recent activity in regard to interest rates?

A. Yes. On December 16, 2009, after a two-day meeting, the Federal Reserve made no changes to the Federal Funds rate which remains at 0.00- 0.25 percent.

Q. Please comment on Mr. Grant's position that UNSE will not be able to earn an appropriate return on common equity if the Commission adopts RUCO's recommendation.

A. Mr. Grant claims that the Company's net income and common equity projections for 2011 indicate that UNS will not be able to achieve its authorized rate of return if RUCO's cost of capital recommendation is adopted by the ACC. However, these are projections made by UNS that are mere speculation. In fact, both Mr. Grant and Ms. Pritz totally ignore RUCO's recommendation to allow UNSE to acquire the Black Mountain Generating Station which would certainly help UNSE's future financial position. RUCO believes that the rates it is recommending in this case will provide the Company with the opportunity to recover its operating expenses and provide a return on its invested capital. From that standpoint I believe that the capital attraction standards set forth in the Hope and Bluefield decisions have been satisfied. Ultimately it is up to the Company to manage its expenses and make prudent investments in order to achieve its authorized rate of return. This also means coming in for rate relief on a timely basis.

Capital Asset Pricing Model (CAPM)

Q. Please address Ms. Pritz's criticism that the 5-year Treasury rate that you used as the risk free rate of return in your CAPM models is not reflective of the "investment period" used by investors to value common stocks.

A. Ms. Pritz cites Dr. Roger Morin's broad assumption that the "relevant" period that the investment community relies on to value common stocks is "a very long period." But the fact is that utilities typically file for rates within a three to five-year period and the investment community is aware of that fact and understands the effect of rate case proceedings on earnings. Information on rate case proceedings is available to investors through SEC filings, investment research firms such as Value Line, and the mainstream financial press. One only has to look at UNSE as proof of this. The Company's prior rates were established on May 27, 2008 and UNSE filed for new rates in less than eleven months. Any investor who follows the Company's publicly traded parent would be aware of the impact that the Company's actions would have on future earnings and would base his or her investment decisions based on that information.

Q. Can you cite another reason why you believe the 5-year treasury instrument used in your CAPM analysis is appropriate?

A. Yes. Professional analysts at investment services such as Value Line and Zacks Investment Research typically do not make projections beyond five years. In fact, the Federal Energy Regulatory Commission ("FERC")

places more emphasis on short-term projections (i.e. one to five years) in the multi-stage DCF model that Ms. Pritz used to derive her cost of equity recommendation (a point that I will discuss later in my surrebuttal testimony).

Q. Please explain why Ms. Pritz's criticism regarding the use of a geometric mean in a CAPM analysis is unfounded.

A. The information on both the geometric and arithmetic means, published by Morningstar, is widely available to the investment community. For this reason alone I believe that the use of both means in a CAPM analysis is appropriate.

The best argument in favor of the geometric mean is that it provides a truer picture of the effects of compounding on the value of an investment when return variability exists. This is particularly relevant in the case of the return on the stock market, which has had its share of ups and downs over the 1926 to 2008 observation period used in my CAPM analysis.

Q. Can you provide an example to illustrate the difference between arithmetic and geometric means?

A. Yes. The following example may help. Suppose you invest $100 and realize a 20.0 percent return over the course of a year. So at the end of year 1, your original $100 investment is now worth $120. Now let's say that over the course of a second year you are not as fortunate and the

value of your investment falls by 20.0 percent. As a result of this, the $120 value of your original $100 investment falls to $96. An arithmetic mean of the return on your investment over the two-year period is zero percent calculated as follows:

(year 1 return + year 2 return) ÷ number of periods =

(20.0% + -20.0%) ÷ 2 =

(0.0%) ÷ 2 = <u>0.0%</u>

The arithmetic mean calculated above would lead you to believe that you didn't gain or lose anything over the two-year investment period and that your original $100 investment is still worth $100. But in reality, your original $100 investment is only worth $96. A geometric mean on the other hand calculates a compound return of negative 2.02 percent as follows:

$$(\text{year 2 value} \div \text{original value})^{1/\text{number of periods}} - 1 =$$

$$(\$96 \div \$100)^{1/2} - 1 =$$

$$(0.96)^{1/2} - 1 =$$

$$(0.9798) - 1 =$$

$$-0.0202 = \underline{-2.02\%}$$

The geometric mean calculation illustrated above provides a truer picture of what happened to your original $100 over the two-year investment period.

As can be seen in the preceding example, in a situation where return variability exists, a geometric mean will always be lower than an arithmetic mean, which probably explains why utility consultants typically put up a strenuous argument against the use of a geometric mean.

Q. Can you cite any other evidence that supports your use of both a geometric and an arithmetic mean?

A. Yes. In the third edition of their book, Valuation: Measuring and Managing the Value of Companies, authors Tom Copeland, Tim Koller and Jack Murrin ("CKM") make the point that, while the arithmetic mean has been regarded as being more forward looking in determining market risk premiums, a true market risk premium may lie somewhere between the arithmetic and geometric averages published in Morningstar's SBBI yearbook.

Q. Please explain.

A. In order to believe that the results produced by the arithmetic mean are appropriate, you have to believe that each return possibility included in the calculation is an independent draw. However, research conducted by CKM demonstrates that year-to-year returns are not independent and are

actually auto correlated (i.e. a relationship that exists between two or more returns, such that when one return changes, the other, or others, also change), meaning that the arithmetic mean has less credence. CKM also explains two other factors that would make the Morningstar arithmetic mean too high. The first factor deals with the holding period. The arithmetic mean depends on the length of the holding period and there is no "law" that says that holding periods of one year are the "correct" measure. When longer periods (e.g. 2 years, 3 years etc.) are observed, the arithmetic mean drops about 100 basis points. The second factor deals with a situation known as survivor bias. According to CKM, this is a well-documented problem with the Morningstar historical return series in that it only measures the returns of successful firms, that is, those firms that are listed on stock exchanges. The Morningstar historical return series does not measure the failures, of which there are many. Therefore, the return expectations in the future are likely to be lower than the Morningstar historical averages. After conducting their analysis, CKM concluded that 4.00 percent to 5.50 percent is a reasonable forward looking market risk premium. Adding the current 5-year Treasury yield of 2.23 percent to these two estimates indicates a cost of equity range of 6.23 percent to 7.73 percent. Taking into consideration the fact that utilities generally exhibit less risk than industrials, a return in the low end of this range would be reasonable. In fact, my 9.25 percent cost of

common equity estimate is 375 basis points more than the high end of the range exhibited above.

Q. Has the Commission authorized rates of return that were derived through the use of both arithmetic and geometric means in prior decisions?

A. Yes. A case that specifically comes to mind involved another UniSource Energy subsidiary, UNS Gas Inc., in which Decision No. 70011, dated November 27, 2007, stated the following:

> "We agree with the Staff and RUCO witnesses that it is appropriate to consider the geometric returns in calculating a comparable company CAPM because to do otherwise would fail to give recognition to the fact that many investors have access to such information for purposes of making investment decisions."

In the UNS Gas, Inc. case, the ACC Staff witness was Mr. Parcell, who, as I do, consistently relies on both arithmetic and geometric means in our CAPM analyses.

Q. Can you provide further support for the reasonableness of the market risk premiums used in your CAPM models?

A. Yes. In his direct testimony in a prior Arizona Public Service Company ("APS") rate case proceeding, RUCO consultant Stephen G. Hill makes the argument for market risk premiums ranging from 4.0 percent to 6.0 percent[1] (Attachment A). On page 46 of his APS testimony, Mr. Hill supports his argument for lower market risk premiums by citing two

[1] Lines 25 through 29 of page 45, and lines 1 through 4 of page 46 of the direct testimony of RUCO consultant Stephen G. Hill, Docket No. E-01345A-05-0816 et al.

scholarly articles on the subject published by noted academics. In the first paper titled *The Equity Premium*, published in 2002, Eugene Fama and Kenneth French take the position that Ibbotson Associates' historical market risk premiums (now published by Morningstar) have overstated investor expectations.

Q. Can you cite any other sources that support Mr. Hill's views, in his APS rate case testimony, that 4.0 percent to 6.0 percent is a reasonable market risk premium on a forward-looking basis?

A. Yes. During the 39th annual Financial Forum of the Society of Utility and Regulatory Financial Analysts, which was held at Georgetown University in Washington D.C. on April 19 and 20, 2007, I had the opportunity to hear the views of Aswath Damodaran, Ph. D. and Felicia C. Marston, Ph. D., professors of finance from New York University and the University of Virginia respectively, who have conducted empirical research on this subject. Dr. Damodaran and Dr. Marston advocated 4.0 to 5.5 percent estimates during a panel discussion that provided both professors with the opportunity to explain their research on the equity risk premium and to answer questions from other financial analysts in attendance. Each of the panelists stated that they believed that a reasonable market risk premium fell between 4.0 percent and 5.0 percent when asked to provide estimates based on their research.

Q. What would your CAPM results be if the market risk premiums of 4.0 percent to 6.0 percent, advocated by Mr. Hill, were used in your CAPM model?

A. Using the 2.41 percent yield on a 5-year Treasury instrument (r_f) and the average beta of 0.73 used in my CAPM model, and the market risk premiums (r_m - r_f) of 4.0 percent to 6.0 percent, advocated by Mr. Hill, produces the following results:

<u>Using a 4.0% Market Risk Premium</u>

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

$$k = 2.41\% + [\, 0.73\, (4.0\%)\,]$$

$$k = 2.41\% + 2.92\%$$

$$k = \underline{5.33\%}$$

<u>Using a 6.0% Market Risk Premium</u>

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

$$k = 2.41\% + [\, 0.73\, (6.0\%)\,]$$

$$k = 2.41\% + 4.38\%$$

$$k = \underline{6.79\%}$$

These results are lower than the 5.46 percent and 6.83 percent estimates that I relied on to arrive at my recommended 9.25 percent cost of common equity. When the market risk premium information noted above is taken

into consideration, it is clear that Ms. Pritz's market risk premium inputs, as opposed to mine, appear to be out of line.

Q. Do you have any data that supports a 4.00 percent equity risk premium during the market crises which unfolded in September of 2008?

A. Yes. In September 2008 Dr. Damodaran, who I noted earlier in my testimony, presented a paper titled Equity Risk Premium (ERP): Determinants, Estimation and Implications, which contained an October update that presented data on the swings in implied equity risk premium that occurred between September 12, 2008 and October 16, 2008. During that time frame, implied equity risk premiums ranged from 4.20 percent to 6.39 percent. The 5.30 percent mean average of that range falls within the 4.20 percent to 6.10 percent range of my market risk premiums using geometric and arithmetic means respectively.

Q. On page 17 of her rebuttal testimony, Ms. Pritz acknowledges the fact that the spreads between 30-year U.S. Treasury instruments and Baa/BBB-rated debt has narrowed since her direct testimony was filed. What is the current spread between those two financial instruments?

A. As can be seen in the most recent Value Line Selection and Opinion publication (Attachment B), the current spread between the 30-year U.S. Treasury yield of 4.64 percent and the 6.53 percent yield on Baa/BBB-rated debt is 189 basis points. As Ms. Pritz points out, this is mainly due

to the calming of the U.S financial markets since her direct testimony was filed. This clearly illustrates that periods of volatility in the financial markets eventually subside and things eventually return to normal. This only strengthens my rationale for relying on the historical market risk premium used in my CAPM model, which captures the effects of a number of events on the financial markets such as the Great Depression, numerous economic recessions (with varying degrees of severity), the U.S. involvement in five major armed conflicts (including World War II), and periods of domestic political and social strife.

Discounted Cash Flow (DCF)

Q. Please address Ms. Pritz's criticism of your DCF analysis, which takes into consideration the concept that a utility's market-to-book ratio will move toward a value of 1.0 if regulators set a utility's rate of return at a level that is equal to the cost of capital of firms with similar risk.

A. A utility's market price should equal its book price over the long run if regulators allow a rate of return that is equal to the utility's cost of capital. *That is assuming that the utility's rate of return ("ROR") is comparable to the rates of return of other firms in the same risk class.*[2] For example, if a hypothetical utility's book price is $20.00 per share and regulators adopt a rate of return that is equal to the utility's cost of capital of 10.0%, the utility will earn $2.00 per share ("EPS"). With earnings of $2.00 per share, and a

[2] An in-depth discussion of market-to-book ratios can be found in Chapter 10 of Roger A. Morin's text Regulatory Finance, Utilities' Cost of Capital.

market required rate of return on equity of 10.00%, for firms in the utility's risk class, the market price of the utility's stock will set at $20.00 per share ($2.00 EPS ÷ 10.0% ROR = $20.00 per share price). If the utility records earnings that are higher than the earnings of other firms with similar risk, the market value of the utility's shares will increase accordingly, (e.g. $2.50 EPS ÷ 10.0% ROR = $25.00 per share). On the other hand, if the utility posts lower earnings, the stock's market price will fall below book value, (e.g. $1.50 EPS ÷ 10.0% ROR = $15.00 per share).

Because of economic forces beyond the control of regulators, it is not reasonable to assume that the utility will have earnings that match those of firms of similar risk in every year of operation. In some years, earnings may drop causing the market-to-book ratio to fall below 1.0, while in other years the utility may have earnings that exceed those of other firms in its risk classification. However, over the long run the utility's earnings should average out to the earnings that are expected based on its level of risk. These average earnings over time will result in a market-to-book ratio of 1.0. It has been suggested that regulators should set a utility's rate of return at a level that is slightly higher than that of firms in the same risk class of the hypothetical utility. In theory, this will send a message to investors that average long-term earnings will not be less than what is expected. A 1.0 ratio may never be achieved in practice and many investors may not even care what the market-to-book ratio is as long as

they receive their required rate of return. In this respect, a utility stock is similar to a corporate bond whose value fluctuates as interest rates move above or below the stated yield on the bond. As long as the bond provides the level of income (i.e. the stated interest payment in the case of a bond or a dividend payment in the case of a utility stock) that the investor expects, the price of the instrument at any given point in time is immaterial (so long as the intent is to hold the bond until maturity or the utility stock over a long-term period).

Q. Does your recommended cost of equity take into consideration the theoretical concepts that you have just described?

A. Yes. As I just explained, in theory, a market-to-book ratio of 1.0 would be achieved if a utility's rate of return equaled the cost of capital that is close to the returns of firms with similar risk. The results of the CAPM analysis that I performed earlier in this testimony (using the yield on a 5-year U.S treasury instrument and average beta I presented in my direct testimony and the market risk premium inputs advocated by Mr. Hill) indicate that the rate of return for a firm with UNSE's level of risk is much lower than my recommended 9.25 percent cost of equity capital. This being the case, the adoption of my recommended 9.25 percent cost of capital would be consistent with the theory I have presented above.

Q. Are there any other reasons why your market-to-book ratio calculation is valid?

A. Yes. The utilities included in my samples, are engaged in unregulated activities to some degree. Because it is difficult to obtain a sample comprised only of "pure play" utilities, the calculation that I have employed in my DCF model helps to eliminate the impact that those unregulated operating segments would have on the market-to-book ratio of the utilities included in my sample.

Q. Do you agree with Ms. Pritz's assertion, on page 18 of her rebuttal testimony, that you ignored data in your workpapers to develop the growth estimate that you used in your DCF model?

A. No. In fact my growth estimate took all of that data (displayed in Schedules WAR-5 and WAR-6 of my direct testimony) into consideration. I also provided Ms. Pritz with an explanation of how I arrived at my growth estimates for each of the utilities in my sample.

Q. Please respond to Ms. Pritz's statement (on page 19 of her rebuttal testimony) that you failed to note that her multi-stage DCF growth estimate also took into consideration growth estimates for the electric utility industry and the U.S. Economy as a whole.

A. While I will admit that I did not note those facts in my direct testimony, Ms. Pritz's use of those growth rates raises several concerns.

Q. Please explain.

A. The argument for the use of an industry growth rate assumes that investors place their funds in individual electric stocks because they expect the individual electric's growth rates to converge with the long-term average of the electric utility industry. In other words, if you've seen one electric stock, you've seen them all because you are essentially investing in an industry as opposed to an individual utility. If this argument were true, then investors would be investing in the electric industry as a whole (i.e. through an investment vehicle such as a mutual fund) as opposed to investing in an individual electric utility. This argument totally ignores the premise that rational investors place their funds in individual stocks because they feel comfortable with the dividend yields and the growth potentials offered by the individual electric utility that they are investing in. I believe that rational investors also weigh other factors such as superior management, corporate culture and philosophy, and past records of performance when making their investment decisions. If you subscribe to the argument at hand, then it would not make any difference which electric utility you made an investment in since they will all eventually provide the same returns in growth. This begs the question as to why there is so much investor information available on individual companies or why the managements of publicly traded firms tout their ability to provide returns that will exceed industry averages.

Q. Please address the reliance on growth rates for the U.S. economy as a whole.

A. This argument assumes that every individual electric utility is going to have inflation-adjusted growth that mirrors the GDP of the entire U.S. economy into perpetuity. This in itself is a rather broad and unrealistic expectation. Professional analysts often have enough trouble making accurate projections of the near-term (i.e. one-year) earnings of the companies that they follow. It would be unrealistic to believe that projections that extend into perpetuity would be more accurate than the near-term projections. The growth estimates used in my DCF model are a balance of known historical 5-year growth figures and projected growth estimates over the next five-year period (i.e. 2009 through 2014). I believe that this is a reasonable horizon for future growth estimates, given the fact that utilities typically apply for rate relief within a three to five-year time frame.

Q. Are there any other reasons why you believe that the results obtained by Ms. Pritz's multi-stage model should be discounted?

A. Yes. As I noted earlier, the FERC places more emphasis on short-term projections (i.e. one to five years) in the multi-stage DCF model.

...

Q. Please explain how the FERC places more emphasis on short-term projections in the multi-stage DCF model.

A. The multi-stage DCF model required by the FERC weighs short-term estimates of growth, similar to the one to five-year projections that I relied on to develop the "g" component in my single stage DCF model, by a factor of two-thirds. The FERC's rationale is that short-term estimates of growth are more predictable and deserve more weight than long-term estimates such as the equally-weighted long-term estimates of growth used in the multi-stage DCF model that Ms. Pritz has relied on. This is explained in the following excerpt from the FERC's Cost-of-Service Rates Manual (Attachment C):

> "**Return on Equity or Cost of Equity:** This is the pipeline's actual profit, or return on its investment. The return on equity is derived from a range of equity returns developed using a Discounted Cash Flow (DCF) analysis of a proxy group of publicly held natural gas companies. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short-term growth estimates and the other long-term growth estimates. These estimates are then weighted, two-thirds for the short-term growth projection and one-third on the long-term growth, and utilized in determining a range of reasonable equity returns. Two-thirds is used for the short-term growth rate on the theory that short-term growth rates are more predictable, and thus deserve a higher weighting than long-term growth rate projections. An equity return is then selected within this zone based on an analysis of the company's risk."

Although the FERC excerpt cited above is from the FERC's manual on natural gas utilities, there is no reason why it would not apply also to electric or water utilities.

Q. Does Ms. Pritz give equal weight to the near-term and long-term growth estimates in her multi-stage model?

A. Yes. As I pointed out in my direct testimony, Ms. Pritz gives equal weight to both her near-term and long-term multi-stage inputs. As can be seen in the excerpt above, a good argument can be made that more emphasis should be placed on the near-term component of Ms. Pritz's 's multi-stage DCF model as opposed to the long-term growth rate that is carried out into perpetuity.

Q. Has Ms. Pritz made any updates to the inputs of his models that were used to derive his recommended cost of common equity?

A. No. Ms. Pritz has not provided any such revisions in her rebuttal testimony.

Q. Does your silence on any of the issues or positions addressed in the rebuttal testimony of the Company's witnesses constitute acceptance?

A. No, it does not.

Q. Does this conclude your surrebuttal testimony on UNSE?

A. Yes, it does.

ATTACHMENT A

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY

OF

STEPHEN G. HILL

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 18, 2006

Schedule 8 attached to this testimony shows the detail regarding the CAPM analysis. The average beta coefficients for the electric utility sample group was 0.83. Schedule 8 shows a CAPM cost of capital for the electric companies ranging from 9.23% to 10.56%.

Schedules 9 and 10 shows the theoretical basis and the data and calculations, respectively, for the Modified Earnings Price Ratio (MEPR) analysis. The MEPR analysis indicates a current cost of equity capital for electric companies in a narrow range from 8.79% to 9.13%. Finally, Schedule 11 attached to this testimony contains the supporting detail for the Market-to-Book Ratio (MTB) analysis, which indicates a current cost of equity capital for the electric utility companies of 9.31% (near-term) to 9.38% (long-term).

C. SUMMARY

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY CAPITAL COST ANALYSES FOR THE SAMPLE GROUP OF SIMILAR-RISK ELECTRIC UTILITY COMPANIES.

A. My analysis of the cost of common equity capital for the sample group of electric utility companies is summarized in the table below.

METHOD	Electric Utility Companies
DCF	9.44%
CAPM	9.23%/10.56%
MEPR	9.13%/8.79%
MTB	9.31%/9.38%

For the electric utility sample group, the DCF result is 9.44%. In addition, the corroborating cost of equity indications (MEPR, MTB, and CAPM) indicate that DCF result is reasonable. Averaging the lowest and highest results of all the corroborative analyses for the electric companies produces and equity cost range of 9.11% to 9.69%,

with a mid-point of 9.40%, only 4 basis points below the DCF result.

Therefore, weighing all the evidence presented herein, my best estimate of the cost of equity capital for a company like Arizona Public Service, facing similar risks as this group of electric utilities, ranges from 9.25% to 9.75%, with a mid-point of 9.50%.

Q. ARE THERE OTHER FACTORS TO BE CONSIDERED BEFORE DETERMINING A POINT-ESTIMATE FOR APS WITHIN A REASONABLE RAGE FOR SIMILAR-RISK FIRMS?

A. Yes. First, the electric sample group companies have similar operating risk to APS. The average S&P business risk score of my sample of electric utilities is 6—the same as that for APS. Therefore, on that basis there would be no reason to adjust the equity return from the mid-point of a reasonable range. However, because the capital structure I recommend for ratesetting purposes contains considerably more common equity and less debt than average for the sample group, APS, prospectively will have less financial risk than the sample group and should be awarded an equity return below the mid-point of a reasonable range.

Q. IS THERE A RECOGNIZED METHOD WITH WHICH DIFFERENCES IN FINANCIAL RISK CAN BE QUANTIFIED?

A. Yes. The cost of equity capital is affected by the capital structure a company employs. When a company increases the proportion of debt in its capital structure, it increases the riskiness of its equity. Financial risk (created by the use of debt in the capital structure) causes investors to demand a higher rate of return; that is, financial risk increases the cost of equity capital.

The impact of debt leverage on the cost of equity capital can be approximated through an examination of the changes in beta, which occur when leverage is increased or decreased. The Value Line betas for the sample companies used in my cost of capital analysis in this proceeding reflect the market's (investors') perception of both the business risks and the financial risks of a firm. That is, one portion of the beta of a firm is

related to the business risk of the firm (the risk inherent in its operations) and one portion of the beta is related to the financial risk of that firm (the risk associated with the use of debt). Therefore, if a firm elects to finance its operations with debt as well as equity, the beta coefficient of that firm will reflect both the business and financial risk. When a firm uses debt to finance its operations, the beta can also be referred to as a "levered" beta (i.e., a beta coefficient that includes the impact of debt leverage).

The average beta coefficient of the sample group of utilities can be "unlevered." That is, the beta-risk related to the level of debt capital used by the firm can be removed. "Unlevering the betas" amounts to estimating what the average beta would be if the companies were financed entirely with equity capital. Equation (2) is used to estimate the unlevered beta for a firm or a group of similar-risk firms.[19]

$$\beta_U = \frac{\beta_{Measured}}{(1+(1-t)D/E)} \qquad (2)$$

Equation (2) indicates that an estimate of the unlevered beta (β_U) of a firm can be calculated by dividing the measured beta ($\beta_{Measured}$, e.g. the beta coefficient reported by investor services such as Value Line) by one plus the average debt-to-equity ratio, adjusted to account for taxes. The debt-to-equity ratio is measured using the average market value of the sample group's common equity capital. Once the unlevered beta for the firm (or, in this case, for the sample group of market-traded utility companies) is calculated, the beta coefficient is "re-levered" and adjusted to conform to the less leveraged capital structure of APS, which contains 50% common equity. The formula used to "re-lever" the utility betas is shown below.

$$\beta_{Relevered} = \beta_U (1+ (1-t)D/E) \qquad (3)$$

[19]Equation (1) is a version of the Hamada equation which combines the Miller-Modigliani theories regarding capital structure and the logic of the CAPM: Hamada, R.S., "Portfolio Analysis, Market equilibrium and Corporation Finance," *Journal of Finance*, March 1969, pp. 13-31.

Equation (3) states that the relevered beta equals the unlevered beta (β_U) multiplied times one plus the target debt-to-equity ratio (in this case APS's ratemaking capital structure—50% equity/50% debt), again adjusted for taxes.

Schedule 12 shows that, the average capital structure of the sample group of electric companies used to estimate the cost of equity capital in my direct testimony consists of 45.13% common equity and 54.69% fixed-income capital. That capital structure, adjusted to market levels by an average 1.69 market-to-book ratio and accounting for a 35% tax rate, produces an average value for (1-t)D/E in Equation (2) of 0.53.

Schedule 12 shows further that the measured (average Value Line) beta coefficient of the sample group of gas utility firms is 0.83, and the <u>unlevered</u> beta coefficient of those firms (i.e., what the average beta would be if those firms were financed entirely with common equity) is 0.54. When that beta is "relevered" using the methodology described above to conform to APS's ratemaking capital structure, the resulting average beta coefficient is 0.75, an decrease in beta of 0. 079 due to the sample group's lower average equity capitalization ["measured" beta of 0.83 vs. "relevered" beta of 0.751].

Finally, with the increase in beta determined, the CAPM can be used to estimate the impact of that adjustment on the cost of capital. A review of the CAPM equation (Equation (i) in Appendix D) indicates that the beta coefficient is multiplied by the market risk premium (r_m - r_f) as a step in the determination of the cost of capital. Therefore, it is possible to measure the impact of an adjustment to beta by multiplying the difference in the measured and relevered betas of the electric companies by the market risk premium.

As I noted in my discussion of the CAPM analysis in Appendix D, the long-term historical market risk premium provided by Ibbotson Associates' historical database is 5% to 6.6%. I also discuss the fact that the most recent research by Fama and French regarding the market risk premium indicates that the Ibbotson historical risk premium data overstate investor expectations, which are a return of 2.5% to 4.5% over the risk-free

rate of interest.[20] Ibbotson has also published a paper recently, which indicates that investors can expect returns in the future of from 4% to 6% above the risk-free.[21] Therefore, for purposes of this analysis, I will use a range of market risk premium from 4% to 6%.

As shown in Schedule 12, an decrease in the average beta coefficient of 0.079, multiplied by a market risk premium ranging from 4% to 6%, indicates an decrease in the cost of equity capital due to reduced leverage at APS of from 32 to 48 basis points (0.079 x 4%-6% = 0.317%-0.476%).

The mid-point of the cost of common equity for the electric utility sample group, presented previously is 9.50%. Although the equity return decrement indicated is slightly higher, recognizing the decrease in financial risk due to reduced leverage at APS, a cost of equity of 9.25% for ratemaking purposes is reasonable. That represents a decrease in the cost of equity for APS (with a 50% common equity ratio) of 25 basis points below the mid-point of a reasonable range for electric utility operations, which are capitalized on average with about 45% common equity.

It is important to emphasize here that if the Commission elects to utilize the Company's requested 54.5% common equity ratio for ratesetting purposes, rather than the 50% I recommend, the equity return decrement due to lower financial risk would have to be greater than the 25 basis points I recommend. If a "target" capital common equity ratio of 54.5% were substituted in Schedule 12, the "relevered" beta would be 0.72, rather than the 0.75 used in my analysis. Also the indicated reduction in the cost of equity would range from 0.45% to 0.68%. Those data indicate that if this Commission elects to set rates for APS using its requested capital structure, an equity return decrement of 50 basis points would be reasonable.

Q. DOES THAT 9.25% EQUITY COST ESTIMATE INCLUDE AN INCREMENT FOR

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[20] Fama, E., French, K., "The Equity Premium," *The Journal of Finance*, Vol. LVII, No. 2, April 2002, pp. 637-659.

[21] Ibbotson, R, Chen, P., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts Journal*, January/February 2003, pp. 88-89.

FLOTATION COSTS?

A. No, it does not.

Q. CAN YOU PLEASE EXPLAIN WHY AN EXPLICIT ADJUSTMENT TO THE COST OF EQUITY CAPITAL FOR FLOTATION COSTS IS UNNECESSARY?

A. An explicit adjustment to "account for" flotation costs is unnecessary for several reasons. First, it is often said that flotation costs associated with common stock issues are exactly like flotation costs associated with bonds. That is not a correct statement because bonds have a fixed cost and common stock does not. Moreover, even if it were true, the current relationship between the electric utility sample group's stock price and its book value would indicate a flotation cost reduction to the market-based cost of equity, not an increase.

When a bond is issued at a price that exceeds its face (book) value, and that difference between market price and the book value is greater than the flotation costs incurred during the issuance, the embedded cost of that debt (the cost to the company) is *lower* than the coupon rate of that debt.

In the current economic environment for the electric utility common stocks studied to determine the cost of equity in this proceeding, those stocks are selling at a market price 69% above book value. (Exhibit__(SGH-1), Schedule 4, p. 1) The difference between the market price of electric utility stock and book value dwarfs any issuance expense the companies might incur. Therefore, if common equity flotation costs were exactly like flotation costs with bonds, then, if an explicit adjustment to the cost of common equity were necessary, it should be downward, not upward.

Second, flotation cost adjustments are usually predicated on the prevention of the dilution of stockholder investment. However, the reduction of the book value of stockholder investment due to issuance expenses can occur only when the utility's stock is selling at a market price at to or below its book value. As noted, the companies under review are selling at a substantial premium to book value. Therefore, every time a new share of that stock is sold, existing shareholders realize an *increase* in the per share book

value of their investment. No dilution occurs, even without any explicit flotation cost allowance.

Third, the vast majority of the issuance expenses incurred in any public stock offering are "underwriter's fees" or "discounts". Underwriter's discounts are not out-of-pocket expenses for the issuing company. On a per share basis, they represent only the difference between the price the underwriter receives from the public and the price the utility receives from the underwriter for its stock. As a result, underwriter's fees are not an expense incurred by the issuing utility and recovery of such "costs" should not be included in rates.

In addition, the amount of the underwriter's fees are prominently displayed on the front page of every stock offering prospectus and, as a result, the investors who participate in those offerings (e.g., brokerage firms) are quite aware that a portion of the price they pay does not go to the company but goes, instead, to the underwriters. By electing to buy the stock with that understanding, those investors have effectively accounted for those issuance costs in their risk-return framework by paying the offering price. Therefore, they do not need any additional adjustments to the allowed return of the regulated firm to "account" for those costs.

Fourth, my DCF growth rate analysis includes an upward adjustment to equity capital costs which accounts for investor expectations regarding stock sales at market prices in excess of book value, and any further explicit adjustment for issuance expenses related to increases in stock outstanding is unnecessary.

Fifth, research has shown that a specific adjustment for issuance expenses is unnecessary[22]. There are other transaction costs which, when properly considered, eliminate the need for an explicit issuance expense adjustment to equity capital costs. The transaction cost that is improperly ignored by the advocates of issuance expense adjustments is brokerage fees. Issuance expenses occur with an initial issue of stock in a primary market offering. Brokerage fees occur in the much larger secondary market

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[22] "A Note on Transaction Costs and the Cost of Common Equity for a Public Utility," Habr, D., National Regulatory Research Institute Quarterly Bulletin, January 1988, pp. 95-103.

where pre-existing shares are traded daily. Brokerage fees tend to increase the price of the stock to the investor to levels above that reported in the Wall Street Journal, i.e., the market price analysts use in a DCF analysis. Therefore, if brokerage fees were included in a DCF cost of capital estimate they would raise the effective market price, lower the dividend yield and lower the investors' required return. If one considers transaction costs that, supposedly, raise the required return (issuance expenses), then a symmetrical treatment would require that costs that lower the required return (brokerage fees) should also be considered. As shown by the research noted above, those transaction costs essentially offset each other and no specific equity capital cost adjustment is warranted.

Q. WHAT IS THE OVERALL COST OF CAPITAL FOR APS's INTEGRATED UTILITY OPERATIONS, BASED ON AN ALLOWED EQUITY RETURN OF 9.25%?

A. Schedule 13 attached to my testimony shows that an equity return of 9.25%, operating through an appropriate ratemaking capital structure of 50% equity and 50% debt, and the Company's requested embedded capital cost rates, produces an overall return of 7.33% for APS. Schedule 13 also shows that a 7.33% overall cost of capital affords the Company an opportunity to achieve a pre-tax interest coverage level of 3.85 times.

According to APS's 2005 S.E.C. Form 10-K (Exhibit 12), the pre-tax interest coverage over the past five years has averaged 2.94x and has ranged from 2.81x to 3.17x. The return I recommend would allow the Company the opportunity to improve its historical average interest coverage. Therefore, the equity return I recommend fulfills the legal requirement of Hope and Bluefield of providing the Company the opportunity to earn a return which is commensurate with the risk of the operation and serves to support and maintain the Company's ability to attract capital.

V. COMPANY COST OF CAPITAL TESTIMONY

Q. HOW HAS COMPANY WITNESS AVERA ESTIMATED THE COST OF EQUITY CAPITAL IN THIS PROCEEDING?

ARIZONA PUBLIC SERVICE COMPANY
LEVERAGE/BETA ADJUSTMENT TO THE COST OF EQUITY CAPITAL

COMPANY	COMMON EQUITY	FIXED INCOME CAPITAL	M/B RATIO	MKT. VALUE DEBT(1-t)/EQ.
Central Vermont P. S.	63.00%	37.00%	1.05	0.36
FirstEnergy Corp.	45.00%	55.00%	1.77	0.45
Green Mountain Power	56.00%	44.00%	1.30	0.39
Progress Energy	41.00%	59.00%	1.29	0.73
Ameren Corp.	50.00%	50.00%	1.58	0.41
Cleco Corporation	52.00%	48.00%	1.52	0.39
DPL, Inc.	35.00%	65.00%	4.51	0.27
Empire District Electric	46.00%	54.00%	1.37	0.56
Entergy Corp.	46.00%	54.00%	1.77	0.43
Hawaiian Electric	37.00%	63.00%	1.77	0.63
PNM Resources	38.00%	62.00%	1.31	0.81
Pinnacle West Capital	48.00%	52.00%	1.11	0.63
Unisource Energy	32.00%	68.00%	1.64	0.84
AVERAGES	45.31%	54.69%	1.69	0.53
TARGET CAP. STRUCTURE	50.00%	50.00%	1.69	**0.38**

AVERAGE (LEVERED) UTILITY BETA = 0.83

Beta (Unlevered) = Beta (Levered)/(1+D(1-t)/E)

Beta (Unlevered)= 0.83/(1+.53)= **0.54**

Beta (Relevered)= Beta (Unlevered)*(1+D(1-t)/E)

Beta (Relevered)= 0.54(1.38)= **0.75**

IMPACT ON COST OF EQUITY CAPITAL

	Measured Beta	0.830
	Relevered Beta	0.751
[1]	Diff. in Beta	0.079
[2]	Market Risk Premium (rm-rf) =	4% to 6%

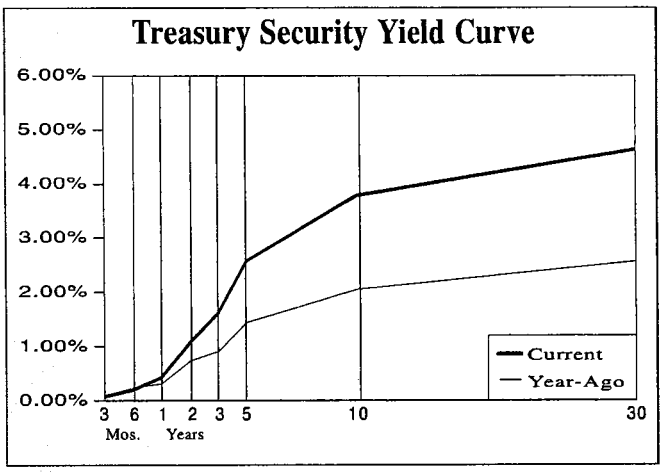
Average Cost of equity impact = [1] x [2] = **0.32% to 0.48%**

ATTACHMENT B

Selected Yields

	Recent (12/29/09)	3 Months Ago (9/30/09)	Year Ago (12/30/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	0.50
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.11	0.18	0.06
3-month LIBOR	0.25	0.29	1.44
Bank CDs			
6-month	0.29	0.40	1.16
1-year	0.54	0.64	1.43
5-year	1.97	2.27	2.51
U.S. Treasury Securities			
3-month	0.08	0.11	0.09
6-month	0.20	0.17	0.24
1-year	0.43	0.38	0.31
5-year	2.57	2.31	1.44
10-year	3.80	3.31	2.05
10-year (inflation-protected)	1.36	1.53	2.33
30-year	4.64	4.05	2.56
30-year Zero	4.81	4.13	2.42

	Recent (12/29/09)	3 Months Ago (9/30/09)	Year Ago (12/30/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.72	3.63	4.11
FHLMC 6.5% (Gold)	2.56	2.82	4.03
FNMA 6.5%	2.47	2.60	3.89
FNMA ARM	2.41	2.62	4.22
Corporate Bonds			
Financial (10-year) A	5.52	5.61	7.08
Industrial (25/30-year) A	5.80	5.31	5.90
Utility (25/30-year) A	5.98	5.40	5.85
Utility (25/30-year) Baa/BBB	6.53	5.73	6.58
Foreign Bonds (10-Year)			
Canada	3.62	3.31	2.66
Germany	3.37	3.22	2.95
Japan	1.31	1.30	1.17
United Kingdom	4.08	3.59	3.09
Preferred Stocks			
Utility A	5.98	5.77	6.00
Financial A	6.82	6.61	7.89
Financial Adjustable A	5.48	5.48	5.48



	Recent (12/29/09)	3 Months Ago (9/30/09)	Year Ago (12/30/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.21	4.04	5.46
25-Bond Index (Revs)	4.94	4.86	6.22
General Obligation Bonds (GOs)			
1-year Aaa	0.28	0.37	0.85
1-year A	1.22	0.80	0.95
5-year Aaa	1.65	1.57	2.57
5-year A	2.77	2.00	2.87
10-year Aaa	3.25	2.57	3.70
10-year A	4.19	2.95	4.20
25/30-year Aaa	4.48	3.92	5.17
25/30-year A	5.42	4.45	6.15
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.77	4.70	6.15
Electric AA	4.72	4.75	6.20
Housing AA	5.81	5.10	6.50
Hospital AA	5.18	5.25	6.55
Toll Road Aaa	4.80	4.75	6.25

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	12/16/09	12/2/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1089691	1119560	-29869	1010650	882362	829643
Borrowed Reserves	171457	206509	-35052	243588	306498	438064
Net Free/Borrowed Reserves	918234	913051	5183	767063	575864	391580

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	12/14/09	12/7/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1683.0	1684.7	-1.7	2.6%	3.5%	5.2%
M2 (M1+savings+small time deposits)	8405.5	8402.0	3.5	3.9%	0.4%	3.2%

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ATTACHMENT C

Cost-of-Service Rates Manual

Federal Energy Regulatory Commission
888 North Capitol Street, N.E.
Washington, D.C. 20426
United States of America
www.ferc.gov

June 1999

Table of Contents

Introduction 1

Step 1: Computing the Cost-of-Service 6
- **The Cost-of-Service Formula** 6
- **Test Period** 7
- **Rate Base** 8
  - **Gross Plant** 9
    - **Allowance For Funds Used During Construction (AFUDC)** 9
  - **Accumulated Reserve for Depreciation** 10
    - **Management Fee** 10
  - **Accumulated Deferred Income Taxes (ADIT)** 11
  - **Working Capital** 12
    - Cash working capital 12
    - Materials and Supplies, and Prepayments 13
- **Cost-of-Service** 13
  - **Return** 13
    - **Capitalization or Capital Structure** 15
    - **Cost of Debt** 16
    - **Return on Equity** 16
    - **Pretax Return** 17
  - **Operation and Maintenance Expenses** 18
  - **Administrative and General Expenses** 19
  - **Depreciation Expense** 19
  - **Federal and State Income Taxes** 20
    - **AFUDC** 21
    - **Effective Tax Rate** 22
    - **Limited Liability Companies** 22
  - **Non-Income Taxes** 22
  - **Credits to the Cost-of-Service** 23

Step 2: Computing a Functionalized Cost-of-Service 23
- **K-N Method** 24

Step 3: Cost Classification 28
- **Classification of Costs Between Fixed and Variable** 28
- **Classification of Costs Between Demand and Commodity** 29
  - Volumetric 30
  - Fixed-Variable 30
  - Seaboard 30
  - United 31
  - Modified Fixed-Variable 32
  - Straight Fixed-Variable 32

Step 4: Cost Allocation 33
- **Mcf's and Dth's** 34

$159,602,000, is equity financed. This means that the owners of Pipeline U.S.A. used their own funds to finance this portion of their investment.

** Pipeline U.S.A. issues its own debt which is not guaranteed by its parent, has its own bond rating and its capital structure is comparable to other equity capitalizations approved by the Commission. Therefore, Pipeline U.S.A. meets the Commission's criteria for using its own capital structure for setting its rates.*

Cost of Debt: This refers to the cost of long term debt incurred by the pipeline to construct or expand the pipeline. For ongoing pipelines that have been issuing debt, we use the actual imbedded cost of debt in the capital structure. The actual imbedded cost of debt is the weighted average of all the debt issued and the cost at which the debt was issued. For new pipelines that have indicated that they would issue debt to finance their investment, but have not yet actually issued the debt, we compute the cost of debt based on a projection, or recent historical debt cost such as historical average Baa utility bonds (Moody's Bond Survey), which is the most prevalent rating for utilities. We also use Moody's to compute the cost of debt if we decide use of a hypothetical capital structure is appropriate.

A-8, column 3, shows the cost of debt of Pipeline U.S.A. of 8.25%. The cost of debt represents a return to Pipeline U.S.A.'s bondholders. The debt return dollars appearing in Column 5 represents the cost to Pipeline U.S.A. to pay the interest on the debt to its bondholders. This debt return, or interest on debt, of $30,723,000 as shown in column (5) is included in the Return component of the cost-of-service.

Return on Equity or Cost of Equity: This is the pipeline's actual profit, or return on its investment. The return on equity is derived from a range of equity returns developed using a Discounted Cash Flow

(DCF) analysis of a proxy group of publicly held natural gas companies. The Commission currently uses a two-stage Discounted Cash Flow (DCF) methodology. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short term growth estimates and the other long term growth estimates. These estimates are then weighted, two-thirds for the short-term growth projection and one-third on the long-term growth, and utilized in determining a range of reasonable equity returns. Two-thirds is used for the short-term growth rate on the theory that short-term growth rates are more predictable, and thus deserve a higher weighting than long term growth rate projections. An equity return is then selected within this zone based on an analysis of the company's risk. It is assumed, that most pipelines face risks that would place them in the middle of the zone of reasonableness. However, a case could be made depending on the facts of the specific pipeline that the return on equity should be outside the zone. As an example, a pipeline with a high debt capitalization ratio is usually considered more risky and thus, a higher return on equity would be expected.

We have determined that a reasonable return on equity for Pipeline U.S.A. is 14.00%. This return was at the high end of our range of equity returns because Pipeline U.S.A. is a relatively new pipeline company with a high debt capitalization ratio. The equity portion of the return permitted to be collected in rates is $22,344,000 shown in column (5) of A-8.

