ORIGINAL

0000075873

RECEIVED

2007 AUG 14 P 4: 24

AZ CORP COMMISSION
DOCKET CONTROL

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783

NOTICE OF FILING

REBUTTAL TESTIMONY

UNS Electric, Inc. ("UNS Electric" or "Company"), through undersigned counsel, files Rebuttal Testimony of James S. Pignatelli, Thomas J. Ferry, Kentton C. Grant, Kevin P. Larson, Karen G. Kissinger, Dallas J. Dukes, Michael J. DeConcini, Edmund A. Beck, D. Bentley Erdwurm, Denise A. Smith, and Thomas N. Hansen and in the above-captioned docket.

. . .

. . .

. . .

. . .

. . .

. . .

. . .

Arizona Corporation Commission
DOCKETED
AUG 14 2007
DOCKETED BY nr

RESPECTFULLY SUBMITTED this 14th day of August 2007.

UNS Electric, Inc.

By _____

Michael W. Patten
ROSHKA DEWULF & PATTEN, PLC.
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

and

Raymond S. Heyman
Michelle Livengood
UniSource Energy Services
One South Church Avenue
Tucson, Arizona 85702

Attorneys for UNS Electric, Inc.

Original and thirteen copies of the foregoing filed this 14th day of August 2007, with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copy of the foregoing hand-delivered this 14th day of August 2007, to:

Chairman Mike Gleason
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Commissioner William A. Mundell
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Commissioner Jeff Hatch-Miller
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Commissioner Kristen K. Mayes
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Commissioner Gary Pierce
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Daniel Pozefsky, Esq.
Residential Utility Consumer Office
1110 West Washington, Suite 220
Phoenix, Arizona 85007

Marshall Magruder
P. O. Box 1267
Tubac, Arizona 85646

Thomas Mumaw
Deborah R. Scott
Pinnacle West Capital Corporation
P. O. Box 53999, Station 8695
Phoenix, Az 85072

Robert J. Metli
Snell & Wilmer LLP
One Arizona Center
400 East Van Buren
Phoenix, AZ 85004

Teena Wolfe, Esq.
Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Maureen A. Scott, Esq.
Kevin Torrey, Esq.
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Ernest Johnson, Esq.
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

By Mary Ippolito

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	)	DOCKET NO. E-04204A-06-0783

UNS ELECTRIC, INC.

REBUTTAL TESTIMONY

August 14, 2007

Rebuttal Testimony
of
James S. Pignatelli

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783

Rebuttal Testimony of

James S. Pignatelli

on Behalf of

UNS Electric, Inc.

August 14, 2007

TABLE OF CONTENTS

I. Introduction 1

II. The Commission Should Include All of the Company's CWIP in Rate Base in this Case 5

III. The Commission Should Grant the Company's Proposed Treatment of the Black Mountain Generating Station 6

IV. The Commission Should Reject the Compensation Related Disallowances Proposed by Other Parties 7

V. The Company's Proposed Cost of Capital Should Be Adopted by the Commission 9

VI. Purchased Power and Fuel Adjustment Clause 10

VII. Time-of-Use and Demand-Side Management 12

VIII. Renewable Energy Standard and Tariff 16

IX. Low-Income and the CARES Program 16

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is James S. Pignatelli. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. Are you the same James S. Pignatelli that filed Direct Testimony in this case?

A. Yes.

Q. Have you reviewed the Direct Testimony filed by the Commission Staff and other parties (collectively, "other parties") to this rate case?

A. Yes I have.

Q. Please provide your response to the other parties' Direct Testimony.

A. Let me start by pointing out that there are several UNS Electric witnesses who are filing Rebuttal Testimony in addition to me. All of our Rebuttal Testimony should be taken as a whole as our response to the other parties' Direct Testimony. However, there are a few items that I will discuss in my Rebuttal Testimony that I wish to emphasize to the parties and the Commission.

First, the rate increases recommended by the Commission Staff ("Staff") and by the Residential Utility Consumers Office ("RUCO") are insufficient to sustain the necessary levels of operation of UNS Electric. The end result of their recommendations, if adopted, would be that UNS Electric could suffer a degradation of reliability and service quality and, therefore, have to immediately file another request for a rate increase. It is counterproductive to sound regulatory principles (and the best interest of our customers) to require the parties to go to the time and expense of preparing and adjudicating a series of

rate case applications when the very issues that would be presented in those future cases can and should be addressed now.

Second, I am a strong proponent of CWIP in rate base in situations such as those facing UNS Electric at this time. The single largest factor contributing to the lower level of rate relief being recommended by Staff and RUCO is their rejection of the Company's request to include construction-work-in-progress ("CWIP") in rate base. Unfortunately, rejection of CWIP in rate base in this case ignores the financial realities facing UNS Electric and its customers.

UNS Electric's service areas are some of the fastest growing in the country. CWIP in rate base is appropriate in this case because UNS Electric is adding generation, transmission and distribution facilities at a rapid pace to meet this growth. The paradigm of a historical test year, without CWIP in rate base, does not timely recognize these expenses and investments in rates. The addition of CWIP in rate base will provide a mechanism by which the customers can benefit from these new facilities and the Company will receive recovery of the costs incident thereto at the same time.

For example, in this case, a large portion of the CWIP, as of the end of the Test Year (June 30, 2006) has already been transferred to plant-in-service. Customers are already receiving a benefit from this investment, and the customer advances relating to these projects have already been recognized as a reduction to rate base. The CWIP identified in the Company's filing should be included in rate base.

Third, the Commission should adopt the Company's proposal concerning the new Black Mountain Generating Station ("BMGS"). Acquiring BMGS is necessary and is in the best interest of the Company and its customers because BMGS will provide the Company with

numerous operational and financial benefits – which will benefit UNS Electric's customers over the long-term. Neither a short-term purchased power agreement nor an accounting order allowing cost deferrals provides those benefits, and neither will allow the Company to acquire BMGS

Fourth, it is important that the Company's Purchased Power and Fuel Adjustment Clause ("PPFAC") request in this case be adopted by the Commission. I will briefly discuss a proposal that somewhat modifies our original PPFAC testimony in this case.

Fifth, it is important that UNS Electric be able to attract and retain a qualified and dedicated work force - at all levels. I think the other parties' proposals to reject inclusion of costs related to compensation programs undermines our ability to do so and should be rejected by the Commission.

As evidenced by the rebuttal testimony of other UNS Electric witnesses, the Company disputes various other adjustments and recommendations proposed by the other parties to this case.

I indicated previously that without the rate increase levels requested by the Company in this case, UNS Electric could suffer in its ability to provide service. UNS Electric would also be disadvantaged as it attempts to finance necessary facilities to its ever growing service territories. Equally disturbing would be the signal that the Commission would be sending to UNS Electric, that new generation, transmission and distribution facilities will not be recognized (in a timely fashion, if at all) in rates regardless of their need and prudence.

II. THE COMMISSION SHOULD INCLUDE ALL OF THE COMPANY'S CWIP IN RATE BASE IN THIS CASE.

Q. What is the Company's overall reaction to Staff's and RUCO's recommendations regarding CWIP?

A. Staff and RUCO recommend that none of the Company's CWIP be included in the UNS Electric rate base in this proceeding. The unfortunate consequence of these recommendations is that the costs associated with many facilities that are now, or will shortly be, in service (and providing valuable benefits to customers) will not be included in the Company's rates in this case, thereby depriving UNS Electric of the revenues associated therewith. This will have a negative impact on the operations, ability to finance and fiscal health of UNS Electric.

I believe that CWIP should be allowed in rate base where there is rapid growth requiring significant ongoing construction and when it is needed to maintain and protect a utility's financial integrity. The UNS Electric situation meets both of these criteria.

Staff and RUCO rely upon an "extraordinary circumstances" test for inclusion of CWIP in rate base. Unfortunately, neither Staff nor RUCO (i) provide any precedent in support of its test; nor (ii) define what "extraordinary circumstances" are. I believe that to the extent the Commission would apply an extraordinary circumstances test to determine whether to include CWIP in rate base in this case, the UNS Electric situation would fall under any reasonable definition of extraordinary circumstances.

Mr. Kentton Grant addresses the shortcomings of the other parties' opposition to the inclusion of CWIP in rate based in this case in more detail in his Rebuttal Testimony.

III. THE COMMISSION SHOULD GRANT THE COMPANY'S PROPOSED TREATMENT OF THE BLACK MOUNTAIN GENERATING STATION.

Q. Please explain your disagreement with Staff's and RUCO's rejection of the Company's proposed treatment of BMGS.

A. I think RUCO and Staff are being short-sighted. We have presented evidence to show that BMGS will be in commercial operation at or shortly after the time that an order in this case will be issued. Also, BMGS will provide both financial and operational benefits to the Company and its customers. As UNS Electric witnesses Mr. Kevin Larson and Mr. Michael DeConcini detail in their Rebuttal Testimony, (i) BMGS will provide numerous financial benefits – including improving UNS Electric's credit profile and allowing the Company to attract financing on better terms; (ii) owning generation reduces the Company's revenue requirement over the long-term because of depreciation and deferred income taxes and adds to more long-term stability versus continually relying entirely on purchased power agreements and market prices; and (iii) there are operational benefits to UNS Electric owning BMGS – including added flexibility, improved reliability, better efficiency and lower costs for delivery (because of BMGS' location).

I am particularly perplexed by Staff's comments about its uncertainty about the economics of BMGS. I note that customers of UNS Electric – when the electric assets were owned by Citizens – were forced into a situation where they faced paying for $135 million of deferred purchased power costs. Those costs were the result of a full requirements contract set to expire on May 31, 2008. Thankfully, we did not have to collect that money from UNS Electric customers. The diversity and flexibility that BMGS provides the Company in the future is extremely important to customers, as was evidenced by the scenario I just described. Including BMGS costs in rate base will give the Company options to provide electric service in a way that is best for our customers.

Q. What measures did the Company propose to give Staff and RUCO assurance about its proposed treatment being known and measurable and to provide the Parties with additional comfort?

A. First – to provide Staff and RUCO with additional comfort – we indicated that we would not seek to implement rate base treatment until *after* BMGS becomes commercially operable. Even so, this treatment will not occur before June 1, 2008. UNS Electric commits to filing a project completion report before implementing the rate reclassification. Also, the Company's proposed adjustment to rate base in this case for BMGS will be $60 million; this is the *minimum* cost estimate for BMGS. No party disputes $60 million as the minimum cost estimate. If the cost to complete BMGS were to be less than $60 million – which is extremely unlikely – the Company would then reduce the size of the requested rate reclassification in proportion with the change in the final cost. If the actual project costs exceed $60 million, then UNS Electric will not seek rate base treatment for any additional amount until the Company's next rate case. So the $60 million is a cap on the Company's requested treatment for this case. We hoped that these assurances would give Staff and RUCO ample basis to support what is in the long-term, a benefit to our customers.

IV. THE COMMISSION SHOULD REJECT THE COMPENSATION RELATED DISALLOWANCES PROPOSED BY OTHER PARTIES.

Q. Mr. Pignatelli, what do the other parties recommend regarding compensation related costs in this case?

A. Staff and RUCO recommend that none of the costs associated with important compensation programs such as be recovered through rates.

Q. Why are Staff's and RUCO's disallowance recommendations inappropriate?

A. Staff and RUCO fail to recognize that these programs are important and, I believe, necessary to attract and keep a qualified and dedicated workforce at UNS Electric. Rather than acknowledging these benefits, Staff and RUCO merely look at these programs as unnecessary additional costs. That is inappropriate.

Programs such as UNS Electric's Performance Enhancement Plan ("PEP") are geared heavily toward providing benefits and reducing costs to customers, promoting safety and increasing customer service. The PEP program is designed to motivate and encourage employees to be more efficient and improve performance.

UNS Electric witness Mr. Dallas J. Dukes addresses this issue in more detail in his Rebuttal Testimony.

I note that Staff and RUCO both seem to base some of their adjustments and recommendations regarding compensation related issued based on the Commission's treatment of Southwest Gas Corporation ("SWG") in its last rate case – Decision No. 68487 (February 26, 2006). This comparison is without merit. UNS Electric and SWG do not allocate affiliate costs in the same fashion. I believe that the way that we do so is beneficial for our customers. For instance, UNS Electric directly allocates the actual cost for services that TEP shared service departments provide to TEP – versus using the Massachusetts Formula to indirectly allocate those costs. This saves UNS Electric customers $2.3 million. Staff and RUCO penalize UNS Electric by failing to recognize this important difference. Also, UNS Electric's PEP is different than SWG's incentive program, but those differences apparently are not accounted for by Staff and RUCO.

Similarly, UNS Electric also opposes disallowances to the Officers' Long-Term Incentive Program, the Deferred Compensation Plan and the Supplemental Executive Retirement

Plan ("SERP") because those costs represent vital components to an overall competitive compensation program.

V. THE COMPANY'S PROPOSED COST OF CAPITAL SHOULD BE ADOPTED BY THE COMMISSION.

Q. Mr. Pignatelli, please summarize the Company's cost of capital recommendations in its Direct Testimony?

A. As Mr. Grant explained in his Direct Testimony, the Company's 9.89% cost of capital recommendation is just and reasonable. This conclusion was based on an 11.8% cost of common equity capital, an 8.22% cost of long-term debt and a 6.36% cost of short-term debt, with a capital structure consisting of 48.85% common equity, 47.18% long-term debt and 3.97% short-term debt. The Company stands by its recommendations.

Q. What are the cost of capital recommendations from Staff and RUCO?

A. Staff recommends an overall cost of capital of 8.97%, based on a cost of equity of 10.00%, a cost of short-term debt of 6.36%, a cost of long-term debt of 8.16% and a capital structure of 48.83% equity, 3.96% short-term debt, and 47.21% long-term debt. RUCO recommends an overall cost of capital of 8.67%, based on a cost of equity of 9.3%, a cost of long-term debt of 8.22%, cost of short-term debt of 6.36% and a hypothetical capital structure of 47.18% long-term debt, 3.97% short-term debt and 48.85% equity. Neither Staff's nor RUCO's recommendations are sufficient or reasonable. In his Rebuttal Testimony, Mr. Grant details the problems with both Staff's and RUCO's recommendations.

Q. Would you highlight some of those problems?

A. I believe that the awarded return on equity should be commensurate with the risk the Company faces. Neither Staff nor RUCO account for the increased business risks faced by UNS Electric, nor do they account for the Company's need to raise substantial additional capital to fund the significant amount of growth occurring within the Company's service territory. Also, neither Staff nor RUCO did any analysis on how their recommendations affect the Company's cash flow or earnings. The Company is not proposing a new ratemaking methodology; rather, UNS Electric is requesting the Commission to look at these important factors within the regulatory framework established.

We try to secure capital on the best terms we can for UNS Electric, so that the Company can continue to provide reliable service. That is not an easy thing to do, and it is harder when the return on equity awarded is the same as that of far less riskier companies. The bottom line is that the Company will be at a competitive disadvantage when it comes to attracting capital compared to other utilities if either Staff's or RUCO recommendations are adopted. To put the Company in that position is not reasonable to it and will not be beneficial to customers over the long term.

VI. PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE.

Q. Is UNS Electric proposing a PPFAC different from the mechanism it proposed in its original rate case filing?

A. Yes. The Company is proposing a modification to the PPFAC it proposed in Mr. DeConcini's Direct Testimony. Essentially, the Company's new PPFAC is the same PSA mechanism that Staff proposed for APS in its last general rate case (Decision No.

69963 (June 28, 2007), with the exception that there is no Transition Component, and is virtually the same mechanism that was recently filed in TEP's rate case.

Q. Why is UNS Electric proposing this modification now?

A. The Commission recently approved Staff's proposed PSA mechanism for APS, and TEP recently filed a mechanism that was developed along the lines of Staff's proposal. UNS Electric believes that Staff's proposed mechanism will be effective in mitigating the volatility in its power supply and delivery costs and believes a similar mechanism is preferable to what the Company originally filed in this case.

Q. Please provide more detail on this new proposed PPFAC.

A. As outlined in the Company's proposed PPFAC Plan of Administration ("POA"), attached as Exhibit MJD-3 to Mr. DeConcini's Rebuttal Testimony, the PPFAC Year begins June 1st and ends on May 31st of the following year. The first full PPFAC Year in which a PPFAC rate would apply would begin on June 1, 2008 and end on May 31, 2009 ("2008 PPFAC Year"). We are also proposing that the initial PPFAC rate be set at zero in this case and the first new PPFAC rate be established for the 2008 PPFAC Year, as described in Mr. DeConcini's Rebuttal Testimony.

Q. How is the PPFAC structured?

A. Again, Mr. DeConcini will provide greater detail on the PPFAC, but generally, UNS Electric proposes that there be two primary components to the PPFAC rate:

1. the Forward Component, based on the forecasted fuel and purchase power costs for the following year; and
2. the True-Up Component, a comparison of actual fuel and purchase power costs with the amount UNS Electric collected through base rates as well as the PPFAC rate for the prior year.

Q. How will the new PPFAC rate be approved each year?

A. UNS Electric proposes annual filings, with designated due dates, to change the PPFAC rate every twelve months. We believe this will provide enough frequency to allow the Company to promptly recover fuel and energy costs from customers without burdening the Commission with multiple dockets in a 12-month period. Under normal circumstances, there would only be one proceeding every 12 months to adjust the PPFAC rate. Mr. DeConcini will provide more detail on this in his Rebuttal Testimony.

VII. TIME-OF-USE AND DEMAND-SIDE MANAGEMENT.

Q. Has UNS Electric proposed new TOU options?

A. Yes, UNS Electric has proposed newly designed TOU rate options. Specifically, the Company's proposal requires TOU rates for all new residential, new small general service, and new large general service (<1000 kW) customers, as well as all new and existing general service customers with over 1000 kilowatt demand and all new and existing Large Power Service customers. Existing residential and small general service customers will have an opportunity to remain on the non-TOU pricing plans, or switch to the new TOU rates. There is no service charge for switching to the TOU alternative.

Q. Why is the Company proposing mandatory TOU?

A. Including TOU rates within the overall rate design will provide a stronger price signal to customers to shift load out of the critical peak period. Reducing peak means that less power will be needed when it is most costly. Consequently, less power will have to be purchased from the spot market during peak times. This will result in savings for the Company and its customers. Given the Commission's strong desire to promote energy conservation, I am surprised that there is any opposition to mandatory TOU rates for new residential and small commercial customers – as well as mandatory TOU rates for all

customers in other classes. RUCO does support implementing mandatory TOU rates for all new residential and small commercial customers and for all new and existing larger general service customers.

Q. What is your response to Staff's and RUCO's comments regarding UNS Electric's proposed on-peak, shoulder and off-peak times?

A. Generally, it appears that Staff and RUCO support the type of super-peak rates (limited number of on-peak hours) proposed by UNS Electric in this rate case, although there are still some rate design issues to be addressed.

Q. What about Staff and RUCO's Direct Testimony regarding other aspects of the Company's proposed rate design?

A. I am surprised that there is opposition to the implementation of a tiered-inverted-block rate structure. UNS Electric proposed this rate structure for non-TOU customers to encourage conservation. I am aware that Staff and the Commission recommended and approved inverted-block rates for several water companies in recent rate cases. I would think that there would not be any opposition for UNS Electric to do the same thing now. As Mr. D. Bentley Erdwurm describes in his Direct Testimony, for non TOU-customers, residential and small general service customers will now be able to purchase their first 400 kWh per month at a one-cent per kWh discount relative to second block consumption (over 400 kWh per month). This allows customers who are able to conserve to be rewarded for their efforts to conserve electricity. Like the Company's TOU and DSM proposals, the inverted block structure is aimed at deferring capacity additions, reducing peak demand, and keeping costs low. The second change in residential and small general service rate design is the elimination of separate rates for Mohave and Santa Cruz Counties. Consolidating rates provides a distinct benefit to Santa Cruz County customers. I encourage the consolidation in this case.

Q. Will an additional witness testify in response to Staff's Direct Testimony about DSM?

A. Yes. Ms. Denise Smith, the Director of Conservation and Renewable Programs at TEP, is providing Rebuttal Testimony on DSM issues. I will provide some general comments here.

Q. Did UNS Electric file a new DSM plan in a separate docket?

A. Yes. UNS Electric takes seriously its responsibility to implement effective and efficient DSM programs. To that end, the Company continued to review potential DSM programs after it filed its Application on December 15, 2006. UNS Electric also considered the DSM comments made by parties in the UNS Gas rate case (Docket No. G-04204A-06-0463) and in TEP's Motion to Amend Decision No. 62103 docket (Docket No. E-01933A-05-0650). Accordingly, the Company filed its DSM Program Portfolio on June 13, 2007 in Docket No. E-04204A-07-0365 ("UNS Electric DSM Docket"), adding two new DSM programs and enhancing its Direct Load Control ("DLC") Program ("Amended DSM Program Portfolio"). This Amended DSM Program Portfolio is intended to replace the original DSM information filed on December 15, 2006, as part of Mr. Ferry's Direct Testimony.

Q. What are your general comments regarding Staff's DSM Direct Testimony?

A. UNS Electric agrees with Staff's comments and recommendations regarding DSM. Furthermore, the Company agreed to modify two major items in Mr. Ferry's Direct Testimony when it filed its Amended DSM Program Portfolio in June:

1. UNS Electric agreed to re-categorize $20,000, previously allocated to the Emergency Bill Assistance component of the LIW Program, to the proposed Warm Sprits Program. This amount will not be funded with DSM dollars; and

2. UNS Electric agreed that its TOU pricing plans will not be considered DSM, nor will these pricing plans be funded with DSM dollars.

Q. What changes is UNS Electric proposing?

A. In addition to the DSM programs filed in Mr. Ferry's Direct Testimony, UNS Electric proposed Residential HVAC and Commercial Facilities Efficiency Programs, and enhanced its DLC Program in its Amended DSM Program Portfolio. The Company removed TOU from its list of specific DSM programs, although it remains an important part of UNS Electric's DSM strategy. As it is essentially a rate design issue, Mr. D. Bentley Erdwurm addresses TOU rates in his Direct and Rebuttal Testimonies. Ms. Smith provides greater detail on the Amended DSM Program Portfolio in her Rebuttal Testimony.

Q. What about Staff's proposed DSM Adjustor Mechanism?

A. The Company agrees with Staff's recommendation to utilize a DSM Adjustor Mechanism. While UNS Electric is requesting approval of the DSM programs in the UNS Electric DSM Docket, the Company requests that funding for the DSM programs, through the DSM Adjustor Mechanism, be approved in this docket. Implementation of the Amended DSM Program Portfolio should coincide with, and is contingent upon, Commission approval of the DSM Adjustor Mechanism.

Q. What does the Company propose to collect in its initial DSM Adjustor Mechanism?

A. The Company proposes to collect 100 percent of its Low-Income Weatherization ("LIW") Program, and 25 percent of the other programs, in its initial DSM Adjustor Mechanism. This initial amount will fund the first year start-up costs for the implementation of new or enhanced programs.

VIII. RENEWABLE ENERGY STANDARD AND TARIFF.

Q. Will UNS Electric comply with the REST rules?

A. Yes. UNS Electric will file its compliance plan with the Commission within sixty (60) days of the effective date of the REST rules. Mr. Thomas N. Hansen will respond to Mr. Magruder's Direct Testimony regarding the Environmental Portfolio Standard ("EPS") and the REST in his Rebuttal Testimony.

IX. LOW-INCOME AND THE CARES PROGRAM.

Q. Is the Company modifying its CARES proposal from its original Direct Testimony?

A. Yes. We have reconsidered our original proposal and now offer a separate Medical CARES discount of $10.00 per month, or up to the amount of the customer's bill if less than $10.00. We maintain our proposal for a monthly $8.00 discount, or up to the amount of the customer's bill if less than $8.00. The Company still believes a monthly discount is preferable to a volumetric discount for the reasons Mr. Erdwurm describes in his Direct and Rebuttal Testimonies.

Q. Does that conclude your Rebuttal Testimony?

A. Yes it does.

Rebuttal Testimony
of
Thomas J. Ferry

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783

Rebuttal Testimony of

Thomas J. Ferry

on Behalf of

UNS Electric, Inc.

August 14, 2007

TABLE OF CONTENTS

I. Introduction 1

II. Rebuttal to RUCO Witness Marylee Diaz Cortez 2

III. Rebuttal to RUCO Witness Rodney L. Moore 3

IV. Rebuttal to Staff Witness Julie McNeely-Kirwan 7

V. Rebuttal to Staff Witness Bing E. Young 9

VI. Rebuttal to Staff Witness Steve Taylor 10

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Thomas J. Ferry. My business address is 2498 Airway Avenue, Kingman, Arizona 86401.

Q. Are you the same Thomas Ferry that filed Direct Testimony in this case?

A. Yes.

Q. Have you reviewed the Direct Testimony filed by the Arizona Corporation Commission Staff ("Staff"), the Residential Utility Consumer Office ("RUCO") and other parties in this rate case?

A. Yes, I have.

Q. Which Commission Staff and/or Intervener testimony will you be addressing in your rebuttal testimony?

A. I will be addressing the Direct Testimonies submitted by the following witnesses:

- Ms. Marylee Diaz Cortez on behalf of RUCO (Miscellaneous Service Fees and Rules and Regulations)
- Mr. Rodney L. Moore on behalf of RUCO (Adjustments to Operating Income and Expenses)
- Ms. Julie McNeely-Kirwan on behalf of Staff (Low Income Assistant Programs)
- Mr. Bing E. Young on behalf of Staff (Free Footage Allowance and Bill Estimation)
- Mr. Steve Taylor on behalf of Staff (Reliability and Used And Useful Assessment)

II. REBUTTAL TO RUCO WITNESS MARYLEE DIAZ CORTEZ.

Q. Do you agree with Ms. Diaz Cortez's recommendation for billing and collection notices?

A. No. It appears there may be some confusion about what UNS Electric is requesting. The primary purpose of the recommended changes was to avoid confusion for customers served by both UNS Electric and UNS Gas. Under UNS Electric's proposal, any payment not made after ten days from when the bill was rendered is *past due*. Then, an additional *fifteen* days must elapse before the bill will be considered delinquent. So, 25 days go by from when a bill is rendered until it becomes delinquent. This is more generous than the Commission's rules – A.A.C. R14-2-210.C. – which states that "any bill for utility services are due and payable no later than 15 days from the date of the bill," and "[any] payment not received within this time-frame shall be considered delinquent and could incur a late payment charge."

Also – contrary to Ms. Diaz Cortez's Direct Testimony – the number of days from the bill date to the reminder notice being mailed is unchanged at 26 days. The Company would then give at least a 5-day advance written notice of service disconnection following the bill becoming delinquent. The actual disconnection would not occur before the 31st day of the normal billing cycle. UNS Electric would propose to apply the late payment assessment on delinquent bills only (*i.e.*, 25 days after the date the bill is rendered). The suggested rule language can be modified to clarify that the late payment charges would begin on the day after the delinquency date or 26 days after billing. The Company feels that an average thirty day billing/collection cycle is reasonable and avoids carrying over balances to the next billing period on a routine basis. The Company will continue the current practice of working with customers that request or are in need of payment extensions.

Q. Does that conclude your rebuttal to Ms. Diaz Cortez's Direct Testimony?

A. Yes.

III. REBUTTAL TO RUCO WITNESS RODNEY L. MOORE.

Q. Do you agree with Mr. Moore's Direct Testimony and the adjustments he made to Operating Expenses regarding the call center?

A. No. Mr. Moore stated that the integrated call center does not provide improved service for UNS Electric customers. This is not correct. UniSource now has a consolidated call center supporting UNS Gas, UNS Electric, Inc. and TEP. All share in paying the significant cost of supporting this center based on proportional usage. The Company's response to RUCO's Data Request No. 2.14 details the significant strides made to improve customer service. That response highlights:

- That 8.5 hours per day of coverage has been expanded to 12 hours per day;
- That an IVR capability has been added;
- That an assisted credit card payment option has been added;
- That dedicated Customer Service Representatives have been added;
- 237 trunk lines now available;
- That customers in Mohave and Santa Cruz counties can now call one phone number for both gas and electric inquiries; and
- That extensive call volume tracking and automated call routing is now available

These facts are undisputed. So Mr. Moore is incorrect when he states that the same level of service exists today as in the pre-consolidation of the call center.

Further, Mr. Moore utilizes a Commission report to conclude that the proportion of quality of service complaints in 2004 and 2007 are identical at a value of 15.3% of complaints filed

with the Commission. However, the "quality of service" designation is rather broad and includes issues that do not necessarily involve an interaction with the call center. Issues which may be coded a quality of service complaint include Field or Premises Visit, Outage or Interruptions, Voltage, and finally the catch all category of Other.

Q. Why did the Company transfer its call center functions over to a consolidated call center at TEP?

A. First, UNS Electric did not have a call center. The Company had different phone numbers for various locations within Mohave and Santa Cruz counties. The Company was struggling with call volume before routing customer calls to the call center. Previously we had three to six employees at a time answering calls – in addition to other duties – at three different offices. Today there are normally 65 customer service representatives answering calls with a total capability of 80 customer service representatives available during high volume times. The previous phone systems were only capable of handling 24 calls at once counting internal traffic. There were frequent times that customer complained about not being able to reach a representative. When an outage occurred the conditions were even worse because the phone system would quickly overload resulting in a busy signal for the customer. The consolidated call center has 237 lines and sophisticated call routing and monitoring equipment to assure service quality. Furthermore, the call center environment has greatly improved employee training and more consistent application of company policies. This was a challenge in the individual business offices where employees were performing multiple tasks.

Basically, the system could not continue as it was configured with the high customer growth the Company was experiencing and would have required a significant investment in new systems, phone lines, personnel, facilities and increased staffing and supervision levels to provide adequate customer service. This was regardless whether call center operations

were merged or not. The solution that made the most sense was to transfer the responsibilities to the TEP call center and take advantage of only paying that portion of the fixed cost related to what UNS Electric used rather than it making all of the investment itself.

Q. Have costs and service levels changed?

A. Yes. Costs in total have increased, but the costs had to increase if we were to stay ahead of increasing call volumes. UniSource Energy chose to integrate the call center function because of the investment and technology already in place at the existing TEP call center facility, rather than duplicate a call center elsewhere. To do the latter would have been less cost-effective. Any new investment in additional staff and technology equipment required to provide the above service levels would have been even more significant proportionately to UNS Electric than the existing allocation of costs.

Q. Do you agree with Mr. Moore's assumption regarding training cost disallowance?

A. No. MARC training is just one of a core set of training initiatives to improve employee skills. The Company will continue to provide employee training and the costs of such will be ongoing. Training is necessary to ensure reliability of service and a safe work environment for our employees. The types of training we typically will have employees undertake include:

- supervisory and communications skills;
- extensive safety training;
- environmental education related to handling of hazardous substances and protection of protected plants and animals; and
- technical job related training for customer service specialists and representatives, engineering, metering, construction and maintenance personnel.

I am confident that RUCO believes in continuous employee development provided by good training programs that improves service to customers.

Q. Do you agree with Mr. Moore's adjustment for unnecessary expenses?

A. Not entirely. The Company did carefully review the work papers provided by Mr. Moore as part of our response to RUCO Data Request No. 5.01 and agreed to removing a number of expenses for various reasons. We provided explanations for other expenses which Mr. Moore had assumed were either extensive or inappropriate because he did not have backup details available in his initial review. For example, he assumed that purchases from Walgreens, Wal-Mart or Home Depot were inappropriate while we often use these local stores for miscellaneous office supplies or small tools and hardware for the construction crews. The Company often depends on businesses within the communities we serve as a source for supplies.

Mr. Moore also ignored our explanation of meals either purchased in local restaurants or brought into office meetings.[1] All of these meals were for business reasons or during employee training. Many times our employees work through their normal personal lunch period in order to complete a project or training session. This directly benefits the customers because the employees are in fact being more efficient and productive. Many of our training classes are conducted in one of our Northern Arizona locations for employees from both UNS Electric and Gas. This is less costly for our customers than conducting the same classes at multiple times in several locations. It is unreasonable for Mr. Moore to simply reject valid reasons for such expenses. For example, his denial of a specific expense, such as a barbeque grill, ignores the fact that it was purchased to conduct employee appreciation hamburger lunches following extraordinary efforts these employees

[1] In fact, many of his "out of state" assumptions were in fact local restaurant charges.

during a severe storm season. These employees made those extraordinary efforts *directly* for the customer's benefit. We all understand that hourly employees are paid for the hours they work, but it is my belief that showing appreciation for efforts above and beyond the call of duty is not only the right thing to do but also translates to improved service to our customers. Furthermore, it is common in our small communities for exempt employees to show up without being asked to work along side the non-exempt staff making customer call backs, delivering food to crews in the field , or supporting the dispatchers in tracking storm restoration progress on maps. All of this results in quicker power restorations for our customers and improved safety for our field personnel.

Finally, air travel for the purposes of company travel between a district office in Kingman to the Tucson office by an engineer or manager to conduct business was also deemed inappropriate. However, many times these were very long single-day round trips which were in fact more productive and less expensive than driving five hours each way and staying overnight.

Q. Does that conclude your rebuttal to Mr. Moore's Direct Testimony?

A. Yes, it does.

IV. REBUTTAL TO STAFF WITNESS JULIE MCNEELY-KIRWAN.

Q. Mr. Ferry, could you please summarize your review Staff witness Ms. McNeely Kirwan's Direct Testimony?

A. Yes. I generally agree with most of Ms. McNeely-Kirwan's recommendations. The Company has suggested a number of changes to assist low income customers and agrees with the recommendations to maximize participation by establishing communication with Arizona Health Care Cost Containment System ("AHCCCS") to assist with identifying

eligible customers as is currently done with other community assistance agencies. UNS Electric proposed to implement the Warm Spirits program similar to UNS Gas. The Company agrees with Ms. McNeely-Kirwan's suggestion for administration and promotion of that program.

Q. Do you have any comments about Ms. McNeely-Kirwan's recommendations for Medical CARES disconnects?

A. Yes. Ms. McNeely-Kirwan correctly stated that the Company disconnected six Medical CARES accounts during the test year. The Company understands the special circumstances of Medical CARES customers and has made an extra effort to avoid any disconnection of services. Each disconnect was done only following extensive research and attempts to contact the customer. In five of the six cases, the person that qualified for the Medical CARES tariff was no longer at the service location. The other customer, account #580688, was set up in the system originally as a CARES – Medical customer in error. Her application was actually for regular CARES only. This we believe may have caused some confusion internally and could have contributed to the disconnect in June 2006. The same customer moved to a different address in January 2007 and did not make application as a CARES customer. The account is currently classified as a Residential customer only.

The Company is open to meeting with Staff and other interested parties regarding interpretation of rules and revising practices to address concerns. Also – in light of the concerns the Parties raised in this case – the Company has reconsidered its CARES proposal. UNS Electric now proposes a separate monthly Medical CARES discount of $10 per month, that Mr. Erdwurm describes further in his Rebuttal Testimony.

Q. Does that conclude your rebuttal to the Ms. McNeely-Kirwan's Direct Testimony?

A. Yes, it does.

V. REBUTTAL TO STAFF WITNESS BING E. YOUNG.

Q. Do you agree with Mr. Young's testimony regarding line extension tariff changes?

A. No. The recommended changes proposed by the Company were made to clarify language to avoid customer confusion about current language, update policies to follow the Commission's rules and to be more consistent with UNS Gas and TEP rules as appropriate. Subsection 6.2.a. of the Rules and Regulations was changed to allow only one span of wire from existing facilities to the customer's point of service. The Company suggested a reduction in the service line extension policy which currently allows 150 feet of service wire and one carryover pole. This change would recognize that each customer will have a service drop; but if an individual desires to locate their point of service further from the lines than one span, they should pay for the longer line. Therefore, Mr. Young's statement that the Company is proposing an increase in the footage is not correct. In Subsection 9.D. of the Rules and Regulations the Company proposed combining the current distribution line footage allowance of 400 foot with a service allowance of 100 feet for the total of 500 foot per customer; the combined total being 50 foot and one carryover pole less than what is currently allowed per customer.

Further, Mr. Young must recognize the impacts his proposal will have. The Company believes, generally, that growth should pay for growth. But we also feel that growth is, in fact, good for the communities we serve. Removing the free footage allowance would be a major shift in policy, which would be contrary to the economic development efforts of the communities that UNS Electric serves. Staff must recognize that the construction industry is a major driver of the local economy in rural communities such as Kingman, Lake Havasu

City and Nogales. UNS Electric's policy of requiring developers to advance funds necessary to install electric facilities with refunds only made for permanent customer additions eliminates the risk to other rate payers and the Company. We believe that eliminating the opportunity for developers to recover advances to the Company made for electric facilities could have far-reaching, negative impact on development in our service territories.

Q. Do you agree with Mr. Young's testimony regarding bill estimation?

A. The Company is not aware of "customer confusion" about the current methodology of estimating bills, but is open to reviewing policies to address the new challenges presented to UNS Electric and its customers when time-of-use billing is offered to a larger customer base.

Q. Does that conclude your rebuttal to Mr. Young's Direct Testimony?

A. Yes, it does.

V. REBUTTAL TO STAFF WITNESS STEVE TAYLOR.

Q. Mr. Ferry, please summarize your view of the direct testimony filed by Steve Taylor on behalf of staff.

A. The Company generally agrees with recommendations made by Mr. Taylor.

Q. Do you have any comments regarding reliability suggestions made by Mr. Taylor?

A. Yes, I do. Mr. Taylor noted in his Direct Testimony that UNS Electric's Mohave operations should consider improving reliability tracking. In response, UNS Electric in Mohave is updating our Global Position System/work order system, which will include the implementation of an automated outage management system. This will enable the

Company to track performance of individual feeders as Mr. Taylor suggested. The Company will review other measurement suggestions Mr. Taylor made for immediate implementation which will result in improved industry indices comparisons.

Q. Mr. Taylor suggested that the Company should review the application of lightning arresters for lines in addition to equipment protection.

A. The Company will review the application of lightning arresters on feeders in the next twelve months.

Q. Do you agree with Mr. Taylor's suggestions for London Bridge Substation?

A. We appreciate the recommendation from Mr. Taylor regarding the barbed wire on the gate and oil containment. The gate repairs were completed immediately after Mr. Taylor's visit.

The original substation was constructed in the early 1970's before oil containment was recommended. The new power transformer does include oil containment. A Spill Prevention Control and Countermeasure Plan ("SPCC") for the London Bridge Substation was prepared and certified by an Arizona registered Professional Engineer that addressed the existing transformers. Since that time, EPA promulgated amendments to the SPCC regulations, which among other things, clearly established the applicability of SPCC requirements to oil-filled electrical equipment, and allowed for greater flexibility in meeting secondary containment requirements. The effective date of these rule amendments is July 1, 2009. UNS Electric is currently in the process of revising its SPCC plans in accordance with the amended regulations.

Q. Does this conclude your rebuttal to Mr. Taylor's Direct Testimony?

A. Yes, it does.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Rebuttal Testimony
of
Kentton C. Grant

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	)	DOCKET NO. G-04204A-06-783

Rebuttal Testimony of

Kentton C. Grant

on Behalf of

UNS Electric, Inc.

August 14, 2007

TABLE OF CONTENTS

I. Introduction 1

II. Rebuttal to RUCO Witness William A. Rigsby 3

III. Rebuttal to RUCO Witness Marylee Diaz Cortez 8

IV. Rebuttal to Staff Witness David C. Parcell 20

V. Rebuttal to Staff Witness Ralph C. Smith 33

Exhibits

Exhibit KCG-10 Impact of Plant and Customer Additions on Annual Revenue Deficiency
Exhibit KCG-11 Growth Rates Experienced by Arizona Utilities
Exhibit KCG-12 Forecast of Key Financial Indicators with Company and Staff Proposals
Exhibit KCG-13 Forecast of Key Financial Indicators with Purchase of the BMGS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Kentton C. Grant. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. Are you the same Kentton C. Grant that filed Direct Testimony in this case?