Pretax Return. Pretax return is the amount earned by a pipeline before income taxes and debt interest payments. Pretax return is often calculated for pipelines and used to further settlement negotiations. Using a pretax return figure can avoid the lengthy discussions and debates that surround the issues of capitalization ratios and ROE calculations and analyses. Use of a pretax return reduces these issues down to one number, a pretax percentage that can easily be compared to other pipeline's pretax returns. The pretax return figure

EXHIBIT
RUCO-12
ADMITTED

1 BEFORE THE ARIZONA CORPORATION COMMISSION

2

3 IN THE MATTER OF THE APPLICATION OF)
UNS GAS, INC. FOR THE ESTABLISHMENT)
4 OF JUST AND REASONABLE RATES AND) DOCKET NO.
CHARGES DESIGNED TO REALIZE A) G-04204A-08-0571
5 REASONABLE RATE OF RETURN ON THE)
FAIR VALUE OF THE PROPERTIES OF UNS)
6 GAS, INC. DEVOTED TO ITS OPERATIONS)
THROUGHOUT THE STATE OF ARIZONA.)
7) EVIDENTIARY
) HEARING

8

9

10 At: Phoenix, Arizona

11 Date: August 18, 2009

12 Filed: AUG 25 2009

13

14

15 **REPORTER'S TRANSCRIPT OF PROCEEDINGS**

16 **VOLUME VI**

17 **(Pages 809 through 929, inclusive)**

18

19

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25 **RUCO**

1 the resulting fair value cost of capital is 6.37 percent.
2 MR. TORREY: Your Honor, I have no further
3 questions for Mr. Parcell at this time.
4 ACALJ NODES: All right.
5 Mr. Pozefsky.
6 MR. POZEFSKY: Thank you.
7
8 CROSS-EXAMINATION
9
10 BY MR. POZEFSKY:
11 *Q.* Good morning, Mr. Parcell. How are you?
12 *A.* Good morning.
13 *Q.* Mr. Parcell, did I hear you that your CAPM range
14 was 7.3 percent to 7.7 percent?
15 *A.* You did.
16 *Q.* And you did not consider this range in your final
17 determination?
18 *A.* Well, I considered it, but it's not reflected in
19 my 9.5 to 10.5.
20 *Q.* Okay. And, Mr. Parcell, you would agree with me
21 that you testified before the Commission as a cost of
22 capital witness in numerous cases before this Commission;
23 is that correct?
24 *A.* Several, yes.
25 *Q.* And in all of those cases, Mr. Parcell, have you

1 always done a cost CAPM analysis as part of your cost of
2 capital analysis?
3 *A.* That has been the case in the last 20 or
4 25 years, yes.
5 *Q.* And when was the last time that you excluded from
6 your range the results of your CAPM analysis?
7 *A.* I don't know. I testified in March in an
8 Arizona-American Water Company case, and I don't recall
9 sitting here if I excluded that case or not. I just don't
10 remember.
11 *Q.* Okay. Mr. --
12 *A.* But beyond that, the prior cases I would have
13 testified in where I did my own analyses from scratch, so
14 to speak, would have gone back into early to mid 2008,
15 like Southwest Gas. And in those cases I did not --
16 because that preceded the turmoil in the financial market.
17 Now, I did file testimony in December in the APS
18 case. I don't recall if I excluded the CAPM in that or
19 not.
20 *Q.* Would you agree with me, Dr. Parcell --
21 *A.* Mr. Parcell.
22 *Q.* Mr. Parcell -- excuse me -- that CAPM is
23 frequently used as a check for the DCF analysis results?
24 *A.* Yes.
25 *Q.* Do you also agree with me, Mr. Parcell, that the

1 economic conditions are factors to be considered when
2 determining cost of capital?
3 *A.* Yes, in two ways. The first way is economic
4 conditions can be and often are a factor that influences
5 the inputs in these models. For example, economic
6 conditions influence the input risk-free rate. And
7 economic conditions influence the inputs for the CAPM of
8 the market risk premium. And economic conditions also
9 affect the inputs in DCF in dividend yield and growth
10 rates.
11 So conditions affect the inputs. In addition,
12 from what I refer to as a policy perspective, economic
13 conditions could impact what is deemed to be the proper
14 cost of capital in utilities cases. I don't mean from the
15 standpoint of what the models show, but from a policy
16 perspective that the Commission could and should do.
17 There are two aspects of it.
18 *Q.* Would you agree with me that in general there has
19 been an economic downturn in the last year and a half?
20 *A.* Very much so, and it is continuing to -- I'm just
21 an economic forecaster, but I follow these trends, and
22 it's anticipated that the downturn is continuing down and
23 will last at least through the current quarter. The
24 question is will the fourth quarter of 2009 reflect an
25 uptick, if you will, or continue to decline. It has

1 declined a lot in the last year and a half -- well, almost
2 two years now.
3 *Q.* I believe in your summary, Mr. Parcell, didn't
4 you say that the company's credit ratio has improved since
5 its last rate case?
6 *A.* That's correct.
7 *Q.* And you also said that the company has been able
8 to secure an investment-grade bond rating since its last
9 rate case?
10 *A.* That's correct.
11 *Q.* In fact, you said the company is more financially
12 sound than it was in the last rate case; is that correct?
13 *A.* Yes. In fact, I think that is apparent from last
14 Monday's transcript, too.
15 *Q.* You also said that the company is actually less
16 risky than it was since its last rate case; correct?
17 *A.* I believe it to be, yes.
18 *Q.* And company has not experienced any significant
19 earning erosion since its last rate case; is that correct?
20 *A.* Well, they say they earned their cost of capital,
21 which is why they are here. I don't know what you mean by
22 earnings erosion. They want more money.
23 *Q.* I understand that.
24 You would agree that in the last rate case the
25 company was awarded a cost of equity of 10 percent; is

1 that correct?
2 *A.* That's correct, coming off a four-year rate
3 freeze, I might add.
4 *Q.* Which is what Staff is recommending in this case;
5 is that correct?
6 *A.* And in that case, yes.
7 *Q.* Given the answers to all of these questions I
8 have asked you, Mr. Parcell, do you think it would be
9 unreasonable for the Commission in this case to award cost
10 of equity that is actually lower than the 10 percent that
11 you have recommended?
12 *A.* I'm trying to answer this the shortest and
13 quickest possible way.
14 *Q.* That means it's not going to be a yes or no?
15 *A.* No, this is not.
16 Do you still want me to answer it?
17 *Q.* Please. Go ahead.
18 *A.* Okay. As a cost of capital analyst myself I look
19 at the numbers that I think are appropriate, and I see the
20 same average cost of capital in this case as I did in the
21 last case.
22 Now, my methods don't produce the same results in
23 this case from the last case. 9.5 to 10.5 I came by in
24 different manners, because my DCF in the last case was
25 9.25 to 10.5, my CAPM management was 9.5 to 10.2, and my

1 comparable earnings was 10.0. So my individual numbers
2 were different in the last case, but the overall
3 combination of the three was the same, that is a range of
4 9.5 to 10.5. Now, of course, I'm not going to give any
5 weight to the CAPM in this case for reasons I already
6 stated.
7 So from the perspective of myself, a cost of
8 capital analyst, I have the same recommendation as I did
9 in the last case. And I know that the company asked for
10 11 in the last case, and they are asking for 11 in the
11 this case. So the company seems to think its cost of
12 capital is the same.
13 But that is not what you asked me. You asked me
14 is there any rationale for lower cost of equity. And the
15 answer to that is, yes. I mean, from a policy perspective
16 one could be construed. That is, if the Commission chose
17 to focus on the impact of the economy on ratepayers, and
18 because, they said, well, maybe Parcell is wrong in this
19 case and we should focus on the low range as opposed to
20 the midpoint; there is rationale for that.
21 And also if the Commission were to decide that my
22 nonuse of the CAPM results was not proper, that it
23 shouldn't be used, if that was factored in, that would be
24 their rationale. I mean, that is not my recommendation,
25 but I'm saying that there are reasons. And the fact that

1 risks are sort of rare in this case and perhaps less
2 because of improved equity ratio and the fact that the
3 rate freeze is over now, there is public policy or
4 Commission policy reasons why it could be less, yes.
5 *Q.* And just to follow up on that, Mr. Parcell, would
6 you agree that if you were to consider your CAPM and take
7 the midpoint of all three ranges, the midpoint of 7.3 to
8 10.5 -- my back-of-the-envelope calculation, I got a
9 8.9 percent cost of equity.
10 Would you have any reason to disagree with that?
11 *A.* With the numbers?
12 *Q.* Yes.
13 *A.* I will accept the mathematics of it, yes.
14 MR. POZEFSKY: Thank you, Mr. Parcell.
15
16 EXAMINATION
17
18 BY ACALJ NODES:
19 *Q.* Mr. Parcell, before I turn it over to the
20 company's attorney, on this issue of taking into account
21 economic conditions as they exist currently and for the
22 past year or so, is there a math -- is there a method that
23 you believe the Commission can or should use for
24 quantifying economic indicators in setting the cost of
25 capital and/or overall rate of return in this proceeding?

1 *A.* In a longer-term broader-brush perspective, I
2 think the answer is yes. But over the past year I think
3 the answer is no.
4 I mean, the capital markets have been -- it's
5 been so screwed up. If you look at long-term interest
6 rates for corporations, for BBB utilities, for example --
7 I'm on schedule 2, page 4 -- in November of last year, the
8 average yield was like almost 9 percent. And if you tried
9 to focus on interest rates as an indicator of economic
10 conditions across the capital, that would -- I think it
11 produced skewed results just like I think CAPM produces
12 maybe skewed results now.
13 It's just hard to use the period of time from
14 September to at least March of this year as a standard.
15 And in fact I know that the company stopped its cost of
16 capital analysis in August of '08. I'm going to give them
17 some credit; that was a gutsy move to come into a rate
18 case and say we will stop in August and when the update
19 comes, do the same thing. I give them credit; they chose
20 not to jump on the bandwagon of high interest rates. And
21 I think I did the same thing basically by not looking at
22 the CAPM results.
23 But your question, is there a method, there
24 really is not because during the record time of this case,
25 you just can't look at traditional measures of yield

1 spreads or things like that because you just get results
2 that make no sense on a going-forward basis. You know,
3 fortunately you will have -- you, meaning you
4 personally -- only have one or two cases where you have to
5 reach a cost of capital conclusion using these conditions.
6 Because the cases I'm doing right now, things are starting
7 to focus more like we think they used to be -- more like
8 we used to think was common. But during the period of
9 time of this record, that was not the case.
10 *Q.* And I assume as an analyst you generally follow
11 what other state commissions are doing with respect to the
12 cost of capital and rate of return; is that correct?
13 *A.* Yes. Yes, in general, and yes, in particular
14 with cases that I'm involved in.
15 *Q.* And based on your analysis of what is happening
16 in other states, do you know what any other commissions
17 are doing with say, in the past 12 months, with respect to
18 setting the cost of capital as far as giving consideration
19 to economic conditions or indicators?
20 *A.* Well, I cannot point you to any decisions where a
21 commission specifically stated that it was altering the
22 cost of capital because of the complexity of the
23 conditions. But from a general perspective I don't see
24 any major change in returns on equity being authorized.
25 Now, there was an exhibit put in the record last

1 week that summarizes the returns on equity authorized by
2 state commissions. I don't remember if it was the
3 regulatory focus on January 12th. I'm sure it's up here.
4 MR. PATTEN: It's S-1, if that helps you.
5 THE WITNESS: Okay. And the data in there went
6 through fourth quarter of '07. And in the fourth quarter
7 of '07 the average return on equity authorized was
8 10.34 percent. I have seen the first quarter of '09, but
9 I don't have it, the publication. I have seen the result,
10 and that was a little bit lower than the fourth quarter of
11 last year, if I recall correctly.
12 So, of course, the real test would be first and
13 second quarters of this year when the rate cases are
14 decided, using the record from time period late '08, early
15 '09.
16 I have been in some cases recently, two water
17 cases in Delaware, both of which were settled at
18 10.0 percent. Actually those are basically the only cases
19 that I have been in in the early part of this year that
20 were not settled.
21 But, yeah, I don't see a major movement by
22 commissions with awards to reflect this, neither up nor
23 down. It's almost like a business-as-usual because many
24 witnesses try to temper their recommendations to a more
25 normal circumstance on an ongoing basis.

1 *Q.* BY ACALJ NODES: Okay.
2 *A.* I'm not sure I gave you a straight answer to your
3 question, but that is the best I can do.
4 *Q.* Well, and let me ask your opinion and give the
5 answer that you think is appropriate.
6 In your mind if the Commission were to take into
7 account economic indicators, both nationally and on a more
8 localized level, such as unemployment, such as
9 foreclosures and other indicators that reflect the overall
10 state of both national and state economy, should those
11 considerations more appropriately be factored into
12 establishing an appropriate cost of capital or should they
13 be taken into consideration in establishing the overall
14 revenue requirement in a more general sense as far as the
15 impact on ratepayers?
16 *A.* Well, it's a cost of capital guide. It would
17 seem to me that the cleanest and most direct way to do
18 something like that would be through the cost of capital.
19 Because you can specifically do it in a certain way.
20 For example, as I indicated to RUCO a while ago,
21 if it was decided that there needs to be some specific
22 consideration given to the economic conditions, maybe in a
23 so-called shared pain velocity -- if the ratepayers are
24 hurting, maybe the company ought to maybe, I don't want to
25 say share the ratepayers' pain, but at least shouldn't

1 benefit from it. Perhaps they should move to the low end
2 of the fair cost of capital range, but it's a midpoint.
3 And that would be direct and measurable, such
4 that if the next case was a couple years from now, you can
5 say, well, if conditions improve, we move back to the
6 midpoint.
7 So I think the simple answer is, the best way to
8 look is through cost of capital because it's very
9 specific. And I hate to sound like a lawyer, but if you
10 are going to do the bottom range, at least you have
11 something that is in the record and supportable because
12 it's -- anywhere in the range, from my perspective as an
13 economist and a witness, anywhere in the cost of range
14 could be construed as the cost of capital, even the low
15 part -- even the high point, but you wouldn't go to the
16 high point in these market conditions.
17 *Q.* In your expert opinion if the Commission were to
18 consider some -- an overall cost of capital within the
19 range of recommendations by the three cost of capital
20 witnesses, is it your opinion that the Commission should
21 give more weight to lower in the range between the three
22 witnesses as opposed to setting a point higher in the
23 range of the three recommendations given the overall
24 economic conditions that currently exist?
25 *A.* All right. I have to answer that question

1 indirectly.

2 As an analyst and a cost of capital witness I

3 have to -- I have to -- I should maintain and I am

4 maintaining that to me the cost of capital is what it is.

5 I do state in my testimony that you should not use

6 economic conditions as a reason to justify a higher cost

7 of capital because I don't think cost of capital has

8 changed.

9 But moving -- on the other hand, from the policy

10 perspective, I think it's appropriate for the Commission,

11 should they choose to do so, to go to the low end of the

12 range to reflect economic conditions.

13 Do you understand my -- I'm trying to walk the

14 fence here. But from a witness standpoint, you should

15 stick to the numbers; but I think from the Commission

16 policy standpoint, it's appropriate to go anywhere in the

17 range.

18 And if you choose to do so because of the

19 economic conditions, that would be proper and supportable.

20 It's just that you would not find a witness like me that

21 would specifically recommend it based upon the numbers,

22 because the numbers being 9.5 and 10.5. If you want to go

23 to 9.5 for whatever reason, I think that is fine.

24 *Q.* Well -- and you're probably aware -- yesterday

25 there was some discussion with Mr. Rigsby who leveled, I

1 guess, a bit of a criticism of your recommendation that
2 you have come up with a cost of equity recommendation that
3 is the same as was recommended by you in the company's
4 last rate case some two years ago.
5 And the criticism is, I guess, how could this
6 company's cost of capital, given the events of the past
7 year, possibly be the same as two years ago?
8 Can you provide -- I think you have touched on it
9 somewhat, but could you just give an overall, I guess,
10 response to that criticism?
11 *A.* Sure. I would be glad to.
12 I don't have the testimony with me, but I
13 reviewed it on the Commission's web site.
14 In the last case, which is G-04204A-06-0463, I
15 also used DCF, CAPM and comparable earnings methodologies,
16 and I think I can safely say that I performed them in a
17 consistent fashion between that case and this case.
18 In the '06 case my DCF range was 9.25 and 10.5.
19 In this case it's 9.5 and 10.5. So my DCF is roughly the
20 same between the last case and this case; so no movement
21 for DCF.
22 My comparable earnings in that case, my
23 recollection is I concluded that the comparable earnings
24 conclusion was no greater than 10 percent. I didn't use a
25 range. In this case I am using a range of 9.5 to 10.5

1 with a midpoint of 10.0.
2 So my DCF in the last case would have been an
3 average of 9.875. My comparable earnings was 10.0. In
4 this case both of those two have an average of 10.0.
5 The change from my last case and this case is the
6 weighted CAPM. The CAPM in the last case was results of
7 9.5-10.25. In this case it is 7.7-7.9. So the bottom has
8 dropped out of CAPM, so to speak, and I, in this case,
9 have viewed that as an outlier. And because of that I
10 have not given it significant weight in my recommendation.
11 Now, I mean, you could say, well, if you don't
12 give it weight, could you at least go to a viable range?
13 I could have. I did not, but I could have.
14 And DCF results tended to be a little skewed
15 upward because of the economic conditions, too, but not a
16 whole lot, not as much as the CAPM skewed down.
17 Q. Okay. But I guess -- I guess the criticism from
18 RUCO is why not incorporate the CAPM results into your
19 overall range, and I understand you have said that, well,
20 it -- because you had two of the three methodologies and
21 they resulted in a comparable, exactly the same range, you
22 have considered it to be -- the CAPM to be an outlier.
23 But RUCO is indicating, well, why should you
24 throw that out? Why not look at the entirety of the range
25 and come up with an average and then perhaps use the

1 midpoint of that entire range?
2 I mean, what is it that makes the CAPM results an
3 outlier that should not be considered in this proceeding?
4 MR. POZEFSKY: Your Honor, can we call it a
5 disagreement as opposed to a criticism? I think we are
6 just disagreeing more than we are being critical of the
7 company or Staff.
8 I know it's a semantic thing, but I think
9 criticism implies something a little different than
10 disagreement.
11 ACALJ NODES: Well, why don't you just let me ask
12 my questions, if you would.
13 MR. POZEFSKY: That's fair.
14 ACALJ NODES: Thank you.
15 THE WITNESS: Okay. There are two things that
16 give me reason to do it this way. The first is the change
17 in CAPM between the last case and this case, to go from a
18 midpoint of about 10 to a midpoint of about 7.5 in
19 two years. So just on a first glance, you say, why in the
20 world would this happen? And then when you look at the
21 numbers, you say, well, the reason it happened is because
22 of the so-called flight to quality or flight to safety.
23 The risk-free rate dropped from probably 4.5 over the last
24 case to -- even 5 percent to 3.82 percent. So it was a
25 big drop in the risk-free rate. And the drop, what

1 concerns me, is why it dropped. And it dropped because of
2 all the movement of moneys into the government securities
3 because it was a safe haven at that point in time.
4 And the second reason that I would give less
5 weight to a CAPM is the company cost of debt is about
6 6.5 percent. That is their weighted cost of debt basis on
7 historical rates. And my CAPM results are only about
8 100 basis points higher than that. If the company sold
9 debt today, it would probably be at the CAPM rate. And I
10 think the cost of equity should be higher than the cost of
11 debt.
12 *Q.* Is that an indication that the CAPM methodology
13 is influenced much more by current economic conditions
14 than the other methodologies and as such perhaps is not as
15 influential in an analyst's overall evaluation in general
16 terms?
17 *A.* In general terms, yes. But it's complicated. I
18 will keep this answer short though.
19 The CAPM, when the risk-free rate drops a bunch
20 and the stock market fell so much in '08, which influenced
21 both risk-free rate and the risk premium, the CAPM dropped
22 a lot. But these results are also influenced because as
23 stock prices drop, the yields go up.
24 But the real thing with the DCF is the growth
25 rates. If you look at analysts' projections, for example,

1 what -- rhetorical question -- what are the analysts
2 thinking? Are they having future growth rates from the
3 current depressed levels? If so, maybe they are
4 overstated or maybe they didn't start with the current
5 depressed. We don't know.
6 When we look at analysts' forecasts, we don't
7 know what they consider; we just know what they are
8 predicting. And does the base period really reflect the
9 bottom of the trough, which it should, or do the historic
10 growth rates, which should be lower because of the ending
11 period in '08, do they profit?
12 So we don't know the answers to that. And the
13 fact that the DCF growth rates haven't changed as much as
14 CAPM tell me that the analysts are taking a lower-term
15 view. I can't prove that, but logically you would think
16 that either from what has happened or the base going
17 forward, that the growth rates would be influenced by
18 that. But since the growth rates haven't changed much, I
19 think analysts for growth rates are probably taking a more
20 balanced view, and that is likely -- likely why DCF
21 results are not as influenced as CAPM.
22 Because the CAPM uses data you can go out and
23 get -- interest rates, historic-risk premiums. DCF
24 through the growth rates uses other people's judgment and
25 people who can't be cross-examined because they are not in

1 this case. And so the DCF is in that regard less
2 mechanical than CAPM because there's a two-level judgment.
3 The first level is the analyst and the second level is the
4 cost of capital analyst, like myself. And you don't have
5 that in a CAPM; it's all on data.
6 *Q.* Okay.
7 *A.* It's very pertinent as a black-box model. I have
8 not heard it phrased in years, but it used to be.
9 ACALJ NODES: Before we go to the company we will
10 take a ten-minute break and then turn it over to
11 Mr. Patten.
12 (Whereupon, a recess was taken from 10:28 a.m.
13 until 10:41 a.m.)
14 ACALJ NODES: Okay. Back on the record.
15 Mr. Patten.
16 MR. PATTEN: Thank you, Your Honor.
17 And just -- I'll note, I did put a set of five
18 exhibits up on your desk at the start of the day, which
19 were marked UNSG-36 through 40. The other parties have
20 copies of those as well.
21
22 CROSS-EXAMINATION
23
24 BY MR. PATTEN:
25 *Q.* Good morning, Mr. Parcell.

EXHIBIT
S-2
ADMITTED

POWER PURCHASE AND SALE AGREEMENT

This Power Purchase and Sale Agreement (the "Agreement") is entered into this 3rd day of March, 2008 between UNS Electric, Inc. ("Buyer") and UniSource Energy Development Company ("Seller"), (each sometimes referred to individually as a "Party" and collectively as the "Parties").

A. Seller is the owner of the Facility (as more particularly defined in Section 3 below) and desires to sell all of the capacity and associated energy from the Facility to Buyer in accordance with the provisions of this Agreement.

B. Buyer desires to purchase all of the capacity and associated energy from the Facility in accordance with the provisions of this Agreement.

C. Buyer will have the responsibility to operate and maintain the Facility pursuant to a Maintenance Agreement executed contemporaneously with this Agreement.

D. Buyer will have the responsibility and risks associated with all operating and maintenance costs related to the Facility, including fuel and fuel transportation costs, ground lease and other real property related costs, and taxes (other than taxes on the income of Seller).

NOW, THEREFORE, in consideration of the foregoing, the Parties agree as follows:

1. **Seller:** UniSource Energy Development Company

2. **Buyer:** UNS Electric, Inc.

3. **The Facility:** A gas-fired simple cycle electric generating facility consisting of two GE LM6000 PC Sprint gas turbines with inlet chilling and associated equipment and accessories located at a site known as the Black Mountain Generating Station ("BMGS") near Kingman, Arizona. The combined capacity is expected to be 90 MW.

4. **Product and Description:** The capacity and energy being sold to Buyer under this Agreement will be unit contingent, based on availability of the Facility, and fully dispatchable by Buyer.

   In consideration of the payment of a Capacity Charge (as defined below), the Buyer shall have the right, but not the obligation, to schedule and take the energy output from the Facility up to the Contract Capacity at the Delivery Point for the Term (as defined below).

5. **Tolling Arrangement:** Buyer shall have all risk and responsibility during the Term for the costs associated with the operation and maintenance of the Facility, including

without limitation, fuel commodity and transportation charges, equipment replacement and maintenance, taxes (other than taxes on the income of Seller), and real property charges. To the extent that Seller pays for any such costs, Seller will be entitled to invoice Buyer for reimbursement of the same on a pass-through basis.

6. **Contract Capacity:** The contract capacity will be will be the full available output of BMGS as it may vary from time to time with weather and equipment configuration, but no less than 90 MW (the "Contract Capacity"). Buyer will be responsible for maintaining the Facility in a manner designed to ensure that the Contract Capacity is maintained throughout the Term. Buyer may periodically run a capacity test for the Facility in accordance with industry standards to monitor the effective capacity of the plant.

7. **Heat Rate:** The design full load heat rate for the Facility is 9,250 Btu/kWh. The actual heat rate will vary depending on unit dispatch and weather conditions.

8. **Term:** This Agreement will be effective as of the date hereof, subject to the receipt of applicable regulatory approvals, and will continue for a period of five years from the date BMGS commences commercial operation. The expected commencement date of commercial operation is June 1, 2008.

9. **Delivery Point:** All delivered energy shall be at the high voltage side of the BMGS Substation.

10. **Capacity Charge:** **REDACTED**

11. **Fuel:** Buyer shall be responsible for providing gas delivered to the facility to meet expected generation requirements. Buyer will be responsible for all up-stream transportation, fuel, and commodity expenses to deliver gas to the facility as well as applicable gas taxes and balancing requirements and/or fees and penalties. Buyer will be responsible for gas imbalances caused by the inability of the Facility to perform on any scheduled day.

12. **Transmission:** Seller shall be responsible for any transmission arrangements and the costs associated therewith to deliver Energy to the Delivery Point. Buyer shall be responsible for any transmission arrangements and the costs associated therewith to transmit energy from the Delivery Point.

13. Preschedule: Buyer has the right, but not the obligation, to preschedule and accept energy from Seller at the Delivery Point in an amount up to the Contract Capacity, within the operating constraints specified in Section 21 for each hour during any day of the Term.

Buyer will have the flexibility to commit and dispatch the Facility within its physical capabilities on a day-ahead, intra-day, hourly, and intra-hourly basis.

14. Scheduling: Buyer will be responsible for scheduling in accordance with WECC guidelines. Unit capacity will be available with 10 minutes' notice and available at any time, subject to scheduled maintenance outages, forced outages and any applicable force majeure events.

15. Start Costs: **REDACTED**

16. Variable O&M: Buyer shall reimburse Seller for actual variable O&M costs incurred and paid for by Seller.

17. Planned Maintenance: Planned maintenance shall be coordinated with Buyer and shall not be scheduled during the Summer Period. The Summer Period is defined as June 1 through September 30.

18. Force Majeure: Seller will be relieved of any of its obligations under this Agreement to the extent that it is unable to perform due to an event of force majeure. An event of force majeure is defined as event which wholly or partly prevents or delays the performance of any obligation arising under this Agreement, but only if and to the extent (i) such event is not within the reasonable control, directly or indirectly, of the Party affected, (ii) the Party affected has taken all reasonable precautions and measures in order to prevent or avoid such event or mitigate the effect of such event on such Party's ability to perform its obligations under this Agreement, and (iii) such event is not the direct or indirect result of a Party's negligence or the failure of such Party to perform any of its obligations under this Agreement; provided, however, that the occurrence of a force majeure event shall not excuse any Party from any payment obligations hereunder with respect to services previously rendered or which continue to be rendered during a period in which a force majeure event renders a Party only partially able to perform.

19. Regulatory Approvals: This agreement will be subject to the receipt of all necessary regulatory approvals._ In particular, this Agreement will not be binding upon the Buyer unless and until it has received approval of (i) the Arizona Corporation Commission for rate treatment satisfactory to the Buyer, including recovery of all expenses in the Buyer's Purchased Power and Fuel Adjustment Clause, and (ii) the Federal Energy Regulatory Commission ("FERC"). The Buyer will notify the Seller upon receipt of any decision by the Arizona Corporation Commission and the FERC.

20. Gas Agreement Assignments: This Agreement is subject to the satisfactory assignment of the Gas Transportation Agreement Between UNS Gas, Inc. and UniSource Energy Development Company, dated February 28, 2008 and the Interruptible Natural Gas Sales and Agency Agreement between UNS Gas, Inc. and UniSource Energy Development Company, dated February 28, 2008 from Seller to the Buyer without modification, including necessary regulatory approvals.

21. Indicative Operating Parameters: The operation of the Facility, and the delivery of capacity and energy, will be subject to the following operating parameters:

Preferred minimum run-time:	4 hours per unit
Preferred minimum down-time:	4 hours per unit
Maximum starts/day:	2 starts per unit per day
Unit ramp up rate:	10 MW per minute per unit
Unit ramp down rate:	4 MW per minute per unit
Unit start-up fuel:	8,500 scf per start per unit

22. Indemnity: Each Party shall protect, defend, indemnify and hold harmless the other Party, its directors, officers, members, managers, employees and agents, for, from and against all claims, demands, causes of actions, judgments, liability and associated costs and expenses, including reasonable attorney's fees, arising from property damage, bodily injuries or death suffered by any person related to, arising from, or connected to any breach of this Agreement by, or other wrongful act or omission of, the indemnifying Party hereunder, in each case on account of any claim by a person not a Party to this Agreement. Neither Party shall be indemnified hereunder for its loss, liability, injury and damage to the extent resulting from its negligence, gross negligence, fraud or willful misconduct or from its breach of this Agreement. The indemnitor, upon the other Party's request, shall defend any suit asserting a claim covered by this indemnity and shall pay all costs, including reasonable legal fees, that may be

incurred by the other Party in enforcing this indemnity. Each indemnity in this Agreement is a continuing obligation, separate and independent of the other obligations of each Party and survives termination hereof.

23. Limitation of Liability:

UNDER NO CIRCUMSTANCE SHALL EITHER PARTY OR ITS RESPECTIVE AFFILIATES, DIRECTORS, OFFICERS, MEMBERS, MANAGERS, EMPLOYEES AND AGENTS, OR ANY OF THEM, BE LIABLE TO THE OTHER PARTY, ITS AFFILIATES, DIRECTORS, OFFICERS, MEMBERS, MANAGERS, EMPLOYEES AND AGENTS, OR ANY OF THEM, WHETHER IN TORT, CONTRACT OR OTHERWISE FOR ANY SPECIAL, INDIRECT, PUNITIVE, EXEMPLARY OR CONSEQUENTIAL DAMAGES, INCLUDING LOST PROFITS. EACH PARTY'S LIABILITY HEREUNDER SHALL BE LIMITED TO THE LIQUIDATED DAMAGES, IF ANY, SPECIFIED OR, IF NO LIQUIDATED DAMAGES ARE SPECIFIED, DIRECT ACTUAL DAMAGES.

24. Insurance:

Each Party will maintain in effect during the Term insurance coverage covering comprehensive liability and property damage customary in the industry.

25. Defaults:

The occurrence of any one or more of the following events shall constitute an "Event of Default":

(a) a failure by a Party to pay any amount due hereunder, where such failure is not cured within ten (10) days after receipt of written notice of nonpayment.

(b) any other breach by a Party of its obligations under this Agreement (other than a failure to make available Contract Capacity and energy) which causes material damage (other than special, indirect, punitive, exemplary and consequential damages excluded under this Agreement pursuant to Section 24) to the non-defaulting Party if such default has not been cured by the defaulting Party within sixty (60) days after receiving written notice from the non-defaulting Party setting forth, in reasonable detail, the nature of such default; provided, however, that, in the case of a default that is not reasonably capable of being cured within the 60-day cure period, the defaulting Party shall have additional time to cure the default if it diligently commences to cure the default within such 60-day cure period, it diligently pursues such cure, and such default is capable of being cured by the defaulting Party within no more than one hundred eighty (180) days after receiving such notice and is in fact cured within such one hundred eighty (180) day period; or

(c) if either Party commences a voluntary case under Title 11 of the United States Code, or files an answer or other pleading admitting or

failing to deny material allegations of a petition filed against it commencing an involuntary case under said Title 11, or seeks, consents to or acquiesces in the relief sought in such petition, or fails to timely controvert the material allegations of any such petition, or has entered against it an order for relief in any involuntary case commenced under said Title 11 and such order is not vacated within sixty (60) days after issuance, or seeks relief as a debtor under any applicable law, other than said Title 11, of any jurisdiction relating to the liquidation or reorganization of debtors or the modification or alteration of the rights of creditors, or consents to or acquiesces in such relief, or has entered against it by a court of competent jurisdiction a finding of bankruptcy or insolvency, an order or approval of liquidation, reorganization or any modification or alteration of the rights of its creditors, or an assumption of custody or receivership or other custodian for all or a substantial part of its property and such finding, order or approval is not vacated within sixty (60) days after issuance, or makes an assignment for the benefit of, or enters into a composition with, its creditors, or appointing or consenting to the appointment of a receiver.

26. Remedies: Upon the occurrence and during the continuation of an Event of Default, the non-defaulting Party shall have the following rights:

(a) to terminate this Agreement upon ten (10) days' prior written notice to the defaulting Party;

(b) to suspend performance of its obligations and duties hereunder upon written notice to the defaulting Party;

(c) to pursue any other remedy given under this Agreement or now or hereafter existing at law or in equity or otherwise;

provided, however, that if Seller or a Lender has notified Buyer that this Agreement has been collaterally assigned and has provided Buyer with an address to which notices to such Lender may be given, in the case of an Event of Default by Seller, Buyer shall provide the Lenders (if any) with written notice of such Event of Default to the address given and the Lenders shall each have the right (but not the obligation) for one hundred eighty (180) days after receipt of such notice either to cure the Event of Default on behalf of Seller, or, upon payment to Buyer of any amounts due from Seller under this Agreement but not paid by Seller, to assume, or cause its designee or a lessee or purchaser of the Project to assume, all of the rights and obligations of Seller under this Agreement arising from and after the date of such assumption; provided, that if the Lenders are precluded by applicable law or order of a governmental authority from seeking to effect a cure, such 180-day period shall commence from the date the Lenders are no longer precluded from seeking to effect a cure. In

the event that any of the Lenders or its designee assumes this Agreement: (i) Seller shall be released and discharged from any obligations to Buyer arising or accruing hereunder from and after the date of such assumption; (ii) Buyer shall continue this Agreement with any of the Lenders or its designee, as the case may be, substituted in the place of Seller hereunder; and (iii) if the assuming party is any of the Lenders, such party shall not be personally liable to Buyer for the performance of its obligations hereunder except to the extent of the total interest of the Lenders in the Project.

27. Assignment:

This Agreement shall inure to the benefit of and shall be binding upon the Parties and their respective successors and assigns. Except as set forth in this Section 27, this Agreement shall not be assigned or transferred by either Party without the prior written consent of the other Party, which consent shall not be unreasonably withheld, delayed or conditioned. No consent of such other Party shall be required for:

(a) any assignment or transfer of this Agreement to an affiliate of the assignor or transferor, so long as (i) such affiliate is at least as creditworthy as the assigning party as of the date hereof, (ii) the assignor or transferor agrees to remain primarily liable for the obligations of the assignee or transferee pursuant to an instrument acceptable in form and substance to the non-assigning Party, or (iii) the assignor or transferor fully guarantees the performance of the assignee or transferee under this Agreement pursuant to a guaranty acceptable in form and substance to the non-assigning Party; provided, however, that in the case of any such assignment or transfer under clause (i) above, such assignee shall, at the request of the non-assigning Party, produce evidence of, or credit support for, as the case may be, its ability to make the payments required of it, and to otherwise perform its obligations, hereunder; and

(b) any assignment to any Lender as collateral security for Seller's obligations under any financing documents Seller may enter into with such Lenders. Buyer acknowledges that upon an event of default by Seller under any financing documents relating to the Project, any of the Lenders may (but shall not be obligated to) assume, or cause its designee or a new lessee or purchaser of the Project to assume, all of the interests, rights and obligations of Seller thereafter arising under this Agreement. In the event that the rights and interests of Seller in this Agreement and the Project are assumed, sold or transferred as hereinbefore provided, and the assuming party agrees in writing to be bound by and to assume, the terms and conditions hereof, then the obligations and liabilities of Buyer, Seller and the Lenders arising or accruing hereunder from and after the date of such assumption, shall be as set forth in the last sentence of Section 26. Notwithstanding any such assumption by any of the Lenders or a designee thereof, Seller shall not be released and discharged from and shall remain liable for any and all obligations to Buyer arising or accruing hereunder

prior to such assumption. The provisions of this Section 27 are for the benefit of the Lenders as well as the Parties hereto, and shall be enforceable by the Lenders as express third-party beneficiaries hereof. Buyer hereby agrees that none of the Lenders shall be obligated to perform any obligation or be deemed to incur any liability or obligation provided in this Agreement on the part of Seller or shall have any obligation or liability to Buyer with respect to this Agreement except to the extent any of them become a party hereto pursuant to this Section 27 or Section 28.

28. Financing Liens: Each of Seller and Buyer may, without the approval of any Party, grant one or more mortgages (including one or more deeds of trust or indentures) on or security interests in its interest under this Agreement for the purposes of financing the construction and/or operation of the Project, or if otherwise required to do so under the terms of a mortgage or indenture to which it is or becomes a party in connection with the general financing of its assets or operations

29. Entire Agreement: This Agreement shall supersede all other prior and contemporaneous understandings or agreements, both written and oral, between the Parties relating to the subject matter of this Agreement

30. Waivers: No delay or omission in the exercise of any right under this Agreement shall impair any such right or shall be taken, construed or considered as a waiver or relinquishment thereof, but any such right may be exercised from time to time and as often as may be deemed expedient. In the event that any provision hereof shall be breached and thereafter waived, such waiver shall be limited to the particular breach so waived and shall not be deemed to waive any other breach hereof. The rights and remedies provided by this Agreement shall be in addition to those rights and remedies available to the Parties in both law and equity.

31. Third Party Beneficiaries: This Agreement is intended solely for the benefit of the Parties hereto. Except for the Lenders and as set forth in Sections 26 and 27, nothing in this Agreement shall be construed to create any duty to, or standard or care with reference to, or any liability to, or any benefit for, any Person not a Party to this Agreement

32. Dispute Resolution: The Parties agree to attempt to resolve informally all disputes arising under or with respect to this Agreement. Prior to commencing any litigation, a Party believing there is a dispute shall notify senior management of the other Party by notice and offer to hold a meeting of senior management of both Parties. If there is no resolution within thirty (30) days after such meeting (or if no such meeting occurs within thirty

(30) days after notification of senior management of the other Party), the Parties may agree on specific dispute resolution procedures to be followed with respect to the dispute in question or may commence litigation with respect to the dispute, in each case subject to Section 26.

33. Governing Law: This Agreement shall be governed by the laws of the State of Arizona.

34. Confidentiality: Except as set forth in this Section 34, Buyer and Seller shall hold in confidence for the Term and for a period ending on the first to occur of either three (3) years from the date of termination or two (2) years from the scheduled date of expiration hereof, the terms of this Agreement and any confidential information (designated as such) supplied to it by the other Party or otherwise related to this Agreement or the Project. Each Party shall inform its representatives to whom confidential information must be provided in connection with such Party's performance of this Agreement of its obligations under this Section 34 and shall apply the same safeguards used with respect to its own internal confidential information. Notwithstanding the foregoing, Buyer and Seller may disclose the following categories of information or any combination thereof:

(a) information contained in and required to be included in any filing required to be made with the FERC, any other governmental authority, WECC, NERC,, or any similar entity or organization that either Party joins or has rules with which either Party must comply;

(b) information which was in the public domain prior to receipt thereof by such Party or which subsequently becomes part of the public domain by publication or otherwise except by a wrongful act of such Party;

(c) information that such Party can show was lawfully in its possession prior to receipt thereof from the other Party through no breach of any confidentiality obligation to the other Party;

(d) information received by such Party from a third party having no obligation of confidentiality to the other Party with respect thereto;

(e) information at any time developed independently by such Party providing it is not developed from otherwise confidential information;

(f) information disclosed pursuant to and in conformity with applicable law, or a judicial order or in connection with any legal proceedings; and

(g) information required to be disclosed under securities laws applicable to publicly traded companies and their subsidiaries.

In addition, each of Seller and Buyer may disclose information regarding this Agreement, including the material terms hereof and information regarding performance hereunder, to financial institutions and other Persons providing or expressing interest in providing debt financing or refinancing, lease financing and/or other credit support to Seller or Buyer, and the agent or trustee of any of them, to rating agencies, and to Persons to which offering statements or other disclosure documents associated with the private or public offering of securities by or on behalf of Seller, Buyer or the Project are provided.

34. No Agency: This Agreement is not intended, and shall not be construed, to create any association, joint venture, agency relationship or partnership between the Parties or to impose any such obligation or liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or otherwise bind, the other Party.

35. Inspection and Audit Rights: For a period of three (3) years after the issuance of any invoice or other request for payment of costs, payments, settlements or other amounts due under this Agreement, each Party shall have the right to audit, during regular business hours of the Party to be audited, at its own expense, all agreements, books and records regarding such costs, payments, settlements or other amounts and other supporting information pertaining to this Agreement, subject to the auditing Party maintaining the confidentiality of any applicable third party contracts or agreements. The Parties shall cooperate in any such audits. The Parties shall maintain accurate records for all billings under this Agreement in accordance with generally accepted accounting standards. All records and supporting documentation of any Party that are used as the basis for billings shall be retained for three (3) years beyond the date of the invoice. Adjustments to any costs, payments, settlements or other amounts paid under this Agreement that are discovered by any audit shall be payable by the responsible Party to the other Party within sixty (60) days after completion of the audit or, if the results thereof are disputed, within sixty (60) days after final resolution of the dispute.

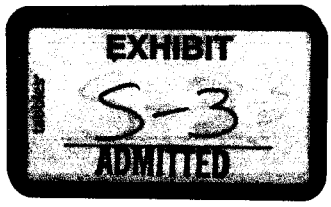
IN WINESS WHEREOF, the Parties have caused this Agreement to be executed as of the date first above written.

UNISOURCE ENERGY DEVELOPMENT COMPANY

By: _____
Title: Treasurer

UNS ELECTRIC, INC.

By: _____
Title: David G. Hutchens
Vice President



UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S FIRST SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
September 18, 2009

STF 1.63.1 What safeguards has the Company implemented to assure that the use of stock incentives do not result in increased risk to rate payers or the Company?

RESPONSE: UNS Electric is in the process of gathering this information and will provide the response to this data request shortly.

RESPONDENT: Regulatory Services

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO
STAFF'S FIRST SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
October 7, 2009

STF 1.63.1 What safeguards has the Company implemented to assure that the use of stock incentives do not result in increased risk to rate payers or the Company?

RESPONSE: UNS Electric is in the process of gathering this information and will provide the response to this data request shortly.

RESPONDENT: Regulatory Services

SUPPLEMENTAL RESPONSE: UniSource Energy Services has adopted a balanced executive compensation program to mitigate risk to the Company's rate payers. The compensation program is balanced between short- and long-term performance objectives, and considers the interests of our shareholders, customers, community and employees. Our annual bonus program is tied to achievement of financial, strategic and operational objectives. Our equity compensation program, combined with executive stock ownership guidelines, rewards long-term value creation and keeps our executives focused on the long-term.

RESPONDENT: Steve Bracamonte

WITNESS: Dallas Dukes

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
September 21, 2009

STF 3.55 List and describe all retirement and incentive programs available to Company officers and employees.

a. Specifically identify the cost of any SERP or similar programs directly charged or allocated.

b. State the cost by program, of each retirement program directly charged or allocated.

RESPONSE: **Incentives:** UNS Electric, Inc. non-union employees participate in UniSource Energy Corporation's ("UniSource") Performance Enhancement Plan ("PEP"). The structure determines eligibility for certain bonus levels by measuring UniSource's performance in three areas:

- financial performance (UniSource's earnings per share and cash flow);
- operational cost containment (UniSource's utility O&M costs); and
- core business and customer service goals.

Levels of achievement in each area are assigned percentage-based "scores," and those scores are combined to calculate the final payout level. The amount made available for bonuses through this formula may range from 15 percent to 150 percent of the targeted payout level.

The financial performance and operational cost containment components each make up 30 percent of the bonus structure, while the core business and customer service goals account for the remaining 40 percent.

The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages as a percent of base salary range from 3% - 14% for regular unclassified employees, and 25% - 80% for Managers and Officers. Bonus percentages as a percent of base salary are used in the calculation of total available dollars, and actual awards may vary at management's discretion based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year.

Retirement Programs: UNS Electric Employees are eligible to participate in the Pension Plan for Employees of UniSource Energy Services, see attached summary plan description. Additionally, UNS Electric Employees are eligible to participate in the Tucson Electric Power Company 401(k) Plan as described below:

401(k) PLAN

Tucson Electric Power Company's 401(k) Plan takes advantage of Section 401(k) of the Internal Revenue Code and permits employees to voluntarily save from

1/2% to 50% of their pay, before any deduction for state or federal income taxes. The Company matches, 50 cents on the dollar, up to the first 6% of pay saved in the 401(k) Plan for UNS Electric employees.

Employees' savings and Company matching contributions are invested in one or any combination of a selection professionally managed investment funds at the direction of the employee. Employees are eligible to join the 401(k) Plan upon their date of employment. Company matching contributions are fully and immediately vested.

a. & b. The cost of each retirement program available to Company officers and employees (1) directly charged and (2) allocated for the test year ended December 31, 2008 are as follows:

(1) UES Plans:	
UES Pension Plan	$572,125
UES 401K Plan	227,076
(2) Allocations from Other Plans:	
SERP Plan	102,142
Total	$901,343

RESPONDENT: Linda Joyce and Gabrielle Camacho

WITNESS: Dallas J. Dukes

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
September 21, 2009

STF 3.82 Please provide complete copies of any bonus programs or incentive award programs in effect at the Company for the most recent three years. Identify all incentive and bonus program expense incurred in 2008 and 2009. Identify the accounts charged. Identify all incentive and bonus program expense charged or allocated to the Company from affiliates in 2008 and 2009.

RESPONSE: Please see UNS Electric's response to STF 3.55 for the description of the bonus program available to UNS Electric Non-Union Employees. Union employees are not eligible for a bonus program. Bonus program expenses for 2008 and June, 2009, are as follows:

Expense:

- UNS Electric Incentive Compensation (PEP) Program (excluding officers):

  2008 = $127,864.53

  2009 (1st & 2nd Quarters) = $59,132.35

  Charged to Account 50100, Sub 0000, Expenditure Type 050, FERC 0546, 0593, 0901, 0903, 0920

- UNS Electric Incentive Compensation (PEP) Program Officer portion: Allocated by Massachusetts Formula

  2008 = $126,261.00

  2009 (1st & 2nd Quarters) = $58,858.00

  Charged to Account 52100, Sub 0000, Expenditure Type 052, FERC 0920

- Stock Option Expense: Allocated by Massachusetts Formula

  2008 = $126,347.85

  2009 (1st & 2nd Quarters) = $66,842.08

  Charged to Account 50100, Sub 4014, Expenditure Type 085, FERC 0920

- Dividend Equivalents on Stock Units: Allocated by Massachusetts Formula

  2008 = $18,274.13

  2009 (1st & 2nd Quarters) = $5,095.42

  Charged to Account 50100, 79040, Sub 3604, Expenditure Type 085, 0230 FERC 0920, 0930

- Performance Share Award: Allocated by Massachusetts Formula

  2008 = $33,753.83

2009 (1st & 2nd Quarters) = $44,034.74

Charged to Account 50100, Sub 4013, Expenditure Type 085, FERC 0920

- Dividend Equivalent on Stock Options: Allocated by Massachusetts Formula

  2008 = $23,164.02

  2009 (1st & 2nd Quarters) = $5,779.64

  Charged to Account 50100, 79040, Sub 4019, Expenditure Type 085, 230, FERC 0920, 0930

- Spot Awards and Other Incentives

  2008 = $25,250.00

  2009 (1st & 2nd Quarters) = $0.00

  Charged to Account 50100, Sub 0000, Expenditure Type 054, 055, FERC 0920

- Directors Stock Awards: Allocated by Massachusetts Formula

  2008 = $70,314.71

  2009 (1st & 2nd Quarters) = $32,135.62

  Charged to Account 79040, Sub 4020, Expenditure Type 230, FERC 0930

We are unable to provide 3rd Quarter 2009 results until we have filed our quarterly reports with the SEC.

RESPONDENT: Gabrielle Camacho and Warner Jones

WITNESS: Dallas J. Dukes

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
September 21, 2009

STF 5.9 List and describe all retirement and incentive programs available to Company officers and employees.

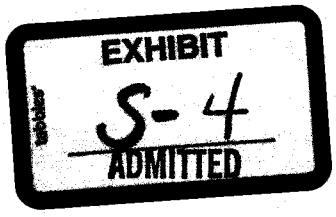
a. Specifically identify the cost of any SERP, PEP, Stock incentive or similar programs directly charged or allocated.

b. State the cost by program, of each retirement program directly charged or allocated.

RESPONSE: Please see UNS Electric's response to STF 3.55 of Staff's third set of data requests.

RESPONDENT: Linda Joyce and Gabrielle Camacho

WITNESS: Dallas J. Dukes



BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-04204A-09-0206

DIRECT

TESTIMONY

OF

KENNETH C. ROZEN

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 06, 2009

TABLE OF CONTENTS

Page

I. INTRODUCTION 1

II. LINE EXTENSION TARIFF REVISIONS 3

A. Revised Line Extension Tariff Filed Pursuant to Decision No. 70360 3

B. Further Modifications to the Line Extension Tariff 4

1. Facilities Operation Charge 5

2. Accounting Treatment in Tariff 8

C. Line Extension Construction Cost Estimates 8

III. SERVICE REESTABLISHMENT AND RECONNECTION CHARGE REVISIONS .. 10

IV. METER ERROR CORRECTIONS REVISIONS 11

V. TECHNICAL AND CLARIFYING REVISIONS 11

VI. SUMMARY OF STAFF RECOMMENDATIONS 12

EXHIBIT

Decision No. 71285 ..... KCR-1

UNSE Data Response STF 17.1 and STF 17.2 ..... KCR-2

Technical and Clarifying Revisions Proposed by UNSE KCR-3

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206

UNS Electric, Inc. seeks Commission approval of various revisions to it Rules and regulations as follows:

- The revised line extension tariff that UNSE submitted pursuant to the Commission's Decision (No. 70360) in UNSE's last rate case, which ordered the elimination of the 400 feet of free footage. Since the Commission approved those revisions in Decision No. 71285 dated October 7, 2009, Staff recommends that UNSE's request that the Commission approve them in this docket is moot.

- Further modifications to the line extension tariff, including the addition of a "Facilities Operation Charge" and a requirement that up-front payments of estimated line extension costs must be Contributions in Aid of Construction ("CIAC"). Staff is of the opinion that the Facilities Operation Charge raises significant issues regarding accounting treatment, rate design, and policy matters which remain unaddressed. Staff opposes implementation of the Facilities Operation charge. Although Staff agrees that the line extension payments should be treated as CIAC, Staff does not believe that the accounting treatment should be specified in the tariff.

- Staff opposes UNSE's proposed revisions that would require customers whose service is being reestablished or reconnected to pay monthly customer charges for the months during which service had been disconnected.

- Revisions to the rules governing meter error corrections, which would specify timeframes for repaying and refunding under-billed and over-billed amounts. UNSE's proposed revisions are consistent with Commission rules; Staff has no objection to adding time-frames for repaying and refunding under-billed and over-billed amounts.

- Numerous technical and clarifying revisions throughout the Rules and Regulations. Staff has no objections.

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kenneth Rozen. My business address is 14218 N. 43rd Street, Phoenix, Arizona 85032.

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

A. I am a self-employed consultant under contract with the Utilities Division of the Arizona Corporation Commission. My duties include evaluating various utility applications and reviewing utility tariff filings on behalf of the Utilities Division Staff ("Staff").

Q. As part of your contractual arrangement, did you accept an assignment to review certain matters contained in Docket No. E-04204A-09-0206?

A. Yes.

Q. Please describe your educational background and work experience.

A. Upon receiving a Bachelor of Arts from the University of Arizona in 1977, I was employed as an archaeologist with the Arizona State Museum for sixteen years. In July 1993, the Arizona State Land Department hired me to fill the position of Cultural Resources Manager, which I held until October 2000, when I assumed the duties of the Department's Legislative Liaison. In January 2003, I left the Land Department to become the Legislative Liaison for the Arizona Corporation Commission. After representing the Commission through two regular Legislative Sessions (2003 and 2004), then-Commissioner Mike Gleason hired me as his Policy Advisor in December 2004. I served in that capacity for four years until the end of Commissioner Gleason's last term in December 2008. I retired from service with the State of Arizona in January 2009, and contracted with the Utilities Division the following month.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to provide Staff's recommendations about the revisions UNS Electric, Inc. ("UNSE" or "the Company") is proposing to its Rules and Regulations, as set forth in the Direct Testimony of Thomas A. McKenna. UNSE's redlined version of its Rules and Regulations is presented in Mr. McKenna's Exhibit TAM-2. I will also identify and offer Staff's recommendations about certain other provisions of UNSE's Rules and Regulations, which warrant revision in Staff's opinion.

Q. Please provide an overview of what UNSE's application requests regarding UNSE's Rules and Regulations?

A. In its application, UNSE requests Commission approval of:

- The revised line extension tariff that UNSE filed in Docket No. E-04204A-06-0783 on June 26, 2008 pursuant to the Commission's Decision (No. 70360) in UNSE's last rate case, which in relevant part, ordered the elimination of the 400 feet of free footage;
- Further modifications to the line extension tariff, which were not in the June 26, 2008, proposed revisions, including the addition of a "Facilities Operation Charge;"
- Revisions to service reestablishment and reconnection charges;
- Revisions to the rules governing meter error corrections; and
- Numerous technical and clarifying revisions throughout the Rules and Regulations.

Q. What are the provisions of UNSE's Rules and Regulations, which are not affected by UNSE's proposed changes, that Staff believes warrant revision?

A. They are UNSE's Rules and Regulations pertaining to the content of line extension cost estimates; in particular, Subsections 9.A.3 and 9.B.e.

II. LINE EXTENSION TARIFF REVISIONS

A. Revised Line Extension Tariff Filed Pursuant to Decision No. 70360

Q. Please summarize the proposed tariff revisions that UNSE filed in Docket No. E-04204A-06-0783 on June 26, 2008 pursuant to the Commission's Decision (No. 70360) in UNSE's last rate case.

A. UNSE's June 26, 2008 filing proposed revisions to Sections 2 (Definitions), 6 (Service Lines and Establishments) and 9 (Line Extensions) of the Rules and Regulations. Of these, the revisions to Section 9 respond directly to Decision No. 70360 by eliminating the 400 feet of free footage and related provisions concerning line extensions exceeding 400 feet, including economic feasibility criteria, line extension agreements and refundable construction advances. Proposed revisions to Section 9 add language requiring the customer to pay the estimated cost of constructing line extension up front, and also add a transition period for customers to make plans before the elimination of the free footage. The proposed revisions to Sections 2 and 6 are for conformance with the revisions to Section 9; in Section 2, the definition of "Advance in Aid of Construction" is stricken and the revisions to Section 6 strike language that is inconsistent with the elimination of free footage, while adding language requiring the customer to pay the estimated cost of construction up front.

Q. What is the status of the Commission's consideration of the tariff revisions that UNSE filed on June 26, 2008, pursuant to Decision No. 70360?

A. The Commission approved UNSE's revised Section 6 (Service Lines and Establishments) and Section 9 (Line Extensions) in Decision No. 71285 dated October 7, 2009, a copy of which is attached to my testimony as Exhibit KCR-1. On October 19, 2009, UNSE filed proposed revisions to Sections 6 and 9 to comply with Decision No. 71285. Once they are final, I recommend that the Company file a copy of the revised tariffs in this docket.

Q. Since the Commission approved the revised line extension tariff that UNSE filed as ordered in the last rate case, is UNSE's request that the Commission approve it in this case now moot?

A. Yes, except that it appears that the revision to Section 2, eliminating the definition of "Advance in Aid of Construction," was inadvertently overlooked in the Decision.

Q. Is it Staff's opinion that UNSE would be able to make that revision as a conforming change, without Commission action?

A. Yes, after approving the revisions to Sections 6 and 9, the Decision No. 71285 orders UNSE to make all conforming changes to its Rules and Regulations.[1]

B. Further Modifications to the Line Extension Tariff

Q. What further modifications to its line extension tariff is UNSE proposing, which are not among those approved in Decision No. 71285, and for which UNSE seeks Commission approval in this case?

A. UNSE is proposing two substantive revisions to Section 9, which remain for Commission consideration in this case. First, UNSE proposes to impose a "Facilities Operation Charge" on line extension applicants under certain circumstances[2]. As Mr. McKenna notes, the proposed Facilities Operating Charge is an additional modification from what was submitted on June 26, 2008.[3] Second, UNSE's proposed revisions to Section 9[4] would include a provision in the tariff specifying that up-front payments of estimated line extension constructions costs will be treated as Contributions in Aid of Construction ("CIAC"). Mr. McKenna's testimony states that UNSE is proposing ". . . to require the customer to pay for all construction costs for such extensions as Contributions in Aid of

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1 Decision No. 71285, ordering paragraph at page 4, lines 9 and 10.
2 Proposed Subsections 9.D.2.a.-c, 9.D.4.a.iii, and 9.D.4.b.iii and 9.E; TAM-2 pages 33, 35, 37, 39, 45 and 46.
3 Thomas A. McKenna, Direct Testimony, page 12, lines 1 and 2.
4 Proposed Subsections 9.D.1, 9.D.3.a, 9.D.4.a.i and 9.D.4.b.i; TAM-2 pages 33, 37 and 39.

Construction."[5] While it is true that such payments may be appropriately treated as CIAC, accounting treatment is not something that is typically specified in a tariff. Further, in Decision No. 70360, the Commission did not require the Company to address the appropriate accounting treatment in its line extension tariff revisions.

1. Facilities Operation Charge

Q. What is the Facilities Operation Charge?

A. As described by Mr. McKenna[6], and set forth in proposed Subsections 9.D.2.a.-c., the Facilities Operation Charge is an amount UNSE would charge a line extension applicant if UNSE's projected operating expenses resulting from the distribution line would exceed projected revenues from the new customer or customers on the new distribution line, as determined by UNSE according to the formula set forth in proposed Subsection 9.E ("Economic Feasibility Criteria."). If applicable according to UNSE's determination, the amount of the Facilities Operation Charge would be the difference between UNSE's projected annual operating revenues and operating expenses attributable to the line extension. UNSE would require the customer to pay the Facilities Operation Charge up front as a condition of the line extension agreement and would reevaluate the charge at the customer's request, but no more often than once every 12 months.

Q. What is the Purpose of the Facilities Operation Charge according to UNSE?

A. UNSE's operating expenses associated with the facilities might exceed revenues until the number of new customers grows to a certain level. The purpose of the Facilities Operating Charge would be to cover UNSE's operating expenses to the extent that they exceed revenues from customers using the facilities. Apart from eliminating free footage,

[5] Thomas. A. McKenna, Direct Testimony, page 11, lines 23-25.
[6] Id, page 11, lines 11-27; page 12, lines 1-5.

UNSE views this charge as a further way to ensure that current customers do not pay for facilities necessitated by growth.[7]

Q. Does Staff have any concerns with UNSE's proposed Facilities Operation Charge, and if so, what are they?

A. Yes. Staff has a number of concerns as follows:

1. By applying to line extension customers whose cost to serve is projected to be greater than the average per-customer cost, the Facilities Operation Charge appears to be consistent with a policy of ensuring that growth pay for itself. However, the Facilities Operation Charge fails to account for revenues from those customers whose cost to serve *will be less than* UNSE's average per-customer cost to serve. Staff is therefore concerned that the Facilities Operation Charge would allow the company to collect more revenue than otherwise authorized in rates.

2. Although UNSE views the Facilities Operation Charge as "separate from what is considered CIAC,"[8] Mr. Mckenna's Direct Testimony does not positively identify how UNSE proposes to treat the Facilities Operation Charge for accounting purposes. Without knowing how UNSE intends to treat the Facilities Operation Charge for accounting purposes, the ratemaking implications of approving the charge are unclear.

3. If the Facilities Operation charge were to be booked as revenue, the additional revenues resulting from the charge would have to be offset against savings resulting from customers whose cost to serve is less than the average per-customer cost. Staff is concerned that the method by which UNSE would calculate this offset is unclear.

[7] Thomas A. McKenna, Direct Testimony page 12, lines 18 through 25
[8] Thomas A. McKenna, Direct Testimony page 12, lines 24 and 25

4. A company's average cost to serve is established for each customer class, but as proposed in Subsection 9.D.2, the Facilities Operation Charge contains no provisions for distinguishing various classes of customers or groups of customers who might be served through a new distribution line. Staff is concerned that the method by which UNSE would calculate the amount of the charge is unclear in that respect.

5. While some of the elements identified in Subsection 9.E as comprising operating expenses, such as depreciation and taxes, appear straightforward, the basis for calculating projected operation and maintenance expense as a percentage of total construction cost for any given extension is unclear.

6. Staff is also concerned that UNSE's proposal to reevaluate the Facilities Operation Charge only at the customer's requests would tend to perpetuate the Charge beyond the time when the number of customers, and therefore operating revenue, are sufficient to cover operating expenses.

7. Finally, as proposed in Subsection 9.2.D, UNSE would have complete autonomy to determine if the Facilities Operation Charge should be imposed on any given applicant using Economic Feasibility Criteria which UNSE alone would calculate on the basis of its own projections. Staff is concerned that this level of autonomy in determining what effectively are prospective customer-specific rates may not be in the public interest.

Q. What is Staff's recommendation regarding the Facilities Operation Charge?

A. In view of the numerous unresolved issues relating to UNSE's proposal to implement the Facilities Operation Charge, Staff opposes the proposal.

2. Accounting Treatment in Tariff

Q. What is Staff's position regarding UNSE's proposal to revise the line extension tariff to specify that payments of line extension construction costs must be CIAC?

A. As I mentioned earlier, accounting treatment is not typically addressed in a tariff. In Arizona Public Services' ("APS") last rate case, for example, the Commission agreed with Staff's recommendation that discussion of the accounting treatment of line extension payments should not be included in the tariff.[9] Staff maintains this recommendation in this case. Regardless of the Commission's determination of the proper accounting treatment, it is inappropriate to specify accounting treatment in the tariff. To do so provides little or no information of practical value to the customer and may have the potential to complicate Commission findings to the contrary under different circumstances in future cases.

C. Line Extension Construction Cost Estimates

Q. What are Staff's concerns with existing provisions in Section 9 relating to line extension construction cost estimates?

A. The estimated cost that a customer is required to pay upfront may not necessarily be sufficiently itemized given the wording of two current provisions in UNSE's Rules and Regulations, Subsections 9.B.1.e and 9.A.3. Subsection 9.B.1.e provides that each line extension agreement must include a cost estimate "to include materials, labor, and other costs as necessary." Similarly, Subsection 9.A.3., states only that UNSE "will provide the Applicant with the estimated costs of extending service." Staff is concerned that this wording allows UNSE to provide a cost estimate consisting essentially of only three estimates; one for aggregate material costs, one for labor and one for aggregate "other" costs. Staff believes that aggregate material costs would not provide the customer with an

[9] Decision No. 70185, Page 2, Finding of Fact 6; Page 5, lines 7 and 8.

adequate basis for evaluating line extension costs, either as proposed in the line extension agreement or in the context of UNSE's comparison between estimated and actual costs after the work is done. In response to Data Requests STF 17.1 and STF 17.2, UNSE filed confidential examples of a cost estimate provided to a line extension applicant pursuant to Subsection 9.A.3 (for the applicant's consideration before accepting) and the corresponding cost estimate included in the line extension agreement, as directed by Subsection 9.B.1.e. Both examples are attached to my Testimony as confidential Exhibit KCR-2. Although the subject line extension entailed over 1,800 feet of overhead distribution line, and may have involved several different types of material costs, only the aggregate materials cost was provided, even though the cost estimate form has a dozen categories for materials. Accordingly, Staff has reason to believe that UNSE's line extension cost estimates are not sufficiently itemized when given to the customer.

Q. What are Staff's recommended revisions to Subsections 9.B.1.e and 9.A.3.?

A. Staff believes that, as a matter of sound regulatory practice, the Company's rules should be clear with regard to the level of itemization the Company is obligated to provide. Therefore, Staff recommends that Subsection 9.B.1.e be revised to provide that line extension agreements must include "A cost estimate to include *itemized* material *costs*, labor and other *itemized* costs as necessary." Staff further recommends that Subsection 9.A.3 be revised to add a new sentence stating that "The estimated costs provided to the applicant will be itemized."

III. SERVICE REESTABLISHMENT AND RECONNECTION CHARGE REVISIONS

Q. What changes to its current service reestablishment and reconnection charges is UNSE proposing?

A. In addition to the amounts currently allowed in Section 14 of its Rules and Regulations, UNSE is proposing to require customers whose service is being reestablished or reconnected to pay monthly customer charges for the months during which service had been disconnected.. These additional charges are reflected in new language UNSE seeks to add to the definitions of "Service Reconnection Charge" and "Service Reestablishment Charge" in Section 2[10], in Section 3[11] and also in a footnote in Section 14 ("Statement of Additional Charges")[12].

Q. What is UNSE's rationale for imposing these additional charges changes?

A. UNSE states that service reconnections and reestablishments are significant costs to the Company and that the cost-causers should incur the costs for these services UNSE provides.[13]

Q. Does UNSE's rationale provide sufficient justification for imposing these additional charges?

A. No. Although Staff does not dispute that service reconnection and reestablishment are significant costs to UNSE, the significant charges already authorized in Section 14 are precisely the means by which UNSE is to recover those costs. UNSE's proposal to collect any additional amount for services, such as meter reading and billing, which UNSE did not provide, and for which it therefore incurred no cost, while it was not furnishing electricity to the customer, is groundless.

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[10] TAM-2, page 6, Subsection 2.A.48; page 7, Section 2.A.49.
[11] TAM-2 page 14, Subsection 3.E.4
[12] TAM-2 page 68, footnote to Subsections A, B, C and D.
[13] Thomas A. McKenna, Direct Testimony, page 13, lines 5-7.

Q. What is Staff's recommendation regarding UNSE's proposed revisions relating to service reconnection and reestablishment charges?

A. Staff opposes UNSE's proposed revisions relating to service reconnection and reestablishment charges.

IV. METER ERROR CORRECTIONS REVISIONS

Q. What revisions to its meter error correction rules is UNSE proposing?

A. UNSE's proposed revisions to Subsection 11.E (Meter Error Corrections)[14] would add language specifying time frames for repaying and refunding under-billed and over-billed amounts resulting from slow or fast meters, respectively.

Q. Does Staff have any concerns with UNSE's proposed revisions to Subsection 11.E?

A. No. UNSE's proposed revisions to Subsection 11.E are based on and consistent with parallel provisions in Commission Rules[15]

Q. What is Staff's recommendation regarding UNSE's proposed revisions to Subsection 11.E of its Rules and Regulations?

A. Staff has no objections to UNSE's proposed revisions to Subection 11.E.

V. TECHNICAL AND CLARIFYING REVISIONS

Q. What are the technical and clarifying revisions that UNSE is proposing?

A. Technical and clarifying revisions that UNSE is proposing throughout its Rules and Regulations are identified by Section and TAM-2 page number in Exhibit KCR-3 attached to my testimony.

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[14] TAM-2, page 54
[15] A.A.C. R-14-2-210, Subsection E, "Meter error corrections"

Q. Does Staff have any concerns with any of the technical and clarifying revisions that UNSE is proposing?

A. No.

VI. SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's Recommendations:

1. Staff opposes UNSE's proposed revisions to Section 9 (Line Extensions) of its Rules and Regulations that would establish the Facilities Operations Charge.

2. Although Staff agrees that the line extension payments should be treated as CIAC, Staff opposes UNSE's proposed revisions to Section 9 that would specify the accounting treatment in the tariff.

3. Staff recommends that Subsections 9.A.3 and 9.B.1. relating to line extension construction cost estimates be revised to require that the estimates include itemized material costs.

4. Staff opposes UNSE's proposed revisions to Sections 2 (Definitions), 3 (Establishment of Service) and 14 (Statement of Additional Charges), that would require customers whose service is being reestablished or reconnected to pay monthly customer charges for the months during which service had been disconnected.

5. Staff has no objections to UNSE's revisions to Section 11 (Billing and Collections) which would add time frames for repaying and refunding under-billed and over-billed amounts resulting from slow or fast meters, respectively.

6. Staff has no objections to the numerous technical and clarifying revisions which UNSE is proposing throughout its Rules and Regulations.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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BEFORE THE ARIZONA CORPORATIO

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

Arizona Corporation Commission
DOCKETED
OCT -7 2009
DOCKETED BY ne

IN THE MATTER OF UNS ELECTRIC, INC.'S APPLICATION FOR APPROVAL OF REVISIONS TO ITS LINE EXTENSION TARIFF

DOCKET NO. E-04204A-06-0783

DECISION NO. 71285

ORDER

Open Meeting
September 22 and 23, 2009
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

1. UNS Electric, Inc. ("UNSE" or "Company") is certificated to provide electric service as a public service corporation in the State of Arizona.

2. Pursuant to Commission Decision No. 70360 issued on May 27, 2008, UNSE filed an application to revise its Rules and Regulations in order to eliminate the free footage allowance contained in its line extension tariff (Section 9).

3. UNSE's current line extension tariff allows for 400 feet of free footage. In other words, customers needing a line extension in excess of 400 feet do not pay for the cost associated with the first 400 feet of the line extension.

4. The proposed tariff revisions also include a transition plan. The plan is as follows:

Transition Period for Elimination of Free Footage

From the effective date of these Rules and Regulations, there is a six (6) month grace period for Customers, developers and subdividers to execute a line extension agreement or receive approval on a new service application from the Company in order to be eligible for the line extension

> policy in effect between August 11, 2003 and May 31, 2008. Those new applicants must make provisions for the Company to install and energize the extension and service facilities within eighteen (18) months from the date of their respective agreement and/or application. In addition, all existing approved line extension agreements and service applications will be grandfathered in under the policy in effect from August 11, 2003 to May 31, 2008. Grandfathered Customers must make provisions for the Company to install and energize the extension and service facilities within eighteen (18) months from the effective date of these Rules and Regulations or they will be subject to the new line extension policy.[1]

5. This proposed language would provide a transition period for customers to make appropriate plans prior to the elimination of the free footage. Dates contained in this passage, however, are outdated and would need to be updated to reflect the timing of the Decision rendered in this matter. Staff has recommended that both references to May 31, 2008 be changed to reflect the date prior to the effective date of the Rules and Regulations approved in the Decision in this matter.

6. The Commission believes it is appropriate for UNSE to outline its plan for raising awareness of the grandfather provisions of the UNSE line extension tariff. Accordingly we believe that UNSE should file by October 23, 2009, as a compliance item to this Decision, a marketing plan detailing UNSE's planned efforts to raise customer awareness of UNSE's new line extension provision to ensure that interested customers are accorded an opportunity to make use of the grandfather provisions within the line extension policy.

7. UNSE's proposed Rules and Regulations includes the following language in the Introduction of Section 9: Line Extensions:

> A standard policy has been adopted to provide service to Customers whose requirements are deemed by the Company to be economical and ordinary in nature.[2]

8. Staff has recommended that this sentence be removed from the Tariff as it is no longer applicable as a result of the removal of the free footage.

---

[1] Application: Proposed Rules and Regulations. Page 37 of 59.
[2] *Ibid.* Page 29 of 59.

9. UNSE's proposed Rules and Regulations includes the following language in Section 9: Line Extensions at item E:

> Construction/Facilities Related Income Taxes
>
> Any federal, state or local income taxes resulting from the receipt of a contribution in aid of construction in compliance with this rule is the responsibility of the Company and will be recorded as a deferred tax asset *and reflected in the Company's rate base*. (Emphasis added) [3]

10. Staff has recommended removal of the above italicized phrase "and reflected in the Company's rate base" as it is unnecessary for a tariff to specify such a rate base treatment. Removal of the phrase would also make UNSE's line extension tariff consistent with Tucson Electric Power's line extension tariff as established in rate case Decision No. 70628 of December 2008.

11. Staff has recommended that UNSE's proposed changes to Section 9: Line Extensions of UNSE's Rules and Regulations be approved, except for the modifications discussed herein.

12. Certain changes have been made to Section 6: Service Lines and Establishments to conform to the free footage change. Staff has further recommended that UNSE's proposed changes to Section 6: Service Lines and Establishments also be approved to conform to the free footage change.

CONCLUSIONS OF LAW

1. UNS Electric, Inc. is a public service corporation within the meaning of Article XV, Section 2, of the Arizona Constitution.

2. The Commission has jurisdiction over UNS Electric, Inc. and the subject matter of the application.

3. Approval of UNS Electric, Inc.'s revised Rules and Regulations, including a revised Line Extension Tariff, does not constitute a rate increase as contemplated by A.R.S. Section 40-250.

---

[3] *Ibid.*

4. The Commission, having reviewed the application and Staff's Memorandum dated September 10, 2009, concludes that it is in the public interest to approve UNS Electric, Inc.'s proposed changes to Section 6: Service Lines and Establishments and Section 9: Line Extensions of its Rules and Regulations, with the modifications discussed herein.

ORDER

IT IS THEREFORE ORDERED that UNS Electric, Inc.'s revised Section 6: Service Lines and Establishments and Section 9: Line Extensions of its Rules and Regulations, including a revised Line Extension Tariff, be and hereby are approved, with the changes discussed herein.

IT IS THEREFORE ORDERED that UNS Electric, Inc. make all conforming changes to its Rules and Regulations.

IT IS FURTHER ORDERED that UNS Electric, Inc. shall docket, as a compliance item in this matter, tariff pages for the revised Rules and Regulations, including a revised Line Extension Tariff, consistent with the terms of this Decision within 15 days from the effective date of this Decision.

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IT IS FURTHER ORDERED that UNS Electric, Inc. shall file by October 23, 2009, as a compliance item to this Decision, a marketing plan detailing its planned efforts to raise customer awareness of the grandfather provisions in UNS Electric, Inc.'s new line extension provision to ensure that interested customers are accorded an opportunity to make use of the grandfather provisions within the line extension policy.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, ERNEST G. JOHNSON, Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 9th day of October, 2009.

ERNEST G. JOHNSON
EXECUTIVE DIRECTOR

DISSENT: _____

DISSENT: _____

SMO:SPI:lhm\MAS

SERVICE LIST FOR: UNS Electric, Inc.
DOCKET NO. E-04204A-06-0783

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KCR-2

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206 **UNS ELECTRIC'S RESPONSES TO STAFF'S 17th SET OF DATA REQUESTS**

UNS Electric, Inc. ("UNS Electric" or "Company"), through undersigned counsel, hereby responds to "Staff's Seventeenth Set of Data Requests for UNS Electric" as follows:

Provided herewith are Responses to Data Requests STF 17.1 and STF 17.2.

RESPECTFULLY SUBMITTED this 19th day of October 2009.

ROSHKA DEWULF & PATTEN, PLC

By _____
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Jason D. Gellman
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Attorneys for UNS Electric, Inc.

RECEIVED
OCT 19 2009
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ARIZ. CORPORATION COMMISSION

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By Mary Ippolito

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S SEVENTEENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
October 19, 2009

STF 17.1 Please provide Staff with an example of the estimated costs that the Company provides to Applicants pursuant to Section 9.A.3. of the Company's Rules and Regulations.

RESPONSE: Please see the attached file STF 17.1 Detailed Cost Letter of Agreement (Confidential), Bates Nos. UNSE(0206)09549 to UNSE(0206)09550, for estimated costs provided to applicants under Section 9.A.3. of the Company's Rules and Regulations.

Bates Nos. UNSE(0206)09549 to UNSE(0206)09550 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

RESPONDENT: Resal Craven

WITNESS: Thomas A. McKenna

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S SEVENTEENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
October 19, 2009

STF 17.2 Please provide Staff with an example of a cost estimate pursuant to Section 9.B.1.e. of the Company's Rules and Regulations.

RESPONSE: Please see the attached file STF 17. 2 Line Extension Cost Estimate Spreadsheet (Confidential), Bates No. UNSE(0206)09551, for an example of estimated costs pursuant to Section 9.B.1.e. of the Company's Rules and Regulations.

Bates No. UNSE(0206)09551 contains confidential information and is being provided pursuant to the terms of the Protective Agreement.

RESPONDENT: Resal Craven

WITNESS: Thomas A. McKenna

Technical and Clarifying Revisions Proposed by UNSE

Page[16]	Subsection	Revision Proposed by UNSE
2	1.D	Strike "ACC" insert Arizona Corporation Commission"
4	2.A.14	Strike "is" insert "are"
13	3.E.2	Strike "working" insert "business"
14	3.E.4	Insert "Service"
17	4.B.1	Strike "transmit" insert "send"
17	4.B.2	Strike "transmitted" insert "sent"
19	6.A.8	Strike "the" insert "an"
19	6.A.8	Strike "an additional" insert "a"
19	6.A.8	Strike "on file with and approved by the ACC" insert "set forth in the Statement of Additional Charges"
19	6.A.8	Insert "Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having staff available; there is no guarantee that the company will have the staffing available for service establishment, reestablishment or reconnection after regular business hours."
46	9.F	Strike "contribution in aid of construction" insert "Contribution in Aid of Construction"

[16] Page numbers in Exhibit TAM-2

EXHIBIT
S-6
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-04204A-09-0206

SURREBUTTAL

TESTIMONY

OF

KENNETH C. ROZEN

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 15, 2010

TABLE OF CONTENTS

		Page
I.	INTRODUCTION	1
II.	SUMMARY OF THE COMPANY'S AND STAFF'S DIRECT TESTIMONY	2
III.	UNSE'S REBUTTAL TESTIMONY	3
IV.	STAFF'S SURREBUTTAL TESTIMONY	5
V.	SUMMARY OF STAFF RECOMMENDATIONS	9

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206

- In its Direct Testimony, Staff opposed UNS Electric, Inc.'s ("UNSE") proposed revisions to its Rules and Regulations which would 1) implement a Facilities Operation Charge, 2) specify accounting treatment of up-front payment of estimated line extension construction costs in its tariff, and 3) increase service reconnection and reestablishment fees by requiring customers whose service was disconnected to pay the applicable monthly customer charges that would have accrued had the Company continued to furnish electricity to the customer. Staff also recommended that Subsections 9.A.3 and 9.B.1.e. of the line extension tariff be revised to specify that materials costs given in line extension construction cost estimates must be itemized.

- In its Rebuttal Testimony, the Company agrees to withdraw it proposals to implement the Facilities Operation Charge, include accounting treatment of estimated construction cost payments in its tariff, and increase service reconnection and reestablishment charges.

- UNSE identifies several concerns with Staff's recommendation relating to material cost itemization in line extension agreements. Despite the Company's arguments to the contrary, Staff continues to recommend that material cost estimates in line extension agreements be itemized.

- Staff recommends that the Company clarify the intent and effect of new language in the line extension tariff related to conditions for rectifying differences in estimated and actual construction costs.

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kenneth Rozen. My business address is 14218 North 43rd Street, Phoenix, Arizona 85032.

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

A. I am a self-employed consultant currently under contract with the Utilities Division of the Arizona Corporation Commission. My duties include evaluating various utility applications and reviewing utility tariff filings on behalf of the Utilities Division Staff ("Staff").

Q. Have you previously filed testimony in this docket?

A. Yes. I filed Direct Testimony concerning revisions that UNS Electric, Inc. ("UNSE" or "Company") proposed to make to its Rules and Regulations, as outlined in the Direct Testimony of Thomas A. McKenna.

Q. Did you review the Rebuttal Testimony that UNSE witness Mr. McKenna filed in response to your Direct Testimony?

A. Yes. I will begin by summarizing Staff's and the Company's positions as set forth in our respective Direct Testimonies. I will then summarize my understanding of Mr. McKenna's Rebuttal Testimony which was filed in response to my testimony. Finally, I will discuss Staff's position on Mr. McKenna's Rebuttal Testimony.

II. SUMMARY OF THE COMPANY'S AND STAFF'S DIRECT TESTIMONY

Q. Please summarize the Company's proposed revisions to its Rules and Regulations that remained for Commission consideration when you filed your Direct Testimony.

A. After the Commission's recent approval of certain previously-ordered revisions to UNSE's line extension tariff[1], a number of other revisions to its Rules and Regulations, which the Company proposed in its Direct Testimony in this case, remain for Commission consideration. They are as follows:

- Further revisions to the line extension tariff (Section 9), including the addition of the "Facilities Operation Charge" and language specifying in the tariff how up-front payments of estimated line extension construction costs are to be treated for accounting purposes.
- Revisions that would increase service reconnection and reestablishment fees (Sections 2, 3 and 14) by requiring customers whose service was disconnected to pay the monthly customer charges that would have accrued had the Company continued to furnish electricity to the customer.
- Revisions adding time frames for rectifying under- and over-billings resulting from meter and meter reading errors (Section 11); and
- Numerous technical and clarifying revisions throughout the Rules and Regulations.

Q. Please summarize Staff's recommendations regarding these proposals and any other matters relating to UNSE's Rules and Regulations?

A. Staff has no objections to UNSE's proposed revisions that would add timeframes for rectifying meter and meter reading errors or to the numerous technical and clarifying changes. For reasons explained in my Direct Testimony, however, Staff opposes UNSE's proposals to: 1) implement a Facilities Operation Charge, 2) specify in the line extension

[1] The Commission approved UNSE's line extension tariff, as revised to eliminate the free-footage allowance, in Decision No. 71285 dated October 7, 2009.

tariff the accounting treatment for the proceeds from up-front payments of estimated construction costs, and, 3) increase service reconnection and reestablishment fees by requiring customers whose service was disconnected to pay the applicable monthly customer charges that would have accrued had the Company continued to furnish electricity to the customer. Apart from UNSE's proposed revisions, Staff is further recommending that Subsections 9.A.3 and 9.B.1.e. of the line extension tariff be revised to specify that materials costs given in line extension construction cost estimates must be itemized.

III. UNSE'S REBUTTAL TESTIMONY

Q. Please summarize Mr. McKenna's Rebuttal Testimony.

A. Mr. McKenna's Rebuttal Testimony indicates that UNSE: 1) withdraws its request to implement a Facilities Operation Charge, 2) agrees to remove proposed language in its line extension tariff that would specify accounting treatment for up-front payments received by the Company for estimated line extension construction costs and 3) agrees to delete the proposed revisions that would have allowed the Company to collect, in addition to the service reestablishment and reconnection fees. However, Mr. McKenna has a number of concerns about Staff's recommendation that Subsection 9.B.1.e of the line extension tariff be revised to specify that material costs listed in construction cost estimates included in line extension agreements should be itemized. Finally, Mr. McKenna's Rebuttal Testimony includes a number of additional requests for technical and typographical revisions to various sections of UNSE's Rules and Regulations.

Q. On December 11, 2009, UNSE filed Exhibit TAM-5, which UNSE states reflects UNSE's proposed changes to its current Commission-approved Rules and Regulations as revised by Mr. McKenna's Rebuttal Testimony. Have you reviewed Exhibit TAM-5?

A. Yes.

Q. Is Exhibit TAM-5 consistent with Mr. McKenna's Rebuttal Testimony?

A. Yes.

Q. Does Staff have any concerns with any of the additional technical and typographical revisions that Mr. McKenna proposes in his Rebuttal Testimony?

A. No.

Q. What are UNSE's concerns with Staff's recommendation to itemize material costs in the construction cost estimates that are contained in line extension agreements?

A. Mr. McKenna states that the Company:

1. Does not believe that itemizing material costs will enhance Applicants' understanding of cost estimates in part because most customers are unfamiliar with power line engineering and construction materials (He does not identify other factors which may contribute to UNSE's belief that material cost itemization would not help Applicant's understand line extension construction cost estimates.);
2. Cannot sacrifice safe and reliable construction and operation in deference to the Applicant's interest in minimizing extension costs, even if materials were itemized; and;

3. Believes that the line extension description and sketch already required by Commission rule[2] and the parallel provision in UNSE's Rules and Regulations are sufficient for the Applicant to understand what the Company requires and why.

IV. STAFF'S SURREBUTTAL TESTIMONY

Q. Please respond to UNSE's concerns regarding Staff's recommendation to itemize materials costs in the construction cost estimates contained in line extension agreements.

A. The line extension description and sketch may provide sufficient basis for an Applicant to understand what is being required and why, but neither a sketch nor a description that does not identify the costs of the various construction items comprising the facility provides the Applicant with an adequate basis for understanding line extension costs. Regardless of the extent to which any one Applicant chooses to consider it, Staff believes UNSE should provide all Applicants with a sound basis for understanding extension costs, including itemized materials costs, both as estimated in the Agreement and in the context of any adjustments necessitated by the results of the Company's comparison between the estimated and actual costs[3].

Staff agrees that the Company must not sacrifice reliability and safety in deference to an Applicant's interest in minimizing costs. It is difficult to understand, however, how requiring the Company to itemize costs would compromise reliability and safety. Further, the Company's concern on this issue seems to presume that Applicants' proclivity to dispute the Company's cost estimates would increase if estimated materials costs were itemized. This presumption remains unsubstantiated. Finally, Staff disagrees with UNSE's view that itemizing estimated materials costs would not enhance Applicant's

[2] A.A.C. R14-2-207.B.1.d
[3] For rectifying estimated and actual costs, see proposed Exhibit TAM-5, relined version, page 31, Subsection 9.D.1.

understanding of cost estimates because most customers are unfamiliar with power line construction materials.

For example, the table at the top of UNSE's response to Data Request STF 17.2[4] lists twelve "Construction Units." Among these, Staff suspects that many if not most customers would know that "Transformer" is a piece of equipment needed to reduce voltage, "Primary Conductor" refers to wires used to transmit electricity, and "Guys" are wires or cables used to support or brace structures, such as poles, which are used to suspend conductor overhead. Although many if not most customers would be unfamiliar with "Tangent," "Angle," and "Dead End," many might correctly surmise that these terms distinguish different kinds of towers and poles, based on their position in and the configuration of the line extension. Regardless of any one Applicant's familiarity with the Construction Units listed in the table, however, Staff fails to see how providing the Applicant with the "Unit Cost" and "# Reqd." for each could *not* enhance the Applicant's understanding of the estimated Total Material cost, and by extension, the Line Extension Cost Estimate, of which Total Material Cost is a significant component.

Q Mr. McKenna notes that the line extension agreement requirements in UNSE's rules and regulations are directly from A.A.C. R14-2-207. Would the application of that rule in any way limit the Commission's ability to require a company to expand information in line extension agreements beyond what is required by R14-2-207.B.1?

A. No. Both A.A.C. R14-2-207.B.1 and Subsection 9.B.1 state "Each line extension agreement [must/shall], *at a minimum*, include the following information:"(emphasis added) Staff is of the opinion that this language allows the Commission to expand the requirements when it finds that such expansion is warranted.

[4] Exhibit KCR-2 to Rozen Direct Testimony

Q. After considering Mr. McKenna's Rebuttal Testimony, does Staff have any reason to change its recommendation that the Company revise Subsection 9.B.1.e to require that material costs be itemized in construction cost estimates that are included in line extension agreements.

A. No.

Q. Are there any other matters relating to UNSE's Rules and Regulations that you would like to address?

A. Yes, there are two such matters, both relating to Section 9, the line extension tariff.

Q. What is the first of these?

A. In the revised line extension tariff that UNSE filed in Docket E-04204A-06-0783, as ordered in Commission Decision No. 71285, Subsection 9.D.1.b, which applies to overhead extensions to Large Light and Power Customers, contains the following provision:

> "Upon completion of construction the Company will compare actual cost to the estimated cost and any difference will be either billed or refunded to the Customer."

UNSE's proposed revision to its line extension tariff shown in TAM-2 and TAM-5 retains this same language, but moves it to the very beginning of Subsection 9.D ("Conditions Governing Extensions of Electric Distribution and Service Lines") and adds new language as follows:

"- except if the difference is less than $500. If the difference is less than $500, the amount may be billed or refunded according to the specific extension agreement with the customer."

Q. Does Staff have any concerns with these changes?

A. Staff supports moving the language that provides for rectifying differences between estimated and actual costs to the beginning of Subsection 9.D because it has the effect of applying the rectification provision to all of the subsections comprising Subsection 9.D. However, Staff is concerned that the intent and effect of the new language is unclear.

Q. What is Staff's recommendation regarding the new language?

A. Staff recommends that the Company clarify the intent and effect of the new language in its Rejoinder Testimony. Staff will respond to the clarification at the hearing.

Q. What is the second matter regarding the line extension tariff that you would like to address?

A. The revised line extension tariff that UNSE filed in Docket E-04204A-06-0783, as well as the revisions proposed in TAM-5, eliminate the free footage allowance as the Commission ordered in Decision No. 70360. However, A.A.C. R14-2-207.C continues to require that each line extension shall include a maximum footage or equipment allowance to be provided by the utility at no charge. Therefore, UNSE's current and proposed line extension tariffs conflict with provisions of R14-2-207, including Subsection A.1, which states "each utility shall file, in Docket Control, for Commission approval, a line extension tariff which incorporates the provisions of this rule."

Q. Does Staff have a recommendation regarding a resolution to this conflict?

A. Yes. Neither the Decision (No. 70360) in which the Commission ordered the elimination of the free footage allowance, nor the Decision (No. 71285) in which the Commission approved the responsive revision to UNSE's line extension tariff, granted UNSE a waiver to A.A.C. R14-2-207.C. Therefore, Staff recommends that the Commission consider granting such a waiver in this proceeding.

V. SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. Staff maintains its recommendation that Subsection 9.B.1.e of UNSE's line extension tariff be revised to require that the materials costs given in construction cost estimates contained in line extension agreements be itemized.

2. Staff recommends that, in its Rejoinder Testimony, the Company clarify the intent and effect of the new language regarding rectifying differences between estimated and actual line extension construction costs.

3. Staff recommends that the Commission consider granting UNSE a waiver to A.A.C. R14-2-207.C in this proceeding.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

EXHIBIT
S-7
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-04204A-09-0206

DIRECT

TESTIMONY

OF

W. MICHAEL LEWIS, P.E.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 06, 2009

TABLE OF CONTENTS

Page

I. INTRODUCTION 1

II. WORK ACTIVITIES AND EVALUATIONS 4

A. Quality of Service/Distribution Performance 5

B. In Service Operations and Facilities Investment 11

B.1 Call Center and Outage Response Operations 13

B.2 Electric Grid Operations 15

B.3 Quality of Service/Distribution System 16

C. Mohave Service Area 19

C.1 UNS Electric Substations 20

C.2 BMGS Facility 24

D. Santa Cruz Service Area 28

III. RECOMMENDATIONS TO THE COMMISSION 31

ATTACHMENTS

William Michael Lewis Resume 1

UNS Electric Response To STF 8.9 2

UNS Electric Response To STF 8.1 3

UNS Electric Response To STF 8.20 4

UNS Electric Response To STF 8.11 5

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206

The Direct Testimony of W. Michael Lewis of W. M. Lewis and Associates, Inc. ("WML&A") presents the evaluations of UniSource Electric ("UNS Electric" "UNSE" or "Company") distribution system reliability and service quality, in service operations and facility investments, facilities proposed for inclusion into rate base that include new distribution facilities with differing standards of construction than those acquired from Citizen's Power Company. Additionally, our evaluations included the field investigation, and discussion with on-site personnel, of the Black Mountain Generation Station ("BMGS") proposed for purchase by the Company from UniSource Energy Development Company. The Company is requesting that the Commission approve the BMGS as a post-test year adjustment to rate base. Our conclusions are based upon field investigations, discussions with UNS Electric and Tucson Electric Power ("TEP") personnel, and UNS Electric responses to data requests submitted by the Arizona Corporation Commission ("Commission") Staff.