A. Yes.

Q. Have you reviewed the Direct Testimony filed by the Commission Staff and Intervenors in this case?

A. Yes, I have.

Q. Please provide your general response to the Commission Staff and Intervenor testimony.

A. The rate increases recommended by the Commission Staff ("Staff") and by the Residential Utility Consumers Office ("RUCO") are clearly insufficient to support the financial integrity of UNS Electric, Inc. ("UNS Electric"). Neither party presented an analysis of how their recommendations would impact the Company's cash flow and earnings, two critical elements to consider when evaluating the ability of UNS Electric to attract capital on reasonable terms. Under Staff's proposed revenue requirement, the Company's earned return on equity ("ROE") is projected to be only four to five percent in the first full year that new rates are in effect. This ROE is substantially lower than the allowed ROE any Party is recommending in this case, and is even lower than the Company's cost of debt. Due to the impact of regulatory lag and the ratemaking adjustments proposed by Staff and RUCO, the end result of their recommendations is to deny UNS Electric any opportunity to earn a reasonable rate of return as required under the *Hope* and *Bluefield* court decisions. I

note here that Staff and RUCO discuss both *Hope* and *Bluefield* in their respective Direct Testimonies; Mr. William A. Rigsby does so in his Direct Testimony at pages 6 through 7, while Mr. David Parcell does so in his Direct Testimony at pages 5 through 7.

The single largest factor contributing to the lower level of rate relief being recommended by Staff and RUCO is their rejection of the Company's request to include construction work-in-progress ("CWIP") in rate base. Unfortunately, this position appears to be based largely on philosophical grounds and does not take into account the financial realities facing UNS Electric and the facts I presented in my Direct Testimony. Likewise, the Company's alternative request to include a post-test-year adjustment to rate base was summarily dismissed by both parties. And since neither Staff nor RUCO adjusted the test-year balance of customer advances that are tied to the Company's CWIP balance, the positions taken by Staff and RUCO actually serve to penalize UNS Electric for having an ongoing construction program. At a minimum, the balance of customer advances related to the test year CWIP balance should have been removed by the Commission Staff and RUCO as additional rate base adjustments.

Finally, the allowed ROE and overall rate of return ("ROR") on invested capital recommended by Staff and RUCO are unreasonably low in light of the business risks faced by UNS Electric, the extraordinary impact of growth and regulatory lag on the Company's financial performance, and the need to raise additional capital for plant investment. The cost of capital witnesses for Staff and RUCO simply base their ROE recommendations on an analysis of large publicly-traded companies having a significantly lower risk profile relative to UNS Electric. Despite the fact that all of these companies currently pay common dividends and enjoy investment-grade credit ratings, attributes that UNS Electric does not share, neither witness acknowledged the additional risk and required rate of return associated with an equity investment in UNS Electric. Additionally, in quantifying the

overall ROR to be applied to fair value rate base ("FVRB"), Staff has proposed a methodology that is mathematically equivalent to the "backing in" method that was expressly rejected in a recent Arizona Court of Appeals ruling involving Chaparral City Water Company ("Chaparral decision"). Staff's methodology should be rejected and replaced with a methodology that actually gives credence to FVRB in setting rates.

Q. Which Commission Staff and/or Intervenor testimony will you be addressing in your Rebuttal Testimony?

A. I will be addressing the testimony of the following witnesses:

- Mr. William A. Rigsby on behalf of RUCO (Cost of capital)
- Ms. Marylee Diaz Cortez on behalf of RUCO (CWIP in rate base)
- Mr. David C. Parcell on behalf of Staff (Cost of capital & CWIP in rate base)
- Mr. Ralph C. Smith on behalf of Staff (CWIP in rate base)

II. REBUTTAL TO RUCO WITNESS WILLIAM A. RIGSBY.

Q. Mr. Grant, could you please summarize your view of Mr. Rigsby's Direct Testimony?

A. Yes. While Mr. Rigsby concurs with the Company's proposed capital structure and cost of debt, the allowed ROE of 9.3% recommended by Mr. Rigsby is unreasonably low. This recommended ROE is unreasonably low for three reasons. First, it is based in large part on a flawed discounted cash flow ("DCF") analysis for a sample group of publicly-traded electric utilities. Second, it does not reflect the substantial difference in risk between UNS Electric and his proxy group of electric utilities. And third, it is insufficient to support the financial integrity of UNS Electric, a concept that Mr. Rigsby acknowledges in discussing the *Hope* and *Bluefield* cases at page 6, lines 18 through 22, of his Direct Testimony.

Q. Please explain why you consider Mr. Rigsby's DCF analysis to be flawed.

A. Certainly. As can be seen on Schedule WAR-2 attached to his direct testimony, Mr. Rigsby uses dividend growth rates for his proxy group ranging from a low of 2.52% for UIL Holdings to a high of 6.01% for NSTAR. Since these growth rates are used by Mr. Rigsby in a single-stage constant growth DCF model, he implicitly assumes that these growth rates will remain in effect in perpetuity. From the standpoint of market expectations, there are two serious problems with this assumption.

First, compared to most industries, the electric utility industry remains highly regulated and is fairly homogeneous with respect to service offerings and type of capital investment. Although near-term expectations for dividend and earnings growth can vary widely between individual companies, over the long-run it is unrealistic to assume such a wide divergence in growth rates and shareholder returns. Over the long-run, investors are much more likely to expect a convergence of individual company growth rates toward the industry average growth rate. This approach to forecasting long-term growth rates, which assumes that growth rates for individual companies will revert to the industry average over time, is widely practiced by securities analysts and investors. Since Mr. Rigsby did not adjust his perpetual growth rates to account for this factor, the cost of equity estimates he obtained were unrealistically low for most of the companies he examined. Indeed, five of the companies in his proxy group have cost of equity estimates ranging from 6.60% to 7.81%, values that are just barely above comparable utility bond yields.

Second, when adjusted for inflation, the perpetual growth rates used by Mr. Rigsby assume a real rate of growth that is unrealistically low for most of the companies in his proxy group. Based on the difference between the yield on 20-year inflation indexed U.S. Treasury securities (2.7%) and the yield-to-maturity on 20-year fixed-rate U.S. Treasury bonds (5.3%), the expected long-term inflation rate for the U.S. economy was

approximately 2.6% as of June 8, 2007. This is the terminal date Mr. Rigsby uses to calculate the average stock prices in his DCF analysis. Subtracting this expected inflation rate of 2.6% from the dividend growth rates that appear in his Schedule WAR-2 results in a range of expected *real* dividend growth rates of negative 0.1% to positive 3.4%. It is hard to fathom that investors would expect any company, even a highly regulated electric distribution company, to grow its earnings and dividends at a perpetual growth rate that is *less than* the expected rate of inflation. When adjusted for inflation, seven of the eight companies in his proxy group have a perpetual *real* growth rate of 1.7% or less. By contrast, expectations for long-term growth in the overall U.S. economy are likely closer to 3.4% in real terms. It is simply unrealistic to assume that dividends and earnings would grow at such a wide discount to overall economic growth for an industry providing basic utility infrastructure to an expanding U.S. economy.

Q. How did the results from Mr. Rigsby's DCF analysis affect his recommendation for an allowed ROE?

A. Mr. Rigsby derived his recommended ROE of 9.30% by averaging his DCF point estimate of 7.89% with the midpoint of 10.71% obtained from his application of the capital asset pricing model ("CAPM"). By giving equal weighting to his DCF and CAPM analyses, the end result of 9.30% is unreasonably low, is not supported by the range established in his own CAPM analysis, and is well below the midpoint of the range of 7.89% to 11.56% that Mr. Rigsby refers to as his "best estimate" of the cost of equity for UNS Electric (see page 30, lines 1 through 3 of Mr. Rigsby's Direct Testimony).

Q. If Mr. Rigsby's DCF analysis is disregarded, what cost of equity is obtained for his sample group of electric utilities?

A. The results obtained from his CAPM analysis, ranging from 9.85% to 11.56%, can be used as a more realistic estimate of the cost of equity for his sample group of utilities. Indeed,

this range is very similar to the cost of equity estimate presented in my Direct Testimony for the same group of electric utilities (9.7% to 11.2%).

Q. In developing his final ROE recommendation, did Mr. Rigsby take into account the higher risk profile of UNS Electric relative to his sample group of electric utilities?

A. No, he did not. On page 55 of his Direct Testimony, Mr. Rigsby dismisses the company-specific risks faced by UNS Electric that I described in my Direct Testimony at pages 19 through 20. These distinguishing risk factors, each being of significant importance to an investor, are so large on a cumulative basis that they simply cannot be ignored. Relative to the companies in Mr. Rigsby's proxy group, UNS Electric is decidedly riskier for the following reasons:

- Speculative-grade credit rating,
- Lack of common dividend payment,
- Financial impact of growth and regulatory lag,
- Termination of all-requirements power supply contract in 2008,
- Maturity of all long-term debt in 2008, and
- Small size.

Even if Mr. Rigsby is correct in assuming that the Company's small size and power supply challenges should be given little or no weight, the other factors listed above represent risks that need to be clearly recognized in setting an allowed ROE for UNS Electric. At a bare minimum, even if the Company had an investment-grade credit rating, it is apparent that UNS Electric's cost of equity lies at the high end of the range established for the proxy group of companies analyzed by Mr. Rigsby. And when the speculative-grade credit rating of UNS Electric is taken into account – which adversely affects both the cost of debt and equity to the Company – it is also apparent that an equity risk premium must be added to the proxy group results. By ignoring the risk factors cited above, and failing to adjust the

results of his proxy group analysis accordingly, Mr. Rigsby underestimates the Company's cost of equity by a very wide margin.

Q. Did Mr. Rigsby provide any analysis of whether or not his recommended ROR would be sufficient to permit UNS Electric to attract capital on reasonable terms?

A. No, he did not. Other than a blanket statement appearing in his Direct Testimony on page 6, lines 14 to18, Mr. Rigsby offers no analysis in support of his conclusion that his recommended ROR meets the criteria established in the *Hope* and *Bluefield* court rulings.

Q. Is Mr. Rigsby's recommended ROR sufficient to support the financial integrity of UNS Electric?

A. No, it is not. When coupled with RUCO's other recommendations, the rate relief recommended by RUCO is projected to result in an earned ROE of only 2.6% in the first full year after new rates are implemented. This ROE is clearly insufficient to attract additional equity capital and is detrimental to the Company's cash flow and credit profile as well. Mr. Rigsby, in his Direct Testimony on page 7 at lines 15 through 18, recognizes the need to provide UNS Electric with an opportunity to earn a reasonable ROR. But under his recommendation the only "opportunity" the Company would have to realize a reasonable ROR would be to lay off employees, slash other operating expenses and drastically reduce capital expenditures. Such moves would result in a very noticeable reduction to customer service, and would clearly not be in the public interest.

Q. How did you calculate the earned ROE that is projected to result from RUCO's rate recommendations?

A. RUCO is recommending a rate increase that is $7.2 million lower than the Company's request. Adjusting this figure for additional sales growth, this difference in annual revenues would grow to approximately $8.0 million by 2008. On an after-tax basis, this

represents a decrease of approximately $4.8 million in net income relative to the Company's base case financial forecast for 2008, the results of which were summarized in Exhibit KCG-9 attached to my Direct Testimony. In that base case forecast, the Company projected net income of $7.0 million and a return on average common equity of 8.3%. As reflected in the following table, the Company's financial forecast would reflect a projected net income of only $2.2 million and a return on average common equity of 2.6% in 2008 when adjusted for the reduced level of rate relief recommended by RUCO.

($ millions)	Company Forecast (Exhibit KCG-9)	Adjustment	Forecast Adjusted for RUCO Proposal
Net Income	$7.0	($4.8)	$2.2
Return on Equity	8.3%	x (2.2 / 7.0)	2.6%

Q. Does that conclude your rebuttal to Mr. Rigsby's Direct Testimony?

A. Yes, it does.

III. REBUTTAL TO RUCO WITNESS MARYLEE DIAZ CORTEZ.

Q. Mr. Grant, could you please summarize your view of Ms. Diaz Cortez's Direct Testimony?

A. Yes. Ms. Diaz Cortez rejects the Company's request to include CWIP in rate base on several grounds. After describing at length how the rate base treatment of CWIP is not an "accepted" ratemaking treatment – and why the Company must demonstrate that it meets an "extraordinary circumstance" standard – she goes on to state that this ratemaking treatment is not necessary to maintain the Company's financial integrity. Ms. Diaz Cortez also doubts the negative effects of regulatory lag and growth on UNS Electric's financial results, and refers to one of the Company's arguments on CWIP in rate base as being "disingenuous at best."

Q. Do you agree with Ms. Diaz Cortez' characterization of CWIP in rate base as not being an "accepted" ratemaking treatment?

A. No, I do not. The inclusion of CWIP in rate base as a means of supporting the financial integrity of public utilities has been an accepted form of ratemaking treatment for many years in many states. Although the standard for granting this ratemaking treatment varies by jurisdiction, I am not aware of any bright-line "extraordinary circumstance" standard that must be met in the State of Arizona to include CWIP in rate base. While both Staff and RUCO state that "extraordinary circumstances" must be met, neither Party provides *any* guidance as to what would meet their so-called standard. In essence, both RUCO and Staff are stating that under *no* circumstances should CWIP ever be allowed in rate base. While I recognize that rate base treatment of CWIP is not typical in the sense that it has not been used for many years in this jurisdiction, it is certainly a tool that is available to the Commission for purposes of setting fair and reasonable rates. And it is a tool other jurisdictions have employed for utilities in those jurisdictions.

Q. Are you aware of cases where CWIP was included in rate base in Arizona?

A. Certainly. Although I am not an attorney, I am aware of at least two Arizona Supreme Court cases decided in the 1970s that have discussed the issue of CWIP in rate base. For instance, it is my understanding that the Arizona Supreme Court did make the statement – in a rate case involving Arizona Public Service Company ("APS") – that the Commission could adopt any of a variety of approaches and consider plant under construction so long as the approach is not arbitrary. In a subsequent Arizona Supreme Court decision involving an APS rate case, my understanding is that the Court specifically stated that CWIP may be included in fair value rate base and that it was reasonable for the Commission to allow inclusion of CWIP in determining rates. I do not recall there being any language about how "extraordinary circumstances" were needed to put CWIP in rate base.

Q. What standard would you recommend using to determine whether or not CWIP should be allowed in rate base?

A. I recommend applying a financial integrity test. If the cash flow and earnings benefit associated with CWIP in rate base is needed to preserve the financial integrity of the utility, then it is clearly in the public interest to include CWIP in rate base. Financial integrity, or the ability to attract capital on reasonable terms, is a fundamental concept in utility regulation. As described in the *Hope* and *Bluefield* decisions, financial integrity is one of the fundamental goals of rate regulation.

The standard I propose is similar to that in other jurisdictions. For instance, the Florida Public Services Commission allowed $158,761,000 of CWIP in rate base for Tampa Electric Company in 1982 because "our overriding concern is to provide the utility with an opportunity to achieve and maintain adequate financial integrity" so that TEC could maintain its AA bond rating.[1] More recently, the Federal Energy Regulatory Commission ("FERC") has recognized that including a significant percentage of CWIP in rate base for Northeast Utilities Service Company[2] and Boston Edison Company[3] improves utilities cash flow in a less costly manner. Likewise, Virginia seems to have employed a standard that commonly allows CWIP in rate base.[4] In Texas, CWIP has been allowed in rate base on a number of occasions based on a consideration of the utility's financial integrity. In a case in which I testified as a staff witness on this subject, the Texas PUC allowed CWIP in rate base in order to support the financial integrity of Texas Utilities Electric Company.

[1] 49 P.U.R. 547 (Fl.P.S.C. 1982).
[2] 114 FERC 61,089 (2006).
[3] 109 FERC 61,300 (2004).
[4] See In re Appalachian Power Company, 2007 WL 1616129 (2007).

Q. Even if the Commission were to require a finding of "extraordinary circumstance" in order to allow CWIP in rate base, would UNS Electric meet such a standard?

A. Yes, I believe it would. As I discussed on page 22 of my Direct Testimony, it will be very difficult, if not impossible, for the Company to earn its authorized rate of return over the next several years. This is due primarily to the high rate of customer growth in UNS Electric's service territory and the wide gap between the Company's embedded cost of plant and incremental cost of plant on a per-customer basis. Additionally, this growth is causing UNS Electric to raise large sums of additional capital to fund necessary plant investments. The combination of these factors, in my opinion, constitutes extraordinary circumstances that justify CWIP in rate base.

Other jurisdictions employing extraordinary circumstances standards have allowed CWIP in rate base when needed to protect a utility's financial integrity. For example, The New York Public Service Commission notes in its Generic Proceeding investigating financing plans for state gas and electric companies that when necessary to improve a utility's financial integrity and interest coverage levels, including CWIP in rate base is appropriate, along with other measures.[5] The Nevada Public Service Commission ("Nevada Commission"), in 1991, approved CWIP in rate base for 90% of two Nevada Power generation units – because to do so will ensure "a healthy utility to serve the ever growing needs of Southern Nevada."[6] UNS Electric's service area is also fast growing and it needs CWIP in rate base to best serve those areas.

More recently, on January 31, 2003, the South Carolina Public Service Commission ("SCPSC") allowed CWIP in rate base for South Carolina Electric and Gas Company.[7] The SCPSC explained that doing so "will improve the quality of the utility's earnings and

[5] 49 P.U.R.4th 329 (N.Y.P.S.C. 1982).
[6] 132 P.U.R.4th 416 (1991).
[7] 225 P.U.R.4th 440 (2003).

send a constructive message to investors," and "will assist the Company in maintaining access to capital on reasonable terms during a period when the Company will be raising substantial capital in national markets." The SCPSC awarded a return on common equity equaling 12.45% in that case. On July 17, 2007, the Nevada Commission allowed $68,147,000 of CWIP for the "Harry Allen to Mead Transmission Line ("HAM Line")" for NPC, concluding that doing so "will lead to an improved financial situation for NPC, which can lead to lower borrowing costs to the benefit of [its] customers, thereby balancing the interests of ratepayers and NPC". The Nevada Commission found a return of equity for NPC between 10.25% and 10.97% to be reasonable.[8] Finally, the Maryland Public Service Commission allowed CWIP in rate base for Potomac Electric Power Company stating that doing so for certain construction projects reduces the need for construction-driven rate proceedings.[9] The Commission awarded a 10.00% return on equity.

Q. On page 16 of her Direct Testimony, Ms. Diaz Cortez characterizes the Company's financial integrity argument as being "without merit." Did Ms. Diaz Cortez offer any financial analysis to support this conclusion?

A. No, she did not. Although she makes reference to the financial integrity of "Arizona utilities" in general, and cites the positive effects of growth and regulatory lag on UNS Electric, she provides no analysis of the Company's financial performance on either an actual or forecasted basis, and provides no quantitative support for her statements regarding regulatory lag and growth.

[8] 2007 WL 2171450 (2007).
[9] 2007 WL 2159658 (2007).

Q. Do you believe it is necessary to include CWIP in rate base in order to preserve the financial integrity of UNS Electric?

A. Yes, I do. As I discussed in my Direct Testimony on pages 27 through 28, the ability of UNS Electric to earn a reasonable rate of return on its invested capital and to generate a healthy level of internal cash flow is essential if the Company is to maintain continued access to capital on reasonable terms.

Q. On pages 16 through 17 of her Direct Testimony, Ms. Diaz Cortez states that "...the Company's growth argument is without merit as growth has a positive effect on the Company, generating more revenue and cash flow." Do you agree with this statement?

A. No, I do not. While it is true that growth does generate additional revenue, and that over the long-run this growth will generate additional cash flow, Ms. Diaz Cortez ignores the fact that over the short-run the Company's earnings and cash flow are adversely affected by high customer growth. Meeting this growth requires substantial capital investment, currently at a level far exceeding the Company's internal cash flow. This additional investment creates additional fixed costs that UNS Electric must bear, including interest expense, depreciation expense and property taxes. Because of these additional costs, and the regulatory lag resulting from the use of an historical test year and a year-long rate review process, the Company's near-term earnings and cash flow are adversely affected by high customer growth.

Q. Can you provide an example showing the financial impact of customer growth and regulatory lag on UNS Electric?

A. Yes. In order to evaluate the financial impact of growth, we examined the growth in customers and net plant investment during the year ending June 30, 2007, the 12-month period immediately following the test year ending June 30, 2006.

Page 1 of Exhibit KCG-10 shows the increase in annual fixed costs associated with the $30million increase in net plant investment that occurred in the year ending June 30, 2007. Applying the Company's requested pre-tax ROR, the composite depreciation rate and the average property tax rate to this increased plant investment, the Company's annual fixed costs increased by approximately $6.0 million. As shown on page 2 of Exhibit KCG-10, new customers added during this same period resulted in an increase of approximately $1.2 million in annual delivery revenues. As summarized at the bottom of this same page, the difference between the $6.0 million of increased fixed costs and $1.2 million of increased delivery revenues represents an annual revenue *deficiency* of $4.8 million attributable to customer growth and plant investment. Stated another way, this $4.8-million deficiency represents the gap between the Company's required return on new plant investment and the Company's actual return on new plant investment. As a consequence, arguments to exclude CWIP from rate base on the basis of assumed growth-related benefits to UNS Electric simply do not hold water.

Q. Do you have any other comments regarding the example provided on Exhibit KCG-10?

A. Yes. Since additional operation and maintenance costs were not included in this example, this example likely understates the true impact on UNS Electric. Additionally, the plant investment balances used in the example already take into account the effects of depreciation and plant retirements. So the "benefits" of regulatory lag cited by Ms. Diaz Cortez – in her Direct Testimony on page 17 at lines 5 through 12 – have been fully reflected in the analysis. Finally, it should be noted that this quantification of financial impact relates to only a single year. UNS Electric has not had an increase in its delivery charges since the mid-1990s, well before UniSource Energy Corporation ("UniSource Energy") acquired the electric properties formerly held by Citizens in 2003. Additionally, the Company will not likely be able to implement new rates from this proceeding until

early 2008, over a year and a half beyond the test year that ended June 30, 2006. Due to the passage of time, high customer growth and increasing plant investment on a per-customer basis, the cumulative annual revenue deficiency at UNS Electric is quite large. Since the rates currently charged by UNS Electric are based on costs for a test year ending March 31, 1995, there is an obvious need for adequate and timely rate relief at UNS Electric.

Q. Will the impact of growth and regulatory lag be as pronounced in future years?

A. Hopefully not. Although customer growth and plant investment are expected to remain high over the next several years, the gap between the Company's embedded plant investment and incremental plant investment on a per-customer basis should narrow over time. As may be seen in the table below, plant investment on a per-customer basis has increased by 47% over the past three years. Over the next three years, this measure of plant investment is expected to increase by a lower, yet still very high amount, of 26%. This table is similar to the one provided on page 22 of my Direct Testimony, but has been updated to reflect actual results for 2006 and has been expanded to include forecasted information for 2009.

	Net Plant ($ Millions)	Customers	Investment per Customer
Dec. 2003	$93	81,146	$1,147
Dec. 2004	$103	85,464	$1,210
Dec. 2005	$127	89,103	$1,427
Dec. 2006	$157	92,917	$1,690
Dec. 2007 (Forecast)	$183	98,210	$1,863
Dec. 2008 (Forecast)	$209	103,822	$2,013

Dec. 2009 (Forecast)	$234	110,314	$2,121
% Change 2003-2006	68.6%	14.5%	47.3%
% Change 2006-2009	49.0%	18.7%	25.5%

Q. How does this growth compare with the growth experienced by other major Arizona utilities?

A. It is substantially higher. As may be seen in Exhibit KCG-11, over the past three years (2003 through 2006) the growth in net plant investment on a per-customer basis was 3.1% for Southwest Gas Corporation, 14.3% for Arizona Public Service Company and 4.4% for Tucson Electric Power Company. Additionally, UNS Electric's rate of growth is even higher than that experienced by its sister company UNS Gas, Inc. ("UNS Gas"), which experienced growth of 19.1% in net plant investment on a per-customer basis over the past three years.

Q. Have the major credit rating agencies commented on the impact of growth and regulatory lag on regulated utilities?

A. Yes. All of the major credit rating agencies (Moody's, Standard & Poor's and Fitch) have commented on the need for timely cost recovery in rates and the impact of large capital spending requirements on regulated utilities. For example, in November 2006 Standard & Poor's published a report titled "Regulatory Rulings, M&A and Fuel Cost Recovery Dominate Global Utilities Credit Environment." In that report, Standard & Poor's makes a specific reference to the rate recognition of CWIP as a means of supporting utility credit ratings:

> "With few exceptions, regulatory outcomes have supported relatively strong credit characteristics for the utility industry. However, prospectively, regulators will be addressing large base-rate relief requests related to new generating capacity additions, environmental

modifications on coal plants, and transmission and distribution (T&D) improvements. Current cash recovery and/or return by means of construction work in progress support what would otherwise be a sometimes-significant cash flow drain, and reduces a utility's need to issue debt during construction. Moreover, allowing rate recovery of projected costs with subsequent periodic updates for actual results reduces lags in cost recovery."

Q. In her Direct Testimony on page 15, Ms. Diaz Cortez states that "...rate base treatment of CWIP does not change a utility's level of earnings, merely the timing of earnings recovery." Do you agree with that statement?

A. If she is referring to a large multi-year construction project on which an allowance for funds used during construction ("AFUDC") is being accrued, then I would generally agree with her statement. However, in the case of UNS Electric, where the CWIP balance is comprised of many short-lived construction projects, I do not agree. As pointed out in my direct testimony, including the $10.8 million test-year balance of CWIP in rate base would provide the Company with an additional $2.1 million of pre-tax earnings and cash flow. This contribution to earnings far exceeds the $366,000 of AFUDC that UNS Electric recorded for all of 2005 and the $1.1 million of AFUDC recorded for all of 2006 (much of which was tied to the recently completed Valencia gas turbine). And since most of the $10.8 million test year balance of CWIP has already been transferred to plant in service, additional accruals of AFUDC on this test year balance will be quite small. In light of the earnings shortfall illustrated in Exhibit KCG-10, and the lack of significant AFUDC accruals on the test-year balance of CWIP, it is readily apparent that the inclusion of CWIP in rate base affects the level of earnings realized by UNS Electric. This rate treatment also provides an additional source of cash flow needed to fund capital expenditures, a benefit that non-cash accruals of AFUDC do not provide.

Q. On page 17 of her Direct Testimony, Ms. Diaz Cortez states that "The Company's argument that CWIP in rate base will lengthen the period between rate cases also has little merit." Do you agree with that statement?

A. No. Although the timing of UNS Electric's next rate filing will depend on numerous factors, the earnings and cash flow benefit associated with CWIP in rate base should help to extend the period between this rate case and the next rate filing. As I pointed out in my Direct Testimony, rate case preparation is very costly and time consuming for a company the size of UNS Electric, and an extension of time between rate filings is beneficial to both the Company and its customers.

Q. On page 17 of her Direct Testimony, Ms. Diaz Cortez characterizes one of the Company's arguments on CWIP in rate base as being "disingenuous at best." What is your response to this characterization?

A. It is unfortunate that Ms. Diaz Cortez portrays the Company as being disingenuous. As shown on line 4 of Schedule B-1 in the Company's rate application, customers are receiving the full benefit of the $93 million negative acquisition adjustment just as promised in 2003, and will continue to receive that benefit until the negative acquisition adjustment is fully amortized. Additionally, customers will have also received the full benefit of a four-year rate moratorium, despite the obvious burden that the rate freeze has imposed on UNS Electric. What could not be reasonably foreseen in 2003, however, was the huge amount of capital required to meet customer growth and system improvement needs since that time. Similarly, it was difficult to predict the future impact of regulatory lag on UNS Electric. In short, the Company had no way of knowing in 2003 that it would need to request CWIP in rate base in 2006. Sadly, it appears that Ms. Diaz Cortez apparently views this as an attempt by the Company to take back part of the benefit associated with a large negative acquisition adjustment. By referring to the existence of a negative acquisition adjustment in this rate case, the Company is simply pointing out a fact

that cannot be ignored when evaluating the need for timely and adequate rate relief.

Q. In excluding CWIP from rate base, Ms. Diaz Cortez made a $10.8 million downward adjustment to rate base. Did she make a corresponding adjustment to rate base to reduce customer advances?

A. No. At the end of the test year, the portion of customer advances payable by UNS Electric related to the $10.8 million CWIP balance was $1.9 million. Since the full balance of customer advances was deducted from rate base in the Company's rate filing, Ms. Diaz Cortez should have adjusted the balance of customer advances by this amount. By denying CWIP in rate base, and not adjusting the balance of customer advances, RUCO is substituting "cost free" customer advances for $1.9 million of debt and equity capital supplied by the Company for plant in-service at the end of the test year. The end result of RUCO's rate base calculation is to penalize UNS Electric for having an ongoing construction program that is partially financed with customer advances.

Q. Did Ms. Diaz Cortez address the Company's alternative proposal for a post-test year adjustment to rate base?

A. No, I did not find any reference to that proposal in her Direct Testimony. It is likely that her views on post-test year plant adjustments are similar to the views she expressed on CWIP in rate base. However, it should be noted that as of June 30, 2007, $8.7 million of the test year balance of CWIP had already been closed to plant in service and was providing service to UNS Electric customers.

Q. Does that conclude your rebuttal to Ms. Diaz Cortez's Direct Testimony?

A. Yes, it does.

IV. REBUTTAL TO STAFF WITNESS DAVID C. PARCELL.

Q. Mr. Grant, could you summarize your view of the Direct Testimony filed by Mr. David Parcell on behalf of the Commission Staff?

A. Yes. The allowed ROE recommended by Mr. Parcell understates the cost of equity to UNS Electric by a substantial margin. This is due primarily to the conclusions he reached as a result of his CAPM analysis and comparable earnings approach, as well as to his dismissal of Company-specific risk factors and the speculative-grade credit rating assigned to UNS Electric.

The cost of debt and capital structure recommended by Mr. Parcell are very similar to those requested by the Company. However, because he did not take into account the cost of the amendment to UNS Electric's credit agreement completed in August 2006, his recommended cost of debt (8.16%) is slightly lower than the Company's current cost of debt (8.22%), and the percentage of long-term debt in Mr. Parcell's capital structure (47.21%) slightly exceeds the percentage used in the Company's proposed capital structure (47.18%).

For the reasons cited above, the overall ROR recommended by Mr. Parcell on the Company's original cost rate base ("OCRB") is unreasonably low. Additionally, due to his recommendation to assign a zero cost of capital to the difference between the Company's OCRB and FVRB, his recommended ROR on FVRB is also unreasonably low.

Finally, and most importantly, I find Mr. Parcell's analysis of UNS Electric's financial integrity to be severely lacking. The only quantitative financial analysis provided by Mr. Parcell on this topic is a hypothetical calculation of interest coverage that fails to consider the large reduction to the Company's requested rate relief being recommended by Staff.

Additionally, in rejecting the Company's request for CWIP in rate base, Mr. Parcell mistakenly assumes that UNS Electric receives its financing based on the credit quality of UniSource Energy and not on the "...situation of the Company itself." Since lenders and trade creditors having credit exposure to UNS Electric cannot look to UniSource Energy for repayment, the stand-alone credit quality of UNS Electric cannot be ignored, contrary to what Mr. Parcell suggests. By focusing attention on UniSource Energy and away from UNS Electric, it appears that Mr. Parcell is attempting to avoid the "end result" test that he describes on page 6 of his Direct Testimony, where he discusses the financial integrity test required under the *Hope* court ruling.

Q. Please elaborate on Mr. Parcell's cost of equity analysis.

A. Certainly. Regarding Mr. Parcell's DCF analysis, the range of 9.5% to 10.5% he established for his proxy groups is very similar to the range of 9.7% to 10.5% I observed for a similar group of companies. However, the range of 10.0% to 10.5% he established using the CAPM is significantly flawed in at least one respect. Due to this flaw, the cost of equity estimate made by Mr. Parcell in his proxy group analysis is significantly understated. Additionally, Mr. Parcell's comparable earnings analysis is based on a faulty underlying assumption and is influenced by reported earnings that are clearly outside of normal investor expectations.

Q. What issue do you have with Mr. Parcell's application of the CAPM?

A. In establishing a range for his CAPM analysis, Mr. Parcell uses a market risk premium that significantly understates the high end of that range. Although Mr. Parcell recognizes that investors consider arithmetic mean returns in forming opinions on the size of the market risk premium, he does not actually use the arithmetic mean risk premium in establishing his range of CAPM cost estimates. Instead, he uses the average of three different risk premiums in his CAPM calculations, two of which are substantially lower than the

arithmetic mean risk premium. Doing so serves to understate the range of investor expectations for the market risk premium and the cost of equity. Had he used the 6.5% arithmetic mean risk premium he describes instead of the lower 5.9% "average" risk premium from page 25, lines 20 through 25 of his Direct Testimony, the upper end of the range for his CAPM results would have been higher by 0.5% using the median Beta values shown on Schedule 9 attached to his testimony. As a consequence, the upper end of the range for his CAPM analysis would have been 11.0% instead of the 10.5% value described in his testimony. By comparison, the upper end of the range established using the CAPM was 11.2% in my Direct Testimony, and 11.56% in Mr. Rigsby's Direct Testimony.

Q. Did Mr. Parcell also conduct a comparable earnings analysis?

A. Yes, he did. As reflected in the table on page 28 of his Direct Testimony, Mr. Parcell indicated that the average historical earned ROE for the proxy groups he examined ranged from 9.0% to 10.6%, while the average prospective ROE ranged from 9.5% to 10.7%. He uses these ranges to provide further support for his recommended ROE of 10.0% for UNS Electric.

Q. Should any weight be given to Mr. Parcell's comparable earnings analysis?

A. No. First, there is a false presumption that the historical earned returns reported by these companies and the accounting returns projected by Value Line are indicative of the cost of equity to these companies. Second, there are some obvious outliers in the data used by Mr. Parcell that cast further doubt on the validity of this approach.

Q. Please expand on your first concern.

A. Certainly. Several of the companies included in Mr. Parcell's comparison group, which are listed in the top half of Schedule 10 attached to his Direct Testimony, have significant investments in wholesale generation or non-utility affiliates. Furthermore, some of these

companies have experienced prolonged periods of financial stress, including bankruptcy in the case of PG&E Corporation. Under these circumstances, it is difficult to understand how the historical earned returns reported by these companies can be used to estimate the forward-looking cost of equity for a regulated distribution company.

Q. Could you also expand on your second concern?

A. Yes. As may be seen on page 1 of Schedule 10 attached to his testimony, the data relied upon by Mr. Parcell includes some extreme outliers such as Northeast Utilities (3.8% historical earned ROE), PG&E Corporation (5.4% historical earned ROE) and DPL, Inc. (25.5% projected ROE). Such values are obviously not reflective of the cost of equity to a regulated utility, and serve to undermine Mr. Parcell's assumption that earned accounting returns for these companies are somehow indicative of the forward-looking cost of equity. If the presumption underlying the comparable earnings approach has any merit at all, then the earnings of a broader industry composite should be used instead of the relatively small sample groups used by Mr. Parcell. As may be seen in the first page of Attachment A to Mr. Rigsby's Direct Testimony, on the lower left hand corner, Value Line expects the composite return on common equity for the electric utility industry to be 11% for the periods 2007, 2008 and 2010-2012. On an historical basis, Value Line shows a composite earned ROE of 10.9% to 12.4% for the industry over the period 2003-2006. These values are significantly higher than the sample group averages cited by Mr. Parcell.

Q. Do you have any further comments regarding Mr. Parcell's cost of equity analysis?

A. Yes. Similar to Mr. Rigsby, Mr. Parcell dismisses the company-specific risk factors cited in my direct testimony for UNS Electric. As a consequence, his cost of equity estimate for UNS Electric is significantly understated. I discuss these company-specific risk factors, and why they must be considered in setting the allowed ROE for UNS Electric, when rebutting Mr. Rigsby's testimony earlier in my Rebuttal Testimony.

Q. On page 14 of his direct testimony, Mr. Parcell refers to a 2003 rating agency report on UNS Electric. Is UNS Electric rated by any of the major credit rating agencies?

A. No, it is not. However, as indicated in my Direct Testimony, the Company did receive a rating of NAIC-3 on the long-term debt issued to finance the acquisition of Citizens' Arizona Electric properties in August 2003. This rating was assigned by the credit committee of the Securities Valuation Office of the National Association of Insurance Commissioners ("NAIC").

Q. What does a security rating of NAIC-3 say about the credit profile of UNS Electric?

A. A rating of NAIC-3 is roughly equivalent to a speculative-grade credit rating of "BB" (or double-B) assigned by Standard & Poor's and Fitch, or the speculative-grade rating of "Ba" assigned by Moody's. By contrast, UNS Electric's sister company, UNS Gas, received a higher investment-grade rating of NAIC-2. The definitions for these security ratings, as published by the NAIC, are provided below (with emphasis added):

> **NAIC 2** is assigned to obligations of high quality. Credit risk is low but may increase in the intermediate future and ***the issuer's credit profile is reasonably stable.*** This means that for the present, the obligation's protective elements suggest a high likelihood that interest, principal or both will be paid in accordance with the contractual agreement, but there are suggestions that an adverse change in circumstances or economic, financial or business conditions will affect the degree of protection and lead to weakened capacity to pay. An NAIC 2 obligation should be eligible for relatively favorable treatment under the NAIC Financial Conditions Framework.

> **NAIC 3** is assigned to obligations of medium quality. Credit risk is intermediate and ***the issuer's credit profile has elements of instability. These obligations exhibit speculative elements.*** This means that the likelihood that interest, principals or both will be paid in accordance with the contractual agreement is reasonable for the present, but an exposure to an adverse change in circumstances or economic, financial or business conditions would create an uncertainty about the issuer's capacity to make timely payments. An NAIC 3 obligation should be eligible for less favorable treatment under the NAIC Financial Conditions Framework.

Q. Is there any reason to believe that UNS Electric would achieve a higher security rating today?

A. No. The Company is currently at a low point in terms of earnings and cash flow. While it is possible that UNS Electric could achieve a higher rating following the conclusion of this rate case, that possibility exists only if all (or substantially all) of the Company's requested rate relief is granted by the Commission.

Q. How does a speculative-grade credit rating affect the cost of debt and equity capital?

A. As I discussed on pages 20 through 21 of my Direct Testimony, a speculative grade credit rating adds at least 60 basis points (or 0.6%) to the cost of debt and equity. This observed risk premium is low relative to historical credit spreads, which were significantly higher just a few years ago. For example, in 2003 when UNS Electric and UNS Gas issued their existing long-term notes, investors required a coupon of 7.61% for UNS Electric and only 6.23% for UNS Gas. Furthermore, the maturity of the UNS Electric note was shortened to five years, compared with an average maturity of ten years for the UNS Gas notes. This real life example serves to illustrate the impact of credit quality on the cost of capital. Unfortunately, Mr. Parcell chooses to ignore this reality in making his cost of equity recommendation for UNS Electric.

Q. Did Mr. Parcell adopt the Company's proposed cost of debt and capital structure for UNS Electric?

A. Not exactly. While the Company adjusted the test year cost of debt and capital structure for the cost of amending UNS Electric's credit facility in August 2006, Mr. Parcell chose to use the unadjusted test year values. Since the Company was able to significantly reduce its cost of short-term borrowing by making this amendment, UNS Electric believes that it is appropriate to adjust the cost of debt and capital structure to reflect the cost of this amendment. Furthermore, the savings associated with this amendment are already

reflected in the 6.36% cost of short-term debt proposed by the Company and used by Mr. Parcell in his overall ROR recommendation.

Q. On page 31 of his testimony, Mr. Parcell concludes that his cost of capital recommendation provides the Company with "a sufficient level of earnings to maintain its financial integrity." Do you agree with his conclusion?

A. No, I do not. Mr. Parcell made no attempt to determine whether or not the Company could actually earn his recommended ROE of 10.0% or his overall ROR of 8.99%. Based on all of the adjustments made by Staff, the recommended rate increase for UNS Electric is only $3.8 million, or 45% of the Company's requested increase. If Staff's recommendations were accepted in their entirety, the Company would have no opportunity to actually earn the ROR recommended by Mr. Parcell. As a result, the pre-tax interest coverage calculation presented on Schedule 14 attached to his Direct Testimony represents nothing more than a hypothetical example. While I appreciate Mr. Parcell's intent, which is to examine the impact of his recommendations on the Company financial integrity, it does not take into account the numerous adjustments made by other Staff witnesses that serve to limit any improvement in the Company's earnings and cash flow.

Q. Did Mr. Parcell make any other observations regarding the Company's financial integrity?

A. Yes. On pages 14 through 15 of his Direct Testimony Mr. Parcell addresses the Company's ability to attract capital. In this section of his testimony, he states that it is not "necessary" for UNS Electric to include CWIP in rate base in order to attract capital. In support of his conclusion, he cites rating agency reports that refer to UNS Electric as "low risk." However, the only rating agency report specifically cited by Mr. Parcell is a report by Standard & Poor's published in 2003. This report is now four years old and was written at a time when UNS Electric had five years remaining on a full-requirements power supply

agreement and when the cumulative effects of growth and regulatory lag on UNS Electric had not yet materialized. Mr. Parcell also makes reference to the supposed ability of UNS Electric to attract financing based on the credit quality of UniSource Energy. However, this assumption is incorrect, since no guarantees of UNS Electric debt obligations have been issued by UniSource Energy, TEP, or any other corporate affiliate other than UniSource Energy Services ("UES"), the parent company of UNS Electric and UNS Gas.

Q. Do you agree with Mr. Parcell's conclusion that CWIP is not necessary for UNS Electric to attract capital?

A. I agree that over the short-run, assuming no significant changes occur in the capital markets, that UNS Electric could probably attract additional capital without having CWIP in rate base. However, what Mr. Parcell does not address is the ability of the Company to attract capital on *reasonable terms*. If capital market conditions were to deteriorate, resulting in tighter lending standards and a more risk averse environment, the Company would face significantly higher borrowing costs and a contracting market for its speculative-grade debt. Even if the capital markets were to remain fairly stable, the prospect of earning low single-digit returns on equity, having high capital spending requirements and no common dividend payout would cause any prospective equity investor to think twice before committing additional equity capital to UNS Electric. Under these circumstances, the Company would have to rely more heavily on debt capital to fund its capital spending needs. With this additional debt leverage comes additional lending risk, and the cost of debt to UNS Electric would likely increase significantly. Additionally, it should be recognized that the Company's borrowing capacity is not infinite. So while Mr. Parcell is correct that additional capital could probably be attracted over the short-run, the cost of this capital will be significantly higher, resulting in adverse long-term effects on the Company and its customers.

Q. Is the calculation of a hypothetical interest coverage ratio sufficient to determine whether or not UNS Electric will be able to attract capital on reasonable terms?

A. No, it is not. In order to assess the real financial impact of Staff's recommendations, it is necessary to examine the Company's financial forecast and to adjust that forecast for the reduced level of rate relief recommended by Staff. Financial forecasts for UNS Electric were provided to Staff through the discovery process, along with supporting calculations of key financial indicators. While I am well aware of the complexities involved in adjusting financial forecasts, it is a relatively easy task to assess the impact of a reduced rate recommendation on certain key financial measures such as net income, operating cash flow and return on equity.

Q. How does Staff's recommended rate increase impact key financial indicators forecasted for UNS Electric?

A. Staff has recommended a $4.7 million reduction to the Company's requested level of rate relief based on test-year sales levels. Adjusting this figure for additional sales growth, this difference in annual revenues would grow to approximately $5.2 million by 2008. On an after-tax basis, this represents a decrease of approximately $3.1 million in net income and operating cash flow relative to the Company's base case financial forecast for 2008, the results of which were summarized in Exhibit KCG-9 attached to my Direct Testimony. In that base case forecast, the Company projected net income of $7.0 million, a return on average common equity of 8.3%, and operating cash flow of $17.8 million in 2008. As reflected in the following table, the Company's financial forecast would reflect a projected net income of only $3.9 million, a return on average common equity of approximately 4.6%, and operating cash flow of $14.7 million in 2008 when adjusted for the reduced level of rate relief recommended by Staff.

($ millions)	Company Forecast (Exhibit KCG-9)	Adjustment	Forecast Adjusted for Staff Proposal
Net Income	$7.0	($3.1)	$3.9
Return on Equity	8.3%	x (3.9 / 7.0)	4.6%
Operating Cash Flow	$17.8	($3.1)	$14.7

If Mr. Parcell's hypothetical 10.0% earned ROE on Schedule 14 of his Direct Testimony is replaced with the 4.6% adjusted ROE from the table above, the pre-tax coverage ratio calculated by Mr. Parcell would fall from 3.0X to 1.9X. Although Schedule 14 attached to his testimony indicates that a minimum coverage ratio of 1.8X is required for a "BBB" investment-grade credit rating, such a rating would not be feasible for UNS Electric due to the cash flow impact of Staff's rate recommendation.

Q. Does UNS Electric have a more recent base case financial forecast that can be used to evaluate the prospective financial condition of the Company?

A. Yes. Exhibit KCG-12 provides an updated summary of projected key financial indicators. This exhibit has been updated to include actual reported results through June 30, 2007, and includes an updated base case forecast reflecting the Company's requested rate increase, as well as a forecast reflecting Staff's recommended rate increase. Additionally, it should be noted that the forecast reflecting Staff's proposal also incorporates the recommendation of Staff witness Bing Young to eliminate the free footage allowance for new line extensions, a recommendation that would reduce UNS Electric's net capital expenditures by approximately $3 million per year.

Q. What do these financial forecasts reveal about UNS Electric's need for rate relief?

A. Even under the base case, which assumes that UNS Electric's requested rate increase is granted in full, the Company will still not be able to earn its requested ROE. Due to the

extraordinary growth in net plant investment, increases to operating expenses and the need for substantial amounts of new capital, the Company's earned ROE is projected to peak at 8.4% in 2008 (assuming a full year of rate relief) and is expected to decline gradually from that point forward. (See page 1 of Exhibit KCG-12.) Under the Staff case, the Company's earned ROE is projected to peak at 4.8% in 2008 (again assuming a full year of rate relief), and is expected to gradually decline in subsequent years. Based on this measure alone, it is apparent that the Company is in dire need of rate relief.

Q. How is the Company's credit profile affected by the rate increases proposed by UNS Electric and by Staff?

A. As may be seen at the bottom of page 1 of Exhibit KCG-12, under the Company's rate proposal operating cash flow is projected to improve modestly relative to the levels recorded in 2006 and forecasted for 2007. However, under the Staff case, operating cash flows are projected to remain near current depressed levels. This impact on cash flow can also be seen in two key credit quality ratios: the funds from operations ("FFO") interest coverage ratio and FFO as a percentage of total debt. These forecasted ratios, which are shown on page 3 of Exhibit KCG-12, indicate modest improvement relative to 2006 and 2007 under the Company's rate proposal. By contrast, Staff's rate proposal is projected to result in a further deterioration of these two key ratios. This trend is understandable since no significant improvement in operating cash flow is forecasted to occur per Staff's recommendations, while at the same time the Company is borrowing additional debt capital to fund capital expenditures. Such a scenario would not bode well for the Company's credit profile and access to capital.

Actual and forecasted values for two other credit quality ratios are shown on page 2 of Exhibit KCG-12. Net cash flow as a percentage of capital expenditures is expected to remain low relative to industry median values even if the Company is granted its full rate

request. In terms of capital structure, UNS Electric's equity ratio is projected to improve gradually under the Company's rate proposal. Under the Staff case, however, the Company's equity ratio is projected to remain below the test year level of 49% through at least 2009 due to a combination of lower earnings and higher borrowing at UNS Electric. Furthermore, this forecast assumes that an additional $10 million of equity capital is injected into the Company in 2008. In light of the anemic ROE forecast for UNS Electric under Staff's rate proposal, it is unlikely that such an investment could be justified to UniSource Energy's shareholders.

Q. In light of these projections, do you believe that Staff's rate proposal would give UNS Electric an opportunity to earn a reasonable ROR and enable the Company to maintain its credit?

A. No, I do not. An earned ROE of four to five percent, coupled with further deterioration in the Company's debt and interest coverage ratios, will not allow the Company to maintain its credit or attract capital on reasonable terms.

Q. Would your opinion change if the Company were granted deferred accounting treatment for the Black Mountain Generating Station ("BMGS") as Staff's witness Ralph C. Smith recommends?

A. No, it would not. Such accounting treatment would do nothing for the Company's cash flow, even though large amounts of capital would have to be raised in order to fund the purchase of this $60 million to $65 million generating facility. Adding this additional capital, with no commensurate increase in cash flow, would seriously degrade the Company's credit profile.

Q. Has the Company prepared financial forecasts that include the proposed purchase of the BMGS?

A. Yes. Exhibit KCG-13 contains key financial ratio projections reflecting both the Company's rate proposal and Staff's rate proposal.

Q. What conclusions can be drawn from these forecasts?

A. First, as described in Mr. Kevin P. Larson's Direct Testimony, the Company's financial profile is modestly improved if the BMGS is afforded rate base treatment and the proposed rate reclassification is implemented upon commercial operation. As may be seen at the bottom of page 1 of Exhibit KCG-13, the most visible sign of improvement is the significant increase in operating cash flow under the Company's rate proposal. As may be seen on page 2 of this same exhibit, this also translates into a significant improvement in the ratio of net cash flow to capital expenditures in 2009. Although other key ratios under the Company's rate proposal remain about the same as shown in Exhibit KCG-12, which does not reflect the proposed purchase of the BMGS, the overall financial condition of UNS Electric is modestly improved despite having raised a substantial amount of additional debt and equity capital.

Under Staff's proposal, which reflects only a $3.8 million rate increase and a deferred accounting order for the BMGS, the forecasted results are decidedly different. Instead of increasing, the Company's operating cash flow is actually projected to decrease relative to current levels. And, since additional debt is needed to fund the purchase of the BMGS, the FFO interest coverage ratio and FFO as a percentage of total debt both decline markedly from current levels. (See page 3 of Exhibit KCG-13.) Additionally, despite the assumption that all non-fuel costs of the BMGS would be deferred on the Company's income statement, the earned ROE for UNS Electric is projected to remain in the four to five percent range through 2009. (See page 1 of Exhibit KCG-13.) Such a ROE is clearly

insufficient to attract the capital needed to finance the proposed purchase of the BMGS.

Q. Does Mr. Parcell make a recommendation regarding the appropriate ROR to apply to fair value rate base ("FVRB")?

A. Yes, he does. On page 38 of his Direct Testimony, Mr. Parcell recommends assigning a zero cost of capital to the difference between OCRB and FVRB. This methodology is mathematically equivalent to the "backing-in" method traditionally used by Staff to determine the ROR on FVRB, a method that was recently found deficient by the Arizona Court of Appeals in the Chaparral decision.

Q. Do you have a different recommendation for determining the ROR on FVRB?

A. Yes, I do. I recommend that the Commission apply the weighted average cost of capital (or overall ROR) to the Company's fair value rate base for purposes of setting rates in this proceeding. To the extent such a calculation would result in a higher rate increase than proposed by the Company, UNS Electric would still be limited to the original rate relief sought in the Company's rate application.

Q. Does that conclude your rebuttal to Mr. Parcell's Direct Testimony?

A. Yes, it does.

V. <u>REBUTTAL TO STAFF WITNESS RALPH C. SMITH.</u>

Q. Mr. Grant, could you please summarize your view of Mr. Smith's Direct Testimony?

A. Yes. Similar to Ms. Diaz Cortez, Mr. Smith rejects the Company's request for CWIP in rate base largely on philosophical grounds. Although he recognizes that the inclusion of CWIP in rate base is up to the Commission's discretion, he offers several reasons why Staff does not recommend this ratemaking treatment.

Q. What specific reasons are offered by Mr. Smith in rejecting the Company's request for CWIP in rate base?

A. On page 14 of his Direct Testimony, Mr. Smith offers four reasons for rejecting the Company's request for CWIP in rate base. The first two reasons, that CWIP in rate base is not normally allowed by the Commission, and that projects included in the test year CWIP balance were not yet in service as of the test year, are merely statements of the obvious; they are not reasons to automatically disallow CWIP in rate base for UNS Electric. The third reason, which relates to the need to recognize revenues produced by projects included in the test year CWIP balance, is both impractical and unnecessary. It is impractical due to the need to identify the incremental revenue generated by every customer added as a result of the test year investment in CWIP, which by definition includes numerous partially-completed projects that may facilitate customer additions over a number of years. It is also unnecessary for the reason explained in my rebuttal of Ms. Diaz Cortez; namely that growth is detrimental to UNS Electric's earnings over the short-run. The fourth and final reason offered by Mr. Smith in rejecting the Company's request is that UNS Electric has made no specific enforceable commitment to a rate case moratorium period. In offering this reason, Mr. Smith erroneously assumes that UNS Electric would somehow be in a position to make such a commitment prior to knowing how much rate relief it will receive.

Q. In excluding CWIP from rate base, Mr. Smith made a $10.8 million downward adjustment to rate base. Did he make a corresponding adjustment to rate base to reduce customer advances?

A. No. At the end of the test year, the portion of customer advances payable by UNS Electric related to the $10.8 million CWIP balance was $1.9 million. Since the full balance of customer advances was deducted from rate base in the Company's rate filing, Mr. Smith should have adjusted the balance of customer advances by this amount. By denying CWIP in rate base, and not adjusting the balance of customer advances, the result is to penalize

UNS Electric for carrying a balance of CWIP at the end of the test year.

Q. Did Mr. Smith consider the Company's alternative request for including post-test year plant additions in rate base?

A. Yes, he did. However, he did not have any additional reasons to offer for rejecting this ratemaking alternative, which would provide rate base treatment for the $8.7 million of test-year CWIP that has already been place into service.

Q. Assuming the Company were allowed to put the test year balance of CWIP in rate base, does Mr. Smith agree with your recommendation to continue accruing AFUDC on all new construction projects?

A. No, he does not. Unfortunately, he believes that doing so would be improper and would "...give UNS Electric both a cash return on CWIP through its inclusion in rate base and an AFUDC return," as he notes in his Direct Testimony on page 17 at lines 8 through 10. He goes on to state that "If CWIP were to be allowed in rate base, which the Staff is not recommending in this case, then AFUDC accruals on the amount of CWIP included in rate base must cease." While UNS Electric agrees that it would be improper after new rates are implemented to continue accruing AFUDC on specific projects that (i) were included in the test year balance of CWIP and (ii) are still classified as CWIP at the time new rates are implemented, Mr. Smith is advocating something entirely different. Instead, Mr. Smith is advocating that the *amount* of test year CWIP allowed in rate base (e.g., $10.8 million per the Company's request) be deducted from all future CWIP balances in calculating AFUDC, even if the test year CWIP projects have long since been closed to plant in-service. As pointed out in my Direct Testimony, this would be unfair to a Company such as UNS Electric that has many short-lived construction projects in its CWIP balance at any given time. Since the FERC accounting guidelines on CWIP and AFUDC accounting were intended to address the inequity associated with earning both a cash return and an

AFUDC return on a large project at the same time, such as might occur with the construction of a large baseload generating facility, an exception to this accounting guideline is warranted in the case of UNS Electric.

Q. Do you have any other comments on Mr. Smith's testimony?

A. No. Most of his concerns regarding CWIP in rate base are similar to the concerns voiced by Ms. Diaz Cortez, which I have already addressed earlier in my Rebuttal Testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT

KCG-10

UNS Electric, Inc.
Impact of Plant and Customer Additions on Annual Revenue Deficiency

Increase to Annual Fixed Costs from Plant Additions

Net Utility Plant at 6/30/07	$171,456,000
Less: Net Utility Plant at 6/30/06 (end of test year)	($141,550,000)
Increase in Net Plant for Year Ended 6/30/07	$29,906,000
x Fixed Cost Factor	20.05%
Increase in Annual Fixed Costs	**$5,997,054**

Derivation of Fixed Cost Factor:

	% Capital Structure	Cost	Weighted Cost	Tax Factor	Pre-Tax Cost
Equity Capital	48.85%	11.80%	5.76%	1.635	9.42%
Long-Term Debt Capital	47.18%	8.22%	3.88%	1.000	3.88%
Short-Term Debt Capital	3.97%	6.36%	0.25%	1.000	0.25%
	100.00%		9.64%		13.55%

Composite Depreciation Rate	4.18%
Composite Property Tax Rate	2.32%
Annual Fixed Cost of Plant Additions	20.05%

UNS Electric, Inc.
Impact of Plant and Customer Additions on Annual Revenue Deficiency

Increase to Annual Delivery Revenues from Customer Additions

	Residential	Commercial	Other	Industrial	Total
Estim. Increase in Customers for Year Ended 6/30/07	2,483	219	9	0	2,712
x Use per Customer (normalized test year kWh)	10,355	63,135	1,308	N/A	14,588
Increase in Annual kWh Sales	25,714,313	13,831,180	12,211	-	39,557,704
x Average Revenues per kWh (test year)	$0.0303	$0.0287	$0.1110	N/A	$0.0298
Increase in Annual Revenues	$779,544	$397,633	$1,356	-	$1,178,533

Increase to Annual Revenue Deficiency from Plant and Customer Additions

Increase in Fixed Costs	$5,997,054
Less: Increase in Delivery Revenues	($1,178,533)
Increase to Revenue Deficiency	$4,818,521

EXHIBIT

KCG-11

Growth Rates Experienced by Arizona Utilities

Southwest Gas Corporation

	Net Plant ($ Millions)	Customers	Investment per Customer
1995	$1,138	985,043	$1,155
1996	$1,278	1,044,506	$1,224
1997	$1,360	1,104,060	$1,232
1998	$1,459	1,162,831	$1,255
1999	$1,581	1,224,770	$1,291
2000	$1,686	1,289,104	$1,308
2001	$1,826	1,348,970	$1,354
2002	$2,034	1,407,286	$1,445
2003	$2,176	1,467,752	$1,483
2004	$2,336	1,550,509	$1,507
2005	$2,489	1,645,004	$1,513
2006	$2,668	1,745,125	$1,529
Compound Annual Growth Rate (1995 - 2006)	8.1%	5.3%	2.6%
Absolute Growth Over Last 3 Years (2003 - 2006)	22.6%	18.9%	3.1%

Arizona Public Service Company

	Net Plant ($ Millions)	Customers	Investment per Customer
1995	$4,647	704,993	$6,592
1996	$4,655	737,504	$6,312
1997	$4,678	766,531	$6,103
1998	$4,731	796,410	$5,940
1999	$4,753	826,935	$5,748
2000	$4,910	864,990	$5,676
2001	$5,059	892,805	$5,666
2002	$5,886	921,251	$6,389
2003	$6,070	953,251	$6,368
2004	$6,258	989,502	$6,324
2005	$7,525	1,033,423	$7,282
2006	$7,827	1,075,191	$7,280
Compound Annual Growth Rate (1995 - 2006)	4.9%	3.9%	0.9%
Absolute Growth Over Last 3 Years (2003 - 2006)	28.9%	12.8%	14.3%

Growth Rates Experienced by Arizona Utilities

Tucson Electric Power Company

	Net Plant ($ Millions)	Customers	Investment per Customer
1995	$1,125	302,517	$3,719
1996	$1,117	310,950	$3,592
1997	$1,116	316,895	$3,522
1998	$1,114	324,866	$3,429
1999	$1,293	334,137	$3,869
2000	$1,298	342,914	$3,786
2001	$1,299	350,938	$3,701
2002	$1,480	359,372	$4,118
2003	$1,506	367,239	$4,101
2004	$1,538	375,532	$4,096
2005	$1,616	384,898	$4,199
2006	$1,681	392,477	$4,283
Compound Annual Growth Rate (1995 - 2006)	3.7%	2.4%	1.3%
Absolute Growth Over Last 3 Years (2003 - 2006)	11.6%	6.9%	4.4%

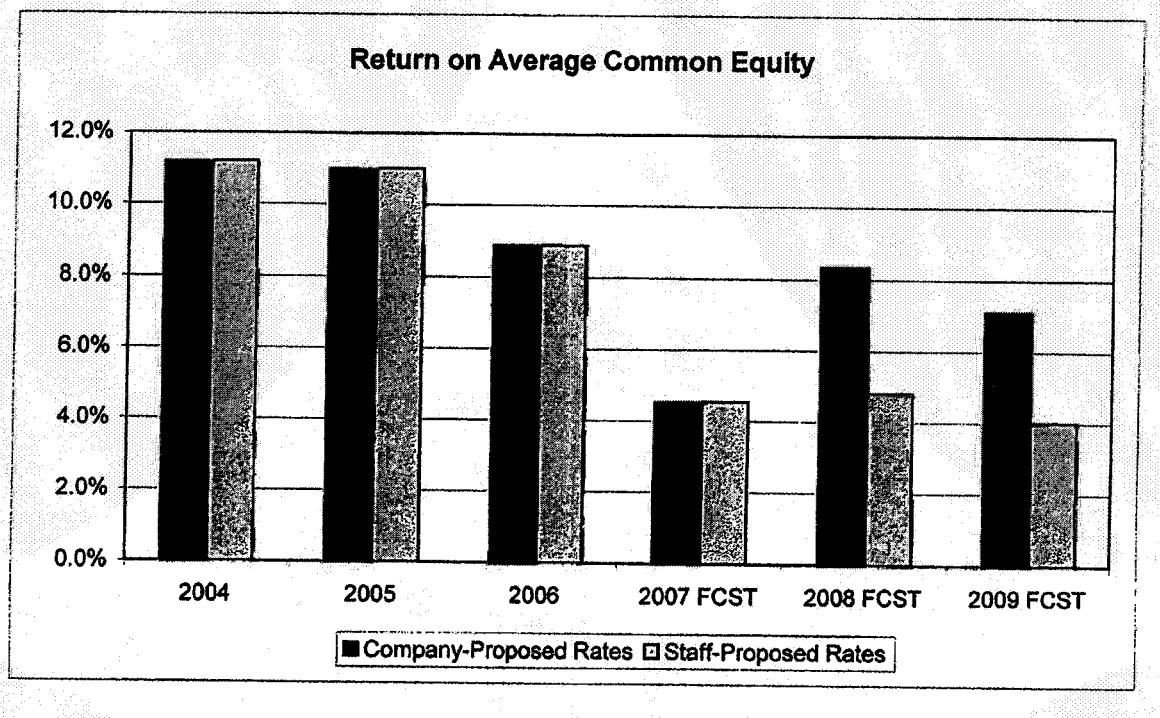
UNS Electric, Inc.

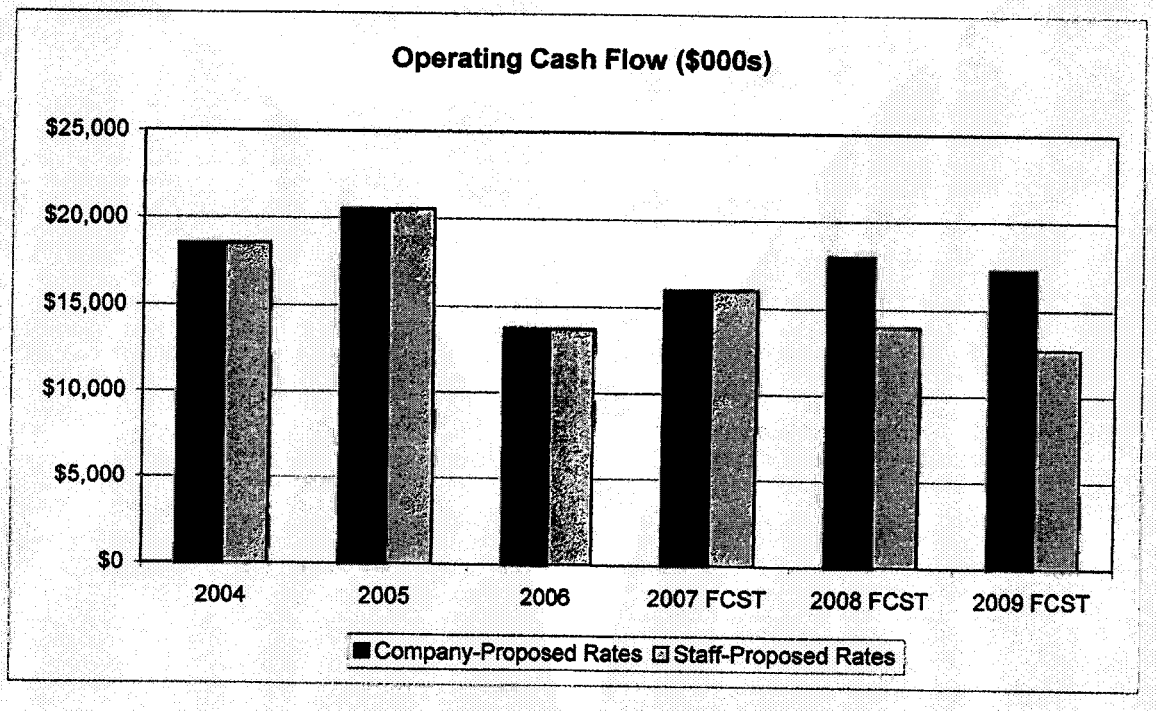
	Net Plant ($ Millions)	Customers	Investment per Customer
2003	$93	81,146	$1,147
2004	$103	85,464	$1,210
2005	$127	89,103	$1,427
2006	$157	92,917	$1,690
2007 Fcst.	$183	98,210	$1,863
2008 Fcst.	$209	103,822	$2,013
2009 Fcst.	$234	110,314	$2,121
Compund Annual Growth Rates			
2003-2006	19.0%	4.6%	13.8%
2006-2009 Fcst.	14.2%	5.9%	7.9%
Absolute Growth			
2003-2006	68.6%	14.5%	47.3%
2006-2009 Fcst.	49.0%	18.7%	25.5%

EXHIBIT

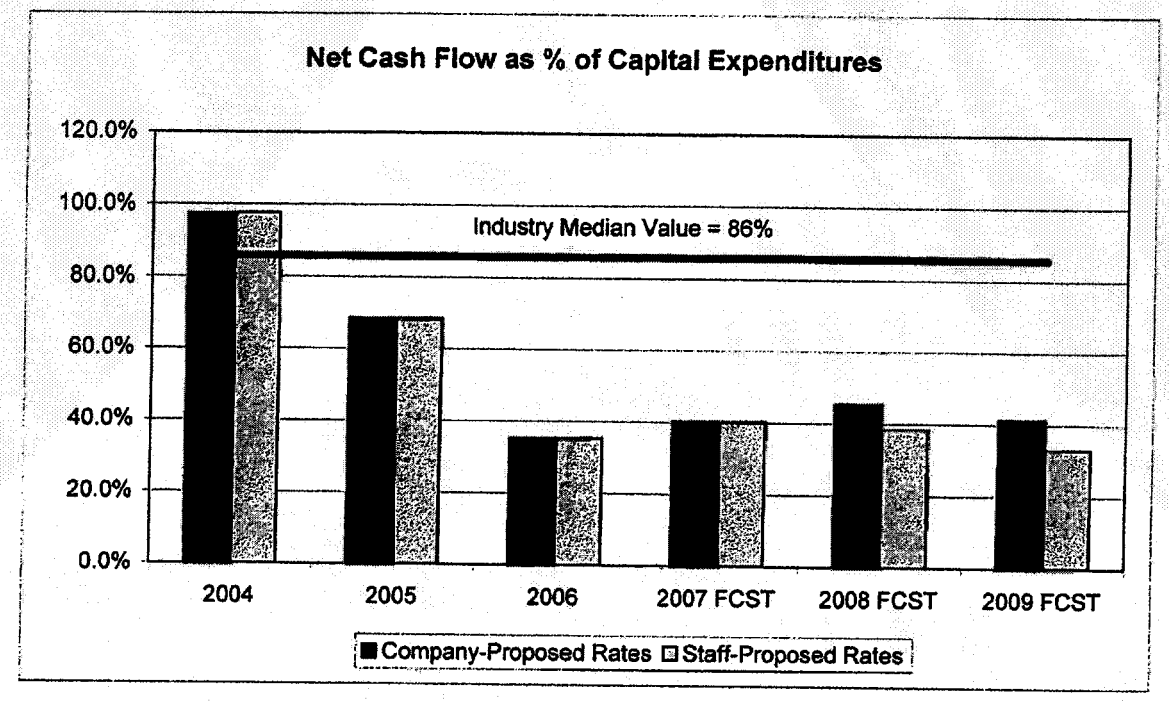
KCG-12

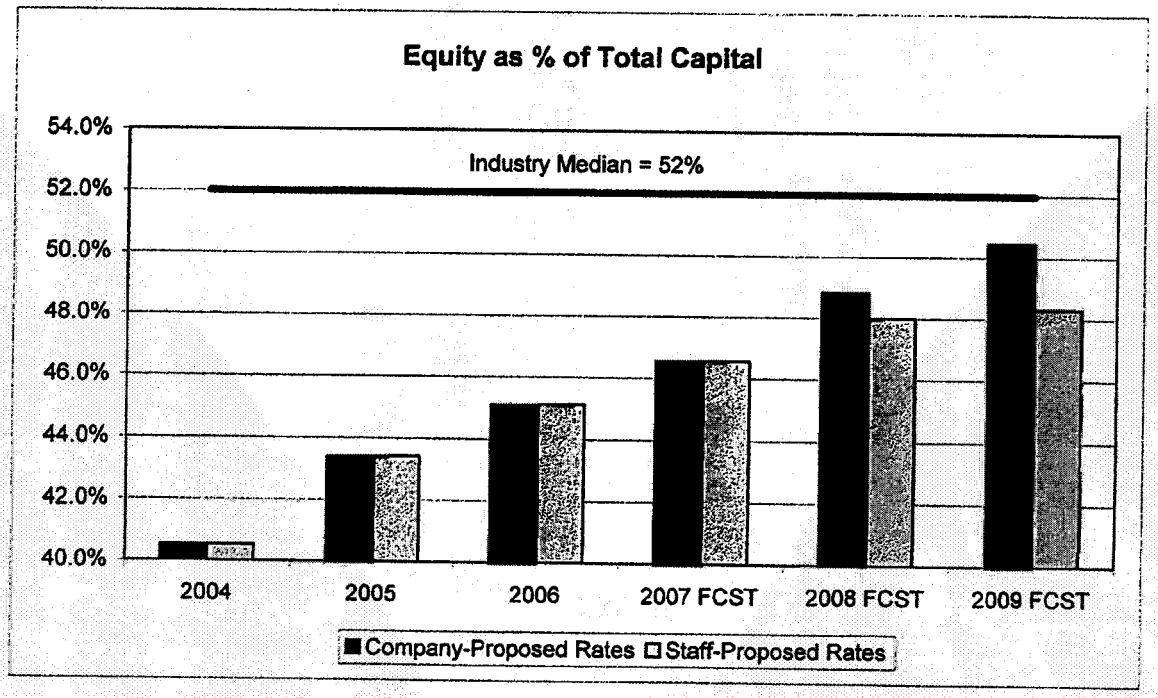
UNS Electric, Inc.
Updated Financial Forecast with Company and Staff Rate Proposals
Summary of Key Financial Indicators



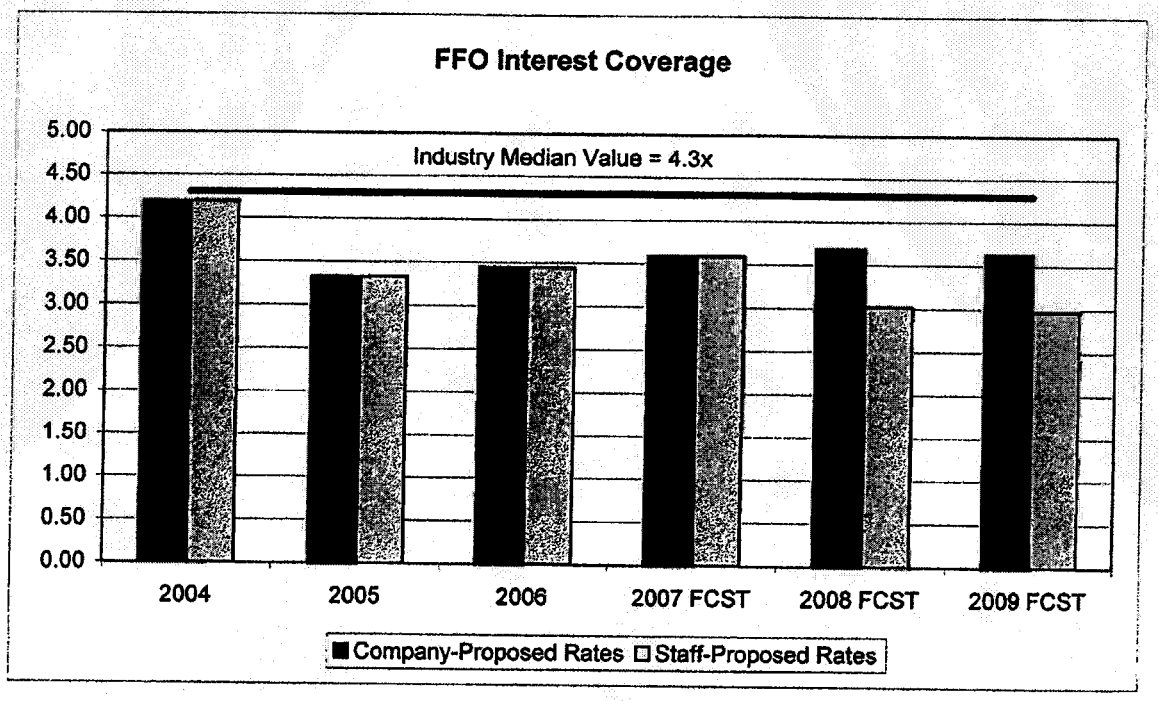


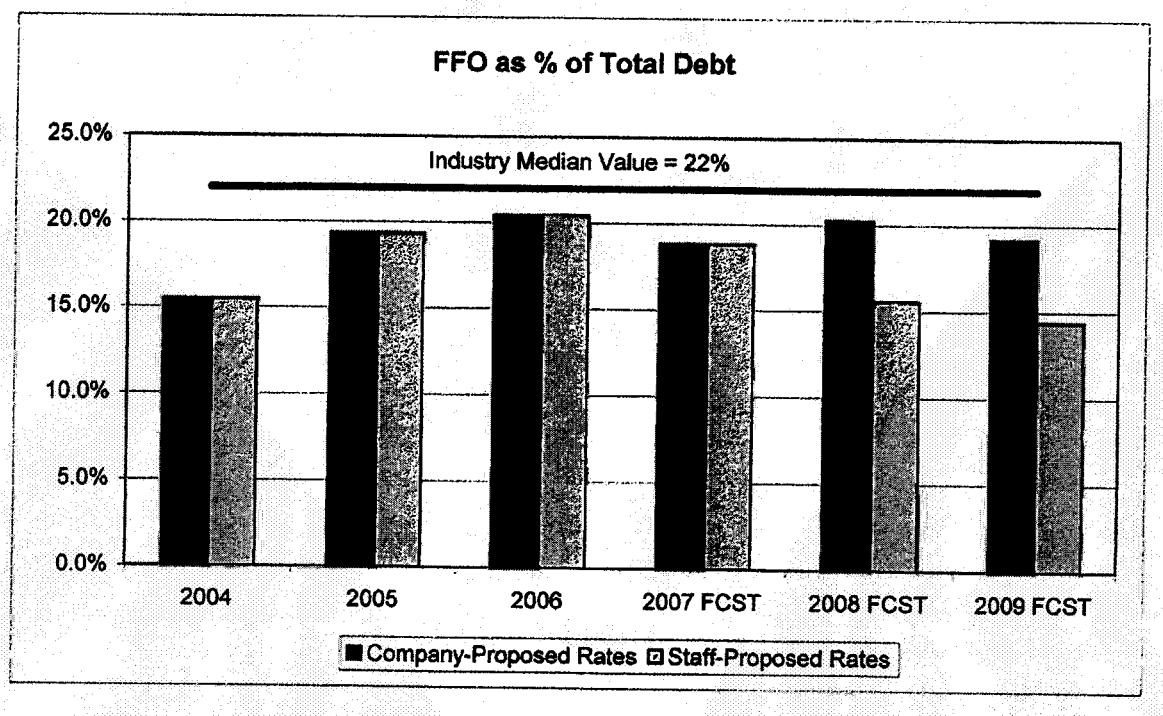
UNS Electric, Inc.
Updated Financial Forecast with Company and Staff Rate Proposals
Summary of Key Financial Indicators





UNS Electric, Inc.
Updated Financial Forecast with Company and Staff Rate Proposals
Summary of Key Financial Indicators