Quality of Service/Distribution Indices

The service quality and reliability of the UNS Electric distribution system was evaluated by analysis of the reliability indices for calendar years 2007 and 2008, and for the initial eight months of 2009. The determinations of the indices were discussed with TEP personnel during our field investigation, and provided in response to a Commission Staff data request. The indices evaluated are Customer Average Interruption Duration Index ("CAIDI"), System Average Interruption Frequency Index ("SAIFI"), and System Average Interruption Duration Index ("SAIDI"). Our review and analysis of the outage data and determinations indicate that the distribution system provides service quality and reliability comparable to an average to somewhat below average electric utility system of similar size and service area characteristics. We noted that the indices for "Major Event Days" which are periods of significant adverse weather, grid outages, or other system disruptions were not a source of lower service quality as might be expected. Our discussions with TEP personnel who had evaluated the indices suggested to us that this was their initial compilation of the indices. There is, however, a plan to initiate routine collections and analyses of service quality indices that will be considered by UNS Electric management in the very near future.

Facilities Investment/In-Service Operations

Our field investigations included the Call Center where customers report outages, service and billing problems. The Call Center operates effectively as a means of notification to maintenance personnel of the need to respond to outages and other network problems reported by electric, as well as gas customers. Electric maintenance personnel are separate from gas maintenance personnel. The integration of the Call Center with the maintenance facilities and dispatching of personnel (troublemen) affects the duration of outages in a significant manner. We found the Call Center, which also receives outage and bill calls for TEP, to be an efficient and effective means of customer contact and maintenance notification.

In evaluating the effectiveness of UNS Electric grid and distribution operations, we investigated system losses and power factors of the UNS Electric distribution system. The distribution losses and the average and peak power factor data were provided as a response to Commission Staff data requests. We determined that the UNS Electric system distribution losses were in line with similar utility performance as were the power factors. We also reviewed the number and placement of capacitors for power factor correction on the UNS Electric system, and found both to be in keeping with accepted utility practices. UNS Electric studies of the distribution and transmission systems were performed by TEP personnel on an "as-needed" basis. We found this approach to be an acceptable means of addressing periodic needs for such studies.

Field investigations of the major distribution substations installed prior to and after the acquisition of the Citizens system by UNS were made to assess their standards of construction and suitability for inclusion into rate base. In addition, we considered whether there was a pressing need to bring the acquired facilities into conformance with TEP standards to assure proper maintenance and performance. Our investigations and observations of these facilities, and subsequent repairs and replacements that had been made by UNS Electric already, indicated that the facilities were properly functional and that any divergence from TEP standards would not constitute any impairment to the on-going maintenance activities. We also concluded that the facilities we observed and proposed for inclusion into rate base were complete and in-service.

Field observations of two generating facilities were also made. These included the existing Valencia Generating Station located in the Santa Cruz service area which had been improved by the addition of Unit #4 gas turbine set and substation upgrades, and the BMGS located in the Mohave service area. The BMGS facility is a two unit gas turbine station which is proposed for acquisition by UNS Electric and currently operated by UNS Electric personnel. We found the Valencia improvements and its Unit #4 to be properly installed, in-service, and well maintained. As for BMGS, we observed that one of its two units had recently been damaged by numerous blade failures and was currently being evaluated as to the extent of the damage and necessary repairs. Both of the two units have been previously operated and provided generation for about 15 months prior to this failure. Further observations of the common facilities and substation at BMGS indicated that the site is suitable for future expansion and that the facilities are well maintained. We subsequently questioned if the site auxiliaries could support the continuous operation of both units at rated output for extended periods of time. UNS Electric responded to a Commission Staff data request that there are emissions limitations, but did not indicate any other limiting factors, such as water treatment capacity. We have stated in the testimony that UNS Electric should discuss this aspect further in subsequent testimony.

Our recommendations to the Commission include:

1. The Commission should require an annual report of the distribution indices including a listing of the worst performing circuits and what steps are being taken to mitigate these circuits poor performance by UNS. The report should be separated by service area and by the results for the overall UNS system. Other requirements for this report should conform to those required of Arizona Public Service as described in the current settlement proceedings.

2. The Company states in response to STF 8.1 that they invested approximately $86 million of new plant since the end of the last test year. WML&A reviewed the major plant additions which I discuss in my testimony. Of the plant items we inspected, we found that they were well constructed, functioning at expected levels, and are presently being used for the provision of service to rate payers. Therefore, we recommend that the portion of plant items completed and used and useful at the end of the test year in this proceeding be included in this rate case.

3. Currently, BMGS is owned by UniSource Energy Development ("UED"), however, our inspection of the BMGS facility indicates that the facility is properly constructed and should be back to full operational levels once the repairs are made by UED.

4. At such time if and when UNSE acquires the BMGS, any costs of repair not covered by warranty should be borne by UED and not by UNSE at the time of purchase.

5. If UNSE ultimately acquires BMGS, UNSE should be required to demonstrate to the Commission that there are no limitations due to water availability on the required operations of both Unit #1 and Unit #2.

6. UNS Electric's maintenance scheduling at the BMGS Facility should include thermal scanning of the substation/switchyard bus and connected lines on a regular basis, if it ultimately acquires the facility.

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Michael Lewis. My business address is 934 Valley Street, Wheelersburg, Ohio 45694.

Q. What is your present employment?

A. I am employed by the firm of W. M. Lewis and Associates, Inc. ("WML&A"). I am the President of the firm.

Q. Please describe the nature of the firm.

A. WML&A is a Consulting Engineering firm which provides various engineering services, primarily in areas of electrical power and electric utility operation, to a range of clients including investor-owned electric utilities, municipal utilities, international investment organizations, and regulatory bodies. The firm was established in 1958.

Q. Please describe your background, education, and experience.

A. I have been employed by WML&A since 1979. Prior employment was with Goodyear Atomic Corp. and Westinghouse Electric. Positions that I have held at WML&A include Sr. Engineer, Manager of Engineering, Vice-President, and President. I hold a BSEE degree from Ohio State University and an MBA from Ohio University. For the past 15 years, much of my work has involved foreign assignments on behalf of the Asian Development Bank and World Bank in project post-evaluation, feasibility studies, and reviews of operation and maintenance of various generating stations, urban and rural transmission and distribution systems, and utility management. Additional tasks included the design of facilities and preparation of agreements for the interconnection of utilities,

preparing operating agreements between utilities and independent power producers, and various tasks related to the privatization of electric utilities in the South Asian area. Additional aspects of my experience and education are presented in my resume, which is attached to this testimony as Attachment 1.

Q. Are you filing direct testimony on behalf of Arizona Corporation Commission ("Commission") Staff?

A. Yes.

Q. What is the nature of your testimony in this proceeding?

A. My testimony describes and presents evaluations, observations and recommendations regarding the above captioned matter. We were to evaluate the service quality and reliability of the distribution system, observe and evaluate some of the major items of investment proposed for post test year inclusion into rate base as to their status, evaluate the comparative standards of construction between the acquired system and subsequent installations, and to observe the facilities of the Black Mountain Generating Station ("BMGS") as to construction quality.

Q. What was the major component of your evaluation?

A. Consistent with the authorization and in concert with Commission Staff direction, a major component of the investigation was the field inspections of UniSource Electric, Inc. ("UNS Electric," "UNSE," or "Company") facilities in the Tucson, Kingman, and Nogales areas. Field inspections were made on October 5, 2009 through October 8, 2009 accompanied by UNS Electric and Tucson Electric Power ("TEP") personnel.

Q. Who participated in the field investigations with you?

A. I performed the field inspections with the assistance of Kenneth Strobl, P.E. of the firm of Technical Associates, Inc. Mr. Strobl also contributed to the preparation of this testimony.

Q. Please describe the major elements of your investigations.

A. The major elements of our investigation focus on UNS Electric's service quality, distribution system indices, and the operations of selected generation, transmission, and distribution facilities currently in service. The field inspections included discussions with the Company engineering and other technical personnel, as well as control room and shift operators who monitor and operate the Company's generation assets and its electrical transmission and distribution network assets. In anticipation of, and in conjunction with, these activities, we also reviewed portions of UNS Electric's prefiled Application and testimony in this case, as well as public documents such as its Federal Energy Regulatory Commission ("FERC") Form 1. Additionally, we prepared data requests to the Company that addressed service quality, electric distribution and generation system operations. Upon review of responses and discussions with UNS Electric and TEP personnel, follow-up data requests were prepared and submitted to the Company as well.

Q. What were the impacts of these efforts?

A. The field inspections, the discussions with UNS Electric and TEP personnel, the reviews of UNS Electric-filed documentation in this case and public documents, and the discussions with Commission Staff provided some understanding of the Company's installations and operations of its electrical network assets in Arizona. Accordingly, the

remainder of this testimony discusses these observations and evaluations, and provides recommendations to the Commission regarding operations of the UNS Electric network assets. This testimony also contains our comments regarding the Company's personnel we met in our field visits that are charged with ensuring that system operations are safe, reliable, and meet the electrical service needs of the Company's customers.

II. WORK ACTIVITIES AND EVALUATIONS

Q. Please describe your evaluations and the role of your field investigations.

A. Our work activities began with reviews and analyses of UNS Electric's Application and prefiled testimony and exhibits in this proceeding. In addition to the information in the Application and prefiled materials, we reviewed the Company's Annual Reports, FERC Form No. 1 and supplemental documents filed in support of the Application.

Additional information was acquired and analyses undertaken through UNS Electric responses to data requests issued by the Commission Staff, in particular Commission Staff requests, STF 8, STF 9 and STF 15. Responses to STF 8 data requests addressed the Company's Construction Work in Progress ("CWIP") projects being requested for rate base treatment, which included an itemization of project investments and their corresponding in-service dates. Additionally, responses to Commission Staff data requests STF 8 and STF 9 provided information regarding the Company's distribution system performance, operations, and reliability, call center and maintenance dispatch procedures, and operations of the BMGS facility. BMGS is currently owned by UNS Energy Development Company, with UNS Electric requesting in this case that it be allowed to acquire the facility and include it in rate base.

UNS Electric responses to STF 9 and STF 15 provided operational information regarding the Valencia generating facility, and operating and maintenance data regarding the monitoring of the Company's overhead lines and substation facilities. Additionally, the Company's response to STF 15 addressed operational aspects of the Western Area Power Administration ("WAPA") interconnections with UNS Electric, and operating and performance measures regarding the Valencia and Black Mountain generating facilities.

A. Quality of Service/Distribution Performance

Q. Please discuss the determination of the Company's Quality of Service as it relates to Distribution Performance.

A. The electric utility industry has developed various indices as indicators of distribution performance and reliability. These include measures of customer average outage duration and average frequency of outages. These indices are defined by IEEE standard P1366 which has set a 5-minute disruption of service as the threshold to be considered an outage for the calculation of the various indices. In 2003, IEEE-1366 included the concept of a "Major Event Day" ("MED") to account for outages deemed to be caused by unusually severe weather and similar incidents so that such incidents could be considered separately from normal operating conditions. MED thresholds are calculated on a 5-year (rolling) average. The indices of most concern are "Customer Average Interruption Duration Index ("CAIDI"), System Average Interruption Frequency Index ("SAIFI"), and System Average Interruption Duration Index ("SAIDI"). In Data Request STF 8.9, we requested that the Company furnish the values of these three indices for the years of 2007, 2008, and to date for 2009. We also requested that the Company indicate the four worst performing circuits in both the Mohave and Santa Cruz service areas based upon their indices. Prior to receiving the Company's response, we discussed their progress and

preliminary results with the Company representatives in a meeting on October 5, 2009 as a part of our field investigations.

Q. Was this data then furnished to you by the Company?

A. Yes, and the response is included here as Attachment 2.

Q. Please describe the nature of the Company's response.

A. The Company's response included the results for SAIFI and CAIDI for each of the service areas with the Mohave area separated into the Kingman and Lake Havasu areas together with the same two indices for the UNS Electric combined system. Included were the results for 2007, 2008, and 2009 through August 31 as we had requested. In addition, the two indices were presented for MED periods, normal or "clear weather" periods, and for the total time-period indicated. SAIDI results were not furnished nor were the requested worst circuits indicated.

Q. Is the absence of the SAIDI calculations an impairment to your evaluation?

A. No. The SAIDI index value is, in fact, the product of SAIFI times CAIDI so that the value can be calculated from the values provided.

Q. What about not having the "worst performing circuits" provided?

A. The purpose in our request for these circuit identifications was to evaluate the effect of those outages on the over-all system results, to know the cause of the outages, and what (if any) mitigation efforts had been made or were planned to minimize those outages and thus, reduce the overall system indices values.

Q. What was the Company's reason for not providing the circuit designations?

A. As was stated by Company personnel during our discussion meeting and in the Company's response, indices are not calculated for any of the three service areas at a circuit level, therefore, the Company could not furnish that criteria.

Q. How do you interpret that response?

A. I have taken their responses to mean that outage data by specific circuit is not available or that the Company did not calculate a separate index for each distribution circuit.

Q. Has the Company been determining these indices in the past?

A. It was our impression from our discussions that this response is the first time that the Company has performed such an analysis. However, we were made to understand that the personnel preparing this response is also preparing a recommendation to present to Company management that an on-going program for the collection of outage data and indices determination per IEEE 1366 for the UNS distribution system be initiated along the lines as is presently performed by TEP for its system.

Q. Would you recommend that these determinations be initiated by the Company?

A. Certainly. Further, we will be recommending to the Commission that as a result of this proceeding, the Company should be required to submit a report along the lines of our Data Request to the Commission for review on an annual basis. We believe that such reporting is currently required of TEP and Arizona Public Service.

Q. What are the physical features of a distribution system that affect its indices?

A. The values of SAIFI, i.e., the frequency of outages to an average customer, are affected by the circuit configuration, circuit lengths, and the relative severity of lightning and weather events in the service area. In general, overhead radial circuits tend to have a higher frequency of outages as compared to network or looped configurations. Longer line lengths tend to have more exposure to various physical damage such as wind, ice, birds, etc. and, obviously, the greater the number of lightning strikes in a given area, the greater the likelihood of an outage; even more so for longer line lengths. CAIDI values, i.e., the duration of an outage to an average customer, is affected by the physical size and terrain of the service area, as that tends to increase the distance between the cause of the outage and the location of repair personnel. The availability of replacement equipment and their placement can also have an adverse effect.

Q. Given your observations of the service areas and facilities of the Company, what aspects would affect its performance?

A. The Company's typical circuit configuration is of overhead radial design which is well suited for its customer base and density. However, as stated above, that configuration tends to be less reliable than others. In addition, all of the three service areas include extensive rural areas where customers are remote from the central maintenance facilities, and most likely, from the assigned "troubleman" who will be charged with responding to reported outages. The nature of the service areas and the circuit configurations would tend to result in elevated indices values for both frequency and duration of outages. In addition, the southwest areas of the country are recognized as having high lightning frequency and those are of above average intensity. This also tends to increase outage

frequency in the UNS Electric's service areas. However, the Lake Havasu service area appears to be less rural and more compact for the majority of its customer base.

Q. Is the different condition of the Lake Havasu service area reflected in the resulting indices values?

A. Yes, the reported indices are more favorable in the Lake Havasu area.

Q. Please continue.

A. As described above, the Company furnished SAIFI and CAIDI values separately for the three service areas, the combined Mohave County area, and the UNSE system. Taking the values for 2008 as a typical example (please refer to Attachment 2), the Lake Havasu results for both SAIFI and CAIDI for the "All" conditions are significantly lower than those for either Kingman or Santa Cruz. This would be expected given the service areas.

Q. How do the indices for UNSE compare to those of other utilities of similar size, service areas, and circuit configurations and how would you make such a comparison?

A. A basic comparison can be made by considering the values for SAIDI for the "All" conditions. As mentioned above, the value for SAIDI is the mathematical produce of the values for the listed SAIFI and CAIDI. For UNSE values in 2007, the SAIDI would be calculated as 1.586 X 65.860 = 104.45. Recent surveys indicate that for utilities of similar size and generally rural, dispersed service areas, an SAIDI of 60-80 would be indicative of an "upper third" performance, while a "median" performance would fall in the 80-100 range and the "lower third" tier of utilities would have an SAIDI of 120-140 and above.

Q. Was the 2007 performance indicative of subsequent times?

A. No. The corresponding value for 2008 is 2.029 X 113.506 = 230.30 which is clearly a poor result in comparison to others. However, for the first 8 months of 2009, this value would be 2.011 X 42.565 = 85.60. This is bordering on the upper third of utility performance.

Q. What accounts for the improvement in 2009 to date compared to 2008?

A. While the frequency of outages to date for 2009 was very similar to that of 2008, the duration of average customer outages decreased from the 113.506 to 42.565, thus the much lower value for SAIDI.

Q. Was this evident for all of the service areas?

A. Yes, which may indicate that the decrease to date may be a seasonal effect. That could be determined when the Company files an annual report.

Q. What would you consider a reasonable result for the Company for SAIDI?

A. I would consider a value for SAIDI between 80-100 for the "All" case to be reasonable for the present with demonstrated improvement toward the lower end of that range to be reasonable.

Q. Do you believe that the Company requires a significant increase in O&M to attain and maintain SAIDI of between 80-100?

A. No. I believe that instituting a program of monitoring and evaluating outage reports and identifying the more problematic circuits with mitigation will result in improvements in the distribution reliability and performance indices and in customer satisfaction.

Q. Do you have any further comments as to the reported indices?

A. Yes. We noted that the reported SAIFI and CAIDI values for MED periods appear to be superior to the "Clear Weather" periods in many of the time periods and individual service areas and for UNSE. This is unexpected. This may be due to heavier staffing levels during weather events or some other reason. It may be that the appropriate Company witness could present the Company's comments on this result during presentation of testimony.

Q. What other aspects of the Company's operations and development would tend to improve its reliability indices?

A. As the Company continues to replace the older circuit facilities and standardize in its distribution substations, there should be a corresponding decrease in the frequency of outages and a decrease in restoration times.

Q. Would you recommend that any program of accelerated replacement to enhance the standardization be put into effect?

A. No. I would recommend that efforts toward revising circuit configurations, equipment types, etc. be accomplished in the course of normal maintenance and repair.

B. In Service Operations and Facilities Investment

Q. Please discuss the Company's CWIP investments and its request for inclusion of these in rate base in this proceeding.

A. In UNS Electric witness DeConcini's Direct Testimony filed April 30, 2009, the Company claims that it has "substantial used and useful plant" that reflects capital expenditures from June 30, 2006 through December 31, 2008 that are not reflected in

current rates. In response to Commission Staff STF 8.1 (and STF 1.1), UNS Electric identifies these capital expenditures as $19,240,000 (2006), $37,582,000 (2007) and $29,664,000 (2008) for a total of $86,486,000. The Company supports its request for the inclusion of the $86.486 million in its response to STF 1.1 by listing hundreds of individual projects, the dollar amounts of each and the in-service dates. The Company's requests for inclusion of these investments in rate base reflect plant in-service through the end of the test year, December 31, 2008.

Q. Please continue.

A. One of the objectives of our field investigations of October 5 through October 8 was to observe many of the projects, and discuss them with the UNS Electric and TEP personnel responsible for their development and performance. Due to the limited time and resources available for the field investigations, we concentrated on the larger and most expensive projects that are contained in the list of $86 million of CWIP projects requesting to be included in rate base in this case. The full listing of the projects requested for inclusion were provided by Company in their response to data request STF 8.1. A copy of that response is included here as Attachment 3.

In addition to these projects, we visited the BMGS in the Kingman area, toured the facilities, and talked to the on-site personnel responsible for the operations of the two gas-fired turbines. The Company is separately requesting approval of the acquisition of the BMGS and that it be included in rate base as described in UNS Electric witness Grant's Direct Testimony filed April 30, 2009.

B.1 Call Center and Outage Response Operations

Q. Please describe the Company's call center and its response operations to outage and other trouble calls from customers.

A. We visited the call center operations in Tucson, on the site of TEP's Sundt generation station. This call center receives calls regarding both UNS Electric and UNS Gas service operations as well as those of Tucson Electric. The call center has a rotating staff of about 60 employees. Supervisors monitor all call center personnel that are discussing outages and other problems; e.g., bill inquiries, on a real-time basis. There are also personnel available in the call center room to assist operators with complaints and/or requests that need some additional information or help.

The call center manager accumulates and analyzes calls to this facility on a monthly basis based on a tracking of daily call volumes and subject matter. These statistics provide the call center with quantitative metrics to evaluate the efficiency and thoroughness of their operations. In addition to complaints made to UNS Electric by customers that involved claims of poor power quality, such as provided in response to Commission Staff data request STF 8.20 (Attachment 4) for the period January 1, 2008 through August 2009, the Company archives the audio recording of customer calls for 3 years.

Customer calls regarding outages and other service quality problems are immediately relayed to the Control Area Operations center for disposition and remedy. The call center personnel are also well aware of the potential geographic problems with responding to outages, such as in the Kingman area. The Kingman service area is very rural and travel times by repair crews (troublemen) can be much longer than in more urban areas. In this regard, the accuracy of outage information gathered by the call center personnel is even

more critical to affective responses to calls from customers. Moreover, the call center manager has instituted a procedure such that all elderly/senior citizens have a "flag" on their accounts to alert personnel responding to an outage to be aware that extra assistance may be necessary. The dispatching process is described in some detail with regard to both the Mohave and Santa Cruz service areas in the Company's response to STF 8.11. (Attachment 5)

Q. What is the next step in the Company's responses to outages and other service quality problems?

A. The calls from customers reporting outages and other service quality problems that have been reported to the Control Area Operations are then dispatched to field service personnel with as much information as possible regarding the electrical circumstances and geographical location of the problem. This dispatching operation is part of the Company's network and grid control operations located in the same building as the call center operations.

UNS Electric personnel and vehicles are maintained for responses to customer outages and other problems in the Mohave and in the Santa Cruz service areas. Our discussions with Company personnel confirm the Company's responses to STF 8.10 and STF 8.11 in terms of the manpower (journeyman lineman, lineman/troublemen) and equipment available to respond to customer electrical service complaints. In the Mohave service area, there are personnel and vehicles dispatched either from the Kingman District or from the Havasu District. In all the areas (Kingman and Havasu Districts and in Santa Cruz) in other than "normal" business hours (as outlined in STF 8.10), there are qualified journeymen linemen and/or linemen/troublemen "on call" with their equipment to

respond from their homes to the calls from customers. The other than "normal" hours include weekends and holidays.

Q. Referring back to the subject of distribution system performance, do you believe that the current call center and its procedures are adequate to maintain acceptable outage restoration in the Mohave service areas?

A. Yes, I do. While there may be a small delay while outage or trouble reports are transmitted to the Kingman/Lake Havasu facilities or assigned troubleman, duplicating a similar call center in the Mohave area would negate the overhead savings and efficiency of the present call center which would not justify the small time delay.

B.2 Electric Grid Operations

Q. Please describe the Company's Electric Grid Operations.

A. The Control Area Operations center monitors the Company's 69/230 KV ties with WAPA, and monitors and manages the operations of its 115 KV system. Telemetering between the control center and substations and generating stations is predominantly microwave and radio, with some fiber optics communications.

The Energy Management System ("EMS"), a Siemens software system, which monitors and controls the UNS Electric system has been upgraded and adopted for use by UNS Electric. UNS Electric has in-place multiple back-up power source facilities; e.g., generators, generating station facilities, etc. to support the EMS and the control center generally. Moreover, UNS Electric has a back-up control center facility located at another area of its system in the event the Control Area Operations center is for some reason unable to operate.

The EMS in this control center also controls the generating facilities in the Nogales area (Valencia) and in the Kingman area (BMGS). Bulk power transformers also are monitored in real-time from this facility. As indicated in the Company's response to STF 8.7, and verified in discussions with the control center personnel, there are no must run power requirements ("RMR") for the Mohave service area through 2008. Since 2006, however, RMR requirements have been in place for the Santa Cruz area. The Valencia generator (Santa Cruz area) start guideline is currently 51 MW (effective February 19, 2009). The Valencia generation starts had been based on a load of 65 MW or higher through the 2008 peak.

Q. Are you satisfied that the Control center will manage the UNS system in a reliable and adequate manner?

A. Yes.

B.3 Quality of Service/Distribution System

Q. What information was obtained and discussions undertaken through your field investigations regarding the reliability of the Company's distribution system operations?

A. We met with distribution system planning and technical (engineering) services personnel to discuss system reliability metrics and generally system planning efforts. These personnel are TEP employees who wear two hats, assigning their work hours to both TEP and UNS Electric depending on what projects they are working on.

Reliability Metrics. With regard to UNS Electric's distribution service quality indices, Section II.A. of this testimony describes the Company's analyses and the results of their

evaluations of CAIDI, SAIDI and SAIFI for each of the non-contiguous UNS Electric service areas. The personnel with whom we discussed these analyses undertake the determinations of these evaluations for both UNS Electric and TEP. The results of their analyses for UNS Electric, however, are not submitted to the Commission.

Distribution System. Most of the current UNS Electric facilities are the Citizens electric utility system prior to the acquisition of Citizens by UniSource, the parent company of TEP. Accordingly, a principle effort of the Company is the integration of the UNS Electric plant and equipment facilities to more closely reflect those of TEP on an operational basis, as well as on a compatibility of network electrical components basis. UNS Electric personnel indicate that these efforts are, however, made more difficult by the remoteness and differences in the character of the non-contiguous service areas served by UNS Electric. UNS Electric develops a 5-year distribution system plan (as does TEP) and is working on developing more long-range plans, such as those prepared by TEP; i.e., 10-20 year plans.

In conjunction with its distribution system planning and responsibilities, the planning and technical services group also is cognizant of maintaining necessary interconnection facilities with WAPA and correspondingly sufficient available capacity on the WAPA transmission network. In this regard, maintaining a high power factor is an objective that has been addressed by UNS Electric over the years. In response to STF 8.16, UNS Electric states that power factor data are not available at the distribution system level. In the response, UNS Electric opines that since the Mohave and Santa Cruz distribution systems "operate as radial distribution systems" that the power factors at the point of delivery from the transmission system are "reasonable proxies for the overall distribution

system." Calculated average power factors for each of the delivery points from WAPA to Mohave and Santa Cruz service areas show improvements in power factors from 2006 to 2008.

UNS Electric's objective of improvement in service area power factors and in system stability is supported by the Company's response to STF 8.19. The Company lists capacitor bank installations (at various KVAR levels) in the Kingman, Lake Havasu City and Santa Cruz Districts over the 2005-2008 time period (i.e., 52 capacitor additions and locations). Approximately 50 percent of the additions and locations of new capacitor bank installations were placed in-service in 2007 and 2008.

Q. What distribution system studies and analyses are undertaken by UNS Electric?

A. UNS Electric personnel indicated that they do not undertake harmonic studies, but do perform load-flow and short-circuit studies on individual distribution feeder circuits. In this regard, the Company's response to STF 8.18 outlines some of the reasons for load flow studies (e.g., reported voltage problems, load growth considerations, etc.), and for the short-circuit studies (e.g., provide data to facilitate electrical device protection), as well as the improvements that are implemented by UNS Electric based on these studies.

Q. Do you consider the current studies and analyses of the distribution system undertaken by UNS Electric adequate?

A. Yes. The needs of UNS Electric for studies and analysis are being adequately addressed given the current and expected levels of growth. In any event, UNS Electric's ability to engage the resources of TEP engineering when such needs arise gives assurance that analysis is available when required.

C. Mohave Service Area

Q. Please discuss the UNS Electric facilities you observed in the Mohave Service Area during your field investigation.

A. Our visit to the Mohave Service Area included observations of several substations, and the BMGS gas turbine units and the auxiliary equipment and attendant switchyard/substation at the BMGS site. As was the case with all our visits, we were accompanied by UNS Electric/TEP technical personnel knowledgeable about the operating functions of the electric facilities at the particular sites.

Q. Please discuss the characteristics and functions of the substation facilities you observed in the Mohave Service Area.

A. The substations we observed included in part older equipment and structures (Citizens installations) and in part UNS Electric upgrades. It was obvious from our visits to these substations that UNS Electric was making a concerted effort and commitment to standardization of equipment to limit its required inventory of parts and materials. As substantiated by the personnel who accompanied us, these efforts are focused on developing a more standard substation layout across the UNS Electric system, and to be more compatible with TEP's substation equipment and structures. Accordingly, at this time, there is no reason to recommend to the Commission that UNS Electric undertake any dramatic efforts in this regard. In our opinion, UNS Electric should continue with these efforts since they would seem to be the technologically (and economically) reasonable avenues to pursue.

C.1 UNS Electric Substations

Q. Please discuss the UNS Electric Substations in the Mohave Service Area.

A. In the Mohave Service Area, we viewed the following substations: Jagerson, Eastern, Hilltop, West Golden Valley, Griffith, Franconia, North Havasu, Desert Hills, and Clearwater. From a general engineering perspective, the substations are structured fairly similarly, with mostly compression and some welded fitting structures. Equipment types and manufactures of particular components are not the same across the substations. The latter is due to the initial installation of substation facilities by Citizens and subsequent upgrades by UNS Electric. All substations have sufficient space within the substation enclosure for expansion, with a couple of substations currently containing concrete pads for setting future transformers. The additional space, however, is not extraordinary, and should be considered as used and useful. All transformer pads are surrounded by oil-retention trenches filled with coarse, crushed stone. These oil spill enclosures contain trapped drains for oil removal. For the most part, these substations contain concrete cable runs with concrete or steel covers. The substation enclosures are chain-link fencing with vertical slants to help obscure the equipment inside in the rural areas, and textured block walls and caps in the more urban areas around commercial and residential areas.

The Jagerson Substation (Project No. 382061S) was placed in-service December 19, 2007 according to the Company's response to STF 8.1 (STF 1.1). This Substation is a 69 KV/13.2 KV step-down facility currently containing a single 45 MVA transformer. The Jagerson Substation contains a new control room, which UNS Electric claims was necessary because components were no longer available to undertake any repairs to the original control room. The Substation was designed by an engineering group out of Phoenix, and not by TEP personnel.

The Eastern Substation (Project No. 368061S) has been in service since about 2000, with space available for expansion. Modifications to structures and equipment have been on-going with a new transformer and auxiliary equipment to be completed soon. The UNS Electric personnel indicated that this Substation would be fully operational with the new transformer in December 2009. Our observations of the Substation layout agrees with the evolution of the current configurations and plans for the expansion of the facilities.

The Hilltop Substation provides an interconnection with the WAPA 230 KV transmission facilities. There are 2-230 KV/69 KV transformers each at an 80 MVA rating (manufactured by ABB) currently in service, with space available for expansion. There are two (2) WAPA circuits into the Hilltop Substation and three (3) UNS Electric circuits exiting to serve customer loads. UNS Electric personnel indicate very little trouble with this facility except for some breaker maintenance problems.

The West Golden Valley Substation (Project No. 330061S) was placed in-service December 1, 2006 according to the Company's response to STF 8.1 (STF 1.1). This Substation has space available for expansion, and is a TEP design. The West Golden Valley Substation contains a single 40 MVA transformer with an earth and gravel berm oil spillage containment area. This Substation is currently providing electrical power to the Mercator Mine facility (copper and molybdenum) approximately 10 miles away. The majority of the line was paid for by the Mercator Mine, about eight miles. The Company lists its portion of this line (Project No. 311761S) in its response to STF 8.1 (STF 1.1). The line to the Mine is an all steel pole 69 KV line with UNS Electric distribution lines in an underbuild configuration.

The Griffith Substation (Project No. 3270621) has a very large footprint with the majority of the Substation occupied by WAPA. The in-service date for the investment requested in this case is December 21, 2007 according to the Company's response to STF 8.1 (STF 1.1). UNS Electric has a single 84 MVA transformer on site, with room for on additional transformer as system demands may dictate. In this regard, if UNS Electric constructs a Kingman to Havasu line (could be a future development) the available space would be used to set a transformer for the potential 230 KV line. There are currently 3-69 KV UNS Electric circuits from this Substation.

The Franconia Substation is at the terminus of UNS Electric's double circuit structure transmission line (Project No. 331061S) which currently has a single circuit operated at 69 KV. UNS Electric's future plans are to install and operate on the same structures a single circuit 230 KV line to enhance electric network service in the Lake Havasu area. As with UNS Electric's other substations, the Franconia Substation has space available for expansion and placement of another transformer and attendant switch gear.

UNS Electric's North Havasu Substation has a block wall and cap enclosure on the Lake Havasu City side and the chain link with vertical slats fencing on the sides away from the City. This Substation is an interconnect with WAPA's 230 KV system currently with a single 80 MVA transformer. There is currently an open pad for another transformer with implementation of new equipment and interconnection to the network planned by UNS Electric for 2010.

The Lake Havasu City area is expected to continue to increase load in the future. This area has some light commercial loads and is the destination of "snowbirds" starting in

October/November. This tourism has prompted UNS Electric to undertake various improvements and expansions (e.g., Project No. 3270621) in this area to support the system loads.

Load growth in the area, including the construction of a large mall and household supply stores, provided the impetus for UNS Electric to construct the Desert Hills Substation (Project No. 354062S) placed in-service June 30, 2006. Currently, this Substation contains a 44 MVA transformer and is electrically a radial component of the system configuration. UNS Electric plans to loop this Substation in 2010 to enhance support of the electrical loads in this area of the Company's network.

The Clearwater Substation is located in a residential neighborhood with residential houses on all sides. The Substation has a block wall and cap enclosure. While it is in a residential area, the Substation footprint is not lowered (excavated ground configuration) to obscure electrical structures since it is located on a hill and almost all of the houses are below the Substation location. Currently, the Clearwater Substation has two (2) 44.8 MVA transformers (64 KV/13.2 KVA) with firewalls between them. There is also a firewall between the transformers and the control building. The design and on site workmanship was all done by in-house personnel; i.e., UNS Electric personnel.

Q. In general, what is your opinion of the quality and design efficiency of the substations observed?

A. We were satisfied that the quality of construction, the overall design of the stations, reliability aspects, and the capacity of the installed components were in keeping with

prudent utility practice and suitable for the expected loadings. Further, provisions for future expansion appear to be adequately provided for in the stations observed.

Q. Are there any other comments as to aspects of the Mohave facilities that you would make?

A. Yes. The 44 MVA transformer installed at the Desert Hills Substation appears to be rated, according to its nameplate, at a 45 degree C. temperature rise. This is very unusual and is either a misprint or TEP (the substation designers per UNS personnel) specified a unique transformer. I have just received a response from the Company to a Data Request I sent regarding this issue. I will address the Company's response in my Surrebuttal Testimony.

Q. Are you requesting that this be addressed by the Company?

A. Yes. Perhaps Company could address this item in subsequent testimony.

C.2 BMGS Facility

Q. Please discuss the generating units and auxiliary equipment at the BMGS Facility.

A. The BMGS Facility consists of 2-45 MW gas-fired generating units with an attendant substation/switchyard located near Kingman. In UNS Electric witness Grant's Direct Testimony of April 30, 2009, he states that BMGS "entered service on May 30, 2008" and is currently owned by UniSource Energy Development Company. It is UNS Electric's proposal to acquire BMGS, which requires approval from the FERC. Mr. Grant states that UNS Electric believes that approval by FERC is likely in a "timely manner," and, therefore, UNS Electric is requesting that the "Commission approve a

post-test year adjustment to rate base for the BMGS", at the time of transfer of ownership should that occur.

The BMGS Facility contains Continuous Emission Monitoring systems which are part of the generation equipment package for both units. The Facility layout includes cooling water towers and reservoirs to implement the supply and treatment of necessary water for operation of the units. A connection to a county water source is said to be planned and included as a supplemental source to the ground water wells serving the Facility. The technical personnel at the BMGS Facility indicated to us that the BMGS units could be limited in their hours of operation due to limitations in the water treatment process. Staff submitted a Data Request to clarify the situation as we could consider a limitation in operating duration to affect the value of the station. The Company responded indicating that water availability is not a limitation. However, I recommend that the Company be required to demonstrate adequate water availability at the time of any transfer of BMGS from UniSource Energy Development ("UED") to UNSE.

The week before we visited the BMGS Facility, Unit #1 was taken out of service because of a failure in the turbine section of the Unit. The cause of the failure was evidently a blade failure (breaking) in the 3rd or 4th stage of the turbine section, which precipitated damage to blades in the other turbine stages. Since the Unit had not been dismantled at the time of our visit, a bore scoping of the turbine section indicated that some of the stages had damage to over 50 percent of the blades. In the response to STF 15.3 (received October 20, 2009), the Company states that the estimated time to repair the damage to Unit #1 is 6 to 8 weeks. Additionally, the Company's response states that the "damage is under warrantee and the estimated cost to the Company is zero dollars."

From an engineering perspective, BMGS was properly constructed and should be back to full operational levels once the repairs are made by UED. Both units have been available (with the exception of the recent problem with Unit #1) and have provided generation to the UNS Electric grid since June 2008, under a Purchase Power Agreement. The Company's responses to STF 8.6 and STF 4.3 summarize the net KWH generation and peak net KW for each of the two (2) Units over the period June 2008 through June 2009. In particular, STF 8.6 presents the BMGS monthly KWH generation and peak KW for this period. The following table shows the maximum and minimum outputs for each of the Units as shown in STF 8.6:

	Unit #1		Unit #2	
	KWH Generation	Peak KW	KWH Generation	Peak KW
Maximum	11,960,355 (Dec '08)	47,274 (Dec '08)	13,346,064 (Dec '08)	48,268 (Dec '08)
Minimum	3,198,826 (Jun '09)	43,081 (Sept '08)	1,586,153 (Apr '09)	41,790 (Jun '09)

The response to STF 8.6 shows that there was KWH generation and peak KW output for each Unit in each of the 13 months from June 2008 through June 2009.

The unavailability of BMGS Unit #1 is an unforeseen circumstance that could affect the availability of peaking generation to UNS Electric under its Purchase Power Agreement with UED. That is, the Company has to replace the generation that would have been available from Unit #1 until it can be placed back in-service.

Q. Are there other aspects of BMGS that you considered during your visit?

A. Yes. We noted that the general level of maintenance and house keeping appeared to be of very high quality. However, we recommend that Staff re-observe the BMGS facility

prior to any purchase of BMGS by UNSE. The control and monitoring system for the unit and auxiliaries and associated software appeared to be well suited to their tasks. We also noted that the software includes a parameter histogram function and that the units are equipped with vibration sensors as well as the expected monitoring for a current modern gas turbine unit.

Q. What was your impression of the common plant items?

A. We observed the substation and connected transmission facilities which are well constructed. The substation is of adequate capacity for the rated output of the units and appears to be well maintained. Responses to our questions as to periodic oil testing and transformer testing were satisfactory. However, the operating personnel appeared to be unsure if thermal scanning of the substation bus and connected lines was to be performed on a regular basis. We would recommend that such be included in the maintenance schedule for the station.

Q. What other aspects did you consider?

A. There appears to be adequate room at the site for the possible expansion of the station to four units of equal capacity. It would appear that with the addition of two more gas turbines and the necessary steam generators and steam turbines that a combined-cycle installation of about 240 MW capacity could be sited on the available area if sufficient water is available. This would include room for the necessary expansion of the substation and transmission. We would consider this possible future expansion of the BMGS site to be a positive consideration in the purchase decision.

Q. What is your impression of the operating efficiency of the BMGS units?

A. The heat rates of the units are reported to have been determined to be 9503 BTU/KWH and 9436 BTU/KWH. These values indicate that the units are operating at the claimed efficiencies and could be considered as efficient sources of periodic peaking power for the UNS Electric system needs.

D. Santa Cruz Service Area

Q. Please describe the characteristics and functions of the facilities observed during your visit to the Santa Cruz Service Area.

A. We visited the Santa Cruz service area on October 7, 2009. Facilities of interest were the addition of Unit #4 turbine at the Valencia Generating Station, the Valencia Substation, the Vail transmission line, the addition of the Motorized Air Break ("MOAB") switch and the Sonoita and Canez Substations. We also discussed general maintenance concerns and service outage response in the Santa Cruz service area with the Lead Superintendent for the Santa Cruz District.

Q. What is your opinion of the Valencia Unit #4?

A. The installation of Unit #4 gas turbine added 19 MW of generating capacity to the Valencia station. This brought the station to a total of 66 MW. The Valencia units are necessary to provide voltage support to the Nogales service area when the load exceeds about 51 MW due to limitations of the supplying transmission line. The line has a rated capacity of 62 MW with the voltage support provided. In addition, Valencia can, if required, supply the Nogales area in the event of an outage of the connected transmission albeit with manual control. Currently, the unit can be dispatched by the Tucson area

control facility. This addition was necessary to maintain reliable supply to the Nogales area with a current peak load of about 72 MW and for load growth in the future.

Q. Please continue.

A. Unit #4 has a determined heat rate of about 11,021 BTU/KWH as compared to the existing three older unit's heat rates of about 16,620-16,932 BTU/KWH. This gain in efficiency will result in significant fuel savings when supplying voltage and peaking service to the Nogales area.

Q. What is your opinion of the installation?

A. Our inspection of Unit #4 indicated that it is very well maintained and has operated well since initial operation. However, the unit is currently not capable of a "black start". "Black start" capability refers to the ability of a generating unit to start and deliver proper voltage and frequency to its connected load without connection to or assistance of the area power grid. However, in the case of Unit #4, a black start can be performed by the older units which can then allow Unit #4 to be put on-line. We were informed that a project is planned to provide black start capability for unit #4 in the near future.

Q. What was your impression of the Valencia Generating Station as a whole?

A. The station appears to be in good repair and well maintained. One aspect is that we were informed that there are times when water of suitable quality is required to be transported to the station by truck. While this could be a serious limitation at times when the station is required to serve as the sole source for the area, we were informed that another project is in the planning stages to provide for this water need on a local basis.

Q. What of the Valencia Substation?

A. The installation of a new 50/56 MVA transformer and the upgrading of the bus work has resulted in adequate capacity for the area. The transformer is of dual voltage for future changes in the supply voltage. This Substation is well constructed and appeared to be well maintained.

Q. Are there plans to upgrade the Vail 115 KV transmission line?

A. This line is to be upgraded to 138 KV operation planned for 2012. This voltage increase will allow the threshold for voltage support from Valencia to be increased and to increase the capacity of the line. We are of the opinion that this is a necessary improvement as well as one which should result in future fuel savings.

Q. Were you able to visit the MOAB switch and what was your impression?

A. The motorized air break switch or MOAB is in working order. This switch allows the isolation of the Nogales area at the Canez Substation and can be operated remotely via SCADA. This addition has added needed flexibility to system operation.

Q. Please discuss the substations and distribution network facilities you observed in the Santa Cruz area.

A. Accompanied by an employee of UNS Electric, we observed the Sonoita Substation and the Canez Substation. These Substations are located in a vast development known as Rio Rico, north of Nogales. The Sonoita Substation is a configuration inherited from Citizens with 115 KVA service into the Substation and includes a sizable capacitor bank to increase the power factor in this area.

The Canez Substation is also a Substation inherited from Citizens, with space available for additional transformers and auxiliary equipment as the need arises. UNS Electric is currently anticipating setting another transformer in this Substation. The MOAB switch is located just outside of the chain link fence enclosure of the Canez Substation.

Per our discussions with UNS Electric employees, the distribution network facilities in the area will over time be compatible with the current TEP standards. This will occur as replacements and repairs are needed to distribution lines, structures and equipment. We observed replacements of structures and equipment at several locations in the distribution system.

III. RECOMMENDATIONS TO THE COMMISSION

Q. What recommendations would you offer the Commission based upon the scope of your reviews and field investigations of UNS Electric?

A. We have several recommendations that we offer to the Commission for its consideration regarding UNS Electric.

Our recommendations to the Commission include:

1. The Commission should require an annual report of the distribution indices including a listing of the worst performing circuits and what steps are being taken to mitigate these circuits poor performance by UNS. The report should be separated by service area and by the results for the overall UNS system. Other requirements for this report should conform to those required of Arizona Public Service as described in the current settlement proceedings.

2. The Company states in response to STF 8.1 that they invested approximately $86 million of new plant since the end of the last test year. WML&A reviewed the major plant additions which I discuss in my testimony. Of the plant items we inspected, we found that they were well constructed, functioning at expected levels, and are presently being used for the provision of service to rate payers. Therefore, we recommend that the portion of plant items completed and used and useful at the end of the test year in this proceeding be included in this rate case.

3. Currently, BMGS is owned by UniSource Energy Development ("UED"), however, our inspection of the BMGS facility indicates that the facility is properly constructed and should be back to full operational levels once the repairs are made by UED.