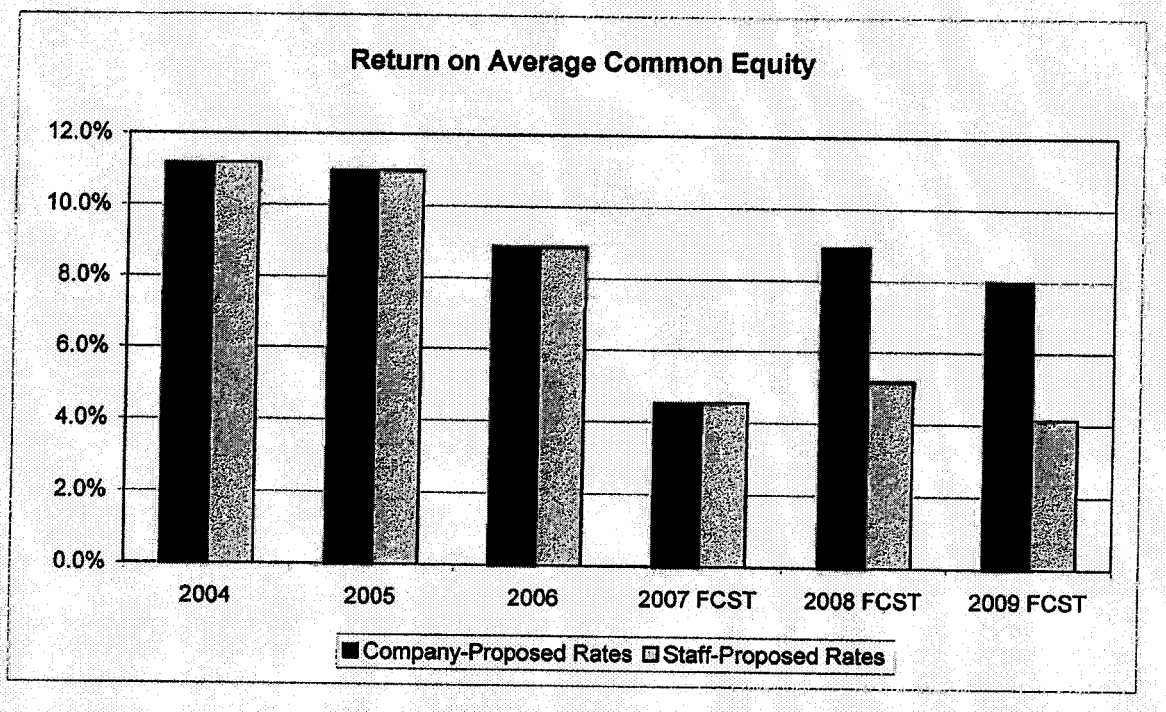


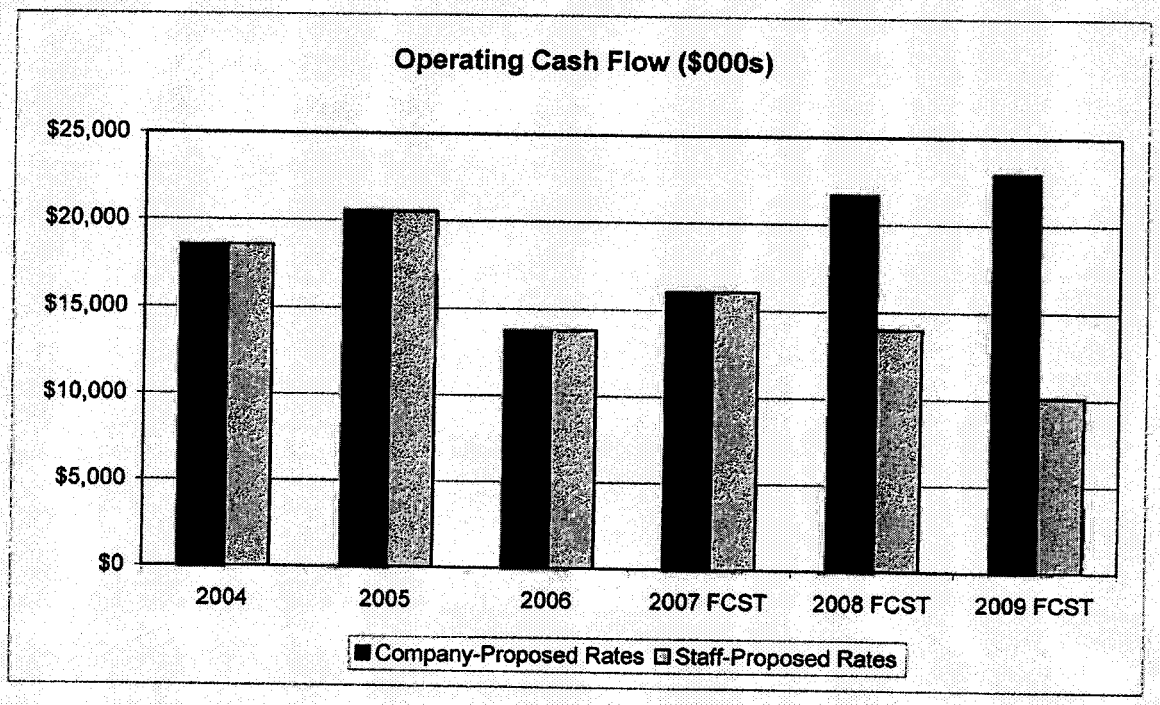


EXHIBIT

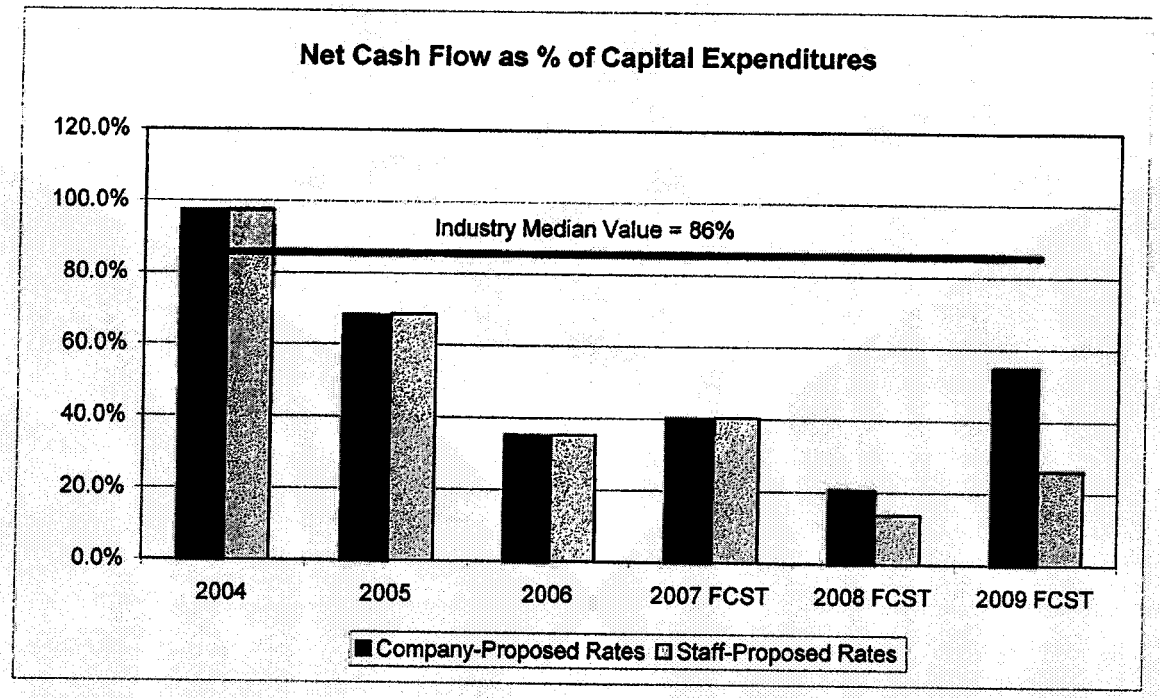
KCG-13

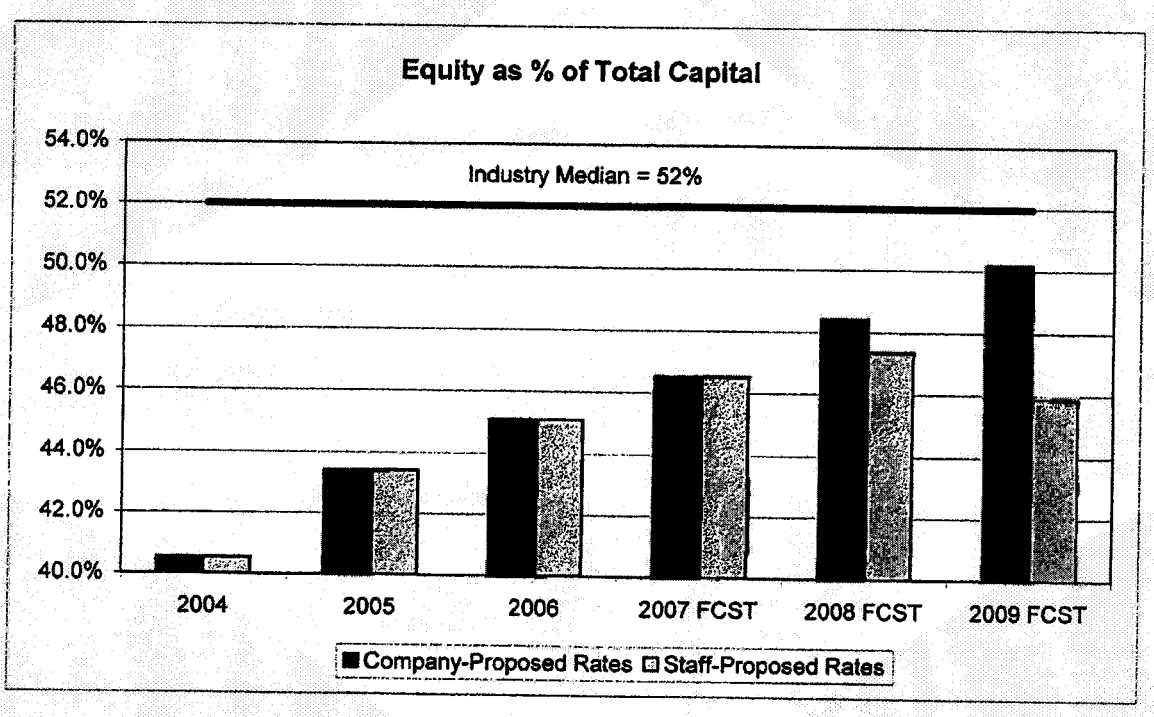
UNS Electric, Inc.
Updated Financial Forecast with Company and Staff Rate Proposals
Summary of Key Financial Indicators with BMGS



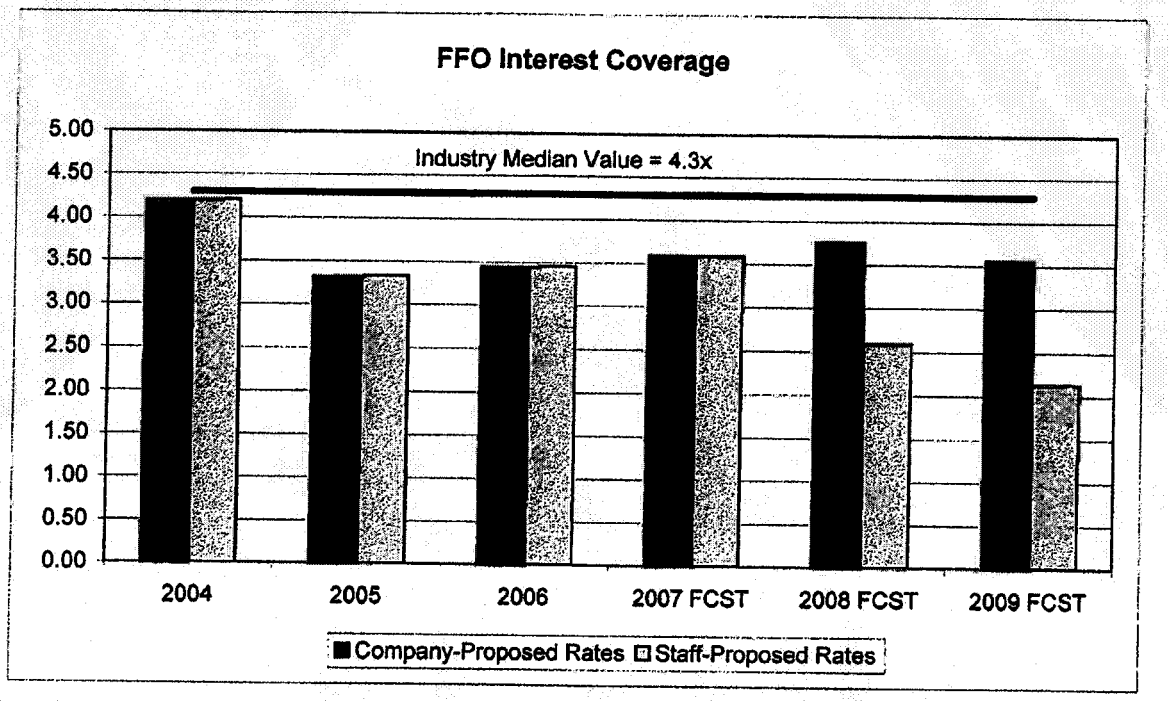


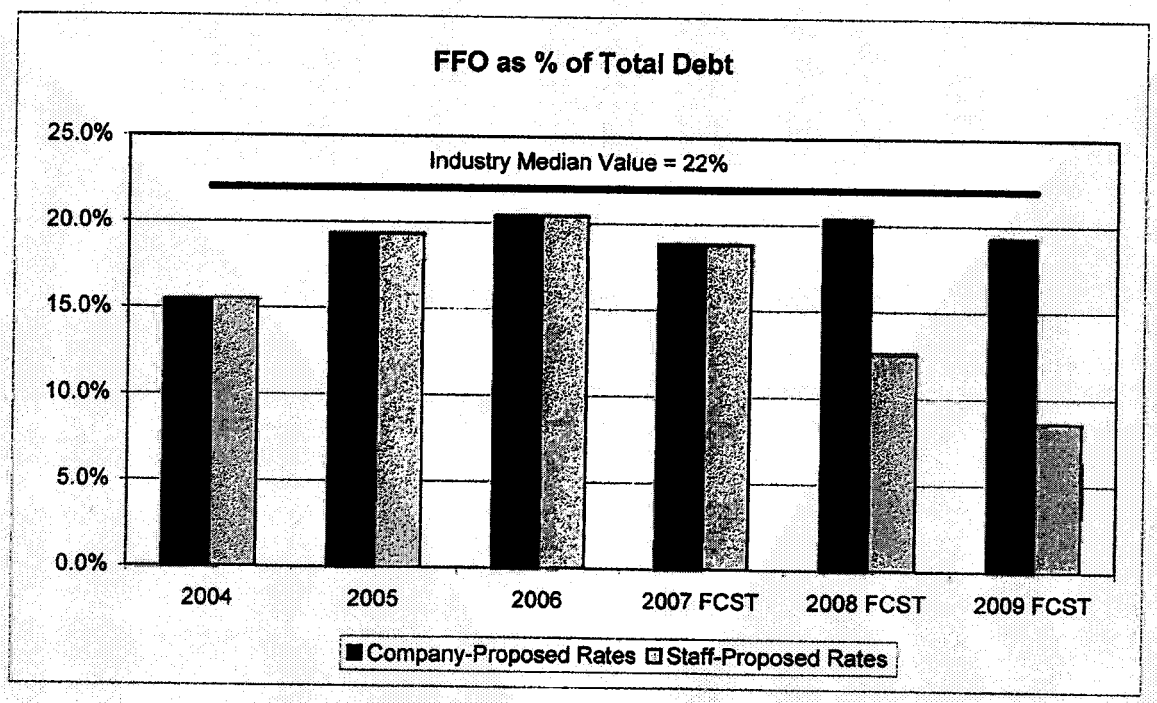
UNS Electric, Inc.
Updated Financial Forecast with Company and Staff Rate Proposals
Summary of Key Financial Indicators with BMGS





UNS Electric, Inc.
Updated Financial Forecast with Company and Staff Rate Proposals
Summary of Key Financial Indicators with BMGS





Rebuttal Testimony
of
Kevin P. Larson

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783

Rebuttal Testimony of

Kevin P. Larson

on Behalf of

UNS Electric, Inc.

August 14, 2007

TABLE OF CONTENTS

I. Introduction 1

II. Requested Rate Treatment of Black Mountain Generating Station 1

III. Rebuttal to Staff 2

IV. Rebuttal to RUCO 9

I. INTRODUCTION.

Q. Please state your name and address.

A. Kevin P. Larson. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. Are you the same Kevin P. Larson that previously submitted Direct Testimony on behalf of UNS Electric in this Docket?

A. Yes.

Q. Have you reviewed the Direct Testimony filed by the Commission Staff and other parties to this rate case?

A. Yes I have.

Q. On whose behalf are you filing your rebuttal testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of UNS Electric.

Q. What is the purpose of your rebuttal testimony?

A. My Rebuttal Testimony is related to UNS Electric's requested rate treatment of the Black Mountain Generating Station ("BMGS"). I will offer rebuttal to the Direct Testimonies of both Arizona Corporation Commission Staff ("Staff") and the Residential Utility Consumer Office ("RUCO").

II. REQUESTED RATE TREATMENT OF BMGS.

Q. Please summarize the Company's proposed rate treatment of BMGS.

A. The Company is requesting a post-test-year adjustment to rate base and a corresponding

reclassification of rates effective June 1, 2008 – or at a later date if commercial operation is delayed beyond June 1, 2008. The June 1, 2008 effective date is tied to the May 31, 2008 expiration date of UNS Electric's full requirements supply agreement with Pinnacle West Capital Corporation ("PWCC"). The effect of purchasing BMGS is to add approximately $10 million to the Company's non-fuel revenue requirement, assuming a $60 million project completion cost. If approved, then starting June 1, 2008 at the earliest, UNS Electric would increase the average base delivery charge to customers by approximately 0.6 cents per kWh while simultaneously making a corresponding decrease of 0.6 cents per kWh to the base power supply rate. The rationale for reducing the base power supply rate is that UNS Electric, by acquiring this facility, will avoid buying up to 90 MW of wholesale market capacity, a large portion of required ancillary services, and a significant volume of wholesale transmission wheeling due to the location of this facility.

III. REBUTTAL TO STAFF.

Q. Have you read Staff's Direct Testimony regarding the proposed rate treatment of BMGS?

A. Yes.

Q. Does Staff agree with UNS Electric's proposal to make a post-test-year adjustment for BMGS?

A. No. Staff opposes a post-test-year adjustment for BMGS. Ralph C. Smith for Staff testifies – in his Direct Testimony on page 89 at lines 5 through 6 – that "[one] of the primary deficiencies is that the plant is not expected to be in commercial operation until May or June 2008." UNS Electric is not requesting its proposed rate treatment for BMGS until it becomes commercially operational and no sooner than June 1, 2008. This is because the Company has a full requirements purchased power supply agreement with

PWCC through May 31, 2008. So, we are unclear as to why Staff views the timing of BMGS' completion as a "deficiency" in terms of the Company's rate base request, given that the request would not take effect until BMGS is operational.

BMGS is scheduled to be commercially operational on or before June 1, 2008. Until then, UNS Electric will continue receiving nearly all of its energy needs under its agreement with PWCC.

Q. Does Staff have concerns about the cost of BMGS?

A. Yes. Mr. Smith says in his Direct Testimony on page 89 at line 8 that "...there is uncertainty regarding the total cost of the plant." However, the total cost to complete BMGS has not changed from the estimates provided by the Company in our Direct Testimony. Further, the Company's proposed adjustment to rate base in this case reflects the *minimum* cost estimate of $60 million. If actual project costs exceed $60 million, UNS Electric will not seek rate base treatment for any additional amount until the Company's next rate case. In addition, the Company is committed to filing a project completion report with the Commission prior to making the rate reclassification. Finally, if the project were to be completed at a cost of less than $60 million, the Company would reduce the size of the requested rate reclassification in proportion with the change in the final cost. But all the evidence suggests that the costs to complete BMGS will be at least $60 million. Neither Staff nor RUCO provided any analysis regarding the cost to build BMGS.

Q. Does Staff have concerns about the economics of UNS Electric owning BMGS?

A. Yes, it appears so. Despite being presented with extensive analysis, discovery and testimony from the Company, Staff still seems unwilling to accept that BMGS is a good investment for UNS Electric and its customers. For instance, Mr. Smith states in his

Direct Testimony on page 89 at lines 10 though 12, "[t]here is uncertainty regarding whether it would be economical for UNS Electric and its ratepayers for the utility to own the plant or to obtain power by some other method." Mr. Smith does not describe what he thinks those uncertainties are. However, I pointed out in my Direct Testimony and showed in several exhibits that UNS Electric and its customers will realize numerous operating and financial benefits if the Company owns BMGS. And Mr. Smith did not substantially refute those benefits. I will reiterate these benefits below:

1. Financial Benefits.

Rate base treatment of BMGS will improve UNS Electric's cash flow. This is because of the return allowed on the original cost of the investment, the rate recognition of depreciation, and by using accelerated tax depreciation for UNS Electric's income tax filings. The improvement in cash flow would benefit the Company and its customers by:

- Providing another source of funding for transmission and distribution projects;
- Improving the credit profile of UNS Electric; and
- Allowing the Company to attract financing on more reasonable terms.

Also, on page 1 of Exhibit KPL-2 of my Direct Testimony, I showed the benefits of rate basing BMGS upon commercial operation versus waiting until a subsequent rate case (*e.g.* in 2011). Also, as discussed in the Rebuttal Testimony of Mr. Kentton C. Grant, UNS Electric's cash flows are projected to improve significantly if BMGS is added to rate base in 2008[1]. Higher cash flows allow the Company to finance more of its transmission and distribution investments with internal funds. Under Staff's proposal, which reflects a deferred accounting order for BMGS, there is a projected decrease in

[1] See page 1 of Exhibit KCG-13 of UNS Electric witness Kentton C. Grant's rebuttal testimony.

operating cash flow, and since additional debt is needed to fund the purchase of BMGS, UNS Electric's financial profile would be materially weakened[2]. Additionally, despite Staff's assumption that all non-fuel costs of BMGS are deferred on the Company's income statement, the earned ROE for UNS Electric is projected to remain in the 4-5% range in 2008 and 2009. Such an ROE would make it difficult for UNS Electric to attract the capital needed to finance the purchase of BMGS[3].

From a long-term rate perspective, customers benefit from having long-lived assets dedicated to public service. The cumulative effects of depreciation expense and deferred income taxes on rate base will reduce the Company's revenue requirement for owned generating capacity over time, and will provide more long-term price stability relative to purchased power agreements or lease agreements that must be replaced or renewed at market prices when those agreements expire. Exhibit KPL-3 attached to my Direct Testimony illustrates the long-term benefits of UNS Electric owning BMGS.

2. Operating Benefits.

Ownership of BMGS by UNS Electric would provide the Company with:

- flexibility with full, unfettered dispatch rights;
- reliability with the Company having complete discretion and control over maintenance and operation of the facility;
- efficiency by meeting the exact peaking capacity and reserve needs of UNS Electric's supply portfolio; and

[2] See page 3 of Exhibit KCG-13 of UNS Electric witness Kentton C. Grant's rebuttal testimony.
[3] See page 1 of Exhibit KCG-13 of UNS Electric witness Kentton C. Grant's rebuttal testimony.

- location benefits by being built in UNS Electric's load area minimizing transmission costs and enhancing system reliability and connection to dual pipeline systems for fuel supply redundancy.

Mr. Michael J. DeConcini describes the operating benefits UNS Electric will receive by owning BMGS in his Direct and Rebuttal Testimonies.

Q. Does Staff's recommendation that UNS Electric should apply for deferred accounting treatment for BMGS solve the problems you describe?

A. No. Deferred accounting treatment would not provide UNS Electric with sufficient cash flows to support the BMGS' estimated cost of $60 million to $65 million. Given the size of the BMGS investment relative to UNS Electric's Original Cost Rate Base ("OCRB") of $141 million, and the looming maturity of all $60 million of the Company's outstanding long-term debt in August 2008, the only realistic option is to request a post-test-year adjustment to rate base and corresponding rate reclassification.

Q. Do you have any other concerns about deferred accounting treatment?

A. Yes. Staff is merely recommending that the Company *apply* for deferred accounting treatment. There is no assurance, however, that UNS Electric's investment will be approved into rate base in a future proceeding. This means the Company still bears substantial risk until a decision is rendered about BMGS. The Company cannot take the risk that BMGS could be found imprudent in UNS Electric's next rate case even though all the evidence shows that BMGS is a prudent and economical investment. Also, if the economic benefits of owning BMGS are subject to questioning in a future rate proceeding, the Company may not be able to book any deferrals for financial reporting purposes even if an accounting order is granted.

We also have concerns regarding the impact of deferred accounting treatment on UNS Electric's customers. Since the non-fuel revenue requirement for BMGS is approximately $10 million per year, the balance of cost deferrals would be quite large by the time a rate case could be filed and acted on by the Commission. By contrast, UNS Electric's proposed rate treatment of BMGS is designed so that customers do not have to pay large deferral balances in future years. Additionally, the Company would prefer to wait longer before filing another rate case. However, due to cash flow concerns, the use of deferred accounting would give the Company no choice but to file another rate case shortly after this proceeding is concluded.

Q. Does Staff raise any other concerns?

A. Yes. These concerns are as follows:

Lack of Test-Year Spending.

Mr. Smith – in his Direct Testimony on page 88 at lines 1 to 2 – states that, "[i]t appears that only minimal, if any costs have been incurred by UNS Electric in the test year." As we indicated, UniSource Energy Development Company ("UEDC") is constructing BMGS, not UNS Electric. Also, construction of BMGS did not begin until after the end of the test year, so neither UNS Electric, nor UEDC for that matter, incurred any costs for BMGS during the test year. Since the costs of the plant will simply displace purchased power costs when the rate reclassification and post-test-year adjustment is made, the significance of historical test-year expenditures is difficult to understand in this circumstance. Mr. Smith's statement about costs incurred during the test year has no relevance to what the Company is proposing.

Ability to Finance BMGS.

Staff is also unclear as to "how UNS Electric would be unable to raise capital to purchase

BMGS when UEDC could raise the capital to construct the plant", as Mr. Smith states in his Direct Testimony on page 91, at lines 4 through 8. What Staff does not appear to understand is that – if UEDC owns BMGS – UEDC could *immediately* begin to recover non-fuel costs by receiving *demand charges* under a wholesale purchased power agreement. The ability to begin immediate cost recovery provides UEDC with an advantage in terms of financing BMGS. Without immediate cost recovery, UNS Electric could attempt to finance the purchase of BMGS. However, UNS Electric's small size and unfavorable cash flow position would make it difficult to access the capital markets on favorable terms.

Cash Flow Impact of Rate Reclassification.

Staff is unclear of how UNS Electric's proposed "revenue neutral" rate reclassification would result in a substantial improvement in the Company's cash flow, as stated in Mr. Smith's Direct Testimony at page 91, lines 16 though 18. Mr. Radigan also alludes to this specific proposal in his Direct Testimony at page 26. Initially, the rate reclassification will be revenue neutral to ratepayers. However, by moving approximately $10 million out of the base power supply rate and into the Company's delivery charge, UNS Electric will have a reasonable opportunity to earn a return on this substantial investment. That is because the revenues produced by a power supply rate are reconcilable against fuel and purchased power costs, whereas the Company's delivery charges are not reconcilable and are retained for non-fuel cost recovery. This in turn allows the Company to earn a *current* rate of return on the asset and protects customers against a higher rate increase in the future if costs are deferred or under-recovered. Based on the Company's changes to UNS Electric's power supply portfolio and the proposed PPFAC mechanism, the actual amount of revenues to be collected by the Company after June 2008 will depend on the actual cost of fuel, purchased power and transmission wheeling services purchased by UNS Electric to serve its customers.

Q. Should the rate making treatment of BMGS be addressed in the context of UNS Electric's *next* rate case, as suggested by Staff?

A. No. This issue needs to be determined in this case. As previously stated, UNS Electric needs to acquire energy resources well before its full requirements purchased power agreement with PWCC expires on May 31, 2008. To acquire BMGS, the Company needs the cash flow that its proposal provides. Without it, UNS Electric simply cannot acquire BMGS. The Company has committed to filing a project completion report once BMGS is operational and prior to making the proposed rate reclassification. Additionally, the prudence of construction costs can be addressed in the Company's next rate case. We believe the information we provided in our direct filing on December 15, 2006 has given and still gives the Commission ample opportunity to review all aspects of BMGS at the appropriate points in time. Also, we believe the proposed rate base amount for BMGS is reasonably known and measurable - $60 million – for a facility that will serve *existing* customers in approximately 10 months, when it is in commercial operation. While not typical ratemaking treatment, the Company believes the benefits of a post-test-year adjustment for BMGS are in the public interest.

IV. REBUTTAL TO RUCO.

Q. Have you read RUCO's Direct Testimony regarding the proposed rate treatment of BMGS?

A. Yes.

Q. Does RUCO agree with UNS Electric's proposal to make a post-test-year adjustment for BMGS?

A. No. Specifically, RUCO opposes UNS Electric's rate reclassification proposal. Ms. Marylee Diaz Cortez for RUCO – in her Direct Testimony at page 7 at lines 1 through 2

and 19 through 22 – states that "[the Company's] proposal is contrary to nearly every rate-making principal to which Arizona adheres. It violates the known and measurable principal, the matching principal, the historical test year principal, and the used and useful principal. The proposal also would circumvent the higher level of scrutiny typically afforded related party transactions and, in large part, pre-determine prudency." We believe the present facts and practical circumstances described in our proposal justify the Company's position.

Q. Please address each of RUCO's concerns.

A. I will address each of RUCO's theoretical concerns individually.

<u>Known and measurable principal.</u>

The costs of BMGS will be known prior to the rate reclassification. As stated above, the Company's proposed adjustment to rate base reflects the minimum cost estimate of $60 million; we are proposing a known and reasonably measurable – and minimal – cost. As of June 30, 2007, approximately $33 million had been spent on BMGS. Even if actual project costs exceed this amount, UNS Electric is not seeking rate base treatment for any additional amount in this case; it will wait until the Company's next general rate case. Following the purchase of the project by UNS Electric, and upon commercial operation of the facility, the Company will provide the Commission with a project completion report detailing the cost of completion and the results of pre-commercial testing. Thirty days after this report has been filed, or on June 1, 2008 if the project is completed prior to May 1, 2008, the Company would then implement the rate reclassification described above. The Company is not proposing that the post-test-year adjustment of BMGS take effect until after the facility is providing electricity to UNS Electric's customers (*i.e.* used and useful.) Further, no one disputes that the plant is going to serve existing customers as of June 1, 2008 because that is when the PWCC purchased power contract expires. In

addition, the Commission still has the authority to review of construction costs to ensure they are prudent in the next rate case.

Matching principal.

The Company's rate reclassification proposal is designed to *exactly* match the timing of rate recovery with purchased power cost avoidance. The effect of this post-test-year adjustment is to add approximately $10 million to the Company's non-fuel revenue requirement, assuming a $60 million project completion cost. On the effective date of this adjustment, UNS Electric would increase the average base delivery charge to customers by approximately 0.6 cents per kWh, *and* make a corresponding decrease of 0.6 cents per kWh to the base power supply rate. If UNS Electric acquires BMGS, it can reduce the base power supply rate because the Company will (1) avoid buying up to 90 MW of wholesale market capacity; (2) have a large portion of required ancillary services; and (3) have a significant volume of wholesale transmission wheeling due to BMGS' location. Again, the plant would serve existing customers, particularly given the expiration of the PWCC contract at the end of May 2008; BMGS is not a "revenue enhancer" to simply address future growth as RUCO seems to suggest without any support. So, this is a case where abiding by RUCO's strict interpretation of the matching principle would mean the Company and its customers would miss out on the opportunity to obtain both financial and operational benefits from rate basing BMGS.

Historical test year principal.

The PWCC contract, which currently supplies nearly all of UNS Electric's energy requirements, did not expire during the test year. The PWCC contract expires on May 31, 2008 and UNS Electric must begin procuring energy or generation now to supply nearly all of its customers' energy demand beginning June 1, 2008. UNS Electric does not have the luxury of waiting until 2010 for non-fuel cost recovery for an asset that would

increase the Company's test-year OCRB by 43% and requires financing that would increase the Company's test year capitalization by approximately 50%. The Commission's regulations allow for pro forma adjustments when appropriate. The Company believes that such an adjustment is appropriate in this situation.

Used and useful principal.

Upon receipt of the completion report of BMGS, the Commission will confirm that the asset is used and useful. No one disputes that the plant will serve *existing* customers once in commercial operation, starting June 1, 2008. The proposed rate reclassification will not occur until the Commission reviews this report.

Related party transaction.

UNS Electric has committed to acquiring BMGS at *cost* from UEDC. UNS Electric is open to a full a prudence review of those costs in the next rate case.

Pre-determination of prudency.

The only "pre-determination" being sought by UNS Electric is that the acquisition of BMGS is in the public interest. The financial and operating benefits are summarized in this testimony and are fully addressed in my Direct Testimony and in Mr. DeConcini's Direct Testimony. The Commission maintains its authority to review construction costs in its next rate case.

Q. What is RUCO's recommendation?

A. In her Direct Testimony at page 8 at line 14 through page 9 at line 1 – Ms. Diaz Cortez for RUCO recommends that UNS Electric enter into a purchased power agreement with UEDC to acquire the output of BMGS, and then file a request for the acquisition of BMGS in a rate case.

Q. Does UNS Electric agree with RUCO's recommendation regarding a short-term purchased power agreement between UNS Electric and UEDC?

A. No. A short-term purchased power agreement would expose UNS Electric and its customers to refinancing risks. A short-term purchased power agreement would not allow UNS Electric to lock-in long-term financing; therefore, the long-term cost of capacity from this facility would depend on the cost of capital obtained at some point in the future. Purchasing BMGS now would enable the Company to secure long-term financing and eliminate future refinancing risk. Ownership of generation contributes to a stable and declining non-fuel revenue requirement relative to purchased power agreements over the long-run. As shown in Exhibit KPL-3 in my Direct Testimony, owning BMGS provides long-term financial benefits and is in the public interest. The cost of owning BMGS is approximately $12 million less than a purchased power option on a net present value basis.

Q. Does this conclude your testimony?

A. Yes.

Rebuttal Testimony
of
Karen G. Kissinger

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783

Rebuttal Testimony of

Karen G. Kissinger

on Behalf of

UNS Electric, Inc.

August 14, 2007

TABLE OF CONTENTS

I. Introduction 1

II. Depreciation Expense 2

III. Property Tax Expense 2

IV. Miscellaneous Plant Adjustments 3

V. Accumulated Deferred Income Taxes – CIAC 5

VI. Accumulated Deferred Income Taxes – A&G 8

VII. Accumulated Depreciation 10

VIII. Income Taxes 11

Exhibits:

Exhibit KGK-2: Arizona Corporation Commission Staff Policy Directive on Changes in the Regulatory Treatment of Contributions and Advances due to the Tax Reform Act of 1986.

Exhibit KGK-3: Decision No. 55774

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Karen G. Kissinger. My business address is 4350 East Irvington Road, Tucson, Arizona 85714.

Q. Are you the same Karen G. Kissinger that previously submitted Direct Testimony on behalf of UNS Electric in this Docket?

A. Yes.

Q. Have you reviewed the Direct Testimonies filed by the Arizona Corporation Commission Staff ("Staff") and the Residential Utility Consumer Office ("RUCO") in this rate case?

A. Yes I have.

Q. Please provide your general assessment of such Direct Testimony.

A. With respect to the scope of my Direct Testimony, I respond to one depreciation adjustment, one property tax adjustment and two rate base adjustments proposed by Staff witness Mr. Ralph C. Smith. I also respectfully disagree with certain positions taken by RUCO witnesses Ms. Marylee Diaz Cortez and Mr. Rodney Moore as it relates to income tax and depreciation calculations.

Q. What areas of Staff witness Mr. Smith's testimony do you wish to address?

A. I respond to one depreciation, one property tax and two plant adjustments proposed by Mr. Smith.

Q. Which areas of RUCO testimony will you be addressing in your Rebuttal Testimony?

A. I disagree with Ms. Diaz Cortez's Direct Testimony proposing that the balance of Accumulated Deferred Income Taxes – CIAC be excluded from rate base. I also disagree with her proposed adjustment to Accumulated Deferred Income Taxes – A&G. For several reasons, I cannot accept the adjustment proposed by Mr. Moore that would increase the balance of Accumulated Depreciation that is deducted from rate base. Finally, I have a conceptual disagreement with Mr. Moore's approach to computing income tax expense.

II. DEPRECIATION EXPENSE.

Q. What comments do you have with respect to depreciation adjustments proposed by Staff Witness Mr. Ralph Smith?

A. In Mr. Smith's adjustment C-15, he appropriately points out that UNS Electric acknowledged an error in the depreciation study as originally filed with respect to transportation equipment. The Company acknowledged the error in responses to two staff data requests which Mr. Smith attached to his testimony. Mr. Smith correctly reflects in his adjustment the fact that a portion of the transportation depreciation is charged to capital accounts, and thus does not impact the income statement. Therefore his proposed adjustment is correct, while the adjustment proposed by RUCO for this issue is incorrect in that it does not recognize that a portion of transportation depreciation is capitalized.

III. PROPERTY TAX EXPENSE.

Q. What issue do you wish to address with respect to the property tax adjustment of Mr. Ralph Smith?

A. Mr. Smith proposes the Company use the 23.5% assessment ratio that would be in effect at January 1, 2008. The Company acknowledges that such assessment ratio is scheduled to

be effective at January 1, 2008 due to the legislation he describes and, as such, would be a known and measurable change. In that respect, the Company accepts the adjustment. However, at the same time, the use of such assessment ratio creates a mis-match in that the rates of taxation determined by the school districts and other taxing authorities that will be in effect at January 1, 2008 are not yet known, but should be known by the end of September 2007. The fact that the assessment ratio declines does not necessarily mean that property tax expense will correspondingly decline. The tax districts have their budgets to consider and it has been our experience that a reduction in the assessment ratio does not necessarily have a significant impact on our property tax expense. The tax rate increases as the tax districts' budgetary needs increase. The Company seeks an opportunity to review those bills as soon as the tax bills are available and supplement this docket with that information, as that tax rate change would also be known and measurable before the rates would be expected to go in effect.

IV. MISCELLANEOUS PLANT ADJUSTMENTS.

Q. You state that you wish to address two plant adjustments proposed by Staff Witness Mr. Ralph Smith. Please identify those adjustments.

A. Beginning at line 24 on page 18 of his Direct Testimony, Mr. Smith proposes an adjustment that would increase the end-of-test year balance of plant in service for a project reported in CWIP that was actually in service at the end of the test year. Beginning at line 25 on page 19 of his Direct Testimony, Mr. Smith proposed a rate base reduction to reflect a contribution that he does not believe has been incorporated into the Company's rate base.

Q. Do you agree with these proposed adjustments?

A. With respect to the adjustment described on page 18 of Mr. Smith's testimony, to the extent that the Commission denies the Company's request to include CWIP in rate base, I

would agree with his recommendation to increase plant in service by $442,255. I further agree that depreciation and property tax expense should be increased to reflect the depreciation and property tax associated with this property. With respect to the adjustment described beginning on page 19 of Mr. Smith's testimony, I do not believe that his proposed adjustment is necessary.

Q. Please explain your position with respect to the first adjustment.

A. Mr. Smith recommends that the Commission deny the Company's request to include CWIP in rate base. In connection with that recommendation, he reviewed the data underlying the individual construction projects comprising the requested CWIP balance and determined that one of the projects was actually in service by June 30, 2006, the end of the test year. The project to which he refers is Task 8009729 which covers the installation of five miles of overhead lines to supply service to water pumps for a proposed housing development. That specific project is included in the recorded balance of CWIP at June 30, 2006. Upon further investigation, we have discovered that the project actually went into service in May 2006, but was not unitized, and thus, transferred from CWIP to Plant in Service until *after* the end of the test year. While the Company opposes Mr. Smith's proposal to exclude CWIP from rate base, to the extent that he prevails on the issue, his proposal to increase rate base by $442,255 would be appropriate. To the extent that the Company prevails and CWIP is included in rate base, the adjustment would be unnecessary.

Q. Please explain your position with respect to the second rate base adjustment proposed by Mr. Smith.

A. Mr. Smith has identified a construction project (Task CE64023) at the Tubac Golf Resort that is included in end-of-test-year plant in service at a cost of $236,874 that he believes should be reduced by a related Contribution in Aid of Construction. Upon further investigation, we determined that there was, in fact, a Contribution in Aid of Construction

in the amount of $236,161 that was received in July 2005, but we incorrectly credited it to a different project (Task 141637) also at the Tubac Golf Resort. The cost of that project is also included in end-of-test-year plant in service, but at an amount that is net of the $236,161 contribution. Accordingly, the amount was already accounted for as CIAC and it is unnecessary to further reduce rate base by the $236,874 proposed by Mr. Smith. To do so would represent an incorrect double counting of a single contribution.

V. ACCUMULATED DEFERRED INCOME TAXES – CIAC.

Q. Ms. Kissinger, what is CIAC?

A. CIAC is the acronym used for Contributions in Aid of Construction. CIAC represents nonrefundable provisions of cash or property from utility customers intended to offset the cost of certain property additions made to extend service to the remitting party. Accumulated Deferred Income Taxes – CIAC represents the income tax effect of the cumulative difference between the way such amounts are treated for accounting and tax purposes.

Q. You disagree with the adjustment proposed by Ms. Diaz Cortez that would exclude the balance of Accumulated Deferred Income Taxes – CIAC from rate base. Please explain.

A. I disagree for several reasons. The explanation contained in her testimony for such exclusion fails to consider the manner in which CIAC is accounted for and also is contrary to the specific direction of the Arizona Corporation Commission with respect to the manner in which the deferred income taxes associated with CIAC are to be considered in ratemaking.

Q. Please explain your assertion that the justification offered by Ms. Diaz Cortez fails to consider the manner in which CIAC is accounted for.

A. On page 19 of Ms. Diaz Cortez's Direct Testimony, she states that she is proposing the exclusion because she cannot see any FERC Account 271 liability for CIAC in either the Company's FERC Form 1 annual report or in the Company's general ledger; thus, there is apparently no rate base deduction for CIAC. Continuing her assertion, since CIAC is not deducted from rate base, the Accumulated Deferred Income Taxes-CIAC should similarly be excluded from rate base. I believe that Ms. Diaz Cortez is confusing the way that water and waste water utilities account for CIAC with the manner by which electric utilities account for CIAC.

Most water and waste water utilities follow the NARUC Uniform System of Accounts which provides an Account No. 271 for use in accounting for CIAC proceeds. Such balances are typically deducted from rate base as a separate line item in rate cases. In accordance with R14-2-212.G of the Arizona Administrative Code, UNS Electric maintains its accounting records in accordance with the Federal Energy Regulatory Commission Uniform System of Accounts ("FERC USOA"). The FERC USOA does *not* have an Account 271 for use in accounting for CIAC. Instead, such amounts are directly credited to (*i.e.*, deducted from) the respective plant account upon receipt. The controlling language is contained in Part D of Electric Plant Instruction No. 2 in the FERC USOA, which reads in part:

> The electric plant accounts shall not include the cost or other value of electric plant contributed to the company. Contributions in the form of money or its equivalent toward the construction of electric plant shall be credited to accounts charged with the cost of such construction. Plant constructed from contributions of cash or its equivalent shall be shown as a reduction to gross plant constructed when assembling cost data in work orders for posting to plant ledgers of accounts.

UNS Electric accounts for CIAC in the required manner; thus, the plant balances in rate base have already been reduced by any and all applicable CIAC.

Q. You also state that the proposed exclusion by Ms. Diaz Cortez fails to consider the manner in which the Commission has directed that such amounts be considered in ratemaking. Please explain.

A. Prior to the enactment of the Tax Reform Act of 1986 ("TRA '86") the Internal Revenue Code ("Code") contained a provision that enabled utilities to treat CIAC as a non-taxable contribution of capital, meaning that such receipts were not required to be recognized as taxable income; however, the assets acquired with the CIAC proceeds were not permitted to be depreciated for tax purposes. After TRA '86 became law, these Code provisions were repealed. This meant that, with minor exceptions, CIAC proceeds were to be considered as taxable ordinary income upon receipt. Such change also permitted the CIAC recipient to treat the asset cost as a depreciable tax basis that could be reflected as deductions on current and future tax returns over the tax life of the respective assets.

Because the change in tax treatment of CIAC brought on by TRA '86 had such a potentially significant effect on the utilities under its jurisdiction, the Arizona Corporation Commission initiated an inquiry into the issue, in Docket No. U-0000-87-257. The Commission Staff conducted workshops on January 28th and February 12th of 1987. In September 1987, Staff issued a Report which addressed the CIAC tax issue and contained ratemaking recommendations. In Decision No. 55774 (October 21, 1987) the Commission accepted the Staff Report and its recommendations. The Staff Report is attached hereto as Exhibit KGK-2. Decision No. 55774 is attached as Exhibit KGK-3.

Specifically, Arizona utilities were provided with two methods for addressing the tax liabilities associated with CIAC — gross-up and self-pay. Companies using the gross-up

method were permitted to require the remitter of CIAC to include an amount representing the associated income tax liability. Companies electing the self-pay method paid the taxes themselves. When a utility self-pays the tax on CIAC, a deferred tax asset (Accumulated Deferred Income Taxes – CIAC) is created. This asset represents the tax effect of the cumulative difference between the way the proceeds are treated for accounting and tax purposes. This asset is extinguished as tax depreciation deductions are reflected on the utility's tax returns. Decision No. 55774 specifically addresses the ratemaking treatment of the deferred tax asset on page 3 at lines 26 through 28:

> If the utility utilizes the self-pay method, then the utility is allowed to claim rate base treatment for its average investment in the tax thus paid.

In this rate case UNS Electric has reflected Accumulated Deferred Income Taxes – CIAC in the manner required.

Q. What is your recommendation to the Commission?

A. There is no basis for the Commission to accept the adjustment Ms. Diaz Cortez proposes. UNS Electric has correctly reflected the effect of CIAC in rate base as reductions of the book cost of the assets to which it relates. The treatment of the corresponding Accumulated Deferred Income Taxes is consistent with the manner in which the Commission directed such amounts to be considered for ratemaking purposes.

VI. <u>ACCUMULATED DEFERRED INCOME TAXES – A&G.</u>

Q. You disagree with an adjustment to Accumulated Deferred Income Taxes – A&G Capitalization that Ms. Diaz Cortez has proposed. Please explain.

A. Ms. Diaz Cortez – in her Direct Testimony on page 20 – states that this adjustment relates to the Company's proposed adjustment that would change the test-year level of

Administrative and General ("A&G") expenses that are allocated to CWIP. Elsewhere in her Direct Testimony, Ms. Diaz Cortez recommends that the Commission reject the Company's proposal. In connection therewith, she has included this adjustment to increase the amount of Accumulated Deferred Income Taxes that are deducted from rate base. This adjustment is unnecessary, even if the Commission accepts Ms. Diaz Cortez' recommendation to reject the Company's proposed adjustment. The Company is proposing an adjustment to reduce the test year level of A&G expenses charged to CWIP and to correspondingly increase the amount remaining in Operating Expense. This adjustment is prospective in nature.

The amount of capitalized A&G expenses is computed differently for book and tax purposes, with the amount capitalized for book purposes typically greater than that capitalized for tax purposes, thereby resulting in a larger current deduction for tax. As a result, there is a corresponding book-tax timing difference that gives rise to deferred income taxes. The effect of the Company's proposed A&G adjustment reduces the related book-tax timing difference, by increasing book expenses while the corresponding tax deductible amount remained the same. This was reflected in the computation of both current and deferred income taxes. However, since the proposed adjustment was prospective in nature, there needed to be no corresponding adjustment made to the related portion of the end-of-test year balance of Accumulated Deferred Income Taxes deducted from rate base. Since the proposed adjustment did not result in any change to Accumulated Deferred Income Taxes, a rejection of the proposed adjustment likewise does not require any adjustment to Accumulated Deferred Income Taxes.

VII. ACCUMULATED DEPRECIATION.

Q. You disagree with the adjustment to Accumulated Depreciation recommended by RUCO witness Mr. Moore. Please explain.

A. From my review of Mr. Moore's Schedule RM-5, it appears that Mr. Moore has attempted to recompute the end-of-test year balance of Accumulated Depreciation by using additions, retirements and balances by FERC plant account from 2002 through June 30, 2006. As a result, he is proposing an adjustment to increase Accumulated Depreciation (and therefore reduce rate base) by approximately $2.3 million. I disagree with the result of his analysis and resulting adjustment because his analysis fails to reflect the depreciation rates and methods, and capital recovery accounting procedures that were in effect during this period (*i.e.*, from 2002 through June 30, 2006). Such flaws in his analysis would tend to produce a computed depreciation reserve greater than what was recorded on the Company's books at the end of the test year.

Q. Please explain why you believe Mr. Moore's analysis was flawed.

A. First, Mr. Moore's analysis is based on a *mid-year* depreciation convention. That would result in one-half year of depreciation being computed on each asset added or retired during the year. As explained in the response to RUCO Data Request No. 1.09, the Company uses a *mid-month* depreciation convention, meaning that one-half month of depreciation being computed on each asset added or retired during a given month. If a $1,000,000 asset with a 5% annual depreciation rate was placed in service in October, Mr. Moore's methodology would add $25,000 to Accumulated Depreciation during that year. By contrast, only $10,416 would have been actually provided on the Company's books during the period.

Second, Mr. Moore has failed to consider any salvage or removal costs associated with assets retired from service during the periods of his analysis. Such amounts are respectively credited or charged to Accumulated Depreciation as realized or incurred.

Finally, Mr. Moore's depreciation calculations are made as though all categories of plant assets are depreciated using the group method. That is not correct. Although the Company is requesting a change to the group depreciation method for Transportation Equipment as part of Dr. White's testimony, the Company's vehicles have historically been depreciated using a "Unit Depreciation" procedure. Under Unit Depreciation, assets are depreciated individually, to the extent of their respective recorded cost. This differs from group depreciation where the entire cost balance of the group is used for computing depreciation, with no specific recognition of the depreciation associated with individual members of the group.

The traditional use of unit depreciation by Citizens was not initially recognized at the time that the UNS Electric assets were acquired. As a result, for a period of several months, depreciation provisions were made using the group method. As data was being assembled for the depreciation study submitted in this rate case, the error was discovered and corresponding adjustment to the Company's books were made. Disclosure of this error was made on page 8 of the Company's financial statements, a copy of which appears as Exhibit KGK-1 to my Direct Testimony. Correction of the adjustment required a charge totaling $2,013,847 to Accumulated Depreciation. That correcting adjustment was not reflected in Mr. Moore's analysis.

VIII. INCOME TAXES.

Q You state that you have a conceptual disagreement with the manner by which Mr. Moore has recomputed income tax expense to reflect RUCO's proposed rate case adjustments. Please explain.

A. In its filing, the Company has reflected pro forma income tax expense comprised of current and deferred portions computed separately. This requires the identification and proper

reflection of all book-tax accounting differences, both timing and permanent, implicit in final adjusted test-year results. Such bifurcation is required for several reasons. First, the non-cash deferred income taxes are shown separate from current income taxes in the lead-lag study supporting the Company's requested level of working capital. Second, deferred income taxes are separately computed to enable the Company to demonstrate that they reflect the extent of normalization that the Company has been authorized for ratemaking purposes, and also to demonstrate that all normalization requirements of the Internal Revenue Code have been met.

In his income tax adjustment appearing on Schedule RLM-15, Mr. Moore has simply computed a total income tax expense based on his recommended adjusted pre-tax operating income less synchronized interest. He makes no distinction between current and deferred income taxes. That fails to recognize that some items are viewed differently for book and tax purposes, and some of the differences are permanent. For example, some of the items included in his adjustment appearing on Schedule RLM-12 are for meals and/or entertainment. Such costs are only 50% deductible for tax purposes and are permanent book-tax differences rather than timing differences. There is no way to check the final adjusted income taxes recommended by Mr. Moore for proper inclusion of deferred income taxes based on the Company's normalization authority or for compliance with the Internal Revenue Code. A correct determination of revenue requirements in a rate case requires a proper bifurcation of current and deferred income taxes.

Q. What do you recommend?

A. When the final adjusted operating income and rate base are known, income taxes should be properly computed separately, as I described above.

Q Does this complete your Rebuttal Testimony?

A. Yes it does.

EXHIBIT

KGK-2

OPEN MEETING ITEM

RECEIVED
AZ. CORP. COMMISSION
SEP 28 4 19 PM '87
DOCUMENT CONTROL

MEMORANDUM

TO: THE COMMISSION

FROM: Utilities Division

DATE: September 28, 1987

RE: POLICY DIRECTIVE ON CHANGES IN THE REGULATORY TREATMENT OF CONTRIBUTIONS AND ADVANCES DUE TO THE TAX REFORM ACT OF 1986

Staff's report on the tax and regulatory implications of the Tax Reform Act of 1986 related to the taxability of contributions in aid of construction and advances for construction is forwarded for discussion and review. Attached to the report is the Utilities Division proposed policy directive for managing both the line extension program and the associated ratemaking implications of the policy.

Briefly, Staff has proposed that utilities be allowed to either "gross up" monies collected for line extension agreements or to pay the tax and to receive rate base treatment for the taxes thus paid. Staff recommends that the tax benefits the utility receives under the "gross up" treatment be retained by the utility to be recovered by the general body of ratepayers in a rate case. Staff has also recommended that if the utility self-pays the associated tax, the rate base be reduced by amortizing the pre-paid tax by the tax benefit from the asset over the tax life of the asset.

Gary Yaquinto, Jr.

Wayne E. Ruhter
Director
Utilities Division

WER:MS:mpv/TMH

AGENDA VERBIAGE: Same as above

ORIGINATOR: Marilyn Shepperd

STAFF REPORT

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

REGULATORY TREATMENT OF ADVANCES FOR CONSTRUCTION AND CONTRIBUTIONS IN AID OF CONSTRUCTION DUE TO TAX REFORM ACT OF 1986

SEPTEMBER 1987

Table of Contents

		Page
1.	Introduction	1
2.	Background	2
3.	Alternative Regulatory and Accounting Treatments	4
	3.1 Gross-up Contributions and Advances to Provide for Payment of Associated Tax Liability	4
	3.2 Gross-up on Contributions and Advances on a Present Value Basis	8
	3.3 Utility Pays Taxes Associated with Contributions and Advances	9
	3.4 Alternate Forms of Financing	11
4.	Tariff and Construction Agreement Requirements	11
5.	Summary of Recommendations	12

2. BACKGROUND

In Arizona, nonrefundable CIACs and advances for construction are made to a public utility by a customer or developer whose demands on the utility system require additional investments in utility plant. CIACs have provided utilities with a cost-free source of funds for construction of incremental plant because CIACs bear no interest, require no dividends and are not required to be repaid. Advances have provided utilities with cost-free funds in the form of interest-free debt to utilities. The effects of CIACs and advances on utility customers are minimal because plant built with CIACs or advances is not included in the rate base.

CIACs are generally used for service line extensions in the electric and gas industries and for access line connections in telecommunications. Refundable advances are used for line and main extensions and larger construction projects. Under ACC rules, the utility's refund liability for the advance is limited to five years for electric, gas and telephone utilities and ten years for water utilities unless the terms of the approved advance agreement or approved tariff state otherwise. After this time period, the unrefunded balance of the advance is converted to a CIAC.

Previous ~~tax~~ code Section 118b excluded customer CIACs from the utility's gross income provided those contributions were excluded from the rate base for ratemaking purposes. The

1. INTRODUCTION

On October 22, 1986, the Tax Reform Act of 1986 (TRA-86) was signed into law. TRA-86 made substantial revisions in the federal taxation of regulated utilities. Although utilities will realize immediate reductions in income tax rates, the TRA-86 contains a number of adverse provisions that may raise the amount of taxes paid. One of these provisions changed status of contributions-in-aid of construction (CIAC) from non-taxable to taxable income. Although other issues may have a significant impact on revenue requirements, the issues relating to CIAC and advances affect not only the utilities and ratepayers, but may also affect economic development within the state.

The limited purpose of this report is to explore the effects of TRA-86 on CIAC and advances for construction, and to identify Staff's proposed regulatory treatment of CIAC and advances. It must be remembered that since the tax law is so new, there are as yet no test cases, letter rulings, or regulations upon which one can rely for authoritative interpretation. In the event that definitive interpretations of the new tax laws become available, then the regulatory treatments proposed in this report may need to be adjusted.

for exclusion was that these amounts represented "contributions to capital." Customer advances were also excluded from taxable income.

TRA-86 repeals Section 118b and states that contributions from customers or potential customers received after December 31, 1986, are now to be included in taxable income. Proposed technical amendments to TRA-86 indicate that an advance for construction is included under TRA-86 as a CIAC.

Prior to TRA-86, CIAC received a zero tax basis. That is, for tax purposes, the utility was not permitted to claim depreciation for the contributed plant, nor was it permitted to claim any other favorable tax treatment. Under TRA-86, the utility will gain a tax basis for the CIAC, and the utility will be allowed to claim tax benefits for depreciation for that part of the contribution used to construct plant.

Prior to TRA-86, tax basis for advanced plant was often acquired when the plant was constructed because the advance (or a portion of the advance) was considered to be a liability that financed the acquisition of depreciable assets. However, under the new act, the advance is considered to be a contribution, and taxable basis is acquired immediately.

The impact of taxation of CIAC and advances for construction presents a serious problem for regulated utilities in Arizona. Rapid commercial and residential development in many areas of

the state have placed demands for new plant and services on regulated utilities, and have contributed to the proliferation of small water utilities where existing utilities are unable or unwilling to serve in newly developing areas.

3. ALTERNATIVE REGULATORY AND ACCOUNTING TREATMENTS

Staff conducted workshops on January 28, 1987, and February 12, 1987, to discuss the new taxability associated with contributions and advances, and to explore appropriate company responses and regulatory treatments to be afforded contributions and advances. As a result of these discussions, four clearly distinct proposals were made. The proposals were to "gross-up" CIAC and advances for the full tax liability; to "gross-up" CIAC and advances on a present value basis; to have the utility pay the tax, but allow the utility rate base recognition of the taxes paid; or to use alternative financing methods. In the discussion below, the term "contribution" is also intended to apply to advances.

3.1 Gross-up Contributions and Advances to Provide for Payment of Associated Tax Liability

This proposal requires that the customer contribute an amount sufficient to cover the actual cost of construction and to pay the associated income taxes. The proposal provides for relative ease of administration from both the utility's and regulator's perspectives. Agreements are relatively easy to

monitor and the accounting appears to be straightforward. Further, the proposal appears to be equitable in that the cost causer would pay the total cost of the plant and, thus, the plant addition would not affect the rates paid by existing customers.

However, this proposal may create a potential hardship on customers who must advance sufficient cash to pay taxes for service main extensions.

There may also be some problems in that this method is a "flow through" method of collecting taxes where the TRA-86 has mandated that "normalization" methods will be used in computing taxes for accounting and ratemaking purposes. However, Staff believes this potential impediment to gross-up strains the definition of normalization. Normalization usually refers only to the amortization of timing differences that occur with expenses that are recognized on a different basis for book and tax purposes. Staff does not believe there are any timing differences in taxing contributions, but that a permanent basis difference will exist over the tax life of the contributed plant.

The mechanics of the gross-up proposal will require the utility to estimate the marginal tax rate for the year in which the contribution is made and then to "gross-up" the contributed plant for tax purposes. The marginal tax rate is appropriate because the income derived from the contribution

of incremental plant represents income to the utility that is in addition to its operating income that results from approved rates. The gross-up must account for the fact that the utility will pay taxes on the amount that includes the gross-up in the calculation. That is, there is a tax-on-tax phenomenon that must be accounted for.

For example, consider a contribution of $1000, and a combined federal and state tax rate of 40 percent. An initial reaction would be to conclude that the tax bill on the contribution will be $400 (40 percent of $1000) and, hence, require the contributor to contribute $1400. In this event, the utility will pay taxes on the total contribution of $1400 and at a 40 percent composite rate, the related tax bill will be $560. However, now the related contribution is $1560 and the related tax grows larger. The appropriate gross-up rate will reflect this tax-on-tax and will use a multiplier calculated as shown below:

$$\text{tax rate}/(1-\text{tax rate}) + 1$$

or

$$0.40/(1-0.40) + 1 = 1.667$$

Utilizing this example, the contributor will be required to pay $667 in addition to the $1000 cost of construction. In the interest of fairness to the contributor, the utility should be required to maintain records of contributors, so as

to refund any overpayment of taxes in the year of the contribution.

One further problem exists. The utility will now be gaining a permanent tax advantage through its ability to depreciate the plant for tax purposes. For example, if $1000 in plant were depreciated for tax purposes over ten years at $100 per year, and the 40 percent composite tax rate does not change, then the deductability of depreciation creates a tax advantage to the utility. The advantage, in this example, is worth $40 per year. However, Staff recommends that this tax advantage be retained by the utility and returned to the general body of ratepayers over the life of the assets, rather than refunded to the contributor. The advantage to this treatment is to limit the recordkeeping costs and administrative burden caused by refunding small sums to individuals over the tax life of the asset. In setting rates, the benefit can be used as a reduction of current income tax expense.

Due to a small asset and revenue base, many Arizona utilities will be unable to support tax payments associated with new contributions and advances without receiving "grossed-up" contributions to do so.

The accounting entries for this gross-up method are shown on Figure 1.

3.2 Gross-up on Contributions and Advances on A Present Value Basis

In this suggested treatment the contributor would gross-up the contribution or advance for the tax liability net of the present value of the tax benefits to be received by the utility.

In the example developed earlier, the required gross-up for a $1000 investment was $667, assuming a 40 percent composite federal and state tax rate. Assuming a straight-line depreciation over 10 years, the utility would receive a $40 tax benefit per year as a reduction in taxes paid, provided tax rates were constant. To continue the example, also assume that the utility's cost of capital were constant over the 10-year period, known to be 10 percent, and is the appropriate rate to use in computing the present value of the tax benefit. Under these assumptions, the present value of the tax benefits is $246. The contributor would then pay $1000 for the initial investment plus the difference between the tax liability ($667) and tax benefits ($246), or a total of $1421.

Staff does not recommend the use of this technique because the method is imprecise. Neither tax rates nor the cost of capital remains constant. For many small utilities, the marginal tax rate and, thus, the size of the tax benefit varies from year to year. Furthermore, many utilities will experience difficulty in determining the appropriate

assumptions to be used in computing the present value of the benefits.

3.3 Utility Pays Taxes Associated with Contributions and Advances

Arizona's larger utilities may be able to support the tax payments associated with contributions and advances. Many companies, for business and competitive reasons, may choose to use this option. Staff believes that this self-pay option is a viable method for financing incremental plant inasmuch as the utility will only be paying the associated taxes, and not the entire amount of the plant that is being contributed. However, Staff believes that only Class A utilities should utilize this method.

If the company were to pay the contribution-associated taxes, several regulatory accounting and ratemaking principles must be borne in mind. The utility's book or ratemaking income is not increased as a result of the acceptance of the contribution, only the taxable income is increased. Contributions would continue to receive the same ratemaking treatment offered these financing mechanism as were in place prior to TRA-86. There is no tax timing difference to be "normalized" because the CIAC does not contain a book basis; the contribution contains only a tax basis. Although there would be an initial increase in the tax liability of the

utility due the receipt of contribution, over the tax life of the contributed plant, there would be an increase in the amount of depreciation expense allowed for tax purposes. The benefits of the increased tax depreciation expense will serve as a basis for the utility's recovery of the initial tax payment. In effect, the utility pays the associated tax, then receives an offset through tax depreciation benefits.

The accounting and proposed ratemaking treatment for this self-pay method are shown on Figure 2. The ratemaking treatment recommended is to allow the utility a return on its average investment in the pre-paid tax over the tax depreciable life of the CIAC-plant. The return would be earned by admitting the average balance of the pre-paid tax in rate base for each year of the tax life of the asset.

Allowing the utility to earn a return on the "prepaid tax," or debit balance of the deferred tax, may seem unfair to existing ratepayers. However, the purpose of the contribution or advance is to finance incremental plant which will allow the utility to gain more customers so as to spread the utility's fixed costs over a larger body of ratepayers. Further, depending on the size of the contribution relative to the rate base of the utility, the return that would be allowed on the pre-paid tax could produce a dollar amount so small as to be unable to affect the rates that the utility is allowed to charge.

3.4 Alternate Forms of Financing

During the workshops, several suggestions including the use of financing incremental plant with preference stock, or preferred stock, net leases, subsidiary operations, and the like were advanced. Staff suggests that financing incremental plant by means other than contributions and advances is a business decision the utility must make after consideration of the costs, risks and benefits to be derived from that plant. Staff further suggests that utilities considering these alternate financing vehicles review the merits of the proposals with their tax and legal advisors prior to entering into agreements, and when applicable, to seek pre-approval of these arrangements by the Commission in accordance with the Arizona Revised Statutes and Commission Rules.

4. TARIFF AND CONSTRUCTION AGREEMENT REQUIREMENTS

Commission rules currently allow utilities to recover the cost of construction when line extension agreements and other contractual agreements are necessary to finance plant additions. Unless desired by a utility, Staff sees no need, at this time, for utilities to revise their tariffs. However, for utilities choosing a gross-up method, line and main agreements filed with the Commission should provide for refunding the tax portion of the CIAC or advance in the event tax assumptions were in error.

5. SUMMARY OF RECOMMENDATIONS

Staff recommends that companies be allowed a choice of approaches in seeking accounting and ratemaking treatments so as to be able to meet the business situations in their service territories. However, companies must also be ware that discrimination among classes of customers and among customers is precluded. In effect, a company may choose one method of handling the tax liability for contributions, a second method for advances, but may not mix methods. For example, the utility may choose to gross-up contributions, but to self-pay taxes on advances. However, once the company chooses to gross-up contributions for tax liability, it must do so for all contributions and must continue to self-pay taxes on advances.

Staff also recommends that small companies utilize the gross-up method for both CIAC and advances so as to minimize the impact of the tax liability for CIAC and advances on cash flow.

Staff further recommends that these choices be made on an interim basis, subject to review and adjustment if subsequent interpretations of or amendments of the TRA-86 alter the anticipated application of TRA-86.

FIGURE 1

Gross-Up Method

	Debit	Credit
Cash	$1667	
A/P - Federal and State Taxes (CIAC)		$ 667
Contribution in Aid-of-Construction		$1000
To record receipt of contribution for plant		
Utility Plant-in-Service	$1000	
Cash		$1000
To record payments for parts and labor to install plant		
A/P - Federal and State Taxes	$ 667	
Cash		$ 667
Payment of taxes due on Contributions-in-Aid of construction		

FIGURE 2

Self-Pay Method

Journal Entries

	Debit	Credit
Cash	$1000	
Contribution in Aid-of-Construction		$1000
To record the receipt of a contribution		
Plant-in-Service	$1000	
Cash		$1000
To record the construction of plant		
Deferred Taxes (Prepaid CIAC-Tax)	$ 400	
Cash		$ 400
To record the liability for contribution-related taxes		
Taxes Payable	$ 40	
Deferred Taxes		$ 40
To amortize the deferred taxes created by the contribution and reduce current year tax obligation due to the receipt of tax benefits.[1]		

[1] The deferred taxes will be amortized annually as the contributed plant is depreciated for tax purposes. For regulatory accounting and reporting purposes, the contribution has no tax consequences. Therefore, there is no tax expense associated with the amortization of deferred taxes. The amount amortized will be the tax depreciation amount times the company's marginal tax rate. For illustrative purposes, the plant above is depreciated straight-line over 10 years, at $100 per year. This tax depreciation reduces the tax liability from ordinary income by the tax rate multiplied by the depreciation amount, i.e., $40 annually. The annual entry is shown above.

FIGURE 2

Self-Pay Method

Journal Entries

Ratemaking Treatment

Contribution	
Plant-in-Service	$2000
Accumulated Depreciation	500
Net Plant	$1500
Rate Base	$1500

Income Statement	
Revenues	$1000
Expenses (including taxes)	850
Operating Income	$ 150
Allowed Return	10%

Rate Base with Contribution of $1000	
Plant-in-Service	$3000
Accumulated Depreciation	500
Net Plant	$2500
Less CIAC	<1000>
Pre-paid Tax $400, Average Investment $200	$ 200
Rate Base	$1700

EXHIBIT

KGK-3

BEFORE THE ARIZONA CORPORATION COMMISSION

MARCIA WEEKS
Chairman
RENZ D. JENNINGS
Commissioner
DALE H. MORGAN
Commissioner

COMMISSION POLICY DIRECTIVE TO THE UTILITIES DIVISION ON TREATMENT OF TAXES ON CONTRIBUTIONS IN AID OF CONSTRUCTION AND ADVANCES FOR CONSTRUCTION.	DOCKET NO. U-0000-87-257 DECISION NO. 55774

Open Meeting
October 21, 1987
Phoenix, Arizona

BY THE COMMISSION:

DISCUSSION AND BACKGROUND

The Tax Reform Act of 1986 requires the inclusion of funds received by a utility in the form on contributions in aid of construction and advances for contribution in the utility's taxable income. As a result of the substantial impact of this tax code change on the financial condition of many utilities the Commission regulates, particularly water utilities, the Commission Staff held workshops on January 28, 1987, and February 12, 1987, to explore alternative regulatory and accounting treatments of contributions and advances received through line extension agreement: Staff has prepared a Staff Report, dated September 1987, that analyses and provides recommendations for treatment of contributions and advances for accounting and ratemaking purposes in light of the tax code changes.

. . .

In its Report, Staff recommends that utilities subject to the jurisdiction of the Commission be offered two methods for treating the tax liability associated with acceptance of contributions and advances through line extension agreements. The first method ("self-pay") requires that the utility pay the tax liability. In using this method, Staff recommends that the utility record a "pre-paid" tax as a deferred debit which will be amortized over the tax life of the asset. The second method ("gross-up") requires that the utility include in the contribution or advance the associated tax liability. If this method is applied, Staff recommends that the tax savings resulting from depreciation of the associated assets for income tax purposes be passed on to ratepayers in setting the utility's rates in rate cases.

Staff further recommends that once a utility has chosen a method to accommodate the tax liability associated with all contributions, all advances, or both, the utility utilize the method for all contributions, all advances, or both on a non-discriminatory basis. Finally, Staff recommends that these treatments be subject to review and adjustment as required by subsequent interpretation of or amendment to the Tax Reform Act of 1986.

POLICY DIRECTIVE

WHEREAS: The Arizona Corporation Commission finds that clarification and establishment of guidelines for treating the income tax consequences of contributions in aid of construction and advances for contribution are necessary as a result of the Tax Reform Act of 1986. The Commission further finds that

Staff's recommendations contained in its Staff Report, dated September 1987, and described above for the basis for this policy directive that provides direction to Staff for assessing line and main extension agreements and for accounting for contributions and advances for ratemaking purposes.

NOW, THEREFORE be it resolved that Utilities Division assessment of the line and main extension agreements shall:

1. Permit utilities to collect sufficient funds under the line extension agreement to pay the associated tax on the advance or contribution if the utility has selected the gross-up method for all contributions, all advances, or both. The line extension agreement will contain a provision that requires the utility to refund any excess funds thus collected at the close of the tax year when tax returns are completed.

2. If the utility has elected to self-pay the associated tax on all contributions, all advances, or both, then the Utilities Division will assure that the utility does not then require some contributions or advances be grossed-up for tax purposes.

IT IS FURTHER resolved that in a ratemaking proceeding, the Utilities Division will assure that the utility has properly accounted for contributions and advances received after January 1, 1986, as follows:

1. If the utility utilizes the gross-up method, then tax benefits from tax depreciation are used to reduce the income tax expense for ratemaking purposes.

2. If the utility utilizes the self-pay method, then the utility is allowed to claim rate base treatment for its average investment in the tax thus paid. The investment is to be

amortized utilizing the tax benefits from tax depreciation over the tax life of the asset.

IT IS FURTHER resolved that the Utilities Division shall monitor all agreements to ensure that companies inform all parties of the tax rate and amount added to any Contribution in Aid of Construction or Advance for Construction of any project at the time of the initial contact with the company if the gross-up method is used. Failure to notify the parties will result in the utility being solely responsible for payment of the tax thereby eliminating the contributor from any liability towards payment of the tax on Contribution in Aid of Construction and Advances for Construction.

IT IS FURTHER resolved that any additional tax benefits that may be gained from contributions or advances will also be utilized to offset allowable income tax expense for ratemaking purposes.

IT IS FURTHER resolved that the Utilities Division will monitor subsequent interpretations of and amendments to the Tax Reform Act of 1986 and inform the Commission of necessary changes, if any, in this policy directive.

. . .

. . .

. . .

. . .

. . .

. . .

. . .

. . .

IT IS FURTHER resolved that the Utilities Division shall review all requests for waivers to this policy and bring each of them to the Commission for consideration.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN COMMISSIONER COMMISSIONER

I, JAMES MATTHEWS, Executive Secretary of the Arizona Corporation Commission, hereby certify that the foregoing policy was duly introduced, passed, and adopted at an Open Meeting of the Arizona Corporation Commission held on the 21 day of October, 1987.

JAMES MATTHEWS
Executive Secretary

DISSENT _____

S0009.O

Decision No. 53774

Rebuttal Testimony
of
Dallas J. Dukes

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATING FINANCING	)	DOCKET NO. E-04204A-06-0783

Rebuttal Testimony of

Dallas J Dukes

on Behalf of

UNS Electric, Inc.

August 14, 2007

TABLE OF CONTENTS

I. Introduction 1

II. Rebuttal to Staff Witness Ralph C. Smith 2

A. CARES Discount (Staff Adjustment C-1) 2

B. Remove Depreciation & Property Taxes for Construction Work in Progress (Staff Adjustment C-2) 2

C. Fleet Fuel Expense (Staff Adjustment C-4) 3

D. Postage Expense (Staff Adjustment C-5) 3

E. Injuries and Damages Expense (Staff Adjustment C-6) 4

F. Incentive Compensation (Staff Adjustment C-7) 6

1. Performance Enhancement Plan 6

2. Officer's Long Term Incentive Program 13

3. Supplemental Executive Retirement Plan (Staff Adjustment C-8) 14

G. Stock Based Compensation (Staff Adjustment C-9) 15

H. Rate Case Expense (Staff Adjustment C-11) 16

I. Edison Electric Institute (Staff Adjustment C-12) 17

J. Other Membership and Industry Association Dues (Staff Adjustment C-13) 18

K. Emergency Bill Assistance Expense (Staff Adjustment C-16) 19

L. Other Adjustments to Operating Expenses 19

1. Normalized Overtime Expense 20

2. Salaries and Wage Increases 21

III. Rebuttal to RUCO Witness Marylee Diaz Cortez 21

A. Bad Debts – Uncollectibles (RUCO Income Statement Adjustment 6) 21

B. Fleet Fuel Expense (RUCO Income Statement Adjustment 7) 22

C. Year End Accruals (RUCO Income Statement Adjustment 9) 22

D. A&G Capitalization (RUCO Income Statement Adjustment 10) 23

E. CWIP Property Taxes (RUCO Income Statement Adjustment 11) 25

F. Corporate Cost Allocations (RUCO Income Statement Adjustment 12) 25

G. Valencia Turbine Fuel (RUCO Income Statement Adjustment 14) 26

H. Outside Services – Demand Side Management (RUCO Income Statement Adjustment 21).....27

IV. Rebuttal to RUCO Witness Rodney L. Moore 27

A. Pension and Benefits (RUCO Income Statement Adjustment 2) 27

B. Worker's Compensation (RUCO Income Statement Adjustment 3).....27

C. Incentive Compensation (RUCO Income Statement Adjustment 4) 28

D. Rate Case Expense (RUCO Income Statement Adjustment 5) 29

E. Postage Expense (RUCO Income Statement Adjustment 8) 29

F. SERP (RUCO Income Statement Adjustment 16).....30

G. Unnecessary Expenses (RUCO Income Statement Adjustment 17).....30

H Maintenance of Overhead Lines (RUCO Income Statement Adjustment 18).....31

I. Non-Recurring/Atypical Expenses (RUCO Income Statement Adjustment 20).....31

Exhibits:

Exhibit DJD-1 Comparison of Adjustments to Revenue Requirements
Exhibit DJD-2 General Liability Insurance Expense
Exhibit DJD-3 Competition compensation Analysis (Confidential – Redacted)
Exhibit DJD-4 Summary of A&G Labor Allocation
Exhibit DJD-5 Response to Staff Data Request No. 11-11

I. INTRODUCTION.

Q. Mr. Dukes, did you file Direct Testimony is this case?

A. Yes, I did.

Q. Have you reviewed the direct testimony filed by the Commission Staff and Intervenors in this case?

A. Yes, I have.

Q. Which Commission Staff and/or Intervenor testimony will you be addressing in your Rebuttal Testimony?

A. In my Rebuttal Testimony, I address certain adjustments that Staff Witness Ralph C. Smith recommends in his Direct Testimony. I also address several adjustments that Residential Utility Consumer Office ("RUCO") witnesses Marylee Diaz Cortez and Rodney L. Moore propose in their Direct Testimonies. While I agree with some of the adjustments made, the majority of adjustments made by Staff and RUCO are inappropriate and should be rejected. I have provided a comparison of adjustments to revenue requirements for UNSE, Staff and RUCO that is attached as Exhibit DJD-1. My Rebuttal provides ample justification for rejecting Staff and RUCO adjustments in favor of UNS Electric, Inc.'s ("UNS Electric" or the "Company") proposals on these adjustments. In short, I believe that adoption of many of Staff's and RUCO's adjustments is not supported by all of the evidence and documents in this case.

II. REBUTTAL TO STAFF WITNESS RALPH C. SMITH.

Q. Could you please summarize your view of the testimony filed by Mr. Ralph C. Smith on behalf of Staff?

A. I disagree with several of the adjustments he makes in his Direct Testimony.

A. CARES Discount (Staff Adjustment C-1).

Q. Mr. Dukes, do you agree with Mr. Smith's adjustment to remove the impact of the Company's proposed change in CARES discount structure?

A. No, Mr. Smith and Ms. McNeely-Kirwan are recommending that the present CARES discount structure be retained and the Company's proposed structure be rejected. UNS Electric witness, D. Bentley Erdwurm, will be directly addressing the Staff witnesses' proposal in his Rebuttal Testimony.

B. Remove Depreciation & Property Taxes for Construction Work in Progress ("CWIP") (Staff Adjustment C-2).

Q. Do you agree with Mr. Smith's adjustment to remove the Company's proposed Depreciation and Property Tax adjustment for CWIP included in rate base?

A. No. The adjustment is directly associated with the inclusion of CWIP in rate base as a plant item. Mr. Kentton C. Grant is the Company's witness in support of including CWIP in rate base. Because CWIP should be included in rate base, the Company's depreciation and property tax adjustment should not be adjusted as Mr. Smith proposes.

C. Fleet Fuel Expense (Staff Adjustment C-4).

Q. Do you agree with Mr. Smith's adjustment to Fleet Fuel Expense?

A. I agree with part of his adjustment. I agree that it should be updated to reflect the most recent market cost of fuel. Upon further analysis on this issue, it appears that both the Company's and Staff's proposed adjustments to Fleet Fuel Expense are inaccurate and should be corrected. My initial adjustment reflected the average cost of fuel based on June through August of 2006. That was the most recent data I had at the time, but that was also at the peak of seasonal cost. Therefore, my adjustment was inflated, when that rate was applied to pro forma annual usage. Mr. Smith's revised calculation is based on UNSE gasoline purchases for the months of September 2006 through April 2007. His calculation suffers from the opposite problem; which is that it excludes the portion of the year when gasoline is historically at its highest level. So, the period Mr. Smith used excludes the months of May, June, July and August. The weighted average cost for the period Mr. Smith chose was $2.69 per gallon, but if you add July through August of 2006 and May and June 2007 to the evaluation to include all seasons of the year the weighted average cost increases to $2.82. This equates to an additional $28,482 that should be added to Mr. Smith's adjustment. This means that I have decreased the Company's original adjustment by $41,909 to $605,498.

D. Postage Expense (Staff Adjustment C-5).

Q. Do you agree with Mr. Smith's adjustment to Postage Expense?

A. Yes. Mr. Smith has adjusted the Company's postage expense adjustment upward to reflect a fixed, known and measurable postage rate increase that happened within twelve months of the test year and will be in effect when the rates set in this proceeding are being charged.