4. At such time if and when UNSE acquires the BMGS, any costs of repair not covered by warranty should be borne by UED and not by UNSE at the time of purchase.

5. If UNSE ultimately acquires BMGS, UNSE should be required to demonstrate to the Commission that there are no limitations due to water availability on the required operations of both Unit #1 and Unit #2.

6. UNS Electric's maintenance scheduling at the BMGS Facility should include thermal scanning of the substation/switchyard bus and connected lines on a regular basis, if it ultimately acquires the facility.

Q. Does this conclude your testimony?

A. Yes.

ATTACHMENT 1

BACKGROUND & EXPERIENCE PROFILE

W. MICHAEL LEWIS, P.E.

PRESIDENT

W.M. LEWIS & ASSOCIATES, INC.

EDUCATION

1981 - 1988	Master of Business Administration, Ohio University, Athens Office
1971 - 1971	B.S., Electrical Engineering, Ohio State University, Columbus, Ohio
Special Courses:	Power Circuit Breakers, Ohio State University Modern Power System Analysis, University of Wisconsin Digital Electronics for Power Application, IEEE Modern Methods of Analysis and Protection of Electric Power Systems, IEEE Project Management and Planning, University of Wisconsin Construction Contract Administration, University of Wisconsin High Voltage Testimony, Pennsylvania State Lighting Solution and Design, IIT/AEE Cogeneration Theory and Design, University of Wisconsin Planning, Procurement, and Installation of SCADA Systems, University of Wisconsin, 1989

REGISTRATIONS

Registered Professional Engineer in Kentucky and Ohio
Registered Consultant to the Asian Development Bank, Manila, Philippines

POSITIONS

1979 - Present	President and Manager of Engineering of W.M. Lewis & Associates, Inc.
1974 - 1979	Electric Power Engineer, Goodyear Atomic Corporation (now Martin Marietta Energy Systems)

EXPERIENCE

<u>Summary</u> -- Extensive experience in utility practice, including serving as an expert witness on topics of planning, design, construction, operation, and maintenance of high-voltage transmission lines and facilities, (overhead and underground); high-voltage transformer and circuit breaker loading, operation, and maintenance; working and design clearances on facilities at 230 kV and above and other aspects of utility practice before the State Corporation Commission of Virginia; and on aspects of electric utility design and operation before the Federal Energy Regulatory Commission. Also served as an expert witness in numerous electrical accident litigation concerning interpretation of the NESC, OSHA regulations, and the concept of "Prude nt Utility Practice." Has performed reviews of rural electric utilities in 14 countries.

In addition to experience and expertise in engineering, operation, and code application, prepared operation manuals for client utilities and industries, prepared training curriculum for power operators, trained power operators and linemen, and prepared PM program criteria for utilities and industry. Experienced in HV and EH V testing techniques of transformers and cables and circuit breakers, including OCB and SF_6 designs.

Graduate level studies include concentrated studies of staffing level theory and the use of statistical techniques in electric rate design and preparation of tariffs for electric utilities. Training in safety audits and compliance plans.

ATTACHMENT 2

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S EIGHTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
September 29, 2009

STF 8.9 Please provide determinations of the reliability indices (Distribution System Indices); i.e., Customer Average Interruption Duration Index (CAIDI), System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI)), as well as any other distribution system performance metrics that UNS Electric evaluates for each of 2007, 2008, and to date for 2009. Please state the time threshold used for the calculation of these indices. How do these indices compare with the IEEE standard/guidelines for such indices?

In terms of these indices, please indicate four worst circuits in both the Mohave County and the Santa Cruz County service areas. Please also explain the reasons for the outages and the mitigation measures taken to correct the problems.

RESPONSE: UNS Electric is in the process of gathering this information and will provide the response to this data request shortly.

RESPONDENT: Regulatory Services

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S EIGHTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
October 2, 2009

STF 8.9 Please provide determinations of the reliability indices (Distribution System Indices); i.e., Customer Average Interruption Duration Index (CAIDI), System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI)), as well as any other distribution system performance metrics that UNS Electric evaluates for each of 2007, 2008, and to date for 2009. Please state the time threshold used for the calculation of these indices. How do these indices compare with the IEEE standard/guidelines for such indices?

In terms of these indices, please indicate four worst circuits in both the Mohave County and the Santa Cruz County service areas. Please also explain the reasons for the outages and the mitigation measures taken to correct the problems.

RESPONSE: UNS Electric is in the process of gathering this information and will provide the response to this data request shortly.

RESPONDENT: Regulatory Services

SUPPLEMENTAL RESPONSE: Please see the following tables:

Kingman	2007	2008	2009 - 8/31
SAIFI - All	1.930	2.516	2.816
SAIFI - Clear Weather	1.734	2.010	2.707
SAIFI - MED	1.930	0.985	0.626
CAIDI - All	51.199	100.995	35.716
CAIDI - Clear Weather	49.042	107.932	35.556
CAIDI - MED	51.199	70.994	52.698

Lake Havasu	2007	2008	2009 - 8/31
SAIFI - All	0.912	0.496	0.866
SAIFI - Clear Weather	0.867	0.490	0.656
SAIFI - MED	0.776	0.217	0.661
CAIDI - All	75.327	72.414	40.628
CAIDI - Clear Weather	68.618	72.495	29.630
CAIDI - MED	59.107	71.663	30.163

Santa Cruz	2007	2008	2009 - 8/31
SAIFI - All	1.996	3.713	2.026
SAIFI - Clear Weather	0.977	3.139	1.916
SAIFI - MED	1.881	1.769	1.306
CAIDI - All	84.156	144.393	64.444
CAIDI - Clear Weather	95.566	152.552	63.944
CAIDI - MED	77.866	75.155	60.343

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S EIGHTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
October 2, 2009

Mohave	2007	2008	2009 - 8/31
SAIFI - All	1.481	1.604	2.007
SAIFI - Clear Weather	1.357	1.336	1.826
SAIFI - MED	1.189	0.892	1.962
CAIDI - All	59.518	95.879	36.960
CAIDI - Clear Weather	56.044	100.407	34.306
CAIDI - MED	60.631	73.298	24.315

UES	2007	2008	2009 - 8/31
SAIFI - All	1.586	2.029	2.011
SAIFI - Clear Weather	1.280	1.706	1.844
SAIFI - MED	1.586	1.264	1.975
CAIDI - All	65.860	113.506	42.565
CAIDI - Clear Weather	62.214	119.412	40.540
CAIDI - MED	65.860	72.348	32.642

The sustained outage threshold for these indices is 5 minutes. All indices are calculated according to the methods laid out in IEEE 1366-2003.

Indices designated as "All" include all outages that occurred during the indicated year. Indices designated as "Clear Weather" include all outages that occurred during the indicated year, except for those outages caused by storms. Indices designated as Major Event Days "MED" include all outages that occurred during the indicated year, except those outages which occurred on days that were determined to be MED, as defined by IEEE 1366-2003. Due to the availability of properly formatted historical data, MED was calculated using 3 years of historical data for 2007, 4 years for 2008, and 5 years for 2009. All future MED thresholds will be calculated with the rolling 5-year period of historical data.

Indices labeled Kingman, Lake Havasu, and Santa Cruz are calculated with outages from only their respective areas. Mohave indices are calculated by combining the Kingman and Lake Havasu outages. UNS Electric indices are calculated by combining Kingman, Lake Havasu, and Santa Cruz outages.

Indices for Santa Cruz, Kingman, and Lake Havasu are not calculated at a circuit level; therefore, worst circuits, as defined by those criteria, are not available.

RESPONDENT: Lauren Briggs

WITNESS: Thomas A. McKenna

ATTACHMENT 3

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S EIGHTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
September 29, 2009

STF 8.1 At Page 2 of the Direct Testimony of UNS Electric Witness Michael J. DeConcini, there is the claim that since June 30, 2006 through December 31, 2008 the Company has made capital expenditures of approximately $86 million and that the expenditures are not reflected in current rates. Please provide a list of these capital expenditures by project (and all other projects that are applicable) that represent the post test year rate base adjustment requested by the Company in this case. Include in this response the following:

(a) the identification and description of each project;
(b) the dollar amount of each project;
(c) the date that each project provided in (a) was completed or is expected to be completed; i.e., completed and ready for final testing and inspection prior to placing in-service;
(d) the date that each project provided in response to (a) was placed in-service or is expected to be placed in-service to serve customers;
(e) the date that each project provided in response to (a) was "closed to plant" in UNS Electric's accounting records;
(f) the dollar amount of each project in (a) that was "closed to plant" or the projected dollar amount of each project in (a) at the time it is expected to be "closed to plant"; and,
(g) the separation of the projects in (a) by Generation, Transmission, Distribution, and General Plant categories, as well as other system improvements that are part of the requested rate base adjustment.

RESPONSE: a. – g. Please see UNS Electric's response to STF 1.1 in Staff's first set of data requests.

RESPONDENT: Carl Dabelstein

WITNESS: Michael J. DeConcini

ATTACHMENT 4

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S EIGHTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
September 29, 2009

STF 8.20 Please provide a listing of all complaints, either formal or informal, made to UNSE by customers that involve claims of poor power quality, including but not limited to , voltage levels, harmonics, "flicker", etc. and a description of UNSE's response. Please include details of all resulting investigations performed by UNSE including what equipment was modified or newly installed as a result of the investigations and if such resolved the complaint.

RESPONSE: Please see the PDF file STF 8.20, Bates Nos. UNSE(0206)08481 to UNSE(0206)08511, on the enclosed CD for all complaints made to UNS Electric that involve claims of poor power quality for the test year (January 1, 2008 to December 31, 2008) through August, 2009.

RESPONDENT: Brenda BeVard

WITNESS: Thomas A. McKenna

STF 8.20

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Brad Morton Phone: (602) 542-0836 Fax: (602) 542-2129

Priority: Respond Within Five Days

Complaint No. 2 008 - 66025 Date: 1/24/2008

Complaint Description: 05E Quality of Service - Outage/Interruptions
N/A Not Applicable

	First:	Last:	
Complaint By:	Jacquie	Svidran	
Account Name:	Jacquie & Arthur Svidran / Acct# 2787400000		Home: (928) 854-1998
Street:	3120 Gatewood Dr		Work:
City:	Lake Havasu City		CBR:
State:	AZ Zip: 86404		is:

Utility Company. Unisource ** Energy Services (UNS)
Division: Electric
Contact Name: Brenda Bevard Contact (520) 917-2647

Nature of Complaint:
Mrs upset about power outage at her home while she was in residence at another home. Property was aparently out of service for two months and utility never checked to see what the problem was although no energy was used. Customer claims damages but advised ACC does not handle claims. She wants to understand what cause outage and why it was not discovered before they returned to home after two months.
End of Complaint

Utilities' Response:

January 31, 2008

UNS Electric, Inc. ("UNS Electric") was not made aware of an outage which affected 3120 Gatewood Drive during the time the Svidran's were away. The Svidran's account reflects no usage from September 6, 2007 through December 5 2007. The reads taken within this time were verified reads for three consecutive months which UNS Electric billed the customer on October 8, 2007, November 6, 2007 and December 7, 2007.

UNS Electric does not have record of anyone reporting outages that are also served through the same transformer as the Svidrans.

Please review the UNS Electric Rules and Regulations, Section I, S. 1. a.

S. Continuity of Service

1. The Company shall make reasonable efforts to supply a satisfactory and continuous level of service. However, the Company shall not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from:
   a. Any cause against which the Company could not have foreseen, or made provision for, i.e., force majeure.

Investigator's Comments and Disposition:

Date Completed:

Complaint No 2008 - 66025

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Deb Reagan Phone: (602) 364-0236 Fax: (602) 542-2129

Priority: Respond Within Five Days

Complaint No. 2 008 - 66552 Date: 2/19/2008

Complaint 05E Quality of Service - Outage/Interruptions
N/A Not Applicable

	First:	Last:	
Complaint By:	Jon B.	Coppa, M.D.	
Account Name:	Jon B. Coppa, M.D. / Acct# 5480100000		Home (000) 000-0000
Street:	785 San Rafael Valley Road P.O.Box 517		Work:
City:	Patagonia		CBR:
State:	AZ Zip: 85624		is:

Utility Company. Unisource ** Energy Services (UNS)
Division: Electric
Contact Name: Tobin Voge Contact (520) 884-3734

Nature of Complaint:
***** E-04204A-06-0783 *****

Customer sent the following e-mail -

From: Jon Coppa [mailto:vcb@groundcontrol.us]
Sent: Friday, February 15, 2008 4:52 PM
To: Mayes-WebEmail; Mundell-Web; Gleason-WebEmail; Hatch-WebEmail; Pierce-Web; Utilities Div - Mailbox
Cc: Marshall Magruder
Subject: Re: Unisource Power Outage and grassland fire. Docket #E-04204A-06-0783

TO: Arizona Corporation Commission

RE: Unisource Power Outage and San Rafael Valley Grassland Fire - February 14 & 15, 2008.

DOCKET #E-04204A-06-0783

Beginning at 10:40AM (February 14, 2008) we experienced repeated severe fluctuations in voltage and I immediately reported this to the Unisource Emergency Call Center. This problem continued until the power went out around 2:30PM on the same date. During this same period there were eye witnesses to a "sparking power pole" near the intersection of the San Rafael Valley Road, Meadow Valley Flat Road and the Apache Road. These witnesses included area ranchers and State employees from the Arizona State Parks facility in the San Rafael Valley, Santa Cruz County. A grass fire erupted at this pole and pushed by winds gusting to 30 and 40 miles per hour, rapidly spread to the head of the San Rafael Valley. This fire consumed several pastures for a large ranch, one pasture slated for grazing in two weeks and another pasture containing many cows with newborn calves. The anticipated claims for damage resulting from this fire could be significant. During the evening the fire had crossed the Canelo Hills and "was headed for Elgin" to the north.

ARIZONA CORPORATION COMMISSION
UTILITY COMPLAINT FORM

We were out of power throughout the region until 1:30PM (February 15, 2008) which represents a total outage of 23 hours. The extended delay in power restoration was due to the U.S. Forest Service not allowing Unisource to proceed with equipment replacement until the Forest Service determined the fire site to be safe for entry.

A prolonged power outage also results in loss of our land line telephone service as the Qwest electronic cabinet at the head of the San Rafael Valley receives its power from the nearby Unisource line.

In the past, the majority of our fires have been due to abandoned campfires from activity by illegal aliens and drug smugglers. Now, our last two major fires have been associated with Unisource equipment failure. The site of ignition for the Willow Fire (2006) and this Willow Springs Fire (2008) are power poles that are within 1/4 mile of one another. Unisource has been much better in communicating their problems to the San Rafael Valley customers and they have been repairing and replacing equipment, but it is obvious that much more has to be done to assure reliable service.

Utilities' Response:

February 25, 2008

The service interruption that affected Mr. Coppa's on February 14, 2008 was associated with a grassland fire in the San Rafael Valley south of Sonoita. UNS Electric, Inc. ("UNS Electric") was not able to restore service to the affected area until the Forest Service authorized access to area where the damaged company facilities were located. Once access was granted UNS Electric replaced a power pole and conductor and reenergized the line. UNS Electric has and will continue to communicate with the San Rafael Valley Homeowners Association regarding service upgrades and or interruptions in the San Rafael area. UNS Electric has been actively upgrading equipment that services the San Rafael area. Some examples of the upgrades include newly installed arresters, fault indicators and spacers. UNS Electric has also conducted extensive tree trimming in the San Rafael area.

Investigator's Comments and Disposition:

E-mailed to Unisource.
End of Comments

Date Completed:

Complaint No 2008 - 66552

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Carmen Madrid Phone: (602) 542-0848 Fax: (602) 542-2129

Priority: Expedite

Complaint No. 2008 70039 Date: 7/16/2008

Complaint Description: 05E Quality of Service - Outage/Interruptions
N/A Not Applicable

	First:	Last:	
Complaint By:	Annel	Lizarriga	
Account Name:	Annel Lizarriga		Home:(5 20) 839-9532
Street:	483 W. First St.		Work:(0 00) 000-0000
City:	Nogales		CBR:
State:	AZ Zip: 85621		Is:

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard Contact Phone: (520) 884-3651

Nature of Complaint:

Spanish speaking customer states that she has 2 small children and that they have been without electricity most of the day.. She wanted to know when the service will be restored.

Has the problem been found?
How long before electricity will be restored?
Can you contact customer with update?
End of Complaint

Utilities' Response:

Investigator's Comments and Disposition:

7/16/08 e-mailed to UNS
End of Comments

Date Completed:

Complaint No. 2008 - 70039

BeVard, Brenda

From: ACC Complaints - All
Sent: Monday, July 28, 2008 4:08 PM
To: 'Carmen Madrid'
Subject: ACC Complaints: Lizarriga, Annel SC UNSE Complaint No. 70039: 05E Quality of Service-Outage/Interruptions (Acct# 5181300000)
Attachments: rpt_Complaint_EmailPDF.pdf

Carmen,

Please accept my apologies for the delay in our response. This response was inadvertently emailed to another UNS Electric Employee on July 17, 2008. Please review the following for our response.

Thank you,

Brenda

Has the problem been found?
Yes, a 115 kV line lost power due to a broken cross arm which affected the Santa Cruz County area.

How long before electricity will be restored?
Power was restored at 4:07pm on July 16, 2008.

Can you contact customer with update?
Annette Setherley, Administrative Assistant, called and left a voice message for the customer on July 17, 2008 at 9:00am.

From: Carmen Madrid [mailto:CMadrid@azcc.gov]
Sent: Wednesday, July 16, 2008 3:55 PM
To: ACC Complaints - All
Subject: ACC Complaints: Lizarriga, Annel -UNS Electric Complaint No. 70039

Please see the attached complaint. It is in PDF format.

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ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Trish Meeter Phone: (602) 542-0622 Fax: (602) 542-2129

Priority: Respond Within Five Days

Complaint No. 2008 71541 Date: 9/18/2008

Complaint Description: 04B Service - Defective Equipment
05D Quality of Service - Field/Premises Visit

	First:	Last:	
Complaint By:	Mary	Jazwin	
Account Name:	Mary Jazwin		Home:(9 28) 757-7968
Street:	2160 E. Hearne Ave.		Work:
City:	Kingman		CBR:
State:	AZ Zip: 86409		Is:

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard Contact Phone: (520) 884-3651

Nature of Complaint:

9/17
Customer called stating wiring is bad on the meter. Two company technicians came to the premises and advised her she needed to have new electrical service be put in. She has to force them to do a load test. She received in writing a statement from one of the technicians that " right leg on the meter box is loose and needs a new connection or a new meter box". When calling the supervisor at company, he said the left leg is the responsibilty of the company. Customer states the wires are parallel.

Customer feels this was frivilously handled by the company techs who came out. They did not seem to know anything.

Customer feels that issues in the past may have led up to this recent problem. She has concerns about her home catching fire and being gone in a matter of ten minutes. In the past, (six months) a transformer was not powered downed when there were problems and she wonders if this has something to do with the current problems.
She states she is a lawyer and is not afraid to sue the company. She will not allow anyone to come out and look at things again. She knows she has had an inspector check everything, including electrical in May, 2008. She wants the company to fix this and it had better be tomorrow.

Advised customer of rules regarding responses from utilities and the fact the company may have to send a representative out as part of an investigation.
The meter was not tagged by the techs during the visit.

Questions to the company:

Has customer experienced electrical problems in the recent past?
What was found by company techs on their visit to the property?
Will a new meter need to be provided at the location?

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Please provide the Commission with details to the delivery of service for this customer.
End of Complaint

Utilities' Response:

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Investigator's Comments and Disposition:

9/18
Customer called a second time to go over issues again. She is concerned for her neighbors. She contacted her inspector. She said her ionspector did not know what the UNS rtechs were talking about regarding the problem. Per customer, he stated the area is not accessable to inspection because it is sealed and only the company can open it for inspection.
Customer stated she called 911 in July. 911 person told her to hang up so he could call UNS about the transformer. UNS took a long time to get to the property. The 911 person made it sound urgent.
She stated company is providing gross negligence in service. She will video tape everything.

Advised customer I would attach the additional info to the complaint.
End of Comments

Date Completed:

Complaint No. 2008 - 71541

BeVard, Brenda

From: ACC Complaints - All
Sent: Monday, September 22, 2008 12:40 PM
To: 'tmeeter@azcc.gov'
Subject: ACC Complaints: Jazwin, Mary - UNSE Complaint No. 71541: 04B Service - Defective Equipment (Acct# 2633581613)
Attachments: rpt_Complaint_EmailPDF.pdf; 2160 Hearne Complaint Information 10.9.08.doc

On September 19, 2008, Steve Jacobson, UNS Electric, Inc.'s ("UNS Electric") Construction & Metering Supervisor, and Jim Blem, Working Foreman, met with D. Chapman, Mohave County Building Inspector, at Ms. Jazwin's location on 2160 E Hearne Avenue, Kingman, to investigate her concerns. After reviewing the electrical line and service panel at the location, the Building Inspector told Ms. Jazwin that all the problems were on her side of the service and were her responsibility to repair.

The Mohave County Building Inspector told Mr. Jacobson that he will be sending a letter to the customer giving her five (5) days to have the repairs made, or Mohave County would require her electrical service to be disconnected.

Question: Has the customer experienced electrical problems in the recent past?
Ms. Jazwin requested service with UNS Electric effective June 4, 2008. UNS Electric replaced a bad transformer which serves Ms. Jazwin's property on July 12, 2008. On September 17, 2008 Ms. Jarwin contacted UNS Electric and stated that since the transformer was replaced, someone was hacking into her computer through her electric service. Ms. Jarwin also stated she was getting voltage fluctuations.

Question: What was found by the company technicians on their visit to the property?
On September 17, 2008 a UNS Electric Lineman went to Ms. Jazwin's property to investigate flickering lights and found a loose connection on the line side (customer's side) of the meter. The lineman recommended Ms. Jazwin disconnect service and have an electrical contractor make repairs.

Question: The meter was not tagged by the technicians during the visit?
UNS electric's meter is working properly and will not be replaced.

From: Trish Meeter [mailto:TMeeter@azcc.gov]
Sent: Thursday, September 18, 2008 11:11 AM
To: ACC Complaints - All
Subject: ACC Complaints: Jazwin, Mary - Complaint No. 71541

Please see the attached complaint. It is in PDF format.

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MOHAVE COUNTY PLANNING AND ZONING
COMPLAINT FORM

Permits Plus #: _____

Address of Alleged Violation: 2160 E Hearne Ave

Legal Description: New Kingman Addition, Unit 11, Block 185, Lot 6, Tract 1104 **T:** 22N **R:** 16W **SEC:** 30

APN: 324-23-206 **Zoning:**_____ **Lot Size:** .14 Acres **Allowable OLS:**_____

Owner: Mary Ellen Jazwin

Owner Address: 2160 E Hearne Ave Kingman, AZ 86401

Occupant (If Known): Owner

Nature of Complaint: I Received a call from office about a dangerous electrical problem and was told to meet Uni Source at above address. Steve Jacobson from Uni Source informed me that a wire in the electrical panel box was not making complete contact and how they would de-energize the system so it could be repaired but this was the home owner responsibility to make the repair. The owner felt that the expense should be Uni Source's.

I knocked at the door many times with no answer. The Uni Source rep. brought John and I back to the box to see the item in question. We viewed a wire with signs of burn marks, John asked the Uni Source Rep. if he could tighten the lug to secure the wire, the screw did turn but just slightly.

The owner came out and asked who we were are and I informed her who we were and gave her my business card.

She informed me that she had problems with lights flickering and that was why she contacted Uni Source and they informed her to seek an electrician. The owner felt that Uni Source should make the repair. I informed the owner that I was called based on a dangerous condition and that I would gather all information and let her know my recommendation. The owner asked if I could also give her a copy of the same recommendation in writing and I agreed.

The owner asked Uni source to leave her property and asked John & I in to see the receipt she had gotten from Walker Electric and we came in. She could not find the receipt I then informed the owner that I would make my recommendation based on the information available to me and would let her know in writing what would come next.

The owner informed me that she had a load test performed on the panel and it passed. I informed the owner that the wire showed signs of fire and /or arcing and I could not ignore what I had seen. I informed the owner that the County's position was to maintain safety. I asked her for her phone number so that she could be contacted and she proceeded to give me her name, address, phone number and all of her degrees. I informed her all we needed was her number and John wrote the number on a card. We left and I called Mike to inform him of what was happening and said I would come to the office to go over my recommendation with him. I asked if we could have a letter drafted to present to the home owner.

I sent an E- mail to the secretary and CC Mike.

Received By: D. Chapman Date: 9-19-2008

Inspector: DC/JF Inspection Date/Time: 9-19-2008 10:00 am

Status: Letter to be sent to owner with recommendation to have the wire repaired .

___X_ Setup Case **_____ Unfounded**

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Richard Martinez Phone: (520) 628-6556 Fax: (520) 628-6559

Priority: Respond Within Five Days

Complaint No. 2008 - 71205 Date: 9/4/2008

Complaint Description: 04D Service - Not Working
N/A Not Applicable

	First:	Last:	
Complaint By:	Solange	Gutierrez	
Account Name:	Solange Gutierrez		Home: (520) 375-7740
Street:	890 W. Diaz Lane		Work:
City:	Nogales		CBR:
State:	AZ Zip: 85621		is:

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard Contact Phone: (520) 884-3651

Nature of Complaint:

Customer called to complain that her air conditioner and her clothes dryer can not be operated due to a problem with her 220 line feeding her home. Unisource told this customer not to use her 220 line until they can get someone to dig the hole and see what the problem is.
Customer has only been able to use the swamp cooler to her home and wants to know how much longer her 220 line will be out for. Customer said her neighbor had the same problem recently but her work was fixed right away.

Why caused this problem?

Why is Unisource not placing a higher priority in restoring full services to this customer.

Please investigate this matter.
End of Complaint

Utilities' Response:

Investigator's Comments and Disposition:

Pending
End of Comments

Date Completed:

Complaint No. 2008 - 71205

BeVard, Brenda

From: ACC Complaints - All
Sent: Thursday, September 11, 2008 4:03 PM
To: 'Richard Martinez'
Subject: ACC Complaints: Gutierrez, Solange - SC UNSE Complaint No. 71205: 04D Service-Not Working (Acct# 1434000000)
Attachments: rpt_Complaint_EmailPDF.pdf

Tom Hoyt, UNS Electric, Inc.'s ("UNS Electric") Superintendent spoke with Ms. Gutierrez regarding her electric service. Repairs to Ms. Gutierrez's electric service line were completed on Sunday September 7, 2008 and Ms. Gutierrez has been notified.

Mr. Gutierrez appeared happy to know that the line was replaced and thanked Mr. Hoyt for calling her.

From: Richard Martinez [mailto:RMartinez@azcc.gov]
Sent: Thursday, September 04, 2008 11:43 AM
To: ACC Complaints - All
Subject: ACC Complaints: Gutierrez, Solange - Complaint No. 71205

Please see the attached complaint. It is in PDF format.

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ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Richard Martinez Phone: (520) 628-6556 Fax: (520) 628-6559

Priority: Respond Within Five Days

Complaint No. 2008 - 71197 Date: 9/4/2008

Complaint Description: 04D Service - Not Working
N/A Not Applicable

	First:	Last:	
Complaint By:	Montie	McGovern	
Account Name:	Montie McGovern		Home: (520) 761-1578
Street:	2174 W. Frontage Road		Work:
City:	Tubac		CBR:
State:	AZ Zip: 85646		is:

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard Contact Phone: (520) 884-3651

Nature of Complaint:

Customer is upset as he had Unisource (about 20 years ago), called Citizen's Electric at this time, place a line coming off the electric pole which sits about 500 yards away from the Frontage Road to service both his home and his guest house on separate lines. A swimming pool is also serviced by the 220 line that also serves the guest house. This 220 line services both the pool and guest house went out about 3 weeks ago.
When the line was dug up to see what has happened it appears that about 6 years ago when a backhoe hit this line and was repaired with splice as Unisource ran a new wire from that location going back towards the guest house, that this could be the cause of the current outage. Maybe this line has been wet at the splice causing an outage?.

Unisource is now wanting the customer to put a pedestal a few feet away from the electric pole. Customer believes this may be due to the fact that Unisource does not want to take responsibility up to the current point of attachment.

Please investigate the issues concerning the customer's address.
End of Complaint

Utilities' Response:

Investigator's Comments and Disposition:

Pending
End of Comments

Date Completed:

Complaint No. 2008 - 71197

BeVard, Brenda

From: ACC Complaints - All
Sent: Thursday, September 11, 2008 3:59 PM
To: 'Richard Martinez'
Subject: ACC Complaints: McGovern, Montie - SC UNSE Complaint No. 71197: 04D Service - Not Working (Acct# 5261510000 and 9448120000)
Attachments: rpt_Complaint_EmailPDF.pdf

On August 19, 2008 Carlos Parra, UNS Electric, Inc.'s ("UNS Electric") Planner received a service order with a request to meet with the customer regarding a damaged service wire.

Mr. Parra met with Mr. McGovern and Teo Cordero, Electrician, to review the underground service to the guest house. The underground service to the guest house is 425' long and it is a separate service from the main house . Both services come from a 10kva pad mount transformer (xfmr). Mr. Parra requested Mr. McGovern and Mr. Cordero to expose the existing trench so that he can inspect the service line.

On August 25, 2008 Mr. McGovern called Mr. Parra and informed him that the trench was exposed and ready for inspection by UNS Electric. Mr. McGovern was out of town when Mr. Parra met with Mr. Cordero for the inspection. Mr. Parra did not find any signs of damage to the conduit in the open trench.

Arturo Lorta, UNS Electric's Senior Planner, met with Mr. McGovern on September 5, 2008 and explained to him that UNS Electric provides the first service at no cost, however additional services to the same lot incurred additional charges.

As of September 9, 2008 Mr. McGovern was unable to provide evidence that Citizens had installed the existing second service and agreed to UNS Electric's terms and conditions for a second service installation.

From: Richard Martinez [mailto:RMartinez@azcc.gov]
Sent: Thursday, September 04, 2008 11:47 AM
To: ACC Complaints - All
Subject: ACC Complaints: McGovern, Montie - Complaint No. 71197

Please see the attached complaint. It is in PDF format.

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ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Richard Martinez Phone: (520) 628-6556 Fax: (520) 628-6559

Priority: Respond Within Five Days

Complaint No. 2009 - 74458 Date: 1/9/2009

Complaint Description: 05G Quality of Service - Pressure/Voltage
N/A Not Applicable

	First:	Last:	
Complaint By:	Dara	Mora	
Account Name:	Office Manager-Rio Rico Water Company		Home: (000) 000-0000
Street:	Rio Rico		Work:
City:	Rio Rico		CBR: 520619-1573
State:	AZ Zip: 85648		Is:

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard Contact Phone: (520) 884-3651

Nature of Complaint:

Customer said she has been experiencing voltage fluctuations causing the pumps to burn out and breakers to not work on the sewer pump.

The location of this is on Stable Lane.

The sewer location is on Circulo Mercado

***Customer claims that they have been working on these fluctuations on an on-going basis in order for their customers to continue receiving water and sewer service without any interruptions. The breakers continue to trip: therefore, causing temporary outages.

**Also, why is the Emergency Line not working? According to customer she called Unisource on Monday night beginning at around 8 PM and the line was busy as no one answered the phones.
Also, on Wednesday morning at around 6:30 a.m. until around 8:30 a.m. when customer was attempting to reach the Unisource emergency line there was not answer and no one called back

Please Investigate
End of Complaint

Utilities' Response:

Investigator's Comments and Disposition:

Pending
End of Comments

BeVard, Brenda

From: ACC Complaints - All

Sent: Wednesday, January 21, 2009 4:05 PM

To: 'Richard Martinez'

Subject: ACC Complaints: Mora, Dara - SC UNSE Complaint No. 74458: 05G Quality of Service - Pressure/Voltage (Acct# 0578500000) Responded 1/21 (Nazar provided an update on 3/17)

Attachments: rpt_Complaint_EmailPDF.pdf

Tom Hoyt, UNS Electric, Inc. ("UNS Electric") Superintendent, is making arrangements to meet with Ms. Mora regarding UNS Electric's investigation into voltage fluctuations. A recording chart was set to measure the voltage from January 13, 2009 through January 17, 2009. The results confirmed that UNS Electric 's equipment is functioning properly.

Annette Setherley, UNS Electric Office Specialist, spoke with Ms. Mora on January 14, 2009 and explained that on Monday, January 5, 2009 UNS Electric's emergency line received one call from Rio Rico properties at 8:45 pm reporting low/fluctuating usage. Ms. Setherley explained to Ms. Mora that on Monday night the after hours answering service reported they did not have a heavy call volume from the Nogales/Rio Rico area. On Wednesday, January 7, 2009 there was a large outage in Nogales and this may be why Ms. Mora experienced a busy signal. Ms. Mora thanked Ms. Setherley for calling. Ms. Setherley also advised Ms. Mora that she will be hearing from Mr. Hoyt regarding the voltage fluctuations that Rio Rico Water Company is experiencing.

Rio Rico Utilities has two 88 horse power motors each pulling amps when running and pull over 600 amps during start-up. UNS Electric's voltage is approximately 280 when the motor is off, it then dips to 245 during start up, and recovers to approximately 278 during running mode. UNS Electric's investigation indicates that there is a voltage sag and it is due to the heavy amp requirement during motor start-up on the customers side of the meter.

From: Richard Martinez [mailto:RMartinez@azcc.gov]
Sent: Friday, January 09, 2009 11:55 AM
To: ACC Complaints - All
Subject: ACC Complaints: Mora, Dara - Complaint No. 74458

Please see the attached complaint. It is in PDF format.

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BeVard, Brenda

From: Sandoval, Donovan
Sent: Tuesday, March 17, 2009 4:24 PM
To: BeVard, Brenda
Cc: Couture, David
Subject: SCUNSE Dora Mora Complaint 74458: Rio Rico Utilities/341 Stable Lane (Update from Nazar)

FYI

-----Original Message-----
From: Dhahir, Nazar
Sent: Tuesday, March 17, 2009 11:19 AM
To: Hoyt, Tom
Cc: McAdams, Don; Sandoval, Donovan; Rios, Jeremiah; Darmitzel, Bill
Subject: Re: Rio Rico Utilities

Tom,

Yesterday, Jeremiah and I met with Dara and her boss to discuss their complaint of voltage sags and subsequent motor trips at 341 Stable lane and 1225 Avenida Gloriosa. They claimed that the motors were tripping on phase to phase unbalance exceeding 15%. We presented our charts for 341 Stable lane and showed that their weren't any phase to phase unbalance exceeding 1.6% which is below the recommended ANSI limit of 3%. We also explained that the large magnitude and duration (6 sec) of the voltage sags were due to their motor starts and beyond our control. We recommended that they check their motor undervoltage protection settings for magnitude and time delay to compare it to the actual sags.

As to the overvoltage at 1225 Avenida Gloriosa, they indicated that Unisoruce had adjusted the tabs on the transformer a couple of years ago to help with the sags at this location. They wanted to keep the tabs as is. So there is nothing we need to do here.

Their final concern was that these charts weren't recorded under heavy loading and thus aren't representative of the actual situation. They complained that when a problem occurs they don't get the recorder till a week later when the problem is already gone. We gave them Jeremiah's and my number to call directly when the problem occurs and we will get them a recorder on the same day if there is one available. This seems to make them feel much better and appreciative of our efforts.

Nazar,
3509

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Reg Lopez Phone: (520) 628-6555 Fax: (520) 628-6559

Priority: Respond Within Five Days

Complaint No. 2009 - 77437 Date: 3/11/2009

Complaint Description: 05E Quality of Service - Outage/Interruptions
N/A Not Applicable

	First:	Last:	
Complaint By:	Marcela	Seel	
Account Name:	Marcella Seel		Home: (000) 000-0000
Street:	801 S. San Pedro Rd		Work:
City:	Golden Valley		CBR: Cleopatra525252@aol.com
State:	AZ Zip: 86413		is: E-Mail

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard Contact Phone: (520) 884-3651

Nature of Complaint:

**********CHAIRMAN MAYES AND COMMISSIONER NEWMAN REFFERRAL**********

From: Cleopatra525252@aol.com [mailto:Cleopatra525252@aol.com]
Sent: Sunday, March 08, 2009 6:01 PM
To: Newman-Web
Subject: about UniSource Power Outages !!!!!!!!!!!!!!!!!!!!!!!!!

Saturday Morning the 3-7-09 the Power went OUT again at 7:05 AM till 8:20 AM !!!!!!!!! this time it WASN'T Mother Nature either since they like this for an Excuse every time when it happens !!!!!!!!!!! i called them,was on HOLD for over 20 Minutes what is OUTRAGEOUS !!!!!!!!!!! this House is only 5 Years old & the Temperature went down to 65 Degrees,i have a Cold from Hell & to get it to warm back up to 70 Degrees took a lot of Electricity also for the Hot Water Tank !!!!!!!!!!! is this a new way for UniSource to make Money ????? like they aint getting enough now thanks to you all !!!!!!!!!!!! this keeps on going i'll have UniSource & you all INVESTIGATED !!!!!!!!!! enough is enough !!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!!

ATTENTION UNISOURCE: PLEASE SEE INVESTIGATORS COMMENTS.

PLEASE CONTACT THE CUSTOMER AND ADDRESS THE REFERENCED POWER OUTAGE AND ANY HISTORY OF OUTAGES IN THE AREA.
End of Complaint

Utilities' Response:

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator's Comments and Disposition:

I replied to the consume with the following:

Dear Consumer:

On behalf of Chairman Mayes and Commissioner Newman, this is in acknowledgement of your e-mail. I would be more than happy to look into the outages that you reference to in your e-mail, but I would need more information from you. If you could provide me with your name, street address with city and zip code, inclusive of other dates and times of past outages, I can initiate an investigation into this matter. If you could please respond by Monday, March 16, 2009, I can commence my investigation. I look forward to your reply.

Sincerely,

Reg Lopez
Public Utilities Consumer Analyst II
Utilities Division-Tucson Office

1-800-535-0148 or (520) 628-6555

3-11 Follow up for 3-17.

3-11 Received the following customerreply:

From: Cleopatra525252@aol.com [mailto:Cleopatra525252@aol.com]
Sent: Wednesday, March 11, 2009 5:39 PM
To: Reg Lopez
Subject: Re: about UniSource Power Outages !!!!!!!!!!!!!!!!!!!!!!!!

Mr. Lopez,
my Name: Marcella Seel
801 S. San Pedro Rd
Golden Valley/AZ 86413
Date & Time of Power Outage :
Saturday Morning the 3-7-09 from 7:05 AM till 8:20 AM !!!!

Sincerely,
Marcella Seel

3-12 I repilled to the customer with the following:

Dear Ms. Seel,

Thank you for your reply. I have forwarded this matter to Unisource Energy for their reply regarding the referenced outage and previous outage in your area. Please allow five business days for a reply.

Sincerely,
Reg Lopez
Public Utilities Consumer Analyst II
Utilities Division-Tucson Office

3-12 E-mailed to Unisource @ 10:10 am.

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

3-13 Received the following from the customer:

From: Cleopatra525252@aol.com [mailto:Cleopatra525252@aol.com]
Sent: Friday, March 13, 2009 5:30 PM
To: Reg Lopez
Subject: Re: about UniSource Power Outages !!!!!!!!!!!!!!!!!!!!!!!!!!

Thank you for your Help !!!!!!!!!!!!!!!! M.S
End of Comments

Date Completed:

Complaint No. 2009 - 77437

BeVard, Brenda

From: ACC Complaints - All
Sent: Monday, March 30, 2009 3:30 PM
To: 'Richard Martinez'
Subject: ACC Complaints: Seel, Marcela - UNSE Complaint No. 77437: 05E Quality of Service - Outage/Interruptions (Acct# 2018600000)
Attachments: rpt_Complaint_EmailPDF.pdf

Bill DeJulio, UNS Electric, Inc. ("UNS Electric") General Manager called Mrs. Seel and left a message asking her to return his call regarding her concerns.

Upon review of the trouble orders related to Mrs. Seel service area, UNS Electric believes that the majority of the service interruptions are related to storm activity (lightning). UNS Electric intends to patrol and investigate the lines in the area in question.

Since June 2008, Mrs. Seel has been effected by a number of service interruptions which were related to four (4) transmission interruptions (flicker of lights), six (6) transmission related outages and six (6) distribution related interruptions.

Until March 7, 2009, UNS Electric records indicated that Mrs. Seel had not experienced an interruption to her service since October 7, 2008. The transmission outage on March 7, 2009 was caused by a transformer failing at a customer owned substation.

UNS Electric understands Mrs. Seel 's concerns and frustration and apologizes for any inconveniences caused by the service interruptions.

From: Reg Lopez [mailto:RLopez@azcc.gov]
Sent: Monday, March 23, 2009 1:44 PM
To: ACC Complaints - All
Subject: ACC Complaints: Seel, Marcela - Complaint No. 77437

Please see the attached complaint. It is in PDF format.

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ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Carmen Madrid Phone: (602) 542-0848 Fax: (602) 542-2129

Priority: Respond Within Five Days

Complaint No. 2009 80528 Date: 7/21/2009

Complaint Description: 05E Quality of Service - Outage/Interruptions
N/A Not Applicable

	First:	Last:	
Complaint By:	John	Brock	
Account Name:	John Brock		Home:(0 00) 000-0000
Street:	n/a		Work:(0 00) 000-0000
City:	Dolan Springs		CBR:
State:	AZ Zip: 00000		Is:

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard Contact Phone: (520) 884-3651

Nature of Complaint:

From: Studio [mailto:junostudio@frontiernet.net]
Sent: Monday, July 20, 2009 9:19 AM
To: Utilities Div - Mailbox
Subject: Can You Help Me?

Hello,

I'd like to know if I have any recourse against a power company that provides sub-standard service.

I live in Dolan Springs and had I known that UniSource cannot supply reliable power, I would have never moved here. My power has gone out 8 times just this month (5 times on July 3rd). I call and complain and have even asked to speak to a supervisor but am ignored. I realize sometimes there are weather conditions that may affect service, but many times it's a beautiful day and the power goes out for no apparent reason. If I went back and dug up all the calendar notes in my files for the past 4+ years, I'm sure my power has been interrupted over 50 times. I've had it checked and it's not me - it's UniSource. I'm sure Kingman has better service. Altho it's 35 miles away and I'm out in the boonies, that shouldn't be a factor. I pay for my power on time every month even tho the service is completely unacceptable. Don't I have the right to expect reliable service? Doesn't UniSource have to meet acceptable standards?

I cannot find another company that serves this area, so UniSource must be a monopoly and I suspect their inadequate service may be due to outdated equipment. Aren't they required by law to provide acceptable service? I get excuses all too often that 'a bird flew into a transformer'. Sounds very bogus!

To make it even worse, I'm in the music industry and am trying to record an album. My home is all electric so when my power goes out repeatedly, it interferes with my livelihood and is costing me money. This IS the 21st century and there's no excuse for such bad service. I sunk everything into moving here and buying my home, so it's not a simple solution to move. I've spent about $5,000 for power since I've been here, and I expect (and am entitled to) better service. If it isn't dependable, then what's it worth?

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

I don't want to file a complaint but for now that seems to be the only thing I can do. I spoke to a UnlSource supervisor over a year ago, and the service has not improved. After awhile, this becomes hell on your nerves! I cannot live like this.

Your input would be very helpful. Thank you in advance,

John Brock

Is the area where this person lives experiencing an large number of outages?
Has he contacted the company recently to express his situation?
How many times has he contacted UNS regarding service outages?
Is there a problem with the equipment that supplies power to this person?
End of Complaint

Utilities' Response:

.

Investigator's Comments and Disposition:

7/24/09 e-mailed to UNS
End of Comments

Date Completed:

Complaint No. 2009 - 80528

BeVard, Brenda

From: ACC Complaints - All
Sent: Friday, July 31, 2009 3:42 PM
To: 'Carmen Madrid'
Subject: ACC Complaints: Brock, John - UNSE Complaint No. 80528: 05E Quality of Service - Outage/Interruptions Acct# 7928020000
Attachments: rpt_Complaint_EmailPDF.pdf

Jim Blem, UNS Electric, Inc. ("UNSE") Construction Supervisor spoke with John Brock on July 28, 2009 regarding outages in his service area. UNSE has had several outages in Mr. Brock's area, which occurred because of different causes. An unreliable system was not the cause for these outages. Mr. Blem reviewed the dates and causes for the outages in question with Mr. Brock. Mr. Brock was pleased that Mr. Blem contacted him and said he understood the reasons for these outages.

Regarding the number of outages experienced in this area; UNSE has recently built a new 69 kV line up Pierce Ferry Road with a 559AAAC feeder circuit on it. Customers who live 35 miles out of town in the "boonies" as referred to in the complaint, are serviced through this line which is 15 miles south of Kingman all the way passed Hoover Dam, in total about 85 miles of line. Although it may be clear weather in one area of the line, a storm or wildlife may be causing a problem further down the line which may result in an outage.

Newly built UNSE facilities have bird protection on it. The older areas do not have bird protection at this time, but when there is scheduled maintenance or an outage, UNSE is putting bird protection on the facilities.

Question: Is the area where this person lives experiencing an large number of outages?
Please refer to the explanation above.

Question: Has he contacted the company recently to express his situation?
Yes, on July 15, 2009.

Question: How many times has he contacted UNS regarding service outages?
9

Question: Is there a problem with the equipment that supplies power to this person?
No.

From: Carmen Madrid [mailto:CMadrid@azcc.gov]
Sent: Friday, July 24, 2009 3:40 PM
To: ACC Complaints - All
Subject: ACC Complaints: Brock, John - Complaint No. 80528

Please see the attached complaint. It is in PDF format.

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ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Deb Reagan Phone: (602) 364-0236 Fax: (602) 542-2129

Priority: Respond Within Five Days

Complaint No. 2009 80829 Date: 8/4/2009

Complaint Description: 19A Other - Damages/Claims
01Z Billing - Other

	First:	Last:	
Complaint By:	Mavis J.	Sloan	
Account Name:	Mavis J. Sloan #099010000		Home:(9 28) 279-6473
Street:	2876 N. Mobile		Work:
City:	Golden Valley		CBR:
State:	AZ Zip: 86413		Is:

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard Contact Phone: (520) 884-3651

Nature of Complaint:

Customer says she has been trying to contact Unisource about a damage claim and was referred to the Commission. Customer says a Unisource outage caused damage to her new big screen tv. Customer wants to speak to someone about this.

Customer also says she has been trying to correct the mailing address on her account. It should be the same as her service address.

Do the Unisource records indicate this customer spoke with a rep regarding the damage claim?
If so, why was she referred to the Commission?
Do the records indicate that customer has called Unisource about the address issue?
When will customer's address be corrected?
What caused the customer's outage that resulted in damage to the tv?
End of Complaint

Utilities' Response:

Investigator's Comments and Disposition:

E-mailed to Unisource.
End of Comments

BeVard, Brenda

From: ACC Complaints - All
Sent: Thursday, August 06, 2009 10:19 AM
To: 'Deborah Reagan'
Subject: ACC Complaints: Sloan, Mavis J. - UNSE Complaint No. 80829: 19A Other - Damages/Claims Acct# 0990100000
Attachments: rpt_Complaint_EmailPDF.pdf

Anette Setherley, a UNS Electric, Inc. ("UNSE") Representative, spoke with Mavis Sloan on August 5, 2009 regarding her service.

Ms. Setherley explained to Ms. Sloan that UNSE received an official address change request from the County today, August 5, 2009. Ms. Setherley verified with Ms. Sloan that her address has been corrected to 3384 N Mobile Drive in Golden Valley and that her next bill will be mailed to that address.

Ms. Setherley told Ms. Sloan that a company representative from the Damage Claims department would contact her. Ms. Sloan requested that they contact her daughter, Paula Ciesvko who is actually living at the service address. Paula Ciesvko will be added to the account as a contact person as requested by Ms. Sloan.

Pursuant to its Rules and Regulations, UNSE does not guarantee the constancy of its voltage or frequency, nor does it guarantee against its loss of one or more phases in a three-phase service. The Company will not be responsible for any damage to the Customer's equipment caused by any or all of these occurrences brought about by circumstances beyond its control.

Question: Do the Unisource records indicate this customer spoke with a rep regarding the damage claim?
Yes, on August 4, 2009 Paula Ciesvko called and reported a claim for damages.

Question: If so, why was she referred to the Commission?
The call between the customer and a UNSE Representative on August 4, 2009 was reviewed and the representative did not refer the customer to the Commission.

Question: Do the records indicate that customer has called Unisource about the address issue?
No. The County requested the address change.

Question: When will customer's address be corrected?
The address was corrected on August 5, 2009.

Question: What caused the customer's outage that resulted in damage to the tv?
The customer's service was interrupted on August 4, 2009 due to an equipment malfunction.

From: Deborah Reagan [mailto:DReagan@azcc.gov]
Sent: Tuesday, August 04, 2009 2:16 PM
To: ACC Complaints - All
Subject: ACC Complaints: Sloan, Mavis J. - Complaint No. 80829

Please see the attached complaint. It is in PDF format.

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ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Carmen Madrid Phone: (602) 542-0848 Fax: (602) 542-2129

Priority: Expedite

Complaint No. 2009 80997 Date: 8/10/2009

Complaint Description: 05F Quality of Service - Can't Reach Company
N/A Not Applicable

	First:	Last:	
Complaint By:	Fernando	Palomares	
Account Name:	Fernando Palomares		Home:(5 20) 281-2633
Street:	1591 W. Camino Alto		Work:(0 00) 000-0000
City:	Nogales		CBR:
State:	AZ Zip: 85621		Is:

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard Contact Phone: (520) 884-3651

Nature of Complaint:

Consumer states that he has been trying to contact company and can't get through. He states that the lights in his home has been flickering on an off for at least 1.5 hours. He contacted his neighbor and he is experiencing the same thing. He wants to know if the company can inform him what is happening and why.

Please contact consumer and respond to ACC
End of Complaint

Utilities' Response:

Investigator's Comments and Disposition:

8/10/09 e-mailed to UNS
End of Comments

Date Completed:

Complaint No. 2009 - 80997

BeVard, Brenda

From: ACC Complaints - All
Sent: Wednesday, August 12, 2009 8:38 AM
To: 'Carmen Madrid'
Subject: ACC Complaints: Palomares, Fernando - SC UNSE Complaint No. 80997: 05F Quality of Service - Can't Reach Company Acct# 4863220000
Attachments: rpt_Complaint_EmailPDF.pdf

Denise Quintero, a UNS Electric, Inc. ("UNSE") Representative, spoke with Fernando Palomares on August 10, 2009 regarding flickering lights at his premise.

Ms. Quintero placed a service order for Mr. Palomares and explained to Mr. Palomares that when he is having trouble with his electricity, such as flickering lights or a power outage, he has the option of contacting UNSE at (877) 837-4968 and select option 1 for an emergency to reach the next available representative. Mr. Palomares thanked Ms. Quintero for calling.

From: Carmen Madrid [mailto:CMadrid@azcc.gov]
Sent: Monday, August 10, 2009 11:54 AM
To: ACC Complaints - All
Subject: ACC Complaints: Palomares, Fernando - Complaint No. 80997

Please see the attached complaint. It is in PDF format.

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ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

Investigator: Richard Martinez Phone: (520) 628-6555 Fax: (520) 628-6559

Priority: Respond Within Five Days

Complaint No. 2009 - 81231 Date: 8/18/2009

Complaint Description: 04D Service - Not Working
N/A Not Applicable

	First:	Last:	
Complaint By:	Jon	Sandler	
Account Name:	Jon Sandler		Home: (520) 377-0205
Street:	1192 Zircon, #1		Work:
City:	Rio Rico		CBR:
State:	AZ Zip: 85648		Is:

Utility Company. Unisource ** Energy Services (UNS)

Division: Electric

Contact Name: Brenda Bevard Contact Phone: (520) 884-3651

Nature of Complaint:

Customer wants the following questions answered by UNS Energy.

I have 3 things I could use additional help with in getting Unisource to respond-
1) approx. 3 weeks ago I filed a complaint with Unisource after one of their many power outages damaged my stereo amplifier and DVD player. I have followed up twice with Customer Service (what a misnomer that is with UNS) only to be told that they have a record of my calls and someone will call me. No one ever does and it's getting ridiculous. I don't want to wait anymore. In years past, they sent you a form and then sent you a check. This isn't rocket science.

2) at approx. 8:45 am Saturday 8/15/09, the community I live in, Tubac, Az., had another of our power outages. It goes off so often it's crazy. Assuming it was just a normal problem, I did not call it in. When power was not restored by 9:45 , I called "emergency" and was told there had been no other calls so it must be my house. I checked all breakers and called back to say I found no problem and requested immediate service to restore electricity on a day that was to be at least 95 degrees. By 11;40 am, still no one had shown up and when I called in to find out why (again "emergency"), they now said it was community wide but had no idea when power would be restored. At 11:55, I was pulling out of my driveway and a UNS truck went past so I chased him down. He was looking for my house and told me he had not been alerted to a problem until after 11 am! Power was not restored until approx. 4 pm-over 7 hours without electricity! I would like answers to the following questions-
-what caused the outage?
-what took so long to restore power?
-I called at 9:45. Why was the guy not alerted until after 11 am and didn't show until 12? What is the benefit of calling "emergency" if it is not treated like an emergency?
-how can UNS not know when hundreds of homes suddenly go dead and off the grid? What can be done to alert them when there is a problem and not many people call to report it?
-most importantly, why does our power go out so often and what can be done to prevent this from happening so often?

ARIZONA CORPORATION COMMISSION

UTILITY COMPLAINT FORM

3) Power went off again sometime in the afternoon yesterday! I came home to all the clocks flashing again. What caused this?

I would appreciate any help you can be in getting Unisource to respond as a normal business (which had some competition) would/should. I would like my stereo equipment repaired or replaced and I would like to replace my frozen food which sat without electricity for 8 hours on Saturday.

****

Did Risk Management contact this customer since the time he filed for a damage/loss report?

What is causing the outages as described by this customer and what caused this huge delay in restoration of power?

Please contact customer and explain to him the reasoning behind the non-contact with customer and the fact that UNS continues to lose electrical services to its customers.

Please report your findings to the ACC.
End of Complaint

Utilities' Response:

Investigator's Comments and Disposition:

Pending
End of Comments

Date Completed:

Complaint No. 2009 - 81231

BeVard, Brenda

From: ACC Complaints - All
Sent: Thursday, August 20, 2009 4:27 PM
To: 'Richard Martinez'
Subject: ACC Complaints: Sandler, Jon - SC UNSE Complaint No. 81231: 04D Service - Not Working Acct# 3680220000
Attachments: rpt_Complaint_EmailPDF.pdf

Patty Tilghman, UNS Electric, Inc. ("UNSE") Claims Analyst spoke with Mr. Sandler on August 19, 2009 and explained that UNSE will not make a payment for damage claims related to a problem the Company could not have reasonably foreseen.

Please refer to UNSE Rules and Regulations, Section No. C (page 66).

C. Continuity of Service

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

1. Any cause against which the Company could not have reasonably foreseen, or made provision for (see Subsection 7.E.);

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

3. Curtailment, including brownouts or blackouts.

Brenda BeVard, UNSE Representative and Angelica Orta-Madrigal, UNSE Distribution Supervisor, spoke with Mr. Sandler on August 20, 2009 regarding outages; a request for a damage claim; and to answer Mr. Sandler's questions and concerns.

Customer's Questions:

What caused the outage?
Bad underground cable.

What took so long to restore power?
Emergency cable had to be installed between the transformer and the overhead line.

Why was the guy not alerted until after 11 am and didn't show until 12? What is the benefit of calling "emergency" if it is not treated like an emergency?
The first no power call UNSE received was at 8:55 am and a crew was dispatched to the area at 9:01 am. UNSE crews do not show up to individual houses (premise), they're routed to where the problem is located with the Company's facilities. It also takes time to locate the problem, especially when the problem is in the underground system. An additional crew was also dispatched to this location at a later time to assist with installation for emergency cable to restore power.

How can UNS not know when hundreds of homes suddenly go dead and off the grid? What can be done to alert them when there is a problem and not many people call to report it?
Generally when hundreds of premises are without power, UNSE receives a high volume of calls to report the outage. In this case, there were sixteen (16) premises without power. The first no power call was reported at 8:55 am. Power was restored for ten (10) premises at 12:41 pm and the remaining six (6) premises were restored at 4:14 pm.

Most importantly, why does our power go out so often and what can be done to prevent this from happening so

often?
There has been a variety of reasons for power outages, some localized, others wide spread. Some outages can be explained others cannot be. Unfortunately, that is the nature of the electric system. It is not until a pattern develops that further investigation is warranted. Nonetheless, the Company understands that our customers are burdened when experienced with any type of outage. UNSE takes outages very serious and works as quickly as possible to restore power.

Power went off again sometime in the afternoon yesterday! I came home to all the clocks flashing again. What caused this?
A temporary outage was required to remove the emergency cable and to repair and install the replacement cable.

Question by the Commission:

Question: What is causing the outages as described by this customer and what caused this huge delay in restoration of power?
These outages that have affected this service area are caused by a variety of reasons like equipment failure, which UNSE may not reasonably foresee, storms or safety hazards. In the case of the outage on August 15, 2009, a bad underground cable needed to be temporarily replaced by an emergency cable installed from the overhead line. This is a time consuming process.

From: Richard Martinez [mailto:RMartinez@azcc.gov]
Sent: Tuesday, August 18, 2009 11:04 AM
To: ACC Complaints - All
Subject: ACC Complaints: Sandler, Jon - Complaint No. 81231

Please see the attached complaint. It is in PDF format.

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ATTACHMENT 5

UNS ELECTRIC, INC.'S RESPONSE TO
STAFF'S EIGHTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
September 29, 2009

STF 8.11 Please provide a description of how UNS linemen, maintenance personnel, or "trouble man" personnel are directed to locations of customer complaints and what resources are available to such personnel to identify the distribution system aspects of the problem upon reaching the location of the complaint or outage.

RESPONSE: Work flow for trouble calls:

Santa Cruz County:
Customer calls customer service and reports issue. Between the hours of 7:00 a.m. and 7:00 p.m., the CSR (Customer Service Representative) enters information into Customer Care and Billing ("CC&B"); this data is interfaced into PowerOn, the outage management system. After 7:00 p.m. and before 7:00 a.m., the calls are directed to Kachina, UNS Electric's answering service. Kachina enters the outage data into ICALL (a program to enter trouble calls into PowerOn), an order is then generated by PowerOn and appears in the control window of PowerOn on the dispatchers screen. If this occurs during normal business hours, the dispatcher will make a phone call to the construction supervisor in Santa Cruz County and relay the information. The construction supervisor will then issue the order to a field technician. If the call is during off hours, the dispatcher calls the on call lineman and who responds at that point. Depending on the call, the field technician may call into the dispatch office for more detailed information or may just proceed to the address. If the field technician is required to operate any system devices he will contact the system supervisor for instructions.

Once the issue has been solved or identified, the field technician reports back to the dispatcher. The dispatcher enters data into the PowerOn order. If further work is required, the field technician can have the dispatcher write a work order in STORMS (Severn Trent Operational Resource Management System), the work management system. Also, the dispatcher may call or email the designer for the area if the work that is required is outside the scope of the dispatchers responsibilities.

If there is problem that is monitored thru the EMS (Energy Management System), the system supervisor or the dispatcher will call for a field technician before any customer calls are received. For incidents of this type, the field technician is typically in constant radio contact with the dispatch office. The same protocol is followed once the problem has been solved or identified.

Mohave County – Kingman / Lake Havasu:
Customer calls customer service and reports issue. Between the hours of 7:00 a.m. and 7:00 p.m., the CSR (Customer Service Representative) enters information into customer Care and Billing ("CC&B"); this data is then emailed

automatically into the UESDISP email inbox based on the dispatch priority the CSR places on the the trouble call. After 7:00 p.m. and before 7:00 a.m., the calls are directed to Kachina, UNS Electric's answering service. Kachina enters the outage data into ICALL (a program to enter trouble calls) the trouble call information is then automatically emailed into the UESDISP email inbox. The UniSource System Operator will then enter all the information received by the CSR or Kachina on to an ACCESS program trouble ticket. If this occurs during normal business hours the System Operator will call out the trouble information, on the radio, to the Lake Havasu or Kingman trouble truck lineman. If the call is during off hours the System Operator will then call the on call lineman in that district who will respond at that point. If the lineman is required to operate any system devices he will contact the System Operator for permission and instructions before doing so.

Once the issue has been resolved or identified, the lineman reports back to the System Operator. The System Operator will update the ACCESS program trouble ticket with all of the end result data. If further work is required, the lineman will request the System Operator to forward the information to the district Construction Supervisor or the district engineering group to complete the work or write up a new job request.

If there is a problem that is monitored thru the EMS (Energy Management System), the System Operator will notify the Construction and/or On Call Supervisor in addition to the district trouble truck lineman or on call lineman, via radio or phone, depending on the hour of day, before any customer calls are received. For incidents of this type, the Construction and/or On Call Supervisor in addition to the resonding lineman are typically in constant radio or phone contact the System Operations. The same protocol is followed once the problem has been solved or identified.

RESPONDENT: Thomas Q. Mills III (Santa Cruz) – Bill De Julio (Mohave, Kingman/Lake Havasu) -- Julie McCoy (Lead System Operator, Mohave, Kingman/Lake Havasu)

WITNESS: Thomas A. McKenna

EXHIBIT
S-8
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-04204A-09-0206

SURREBUTTAL

TESTIMONY

OF

W. MICHAEL LEWIS, P.E.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 15, 2010

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
E-04204A-09-0206

The surrebuttal testimony of W. Michael Lewis of W. M. Lewis and Associates, Inc. ("WML&A") presents certain observations and responses to the rebuttal testimony of Mr. McKenna filed on behalf of UNS Electric ("UNSE"). Specifically, Mr. Lewis's rebuttal testimony addresses UNSE's water supply and treatment facilities at the Black Mountain Generating Station ("BMGS"), the thermal scanning of the BMGS substation, and the contents of an annual report to the Arizona Corporation Commission ("Commission") regarding UNSE's distribution network indices.

With regard to the water supply and treatment facilities at BMGS, Mr. McKenna's rebuttal testimony described a nearly complete raw water supply project. This is a project we were not aware of at the time of the filing of direct testimony that addresses our concerns regarding sufficient water supply at the BMGS. On another matter, Mr. Lewis' direct testimony recommended annual thermal scanning of the BMGS substation. In Mr. McKenna's rebuttal testimony, he does not commit to the annual scanning of the BMGS substation. We continue to recommend that UNSE employ thermal scanning at the BMGS substation on an annual basis, but that this should not be contingent on a Commission order. In our view, such an order from the Commission is unnecessary and would be micro-managing UNSE's operations and maintenance programs.

Lastly, Mr. McKenna's rebuttal testimony does not object to the filing by UNSE with the Commission of an annual report regarding distribution network indices, but does object to the identification of the worst performing circuits. We believe that these circuits should be identified in an annual report since the indice values represent average performance in a service area, which can be misleading. This can be the case since some customers may be experiencing more outages (in frequency and/or duration) associated with the more poorly performing circuits.

Q. Please state your name and business address.

A. My name is William Michael Lewis. My business address is 934 Valley Street, Wheelersburg, Ohio 45694.

Q. Have you previously pre-filed testimony in this proceeding?

A. Yes.

Q. What is the nature of your Surrebuttal Testimony?

A. My Surrebuttal Testimony is in response to various references to my Direct Testimony presented in the Rebuttal Testimony of Mr. McKenna filed on behalf of UNS Electric, Inc. ("UNSE").

Q. Please cite these references and your responses.

A. At page 6 of his rebuttal, Mr. McKenna responded to my recommendation that UNSE address limitations on water availability as required for operations at the Black Mountain Generating Station ("BMGS"). Mr. McKenna presented a diagram of the station water supply and treatment facilities and explained that a project to increase raw water supply is apparently close to completion. This project evidently will increase the water supply by some 125 gallons per minute ("gpm").

Q. Does that address your concerns as to water limitations?

A. It does. I was not aware of this project when I prepared my Direct Testimony. I would note that this project does add a redundant source for about 53 percent of the raw water requirements which does address my concerns as to raw water supply. There are other considerations as to the requirements for treated (demineralized) water production and

storage, however, the added raw water supply does address the stated concerns in my Direct Testimony.

Q. Please continue.

A. Mr. McKenna responded to my recommendation that thermal scanning be employed at the BMGS substation on an annual basis. Mr. McKenna noted that UNSE selectively uses this scanning on an annual basis in some service areas, and will do so at the BMGS substation if ordered to do so by the Commission. I assume Mr. McKenna's statement indicates that UNSE will undertake annual scanning of the BMGS substation if ordered by the Commission.

Q. What is your response?

A. I do not understand the implied reluctance to employ thermal scanning at the BMGS substation. Thermal scanning is effective in locating, e.g., loose connections. UNSE apparently agrees as noted by Mr. McKenna's description of using scanning after maintenance at other substations. BMGS, as with peaking operations in general, subjects its associated station works to full thermal stress on a regular, if not daily, basis which can lead to poor connections and other bus problems. Given that UNSE evidently has the necessary equipment in-house or on-call and experience in the use of the results of thermal scans, it doesn't seem reasonable that such would not be employed at the BMGS substation or that it would require an order to do so.

Q. What was another of Mr. McKenna's references to your testimony?

A. At page 19, starting at line 20, Mr. McKenna stated that my testimony was "only partially accurate."

Q. How do you respond to that?

A. I can only state that my testimony as to UNSE's past practice of data collection was based upon my understanding of statements made during a meeting with the Tucson Electric Power personnel who were preparing the indices in response to our initial data requests regarding quality of service indices.

Q. Does Mr. McKenna's clarification affect your subsequent testimony?

A. No.

Q. Mr. McKenna does not agree with your recommendation that UNSE provides a listing of the worst performing circuits in an annual report of the distribution indices. How do you respond and why do you feel that such reporting is necessary?

A. The distribution indices represent an average performance in the affected service area or areas. If, in fact, some customers are experiencing much worse outages, either in frequency or duration, then otherwise acceptable values of indices are, or can be, misleading. A listing of the more poorly performing circuits can indicate to what extent that is the case, and what measures could be taken to mitigate the problems.

Q. How do you respond to Mr. McKenna's concerns as to the effect of such a submission?

A. I believe that Staff is aware of the problems inherent in addressing specific reliability problems as discussed by Mr. McKenna and will not have any unreasonable expectations as to the timing and nature of corrective actions. I do agree that this listing of specific circuits will result in an incentive to UNSE to address them in a timely manner.

Q. Are there other comments in Mr. McKenna's Rebuttal Testimony that you feel should be addressed?

A. Yes. Mr. McKenna stated at page 13 of his Rebuttal Testimony that my conclusion that the Call Center operates in an effective manner "further justifies" the costs for the Call Center as proposed by UNSE in Mr. Duke's Direct Testimony. I do not agree with that statement as the costs of the Call Center were not considered in my review of the operation and procedures of the Call Center. My only consideration was the Call Center's handling of the notification and restoration of service outages.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes.

EXHIBIT
S-9
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-04204A-09-0206

(PUBLIC)

DIRECT

TESTIMONY

OF

THOMAS H. FISH, PH.D.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 06, 2009

TABLE OF CONTENTS

Page

INTRODUCTION 1

REVENUE REQUIREMENT 6

RATE BASE 9

Orignal Cost Rate Base 10
Introduction *10*
Post Test-Year Non-Revenue Producing Plant in Service *11*
Working Capital *17*
RCND Rate Base 18
Introduction *18*
RCND Derivation *18*
RCND Example *20*
Pro Forma RCND Rate Base Adjustments *21*
FairValue Rate Base 22
Introduction *22*
FVRB Derivation *22*

OPERATING INCOME ADJUSTMENTS 23

Incentive Compensation and Executive Comp/Benefits (SERP and PEP) 23
Payroll Tax Expense (SERP/PEP) 24
Call Center 24
Industry Association Dues 26
Outside Legal Expenses 28
Fleet Fuel Expense 29
Rate Case Expense 30
Customer Assistance Residential Energy Support ("CARES") Discounts 31
Bad Debt Expense 32
Depreciation and Property Tax for Post test year plantin Service 34
Income Tax 34

AFFILIATE TRANSACTIONS 34

Introduction 34
Allocations and Pricing 36
Structure 40

DEPRECIATION RATES 40

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE 42

Introduction 42
Development and Operation of the PPFAC 43
Proposed Changes to PPFAC Interest Rate 47
Proposed Recovery of Credit Support Costs 48
Forward Component Cap 49

BLACK MOUNTAIN GENERATING STATION 50

Introduction 50
Background 51
Previous Commission BMGS Considerations 52

Broken Blade 54
BMGS Recommendation 54

PRUDENCE REVIEW OF FUEL AND PURCHASED POWER POLICY 56

Introduction 56
Organization, Staffing, and Controls 57
Fuel Management 60
Fuel and Purchased Power Contracts 61
Hedging and Risk Management 63
Forecasting and Modeling 65
Purchased Power and Off-System Sales 66
Conclusions 68
Recommendations 69

SCHEDULES

Schedules Accompanying
The Direct Testimony of Thomas H. Fish, Ph.D.

Schedule	Description
THF-1	Attachment 1, Resume of Thomas H. Fish, Ph.D.
THF-2	Attachment 2, Revenue Requirement Schedules
	Revenue Requirement
THF A-1	Computation of Increase in Gross Revenue Requirement
	Rate Base
THF B-1	Original Cost, RCND, and Fair Value Rate Base
THF B-2	Pro Forma Adjustments to Original Cost Rate Base
THF B-3	Lead/Lag Study Results
THF B-4	Post test year plantin Service
	Operating Income Adjustments
THF C-1	Adjusted Test Year Income
THF C-2	Income Pro Forma Adjustments
THF C-3	Incentive Compensation-PEP
THF C-4	Incentive Compensation-SERP
THF C-5	Payroll Tax Expense
THF C-6	Call Center Expense
THF C-7	Industry Association Dues
THF C-8	Legal Expenses
THF C-9	Fleet Fuel Expense
THF C-10	Rate Case Expense
THF C-11	CARES
THF C-12	Bad Debt Expense
THF C-13	Depreciation and Property Tax, Post Test Year PIS

EXECUTIVE SUMMARY
UNS ELECTRIC INC.
DOCKET NO. E-04204A-09-0206

My testimony addresses the following issues:

- The Company's proposed revenue requirement.
- Adjustments to test year data.
- Rate base
- Test year revenues
- Affiliate transactions
- Depreciation rates
- The Company's requested modifications to the Purchased Power and Fuel Adjustment Clause ("PPFAC") and Staff's proposed modification to the PPFAC
- Prudence review of the Company's PPFAC policies
- The Company's proposed ratemaking treatment for the Black Mountain Generating Station ("BMGS")

My findings and recommendations for each of these areas are as follows:

- The Company is proposing an increase in gross revenue requirement of $13,500,000 which represents a weighted average cost of capital of 10.38 percent (of which 1.34 percent is fair value adjustment). I am recommending an increase in gross revenue requirement of $7,517,565 which represents a weighted average cost of capital of 8.4 percent (plus a fair value adjustment of 1.5 percent on the increment in fair value rate base over original cost rate base).

- The following adjustments to UNS Electric's proposed original cost and fair value rate base should be made:

Summary of Staff Adjustments to Rate Base		**Original Cost**	**Fair Value**
Adj. No.	Description	Increase (Decrease)	Increase (Decrease)
B-3	Remove post test-year plant in service	($7,263,614)	($7,263,614)
B-4	Cash working capital – lead/lag study	($61,025)	($61,025)
	Total of Staff Adjustments	($7,324,639)	($7,324,639)
	UNS Proposed Rate Base	$175,818,913	$354,485,222
	Staff Recommended Rate Base	$168,494,274	$347,160,583

- The following adjustments to UNS Electric's proposed revenues, expenses and net operating income should be made:

Adj. No.	Description	Increase (Decrease)
C-3	Incentive Compensation PEP	($132,159)
C-4	Incentive Compensation SERP	($102,142)
C-5	Payroll Tax Expense PEP	($10,110)
C-6	Call Center Expense	($281,581)
C-7	Industry Association Dues	($40,792)
C-8	Legal Expense	($58,722)
C-9	Fuel Expense	($75,798)
C-10	Rate Case Expense	($66,667)
C-11	CARES Expense (Revenue Shortfall)	$61,797
C-12	Bad Debt Expense	($105,487)
C-13	Depr. & Property tax for Post TY PIS	($442,526)
C-2	Income Tax	$481,859
	Total of Staff Adjustments to Operating income	**$895,923**
	Company Adjusted Test Year Operating Income	$10,003,347
	Staff Adjusted Test Year Operating Income	$10,899,270

- The Company proposed technical updates to its depreciation schedules. The proposed schedules are reasonable and should be implemented.

- The Company proposed changing the PPFAC interest rate to London Interbank Offered Rate plus 1.0 percent and proposed including Credit Support Costs in PPFAC. I recommend leaving the interest rate based on the One-Year Nominal U.S. Treasury Constant Maturities Rate. This is consistent with the Commission's recent decisions regarding interest rates and will provide incentive for the Company to reduce the bank balance. I also recommend denying the request to include Credit Support Costs in PPFAC. Only Federal Energy Regulatory Commission accounts 501, 547, 555, and 565 that deal directly with fuel and purchased power costs should be included in PPFAC. I recommend that the forward component cap be updated to reflect the first year's operation of the PPFAC.

- With respect to affiliate transactions the Company is adhering to the National Association of Regulatory Utility Commissioners ("NARUC") guidelines for affiliate transactions. Based upon the information supplied by the Company, it appears they are complying with all of NARUC'S guidelines

- The Company's PPFAC policies are prudent with only minor modifications required. These include more frequent internal audits and use of Tucson Electric Power Company resources to minimize natural gas costs via pipeline availability analysis.

- The Company requested the Commission to authorize its purchase of BMGS and allow it to include the net purchase price in rate base as a post test-year plant in service adjustment. I recommend that the Commission deny this request. The Company was granted the ability to finance acquisition of the plant in its last rate case and chose not to do so. Since the Company does not own the plant now it should not be included in rate base.

INTRODUCTION

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

A. My name is Thomas H. Fish. I am President of Ariadair Economics Group. My business address is 1020 Fredericksburg Rd., Excelsior Springs, MO 64024.

Q. What does Ariadair Economics Group do?

A. Ariadair Economics Group provides expert witness and consulting services in administrative and judicial litigation proceedings.

Q. Please describe your educational background.

A. I hold a B.A. (1968) degree in Economics from University of Missouri at Kansas City, a M.A. (1970) degree in Economics from Central Missouri State University, and a Ph.D. (1972) degree in Economics, with minor areas of study in Finance and Marketing, from University of Arkansas.

Q. Please describe your professional experience.

A. I have provided expert witness and consulting services in Economics, Finance, Utility Regulation, Industrial Organization, and related areas in administrative and judicial litigation proceedings for over thirty years. I have also taught graduate and undergraduate college classes in Economics, Finance, Quantitative Methods, Financial Accounting, Managerial Accounting, Cost Accounting, Management and related classes.

I have provided expert testimony in a wide array of utility regulation proceedings regarding many issues. In addition, I recently provided testimony regarding Revenue Requirement and certain adjustments to Revenue Requirement, Original Cost Rate Base ("OCRB"), Reconstruction Cost New ("RCN"), and Fair Value Rate Base ("FVRB"),

Cost of Service ("COS"), Revenue Spread and Rate Design in the UNS Gas proceeding (Docket No. G-04204A-08-0571). UNS Gas is an affiliate of UNS Electric, Inc. My resume is attached as Attachment THF – 1.

Q. What is the purpose of your testimony in this case?

A. I have been directed by the Utilities Division of the Arizona Corporation Commission ("Staff") to review the rate application of UNS Electric, Inc. ("Company" or "UNSE") and to address the following issues: Revenue Requirement and certain adjustments to Revenue Requirement, OCRB, Reconstruction Cost New Depreciation ("RCND"), FVRB; Purchased Power and Fuel Adjustment Clause ("PPFAC"); Review of the Black Mountain Generating Station ("BMGS"); Review of affiliate transactions between the Company, UniSource Energy, and its other affiliates; Analysis of the appropriateness of the proposed depreciation schedules; and a Prudence Review of Fuel and Purchased Power Policy.

Q. Have you reviewed the Company's application for rate relief?

A. Yes. I have reviewed, analyzed and evaluated the Company's application, its proposed rate base, revenue requirement, pro forma adjustments, work papers in support of its pro forma adjustments, and its responses to data requests submitted by Staff and other participants in the proceeding. I have also visited the Company's BMGS plant in Kingman and its Valencia plant in Nogales as well as its Tucson Offices where I met and interviewed Company personnel regarding the above-mentioned issues.

The Company currently provides electric service to approximately 90,000 customers in Arizona. Staff's review of Consumer Services records indicates that UNS Electric had 408 Complaints, 300 Inquiries and 89 Opinions between January 1, 2006 and November

5, 2009. Except for one Complaint, all recorded issues have been fully resolved. Further, the Company is in good standing with the Corporations Division of the Commission.

Q. Have you prepared Attachments and Schedules in support of your testimony?

A. Yes, I have prepared the following:

Attachment	Topic
THF - 1	Thomas Fish Resume
THF - 2	A, B, and C Schedules

Q. Please explain the Attachment THF - 2 Schedules.

A. The A, B, and C Schedules are associated with the rate base/revenue requirement part of my testimony. They are largely consistent with the corresponding Company Application Schedules A, B, and C.

Q. Would you describe the THF A-1 Schedule?

A. The THF A-1 Schedule summarizes the results of my analysis of the Company's rate request. It presents the Company's proposed OCRB, RCND, and FVRB from the Company's A Schedules and Staff's OCRB, RCND, and FVRB from Staff Schedules THF B-1 and THF C-1. It also provides a summary of operating income, rate of return, required return, required operating income, operating income deficiency, and increase in gross revenue requirement as requested by the Company and recommended by Staff.

Q. Would you describe the THF B Schedules?

A. These are Schedules showing derivation of Staff's OCRB, RCND, and FVRB. Schedule THF B-1 provides a summary of the adjustments to OCRB and RCN rate bases and the

resulting FVRB for Company and Staff. The adjustments for Schedule THF B-1 are derived from Schedule THF B-2. Schedule THF B-2 presents the individual Staff adjustments to OCRB. Since, as discussed in detail below, test year values for OCRB and RCND for expenditures made and expenses incurred during the test year are the same, an additional Schedule for the adjustments for RCND is not required. Staff has made two pro forma adjustments to OCRB and RCND rate base. These are removal of the Company's proposed Post-Test Year Plant in Service adjustment and Working Capital Adjustment. The Working Capital Adjustment is necessary to adjust Cash Working Capital requirement for pro forma income and expense adjustments made by Staff. This is shown in Schedule THF B-3. Removal of the Company's Post-Test Year Plant in Service adjustment is shown in Schedule THF B-4.

Q. Would you describe your THF C Schedules?

A. The test-year income statement is shown in Schedule C-1. This Schedule presents adjustments to the Company's proposed Test Year Income Statement that are summarized on Schedule THF C-2 and then used for Schedule THF C-1. Schedule THF C-2 provides a summary of the individual income and expense pro forma adjustments made by Staff. These individual Schedules are show in Schedules THF C-3 through THF C-13.

Q. Were these Schedules prepared by you or under your supervision?

A. Yes.

Q. Would you provide an overview of the process involved in identifying the Company's revenue requirement?

A. The Company's rate base, capital, revenues and operating expenses for the test year are determined from its books and records. Then necessary pro forma adjustments are made

to rate base, capital, revenues and operating expenses, to reflect values that can reasonably be expected to occur over a normal or representative year (the test year). The Company is provided the opportunity to recover its cost of service and earn a return on capital investment (rate base). The required return on capital committed to the enterprise is determined via a financial and economic analysis. In this case Mr. Parcell conducted the cost of capital analysis.

Q. Would you explain the concept of test year?

A. Yes. The cost of providing service is determined on the basis of a test year. A test year reflects a level of operating revenues and expenses and net plant investment that is representative of normal conditions that are expected to exist when the resulting rates are in effect.

Q. What test year did the Company use?

A. The Company used a historic test year ending December 31, 2008.

Q. How is the cost of providing service determined?

A. Regulated utilities such as UNS Electric should be provided the opportunity to recover their cost of providing service, including an opportunity to recover their capital cost. Rates for utility services are set by utility regulators, in this case the Arizona Corporation Commission, so that utilities have an opportunity to recover these costs incurred in the provision of service. This determination is made with reference to a normal, representative, or test year.

Q. What is required to determine the proper, or representative, level of expense, revenues, and investment?

A. In a rate proceeding, test year rate base, revenues and expenses are evaluated and necessary adjustments are made to reflect values that are representatives of cost of service, on an on-going basis. Some rate base items such as plant in service and accumulated depreciation are based on end of test year levels. Other rate base items such as materials and supplies are based on a test year average level. Certain expense items such as payroll and payroll tax expense are annualized. Expense items that have been incurred, but are not necessary for the provision of service, are removed from the test year. In addition, some expense items, such as legal expense, may occur on ongoing but irregular intervals and require adjusting to normal levels. So some items may require no adjustments, some may require removal, some may require annualization and some may require normalization. After all these adjustments have been made, test year operating income is compared to required operating income and, if a shortfall exists, rates are set to provide the utility the opportunity to recover its cost of service and earn its authorized rate of return.

REVENUE REQUIREMENT

Q. What revenue increase has UNS Electric requested?

A. UNS Electric requested an increase in revenues of $13,500,000 or about an 8.5 percent increase over test year revenue.

Q. What are the reasons given for the requested increase in revenues?

A. According to Company witness DeConcini, there are three reasons for the request: (1) the Company's rate base has grown significantly; (2) the Company's operating costs have increased; and (3) its return on equity has deteriorated substantially.

Q. Does Staff agree with the Company's request?

A. Staff has some disagreements with certain adjustments the Company made and with certain adjustments the Company did not make. Staff's finding and recommendations are presented in the THF A, THF B, and THF C Schedules.

Q. What revenue increase does Staff recommend?

A. As shown on Schedule THF A-1, Staff has identified an operating income deficiency of $4,574,216 and is recommending an increase in gross revenue requirement of $7,517,565 or about 4.7 percent over test year revenue.

Q. Did Staff determine a Fair Value Rate of Return and its application to FVRB?

A. Yes. The Commission's traditional calculation of return on FVRB calculation has been called into question by a recent Arizona Court of Appeals ruling involving Chaparral City Water Company. In that ruling, the Arizona Court of Appeals found that Staff's determination of operating income in that case had ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona Constitution.

The Court of Appeals determined at pages 13-24, paragraph 17, that ". . . the Commission cannot ignore its constitutional obligation to base rates on a utility's fair value. The Commission cannot determine rates based on the original cost, or OCRB, and then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate of return. Such a method is inconsistent with Arizona law." Further, at page 13, "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

In Decision No. 70441, Docket No. W-02113A-04-0616, the Commission determined the rate of return on FVRB that was reasonable and appropriate for Chaparral City, noting that there are many methods the Commission can use to determine an appropriate FVROR, including the weighted average cost of capital to exclude the effect of inflation on the cost of equity, and that the FVROR adopted fell within the range of recommendations in that proceeding and reflected the Commission's exercise of its expertise and discretion in the ratemaking process.

Mr. Parcell addressed the cost of capital issue and developed a range of return on fair value rate base. The range determined by Mr. Parcell was 0 percent to 3 percent return on the increment between OCRB and FVRB. I have used the first moment about the mean, or mathematical expectation, of 1.5 percent to derive the return on FVRB as presented in Schedule A-1. This mid-point value was recommended by Mr. Parcell and represents a reasonable estimate of the fair value return.

Q. Other than rate of return, what are the major sources of the difference between the Company's request and Staff's recommendation?

A. The differences are as follows (the Staff values represent pro forma changes from Company proposed values. These are pro forma adjustments to rate base and operating income and are discussed in detail later in the testimony. The remainder of the difference between Company and Staff relates to cost of capital. This issue is addressed by Staff witness Parcell.

	Company Request	Staff
RATE BASE		
Post Test Year PIS	+$7,263,614	Remove
Working Capital		-$61,025

PRO FORMA INCOME AND EXPENSE	
Incentive Compensation PEP	-$132,159
Incentive Compensation SERP	-$102,142
Payroll Tax Expense PEP	-$10,110
Call Center Expense	-$281,582
Industry Association Dues	-$40,792
Legal Expense	-$58,722
Fuel Expense	-$75,798
Rate Case Expense	-$66,667
CARES Expense (Revenue shortfall)	$61,797
Bad Debt Expense	-$105,487
Depr. & Prop tax for Post TY PIS	-$442,526
Income Tax	$481,859

RATE BASE

Q. Would you explain the regulatory concept of rate base?

A. Yes. Regulated utilities are provided the opportunity to recover the cost of the capital used to create the plant necessary to provide service. The capital cost is determined by multiplying the rate base (roughly equal to its capital structure) by the regulated utility's cost of capital (in percentage terms). The Arizona Corporation Commission rules require UNS Electric to file an OCRB and a RCND rate base. In addition, the Company's FVRB must be considered by the Commission in rendering its decision.

Q. What is an Original Cost Rate Base?

A. According to the Commission's definition[1] an OCRB is an amount consisting of the depreciated original cost, prudently invested, of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used or useful, plus a proper allowance for working capital and including applicable pro forma adjustments.

Q. What is a RCN Rate Base?

A. According to the Commission's definition[2] a RCN Rate Base is an amount consisting of the depreciated reconstruction cost new of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments.

Q. What is a Fair Value Rate Base?

A. A FVRB, as accepted and used by the Commission, is the arithmetic mean of the OCRB and RCND Rate Base.

Orignal Cost Rate Base

Introduction

Q. What was the Company's proposed OCRB?

A. The Company proposed a total OCRB of $164,679,539. This was based on gross utility plant in service of $454,177,170. Gross utility plant in service was adjusted by accumulated depreciation, Citizens Acquisition Discount, Accumulated Amortization of Citizens Acquisition Discount, Customer Advances for Construction, Customer Deposits, and Allowance for Working Capital. These adjustments to gross utility plant in service generated the adjusted OCRB.

[1] Title 14, Public Service Corporations, page 7 of 159.
[2] Ibid.

Q. Did the Company propose any pro forma adjustments to OCRB?

A. Yes. The Company proposed adjustments for Post Test-Year Plant in Service, Accumulated Deferred Income Taxes, and Working Capital.

Q. What was the adjusted OCRB proposed by the Company?

A. The Company's proposed adjusted OCRB was $175, 818,913.

Q. Are you proposing any pro forma adjustments to the Company's proposed adjusted OCRB?

A. Yes. I am proposing two adjustments to the Company's proposed OCRB and RCND rate base. My adjustments related to: 1) Post Test Year Non-Revenue Plant in Service and 2) Working Capital.

Post Test-Year Non-Revenue Producing Plant in Service

Q. What pro forma adjustment for post test-year plant in service did the Company propose?

A. The Company proposed to increase test year OCRB (and RCND) by $7,263,615 of post test year plant.

Q. What was the reason given by the Company for this pro forma adjustment?

A. According to Company Witness Dallas Dukes:

> "The Commission should allow UNS Electric to recover such costs. UNS Electric made these investments to serve existing customers. UNS Electric will not begin recovering on these investments until the time the investments are reflected in rate base within a rate proceeding. Including post test year non-revenue producing plant in rate base will allow UNS Electric to recover its investment and an opportunity at (sic) earn a reasonable return in a timely manner. If this current case follows an expected course, new rates will go into effect in June 2010 at the

earliest. The Company's next rate case will likely not be filed until April of 2011, with rates most likely not effective until June 2012. So the recovery of and on investments actually made before the end of the 2008, but not technically in service, will not produce additional revenues until June 2012. In other words, without this adjustment, UNS Electric would not begin recovering its investment for over 3 ½ years after the investments were made to serve existing customers." (Dukes Prepared Direct Testimony, page 12, lines 10 - 21.)

Q. Do you agree with Mr. Dukes' justification for inclusion of post test year plant in service in rate base?

A. No. Presumably, the investment was made in order to increase the Company's efficiency/productivity and hence reduce costs of providing service such as maintenance cost. This could result in a mismatch between post-test year revenue and costs. In addition, the Company has a choice as to when it files an application for rate relief. The Company could have waited to file its application so as to include this investment in its test year. Further, over time the Company will have depreciated its rate base that exists at the end of the test year and retired some of those assets. Rates, however, will continue to reflect the test year values for those assets. This is a benefit ignored by the Company which offsets some of the difficulties cited by Mr. Dukes.

Q. Did the Company provide adequate evidence that the proposed post test-year plant in service adjustment is revenue neutral?

A. No. Company witness Dukes testified that the proposed adjustment was revenue neutral and the work papers supporting the adjustment stated that the proposed adjustment was revenue neutral. He did not, however, provide any studies or analyses that supported that contention, either in aggregate or line item basis.

Q. Does Staff believe the proposed post test year plant is revenue neutral?

A. No. Staff has no basis to make that determination. Staff would suspect that investments are made to either reduce costs or generate revenue or both. Absent any evidence to the contrary, Staff does not accept the Company's revenue neutrality proposal.

Q. Has the Commission permitted utilities to include post test year plant in service in rate base in the past?

A. Yes.

Q. Did you review any of the Decisions where the Commission permitted utilities to include post test year plant in service in rate base?

A. Yes. I have reviewed several decisions where the Commission permitted Post test year plant in Service to be included in rate base. These were Decision Nos. 65350, 66849, 67279, 68176 and 68864. These decisions were referred to by Mr. Dukes in his rebuttal testimony regarding his proposed post test-year plant in service pro forma adjustment in the recent UNS Gas case.