E. **Injuries and Damages Expense (Staff Adjustment C-6).**

Q. Do you agree with Mr. Smith's adjustment to Injuries and Damages Expense?

A. Yes and No. Mr. Smith has used a simple three year average of FERC account 925 to calculate what he believes to be a "normalized" level of injuries and damages expense. The presumption in such an adjustment is that the test year amount does not reflect normal and recurring levels. A problem with Mr. Smith's approach is that the vast majority of injuries and damages expense is directly related to insurance premiums and wages. Both factors are very normal and very recurring expenses that do *not* fluctuate wildly from year to year. On the contrary, they tend to increase year after year. The reality is that these particular expenses have increased significantly since 2004 and it is unreasonable to use a three-year historical average to set the prospective amount to be recovered through rates for the entire portion of FERC account 925.

UNS Electric's test-year expense charged to the expenditure type general liability insurance was $156,480 which was a 9% increase over the cost in 2004. However, the cost was $163,380 for the calendar year 2006; a 4% increase over the test year. These increases were driven by increases in insurance premiums. By averaging the last three years general liability expenses Mr. Smith has only insured that the Company will not come close to recovering the actual cost that will be incurred. The information on general liability expense is provided as Exhibit DJD-2.

The test-year expense charged to the expenditure type Officers' & Directors' liability insurance expense of UNSE was $106,353. This is a 300% increase over the cost in 2004. But that dramatic increase was caused by the fact that this coverage was not allocated to UNSE in 2004 and only partially in 2005. The calendar year 2006 expense was $109,089 and the twelve months ending June 2007 was $116,539. The test-year costs reflect the

premiums and the cost allocations in place presently and to use a three year average only guarantees under recovery of these costs. The information on Officers' and Directors' insurance expense is provided as Exhibit DJD-2.

Mr. Smith did not dispute the reasonableness of the Officers' & Directors' liability insurance premiums themselves or the amount of costs being allocated to UNS Electric. He did however comment on his belief that the monetary benefit of the insurance flowed to the shareholders and as such Mr. Smith indicates that the cost should be incurred by shareholders and ratepayers alike. I disagree with that argument completely; these insurance premiums are normal and recurring cost of doing business in today's world and do not benefit the shareholders. This type of coverage is absolutely necessary to attract and retain Officers and Directors. No one disputes this as being an unreasonable expense, nor is the specific amount being challenged as excessive. Thus, this specific amount should be recovered.

Q. Your response to the question was yes and no, what portion of Mr. Smith's adjustment do you agree with?

A. Another significant portion of the test-year injuries and damages expense is workers' compensation expense. The Company is self insured up to $500,000 on any individual claim. Therefore, that particular area of expense can fluctuate from year to year. It does appear that the test-year amount of $173,456 is abnormally high due to the timing of when activity was actually expensed. So I agree with Mr. Smith's approach of using a three year average of the accrual based expense for worker's compensation. That would mean a reduction in the Company's test year injuries and damages expense of $79,978 ($173,456 minus $93,478).

F. Incentive Compensation (Staff Adjustment C-7).

Q. Mr. Dukes, can you briefly summarize Mr. Smith's adjustment to test year Incentive Compensation?

A. Yes. Mr. Smith has suggested an equal sharing of the costs associated with the Company's various employee incentive programs. Mr. Smith's primary reasoning for this sharing is that it strikes the balance between the benefits attained by both shareholders and customers. He also references a recent Commission Decision No. 68487 (February 23, 2006) – the Southwest Gas Corporation ("SWG") rate case – in which the Commission adopted such a recommendation for SWG's management incentive plan ("MIP").

1. Performance Enhancement Plan ("PEP").

Q. Do you agree with Mr. Smith's adjustments related to the PEP?

A. No, I do not. Mr. Smith's suggested sharing of the PEP program cost has to be based on an assumption that the program is somehow an additional cost to the customers over and above what he deems to be reasonable costs for employee compensation. It also suggests that the specific goals or targets of the program are the only benefits and somehow equally benefit shareholders and customers alike. I strongly disagree with those assumptions inherit in Mr. Smith's adjustment.

Q. Can you provide more detail as to why you disagree with Mr. Smith?

A. Certainly. The evidence I discuss below shows that UNS Electric's total employee compensation including the PEP program is reasonable and to deny recovery of such is to insure that UNS Electric will not have a reasonable opportunity to recover its operating cost. And neither Staff nor RUCO assert that the total employee compensation including

PEP is unreasonable. In effect, UNS Electric is being penalized simply for its compensation structure.

I believe the PEP program costs are actually a net savings to customers. I also believe the program provides a valuable management tool to promote increased earnings, to promote additional cost savings, to motivate individual employees, to encourage groups of employees to work together to impact specific goals, and to aid in the retention of the higher-performing employees. All of these are ultimately benefits passed on to customers.

The goals or targets of the current PEP program are also heavily weighted toward providing benefits to customers. The program uses financial performance measures weighted at 30%, operational cost containment weighted at 30% and customer service goals at 40%. I would argue that the potential benefits of the current program goals and objectives merit full recovery of the expense as it provides benefits to the customers and doesn't provide for unreasonable salary and wage expense.

No party disputes that the PEP program actually reduces the ultimate cost passed on to customers in the form of reduced payroll and benefits cost. It is counter-intuitive to penalize the Company for having an employee compensation program that reduces the ultimate costs passed on to the customers, that promotes increased safety, increased customer service, the reduction of operating costs and increases the financial soundness of the Company and does not result in unreasonable or imprudent employee compensation levels.

Q. Please further explain the PEP and some of the benefits to customers, the Company and to employees.

A. A more accurate description of that program would be "a portion of an individual's fair and reasonable compensation put "at risk" to encourage and enhance group and individual performance". The at-risk compensation portion is used on an individual basis to reward specific performance and provides management with an additional tool to encourage further cost savings, motivate individuals and to encourage employees to impact goals.

PEP is at-risk compensation because there are no guarantees to *individual* employees that payment will be made, on a Company wide basis a payout between 50-150% is normal and recurring. The Company's compensation philosophy is to pay at approximately 50% of market rate for its employees. In benchmarking studies conducted by an outside consulting firm, non-union positions actual total average cash compensation (inclusive of incentives) was 11% below 50% of market (or at 39% of market) at UNS Electric, as Confidential Exhibit DJD-3. Therefore, the overall average PEP payouts are an integral part of the reasonable compensation necessary to attract and retain employees.

If the PEP program is eliminated, there would be considerable increased pressure on base compensation. Employee base compensation would eventually have to be increased toward market to allow the Company to compete in attracting and retaining a skilled workforce. It is not reasonable to assume that the Company would be able to continue to attract employees at compensation rates well below the market median, without the PEP. Furthermore, to stay competitive in attracting and retaining employees, the market is such that performance-based, lump sum cash awards are standard practice at 79% of companies today. So, Staff's recommendation will drive base compensation upward so that little to no compensation is variable or at risk.

Q. Are there advantages to the PEP versus just paying base compensation?

A. From the Company's and the customers' perspectives, there are many advantages to using a program like PEP, rather than just paying median market wages as non-variable base compensation. The most direct savings result because PEP is not part of base compensation; therefore employee costs such as vacation pay, sick pay, long term disability, 401K matching, pension expense and other post-retirement benefits that are based on base pay are all reduced. The impact of reduced compounding wage increases that would be based on a higher base pay total is another benefit. You then have the benefits produced from the specific goals tied to a portion of the employees' compensation, which are the benefit of the Company having greater flexibility to distinguish among and reward high-performers, to attract and retain more talented employees, and to mitigate the costs of training new employees by retaining key ones. Neither Staff nor RUCO dispute these facts and that the PEP brings added flexibility at reasonable cost.

From the employee perspective, the proper mix of base wages and incentive pay has benefits. Individual employees are rewarded for contributing to the overall success of the organization and are allowed a way to directly participate in corporate success with a clear line of sight to goals. Employees can be acknowledged and rewarded for making a difference by exhibiting extra effort, working more hours on the job (for professionals not eligible for overtime pay), or supporting the program goals. Also, payment to individual non-union employees is discretionary, so talented and high-contributing employees can earn more through the program, which can be a motivating factor and can also lead to higher retention rates for more talented employees. Rather than being an over-inflated program, the PEP provides direct benefit to UNS Electric customers economically. Neither Staff, nor RUCO for that matter, have presented any evidence to demonstrate that

the compensation and benefit packages of the UNS Electric employees (including incentive compensation) are not prudent or reasonable.

Q. Has there been any recent Commission decisions since the Southwest Gas decision sited by Mr. Smith that address the recovery of incentive compensation expenses?

A. Yes. Commission Decision No. 69663 (June 28, 2007) for Arizona Public Service Company ("APS"), allowed for recovery of its Cash-based Incentive Compensation plan expenses. The Commission stated in Decision No. 69663 on page 37 that:

> "APS' variable incentive program is an "at risk" pay program where a part of an employee's annual cash compensation is put at risk and expectations are established for the employee at the start of the year. If certain performance results are achieved, a predictable award will be earned based upon objective criteria. The actual amount of the award depends upon the achieved results. The intent of the plan is to: link pay with business performance and personal contributions to results; motivate participants to achieve higher levels of performance; communicate and focus on critical success measures; reinforce desired business behaviors, as well as results; and to reinforce an employee ownership culture. (APS Exhibit No. 51, Gordon Rebuttal, p. 8) Staff did not oppose inclusion of the TY variable incentive expense in cost of service, noting that although corporate earnings serve as a threshold or precondition to the payout, the TY level of expense is tied primarily to performance measures that directly benefit APS customers. (Staff Exhibit No. 43, Dittmer Direct, p. 110)"

Q. Is UNS Electric's PEP the same as SWG's Management Incentive Program?

A. No. SWG's MIP program appears limited to management personnel. UNS Electric's PEP is for all non-union employees. Further, SWG's MIP appears specifically related to

return on equity targets and customer to employee ratios. The Company's PEP is based on broader and more wide-ranging factors, of which financial performance is only a part of the consideration.

Q. You mention the PEP is for all non-unions employees. Why are union employees not eligible for PEP compensation?

A. The union employees wage rates are collectively bargained and up to this time the union members have not been receptive to putting any portion of an individual's pay at-risk and/or allowing equivalent grade employees to earn differing pay levels based on performance.

Q. Have other states fully allowed incentive compensation expenses for similar programs?

A. Yes. Two cases stand out. One involved Nevada Power Company ("NPC") – and its managerial, professional, administrative and technical Short-Term Incentive Program and Total Rewards program in 2002.[1] These programs considered traditional pay and benefits, among other things, and provided incentive pay for individual performance and for contributing to NPC's overall service and financial performance. Factors considered included quality of service, system performance, reliability and cost reduction goals. NPC witnesses testified that its program attracted and retained employees needed to continue to provide excellent service to NPC's customers – while also keeping downward pressure on base salary increases and that its incentive program costs were an essential component of NPC's basic labor costs. The Nevada Public Utilities Commission found that NPC's incentive program helped NPC *to provide reliable service at reasonable rates* and allowed NPC's adjustments for its incentive program In 2007, the Nevada Commission confirmed that NPC's STIP Program did benefit ratepayers either directly or indirectly

[1] Before the Nevada Public Utilities Commission, Docket No. 01-10001, 2002 WL 32862407.

and allowed $6,023,000 of those expenses into rates – even though 35% of the STIP "performance matrix" related to financial performance.[2] The Nevada Commission believed NPC's STIP because "the consumers are beneficiaries of the STIP performance measures." The Nevada Commission did not appear to deny any amount of NPC's STIP on the basis that some goals may be more closely aligned with shareholders than customers. So Nevada believed if reliable service can be provided at reasonable rates, this incentive compensation should be awarded.

Then, there is the Massachusetts Department of Telecommunications and Energy ("Mass. D.T.E.") decision regarding Boston Gas Company dba KeySpan Energy Delivery New England ("Boston Gas") in 2003.[3] Boston Gas' incentive compensation program involved specific performance goals and financial incentives linked to various performance levels. The Mass. D.T.E. found that Boston Gas' incentive program allowed incentive compensation expenses so long as they were reasonable and *were reasonably designed to encourage good employee performance*. The Mass. D.T.E. further stated that if the incentive plan was not solely based on company financial performance, then the incentive plan is reasonably to encourage good employee performance. It was also noted that Boston Gas' program is similar to those of other utilities competing for the same employees, and that several incentive categories directly dealing with cost-containment enhancing value to customers – like customer satisfaction, safety and workforce diversity. The Mass. D.T.E. allowed the Company to recover incentive compensation expenses.

These are but only two examples. The Florida Public Service Commission ("FPSC") allowed Gulf Power Company to recover incentive compensation in 2002.[4] The FPSC

[2] 2007 WL 2141450.
[3] Docket No. D.T.E. 03-40 (2003 WL 22964722).
[4] Docket No. 010949-EI, Order No. PSC-02-0787-FOF-EI.

noted that Gulf offers a plan consisting of base salary and incentive compensation and that only receiving a base salary would mean Gulf employees would be compensated below employees at other companies. The Maryland Public Service Commission ("MPSC") allowed incentive compensation for Washington Gas Light Company in 2003 because the MPSC found that Washington's incentive compensation proposal includes criteria directly benefiting ratepayers.[5] Clearly, other Commissions have recognized how programs similar to UNS Electric's PEP provide direct benefit to ratepayers and are related to providing reliable service to customers at reasonable rates. Neither Staff, nor RUCO for that matter, really dispute UNS Electric's PEP costs as unreasonable or non-recurring. As I explained in my Direct Testimony, UNS Electric's PEP is an integral part of the Company's compensation and benefits program, related to core goals including system reliability, operational cost containment, as well as customer service and financial performance. But having financial performance as part of the PEP evaluation does not justify Staff's recommendation; the PEP is not solely based on financial performance, the costs are reasonable and the bottom line is that all the evidence points to *all* of UNS Electric's PEP expenses as appropriately included.

2. <u>Officer's Long Term Incentive Program.</u>

Q. Do you agree with Mr. Smith's adjustments related to the Officer's Long Term Incentive Program?

A. No, I do not. Mr. Smith again simply applies an equal sharing of the cost methodology to this program and I disagree with the base assumptions behind such treatment. The costs at dispute here are long term incentive costs allocated to the Company from Tucson Electric Power Company ("TEP") for executive oversight of UNS Electric.

[5] Case No. 8959, Order No. 78757 (94 Md.P.S.C. 329)

These costs represent a portion of the Officers' total compensation that is variable and put at risk, but are an integral part of a competitive compensation program. This *total compensation* is targeted at the median of the peer group as reviewed by an independent consultant on behalf of the Compensation Committee of the Board of Directors.

As I discussed previously about the PEP program above, if the costs of the program are reasonable, prudent and provide a benefit to the customers, then the Company should be allowed to recover those costs. The Staff has not presented any evidence to demonstrate that the compensation and benefit packages of the Officers of TEP and UNS Electric are not reasonable. No party states that the package is unreasonable or excessive, or that refutes the evidence the Company provided that the costs are at the median of market and are necessary, reasonable and prudent cost incurred to attract and retain the Officer's of TEP and UNS Electric.

3. Supplemental Executive Retirement Plan ("SERP") (Staff Adjustment C-8).

Q. Please describe the SERP program.

A SERP is a retirement program that allows Officers to have proportionately equivalent retirement benefits to all other eligible employees. The amount that Mr. Smith is recommending be disallowed primarily represents benefit cost allocated to UNS Electric from TEP.

Q. Do you agree with Mr. Smith's adjustment to remove 100% of the SERP expenses allocated to UNSG?

A. No, I do not. I recognize that Mr. Smith has relied upon Commission's recent decision in the SWG rate case (Decision No. 68487) that disallowed the recovery of SERP expenses. The SERP program is a portion of the compensation and benefits package made available

to UniSource Officers. The level of compensation, incentives and benefits are all determined by the Compensation Committee of the Board that is comprised of independent Board members.

The reason a program like SERP is necessary is because of funding deductibility limits defined within the Internal Revenue Code. And those funding limits are set based on tax revenue collection needs, not on the point at which it is no longer fair to provide retirement benefits. They are not a guideline for how much is fair and reasonable as part of an employee benefit program. The evaluation of that should be the reasonableness of the compensation and the executive benefit package itself. All UNS Electric is asking for here is to allow executives to have the same proportion or level of retirement benefits as for other Company employees.

G. <u>Stock Based Compensation (Staff Adjustment C-9).</u>

Q. Mr. Dukes, do you agree with the recommendation of Mr. Smith regarding Stock Based Compensation?

A. No. Mr. Smith asserts that the test-year expense represents compensation over and above the officer's normal levels of compensation. The test-year stock based compensation expenses allocated to UNS Electric is a portion of the normal and recurring compensation and benefits package made available to Officers and Directors. It also gives added incentive for Officers and Directors to be invested in the Company as opposed to cash-based compensation. The level of compensation, incentives and benefits provided to Officers and Directors as a part of their total compensation are all determined by the Compensation Committee of the Board that is comprised of independent Board members. The reasonableness of the amount of compensation and benefit package, which is not

disputed, should be the determining factors evaluated to determine if the expenses can be recovered as part of the Company's cost of service.

H. <u>Rate Case Expense (Staff Adjustment C-11).</u>

Q. Do you agree with Mr. Smith's adjustment for Rate Case Expense?

A. No. Mr. Smith attempts to compare the UNS Electric rate case cost to SWG's most recent rate case and implies that SWG and UNS Electric are comparable companies. That assumption is flawed.

SWG is one entity with operations in Arizona, Nevada and southern California. SWG indirectly allocates its Executive administration and corporate shared services cost to its jurisdictional regulated operations based on a Massachusetts Formula. By contrast, TEP is a completely separate regulated utility. TEP indirectly allocates Executive administration cost through a similar Massachusetts Formula approach. However, TEP directly allocates the actual cost for services provided to UNS Electric by shared service departments of TEP. As a part of that process the shared service departments directly charged UNS Electric for services provided in direct support of this rate case incremental to their normal and recurring activities.

For example, the SWG's Arizona jurisdictional operations gets approximately 55% of all shared service cost from "Corporate" whether they use it or not. In essence, the Arizona customers pay for 50% of the accounting department, 50% of the plant accounting department, 50% of the rates/pricing department, 50% of the legal department, 50% of the payables department, 50% of the budgeting and 50% for other departments. UNS Electric has none of these departments in house; it is only charged for shared services that it uses and obtains from TEP. And in the case of rate case support those incremental cost were charged to and deferred on the balance sheet of UNS Electric.

Q. What would the impact be on UNS Electric if all administrative and general support costs from TEP were allocated based on the same methodology as SWG?

A. The allocations to UNS Electric from TEP for shared services (labor & burdens) would increase approximately $2.3 million annually. This information is provided in Exhibit DJD-4 attached to my Rebuttal Testimony.

Q. Do you believe that UNS Electric should be allowed to collect all of these rate case expenses?

A. Yes, because these are the actual and legitimate outside service costs incurred in the process of preparing and defending the UNS Electric rate case. In this particular instance, it will amount to about $200,000 being built into base rates for rate case expense. UNS Electric's adjustment is basically equivalent to adding an incremental amount to base rates based on actual usage, versus just simply allocating portions of departments and charging them to UNS Electric whether used or not. It would be unduly burdensome to allocate all of the shared service department cost of TEP to UNS Electric on an indirect basis. However, it is also unfair for TEP to provide services to UNS Electric that are not reimbursed; thus TEP and its customers would be subsidizing UNS Electric's customers.

I. <u>Edison Electric Institute ("EEI") (Staff Adjustment C-12).</u>

Q. Do you agree with Mr. Smith's adjustment to reduce the Company's test-year level of EEI dues?

A. Partially. I agree that based on the historical standard of excluding lobbying cost we should have excluded the EEI Utility Air Regulatory Group ("UARG") dues. However, I disagree with Mr. Smith's exclusion of 49.93 percent of EEI core dues. Mr. Smith was provided extensive information in discovery about the multitude of benefits provided to

the Company and ultimately to the customers through its EEI membership. This information is provided in Exhibit DJD-5 attached to my Rebuttal Testimony.

Also the Company provided a pro forma adjustment reducing the test-year expense associated with EEI dues for lobbying activity based on the most recent information provided by EEI themselves. That adjustment along with the additional UARG adjustment mentioned above brings the test year exclusion up to 48% of the annual EEI expense. I believe this is more than an adequate reduction of test-year cost, especially when you apply Mr. Smith's benefit argument and consider that lobbying expense probably benefits customers just as much or even more than shareholders.

The primary objective of a group like the EEI and a sub-group like UARG is to be an advocate on behalf of its electric company members. UARG helps to ensure that legislation does not result in excessive costs against the Company. Because it is the Company's customers who ultimately pay for cost increases and/or increased investment driven by legislation, tax code changes or environmental standards passed that affect the electric industry. Therefore, EEI and UARG do provide real benefits to customers as well as for the electric companies.

J. <u>Other Membership and Industry Association Dues (Staff Adjustment C-13).</u>

Q. Do you agree with Mr. Smith's adjustment to remove other membership and industry dues expenditures from test year activity?

A. Yes. These are expenses that were inadvertently missed in the review and preparation of the Company's filing.

K. Emergency Bill Assistance Expense (Staff Adjustment C-16).

Q. Mr. Dukes, do you agree with the recommendation of Mr. Smith regarding Emergency Bill Assistance expense?

A. Yes. Those expenses for emergency bill expense are more properly reflected in base rates and not in the Demand Side Management program funding.

L. Other Adjustments to Operating Expenses.

Q. Mr. Dukes, do you have any adjustments or additions to the Company's direct filing that were not addressed by Mr. Smith's filing?

A. Yes. I have an adjustment related to the calculation of normalized overtime, and I have adjustments related to known and measurable rate changes that have taken place since the Company's original filing.

Q. Mr. Dukes what do you mean by adjustments related to known and measurable rate changes that have taken place since the Company's original filing?

A. This normally applies to changes in rates, including wage rates and property tax rates. For example, the number of employees and hours worked should be normalized to the end of the test-year level of employees. But, it is also normal to adjust the wage rates applied to those level to the most recently known and measurable rates. It is my understanding, based on the Direct Testimonies of Staff and RUCO witnesses, that their recommended cut-off for such rates changes in this preceding should be when the rates established in this case are presumed to go into effect.

In his Direct Testimony, Mr. Smith for Staff proposed, and I accept, a rate increase adjustment for postage expense. That rate increase is fixed, known and measurable and is

already in effect. Staff has also proposed an adjustment to decrease property tax expense based on the property tax assessment rate that is known, measurable and that will be in effect in 2007. Consistent with those proposed adjustments there are some other rate changes that are known and measurable at this time, that were not at the time of the Company's original filing. Wage increases went into effect for the classified and unclassified employees of UNS Electric and TEP for the year 2007. The contract for wage increases for union employees for 2007 is also currently known and measurable as there is already an approved contract in place.

1. Normalized Overtime Expense.

Q. What is the revised adjustment for normalized overtime expense?

A. In UNS Gas, Inc.'s most recent Rate Case (Docket No. G-04204A-06-0463), Mr. Smith proposed an adjustment to normalize overtime based on a two-year average including the test year and the year immediately preceding the test year. The adjustment took the two-year average for overtime and applied the percentage increase associated with regular payroll charged to O&M expense. The adjustment proposed by Staff reduced UNS Gas' payroll adjustment by approximately $123,010. In the UNS Gas case I accepted Mr. Smith's adjustment as I believed it did more accurately reflect a normalized level of overtime expense versus the calculation I had originally sponsored.

In the current case I used the same calculation for normalized overtime expense as I did originally in the UNS Gas Rate Case. I believe the Mr. Smith proposed format in that case more accurately reflects the normalized level of overtime expense for UNS Electric. Therefore, I have recalculated normalized overtime expense based on the same method Mr. Smith proposed – and I accepted – in the UNS Gas case. That new adjustment results in an increase to pro forma payroll expense of $139,201.

2. Salaries and Wage Increases.

Q. What is the revised adjustment for salaries and wages?

A. The rate increase for unclassified employees that went into effect January 1, 2007 is fixed, known and measurable and is currently in effect as are the wage increases per the classified contracts for 2007. To simplify the adjustment I am only adjusting the direct labor cost for UNS Electric employees and not reflecting the increased rates of TEP employees that were allocated to UNS Electric during the test year. Those changes increase the pro forma payroll expense of UNS Electric by $92,550.

Q. Will the revised adjustments impact other adjustments?

A. Yes. The payroll adjustments will change the payroll tax expense adjustment and all of the revised adjustments will impact income taxes and cash working capital. The revised income taxes and working capital adjustments are sponsored by Ms. Kissinger.

III. REBUTTAL TO RUCO WITNESS MARYLEE DIAZ CORTEZ.

A. Bad Debts – Uncollectibles (RUCO Income Statement Adjustment 6).

Q. Do you agree with Ms. Diaz Cortez's adjustment to reduce the Company's proposed Bad Debt Expense?

A. In part. Ms. Diaz Cortez argues that the Company has overstated the pro forma bad debt expense by using the actual write-offs of bad debt as opposed to the bad debt expense. She is correct that our adjustment mistakenly was calculated using gross write-offs. However, Ms. Diaz Cortez only applies the write-off percentage from the test year to the adjusted test-year revenues. I still believe that an historical percentage of bad debt expense as a percentage of revenue applied to adjusted pro forma revenue is a more

reliable indicator of bad debt expense to be included in cost of service. Bad debt expense can fluctuate materially year over year, and thus it is appropriate to use an average to smooth out those fluctuations. I would prefer to use a three-year average, but at the time of the original filing only two years of reliable data was available. I updated the Company's calculation to be based on the most recent three-year calendar period to calculate the average percentage of uncollectible expense to be expected. The result of this revision is a reduction in the Company's original bad debt expense adjustment of $155,609.

B. <u>Fleet Fuel Expense (RUCO Income Statement Adjustment 7).</u>

Q. Do you agree with Ms. Diaz Cortez's Fleet Fuel Expense adjustment?

A. Not completely. Similar to Staff's recommendation, Ms. Diaz Cortez has updated the Company's fleet fuel calculation for more recent fuel prices incurred by UNS Electric. However, also like Staff she has used a period that excludes the summer months that historically have the highest cost. I believe the revised adjustment I proposed in the discussion of Staff's fleet fuel expense adjustment is the more appropriate pro forma expense level.

C. <u>Year End Accruals (RUCO Income Statement Adjustment 9).</u>

Q. Do you agree with Ms. Diaz Cortez's adjustment to remove expenses associated with an invoice expensed in the test year related to services provided prior to the test year?

A. Yes.

D. A&G Capitalization (RUCO Income Statement Adjustment 10).

Q. Do you agree with Ms. Diaz Cortez's adjustment to remove the Company's proposed adjustment for A&G Capitalization?

A. No. Ms. Diaz Cortez argues that by making this adjustment the Company will somehow double recover these costs. I disagree with that characterization completely. The costs we are discussing are the "recurring" costs of shared service support departments. This is not a one-time expenditure that was capitalized in the test year and then we are asking to expense it in the future. Simply put, these costs will recur year after year and our adjustment only reflects the amount of the expected future costs that will be included in expense based on our best information applied to historical test-year activity.

The cost of these shared service departments is not directly traced on an individual capital project basis. For example, when installing a new service, it is easy to identify the cost of the meter, poles, wire and the hours a servicemen puts in to install it. But there are also the costs associated with managing the servicemen, analyzing and processing the budget for the new service, processing the payroll for the servicemen, for supporting the software that tracks the materials, designs the service and maps where the service is within the system. There are also the costs of unitizing the new asset and putting it into the accounting system and numerous other support services that are an integral part of the capital expenditure process.

As I said above, these shared service groups cannot link their time directly to individual capital projects; it is not practical or cost effective to even try. A normal and acceptable alternative is to test and survey all of these groups periodically and find out how much of their time is spent on any capital projects. Then turn that into a percentage of time that is applied to the cost of each area. So if plant accounting spends 70% of their time dealing

with capital projects, then it follows that 70% or their cost should be allocated to capital projects and 30% will go to expense. You then do this with all of the support areas and come up with a percentage of total support cost to be spread to capital projects as a credit to A&G.

In this particular adjustment the Company has normalized the credit to test-year A&G to reflect the percentage currently being applied that is based on the most recent study of how much of those types of cost should be capitalized. The proposed capitalization percentage is what the Company is currently using in the actual accounting records today.

Regarding Ms. Diaz Cortez claim about double recovery. As I explain above, we are talking about the cost of support services. And a certain percentage of those costs were capitalized in the past. Like any past investment, that percentage is properly included in plant in service or CWIP. The remaining percentage was expensed and is properly recorded in retained earnings. However, we use a historical test year to set rates *"prospectively"* and we therefore adjust test-year activity to reflect fixed, known and measurable changes representing activity that will recur when the new rates are in effect. Thus it is appropriate to reflect that change in the cost of service being established in this case. There is no double recovery, because these are recurring costs. These support services will be there when these rates are in effect and our adjustment accurately reflects how those expenses will be collected in the future.

Finally, I would note that Staff did not challenge the Company's adjustment for A&G Capitalization.

E. <u>CWIP Property Taxes (RUCO Income Statement Adj. No 11).</u>

Q. Do you agree with Ms. Diaz Cortez's adjustment to reduce the Company's proposed Property Tax adjustment for CWIP included in rate base?

A. No. The adjustment is directly associated with the inclusion of CWIP in rate base as a plant item. Mr. Kentton C. Grant is the Company's witness in support of the inclusion of CWIP in rate base. Because CWIP should be included in rate base, the Company's property tax adjustment should not be adjusted as Ms. Diaz Cortez proposes.

F. <u>Corporate Cost Allocations (RUCO Income Statement Adjustment 12).</u>

Q. Do you agree with Ms. Diaz Cortez's adjustment to reduce Corporate Cost Allocations?

A. Partially. Ms. Diaz Cortez is proposing the exclusion of some cost that a portion of which was allocated to UNS Electric indirectly from TEP. I disagree with the portion of her adjustment to exclude a percentage of cost charged to UNS Electric for Meals, Entertainment and Travel. These costs are normal and recurring cost of doing business related to business meetings, company-required travel and employee recognition. However, because of the immaterial magnitude of the amount being excluded I am not going to attempt to address which individual meal is a business expense or not.

But I completely disagree with the portion of her adjustment related to cost allocated to UNS Electric for items charged to "Advertising – Corporate Relations/Communications". Of the $92,410 that Ms. Diaz Cortez identified, I only agree that $500 should be excluded – which was paid to the Tucson Metropolitan Chamber of Commerce. The remaining amount is related to purchasing the domain name UNS.com, the preparation and printing of the UNS annual report, materials for the UNS Board of Directors and a campaign to

promote winter efficiency. All of these items were legitimate corporate expenditures properly allocated to the companies of UNS.

Accordingly, the Company will reflect a reduction of $1,823 in its revised Corporate Cost Allocation adjustment.

G. <u>Valencia Turbine Fuel (RUCO Income Statement Adjustment 14).</u>

Q. Do you agree with Ms. Diaz Cortez's adjustment to remove the Company's adjustment for Valencia turbine fuel?

A. Ms. Diaz Cortez again claims that the Company would double recover if the Valencia turbine fuel adjustment is included in the Company's cost of service. Ms. Diaz Cortez' argument is particularly confusing because under any of the proposed PPFAC mechanisms the ultimate actual cost of providing energy to the customers of UNS Electric is all that will be passed on to the customers. The Company proposes that the Valencia fuel be added to test-year expense to more accurately reflect the base cost of fuel, purchased power and purchased energy expected going forward. This was done using the fixed, known and measurable information available at the time of UNS Electric's rate application. We know that in the future when the Pinnacle West Capital Corporation contract expires that those cost will fluctuate and most likely increase, but that is the best information we had at the time of our filing.

But, as I say above, that is only setting the base cost, ultimately the actual cost will go into a deferred regulatory account and the customers will be charged the approved base rate of fuel, purchased power and purchased transmission cost and any applicable PPFAC charges in the future. The net result is the collection of actual cost, with no double recovery.

H. Outside Services – Demand Side Management ("DSM") (RUCO Income Statement Adjustment 21).

Q. Do you agree with Ms. Diaz Cortez's adjustment to remove test year expense for outside services - DSM?

A. Partially. Ms. Diaz Cortez is suggesting the removal of $49,920 in test-year expense related to DSM activity. I do agree that it should be removed as the Company is proposing to recover it separately through a DSM charge. However, $32,865 of the $49,920 was already included in the Company's DSM and Renewables adjustment. So the additional amount that should be eliminated is $17,055 that was inadvertently missed in the preparation of the Company's original adjustment.

IV. REBUTTAL TO RUCO WITNESS RODNEY L. MOORE.

A. Pension and Benefits (RUCO Income Statement Adjustment 2).

Q. Do you agree with Mr. Moore's adjustment to employee benefits?

A. No. These are normal and recurring business expenses and should not be removed.

B. Worker's Compensation (RUCO Income Statement Adjustment 3).

Q. Do you agree with Mr. Moore's adjustment to Worker's Compensation?

A. I agree that we should use accrual based accounting treatment for the cost of worker's compensation to be recovered. However, I have previously accepted Staff's adjustment that is based on a three year average of the accrual based expense and do not accept RUCO's actual adjustment.

C. **Incentive Compensation (RUCO Income Statement Adjustment 4).**

Q. Do you agree with Mr. Moore's adjustment to Incentive Compensation?

A. No, I do not.

Q. Can you summarize Mr. Moore's reasoning for excluding Incentive Compensation?

A. Yes. Mr. Moore argues that the goals and objectives of the 2004 and 2005 PEP program were designed to provide a greater benefit to stockholders, that the 2005 payout was based on an arbitrary decision made by the Board, that the 2005 award is non-recurring and that he believes the program is discriminatory and only applies to a select group of non-union employees. He also ignores the fact that the test year ends on June 30, 2006. So with actual test-year activity and with accrual accounting the test-year expense reflects 50% of the 2005 program and 50% of the 2006 program expense.

Q. Do you agree with any of the assertions that Mr. Moore makes concerning the Company's PEP plan?

A. No, for several reasons. First, as I discussed earlier in rebutting Mr. Smith's testimony on PEP, I believe that the program actually saves the customers money in multiple ways even before the goals and objectives of the plan are taken into account. Second, the goals and objectives of the current plan are heavily weighted to the benefit of the customers. Third, the total employee compensation is reasonable and neither RUCO nor Staff state otherwise; because PEP is part of employee compensation, eliminating or reducing the level of expense is unreasonable and arbitrary. Furthermore, UNS Electric's financial performance goals also strongly benefit customers. I do not believe that shareholders reap some additional benefit between rate cases when operating costs are reduced below budget levels that exceed the levels approved in the most recent rate case. Mr. Moore provides no evidence to support his suggestion. The current PEP plan is known and

measurable and is what should be the basis for evaluation. Fourth, the 2005 award was not an arbitrary award approved by the Board, but was based on the remaining goals and objectives of the 2005 PEP that were achieved and not related to financial performance. The financial goal was missed primarily as a result of an unplanned outage at Springerville. This award was paid to real employees and was based on real efforts and real results they achieved. Finally, the program applies to "all" non-union employees, not just managers or executives. The employees provide direct benefits to customers in terms of ensuring a high level of service, reliability and safety.

D. <u>Rate Case Expense (RUCO Income Statement Adjustment 5).</u>

Q. Do you agree with Mr. Moore's adjustment to rate case expense?

A. No, Mr. Moore's position is similar to Staff's position. I strongly disagree with Mr. Moore on the same grounds as discussed earlier when I rebutted Mr. Smith's Direct Testimony.

E. <u>Postage Expense (RUCO Income Statement Adjustment 8).</u>

Q. Do you agree with Mr. Moore's adjustment to postage expense?

A. No. Mr. Moore takes test year activity and adjusts for recent postal rate increases and then calculates a test year cost per average customer. He then applies that rate to RUCO's annualized average number of customers to come up with an annualized postage expense. This can be a fair approach if costs within the test year are indicative of normal activity and stable, however postage expense for UNS Electric has fluctuated significantly.

The Company's adjustment and Staff's revision to that are based upon looking at the average historical cost. Which is a reasonable approach in situations were cost fluctuate significantly. In the case of postage expense, even though the rates are continually increasing, we also see the cost per customer bill fluctuate fairly significantly from month to month. This is primarily a result of non-bill items, like informational and educational materials as well as normal business postage. That is why I believe the Company's adjustment revised by Staff is the more appropriate adjustment.

F. <u>SERP (RUCO Income Statement Adjustment 16).</u>

Q. Do you agree with Mr. Moore's adjustment for SERP?

A. No, Mr. Moore's position is similar to Staff's position. I strongly disagree with Mr. Moore on the same grounds as discussed earlier when I rebutted Mr. Smith's Direct Testimony.

.

G. <u>Unnecessary Expenses (RUCO Income Statement Adjustment 17).</u>

Q. Do you agree with Mr. Moore's adjustment for Unnecessary Expenses?

A. Not entirely. There are $10,013 of cost within Mr. Moore's list that the Company had previously agreed with RUCO should be removed from revenue requirements in a response to data requests from Mr. Moore. However, the vast majority of Mr. Moore's excluded items are normal business expenses and should not be excluded from cost of service. The Company's witness Thomas J. Ferry discusses the remaining expenditures Mr. Moore seeks to exclude as "Inappropriate" and "Unnecessary" in his Rebuttal Testimony.

H. Maintenance of Overhead Lines (RUCO Income Statement Adjustment 18).

Q. Do you agree with Mr. Moore's adjustment to test year overhead line maintenance expense?

A. No. This appears to be a mis-understanding of the information provided to Mr. Moore. He used a four-year average to calculate a normalized overhead line maintenance expense. The major flaw with that approach is that the 2003 information is for a partial year. In fact, from 2004 to 2006 (the first three full years of operation for UNS Electric) the Overhead Line Expense averaged about $1.054 million per year. Taking that into consideration, the test-year activity is in line with expected levels.

I. Non-Recurring/Atypical Expenses (RUCO Income Statement Adjustment 20).

Q. Do you agree with Mr. Moore's adjustment for Non-Recurring/Atypical Expenses?

A. No, I do not. Mr. Moore is excluding certain specific training costs that were incurred during the test-year as non-recurring. Mr. Ferry will provide more detail on this issue in his Rebuttal Testimony. But the Company is highly regulated, growing tremendously and continually adding new employees. So training is always on-going and is required regularly for many Company employees. Training costs will very likely continue to increase for the foreseeable future and removing any of these costs from the test year would not be appropriate.

Q. Does that conclude your Rebuttal Testimony?

A. Yes.

EXHIBIT

DJD-1

UNS ELECTRIC, INC.