Q. In Decision No. 65350 what did the Commission determine with respect to post test-year plant in service?

A. In Docket No. 01-0776, Bella Vista Water Company had made a series of capital investments that were in service after the end of the test year but prior to the hearing. The investment at issue amounted to about 24 percent of rate base and was installed to enhance service to existing customers and to increase system reliability. A reason given by the Commission to allow the plant to be included in rate base was that it did not want to discourage companies from proactively addressing system reliability needs and thus incur

another rate case expense. In addition, the Commission agreed with Staff that the Company had the burden to demonstrate that the post test-year plant is revenue neutral.

Q. In Decision No. 66849 what did the Commission determine with respect to Post Test-Year Plant in Service in that Case?

A. In Docket No. 02-0619 Arizona Water Company sought inclusion of $3,349,416 of post test-year plant in service in rate base. Staff and the Company agreed that post test-year plant in service was consistent with pro forma adjustments related to post-test year plant additions. The Commission determined that the Company's pro forma adjustments were correct and allowed the post test-year plant in service to be included in rate base.

Q. In Decision No. 67279 what did the Commission decide with respect to Post Test-Year Plant in Service?

A. In Docket No. 03-0434, Rio Rico Utilities proposed an OCRB of $2,462,446 for water utility plant and $4,136,931 for wastewater utility plant. These included adjustments for post test-year plant additions totaling $595,657 of water utility plant and $293,417 for wastewater utility plant. The Commission allowed the post test-year waste water plant in service to be included in rate base because the plant was in service when Staff inspected it, the new wastewater plant was the replacement for a Lift Station and was not an upsize, and was required because the Company had been experiencing breakages and spills with the old force main. The water utility post test-year plant in service was a 12 inch main and a booster plant. The Commission allowed this post test-year plant to be included in rate base because customers had been complaining of low water pressure.

Q. In Decision No. 68176 what did the Commission decide with respect to post test-year plant in service in that Decision?

A. In Docket No. 04-0616, Chaparral City Water Company proposed $42,538,338 for OCRB. Of that amount, $2,979,239 represented plant additions placed in service after the test year: $2,038,443 for the expansion of a water treatment plant, and $940,979 related to a transmission main. The Commission permitted inclusion of the water treatment plant in rate base. The Commission determined that the water treatment plant allows the Company to reliably meet peak demands during the summer months with CAP water while retaining the ability to take individual modules off line for repairs and to meet emergency needs. Absent the investment the Company had been operating with minimal flexibility for routine maintenance and repairs and had no operating safety margin in the event of a need to shut down some of its treatment facilities. The Commission allowed the cost of the main in rate base because it provided operational flexibility and improved service to customers.

Q. In Decision No. 68864 what did the Commission decide with respect to the issue of post test-year plant in service?

A. In Docket No. 05-0873 Tortolita Water Company reported a rate base of $61,787, comprised of net plant in service. Staff reduced total rate base of old plant that was no longer used or useful by $60,331, to $1,457 and allowed post-test year contributed plant of $381,919. Post test-year plant was treated as contributed plant and net rate base of $1,457 was included in working capital.

Q. What factors did the utilities in these proceedings have in common?

A. Generally, the Post test year plant was large relative to the rate base, the specific capital items were especially important for the provision of safe and reliable service, and factors which caused the delay in completion of plant past test year end were extraordinary.

Q. Does UNS Electric have a similar situation with respect to the capital items it wishes to include in rate base in this proceeding?

A. No. The total of the capital items requested to be included in rate base is less than 4.2% of adjusted original cost rate base. The capital items appear to consist of projects that are normal and on-going for electric utilities. Finally, the Company did not point to any specific factors that prevented the completion of any of the projects beyond the end of the test year.

Q. Did you prepare a Schedule showing this pro forma rate base adjustment?

A. Yes. The adjustment is shown in Schedule THF B-4 and carried over to Schedule THF B-2.

Q. What is Staff's recommendation regarding this issue?

A. Staff recommends that the Commission reject the Company's request to have these capital investments included in rate base as a post test-year plant in service adjustment. The reasons, as discussed above, include the small size of the investments relative to the Company's rate base, the relatively non-essential, or on-going, nature of the investments, and the lack of support for the revenue neutrality contention.

Working Capital

Q. Did you review the Company's proposed Working Capital pro forma adjustment?

A. Yes.

Q. What are the components of Working Capital?

A. Working Capital is composed of Materials and Supplies, Prepayments, and Cash Working Capital. The Company's calculated values for these components are: ($2,810,346) for cash working capital; $8,261,763 for materials and supplies; and $634,351 for Prepayments.

Q. Are you proposing any adjustments in these Working Capital components?

A. Yes. I am proposing a pro forma adjustment to cash working capital. This adjustment is necessary as a result of the proposed pro forma adjustments to income and expenses. The adjustment includes a minor correction in the Company's cash working capital calculation.[3] The pro forma adjustment to working capital is $61,025.

Q. Did you prepare a Schedule showing this pro forma adjustment to rate base?

A. Yes. The pro forma adjustment is shown on Schedule THF B-3 and is carried over to Schedule THF B-2.

[3] In Company Schedule B5 row 15 (property taxes) the lead lag factor, column F, is incorrectly calculated as (.4848) and should be (.4861). This results in a total cash working capital of ($2,814,811) rather than the ($2,810,346) shown on the Schedule. The net effect is a change of ($4,465) and is included in Staff's pro forma adjustment as a consequence of correcting the lead lag factor.

RCND Rate Base

Introduction

Q. What was the Company's proposed RCND Rate Base?

A. The Company proposed a total RCND Rate Base of $337,180,792. This was based on gross utility plant in service of $837,037,541. Gross utility plant in service was adjusted by accumulated depreciation, Citizens Acquisition Discount, Accumulated Amortization of Citizens Acquisition Discount, Customer Advances for Construction, Customer Deposits, and Allowance for Working Capital. These adjustments to gross utility plant in service generated the adjusted rate base.

Q. Did the Company propose any pro forma adjustments to RCND rate base?

A. Yes. The Company proposed adjustments for post test-year plant in service, Accumulated Deferred Income Taxes, and Working Capital.

Q. What was the adjusted RCND rate base proposed by the Company?

A. The Company's proposed adjusted RCND Rate Base was $354,485,222.

RCND Derivation

Q. Would you provide an overview of the process of deriving a RCND rate base?

A. Yes. A RCND study is a point in time measurement, just as an original cost rate base is a point in time measurement. That is, the Company's RCND rate base today most likely will not have the same value as the RCND rate base as of December 31, 2008. Rate Base Income Statement measurements are over time, or flow measurements.

Q What information does the RCND Rate Base convey?

A The RCND rate base provides the gross value of the rate base is a balance sheet idea and balance sheet values are point in time measurements while expressed in today's dollars, and the RCND rate base provides the net value of the rate base expressed in today's dollars. A properly constructed RCND rate base provides an estimate of what the cost would be to reconstruct the existing rate base if it were to be constructed now in today's dollars.

Q. Are there underlying assumptions of RCND studies?

A. Yes. An underlying assumption of RCND studies is that the value of a dollar today, everything else being equal, has more value than a dollar to be received in the future and that a dollar received in the past, everything else being equal, has more value than a dollar to be received now. So the RCND rate base is the value of the rate base when all net dollars invested have the same value regardless of when they were invested. The Original Cost rate base is the value of the rate base when all net dollars have the specific value of those dollars at the time they were spent, that is, they are not adjusted for changes in the value of the dollars. The way to convert current dollars into constant (value) dollars is to create a price (or cost) index for the various types of investments and use the price (or cost) index to convert to constant dollars.

Q. What is a price, or cost, index?

A. Index values provide a relative comparison of prices or costs over time. Price or cost indices have a base period where the index value is 100 and observations away from the base have different values based upon the value of the dollars at those observations. For the RCND rate base derivation we want the base period to be the test year. That is, we want to conduct the analysis in today's dollars because the RCND will show us how much

we would have to spend, in today's dollars, to duplicate the rate base that currently exists. The primary source of index values used in RCND calculations is the Handy-Whitman construction cost index by geographic location and Federal Energy Regulatory Commission ("FERC") account.

Q. Please describe the Handy-Whitman cost indices.

A. The Handy-Whitman indices are index values of plant and equipment costs by FERC account and by region. They have a base value (100) early on in the time series so we need to convert the base from the earlier base period of the series to the end of test year observation. This conversion process is one of dividing the end of test year index by each individual index throughout the series.

RCND Example

Q. Can you give an example of this?

A. Yes. Consider the following example where we are converting the base period from year one in the original index to year four in a new index:

Year	Original index value	Conversion equation	New Index value
1	100.00	(130/100)*100	130.00
2	110.00	(130/110)*100	118.18
3	120.00	(130/120)*100	108.33
4	130.00	(130/130)*100	100.00

Note that the "New Index value" series has the same relative values between the years as does the Original index value series. However, the indices are measured with respect to year 4 values rather than with respect to year 1 values. The conversion of the base period demonstrated above shown under the column headed "New Index Value" corresponds to the Company's term "Trend Value" used in its RCND study.

This process is simply one of changing the base period but not the relative values of the observations between periods. In the example above, the base period was changed from year one to year four.

Q. Are there any unusual characteristics about values calculated using this technique?

A. Yes. By definition, the RCND values for the test year will be the same as the Original Cost values for the test year.

Q. Can you please briefly explain the difference?

A. Yes. The base period always has an index value of 100 which means that current and constant dollars are the same and the base period for RCND studies for regulatory purposes is the test year. This equality that exists in the base period will only occur if the index values for previous, (or subsequent) periods are exactly equal to the base period index value. This will rarely, if ever, be the case.

Q. Does this feature of the construction of RCND rate base have implications for determining the validity of the resulting RCND rate base?

A. Yes. If a pro forma adjustment to the Original Cost rate base and the corresponding pro forma adjustment to the RCND rate base for an expenditure during the test year have different values, then there was an inconsistency in constructing the RCND rate base.

Pro Forma RCND Rate Base Adjustments

Q. Did you make any pro forma adjustments to the Company's RCND rate base?

A. The adjustments made to the OCRB discussed above are also directly applicable to the Company's RCND Rate Base. The reason for this is because the values for OCRB and RCND Rate Base are the same for the base, or test year. Therefore the OCRB adjustments

apply to the RCND Rate Base. That is the adjustments made in Schedules THF B-2, THF B-3, and THF B-4 apply to both rate bases.

FairValue Rate Base

Introduction

Q. What is the procedure for deriving FVRB?

A. Fair Value Rate Base is derived by calculating the average of the OCRB and RCND Rate Base, which the Commission has adopted in the past.

FVRB Derivation

Q. What was the Company's proposed FVRB?

A. The Company's proposed FVRB is $265,152,067. This is the average of the OCRB and RCND Rate Base.

Q. What is Staff's FVRB?

A. Staff's FVRB is $257,827,428.

Q. Did UNS Electric or Staff make adjustments to FVRB?

A. No. The adjustments were made to OCRB and RCND Rate Base so they were included in FVRB indirectly.

OPERATING INCOME ADJUSTMENTS

Q. Do you provide Schedules summarizing your pro forma adjustments to operating income?

A. Yes. Schedule THF C-1 provides a summary of Adjusted Net Operating Income and Schedule THF C-2 provides a summary of pro forma Income Statement Adjustments. The sections below provide a discussion of the pro forma adjustments to Operating Income.

Incentive Compensation and Executive Comp/Benefits (SERP and PEP)

Q. Please explain your pro forma adjustments for incentive compensation and Executive Compensation/Benefits.

A. This program provides retirement benefits to eligible executives in excess of the limits allowed under Internal Revenue Service regulations. In its last rate case the Commission disallowed certain incentive compensation and Supplemental Executive Retirement expenses. For various reasons the Commission decided to disallow 50 percent of certain incentive program costs and 100 percent of Supplemental Executive Retirement Plan costs. The Commission determined that the Performance Enhancement Plan ("PEP") program benefited both ratepayers and owners equally and allowed for ratepayers to pay for one half the cost and for owners to pay the other half. Supplemental Executive Retirement Plan ("SERP"), on the other hand, is a retirement program for high income employees. The Commission did not determine that the Company could not or should not offer this program, only that ratepayers should not be expected to fund it.

Q. What do you recommend with respect to SERP and PEP incentive compensation?

A. Since both Company stock holders and rate payers benefit from PEP incentive compensation I recommend that the Company share the incentive compensation expenses with the owners of the Company for PEP-related incentive compensation. The PEP pro

forma adjustment is shown in Schedule THF C-3 and is one half of the total PEP costs, or $132,158.

Schedule THF C-4 shows the pro forma adjustment for SERP-related expenses. I am recommending that the Commission disallow all $102,142 of SERP related expenses in this proceeding for the same reasons that it disallowed these expenses in the previous UNS Electric case, that is, if the Company wishes to reward its top executives with high levels of retirement benefits, then, since Company owners benefit, owners should shoulder the burden. The Company identified this SERP-related expense amount in its lead lag study.

Payroll Tax Expense (SERP/PEP)

Q. What is your payroll tax expense pro forma adjustment?

A. The Payroll Tax Expense is related to the PEP incentive pay adjustment. Since I am recommending disallowance of certain PEP related expenses, the payroll taxes associated with those expenses should also be disallowed.

Q. Have you prepared a Schedule showing this pro forma adjustment?

A. Schedule THF C-5 shows this pro forma adjustment. Since the PEP incentive pay adjustment is $132,158 the payroll tax expense associated with this amount should also be disallowed. The estimated minimal payroll tax expense is 7.65 percent of the PEP incentive pro forma adjustment, or $10,110.

Call Center

Q. What is the Call Center?

A. The Call Center is a central location that all UNS Electric, UNS Gas and TEP customers can contact for utility-related matters. By using a single call center wasteful duplication of

resources and expenses can be avoided. The three companies share in the expense of the Call Center.

Q. Please explain the Call Center expense.

A. The total test year Call Center charge to UNS Electric was $880,533. In the last rate case, the Company had increased its Call Center costs from $532,154 when it operated its Call Center on a stand-alone basis to $598,951 after the call center operations were consolidated.[4] In Decision No. 70360 the Commission allowed the Company to recover the full amount of Call Center Expenses incurred. The Commission gave two reasons for its determination: First, there had been a significant increase in call volume since the Call Center operations had consolidated; and second, on a stand-alone basis the Call Center would have required additional investment.

Q. What are the benefits to UNS Electric's customers of the Call Center?

A. According to Company witness McKenna at pages 7 – 8 of his Direct Testimony there are several benefits arising from the Call Center. First, it is open five days a week from 7 a.m. to 7 p.m. The customer service representatives can handle a wide range of transactions including service connection, service disconnection, account balance information, payment arrangements, and outage reporting. In addition, the Call Center offers "Virtual Hold" which provides customers the opportunity to remain in line for a representative or to hang up and have the Call Center call back.

Q. With all of these services available, has the call volume increased?

A. No. Call volume has decreased. According to Mr. McKenna call volume was down by 15 percent.

[4] From RUCO witness Moore Schedule RLM-14, Page 1 of 1 in Docket No. E-04204A-06-0783.

Q. Did the Company provide information as to why Call Center volume has decreased by 15 percent?

A. No. It would appear, however, that the Call Center may have been designed for a much larger volume of calls than exists.

Q. What do you recommend with respect to Call Center expenses?

A. I recommend that the Company not be permitted to recover the increase in Call Center expense since the last rate case. A reason given by the Commission in the last rate case to allow recovery of the increase in Call Center expense was increased volume of calls. That reason no longer exists. Therefore I am proposing a pro forma adjustment. I am recommending that the Commission disallow the increase of $281,582. Unless the Company can show that the increased Call Center expense resulted in savings elsewhere, and that customers have benefited by this increase in cost, the Commission should not permit this increase.

Q. Have you prepared a Schedule showing this pro forma adjustment?

A. Yes. I present my Call Center pro forma adjustment in Schedule THF C-6.

Industry Association Dues

Q. Do the Company's ratepayers benefit by the Company's membership in professional organizations?

A. There would clearly appear to be some benefit provided to ratepayers as a result of membership in professional organizations. The Company and its ratepayers can expect to enjoy the benefits of joint research and certain member services. However, there are also organizational activities that most likely do not benefit ratepayers.

Q. What might those activities be?

A. Such things as Utility Air Regulatory Group ("UARG") dues, legislative advocacy, regulatory advocacy, advertising, marketing, and public relations.

Q. Did UNS Electric propose a pro forma adjustment for its Industry Association dues?

A. No.

Q. What did the Commission decide in the last rate case with respect to Industry Association dues?

A. In its last rate case the Commission in Decision No. 70360 disallowed 49.93 percent of EEI dues related to legislative advocacy, regulatory advocacy, advertising, marketing, and public relations (at page 26).

Q. Are you proposing a pro forma adjustment with respect to Industry Association dues in this proceeding?

A. Yes.

Q. What is the basis for your proposed pro forma adjustment?

A. I am proposing that the proportion of dues not related to activities that are not necessary for the provision of service to UNSE customers be disallowed.

Q. Have you prepared a Schedule showing your calculation of this pro forma adjustment?

A. Yes. This is shown on Schedule THF C-7.

Outside Legal Expenses

Q. Does the Company incur outside legal expenses in the normal operation of its business activities?

A. Yes. The Company, like all business, will, from time to time, require outside legal assistance.

Q. Should the Company be allowed to recover its reasonable cost of outside legal assistance?

A. Yes.

Q. Is the Company requesting recovery of its cost of outside legal assistance?

A. Yes.

Q. Are you proposing a pro forma adjustment to legal expenses?

A. Yes. The Company made a pro forma adjustment of $109,433.80 for legal expense and included it in its miscellaneous expense pro forma adjustment. An evaluation of this outside legal assistance expense suggests that the amount includes non-representative expenses. Therefore, Staff made its pro forma adjustment and reduced the Company proposed adjustment by ($58,722), as shown in Schedule THF C-8.

Q How did you calculate this pro forma adjustment?

A. As shown in Schedule THF C-8, the Company included, $180,906, for 2007 in its calculation of three-year average. Staff removed that amount from the calculation and used the allowable amount of $28,830 for 2008 to calculate its three year average. The correct three-year average is $87,572 and the difference in the calculated amounts by Staff and Company is the amount of the pro forma adjustment.

Q. What do you recommend with respect to outside legal expenses?

A. I recommend that the Commission reduce the Company's proposed outside legal expense amount by $58,722. The reason that this adjustment is required is that the Company is using a non-representative value ($180,906 for 2007) in its efforts to derive a normalized outside legal expense amount. The non-representative 2007 legal expense amount causes the three-year average to be overstated. The proper value to use in calculating the three-year average is the 2008 amount.

Fleet Fuel Expense

Q. Does the Company incur an expense for fuel for its fleet of vehicles?

A. Yes.

Q. Is this a legitimate cost of providing service that the Company should be given the opportunity to recover?

A. Yes.

Q. Is the Company proposing to recover its reasonable Fleet Fuel cost on a going forward basis?

A. No. The Company is proposing to recover costs in excess of its reasonable Fleet Fuel cost.

Q. Are you proposing a pro forma adjustment to correct for this over recovery of Fleet Fuel costs?

A. Yes.

Q. Please explain your Fleet Fuel Expense Adjustment.

A. The Fleet Fuel Expense pro forma Adjustment is presented in Schedule THF C-9. The Company experienced average price per gallon for gasoline of $3.32 and of diesel of $3.82 during its test year. Fuel prices for the first half of the test year were unusually high and the average price per gallon of fuel has dropped since the test year. Using the average of 2009 actual monthly prices to date plus the projected average monthly price for the remainder of 2009 results in an average gasoline price per gallon of $2.52 and an average diesel price per gallon of $2.65 for 2009. This is a more reasonable and realistic fuel cost than the actual test year average. I am proposing a pro forma adjustment of $75,798 for Fleet Fuel expense.

Q. What was the source of fuel cost information?

A. The source of the fuel cost information was the AAA.com web site.

Rate Case Expense

Q. Did the Company propose a pro forma rate case expense adjustment?

A. Yes. In its adjustment work papers the Company had removed $58,333 from current year activities, increased rate case expense from Decision No. 70360 by $30,556 and added $166,667 of expenses for this rate case based on rate case expenses of $500,000 for a total pro forma adjustment of $138,890.

Q. Is the Company's proposed rate expense of $500,000 reasonable?

A. No.

Q. Are you proposing a pro forma adjustment to correct the requested amount?

A. Yes.

Q. What was the basis for your adjustment?

A. In Decision No. 70360 the Commission had authorized the Company to recover rate case expense of $300,000 amortized over three years. The Commission also authorized UNS Gas to recover $300,000 rate case expenses amortized over three years in Decision No. 70011.

Q. What are you proposing?

A. The situation here is similar to those two cases. I am proposing that the Commission allow the Company to recover $300,000 in rate case expenses over three years. Therefore, I am proposing a pro forma adjustment to reduce rate case expense by $66,667. This is shown in Schedule THF C-10.

Customer Assistance Residential Energy Support ("CARES") Discounts

Q. What is the CARES program?

A. The CARES program is a pricing plan available to residential customers presently taking service under the Company's residential service pricing plan whose gross annual income is not more than one hundred fifty percent of the federal poverty level guideline effective at the time qualification and annual certification is sought. Residential customers who desire to qualify for the plan must make application to the Company for qualification and provide verification to the Company that the customer's household income does not exceed one hundred fifty percent of the federal poverty level.

Q. Did the Company propose a pro forma adjustment for CARES discounts?

A. Yes. Company witness Erdwurm sponsors a pro forma adjustment to recover $61,797 in additional test year CARES discounts.

Q. What was the basis for the proposed adjustment?

A. According to Mr. Erdwurm's work papers provided in support of the adjustment the number of CARES customers varied by month within the test year and an adjustment was required to account for the change.

Q. Do you agree with Mr. Erdwurm's proposed justification for the adjustment?

A. No. According to Mr. Erdwurm the Company made both customer and weather annualization adjustments and change within the CARES customer class would have been captured in those calculations. The proposed CARES adjustment can be expected to double recover those revenues. In addition, the Company proposed a pro forma adjustment of $52,937 in its last rate case to reflect the reduction in revenues as a result of the switch in residential customers to the CARES program. The Commission rejected that request, and I recommend this Company request be rejected.

Q. Have you prepared a Schedule in support of this pro forma adjustment?

A. Yes, Schedule THF C-11.

Bad Debt Expense

Q. Does the Company incur an expense as a result of some customers not paying for service received?

A. Yes. A certain amount of customers bills are not paid and are counted as bad debts.

Q. How are bad debts measured?

A. Normally as a percentage of sales.

Q. Does this methodology usually require a pro forma expense adjustment?

A. Yes. Changes in revenue resulting from pro forma adjustments to income and expense items may require a pro forma adjustment to properly reflect the bad debt level.

Q. Did the Company propose a pro forma adjustment for bad debt expense?

A. Yes.

Q. How did the Company calculate its bad debt pro forma adjustment?

A. The Company calculated its three-year average ratio of uncollectibles to total retail sales (0.004718) and multiplied this amount by Uncollectible Revenue Adjustment base to derive its base pro forma bad debt expense ($764,063) and subtracted that from its actual bad debt loss for the test year ($1,200,504) to derive its adjustment ($436,441).

Q. What is the basis for your proposed bad debt pro forma adjustment?

A. The Company based its ratio of uncollectibles to sales on gross sales but calculated its adjusted amount on adjusted sales. This resulted in an overstatement of the bad debt expense pro forma adjustment of $105,000. My proposed bad debt pro forma adjustment corrects for the Company mistake.

Q. Have you prepared a Schedule showing the derivation of your pro forma bad debt adjustment?

A. Yes. Schedule THF C-12 shows the calculation of this adjustment.

Depreciation and Property Tax for Post test year plantin Service

Q. Did the Company propose a pro forma adjustment of Depreciation and Property Tax as a result of its proposed Post-Test Year Plant in Service Adjustment?

A. Yes.

Q. Do you propose a pro forma adjustment for this item?

A. Yes.

Q. What is the basis for your proposed adjustment?

A. Since I am proposing to remove the Post-Test Year Plant in Service Adjustment proposed by the Company from rate base, the accompanying Depreciation and Property Tax adjustment must also be removed.

Q. Did you prepare a Schedule showing this pro forma adjustment?

A. Yes. Schedule THF C-13 shows this pro forma adjustment of ($442,526).

Income Tax

Q. Please explain your income tax adjustment.

A. This adjustment is shown on Schedule THF C-2. It reflects the income tax effect of the pro forma changes in income and expense items.

AFFILIATE TRANSACTIONS

Introduction

Q. What is the purpose of your review and evaluation of affiliate transactions?

A. To provide recommendations regarding UNS Electric's dealings with its parent company, Unisource, and its other affiliates.

Q. What is the current structure of the organization providing services to UNS Electric and its affiliates?

A. There is no separate service organization created for the provision of various affiliate services. The (regulatory-related) services appear to be primarily provided by TEP personnel on behalf of UNS Electric although there are payments made by UNS Electric on behalf of TEP. There are also Direct Costs and Indirect Costs assigned to UNS Electric. Staff had only minimal information regarding the performance and operations of unregulated affiliates,[5] because transactions between UNSE and unregulated affiliates during the time period requested were not large in number. Staff, however, has recently issued a follow up data request to the Company to confirm that Staff's understanding of its data request responses on this issue is correct. If need be, depending upon the Company's response to the Staff's follow up data request, the Staff may address this issue further in its Surrebuttal Testimony.

Q. Who are the Company's affiliates?

A. In addition to UNS Electric the following companies are owned by UniSource Energy Corporation:[6]

Advanced Energy Technologies, Inc.
Escavada Leasing Company
MEH Equities Management Company
Millennium Energy Holdings, Inc.
Millennium Environ mental Group, Inc.
Nations Energy Corporation

[5] Most of the non-regulated affiliate information that was provided by the Company dealt with the proposed purchase of BMGS although a few transactions were between SES and UNSE.
[6] From Page 450.1 of FERC FORM NO. 1 for 2008/Q4.

San Carlos Resources, Inc.

Southwest Energy Solutions, Inc.

Tucson Electric Power Company

Tucsonel, Inc.

UniSource Energy Development Company

UniSource Energy Services, Inc.

UNS Gas, Inc.

Q. What criteria do you recommend with respect to evaluating the relations between the Company and its affiliates?

A. I recommend that the relations between the affiliates be patterned after the proposed National Association of Regulatory Utility Commissioners ("NARUC") guidelines for Cost Allocations and Affiliate Transactions.

Q. Would you summarize those guidelines?

A. Yes. In Guidelines for Cost Allocations and Affiliate Transactions the premise is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdictional regulatory authority. Guidelines is composed of the following sections: A. Definitions; B. Cost Allocation Principles; C. Cost Allocation Manual (Not Tariffed); D. Affiliate Transactions (Not Tariffed); E. Audit Requirements; and, F. Reporting Requirements.

Allocations and Pricing

Q. Did the Company provide information regarding cost allocations?

A. Yes. In response to a Staff data request, STF 12.1, requesting a copy of any Cost Allocation Manuals used by the Company, its affiliates, or Unisource Energy, and all cost

allocations used by the Company, any affiliate of the Company or by Unisource Energy, the Company provided purpose, costs, and basis for:

- Allocations within TEP
- Allocations within UNS Electric and UNS Gas
- Allocations across TEP, UNS Electric and UNS Gas
- Overheads on TEP Direct Charges for Labor and/or Material to UNS Electric from TEP
- Common Systems Allocations (from TEP to UNS Electric)
- Corporate Costs – "UNS Allocation" from TEP to UNS Electric

Q. Do the purpose, costs, and bases appear to be reasonable?

A. Yes. They appear to be reasonable and consistent.

Q. What is the pricing policy for services between the Company and its affiliates?

A. In response to a Staff data request, STF 12.4 the Company indicated that it first assigned costs directly where possible. Common costs were then assigned by cost causation where possible. Finally, where cost causation cannot be determined, the cost is assigned on the basis of payroll costs, plant/tangible assets, and total revenue.

Q. Is this approach consistent with the NARUC <u>Guidelines</u>?

A. Yes.

Q. With respect to your requests for information regarding affiliate transactions did the Company provide information regarding transactions involving unregulated affiliates?

A. The Company's responses dealt primarily with regulated affiliates.

Q. In your opinion do unregulated affiliates have a role in this proceeding?

A. Yes. For example, UED built BMGS and UNS Electric is requesting permission to purchase it. The prudence of the construction of the BMGS and of the purchase of BMGS from UED is important in this proceeding.

Q. Does the NARUC approach address pricing of services?

A. Yes. The affiliate transactions pricing guidelines are based on first, affiliate transactions raise the possibility of self-dealing where market forces do not necessarily drive prices and, second, utilities have an incentive to shift costs from non-regulated to regulated monopoly operations. So the objective of the affiliate transactions guidelines is to lessen the possibility for subsidization.

Q. What are the NARUC general rules for pricing?

A. According to the Guidelines at page 4:

1. Generally, the price for services, products and the use of assets provided by a regulatory entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.

4. Entities should maintain all information underlying affiliate transactions with the affiliated utility for a minimum of three years, or as required by law or regulation.

Q. Did the Company provide information showing how self-dealing is prevented and how costs are not over allocated to regulated affiliates?

A. Yes. Based upon the data I reviewed, it does appear that the Company and its affiliates are complying with NARUC's guidelines. However, we have recently sent the Company a follow up data request and I will address this issue further in my Surrebuttal Testimony if necessary.

Structure

Q. What is the current structure of UniSource Energy's service organization?

A. As noted above, there is no formal structure and most of the regulated services are provided by TEP personnel. Further, from the information received by UNSE, it appears that its transactions with unregulated affiliates is limited. From my review, allocations to UNSE are made on both direct and indirect basis.

Q. In your opinion is it beneficial to the Company's ratepayers for certain services to be provided jointly, such as call center, rather than by each Company (TEP, UNS Gas, UNS Electric) individually?

A. Yes. In my opinion total cost of service could be expected to be significantly higher if each of these types of services was provided individually as opposed to jointly.

Q. What do you recommend with respect to affiliate transactions between UNS Electric, its affiliates, and UniSource Energy as a result of your review and evaluation?

A. I recommend that the Company and its affiliates continue to comply with NARUC's guidelines on affiliate transaction. From the information I was provided, I believe the Company is in compliance.

DEPRECIATION RATES

Q. What is the purpose of your review and evaluation of the Company's proposed depreciation schedules?

A. The purpose of my review and evaluation was to provide recommendations regarding the appropriateness of UNS Electric's proposed depreciation schedules and provide revised depreciation schedules if necessary.

Q. Did the Company propose new depreciation rates in this proceeding?

A. Yes. Company witness White conducted 2009 technical updates of depreciation rates for the Company and provided testimony regarding those updates.

Q. How many updates were conducted?

A. The Company conducted two updates on its depreciation rates. One update included Black Mountain Generating Station and one update omitted BMGS.

Q. Did the Company provide the work papers and supporting documentation for the technical updates?

A. Yes. That information was evaluated and analyzed as part of the review of the proposed depreciation rates.

Q. When were the current depreciation rates approved by the Commission?

A. On May 27, 2008 in Decision No. 70360.

Q. What were the results of the technical updates?

A. According to Dr. White the accrual rate for the Company without BMGS changed from 4.24 percent for the total utility to 4.03 percent which resulted in an expense deduction of $938,358. The accrual rate for the Company with BMGS changed from 4.04 percent to 3.85 percent which resulted in an expense reduction of $927,268. The change in accrual rate and corresponding reduction in depreciation expense is the result of a change in the mix of plant investments among primary accounts and changes in the age distributions of surviving plant.

Q. Did the depreciation study address accumulated depreciation?

A. Yes. For both updates depreciation reserves were rebalanced. The computed reserve was less than the recorded reserve so computed reserves were increased to recorded reserve totals so as to maintain the new account accruals.

Q. Do you agree with the results of the study?

A. My review of the technical update and supporting documentation revealed no significant problems.

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

Introduction

Q. What is the purpose of your testimony with respect to the PPFAC?

A. The purpose of my testimony with respect to PPFAC is to: 1) Review the PPFAC mechanism and make recommendations regarding UNS Electric's proposed changes; 2) review the existing PPFAC mechanism and propose changes that would improve its performance; 3) calculate a new base cost of fuel and purchased power; and 4) make any necessary adjustments to the Plan of Administration.

Q. What was the scope of your review of the Company's PPFAC?

A. I reviewed the Company's pro forma adjustment work papers, responses to data requests, submitted PPFAC filings and support documentation, documents from the previous case dealing with the PPFAC, and interviews with Company officials.

Development and Operation of the PPFAC

Q. Would you describe the history of the current PPFAC?

A. Yes. Until June 1, 2008, the Company acquired its power supply through a fixed price, full requirements agreement with Pinnacle West. That agreement expired on May 31, 2008 and the Company was required to obtain a new power supply. As a result, the Company needed a modified PPFAC to recover its cost of purchased power and fuel.

Q. Did you review the Company's purchased power agreements?

A. Yes. A listing of these agreements is given in the "Fuel and Purchased Power Contracts" section of the Prudence Review of Fuel and Purchase Power Policy part of my testimony.

Q. Please describe the Company's PPFAC.

A. A PPFAC is adjustor mechanism that allows a company to recover or refund changes in purchase power and fuel costs between rate cases. UNSE's current PPFAC went into effect on June 1, 2008, and is administered under a POA, i.e., Plan of Administration. The PPFAC has a "forward component" and a "true-up component." The forward component is based on forecasted fuel and purchased power costs. The true-up component compares actual fuel and purchased power costs with the amounts collected through base rates and the PPFAC rate in the prior year. The true-up component reconciles actual and forecast fuel and purchased power costs and is incorporated into the following year's PPFAC rate. The PPFAC runs from June 1 through May 31 of the following year. The Company is required to file information and calculations showing the next year's forward and true-up components by December 31. Staff would have until February 15 to issue comments or recommended adjustments to the Company's December 31 filing. The Company would be required to file a response by April 1 and Staff would respond to that by April 15. The new rate would take effect unless the Commission suspended the PPFAC or decided to

take other action. In the event of extraordinary circumstances the Company could seek a modification to the rate.

Q. What are the current PPFCA rates?

A. In Decision No. 70360 the Commission established the average base cost of Fuel and Purchased Power at $.071218 per kWh. This was the starting point on June 1, 2008 and on June 1, 2009 a new PPFAC rate was set at ($0.010564) per kWh and included a true-up component of ($.007545) per kWh.

Q. What expenses are to be recovered in the PPFAC?

A. Only expenses recorded in FERC accounts 501, 547, 555, and 565 are to be recovered in the PPFAC.

Q. Did you review the Company's expenses to verify that only allowable expenses were included in the PPFAC?

A. Yes. My review indicated that the Company had only included permissible expenses in the PPFAC.

Q. Is the Company's accounting system adequate and reasonably maintained to collect, report, and audit the PPFAC filings, and to conduct testing?

A. The Company's accounting system is audited annually through the annual audit of the Company's financial statements. In my opinion the processes in place are adequate and reasonably maintained to collect and prepare the PPFAC filings and to facilitate the conduct of testing on such filings.

Q. Did the Company propose a new average base cost of purchased power and fuel in this proceeding?

A. Yes. The Company proposed a new average base cost of $0.067738 per kWh.

Q. What was the basis for the proposed new average base cost?

A. The Company proposed three pro forma adjustments to revenue requirement. These were: Retail Revenue & Purchased Power Annualization to annualize test year revenue and expenses to reflect a full year of the previous cases rates, including PPFAC; Wholesale Revenue & Purchased Power to adjust PPFAC eligible costs to reflect the June 1, 2009 PPFAC; and, Normalization of Revenue and Expense for Fuel and Purchased Power to reduce the revenues and expenses associated with the recovery of PPFAC.

Q. Did you review the Company's derivation and calculations of the proposed new base rate?

A. Yes. Staff reviewed the derivation and calculations and does not propose a pro forma adjustment to those calculations.

Q. Has the Commission permitted such a recalculation of base rates in other proceedings?

A. Yes. In the 2007 APS case[7] the Commission permitted the Company to recalculate average base rates and in the previous UNS Electric case[8] the Commission allowed a pro forma adjustment that flowed to base rates.

[7] Decision No. 69663 at pages 31-33.
[8] Decision No. 70360 Page 33 "Valencia Turbine Fuel"

Q. Does Staff recommend that the Commission adopt the new base rate?

A. Staff recommends that the Commission adopt the Company's process for calculating the base rate but that the Commission direct the Company to true up the base rate prior to implementation.

Q. Does the current PPFAC have a cap?

A. Yes. The forward component of the PPFAC has a cap.

Q. What is the current cap?

A. The cap was set at $0.0173 per kWh in Decision No. 70360. The Commission indicated that the cap was implemented because of concerns about the potential magnitude of fuel and purchased power fluctuations.

Q. What was the magnitude of fuel and purchased power changes between June 1, 2008 and June 1, 2009?

A. The difference between base fuel costs on June 1, 2008 and on June 1, 2009 is $.01845 per kWh.

Q. Do you recommend that the cap be changed to recognize the actual experience of the PPFAC?

A. Yes. I recommend that the cap on the forward component of the PPFAC be changed to $.01845 per kWh.

Q. Will your proposed change in the cap on the forward component of the PPFAC require a change to the POA?

A. Yes. At page 3, Section 3. PPFAC, subsection 1, the value $0.0173 should be replaced by $0.01845.

Q. Did the Company propose changes to the PPFAC?

A. Yes. The Company proposed changing the PPFAC interest rate and including credit support costs as recoverable expenses in the PPFAC.

Proposed Changes to PPFAC Interest Rate

Q. What is the current PPFAC interest rate?

A. The current PPFAC interest rate is the one-year Nominal U.S. Treasury Constant Maturities rate. The rate is published in the Federal Reserve Statistical Release H.15 on the first day of each calendar year.

Q What interest rate does the Company request be applied to its PPFAC balances?

A. The Company is requesting use of the 3-month LIBOR rate plus 1 percent. The Company also requests that the rate be reset every month.

Q. Do you recommend that the Commission adopt the Company's proposed change in interest rate?

A. No.

Q. Please explain.

A. I do not agree with the Company's proposed change for two reasons. First, a higher interest rate could provide a disincentive to reduce bank balances and become less inclined

to take all possible measures to reduce the cost of purchased power and fuel to its customers. Second, the Company's current interest rate is consistent with the currently authorized interest rate for both UNS Gas and Southwest Gas.

Q. What do you recommend?

A. I recommend the Commission reject the Company's proposal.

Proposed Recovery of Credit Support Costs

Q. What does the Company request with respect to Recovery of Credit Support Costs?

A. The Company is requesting to recover this cost through the PPFAC.

Q. What are Credit Support Costs?

A. These are credit costs incurred when the Company must finance temporary under-collections of fuel and purchased power costs and when it must provide credit support to wholesale counter-parties. The credit support takes the form of a letter of credit or cash deposit. The Company may be required to provide assurance to a counter-party that it will perform its obligation to purchase power or natural gas as specified by the contract.

Q. What is the magnitude of UNS Electric's credit support?

A. According to Company witness Grant the Company has had between $7m and $12m of letters of credit outstanding and $12 million to $21 million of cash collateral outstanding at any point in time since August of 2008. The annualized cost of any letter of credit is 1.15 percent of the face amount and the cost of cash collateral deposits is equal to LIBOR plus 1 percent. Interest income on the escrow account may offset a portion of the rate paid by the Company, the rate earned on escrow investments is typically lower than LIBOR and does not cover the 1.0 percent credit margin also paid by the Company. Therefore,

according to Mr. Grant, a cost rate of 1.15 percent also represents a reasonable cost estimate of case collateral deposits. The Company wishes to recover this cost through PPFAC.

Q. Do you recommend that the Commission adopt the Company's proposed recovery of Credit Support Costs?

A. No.

Q. Please explain.

A. First, the costs recovered by PPFAC should be directly related to purchased power or fuel costs. The PPFAC currently does this by allowing only for recovery of expenses recorded in FERC Accounts 501, 547, 555, and 565. In its last case the Company requested that certain other costs be recovered through the PPFAC and was denied. The Commission noted that no other utility was permitted to recover such costs and could see no valid reason to depart. The same reasoning still holds. Second, the Company has another way to recover those costs. It can request recovery of credit support costs, broker's fees, legal fees and other related costs through rate cases.

Forward Component Cap

Q. In your opinion has the PPFAC been effective in its current form?

A. In my opinion the PPFAC has worked as intended. It was implemented at a time of high volatility in the energy markets and has responded to the changes in energy prices and appears to have achieved its purposes.

Q. Have you considered alternative PPFAC designs that could be implemented?

A. Yes. The PPFAC in place requires adjustment annually so the change can be dramatic. In the last case both the Company and RUCO proposed forms of 12-month moving average PPFACs. While the bank balance may have been somewhat smaller under this type of plan, the monthly change in rates due to PPFAC changes could have been substantial. The Commission stated its desire to eliminate monthly volatility in Decision No. 70360 by requiring the PPFAC to be adjusted annually rather than monthly and the current PPFAC achieves that goal. There is no assurance that a change to monthly adjustment would be superior, or equal, to the current plan.

BLACK MOUNTAIN GENERATING STATION

Introduction

Q. What is the purpose of your testimony with respect to the Black Mountain Generating Station Peaker Unit?

A. The purpose of my testimony is to review the Company's request to include BMGS in rate base via a post test-year plant in service adjustment.

Q. Who currently owns BMGS?

A. BMGS is currently owned by UFD.

Q. Is the Company requesting Commission preapproval to acquire BMGS?

A. Yes.

Q. Is it the Company's responsibility to decide when to purchase BMGS?

A. Yes. The Company's management has the responsibility to decide whether it acquires BMGS.

Q. What is the Company's request regarding BMGS?

A. The Company requests the Commission to direct it to purchase BMGS and to include it in rate base as a post test-year plant in service pro forma adjustment.

Q. Have you reviewed the Company's request?

A. Yes.

Q. What did your review consist of?

A. I submitted a series of data requests and follow-up data requests to the Company regarding the proposed acquisition of BMGS. In addition, I interviewed Company personnel on-site and at the Company's Tucson offices.

Background

Q. What events led to this request by the Company for authorization to purchase BMGS?

A. The Company had a full requirements Power Supply Agreement with Pinnacle West Capital Corporation ("PWCC" or "Pinnacle West") until May 31, 2008. All energy and ancillary services for the Company's entire load requirements were provided under the agreement. As of June 1, 2008, after that agreement ended, the Company had to obtain power through other arrangements.

Q. Did the Company have a plan in place to ensure it could provide service to its customers at the time of transition?

A. Yes. The Company prepared a Procurement Plan to ensure it had the resources and commitments to serve its load after May 31, 2008.

Q. Have you reviewed the Power Supply agreement and the Procurement Plan?

A. Yes. I requested the Power Supply Agreement, the Procurement Plan, and other documents. I received them, and have reviewed them.

Q. What did the Plan provide for?

A. The Plan provided for a mix of market power purchases, resource acquisitions, and contracts for the provision of necessary capacity, energy, and reserves to meet UNS Electric's requirements.

Q. What is the Company's current power supply?

A. According to Company witness McKenna the Company currently acquires: About 50 percent of its power through power supply contracts for load and on-peak power; a Purchase Power Agreement with UED, the current owner of BMGS and an affiliate of UNS Electric; and use of the 65MW Valencia turbine units. That is, about 25 percent of requirements are fixed price capacity purchases, and approximately 35 percent are gas indexed capacity purchases. The remaining system capacity requirements are met through the PPA with UED for BMGS power, the Valencia Generating Station, and short-term purchases. Long-term sources of power were acquired through the issuance of Requests for Proposals.

Previous Commission BMGS Considerations

Q. Has the Company previously submitted a request to the Commission regarding BMGS?

A. Yes. In its last case, E-04204A-06-0783, the Company requested authority to purchase BMGS which, at the time, was planned for construction by UED. The Company proposal in the last case was to be allowed to implement a post test-year adjustment to rate base for

the BMGS. Staff opposed the Company's request because UNSE did not own the BMGS at that time and in addition the cost of the plant were not known and measureable or used and useful. The Company had merely at that time purchased the two turbine units and had not yet constructed any plant.

Q. What did the Commission decide with respect to that request?

A. The Commission agreed with Staff and RUCO and denied the request because of, among other reasons, the discussed above. The Commission noted, however, that at the time of the Order, the expiration of the tolling agreement with PWCC would occur in two weeks and commercial operation of BMGS was imminent.

Q. Did the Commission look to a possible future acquisition of BMGS by the Company?

A. Yes. The Commission stated (at page 76 of Decision No. 70360): "However, the temporal coincidence of two circumstances specific to this case, expiration of UNSE's contract with Pinnacle West two weeks from now and imminent commercial operation of the plant, is a compelling basis on which to encourage UNSE's acquisition of the BMGS." In a footnote, number 20, the Commission further observed that as of May 1, 2008, BMGS had been in operation and was producing power with performance testing scheduled the next two weeks and commercial operation scheduled for mid-May 2008.

Q. Did the Commission do anything to encourage UNS Electric's acquisition of BMGS?

A. Yes. The Commission authorized UNSE to implement an accounting order to record any and all of the Company's financial activities associated with the BMGS as if the BMGS were in rate base as of June 1, 2008. In this case the Company has made that information available as Volume 4 of its application.

Q. Did the Commission address financing of BMGS by UNSE?

A. Yes. The Commission granted UNS Electric financing authority to acquire BMGS. The Company had requested approval of a financing request of up to $40 million in new equity and up to $40 million in new debt capital. Staff agreed with the request and the Commission authorized this additional financing.

Broken Blade

Q. Has one of the turbines at the BMGS recently been damaged?

A. Yes. On my visit to the plant it was discovered that an event had occurred that had damaged one of the turbines. The event was discovered during routine maintenance inspection of the turbine. This is discussed in more detail in the testimony of Staff witness W. Michael Lewis.

Q. What was the extent of the damage?

A. At the time of my visit the extent of the damage to the turbine was not known. However, in its response to STF 15.3, the Company provided information that the cost of repair is covered under warranty and that repair of the unit would take between 6 and 8 weeks.

Q. At the time of filing this testimony is Unit 1 operational?

A. No. The Company is seeking preapproval of a unit that is not currently operational.

BMGS Recommendation

Q. Did you make any determinations as a result of your review?

A. Yes

Q. What did you determine?

A. The Company does not own BMGS now, so it should not be included in rate base as a post test year plant in service adjustment even if subsequently transferred from UED to UNSE.

Q. Did the Company have an opportunity to purchase BMGS so that it could have been included in rate base in this proceeding.

A. Yes. The Company could have purchased the plant but did not.

Q. What steps has the Company taken to acquire BMGS since Decision No. 70360?

A. To the best of my knowledge, the Company has not taken any steps to acquire BMGS since Decision No. 70360 despite encouragement from the Commission to do so.

Q. Has the Company taken any steps to seek FERC's approval to acquire BMGS?

A. To the best of my knowledge, the Company has not taken any steps to seek FERC approval.

Q. In the Decision in the Company's last rate case did the Commission authorize the necessary financing for BMGS?

A. Yes. In Decision No. 70360, the Commission encouraged the Company to acquire BMGS and authorized the Company to acquire up to $80,000,000 in new debt and equity for the financing of BMGS.

Q. Do you recommend that the Commission authorize the Company to include BMGS in rate base as a post test-year plant in service adjustment?

A. No. In its last rate case the Commission provided the Company the financing capability to purchase the plant. The Company chose not to do so. Therefore, since the Company does not own the plant, it should not be included in rate base.

PRUDENCE REVIEW OF FUEL AND PURCHASED POWER POLICY

Introduction

Q. Did Staff direct you to perform a prudence review of UNS Electric's Fuel and Purchased Power policies?

A. Yes.

Q. How does the Company currently acquire power?

A. The Company has: (1) entered into power supply contracts for base load and on-peak power for 50 percent of its energy requirements; (2) uses its four turbines with a total generating capacity of 65MW at the Valencia Substation in Santa Cruz County; and (3) entered into a Purchase Power Agreement with UniSource Energy Development Company for power from Black Mountain Generating Station.

Q. Describe the Company's power supply contracts.

A. About 25 percent of requirements are fixed price capacity purchases, and about 35 percent are gas indexed capacity purchases. The remaining requirements are met through: the PPA with UED to provide power from BMGS; the Valencia Generating Station; and short-term purchases.

Q. How did you conduct your review?

A. The first step was to issue a series of data requests dealing with specific tasks of the review. Throughout the review as the Company responded to data requests additional requests were submitted concerning areas highlighted by previous responses. Next was on-site inspections of the generating units (Valencia and BMGS) and interviews with Company employees at Kingman, Nogales, and Tucson. Overall, the Company was forthcoming and responsive to the requirements of the review.

The review was broken down into the following components:

- Organization, Staffing, and Controls.
- Fuel Management.
- Fuel and Purchased Power Contracts.
- Hedging and Risk Management.
- Forecasting and Modeling.
- Plant Operations.
- Purchased Power and Off-System Sales.
- Conclusions and Recommendations

Each of the components is discussed in the following sections.

Organization, Staffing, and Controls

Q. What areas did you investigate with respect to Organization, Staffing, and Controls?

A. I investigated the following areas:

- The skills and experience of members of the fuel and procurement work groups.
- The job descriptions under which members work and verification that job descriptions match work effort.

- Access by members to appropriate training.
- The adequacy of procedures and decision processes.
- The sufficiency of the documentation of decisions.
- Procedures for acceptance of offers for gas supply.

Q. What are the procedures for approval of fuel and purchased power procurement policy and procurement transactions?

A. The Risk Management Committee is responsible for reviewing and approving the UNS Electric Fuel and Wholesale Power Hedging Policy. The Committee members are Kevin Larson, Michael DeConcini, Karen Kissinger, Raymond Heyman, David Hutchens, and Kentton Grant.

Q. What were the skills and experience of members of the fuel and procurement work groups?

A. The Company provided resumes of thirteen employees, including Mr. Michael A. Bowling who is the Supervisor, Energy Supply. The employees are well qualified and experienced for the positions they currently hold. The members are employees of TEP that provide the service through affiliate services to UNSE. UNSE is billed via affiliate transaction billing.

Q. What were the results of your review of the job descriptions under which members work and verification that job descriptions match work effort?

A. Their skills and experience match the job description requirements.

Q. What were the results of your evaluation of access by members to appropriate training?

A. Members had access to appropriate training. The training goals and objectives were well laid out and clear. Individual member quantitative and qualitative objectives were presented and tied to training.

Q. What were the results of your analysis of the adequacy of procedures and decision processes?

A. The procedures and decision processes were laid out in detail along with the key controls in the [redacted] The report provided necessary checks and balances to maintain the integrity of the procedures and decision processes.

Q. What were the results of your evaluation of the sufficiency of the documentation of decisions?

A. The sufficiency of the documentation of decisions is provided by the procedures and decision processes. The documentation is thorough with procedures for verification of real time bookouts, approval of discretionary purchases, midterm trades, and other decisions described.

Q. What were the results of your review of procedures for acceptance of offers for gas supply?

A. Natural gas is purchased and scheduled by UNS Gas for the Valencia plant. Transportation is via UNS Gas Pricing Plan T-2, Transportation Service Using Dedicated Transmission Facilities. Gas is purchased and scheduled by UNS Gas for the BMGS in accordance with the "Interruptible Gas Sales Agreement between UNS Gas and UNS

Electric." Gas is transported on the UNS Gas distribution system in accordance with the "Gas Transportation Agreement between UNS Gas and UNS Electric."

Q. What do you conclude as a result of your investigation?

A. I conclude that the Organization, Staffing, and Controls functions of UNSE's PPFAC policy are reasonable and operate as intended.

Fuel Management.

Q. What areas of investigation did you conduct with respect to Fuel Management?

A. I investigated the management of fuel inventory levels, variance analysis, measurement of supplier performance, and analysis of current supplier rate structure with respect to natural gas/diesel fuel.

Q. What did your evaluation of management of fuel inventory levels, variance analysis, measurement of supplier performance, and analysis of current supplier rate structure with respect to natural gas/diesel fuel reveal?

A. There are no coal or natural gas inventories, so the only fuel inventories are those of diesel fuel which is a backup to natural gas for three Valencia turbines. The current inventory level of #2 diesel for use in the Units 1, 2, and 3 is 35,000 gallons and is replenished as needed. Variance analyses and supplier performance measurements are not conducted.

Q. What do you conclude as a result of your investigation?

A. Because of the nature of the Company's system, inventory controls and management are limited to number 2 diesel. The Company's procedures for fuel inventory control are adequate.

Fuel and Purchased Power Contracts.

Q. Does the Company have a Procurement Plan that it follows with respect to Purchased Power and Fuel?

A. Yes. In its previous case the Company created and submitted a detailed Procurement Plan to insure it had the necessary resources and contracts to reliably serve its load after expiration of the Pinnacle West Capital Corporation ("PWCC") contract on May 31, 2008.

Q. Did you review the Plan?

A. Yes.

Q. Would you summarize the Plan?

A. Yes. The Plan examined the existing load, resource mix, and projected future growth. It examined a group of recommended products, how the product purchases would be facilitated and a schedule for purchase. It also covered various credit and accounting treatment considerations which are associated with the future resource needs of UNSE.

Q. Did you review the Company's Fuel and Purchased Power Contracts?

A. Yes. I reviewed the following contracts:

[redacted]

[redacted]

Q. Would you provide an overview of the Gas Swaps and Power Contracts used by the Company?

A. UNS Electric enters into forward contracts to purchase a specified amount of capacity or energy at a specified price for a given period of time, within established limits, to reduce exposure to energy price risk associated with their gas and purchased power requirements to serve retail load, volumetric risk associated with their seasonal load, and operational risk associated with their power plants and transmission systems. UNS Electric also has natural gas supply agreements under which it purchases all of its gas requirements at spot market prices. These positions, by themselves, are risky. So to minimize the risk associated with these purchases the Company enters into gas price swap agreements under which they purchase gas at fixed prices and simultaneously sell gas at spot market prices. The contracts are subject to specified risk parameters established and monitored by the Company's Risk Management Committee.

Q. Does the Company utilize periodic internal and external audits on the procurement of fuel and purchased power?

A. No. According to Mr. DeConcini there were no internal audit reports issued in 2007 or 2008 related to the procurement of fuel and purchased power.[9]

Q. Even though no audit reports were issued in 2007 and 2008 are there additional safeguards regarding prices paid for purchased power?

A. Yes. UNS Electric obtains a significant amount of its long-term energy requirements through Request for Proposal solicitations. The RFP process is overseen by an Independent Monitor. In addition, the Company purchases short-term energy through power brokers that match buyers and sellers in the wholesale market. Hourly energy is obtained primarily through TEP and is priced at the Four Corners Daily Index.

Hedging and Risk Management.

Q. Have you reviewed the Company's hedging activities?

A. Yes.

Q. Are there any constraints regarding the amount of hedging activity?

A. Yes. According to Mr. Michael Bowling at a minimum, 45 percent of the forecasted monthly energy requirements are hedged before the beginning of each month. The Company may purchase additional energy, not to exceed 75 percent of the forecasted energy requirements. Purchases of both natural gas and power are made monthly over a three-year period prior to the month of their delivery for use. Purchasing or dispatching units for the balance of their needs has the effect of "cost averaging" the price of fuel and purchased power.[10]

[9] See Company response to STF 3.135
[10] See response to STF 4.4

Q. What type of hedging instruments have been used by the Company in 2008 and 2009?

A. The Company has used: 1) Firm, fixed price physical power; 2) firm, gas indexed physical power; 3) financial swaps; 4) financial collars; and 5) balance of the month physical power.

Q. How does the Company choose between alternative hedging strategies?

A. According to Mr. DeConcini the Company uses physical power to hedge its forward power risk so that the capacity risk is managed by the same mechanism that limits price risk. Although the Company could use financial power purchases, those purchases would ultimately require financial to physical swaps for physical delivery. When market heat rates are at acceptable level and liquidity for such products is available the company uses gas-indexed forward power. When hedging gas, the Company uses financial swing products because the actual physical gas is supplied by UNS Gas. When hedging, UNS Electric is hedging price risk through the use of fixed price financial swing gas.

Q. Are these types of hedging instruments appropriate for its purchased power and fuel procurement requirements?

A. Yes.

Q. Does the Company use outside hedging consultants?

A. No.

Q. What procedures are in place to assure that hedging operations are not used to speculate?

A. The Company requires adherence to its established hedging policies which prohibits speculation and has no incentive programs tied to trading activities. Purchased power and purchased fuel are the only material hedging participated in and any benefits from this hedging are passed directly to customers though the PPFAC.

Forecasting and Modeling.

Q. Does the Company rely on forecasts of fuel and purchased power volume requirements?

A. Yes.

Q. How does the Company develop forecasts of fuel and purchased power volume requirements?

A. The Company used a production cost model called Planning and Risk. It is built around a chronological unit commitment model that produces optimized unit and market-based dispatch results. An Excel workbook that outlines fuel costs and subsequent unit dispatch costs to determine correct dispatch of resources is used for day-ahead and real time traders. The workbook is updated daily with current market fuel prices.

Q. Does the Company use modeling with respect to demand and load forecasts?

A. Yes. The Company projects load and load demand for at least fifteen years. The forecasts are for Company total and individual customer classes and locations.

Q. Did you review the models and output?

A. Yes. The models appear to be stable and comprehensive. The statistics associated with the output are strong.

Purchased Power and Off-System Sales.

Q. Did you review the Company's purchased power and off-system sales?

A. Yes. I visited the Company's purchased power and fuel operations in Tucson and met with personnel.

Q. Did the Company have significant purchased power and off system sales?

A. The Company had significant purchased power [redacted] and a relatively small amount of off system sales [redacted].

Q. What are the Derivative Instrument Assets used by the Company?

A. Gas Swaps and Power contracts.

Q. How does the Company account for these contracts?

A. According to Company witness Kissinger the Derivative Instrument Assets are assigned to FERC Account 14460 Subacct 1110 for Derivatives-Gas Swaps and FERC Account 14460 Subacct 1100 for Derivatives-Power Contracts. The Derivative Instrument Liabilities are assigned to FERC Account 24200 Subacct 1110 for Derivatives-Gas Swaps and FERC Account 24200 Subacct 1100 for Derivatives-Power Contracts. These are short-term accounts and represent the portion of the contracts that will settle to the PPFAC Bank within twelve months of the reporting dates.[11]

[11] See Company response to STF 1.55.

The movement and magnitude of the values of the derivatives is a function of derivative volumes and forward price curves used in marked-to-market calculations. Gas swap derivatives are valued using NYMEX pricing, adjusted for basin differences. Power contracts are valued using aggregate pricing service or published prices when available. Published prices are not always available because of the local and regional character of power markets. When this occurs certain management assumptions are required. The Company uses assumptions regarding historical price curve relationships to calendar year quotes, apply percentage multipliers to value non-standard time blocks, and including adjustments for transmission and line losses to value contracts at illiquid delivery points.

Q. In your opinion are the techniques used by the Company to mark-to-market reasonable?

A. Yes.

Q. As part of your review did you consider the consistency with which the least-cost dispatch guidelines are conducted?

A. Yes. The resource stack consists of hedged purchases, generation resources (BMGS and Valencia units) and the market. Hedged purchases are dispatched first, followed by the next least cost resource. The determination is made using a dispatch spreadsheet. Therefore, the least-cost dispatch is consistent and efficient.

Q. Did the Company handle purchased power and off-system sales adequately?

A. Yes.

Conclusions

Q. Would you summarize your conclusions regarding your review of UNSE's Fuel and Purchased Power policies?

A. Yes. My conclusions are as follows:

1. Personnel in the fuel and power procurement area have strong skills and sufficient experience to meet their responsibilities and objectives.
2. Job descriptions match job requirements.
3. Communications within the operations area are adequate and sufficient as are communication along management levels.
4. Personnel are adequately trained and cross trained.
5. Training and compliance monitoring is adequate.
6. The relationship between fuel contract management and procurement could be strengthened.
7. Documentation of fuel and power procurement is satisfactory.
8. Internal auditing procedures are inadequate.
9. Procedures for accepting gas supply offers are adequate.
10. Trading management extends to the Board of Directors level with Directors serving on the supervisory committee.
11. Risk management procedures are extensive and sound and are incorporated with hedging policies.
12. Fuel management is primarily natural gas except for back-up diesel for Valencia units and that is reasonable.
13. The Company uses a sound policy for gas commodity.
14. The hedging program is sound.

15. The hedging program effectively considers trade offs between cost and allowing costs to fall.
16. Segregation of utility and non-utility activities is adequate.
17. Modeling to predict fuel and purchased power volume and cost is sufficiently accurate.
18. An appropriate least cost dispatch model is used.
19. Documentation is adequate for regulatory oversight.
20. The performance metrics of BMGS and Valencia demonstrate effective operation.
21. The acquisition process for purchased power is adequate.
22. Electric power trading is conducted in accordance with the goal of achieving least-cost dispatch.

Recommendations

Q. What are your recommendations regarding your review of UNSE's Fuel and Purchased Power policies?

A. My recommendations are as follows:

1. Strengthen the relationship between fuel contract management and procurement.
2. Create internal auditing procedures for contract management and procurement.
3. The analysis of possible excess interstate pipeline capacity optimization by UNS Gas should be extended to UNS Electric fuel procurement.
4. Hedging for gas procurement for August, September, and October should be considered but not required. The price of risk associated with hurricane season should be explicitly considered.

Q. Does that conclude your testimony?

A. Yes.

SCHEDULES

Schedules Accompanying
The Direct Testimony of Thomas H. Fish, Ph.D.

Schedule	Description
THF-1	Attachment 1, Resume of Thomas H. Fish. Ph.D.
THF-2	Attachment 2, Revenue Requirement Schedules
	Revenue Requirement
THF A-1	Computation of Increase in Gross Revenue Requirement
	Rate Base
THF B-1	Original Cost, RCND, and Fair Value Rate Base
THF B-2	Pro Forma Adjustments to Original Cost Rate Base
THF B-3	Lead/Lag Study Results
THF B-4	Post Test Year Plant in Service
	Operating Income Adjustments
THF C-1	Adjusted Test Year Income
THF C-2	Income Pro Forma Adjustments
THF C-3	Incentive Compensation-PEP
THF C-4	Incentive Compensation-SERP
THF C-5	Payroll Tax Expense
THF C-6	Call Center Expense
THF C-7	Industry Association Dues
THF C-8	Legal Expenses
THF C-9	Fleet Fuel Expense
THF C-10	Rate Case Expense
THF C-11	CARES
THF C-12	Bad Debt Expense
THF C-13	Depreciation and Property Tax, Post Test Year PIS

Curriculum Vitae

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ADDRESS/PHONE

1020 Fredericksburg Rd.
Excelsior Springs, MO 64024
(816) 630-0628
email: tfish@ariadaireconomics.com

EDUCATION

University of Arkansas Ph.D., 1972, Major: Economics. Minors: Marketing/Management, Finance, and Quantitative Methods.

Central Missouri State University, 1970, Warrensburg: MA, Economics

University of Missouri - Kansas City, 1969, Kansas City BA, Economics

EXPERIENCE

Administrative proceedings – participated in over 80 proceedings involving economics, statistics, accounting, finance, market structure and industrial organization issues in telecommunications, electric, and oil and natural gas distribution industries.

Managerial experience – Over 20 years experience in managing private businesses. Experience in personnel, economics, market research, finance, accounting, and operations management. Managed technical departments in several firms and was group manager in many major projects.

Judicial proceedings – participated in over 70 proceedings involving antitrust, contract damages, insurance defense, economic loss, market structure and performance, and other related economics/statistics/finance issues.

Other engagements – participated in over 75 private industry and governmental engagements involving economics, market structure, statistics, finance, and operational issues.

Teaching Experience –Through July, 2003 Professor of Business and Economics at William Jewell College. Duties included teaching classes in Economics, Finance, Quantitative Methods, and Management.

Taught classes at Webster University, Avila College, and Longview Metropolitan College on an adjunct basis between 1984 and 1997. Taught graduate and undergraduate classes in the areas of Management, Marketing, Financial Accounting, Finance, Statistics, Quantitative Methods, and Economics.

Experience

1981-1986 Regulatory Consulting and Expert Witness Services. Ariadair Economics Group. Concentration on Regulatory Consulting and Expert Witness Services for Regulatory Commissions and Consumer Advocates.

1986-1987 Directory, Economics Department, LMSL Consultants, Overland Park, Kansas. Concentration on Regulatory Consulting and Expert Witness Services for Regulatory Commissions and Consumer Advocates.

1987-Present Judicial and Administrative litigation consultant and expert witness, Ariadair Economics Group. Regulatory consulting and the regulatory experience led to a large number of utility antitrust and related litigation engagements in addition to regulatory Commission and Consumer Advocate regulatory engagements. During the period 1981 -2000 taught on an adjunct basis at local colleges including Avila University and Webster University. During the period 1981-1999 had Consumer Advocate clients in Arizona, Nevada, Illinois, Ohio, Pennsylvania and Maine. Also during this period had Commission clients in Nebraska, Oklahoma, Tennessee, Pennsylvania, Missouri, and South Dakota,

2001-2006 Full Professor of Business and Economics at William Jewell College, Liberty, Mo. During this period also had several judicial litigation engagements involving asset valuation and economic loss..

PUBLICATIONS

"An Analysis of Valuation of Community Bank Stocks." Quarterly Community Bank Journal, April, 1983.

"An Analysis of Trends in Prices of Community Bank Control Sales." Quarterly Community Bank Journal, July, 1983.

"An Analysis of Publicly Traded Multi-Bank Holding Company Market Performance After Acquisition of Community Banks." Quarterly Community Bank Journal, October, 1983.

"Derivation of a Valuation Index for Community Bank Control Sales." Quarterly Community Bank Journal, January, 1984.

RESEARCH

Professional Presentation

"An Econometric Model of Missouri." Presented at the Missouri Valley Economic Association, 1974.

Consulting Research

Economic Impact of Various Utility Rate Structures on State and Regional Economies.

Demographic Analysis of Economic Regions.

Determination of Market Characteristics and Parameters for Jet Aircraft Manufacturing Firms.

Determination of Optimal Refinancing and Capital Structuring and Corresponding Cost of Capital and Return for Acquisitions and Mergers.

An Econometric Analysis of NECPA Pricing Policies.

An Econometric Analysis of the Effect of the Proposed 15% Severance Tax (Senate Bill #892) on the Economy of the State of Kansas.

Curtailment of Demand Econometric Model for Cincinnati Bell Telephone Company's Service Area.

Development of Control Procedures for Large Construction Projects.

Development of Automatic Bill of Materials Systems of Manufacturing Processes.

Development of Planning and Forecasting Models.

Utilization of Economic Analysis in Business Decision-Making Situations (Seminar).

A Long-Term Forecast of Relative Costs of Alternative Energy Sources.

Analysis of the Validity of Sampling Procedures for Determination of the Growth Component of the DCF Model.

Analysis of the Relative Risk of Customer Classes of Electric Companies.

Development of EDP Models for Determining Optimal Price, Financing Strategy, and Expected Return for Corporate Acquisitions and Mergers.

Analysis of Asset Valuation in Bankruptcy Cases.

Preparation of Bank Charter Applications and Supporting Economic/Demographic Analyses.

COLLEGES COURSE TAUGHT

Management

Bank Management
Financial Management
Global Issues in Business
Human Resource Management
International Business Management
Introduction to Business
Introduction to Management
Marketing Research
Organization and Management
Organizational Behavior
Small Business Management
Strategic Management
Telecommunications Management

Finance

Financial Management
Intermediate Finance
International Finance
Portfolio Selection
Principles of Finance
Readings in Finance
Seminar in Finance I
Seminar in Finance II

Quantitative Methods

Business Math
Econometrics I
Econometrics II
Quantitative Analysis I
Quantitative Analysis II
Statistics I
Statistics II

Computer Information Systems/Information Technology

Computer Applications in Business

IT Systems Analysis and Design
Systems Analysis and Design I
Systems Analysis and Design II

Economics

Advanced Microeconomics
Business Cycles and Forecasting
Current Issues in Economics
Econometrics I
Econometrics II
Fiscal Policy
Industrial Organization
Intermediate Macroeconomics
Intermediate Microeconomics
International Economics
Macroeconomics
Managerial Economics
Microeconomics
Money and Banking
Principles of Econ I
Principles of Econ II
Readings in Economics

Financial Accounting

Cost Accounting
Federal Income Tax
Financial Accounting I
Financial Accounting II
Intermediate Financial Accounting
Managerial Accounting

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Computation of Increase in Gross Revenue Requirements
Test Year Ended December 31, 2008

THF 2 (ATTACHMENT 2)

Schedule THF A-1
Page 1

Line No.	Description	(a) Company Original Cost	(b) Staff Original Cost	(c) Company RCND	(d) Staff RCND	(e) Company Fair Value	(f) Staff Fair Value	Line No.
1	Adjusted Rate Base	$175,818,913	$168,494,273	$354,485,222	$347,160,583	$265,152,067	$257,827,428	1
2	Adjusted Operating Income	$10,003,347	$10,899,270	$10,003,347	$10,899,270	$10,003,347	$10,899,270	2
3	Current Rate of Return (2/1)	5.69%	6.47%	2.82%	3.14%	3.77%	4.23%	3
4	Required Operating Income	$18,253,668	$14,153,519	$18,253,668	$14,153,519	$18,253,668	$14,153,519	4
	Plus Fair Value (Line 6)		$15,493,516		$15,493,516		$15,493,516	
5	Weighted Average Cost of Capital	9.04%	8.40%	9.04%	4.08%	9.04%	5.49%	5
6	Fair Value Adjustment*	1.34%	$1,339,997	-3.89%	$1,339,997	-2.16%	$1,339,997	6
7	Required Rate of Return	10.38%		5.15%		6.88%		7
8	Operating Income Deficiency	$8,250,321	$4,594,246	$8,250,321	$4,594,246	$8,250,321	$4,594,246	8
9	Gross Revenue Conversion Factor	1.6363	1.6363	1.6363	1.6363	1.6363	1.6363	9
10	Increase in Gross Revenue Requirement	$13,500,000	$7,517,565	$13,500,000	$7,517,565	$13,500,000	$7,517,565	10

Supporting Schedules
Columns (a), (c), and (e) Company Schedule A-1
Line 1, columes b, d, & f From Staff Schedule THF B-1
Line 2, columes b, d, & f From Staff Schedule THF C-1

* Staff fair value adjustment is equal to Staff witness Parcel Fair Value return midpoint (0% -3%, or 1.5%) x difference between fair value and original cost rate base

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Original Cost and Adjusted RCND Rate Base
Test Year Ended December 31, 2008

Line No.	Description	(a) Company Adjusted Original Cost Rate Base	(b) OCRB Staff Adjustments	(c) OCRB as Adjusted by Staff	(d) Company RCND	(e)* RCND Staff Adjustments	(f) RCND as Adjusted by Staff	(g)** Company Fair Value Rate Base	(h)** Staff Fair Value Rate Base	Line No.
1	Gross Utility Plant in Service	$454,177,170	$7,263,614	$446,913,556	$844,301,155	$7,263,614	$837,037,541	$649,239,162	$641,975,548	1
									$0	
2	Less: Accumulated Depreciation	193,348,359	0	$193,348,359	$367,590,759	$0	$367,590,759	$280,469,559	$280,469,559	2
3	Net Utility Plant in Service	260,828,810	7,263,614	$253,565,196	$476,710,396	$7,263,614	$469,446,782	$368,769,603	$361,505,989	3
4	Citizens Acquisition Discount	(93,273,341)	0	($93,273,341)	($130,469,005)	$0	($130,469,005)	($111,871,173)	($111,871,173)	4
5	Less: Accum. Amort. - Citizens Acq. Discount	(20,876,317)	0	($20,876,317)	($27,773,948)	$0	($27,773,948)	($24,325,132)	($24,325,132)	5
6	Net Citizens Acquisition Discount	(72,397,024)	0	($72,397,024)	($102,695,057)	$0	($102,695,057)	($87,546,041)	($87,546,041)	6
7	Total Net Utility Plant	188,431,786	7,263,614	$181,168,172	$374,015,339	$7,263,614	$366,751,725	$281,223,563	$273,959,949	7
									$0	
8	Customer Advances for Construction	(12,605,744)	0	($12,605,744)	($17,555,056)	$0	($17,555,056)	($15,080,400)	($15,080,400)	8
9	Customer Deposits	(4,064,671)	0	($4,064,671)	($4,064,671)	$0	($4,064,671)	($4,064,671)	($4,064,671)	9
10	Accumulated Deferred Income Taxes	(2,028,227)	0	($2,028,227)	($3,996,158)	$0	($3,996,158)	($3,012,192)	($3,012,192)	10
11	Total Deductions	(18,698,641)	0	($18,698,641)	($25,615,885)	$0	($25,615,885)	($22,157,263)	($22,157,263)	11
12	Allowance for Working Capital	6,085,768	61,025	$6,024,743	$6,085,768	$61,025	$6,024,743	$6,085,768	$6,024,743	12
13	Regulatory Assets	0	0	$0	0	0	0	0	0	13
14	Regulatory Liabilities	0	0	0	0	0	0	0	0	14
									0	
15	Total Rate Base	$175,818,913	$7,324,639	$168,494,273	$354,485,222	$7,324,639	$347,160,583	$265,152,067	$257,827,428	15

Supporting Schedules
Column A and D from Company filing
Column B and E from THF B-2
*For Column (e) test year OCRB and RCND adjustments have the same value for Post test year PIS and Working Capital so no separate THF B-2 equivalent Schedule is required for RCND
**Fair Value rate base, columns (g) and (h) are derived as an average of OCRB and RCND

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended December 31, 2008

Line No.	Description	(a) Company Actual End of TY	(b) Staff Adjustments (a)	(c) Staff Adjusted at End of TY	Line No.
1	Gross Utility Plant in Service	$454,177,170	$7,263,614	$446,913,556	1
2	Less: Accumulated Depreciation	193,348,359	0	193,348,359	2
3	Net Utility Plant in Service	260,828,811	7,263,614	253,565,197	3
4	Citizens Acquisition Discount	(93,273,341)	0	(93,273,341)	4
5	Less: Accum. Amort. - Citizens Acq. Discount	(20,876,317)	0	(20,876,317)	5
6	Net Citizens Acquisition Discount	(72,397,024)	0	(72,397,024)	6
7	Total Net Utility Plant	188,431,787	7,263,614	181,168,173	7
8	Customer Advances for Construction	(12,605,744)	0	(12,605,744)	8
9	Customer Deposits	(4,064,671)	0	(4,064,671)	9
10	Accumulated Deferred Income Taxes	(2,028,227)	0	(2,028,227)	10
11	Total Deductions	(18,698,642)	0	(18,698,642)	11
12	Allowance for Working Capital	6,085,768	61,025	6,024,743	12
13	Regulatory Assets	0	0	0	13
14	Regulatory Liabilities	0	0	0	14
15	Total Original Cost Rate Base	$175,818,913	$7,324,639	$168,494,274	15

Supporting Schedules
(a) B-2,Pg. 2

Recap Schedules
B-1

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Pro Forma Adjustments to Original Cost Rate Base
Test Year Ended December 31, 2008

Line No.	Description	Post-Test Year Non-Revenue Plant in Service	Working Capital	Total Page Adjustments	Line No.
1	Gross Utility Plant in Service	$7,263,614		$7,263,614	1
2	Less: Accumulated Depreciation				2
3	Net Utility Plant in Service	7,263,614		7,263,614	3
4	Citizens Acquisition Discount				4
5	Less: Accum. Amort. - Citizens Acq. Discount				5
6	Net Citizens Acquisition Discount				6
7	Total Net Utility Plant	7,263,614		7,263,614	7
8	Customer Advances for Construction				8
9	Customer Deposits				9
10	Accumulated Deferred Income Taxes				10
11	Total Deductions				11
12	Allowance for Working Capital		$61,025	61,025	12
13	Regulatory Assets				13
14	Regulatory Liabilities				14
15	Total Original Cost Rate Base	$7,263,614	$61,025	$7,324,639	15

Supporting Schedules
B3, B4

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Lead/Lag Study
Test Year Ended December 31, 2008

Description	FERC	Pro Forma Test Year Amount	Adjustment	Adjusted Amount	Ref (1)	Revenue Lag Days	Expense Lag Days	Lag Days (Col. E - Col. F)	Lead/Lag Factor (Col. H/365)	Capital Required (Col. G X Col.B)
(A)		(B)	(C)	(D)		(E)	(F)	(G)	(F)	(G)
Operating Expenses:										
Non-Cash Expenses -										
Bad Debts Expense	904	$ 764,063	$ 105,487	658,576	THF C-12					$ -
Depreciation	403/404	17,810,236	313,599	17,496,637	THF C-13					-
Amortization	406	(3,575,014)	-	(3,575,014)						-
Deferred Income Taxes	410/411	3,384,947	-	3,384,947						-
Other Operating Expenses -										
Salaries and Wages	MULTI	4,828,118	-	4,828,118		35.59	23.33	12.26	0.0336	162,225
Incentive Pay	MULTI	109,736	102,142	7,594	THF C-4	35.59	267.00	(231.41)	(0.6340)	(4,815)
Purchased Power	555	95,598,854	-	95,598,854		35.59	33.79	1.80	0.0049	468,434
Transmission Other	565	8,082,997	-	8,082,997		35.59	40.67	(5.08)	(0.0139)	(112,354)
Meter Reading	902	839,177	-	839,177		35.59	33.67	1.92	0.0053	4,448
Customer Records & Collection Expenses	903	1,389,213	-	1,389,213		35.59	34.94	0.65	0.0018	2,501
Office Supplies & Expenses	921	505,643	-	505,643		35.59	50.89	(15.30)	(0.0419)	(21,186)
Injuries and Damages	925	309,105	-	309,105		35.59	70.52	(34.93)	(0.0957)	(29,581)
Pension and Benefits	926	1,166,579	-	1,166,579		35.59	51.37	(15.78)	(0.0432)	(50,396)
Support Services (TEP)	MULTI	6,217,822	-	6,217,822		35.59	44.77	(9.18)	(0.0252)	(156,689)
Property Taxes	408	3,307,989	128,927	3,307,989	THF C-13	35.59	213.00	(177.41)	(0.4861)	(1,608,013)
Payroll Taxes	408	445,648	10,110	435,538	THF C-5	35.59	19.87	15.72	0.0431	18,772
Current Income Taxes	409	(1,263,680)	-	(1,263,680)		35.59	41.42	(5.83)	(0.0160)	20,219
Interest on Customer Deposits	431	14,499	-	14,499		35.59	182.50	(146.91)	(0.4025)	(5,836)
Other Operations and Maintenance	MULTI	10,986,786	75,798	10,910,988	THF C-9	35.59	41.21	(5.62)	(0.0154)	(168,029)
Total Operating Expenses		$ 150,922,718		$ 150,315,581						
Other Cash Working Capital Elements:										
Interest on Long-Term Debt	CALC	6,716,282	-	6,716,282		35.59	78.97	(43.38)	(0.1188)	(797,894)
Revenue Taxes and Assessments	CALC	12,430,745	-	12,430,745		35.59	49.43	(13.84)	(0.0379)	(471,125)
Total Cash Working Capital-calculated										$ (2,749,321)
Company Cash Working Capital										(2,810,346)
Change in working capital per staff										(61,025)

$40,792	EEI	THF--C7
$281,582	CALL CENTER	THF--C6
$132,159	INCENTIVE	THF--C3
$58,722	LEGAL EXPENSE	THF--C8
$66,667	RATE CASE EXP	THF--C10
$61,797	C.A.R.E.S.	THF--C11
$641,718		

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Post Test Year Non-Revenue Plant in Service
Test Year Ended December 31, 2008

Line No.	Description	Amount	Reference
1	Company post TY Non-Revenue Plant in Service	$7,263,614	Schedule B-3, Pg 1, line 1, Column C
2	Staff Adjustment to Post TY Non-Revenue Plant in Service	(7,263,614)	Staff Testimony
3	Adjustment	7,263,614	

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Adjusted Test Year Income Statement
Test Year Ended December 31, 2008

Line No.	Description	Company Unadjusted (a)		Company Pro Forma Adjustments (b)	Company	Staff Adjustments	Staff Adjusted	Line No.
	Operating Revenues							
1	Electric Retail Revenues	$181,638,915		($22,358,469)	$159,280,446	$61,797	$159,342,243	1
2	Sales for Resale	10,168,115		(10,168,115)	0	0	0	2
3	Other Operating Revenue	3,103,658		(1,458,039)	1,645,619	0	1,645,619	3
4	Total Operating Revenues	194,910,688		(33,984,623)	160,926,065	61,797	160,987,862	4
	Operating Expenses							
5	Fuel, Purchased Power & Transmission	143,362,723		(32,059,158)	111,303,565	0	111,303,565	5
6	Other Operations and Maintenance Expense	21,569,849	(1)	(2,144,234)	19,425,615	(873,459)	18,552,156	6
7	Depreciation and Amortization	14,429,415		(194,193)	14,235,222	0	14,235,222	7
8	Taxes Other than Income Taxes	3,680,634		156,415	3,837,049	(442,526)	3,394,523	8
9	Income Taxes	2,081,685		39,582	2,121,267	481,859	2,603,126	9
10	Total Operating Expenses	185,124,306		(34,201,588)	150,922,718	(834,126)	150,088,592	10
11	Operating Income	9,786,382		$216,965	$10,003,347	$895,923	$10,899,270	11
	Other Income and Deductions							
12	Allowance for Equity Funds	322,168						
13	Other - Net	76,881						
14	Total Other Income and Ded	399,049						
15	Income Before Interest Expense	10,185,431						
	Interest Expense							
16	Interest on Long-Term Debt	6,546,248						
17	Other Interest Expense	57,412	(1)					
18	Allowance for Borrowed Funds	(181,815)						
19	Total Interest Expense	6,421,845						
20	Net Income Available for Common Stock	$3,763,586						

(1) Includes reclasification of $160,200 for Customer Deposit Interest Expense From Other Interest Expense to Other O&M Expense.

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Income Statement Pro Forma Adjustments
Test Year Ended December 31, 2008

Line No.	Description	Incentive Compensation Adj PEP	Incentive Compensation Adj SERP	Payroll Tax Expense, PEP	Call Center Expense Adj	Industry Association Dues	Legal Expense	Total Page Adjustments
	Operating Revenues							
1	Electric Retail Revenues	$0	$0	$0	$0	$0	$0	$0
2	Sales for Resale	0	0	0	0	0	0	0
3	Other Operating Revenue	0	0	0	0	0	0	0
4	Total Operating Revenues	0	0	0	0	0	0	0
	Operating Expenses							
5	Fuel, Purchased Power & Transmission	0	0	0	0	0	0	0
6	Other Operations and Maintenance Expense	132,159	102,142	10,110	281,582	40,792	58,722	625,507
7	Depreciation and Amortization	0	0	0	0	0	0	0
8	Taxes Other than Income Taxes	0	0	0	0	0	0	0
9	Income Taxes	0	0	0	0	0	0	0
10	Total Operating Expenses	132,159	102,142	10,110	281,582	40,792	58,722	625,507
11	Operating Income	($132,159)	($102,142)	($10,110)	($281,582)	($40,792)	($58,722)	($625,507)

1
Docket No. E-04204A-09-0206
Income Statement Pro Forma Adjustments
Test Year Ended December 31, 2008

Line No.	Description	Fuel Expense Adjustment	Rate Case Expense	C.A.R.E.S. Expense	Bad Debt Expense	Depreciation and Property Tax for Post TY Non-Rev Plant in Service	Income Tax	Total Page Adjustments	Total Adjustment
	Operating Revenues								
1	Electric Retail Revenues	$0	$0	$61,797	$0	$0	$0	$61,797	$61,797
2	Sales for Resale	0	0	0	0	0	0	0	0
3	Other Operating Revenue	0	0	0	0	0	0	0	0
4	Total Operating Revenues	0	0	61,797	0	0	0	61,797	61,797
	Operating Expenses								
5	Fuel, Purchased Power & Transmission	0	0	0	0	0	0	0	0
6	Other Operations and Maintenance Expense	75,798	66,667	0	105,487	0	0	247,952	873,459
7	Depreciation and Amortization	0	0	0	0	313,599	0	313,599	313,599
8	Taxes Other than Income Taxes	0	0	0	0	128,927	0	128,927	128,927
9	Income Taxes	0	0	0	0	0	(481,859)	(481,859)	(481,859)
10	Total Operating Expenses	75,798	66,667	0	105,487	442,526	(481,859)	208,619	834,126
11	Operating Income	($75,798)	($66,667)	$61,797	($105,487)	($442,526)	$481,859	($146,822)	($772,329)

Supporting Schedules
Schedules THF C-3 through THF C-13

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Incentive Compensation PEP
Test Year Ended December 31, 2008

Line No.	Description	Company Amount (A)	Disallowance Percentage (B)	Staff Adj Amount (C)
1	Incentive Compensation TY end Dec '08	$264,317	50%	$132,159

Source:

A: FERC form No. 1 p. 450.1
B: From Decision 70360
C: Column A x Column B

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Incentive Compensation Adj SERP
Test Year Ended December 31, 2008

Line No.	Description	Amount	Reference
1	SERP Amount	$102,142	From FERC Form No. 1 p 450.1
2	SERP Adjustment (100%)	$102,142	Decision 70360

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Payroll Tax Expense, PEP Incentive
Test Year Ended December 31, 2008

Line No.	Description	Amount	Reference
1	PEP Incentive Disallowance	$132,158	Schedule THF C-3
2	Payroll Tax Expense PEP	$10,110	7.65%
3	Adjustment	$10,110	Line 1 X Line 2

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Call Center Expense Adjustment
Test Year Ended December 31, 2008

Line No.	Description	Amount	Reference
1	Annual Allocation Last Case	$598,951	Docket No. E-04204A-06-0783 RUCO RLM-14 Line 23
2	Total Call Center Allocation Test Year	$880,533	TEP Invoices
4	Adjustment	$281,582	Line 2 - Line 3

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Industry Association Dues
Test Year Ended December 31, 2008

Line No.	Description	Amount	Referenc
1	Dues	$81,699	A
2	Percentage Disallowance	49.93%	B
3	Disallowance	$40,792	C
4	Adjustment	$40,792	

Source:

A: FERC Form 1 p. 335
B: Disallowance Percentage Decision 70360
C: Line 1 x Line 2

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Legal Expenses
Test Year Ended December 31, 2008

Line No.	Year	Total Amount	Excluded	Allowable Amount	Staff Adj	Reference
1	2005	127,621.78	0.00	127,621.78	127,621.78	
2	2006	106,263.16	0.00	106,263.16	106,263.16	
3	2007	452,227.78	271,321.65	180,906.13	0.00	A
		686,112.72	271,321.65	414,791.07	233,884.94	
		Prior 3 year Avg.		138263.69	$87,552.00	B
	TY 2008	170,623.45	141,793.56	28,829.89	$28,830.00	
			Proforma	109,433.80	$58,722.00	C

A: Staff Removed as non-normal
B: 3 year Average Allowable Amount 2005, 2006, 2008 TY
C: Company 3 Year Average less Staff 3 Year Average

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Fuel Expense Adjustment
Test Year Ended December 31, 2008

Line No.	Description	A Gasoline	B Diesel	C Total Cost	Reference
1	Gallons	22,392	49,474		STF 1.59
2	Price/Gallon (TY)	$3.32	$3.82		STF 1.59
3	Calculations	$74,341	$188,991		STF 1.59
4	Company Totals			$263,332	A3 + B3
5	Adjusted Prices	$2.52	$2.65		AAA Year to Date Average
6	Adjusted Cost	$56,428	$131,106		Line 2 x Line 4
7	Total Fuel Cost			$187,534	A5 + B6
8	Staff Adjustment			$75,798	C4 - C7

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Rate Case Expense per ACC Decision No. 70360
Test Year Ended December 31, 2008

(A)	nt Test Year Activity to be removed from Test year	$58,333
(B)	Rate Case Expense allowed per ACC Decision No. 70360	$300,000
	Yearly Amortization (Starting June 2008)	$100,000
	Montly Amortization (Starting June 2008)	$8,333
	Amortization June 2008 - June 2010 (25 months)	$208,333
	Remaining Balance @ June 30, 2010	$91,667
	Amortization for Test Year Balance @ June 30, 2010 over 3 years	$30,556
(C)	Estimated Rate Case Expense for Current Case*	$166,667
	TOTAL Company Proforma Adjustment	$138,890
	Staff Adjustment Remove $200,000 from (C)	$200,000
	Reduce (C) by 1/3	$66,667
(D)	Decision No. 70360, pgs 23-24	

1) Assuming new rates will go into effect 14 months after the rate case is filed in May 2009 (in effect as of July 1, 2010)
*UNS Electric is requesting rate case of $500,000 aportized over three years

UNS Electric, Inc.
Docket No. E-04204A-09-0206
C.A.R.E.S
Test Year Ended December 31, 2008

Line No.	Description	Amount	Reference
1	Company C.A.R.E.S. Adjustment	($61,797)	Company Workpapers
2	Remove Company Adjustment	$61,797	T. Fish Direct Testimony
3	Adjustment	$61,797	

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Bad Debt Expense
Test Year Ended December 31, 2008

Line No.	Description	Amount	Reference
1	Test Year Adjusted Revenue	$184,304,880	Schedule THF C-1
2	3 Year Average % Exp/Revenue	0.004718	Pro Forma Work Papers
3	Test Year Average Bad Debt	$869,550	Line 1 x Line 2
4	Test Year Actual Bad Debt	$1,200,504	Proforma Work Papers
5	Adjustment Required	$330,954	Line 4 - lind 3
6	Company Proforma Adjustment	$436,441	Company Schedule C-2
7	Staff Adjustement	$105,487	Line 6 - Line 5

UNS Electric, Inc.
Docket No. E-04204A-09-0206
Depreciation and Property Tax for Post TY Plant in Service
Test Year Ended December 31, 2008

Line No.	Description	Amount	Reference
1	Depreciation & Property Tax .	$442,526	Company Schedule C2 P. 3 Line 11
2	Depreciation & Propery Tax /	$442,526	Remove Post TY PIS Amount
3	Adjustment Amount	$442,526	