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2006

	Adj As Filed	Adj As Filed	Adj As Filed	Adj Revised		
	12/15/06	6/28/07	6/28/07	8/14/07		UNSE
	UNSE	ACC	RUCO	UNSE	Summary	Witness
Original Cost Rate Base - Unadjusted	$126,435,912	$126,435,912	$126,435,912	$126,435,912		Kissinger
Rate Base Adjustments						
Accumulated Depreciation (RUCO Adj. #2, RLM-4)	-	-	(2,295,112)	-	RUCO decreases rate base for accumulated depreciation based on adjustments in annual gross plant levels and the authorized depreciation rates. UNSE disagrees.	Kissinger
Acquisition Adjustment	9,574,286	9,574,286	9,574,286	9,574,286	No adjustments	Kissinger
Plant Held for Future Use	(440,000)	(440,000)	(440,000)	(440,000)	No adjustments	Kissinger
CWIP (Staff Adj B-1)	10,761,154	-	(299)	10,761,154	Staff & RUCO exclude CWIP as not in service at test year end (RUCO reduced rate base by $10,761,453 for CWIP - this amount is $299 more than the original UNSE pro forma of $10,761,154; see RLM-3 and RLM-5, Page 6). There is $1.9 million in customer advances directly related to projects in this CWIP balance that have been included as a reduction of rate base. UNSE disagrees with Staff & RUCO.	Grant
Adjust CWIP for Plant in Service @ Year End (Staff Adj B-2)		442,255	-	-	Staff increases rate base for a specific project involving installation of 5 miles of 21 kV overhead lines to service water pumps for a housing development that was in service before the end of the test year. UNSE agrees if CWIP adjustment is not accepted. If CWIP adjustment is accepted, this adjustment is not needed.	Kissinger
Plant in Service Addition Subject to Reimbursement - Customer Advances for Construction (Staff Adj B-3)		(236,874)	-	-	Staff decreases rate base for a project involving removal of a 13 kV overhead line that should be reimbursable by the customer. Staff alleges insufficient documentation of customer reimbursement provided by UNSE. UNSE received the CIAC; the project was coded incorrectly in the GL but the CIAC was correctly netted against plant in service at the end of the test year. UNSE disagrees - adjustment is unnecessary.	Kissinger
Accumulated Deferred Income Taxes (Staff Adj B-5; RUCO Adj. #4 & #5, RLM-4)	(2,235,928)	(2,397,483)	(3,008,060)	(2,235,928)	Staff removes ADIT for SERP and stock-based compensation expense (expenses with related ADIT balances included in rate base). RUCO removed a CIAC-related deferred tax asset of $888,390 and increased capitalized A&G expense which increased ADIT by $116,258. UNSE disagrees with Staff - adjustments for SERP and stock-based compensation are not accepted. UNSE disagrees with RUCO - ADIT for CIAC is not consistent with accounting and ADIT for capitalized A&G is not necessary.	Kissinger
Cash Working Capital (Staff Adj B-4; RUCO Adj. #6, MDC-1)	(3,104,100)	(2,906,559)	(1,488,845)	(3,060,472)	Staff's & RUCO changes result from proposed rate base adjustments.	Kissinger
Total Adjustments	14,555,412	4,035,625	4,637,082	14,599,040		
Pro Forma OCRB	140,991,324	130,471,537	128,777,882	141,034,952		
Requested Rate of Return	9.89%	8.99%	8.67%	9.89%	Staff recommends **overall return of 8.99% midpoint**; 9.5% - 10.5% cost of equity; 8.16% cost of LT Debt and 6.36% cost of ST debt with a capital structure of 48.83% equity, 47.21% LT debt and 3.96% ST debt. RUCO recommends **overall return of 8.67%**; 9.30% cost of equity; 6.36% cost of ST debt; and 8.22% cost of LT debt with a capital structure of 48.85% equity, 47.18% LT debt and 3.97% ST debt.	Grant
Required Operating Income	$13,946,320	$11,725,569	$11,169,957	$13,950,637		

UNS ELECTRIC, INC.
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2006

	Adj As Filed	Adj As Filed	Adj As Filed	Adj Revised		
	12/15/06	6/28/07	6/28/07	8/14/07		UNSE
	UNSE	ACC	RUCO	UNSE	Summary	Witness
Original Operating Income - Unadjusted	$9,134,955	$9,134,955	$9,134,955	$9,134,955	Test year	Kissinger
Operating Income Adjustments						
Operating Revenue Adjustments						
Customer Annualization	3,249,883	3,249,883	3,249,883	3,249,883	No adjustments	Erdwurm
Weather Normalization	(410,061)	(410,061)	(410,061)	(410,061)	No adjustments	Erdwurm
Service Fees & Late Fees (RUCO Adj #1, MDC-2, & RLM-8 Column B)	285,424	285,424	334,072	285,424	RUCO increases Service Fees for after-hours service from $75 to $125, creating an increase of $48,648 in revenue. UNSE disagrees.	Erdwurm
CARES Revenue (Staff Adj C-1)	(52,937)	-	(52,937)	(56,564)	Staff removes UNSE pro forma adjustment, disagreeing with the change in discount calculation proposed by UNSE; Staff proposes that the existing discount rate structure for CARES be retained. UNSE disagrees. UNSE also further adjusts test year revenues to reflect an increase in the CARES discount from $8 to $10.	Erdwurm
Total Adjustments to Operating Revenues	3,072,309	3,125,246	3,120,957	3,068,682		
Operating Expense Adjustments						
Customer Annualization	2,269,956	2,269,956	2,269,956	2,269,956	No adjustments	Erdwurm
Weather Normalization	(282,462)	(282,462)	(282,462)	(282,462)	No adjustments	Erdwurm
Purchased Power Derivatives	314,928	314,928	314,928	314,928	No adjustments	Dukes
DSM	(458,867)	(458,867)	(458,867)	(458,867)	No adjustments	Dukes
Payroll Expense	107,433	107,433	107,433	339,184	UNSE increases test year expense for revisions to normalized overtime and salaries/wages increases (updates for known & measurable changes).	Dukes
Payroll Tax Expense	9,448	9,448	9,448	27,177	UNSE adjustment is the result of the revision to payroll expense.	Dukes
Pension & Benefits (RUCO Adj. #2, RLM-8 Column C)	82,965	82,965	71,353	82,965	RUCO decreases operating expense by $11,612 for inappropriate benefits such as awards, social events and employee dinners (information provided in response to Staff Data Request 3.81). UNSE disagrees.	Dukes
Post-Retirement Medical	80,388	80,388	80,388	80,388	No adjustments	Dukes
Worker's Compensation (Staff Adj C-6 - Injuries & Damages; RUCO Adj. #3, RLM-8 Column D)	(63,252)	(222,315)	(126,504)	(79,978)	Staff reduces injuries & damages expense by normalizing the test year using a 3-year average through December 2006. RUCO intended to reverse the UNSE change from accrual to cash basis expense (RUCO advocates accrual), but the adjustment was backwards and decreased expense by double the original pro forma (RUCO should have increase expense by $63,252). UNSE accepts Staff's use of the 3-year average and reduces test year worker's compensation expense by $79,978.	Dukes
Incentive Compensation (Staff Adj C-7; RUCO Adj #4, RLM-8 Column E)	39,026	(4,975)	(67,541)	39,026	Staff reduces certain incentive compensation programs by 50% to provide equal sharing of the costs between customers and shareholders. RUCO is disallowing the full amount of the incentive compensation program as non-beneficial ratepayers. UNSE disagrees with Staff & RUCO.	Dukes

UNS ELECTRIC, INC.
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2006

	Adj As Filed 12/15/06 UNSE	Adj As Filed 6/28/07 ACC	Adj As Filed 6/28/07 RUCO	Adj Revised 8/14/07 UNSE	Summary	UNSE Witness
Operating Expense Adjustments (cont'd)						
Rate Case Expense (Staff Adj C-11), (RUCO Adj #5, RLM-8 Column F)	200,000	88,333	83,667	200,000	Staff recommends total rate case expense of $265,000 amortized over 3 years ($88,333 per year), stating that the $600,000 of expense amortized at $200,000 per year as proposed by UNSE is excessive. RUCO recommends total rate case expense of $251,000 amortized over 3 years ($83,677 per year), stating that the $600,000 reasonableness is to large of a financial burden to ratepayers. UNSE disagrees with Staff & RUCO.	Dukes
Bad Debt Expense (RUCO Adj # 6, MDC-3, & RLM-8 Column G)	222,556	222,556	19,518	66,947	RUCO decreases bad debt expense by $203,038 based on actual expense instead of balance sheet accruals. UNSE revised the adjustment by using a 3-year average actual net write-off rate.	Dukes
Interest on Customer Deposits	573	573	573	573	No adjustments	Dukes
Operating Lease Expense	(15,779)	(15,779)	(15,779)	(15,779)	No adjustments	Dukes
Fleet Fuel Expense (Staff Adj C-4; RUCO Adj #7, MDC-4, & RLM-8 Column H)	73,661	3,270	20,411	31,752	Staff increases fuel expense using $2.69 per gallon average cost per gallon from Sep 2006 through April 2007. RUCO decreased fleet fuel expense by calculating the average gasoline price for the first 5 months of 2007 compared to the average fuel prices during June, July, August of 2006. UNSE revised the pro forma adjustment using a fuel cost of $2.82 per gallon reflecting the most recent weighted average cost of fuel using all seasons.	Dukes
Postage Expense (Staff Adj C-5; RUCO Adj # 8, RLM-8 Column I & RLM-9)	66,283	83,786	28,327	83,786	Staff increases postage expense for the rate increase effective 5/14/07 (not included in the UNSE postage expense pro forma). RUCO decreased postage expense by $37,956 overall. RUCO recognized the two changes in the postal rates and included those in their calculation, but also annualized the test-year number of customer bills resulting in a reduction of expense. UNSE accepts Staff's adjustment.	Dukes
Out of Period Expenses	86,583	86,583	86,583	86,583	No adjustments	Dukes
Year-End Accruals (RUCO Adj #9 MDC, & RLM-8 Column J)	140,677	140,677	134,421	134,421	RUCO reduces the pro forma adjustment by $6,256 to exclude a prior period expense incurred in April 2004 but not recorded to expense until August 2005. UNSE accepts the adjustment.	Dukes
Franchise Fee Expense	(15,065)	(15,065)	(15,065)	(15,065)	No adjustments	Dukes
Membership Dues Expense (Staff Adj C-12 & C-13)	(2,000)	(16,952)	(2,000)	(13,759)	Staff removes 49.93% of EEI core dues (based on 2005 NARUC data) and 100% of UARG dues (based on the EEI letter included with the pro forma adjustment showing 100% of UARG (Environmental) as non-deductible). Staff also reduced expense for other membership and industry association dues not needed for the safe & reliable provision of electric service. See Staff Witness Smith direct testimony (Page 38, Lines 1-9) for recommendation for cost-benefit analysis to be done in the future for all industry or trade association dues prior to inclusion in the revenue requirement. UNSE accepts the adjustment for 100% of UARG dues of $5,477 (C-12) and the adjustment for $6,282 (C-13) for other membership and industry association dues (the total was $6,482; $200 for Mohave Museum of History & Arts is included in the RUCO accepted for RUCO #17 Inappropriate Expenses and is excluded from this adjustment).	Dukes
A&G Expense Capitalized (RUCO Adj. #10 MDC, & RLM-8 Column K)	301,187	301,187	-	301,187	RUCO reverses the A&G adjustment, claiming it is being double counted (through depreciation expense and return on rate base and again as part of operating expenses). UNSE disagrees with RUCO.	Dukes
Depreciation & Property Tax for CWIP (Staff Adj C-2; RUCO Adj #11 MDC, & RLM-8 Column L)	689,512	-	-	689,512	Staff & RUCO exclude pro forma expense related to the CWIP rate base adjustment. UNSE disagrees with Staff & RUCO.	Dukes

UNS ELECTRIC, INC.
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2006

	Adj As Filed 12/15/06 UNSE	Adj As Filed 6/28/07 ACC	Adj As Filed 6/28/07 RUCO	Adj Revised 8/14/07 UNSE	Summary	UNSE Witness
Operating Expense Adjustments (cont'd)						
Common Systems Allocations	138,959	138,959	138,959	138,959	No adjustments	Dukes
Operating Systems Allocations	106,925	106,925	106,925	106,925	No adjustments	Dukes
Corporate Cost Allocations (RUCO Adj #12 MDC, & RLM-8 Column M)	97,152	97,152	87,142	95,329	RUCO decreases operating expense by $10,010 ($112,982 *8.86%) for inappropriate travel, meals & entertainment and advertising expenses allocated to UNSE from TEP. UNSE disagrees with RUCO that the expenses are inappropriate but accepts a reduction to operating expense of $1,823 for the portion of travel, meals & entertainment expense allocated to UNSE because the amounts are not material.	Dukes
Valencia Turbine Fuel (RUCO Adj # 14 MDC, & RLM-8 Column O)	266,198	266,198	-	266,198	RUCO removes this proforma adjustment on the basis that it is double counted. RUCO believes this amount will be recovered through the new adjusting PPFAC. UNSE disagrees with RUCO.	Dukes
Depreciation & Property Taxes for CWIP in Plant in Service @ Year End (Staff Adj C-3)	-	26,582	-	-	Staff increases depreciation expense and property tax to reflect the rate base adjustment. UNSE agrees if CWIP adjustment is not accepted. If CWIP adjustment is accepted, this adjustment is not needed.	Kissinger
SERP Expense (Staff Adj C-8; RUCO Adj #16, RLM-8 Column Q)	-	(83,506)	(83,506)	-	Staff & RUCO remove 100% of SERP expense following ACC Order 68487 for SW Gas that removed all SERP expense from the revenue requirement. UNSE disagrees with Staff & RUCO.	Dukes
Stock-Based Compensation Expense (Staff Adj C-9)	-	(82,873)	-	-	Staff removes 100% of stock-based compensation for officers & managers (should be a shareholder expense). See STF 10.11 - adjustment is for stock option & performance share expense. UNSE disagrees with Staff & RUCO.	Dukes
Emergency Bill Assistance Expense (Staff Adj C-16)	-	20,000	-	20,000	Staff increases operating expense for the UNSE requested increase of $20,000 for emergency bill assistance, noting that it disagreed with the UNSE proposal to include this amount in the low-income weatherization program included in the proposed DSM surcharge, instead of in base rates. UNSE accepts the Staff adjustment to keep the expense in base rates.	Dukes
SES Markup Above Cost (Staff Adj C-17)	-	-	-	-	Staff intends to reduce the revenue requirement by the 10% markup in the charges from SES, but as of 6/26/07 UNSE was still in the process of gathering the information for the response to Staff DR 15.1 (submitted 7/13/07 in supplemental response).	Ferry
Inappropriate Expenses (RUCO Adj #17, RLM-12, & RLM-8 Column R)	-	-	(73,620)	(10,013)	RUCO removes inappropriate/unnecessary expenses (payments to chambers of commerce, donations, club memberships, awards, corporate events, advertising and meals, lodging, and refreshments). UNSE accepts the adjustment to reduce test year expense by $10,013 for specific items noted in the response to RUCO data request 5.01 and disagrees with the remainder of the adjustment.	Dukes & Ferry
Over Head Lines Maintenance (RUCO Adj #18, RLM-13, & RLM-8 Column S)	-	-	(267,678)	-	RUCO decreases operating expense for overhead line maintenance trying to normalized the test-year level based a four year average of expenses. RUCO claims there is a wide variation in annual costs from 2003-2006 recorded in FERC 593. UNSE disagrees.	Dukes & Ferry
Customer Service Cost Allocation (RUCO Adj #19, RLM-8 Column T)	-	-	(66,797)	-	RUCO decreases operating expense for costs allocated to UNS Electric for the call center consolidation based on evidence provided by the Commission Consumer Services Section indicating the quality of customer service as not shown improvements and/or enhancements. UNSE disagrees.	Ferry

UNS ELECTRIC, INC.
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2006

	Adj As Filed 12/15/06 UNSE	Adj As Filed 6/28/07 ACC	Adj As Filed 6/28/07 RUCO	Adj Revised 8/14/07 UNSE	Summary	UNSE Witness
Operating Expense Adjustments (cont'd)						
Non-Recurring / Atypical Expenses (RUCO Adj #20, RLM-8 Column U)	-	-	(14,251)	-	RUCO decreases operating expenses for "M.A.R.C. Training based on conversations with Mr. Smith for the UNSG rate case related to Procard detail. Mr. Smith indicated the training was a one-time only instructional session to acquaint Company personnel with the unionized environment. See RUCO data request 5.04. UNSE disagrees.	Dukes & Ferry
Outside Services (DSM) (RUCO Adj #21 MDC & RLM-8 Column V)	-	-	(49,920)	(17,055)	RUCO decreases operating expense for ECOS Consulting expenses (to develop the Residential New Construction DSM Program) since these expenses will be recovered through the DSM surcharge adjustor. UNSE reduced test year expense for $32,865 of the $49,920 in the DSM pro forma adjustment; UNSE reduces operating expense for the remaining $17,055 that was inadvertently missed.	Dukes
Depr. and Amort. Exp. Annualization (Staff Adj C-15; RUCO Adj #13, RLM-10, & RLM-8 Column N)	582,981	519,876	440,896	519,876	Staff & RUCO reduce test year depreciation expense to correct UNSE's proposed depreciation rate for transportation equipment (see data requests STF 3.39 & 11.8). UNSE accepts Staff's adjustment.	Kissinger
Property Taxes (Staff Adj C-10; RUCO Adj. #15, RLM-11 & RLM-8 Column P)	(130,301)	(190,048)	(540,203)	(190,048)	Staff reduces property tax expense for new assessment rates (passed by House Bill No. 2779); the revised assessment rate is 23.5% while UNSE used 24% which was expected at the time UNSE filed the rate case. RUCO reduced property tax expense using an assessment rate of 23% and Net Plant in Service was lower based on adjustment made to Accumulated Depreciation. UNSE accepts Staff's adjustment.	Kissinger
Income Taxes (Staff Adjustment "All C's"), (RUCO Adj # 22, RLM-15, & RLM-8 Column AC)	(1,444,412)	(735,176)	(85,205)	(1,367,782)	All changes are recalculations based on other pro forma adjustments.	Kissinger
Total Adjustments to Operating Expense	3,465,253	2,859,757	1,851,530	3,444,864		
Total Net Adjustments	(392,944)	265,489	1,269,427	(376,182)		
Adjusted Operating Income	$8,742,011	$9,400,443	$10,404,382	$8,758,773		
Operating Income Deficiency	$5,204,310	$2,325,126	$765,575	$5,191,864		
Gross Revenue Conversion Factor	1.634626	1.634626	1.636983	1.634626		Kissinger
Increase in Gross Revenue Requirement	$8,507,097	$3,800,712	$1,253,233	$8,486,757		

EXHIBIT

DJD-2

UNS ELECTRIC, INC.
FERC 925 - INSURANCE EXPENSE

	Test Year				
	TME 6/30/07	TME 6/30/06	TME 12/31/06	TME 12/31/05	TME 12/31/04
General Liability Insurance	$169,176	$156,480	$163,380	$149,504	$143,464
Test Year increase over 2004		9%			
Calender year 2006 increase over test year			4%		
Officers & Directors Insurance	$116,539	$106,353	$109,089	$82,128	$26,594
Test Year increase over 2004		300%			

EXHIBIT

DJD-3

REDACTED

EXHIBIT

DJD-4

UNS Electric, Inc
TEST YEAR ENDING JUNE 30, 2006

	Total payroll	UNSE %	Actual Allocated /charged to
TEP A&G Labor indirectly allocated to UNSE	3,057,068	8.86%	270,856
TEP A&G Labor directly charged	1,819,330	100%	1,819,329
All TEP A&G Labor	44,196,747	0.00%	0
Amount that would have been allocated to UNSE if Mass Formula was applied on Total TEP A&G Payroll	49,073,145	8.86%	4,347,881
		Difference:	2,257,695

EXHIBIT

DJD-5

UNS ELECTRIC, INC.'s RESPONSES TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 14, 2007

STF 11.11 EEI dues. Refer to the response to STF 3.73.

a. Please state exactly what EEI did during the test year to represent the interests of its members in "advocating equitable policies in legislative and regulatory arenas."

b. Please provide a complete copy of the EEI invoices for 2005 and 2006.

c. Please state exactly what advocacy activities before Congress and government agencies EEI engaged in during the test year.

d. Provide a complete copy of the documents that UNS Electric used to determine the lobbying and advocacy portion of the EEI dues.

e. Please explain fully why UNS Electric does not maintain any descriptive material concerning the activities of EEI.

f. Has UNS Electric or its affiliates ever performed an evaluation of whether its ratepayers are receiving a benefit from the EEI membership that is commensurate with the cost? If not, explain fully why not. If so, please provide the analysis. Include any supporting documentation relied upon.

g. During the test year, did UNS Electric make any payments to EEI for anything other than basic dues? If so, please identify, quantify and explain all such payments and show the amounts by account.

RESPONSE: a., c. EEI represents industry positions on North American Electric Reliability Corporation ("NERC") and Federal Energy Regulatory Commission ("FERC') activities related to the Electric Reliability Organization legislation. It also lobbies for carve-outs for integrated resource planning to allow the transmission and generation sides of the company to discuss serving native load, provides information and representation on chief compliance officer issues, environmental disclosure, FERC standards of conduct program and issues and clean water issues. UNS Electric uses the EEI Standards of Conduct training for its compliance with FERC standards of conduct.

EEI sponsors an Annual Chief Executive Officer meeting to review the critical issues facing the industry. EEI sponsors the Annual Government Affairs meeting to review critical issues facing the industry that would result in Congressional legislation. EEI sponsors annual Low-Income Customers Best Practices

meeting reviews efforts to better assist Low-Income customers. Washington Representatives (a working group of company lobbyists) was hosted by EEI weekly to discuss Congressional issues and tactics.

EEI policy committees are populated by members and cover many critical industry topics, such as energy delivery, safety, accounting, finance, labor relations and the environment.

The EEI Information Center is available to members to help identify EEI staff resources and resource materials covering critical industry subjects. The EEI Internet Workroom is available to members to share and gather information about critical industry subjects. The Daily Energy News, a daily e-mail of industry related news clips, is also available to members.

EEI was instrumental in getting Fleet language in the 2005 Highway and Energy bill. The Highway bill allows for an exemption for utility workers for the number of hours they can drive commercial motor vehicles. This exemption is critical in that it allows utility workers to work the hours necessary to restore service during storm season and other emergencies. Additionally, EEI was successful in inserting Fleet language into the Energy bill that allowed for more flexibility for Energy Policy Act of 2005 Compliance. The compliance now allows for flex fuel vehicles and for vehicles used for emergency restoration. Fleet Services also regularly participates in EEI-sponsored functions, surveys and initiatives regarding fleet management and other regulatory issues.

EEI was extensively involved in the interpretation and development of policies related to the Energy Policy Act of 2005, including the development of the Electric Reliability Organization ("ERO"), the delegation agreements related to the ERO and the interpretation and implementation of FERC Standards of Conduct. EEI has taken positions on the need for corridors for transmission and for the need for provisions to allow transmission providers opportunities to discuss native load issues without violating standards of conduct.

EEI actively coordinated efforts to address industry-related legislation in Congress. This included daily e-mails to EEI members regarding draft legislation, proposed amendments to legislation, analysis of legislation and amendments, committee and

floor schedules, fact sheets about proposed legislation and calls to action (letters and e-mails) targeting specific members of Congress. Specific examples of activity related to legislation include the following:

- HR 3 - Hours of Service, exempted utility service workers from hours of service limits as noted above;
- HR 6 - Energy Policy Act 2005, addressed Reliability, Transmission siting, Transmission technology, solar incentives and Low income assistance among many other issues;
- HR 6111 - Extended expiring Tax Credits for Renewables provisions of the Internal Revenue Code;
- S2320 - Home Energy Assistance Act program FY06, Additional funds for low income home energy assistance; and
- S467 - Extended Terrorism Risk Insurance.

Please see STF 11.11 (a & c), Bates Nos. UNSE(0783)08921 to UNSE(0783)08922, on the enclosed CD for a list of EEI environmental advocacy activities.

b. Please see STF 11.11 (b), Bates Nos. UNSE(0783)08923 to UNSE(0783)08931, on the enclosed CD for copies of EEI invoices for 2005 and 2006.

d. Please see Bates No. UNSE(0783)02162, provided in response to RUCO Data Request 1.10 for the document that UNS Electric used to determine the lobbying and advocacy portion of the EEI dues. This document is part of the pro forma adjustment to operating expense for membership dues.

e. Information about EEI activities is available on the EEI website, so it is not necessary for UNS Electric to maintain descriptive material concerning the activities of EEI.. This information is copyrighted and available to EEI the members via a password-protected login.

f. Neither UNS Electric nor its affiliates have performed a study or evaluation but UNS Electric believes its ratepayers are receiving a

benefit from the EEI membership that is commensurate with the cost.

g. UNS Electric did not make any payments to EEI for anything other than basic dues during the test year.

RESPONDENT: Edmond Beck, Gary Kelly, David Thomas, Lawrence Lucero and Jeffrey Yockey (a, c, e, f and g)
Mina Briggs and Janet Zaidenberg-Schrum (b and d)

WITNESS: Tom Ferry and Dallas Dukes

UNS ELECTRIC, INC. - STF 11.11a & 11.11c
EEI ADVOCACY - ENVIRONMENTAL ISSUES
PREPARED BY: J. YOCKEY (ENVIRONMENTAL SERVICES)

Regulatory

- 03/29/2006 - Technical Comments on EPA's Greenhouse Gas Inventory, 1990-2004 - EEI technical comments on EPA's "Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004," submitted in response to EPA's request for consideration in preparing a finalized version (71 Fed. Reg. 9821, February 27, 2006).

- 01/13/2006 - Technical Comments on EPA's "Draft Inventory of Greenhouse Gas Emissions and Sinks: 1990-2004" - EEI technical comments on EPA's "Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004," submitted in response to EPA's request, for consideration in preparing a revised draft prior to the "public review process" planned for "early February."

- 12/19/2005 - EEI's 12/19/05 Comments on EPA Reconsideration of Final Mercury Rules ((Docket ID NO. OAR-2002-0056)) - EEI Comments on Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units From the Section 112(c) List: Reconsideration and Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units; Reconsideration

- 11/17/2005 - Testimony at Public Hearing on Reconsideration of Final Mercury Rules - Testimony of Michael Rossler, EEI, at public hearing in Research Triangle Park, NC, on reconsideration of final clean air interstate and mercury rules (CAIR and CAMR).

- 02/17/2006 - Comments on EPA's NSR Emissions Test Proposal - EEI comments on EPA's emissions test proposal for the prevention of significant deterioration, non-attainment new source review (NSR), and new source performance standards for electric generating units (EGUs) (Docket No. OAR-2005-0163).

- 12/09/2005 - Statement at EPA Public Hearing on Emissions Test for Electric Generating Units - Statement Of Steve Lomax, EEI, at December 9, 2005 EPA public hearing in Research Triangle Park, NC, on prevention of significant deterioration, non-attainment new source review, and new source performance standards: emissions test for electric generating units (Docket No. OAR-2005-0163).

- 04/17/2006 - EEI Comments on Proposed "National Ambient Air Quality Standards for Particulate Matter" - EEI comments on EPA's proposed rule, "National Ambient Air Quality Standards for Particulate Matter" (71 Federal Register 2620, January 17, 2006; Docket ID No. EPA-HQ-OAR-2001-0017).

- 04/17/2006 - Industry Coalition Comments on Proposed "National Ambient Air Quality Standards for Particulate Matter" - Comments of a coaltion of 19 industry trade associations, including EEI, on EPA's proposed rule, "National Ambient Air Quality

Standards for Particulate Matter" (71 Federal Register 2620, January 17, 2006; Docket ID No. EPA-HQ-OAR-2001-0017).

- 03/08/2006 - Statement on EPA's National Ambient Air Quality Standards for Particulate Matter Proposed Rule - EEI statement at concurrently held field hearings in Chicago, Philadelphia and San Francisco, on EPA's "National Ambient Air Quality Standards for Particulate Matter" proposed rule (71 Federal Register pages 2620-2708, January 17, 2006).

Climate Change Science Program

- 06/28/2006 - Comments on IPCC Fourth Assessment Report (WGII-AR4) - EEI comments on the Intergovernmental Panel on Climate Change (IPCC) second-order draft (SOD) of the Working Group II's contribution to the Fourth Assessment Report (WGII-AR4) (71 Fed. Reg. 30469, May 26, 2006).

- 05/12/2006 - Comments on CCSP Draft Prospectus 3.3 on Climate Extremes - EEI comments on Draft Prospectus for Synthesis and Assessment Product 3.3 "Climate Extremes: Analysis of the Observed Changes and Variations and Prospects for the Future" (71 Fed. Reg. 18726, April 12, 2006).

- 05/09/2006 - Comments on IPCC Fourth Assessment Report on Climate Change 2007 - EEI comments on the Working Group 1 "Second Order Draft" of the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report, "Climate Change 2007: The Physical Science Basis," (71 Fed. Reg. 17942, April 7, 2006).

- 11/02/2005 - Comments on Climate Change Technology Program Draft Strategic Plan - EEI Comments on the Department of Energy's (DOE) "U.S. Climate Change Technology Program Draft Strategic Plan" (CCTP) in order "to improve and strengthen the Plan."

Legislative

- 04/04/2006 - Senate Climate Conference Testimony - Oral testimony of Michael G. Morris, president and CEO of American Electric Power, on behalf of EEI before the Senate Committee on Energy and Natural Resources Climate Conference on creating a program to control U.S. greenhouse gas emissions.

- 02/06/2006 - Comments on House Committee on Resources NEPA Task Force Recommendations - EEI comments on the Initial Findings and Draft Recommendations of the House Committee on Resources Task Forces on Improving and Updating the National Environmental Policy Act (NEPA).

UNSE(0783)08922

2005

EDISON ELECTRIC INSTITUTE

Remit To: EEI Accounts Receivable
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696

Main Number: 202-508-5000
Accounts Receivable: 202-508-5428
FAX: 202-508-5030

INVOICE NO.	INVOICE DATE	CUST NO.
1-000025467	12/9/04	407476

FEIN: 13-0659550

Remittance Copy
Please return this copy with payment

SOLD TO
Mr. Cosimo DeMasi
Tucson Electric Power Co
PO Box 711
UE204
Tucson, AZ 85702-0711
United States

RECEIVED
DEC 14 2005
ACCOUNTS PAYABLE

SHIP TO
Mr. Cosimo DeMasi
Tucson Electric Power Co
PO Box 711
UE204
Tucson, AZ 85702-0711
United States

DATE SHIPPED	PURCHASE ORDER NO.		TERMS
PRINT DATE 12/9/04	LOCATION	CUSTOMER	Net 30

ITEM NUMBER	DESCRIPTION	SHIPPED	ORDERED	UNIT PRICE	EXTENSION

APPROVED FOR PAYMENT
By C. DeMasi Date 11/30/05

Please reference invoice number on check and return remittance copy with payment

PN Reference:

AMOUNT PAID 0.00

SUB TOTAL (Payable in U.S. Dollars)
106,984.00

INVOICE NUMBER: 1-000025467

106,984.00
PLEASE REMIT THIS AMOUNT

2005

December 9, 2004

TO: UARG Policy Committee Representative

SUBJECT: UARG Billing for Calendar Year 2005

Enclosed is the invoice for UARG dues for calendar year 2005. Dues amounts were calculated based on (a) Policy Committee members' December 3, 2004 vote to set the year-2005 UARG budget at $6,150,000 (the same level as the year-2004 UARG budget); (b) the number of members that have told us they plan to continue their UARG membership in 2005, and (c) the number of fossil megawatts owned by each such member.

Also enclosed is a table listing the estimated amount of each member's dues for year 2005. Adjustments may subsequently need to be made to these numbers to reflect updated information received concerning the number of fossil megawatts owned by each member. (Recall that a part of each member's dues is based upon the number of megawatts of fossil generation owned by each member as of December 31, 2004.) If we need to recalculate members' dues, we expect that the final dues payment for each member will not vary significantly from the amount listed on the attached table.

Consistent with UARG's Procedures, dues are payable by each member as of the beginning of calendar year 2005. We would appreciate your prompt payment of the enclosed invoice for 2005 so that we will have sufficient funds to prevent any disruption in UARG's activities.

If you have questions regarding your billing, please call EEI's Carol Ray at (202) 508-5428 or cray@eei.org. If you have other questions about the UARG dues, please contact John Kinsman at 202-508-5711.

Sincerely,

Carol L. Ray

Carol L. Ray

Enclosures

EEI EDISON ELECTRIC INSTITUTE

2005

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Main Number 202-508-5000
Accounts Receivable 202-508-5447
FAX 202-508-5630

INVOICE

INVOICE NO: 1-0000254678
DATE: APRIL 1, 2005

TO: TUCSON ELECTRIC POWER CO.
P.O. BOX 711
UE204
TUCSON, AZ 85702-0711
MR. COSIMO DEMASI

TUCSON ELETRIC POWER CO.
P.O. BOX 711
UE204
TUCSON, AZ 85702-0711
MR. COSIMO DEMASI

SALESPERSON	P.O. NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
C. RAY		040105			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	C = Utility Air Regulatory Group		
	2005 UARG PARTICIPATION – 2ND QUARTER		$26,746.00
	CONTACT: MR. COSIMO DEMASI		
	PH: 520-571-4000		
	PAYMENT DUE: MAY 1, 2005		
	P.O. 1343-1		
	Task A101805 (CC0001) - Line 1 = $24,071		
	Task ET P0930 (UNSE300) Line 2 = 2675		
	RECEIVED APR 05 2005		
	Please reference invoice number on the check and return remittance copy with payment.		
	Receipt 9911 4/27/05		
		Remit this amount	$26,746.00

APPROVED FOR PAYMENT
By C. DeMasi Date 4/27/05

RECEIVED
APR 28 2005
ACCOUNTS PAYABLE

UNSE(0783)08925

2005

EDISON ELECTRIC INSTITUTE

Remit To: EEI Accounts Receivable
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696

Main Number: 202-508-5000
Accounts Receivable: 202-508-5447
FAX: 202-508-5000

INVOICE NO.	INVOICE DATE	CUST NO.
1-000031452	5/19/05	407920

FEIN: 13-0656500

RECEIVED
MAY 2 4 2005
C. DeMASI

Remittance Copy
Please return this copy with payment

SOLD TO:
Cosimo DeMasi
UniSource Energy Corp
PO Box 711
Tucson, AZ 85702-0711
United States

SHIP TO:
Cosimo DeMasi
UniSource Energy Corp
PO Box 711
Tucson, AZ 85702-0711
United States

DATE SHIPPED	PURCHASE ORDER NO.	SHIP VIA	TERMS
			Net 30
PRINT DATE	**LOCATION**	**SALESPERSON**	
5/19/05		CHeery	

ITEM NUMBER	DESCRIPTION	QUANTITY ORDERED	QUANTITY SHIPPED	UNIT PRICE	EXTENSION
	UEWAG Membership Dues Unit Price: 0.00, Member Type: Non-Member, NONE Contact: Cosimo DeMasi UEWAG 2005 Membership Dues 2005 Per Share Assessment @ $30.063 Unisource shares - 1,125 Payment due upon receipt [illegible] 671-4000	1		$33,810.00	$33,810.00

TCE = 30,429
UNSE = 3,381

RECEIVED
MAY 27 2005

Please reference invoice number on check and return remittance copy with payment

PN Reference:

AMOUNT PAID 0.00

SUB TOTAL (Payable in U.S. Dollars)
33,810.00

INVOICE NUMBER: 1-000031452

33,810.00
PLEASE REMIT THIS AMOUNT

UNSE(0783)08926

2005

EDISON ELECTRIC INSTITUTE

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Main Number 202-508-5000
Accounts Receivable 202-508-5447
FAX 202-508-5330

INVOICE

INVOICE NO: 1-000025467C
DATE: JULY 1, 2005

TO: TUCSON ELECTRIC POWER CO..
P.O. BOX 711
UE204
TUCSON, AZ 85702-0711
MR. COSIMO DEMASI

TUCSON ELETRIC POWER CO.
P.O. BOX 711
UE204
TUCSON, AZ 85702-0711
MR. COSIMO DEMASI

SALESPERSON	P.O. NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
C. RAY		07/01/05			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	2005 UARG PARTICIPATION – 3RD QUARTER		$26,746.00
	CONTACT: MR. COSIMO DEMASI		
	PH: 520-571-4000		
	PAYMENT DUE: AUGUST 1, 2005		
	P.O. 1343-2		
	Task A101805 (CC0001) = $2675.		
	Task ~~UNSE200 (UN~~ ETP0930 (UNSE200) = 24,071		
	26,746		
	Receipt 14802 7/26/05		

RECEIVED JUL 27 2005 ACCOUNTS PAYABLE

RECEIVED JUL 22 2005 C. DeMASI

Please reference invoice number on the check and return remittance copy with payment.

APPROVED FOR PAYMENT
By [signature] Date 7/26/05

Remit this amount $26,746.00

*JE910 Done to Correct:
Coding Error found = $24,071 should have been TEP'S + 2,675.00 should have been UNSE

UNSE(0783)08927

2006

EDISON ELECTRIC INSTITUTE

701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004-2696
PHONE (202) 508-5000

INVOICE FOR MEMBERSHIP DUES
REMITTANCE COPY

Date	Invoice Number
12/14/2005	1-000038292

MR. JAMES S. PIGNATELLI
CHAIRMAN, PRESIDENT AND CEO
UNISOURCE ENERGY CORP
P.O. BOX 711
TUCSON, AZ 85702-0000

Payment Due on or before February 1, 2006
(Interest charges will accrue after due date)

Description	Total
2006 Membership Dues for:	
Regular Activities of Edison Electric Institute[1]	$ 277,067
Industry Structure Assessment[2]	~~11,560~~
Mutual Assistance Program[3]	~~5,000~~
Total	~~$ 293,627~~

[1] Pursuant to OBRA, the portion of membership dues allocable during 2006 relating to influencing legislation not deductible for Federal Income Tax purposes is estimated to be 25%.

[2] The portion of the voluntary Industry Structure Assessment allocable during 2006 relating to influencing legislation is estimated to be 70%.

[3] Voluntary assessment approved by EEI Executive Committee relating to improvements for the rapid response to disasters. No portion of this assessment is allocable to influencing legislation.

PLEASE NOTE INFORMATION FOR WIRING.

The following is instruction for transferring funds electronically to Edison Electric Institute's account at the Wachovia Bank N.A. in Washington, DC:

Beneficiary's Bank:	**Wachovia Bank, N.A.**
Bank's Address:	**Washington, DC**
Bank's ABA Number:	**054001220**
Beneficiary:	**Edison Electric Institute**
Beneficiary's Acct No:	**2000013842897**
Beneficiary's Address:	**701 Pennsylvania Avenue, NW Washington, DC 20004-2696 USA**
Beneficiary Reference:	**2006 Membership Dues**

$267,067 TEP mb
$10,000 UES mb
(all electric 512)
Voucher for Kevin Larson's Signature

Please refer any questions to Ed Milad at: phone-(202) 508-5430; fax-(202) 508-5030; *or* e-mail-emilad@eei.org

UNSE(0783)08928

2006

EDISON ELECTRIC INSTITUTE

Remit To: EEI Accounts Receivable
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696

Main Number: 202-508-5000
Accounts Receivable: 202-508-5447
FAX: 202-508-5030

INVOICE NO.	INVOICE DATE	CUST NO.
1-000038367	12/14/05	407476

FEIN: 13-0659550

Remittance Copy
Please return this copy with payment

SOLD TO
Mr. Cosimo DeMasi
Tucson Electric Power Co
PO Box 711
UE204
Tucson, AZ 85702-0711
United States

RECEIVED
JAN 0 3 2006
C. DeMASI

SHIP TO
Mr. Cosimo DeMasi
Tucson Electric Power Co
PO Box 711
UE204
Tucson, AZ 85702-0711
United States

DATE SHIPPED	PURCHASE ORDER NO.	SHIP VIA	TERMS
PRINT DATE 12/14/05	LOCATION	SALESPERSON CRay	Net 30

ITEM NUMBER	DESCRIPTION	QUANTITY ORDERED	QUANTITY SHIPPED	UNIT PRICE	EXTENSION	TAX
	2006 UARG - Unit Price: 0.00, Member Type: Non-Member - NONE Contact: Mr. Cosimo DeMasi	1		112,076.00	112,076.00	N
	PH: (520) 571-4000					
	We pay quarterly = $28,019 ~~112,076~~					
	P.O. 1343-2					
	A101805 = 25,217.10 TEP					
	ETP0930 = 2801.90 UNSE ★					
	APPROVED FOR PAYMENT By C. DeMasi Date 1/6/06					
	Receipt 23947 1-6-06					

RECEIVED
ACCOUNTS PAYABLE
JAN 09 2006

Please reference invoice number on check and return remittance copy with payment

PN Reference:

AMOUNT PAID 0.00

SUB TOTAL (Payable in U.S. Dollars) 112,076.00

INVOICE NUMBER: 1-000038367

112,076.00 PLEASE REMIT THIS AMOUNT

UNSE(0783)08929

2006

INVOICE

EDISON ELECTRIC INSTITUTE
MEETING REGISTRATION OFFICE
701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004
ACCOUNTS RECEIVABLE: (202)508-5428

INVOICE NO: 1-000038367C
DATE: JULY 1, 2006

TO: TUCSON ELECTRIC POWER CO.
P.O. BOX 711
UE204
TUCSON, AZ 85702-0711
MR. COSIMO DEMASI

TUCSON ELECTRIC POWER CO.
P.O. BOX 711
UE204
TUCSON, AZ 85702-0711
MR. COSIMO DEMASI

RECEIVED
JUL 11 2006
C. DeMASI

SALESPERSON	P.O. NUMBER	DATE SHIPPED	SHIPPED VIA	F.O.B. POINT	TERMS
C. RAY		07/01/06			NET 30

QUANTITY	DESCRIPTION	UNIT PRICE	AMOUNT
	2006 UARG PARTICIPATION – 3RD QUARTER		28,019.00
	CONTACT: MR. COSMIO DEMASI		
	PH: 520-571-4000		
	PAYMENT DUE BY AUGUST 1, 2006		
	PLEASE REFERENCE INVOICE NUMBER ON THE CHECK AND RETURN REMITTANCE COPY WITH PAYMENT.		
	Tep = 25,217.10 UNSE = 2801.90	RECEIVED ACCOUNTS PAYABLE JUL 18 2006	
		Remit this amount	$28,019.00

UNSE(0783)08930

2006

EDISON ELECTRIC INSTITUTE

Remit To: EEI Accounts Receivable
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696

Main Number: 202-508-5000
Accounts Receivable: 202-508-5426
FAX: 202-508-5030

INVOICE NO.	INVOICE DATE	CUST NO.
1-000045507	7/12/06	407520

FEIN: 13-0659550

Remittance Copy
Please return this copy with payment

SOLD TO
Cosimo DeMasi
UniSource Energy Corp
PO Box 711
Tucson, AZ 85702-0711
United States

SHIP TO
Cosimo DeMasi
UniSource Energy Corp
PO Box 711
Tucson, AZ 85702-0711
United States

DATE SHIPPED	PURCHASE ORDER NO.	SHIP VIA	TERMS
			Net 30

PRINT DATE	LOCATION	SALESPERSON
7/12/06		CRay

ITEM NUMBER	DESCRIPTION	QUANTITY ORDERED	QUANTITY SHIPPED	UNIT PRICE	EXTENSION
	2006 USWAG Dues - Unit Price: 0.00, Member Type: Non-Member - NONE Contact: Cosimo DeMasi SHARES: 1 PH: (520) 571-4000	1		30,655.00	30,655.00

Error on invoice
Should have been
22.99

TEP = 20,691
UNSE = 2300

Please reference invoice number on check and return remittance copy with payment

AMOUNT PAID 0.00

SUB TOTAL (Payable in U.S. Dollars)			
30,655.00	VERISIGN NUMBER:	INVOICE NUMBER: 1-000045507	30,655.00 PLEASE REMIT THIS AMOUNT

UNSE(0783)08931

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	Membership Dues Expense
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	September 21, 2006
PREPARED BY:	Janet Zaidenberg-Schrum JZS
CHECKED BY:	Dallas Dukes D2
REVIEWED BY:	

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	
930.2	Miscellaneous General Expenses		$2,000	19
	ENTRY TOTAL	**$0**	**$2,000**	

Reason for Adjustment

To reduce corporate membership dues expense for EEI by the estimated percentage of the dues used for legislative advocacy expense (lobbying activities).

UNS Electric, Inc.
EEI Membership Dues
for Test Year Ended June 30, 2006

Total EEI Membership Dues Paid	$10,000	2a
Percentage for Legislative Advocacy	20.00%	3a
Expense to Exclude	$2,000	a

9/21/2006 5:19 PM

ENTERED INVOICES INTO ORACLE A/P
BY COST CENTER
AS OF 20-SEP-06
FERC: 0930
GL Month: JAN-06
GL Company: 033
&GL Cost Center

LOC: 000	Co: 033	ET: 251	Period Name: JAN-06

GI Date - Distribution	Vendor Name	Invoice Number	Invoice Date	Description	Amount	Voucher Num	Task Number	PROJ	Cst Ctr	Pymt Method	Paid
26-JAN-2006	AUSA	011706 10000	17-JAN-2006	ANNUAL DUES	$50.00	99664	E610930	UNSE061	544	CHECK	Yes
26-JAN-2006		011706 10000	17-JAN-2006	ANNUAL DUES	$50.00	99664	E620930	UNSE062	544	CHECK	Yes
					Total: $100.00						
17-JAN-2006	EDISON ELECTRIC INSTITUTE	1-000038292	14-DEC-2005		(2) $10,000.00 a	98168	E600930 (1)	UNSE060	512	EFT	Yes
10-JAN-2006		1-000038367	14-DEC-2005	PO 1343 MEMBERSHIP FEES	$2,801.90	97061	ETP0930	UNSE200	805	EFT	Yes
					Total: $12,801.90						
					Total: $12,901.90						

See 2.1a & 2.2a

(1) Task = Gen A&G Exp = FERC 930.2 in GL.

(2) Total invoice = $277,067. $10k to UNSE & $267,067 to TEP membership dues. The GL accounting is the same for TEP & UNSE (79020/930 & ET 251).

UNSE(0783)02159

Voucher Request for Check, EFT or Wire Transfer

COMPANY SELECTION: (Check a box)

- ☐ Millennium Energy Holdings (MEHC)
- ☐ Millennium Environ Group (MEG)
- ☐ Tucson Electric Power (TEP)
- ☐ Other (specify) _____
- ☐ UniSource Energy Corporation (UNS)
- ☒ UNS Electric (UNE)
- ☐ UNS Gas (UNG)

VENDOR#: _____

DUE DATE: Feb 1, 2006 INVOICE#: 1-000038292 AMOUNT: $10,000

PAY TO THE ORDER OF: Edison Electric Institute

ADDRESS: 701 Pennsylvania Avenue, NW

CITY/STATE/ZIP: Washington DC 20004

EXPLANATION/BUSINESS PURPOSE: Membership Dues - UNE

☐ Mail Check

☒ Return check to: WIRE TRANSFER Mail stop: Ext. 0

Requested by (Please Print): Benjamin Modert Signature: [signature] Date 1/12/2006

For Immediate Pay Only: - this voucher must be manually approved.

Approved by (Please Print): Kevin Larson Signature: [signature] Date 1/12/2006

FOR WIRE TRANSFERS ONLY: Vendor's bank routing information must be supported with a letter form the vendor or the bank routing information must be on the vendors' invoice.

Bank Name: WACHOVIA BANK, N.A.

ABA (routing number) 054001220 Account 2000013842897

MATERIALS >$ 2,500: need Procurement & Contracts Dept Approval.

Apvd. by (Please Print) _____ Signature: _____ Date _____

ACCOUNTING INFORMATION:

Project	Task	Expenditure Type	Expenditure Org (Cost Center)	Amount	
UNSE050	~~E500930~~	251	512	10,000	a
	E600997			0	

Account Alias or G/L Account Stream - if applicable	Amount	

Note: Projects can not start with an X and Expenditure Types can not start with a 9. If you need accounting information, contact Amber Young in Financial Accounting at 745-3164. Amber will provide you with the information to put in the following box:

01-10-06P12:24 RCVD

Form 5015 rev. 11/04

21

EDISON ELECTRIC INSTITUTE

701 PENNSYLVANIA AVENUE, NW
WASHINGTON, DC 20004-2696
PHONE (202) 508-5000

INVOICE FOR MEMBERSHIP DUES
REMITTANCE COPY

Date	Invoice Number
12/14/2005	1-000038292

MR. JAMES S. PIGNATELLI
CHAIRMAN, PRESIDENT AND CEO
UNISOURCE ENERGY CORP
P.O. BOX 711
TUCSON, AZ 85702-0000

Payment Due on or before February 1, 2006
(Interest charges will accrue after due date)

Description	Total
2006 Membership Dues for:	
Regular Activities of Edison Electric Institute[1]	$ 277,067
Industry Structure Assessment[2]	~~41,560~~
Mutual Assistance Program[3]	~~5,000~~
Total	~~$ 323,627~~

[1] Pursuant to OBRA, the portion of membership dues allocable during 2006 relating to influencing legislation not deductible for Federal Income Tax purposes is estimated to be 25%.

[2] The portion of the voluntary Industry Structure Assessment allocable during 2006 relating to influencing legislation is estimated to be 70%.

[3] Voluntary assessment approved by EEI Executive Committee relating to improvements for the rapid response to disasters. No portion of this assessment is allocable to influencing legislation.

PLEASE NOTE INFORMATION FOR WIRING.

The following is instruction for transferring funds electronically to Edison Electric Institute's account at the Wachovia Bank, N.A. in Washington, DC:

Beneficiary's Bank:	**Wachovia Bank, N.A.**
Bank's Address:	**Washington, DC**
Bank's ABA Number:	**054001220**
Beneficiary:	**Edison Electric Institute**
Beneficiary's Acct No:	**2000013842897**
Beneficiary's Address:	**701 Pennsylvania Avenue, NW Washington, DC 20004-2696 USA**
Beneficiary Reference:	**2006 Membership Dues**

$267,067 TEP mb
& $10,000 UES mb
(all electric 512)
Voucher for Kevin Larson's Signature

Please refer any questions to Ed Milad at: phone-(202) 508-5430; fax-(202) 508-5030; *or* e-mail-emilad@eei.org.

212

UNSE(0783)02161

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Telephone 202-508-5700
Fax 202-508-5032
Cell Phone 202-236-8447
pokelley@eei.org

www.eei.org

EDISON ELECTRIC INSTITUTE

PATRIC D. O'KELLEY
CFO, Treasurer

July 26, 2006

Dear Committee Members:

We have completed the calculation of EEI's actual expenditures relating to influencing legislation for calendar year 2005. A total of 19.4% of our regular dues, 39.5% of the assessment for the SFA for Industry Structure, and 100% of the assessment for the SFA for Environment were devoted to non-deductible activities in 2005. In addition, the Utility Solid Waste Activities Group ("USWAG") expended 9.9% of their 2005 dues on non-deductible activities. These percentages may affect the extent to which your 2005 EEI dues and SFA payments qualify as a deductible business expense.

These actual figures differ from the earlier estimates contained in your dues invoice and our letter dated July 15, 2005 which estimated that non-deductible expenditures would be 25% for regular dues, 70% for the assessment for the SFA for Industry Structure, 100% for Environment, and 10% for USWAG for the calendar year 2005.

EEI is adjusting its estimate for non-deductible legislative advocacy expenses for calendar year 2006 for Regular Dues and the Industry Structure SFA. However, please note that our current estimate for such expenses is 100% for the Environment SFA and 10% for USWAG. The actual percentages for calendar year 2006 will be provided to you by mid-2007. For your convenience, a chart with original estimates, revised figures and actual figures is provided below.

Summary of 2005 and 2006 Estimated, Revised and Actual Percentages

	Regular Activities	Separately Funded Activities (SFA)		
	Core Dues	Industry Structure	Environment	USWAG
2005				
Original Estimate on dues invoice	25.0%	70.0%	-	-
Revised Estimate – July 2005	25.0%	70.0%	100.0%	10.0%
Actual/Final	19.4%	39.5%	100.0%	9.9%
2006				
Original Estimate on dues invoice	25.0%	70.0%	-	-
Revised Estimate – July 2006	20.0% a	40.0%	100.0%	10.0%

Please do not hesitate to call Ed Milad at (202) 508-5430 or me if you have any questions.

Sincerely,

Rebuttal Testimony of Michael J. DeConcini

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	)	DOCKET NO. E-04204A-06-0783

Rebuttal Testimony of

Michael J. DeConcini

on Behalf of

UNS Electric, Inc.

August 14, 2007

TABLE OF CONTENTS

I. Introduction 1

II. Rate Treatment for Black Mountain Generating Station 2

III. Purchased Power And Fuel Adjustment Clause 7

IV. Conclusion 18

EXHIBITS

Exhibit MJD-3: UNS Electric PPFAC Plan of Administration
Exhibit MJD-4: UNS Electric PPFAC Year Timeline
Exhibit MJD-5: Palo Verde Prices

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Michael J. DeConcini. My business address is One South Church Avenue, Tucson, Arizona 85701.

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

A. I am Senior Vice President and Chief Operating Office for both UniSource Energy Corporation ("UniSource Energy") and Tucson Electric Power Company ("TEP"). I am a Director for UNS Electric, Inc. ("UNS Electric" or "Company").

Q. What areas will you be discussing in your Rebuttal Testimony?

A. In my Rebuttal Testimony, I discuss:

- Staff and RUCO's Direct Testimony regarding the Company's proposed rate treatment of the Black Mountain Generating Station ("BMGS");
- Staff and RUCO's Direct Testimony on the Company's proposed changes to its current Purchased Power and Fuel Adjustment Clause ("PPFAC"); and
- In response to recommendations, UNS Electric's new proposed PPFAC that is modeled on Staff's proposal in the recent APS rate case.

Q: Please summarize your Rebuttal Testimony.

A: First, the Company believes acquiring BMGS is necessary and in the best interest of the Company and its customers, thereby making its proposed rate treatment for BMGS reasonable and appropriate.

Second, based on Staff's Direct Testimony in this case, the recent Commission decision in the APS rate case (Decision No. 69663 (June 28, 2007)) and the PPFAC mechanism that

TEP recently filed in Docket No. E-01933A-07-0402, the Company is proposing to modify the PPFAC it proposed in its Direct Testimony. Essentially, the Company's new PPFAC is the same Power Supply Adjustor ("PSA") that Staff proposed for APS, with the exception of a Transition Component, and is virtually the same mechanism that was recently filed in TEP's rate case.

II. RATE TREATMENT OF BLACK MOUNTAIN GENERATING STATION.

Q. Please summarize the Company's requested rate treatment for BMGS.

A. UNS Electric is requesting that BMGS be included in its rate base effective as of June 1, 2008 when the Pinnacle West Capital Corporation ("PWCC") Power Supply Agreement expires. Specifically, the Company is requesting a post-test-year adjustment to rate base and a corresponding reclassification of rates to be effective June 1, 2008 as described in the Direct Testimonies of Kevin P. Larson, Dallas J. Dukes and D. Bentley Erdwurm.

Q. Please summarize RUCO's Direct Testimony on the Company's requested treatment for BMGS?

A. In short, RUCO opposes UNS Electric's proposed rate treatment for BMGS entirely. Instead, RUCO suggests that UNS Electric enter into a short-term purchase power agreement ("PPA") for power from the facility.

Q. What is the basis of RUCO's opposition?

A. Simply put, RUCO disagrees with the proposal because it is contrary to historical ratemaking principles and treatments. Further, RUCO witness Marylee Diaz Cortez has concerns relating to prudency review and related party transactions.

Q. Why do you disagree with RUCO's position?

A. The Company is proposing unique treatment for BMGS because the Company is in a unique situation to acquire a 90-megawatt facility that can significantly improve its power portfolio at a time when it needs to replace the expiring PWCC full requirements purchased power agreement. Taking advantage of this opportunity requires a creative approach so that the Company and customers can benefit over the long-term. It is important to note that UNS Electric is essentially starting from scratch to build a portfolio of contracts and generating assets to supply its load and that BMGS is a key component in this plan. But RUCO seems willing to dismiss this opportunity due solely to past practice founded in completely different circumstances. Mr. Larson discusses the financial benefits to UNS Electric if its proposal regarding BMGS is approved, as well as countering some of RUCO's arguments. I would like to further address RUCO's prudence concerns and related party concerns.

Q. What are RUCO's prudency and related party concerns?

A. Ms. Diaz Cortez – in her Direct Testimony on page 7 at lines 13 though 16 – states that "[f]urther, the proposed transaction is a related party transaction which requires a high level of scrutiny to insure there are no related party abuses, and that it is equivalent to a transaction that would happen at an arm's length." Later in her Direct Testimony, at page 8 at lines 8 through 10, Ms. Diaz Cortez states "[f]urther, RUCO has concerns that premature rate base approval of this proposed asset might affect any future determination of prudency."

Q. Why are these misplaced concerns?

A. This case *is* the correct time and place to both determine the economic prudence of BMGS and allay any concerns relating to related party transactions because the Company must have the ability to acquire BMGS. It cannot do so without the Commission approving the

specific relief requested. Mr. Larson for UNS Electric provides substantial evidence as to why the Company's proposal makes good economic sense. Additionally, the Company has committed to limit the purchase price to the actual cost of construction that UniSource Energy Development Corporation ("UEDC") – an affiliate of UNS Electric – incurs. Most importantly, UEDC is developing BMGS specifically for the needs of UNS Electric. The Parties have been free and are still free to explore any concerns they have – and the evidence UNS Electric put forth – regarding the cost-based purchase price and the economics of UNS Electric acquiring BMGS relative to alternative power supply arrangements in this proceeding. The Company also agrees to allow the Parties to review and evaluate the prudence of construction costs in the Company's next rate case. But no Party asserts the $60 million figure the Company requests is an over estimation of construction costs. Because the Company is limiting its post-test-year adjustment request to $60 million in this rate case, and because this value represents the minimum cost estimate for BMGS, it is extremely unlikely that a subsequent construction cost review would result in a prudent project cost lower than $60 million.

Q. Will a short-term PPA, as recommended by RUCO, provide an acceptable solution to UNS Electric?

A. No. A short-term PPA is a short-sighted solution. First, there are differences in PPA and ownership cost structures. PPAs are typically designed with escalators in the capacity charges so that costs are lower at the beginning but increase over time. On the other hand, rate base treatment causes the fixed cost recovery to decline over time. Mr. Larson explained this treatment in his Direct Testimony at pages 13 through 14, and in his Exhibit KPL-3. If the short-term capacity market is lower than the early year rate-base cost of BMGS, then the Company would lose this difference with no chance to recover it once BMGS was put into rates at lower cost a few years later. Conversely, if short-term

capacity costs were higher, then customers would pay more for BMGS than the Company is proposing with this rate treatment.

Q. How would a PPA between UNS Electric and UEDC be priced?

A. The PPA would be priced through a competitive bid. Since UEDC is an unregulated affiliate of UNS Electric, in order for FERC to approve a sale between the two, it would require UNS Electric to hold a competitive RFP. UEDC would have to submit a bid into this RFP and be the lowest bid.

Q. What would be the appropriate PPA term to compare to asset ownership?

A. A term that coincides to the expected life of the unit would be appropriate for asset ownership comparison. For BMGS, this would be approximately 30 to 40 years. This allows a true comparison between a PPA and ownership expected life of an asset.

Q. What was Staff's position on the proposed BMGS rate treatment?

A. Staff witness Ralph C. Smith recommends that the Commission deny the Company's requested rate base and ratemaking treatment of BMGS. Instead Staff recommends that the Company apply for an accounting order requesting permission to defer costs related to BMGS until it is recognized in rate base in the Company's next rate case.

Q. Does a deferral order provide the Company with an adequate solution?

A. No. As Mr. Larson explains in his Rebuttal Testimony ,a deferral puts undue financial stress on the Company and precludes acquisition of BMGS.

Q. What is the best long-term solution for both the Company and its customers for the immediate treatment of BMGS?

A. The best long-term solution for both the Company and its customers is the Company's recommended rate treatment in this case. UEDC has acquired these turbines at a substantial discount – as I described on page 11 of my Direct Testimony – and is willing to give this benefit to UNS Electric and its customers in exchange for recognizing them in rates at the expiration of the PWCC power agreement. A short-term PPA cannot guarantee this result and puts both the customer and Company at risk of an unknown market-based capacity charge.

Q. Have either RUCO or Staff raised issue with the benefits of owning this generation as described in your Direct Testimony?

A. Neither party disputes that BMGS will provide the operational benefits I detailed in my Direct Testimony, including:

- Flexibility to use instantaneous, load-following and emergency dispatch capabilities to provide its required reserves and ancillary services, as well as the ability for full, unlimited, economic dispatch to optimize UNS Electric's portfolio. PPAs simply do not provide the flexibility for full, unfettered dispatch rights that ownership provides.
- Reliability by UNS Electric fully controlling its maintenance and operation to ensure it meets high standards for adequacy and safety. Further, the Company avoids having to purchase significant wholesale capacity, transmission wheeling services and certain ancillary services.
- Efficiency through having the exact type of unit needed to meet UNS Electric's particular requirements, and having a benchmark to compare future PPAs to determine the best overall value for the Company and its customers. UNS Electric

would be able to meet its exact peaking capacity and reserve needs through owning BMGS.

- Having generation at a location that minimizes transmission costs – and thereby delivery costs – while also providing must-run generation. BMGS' location provides an additional benefit by having generation close to dual pipeline systems, thereby giving it fuel redundancy.

Mr. Smith for Staff, however, states his belief that "significant uncertainties" still exist with respect to the economics of BMGS relative to alternative power supply arrangements. Mr. Smith does not explain what these "significant uncertainties" are. I find Mr. Smith's statement confusing and frustrating because I described in my Direct Testimony – at pages 11 through 15 – how BMGS compares favorably to alternative power supply arrangements. Now is the time to decide whether BMGS provides a good fit with UNS Electric power supply needs. Mr. Larson also explains the numerous reasons why this particular facility makes good economic sense for UNS Electric and its customers both in his Direct and Rebuttal Testimonies. Instead of deferring this question to some future rate case, the Company urges the Commission to consider the analysis presented in this case and to rule on the prudence of acquiring BMGS in this proceeding.

III. PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE.

Q. Why is UNS Electric changing the PPFAC mechanism it originally filed in this case?

A. In his Direct Testimony, Staff witness Mr. Smith indicated a preference for a mechanism to be developed similar to Staff's proposed PSA in the recently resolved APS rate proceeding (Docket No. E-01345A-05-0816), with appropriate adjustments to fit UNS Electric's circumstances. Mr. Smith had concerns about UNS Electric's original proposed mechanism based on its automatic rolling twelve-month mechanism.

RUCO witness Ms. Diaz Cortez generally agreed with the PPFAC the Company filed in this case with some suggested modifications: 1) not allowing the Company to include Letter of Credit fees; 2) placing a cap of 6 mils per year on the amount that the PPFAC can increase, plus requiring a filing for recovery when a $10 million bank threshold is reached; and 3) a 90/10 sharing between customers and shareholders of any fuel and purchased power costs that exceed the base cost of fuel and purchased power.

In addition, the Commission recently approved Staff's proposed mechanism for APS in Decision No. 69963 (June 28, 2007), with some modifications, and TEP recently filed a mechanism that was developed along the lines of Staff's PSA proposal for APS, as well as the proposed Plan of Administration ("POA") for APS' PSA. For the foregoing reasons and upon further internal review, UNS Electric believes that Staff's proposed mechanism for APS will be effective in mitigating the volatility in its power supply and delivery costs and believes a similar mechanism is preferable to what we originally filed in this case.

Q. Is UNS Electric proposing a different Base Cost of Fuel and Purchased Power with this change in the PPFAC methodology?

A. No. We are proposing to set the Base Cost of Fuel and Purchased Power as originally filed in this case.

Q. Are you proposing that a PPFAC rate be established to begin when the Pinnacle West Capital Corporation wholesale Power Supply Agreement expires?

A. Yes. The full requirements purchased power agreement with PWCC ends on May 31, 2008. We are proposing, as outlined in the Company's proposed PPFAC POA attached as Exhibit MJD-3, the PPFAC Year begin June 1st and end on May 31st of the following year. The first full PPFAC Year in which a PPFAC rate would apply would begin on June 1, 2008 and end on May 31, 2009 ("2008 PPFAC Year"). We are also proposing that the

initial PPFAC rate be set at zero in this case and the first new PPFAC rate be established for the 2008 PPFAC Year as described hereafter.

Q. How would UNS Electric propose to establish the PPFAC rate starting June 1, 2008?

A. I will explain this in more detail later, but UNS Electric would propose a filing by December 31, 2007 to establish the PPFAC rate for the 2008 PPFAC Year. We would propose that Staff review our filing and prepare its initial report within 45 days. Finally, we would propose that Staff issue its final report approving and/or modifying the Company's proposal for the 2008 PPFAC Year rate by April 15, so that the 2008 PPFAC Year rate would be effective on June 1, 2008. That 2008 PPFAC Year rate would be in effect until May 31, 2009. Then the 2009 PPFAC Year rate would be effective starting June 1, 2009 through May 31, 2010. Essentially, we propose that each year's PPFAC rate would be effective from June 1 of that year until May 31 of the following year.

Q. Could you explain how the PPFAC is structured?

A. UNS Electric proposes that there be two primary components to the PPFAC rate. For the 2008 PPFAC Year rate, these two components would be:

1. Forward Component: This component would be based on the forecasted fuel and purchase power costs for the following year. For example, forecasts for fuel and purchase power in late 2007 would be used to establish the PPFAC Forward Component for 2008. Forward prices would also be used to establish the PPFAC Forward Component annually.
2. True-Up Component: This component would compare actual fuel and purchase power costs with the amount UNS Electric collected through base rates as well as the PPFAC rate for the prior year. If actual costs were above what was collected, the True-Up Component would be an additional amount to be collected from customers in the subsequent year. But should actual costs be below what was

collected, the True-Up Component would reflect a credit towards the PPFAC rate for the following year. For instance, reconciling actual versus forecasted 2008 fuel and purchase power rates would be incorporated into the 2009 PPFAC Year rate via the True-Up Component.

Q. Do you have a simple hypothetical to demonstrate how the PPFAC would work?

A. Yes. Suppose the Base Cost of Fuel and Purchased Power is seven cents per kWh, but actual fuel and energy costs were forecasted to be eight cents per kWh for 2008. The PPFAC rate for 2008 was set at one cent per kWh. So, the total fuel and energy cost collected was eight cents per kWh, but the actual total amount of fuel and energy costs for 2008 turned out to be only 7.5 cents per kWh. For 2009, the fuel and energy cost forecasts anticipate 8.5 cents per kWh cost. Under this hypothetical:

Base Fuel and Energy Cost:	7 cents per kWh.
2009 Forward Component:	1.5 cents per kWh[1]
2009 True-Up Component:	-0.5 cents per kWh[2]
2009 PPFAC Rate (Forward + True-up):	1 cent per kWh
2009 Fuel and Energy Cost Collected:	8 cents per kWh

The above example, while simplified to ignore year over year sales volume differences, gives an accurate portrayal of the actual interplay between the Forward and True-Up Components to establish the annual PPFAC rate.

Q. How do you propose to establish the Forward Component for the PPFAC?

A. Earlier in my testimony, I indicated that UNS Electric proposes to file information and calculations for establishing the Forward Component for the 2008 PPFAC Year rate by

[1] 2009 Forecast of 8.5 cents less Base Cost of Fuel and Purchased Power of 7 cents.

[2] 2009 True-up is based on 2008 actual cost versus recovery. 2008 recovery was based on forecast of 8 cents but actual cost was only 7.5 cents. Therefore, True-up = Actual – Recovery = 7.5 – 8.0 = -0.5 cents.

December 31, 2007. UNS Electric would file this information annually every December 31 to start the process for determining the following year's PPFAC rate.

Q. What information would UNS Electric file to establish the Forward Component?

A. UNS Electric would provide the most current forecasts, including any known and measurable changes expected to take place, for the following year. These fuel and energy price forecasts would be the basis for establishing the Forward Component for the PPFAC rate for the following year.

Q. Should the Forward Component be established so that UNS Electric recovers 100 percent of anticipated fuel and energy costs within a 12-month period?

A. Yes. First, the costs are based on forecasts that accurately reflect what fuel and energy costs are anticipated to be. These are costs of providing electric service to customers the Company will actually incur the following year. A 12-month period ensures that the Company is timely compensated for costs it has incurred. Second, to the extent the actual fuel and energy costs are more or less than what was collected, the True-Up Component I describe below will be a charge or credit against the PPFAC rate for the following year. Third, deferring recovery beyond 12 months complicates the PPFAC rate process. A 12-month recovery period avoids having multiple PPFAC rates imposed in one year, or having multiple years incorporated into one PPFAC rate.

Q. How do you propose to establish the True-Up Component for the PPFAC?

A. At the same time that UNS Electric proposes its Forward Component (December 31 of each year), UNS Electric also provides information and calculation of the True-Up Component. Then, by April 1 of the following year, UNS Electric will provide updated information and calculations to supplement its True-Up Component. The purpose of this supplement is to replace estimated balances with actual balances for that year ending.

Q. Would the True-Up Component also be established to ensure 100 percent recovery or refund within 12 months?

A. Yes. For the same reasons the Forward Component should be designed to recover 100 percent of the fuel and purchase power costs (no more and no less); the True-Up Component for each PPFAC rate should be designed to recover or refund 100 percent of the over-recovery or under-recovery that exists from the prior year.

Q. Once UNS Electric makes its PPFAC filing, how would you envision the procedure occurring to approve the new PPFAC rate for the following year?

A. We propose Staff having 45 days (*i.e.,* by February 15 of that year) to issue any initial comments regarding UNS Electric's filing or recommending any adjustments to the Company's calculations. UNS Electric would file updated information and calculations concerning the True-Up Component by April 1 of the following year. We further propose Staff having an additional two weeks (*i.e.,* until April 15) to file any additional comments or recommendations about the True-Up Component. This would allow ample time to implement the new PPFAC rate with or without modification before May 31 so that the new PPFAC rate would be in effect by June 1. We would further propose that PPFAC rate being in effect for the subsequent 12 months (from June 1 through May 31 the following year.) Exhibit MJD-4 outlines the timeline UNS Electric proposes for implementing the PPFAC rate for each PPFAC Year (*i.e.,* from June 1 to the following May 31.)

We further propose that unless the Commission acts to suspend the PPFAC or takes some other action by May 31, the PPFAC rate – as proposed on December 31 and as modified on April 1 – will go into effect on June 1 (*i.e.,* the start of the PPFAC Year.)

Q. So, UNS Electric proposes annual filings to change the PPFAC rate every twelve months?

A. Yes. We believe this will provide enough frequency to allow the Company to promptly recover fuel and energy costs from customers without burdening the Commission with multiple dockets in a 12-month period. Under normal circumstances, there would only be one process every 12 months to adjust the PPFAC rate.

Q. Does the PPFAC allow UNS Electric to address calamities such as a hurricane that radically alters fuel and purchase power prices?

A. If there was an extraordinary event that led to a drastic change in fuel and energy prices for the remaining months in the current PPFAC Year, then UNS Electric would have the option to seek modification of the Forward Component. Staff approval would be required to do so and notice would be provided to the Commission. That modification would only last until May 31, when the new PPFAC rate would be approved.

Q. Would the modification to the Forward Component be reconciled the following year through the True-Up Component?

A. Yes. The True-Up Component would address the modified Forward Component.

Q. Does UNS Electric envision applying for a modification to the Forward Component regularly?

A. No. UNS Electric would only apply for this modification if there were circumstances that led to a drastic difference between fuel and purchased power costs being collected and the actual costs incurred. An example such a situation would be when the Hurricanes hit the Gulf Coast in August and September of 2005 and caused substantial increases in fuel and purchased power costs in the latter third of 2005. In that case, the variance between what was collected through base rates and the existing PPFAC rate and the actual costs incurred

becomes so significant as to warrant a further adjustment to the current PPFAC rate, whether that be positive or negative. But the effect of the modified Forward Component would be to smooth out the PPFAC rate somewhat by ensuring that the True-Up Component does not result in a larger increase than necessary.

Q. Does the Company believe that there should be any caps or restrictions in the size or magnitude of the PPFAC rate?

A. No. The Company does not believe that any limits or caps should be put in place. We believe that the Commission will have ample control of the PPFAC through the proposals described above. Setting artificial restrictions in this proceeding hampers the goal of ensuring timely recovery for the Company, and may have a negative impact on the Company's ability to secure financing on attractive terms and conditions, as well as its overall creditworthiness. If costs are prudent and reasonable, UNS Electric should receive prompt recovery of those costs.

It is understandable that the Commission applied a cap to APS' PSA as APS has a well-established system consisting of significant stable cost nuclear and coal facilities. UNS Electric, on the other hand, is in the process of acquiring and developing its resource requirements and it would not be appropriate to force a cap on the PPFAC rate in this period of flux. A cap could send a wrong message to over-emphasize short-term rate stability at the detriment of what is in the best long-term interest of our customers. That is, putting caps and collars for rate stability in the short-term can lead to large deferrals that can negatively impact both the Company – making it a riskier investment – and its customers – who have to pay for those cost deferrals eventually.

Q. Is UNS Electric proposing to recover broker's fees, credit costs, and legal fees through the PPFAC?

A. Yes. The Company has not incurred these costs in the past and therefore no such costs are reflected in any rates filed in this case. These fees are an inevitable and necessary part of procuring fuel and purchase power supply for after the expiration of the PWCC full requirements purchase power agreement. These costs are reasonable for UNS Electric to incur in order to continue to be a reliable electric service provider. Consequently, they should be recovered.

Q. Is the Company proposing a sharing mechanism as part of the PPFAC?

A. No. UNS Electric has ample incentive to procure reliable sources of fuel and energy at reasonable prices, to hedge an appropriate amount of fuel and purchased power to provide stability in price, and to seek to procure a stable, reliable, and affordable supply of fuel and purchase power. The Company does not receive any return for these costs, and does not have anything to gain by not seeking out the most economical sources of fuel and purchase power. Further, a sharing mechanism leaves the Company and its customers exposed to the vagaries of the short-term energy markets. Even if the Company made absolutely prudent and well designed purchases, the volatility of the short-term energy markets that are completely beyond the Company's control could cause either the Company or its customers to bear an unfair burden of cost. In the Company's case this would be confiscatory rate policy; in the customers' case this could lead to significantly higher rates. Therefore, we do not believe a sharing mechanism is appropriate in the PPFAC and would strongly oppose such a feature.

Q. What specific circumstances make a sharing mechanism especially inappropriate for the Company?

A. The Company is shifting from a full requirements power supply agreement to its own portfolio of generation and contracts to serve its load. As such, the Company has only a small amount of existing generation in rate base and is requesting the addition of BMGS as I discussed earlier. Even with the BMGS addition, the Company will have a larger reliance on market power prices for mid- and short-term gas and power requirements than other utilities in the State. While the Company has both a Resource Procurement Plan and a Fuel and Purchased Power Hedging Policy to address this, there is invariably an amount of remaining energy price risk. To give a historical perspective to the variation in spot prices, I have included the Palo Verde average monthly prices for the last 5 years in Exhibit MJD-5. In addition, the next few years will likely bring additional resources and contracts that cannot be forecasted at this point in time. If a sharing mechanism is instituted in this current environment it will introduce additional risk to the Company for under-recovery and additional risk to our customers for over-payment. This additional risk can translate ultimately to higher costs of power to our customers through increased credit costs from our suppliers as well as higher debt costs.

Q. How are short-term off-system wholesale revenues treated?

A. Although UNS Electric does not anticipate substantial short-term off-system wholesale revenue, to the extent they exist, UNS Electric will credit the revenues to the PPFAC.

Q. Does the Company's proposed POA demonstrate how all of the PPFAC Components would be calculated?

A. Yes. The POA (Exhibit MJD-3) provides all the details as to how the PPFAC operates, what specific fuel and energy costs would be included from specific FERC accounts, applicable interest rates to apply and other specifics about the UNS Electric's proposed

PPFAC. We hope that this is helpful in allowing Staff, RUCO and the Commission, as well as other parties, to better understand what exactly we are proposing in this filing.

Q. In general, what costs does the Company propose be included in the PPFAC?

A. As described more completely in the attached POA, the PPFAC includes costs associated with FERC accounts 501, 547, 555 and 565. As previously mentioned, the off-system wholesale revenue is credited to the PPFAC. UNS Electric is also proposing to include any Coal and/or Carbon taxes and to include broker fees, credit costs and legal fees associated with its power supply and procurement, as previously discussed. UNS Electric is also proposing to recover amortized new natural gas and electric interconnection costs through the PPFAC.

Q. Mr. Frank W. Radigan for Staff – in his Direct Testimony at page 15 – states that because the PWCC full requirements purchased power agreement will not expire until May 31, 2008 – the base power supply rate remain at $0.05194 per kWh. What is your response to Mr. Radigan's recommendation on this issue?

A. Simply put, $0.05194 per kWh is not remotely accurate for UNS Electric's power supply rate now or going forward. In Decision No. 66028 (July 3, 2003) the Commission established a $0.01825 PPFAC rate to recognize that the total rate necessary to recover the cost of the PWCC supply was $0.07019 ($0.05194 base rate plus $0.01825 PPFAC rate). The base rate established in this case should reflect the total cost of UNS Electric's current supply. Fuel and purchased power costs have risen substantially since the $0.05194 base power supply rate was set in Decision No. 59951 (January 3, 1997). Over ten years have elapsed since that rate was established. Further, I am confused by Mr. Radigan's comments about Mr. Smith's recommendation regarding the PPFAC. In contrast to Mr. Radigan's statements, I interpret Mr. Smith's recommendation on Staff's proposed PPFAC to commence June 1, 2008. Therefore, it makes no sense to delay setting an accurate base

fuel and purchased power rate. The Company's proposal is based on the most accurate information available and reflects its current supply arrangements. Further, resetting the PPFAC to zero will make the "new PPFAC" easier to implement and lessen the volatility in the PPFAC rate. We maintain our request to reset the base power supply rate while zeroing out the PPFAC rate.

IV. CONCLUSION.

Q. Mr. DeConcini, could you summarize what you are requesting the Commission to approve in this docket?

A. Yes. The Company's proposed rate treatment for BMGS is both necessary and in the best long-term interests of its customers and should be accepted for the reasons that I have described in my Direct and Rebuttal Testimonies, as well as what Mr. Larson describes in his Direct and Rebuttal Testimonies. UNS Electric requests that the Commission approve the new PPFAC described in my Rebuttal Testimony and that Staff offered in its Direct Testimony, effective as of June 1, 2008. This new PPFAC mechanism is designed and intended to provide UNS Electric the ability to plan and procure a power supply portfolio that is most advantageous to both UNS Electric and its customers in terms of both economic and reliable electric power service. UNS Electric believes this is the appropriate time to address both BMGS and the PPFAC, since its full requirements purchased power agreement with PWCC expires May 31, 2008, and the related need of UNS Electric to procure replacement power supply.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

EXHIBIT

MJD-3

UNS Electric, Inc.
Purchased Power and Fuel Adjustment Clause
Plan of Administration

Table of Contents

1. General Description.....1
2. Definitions.....1
3. PPFAC Components.....3
4. Calculation of the PPFAC 5
5. Filing and Procedural Deadlines.....5
6. Verification and Audit.....6
7. Calculations.....6
8. Compliance Reports.....9
9. Allowable Costs.....11

1. GENERAL DESCRIPTION

This document describes the plan for administering the Purchased Power and Fuel Adjustment Clause ("PPFAC") the Arizona Corporation Commission ("Commission") approved for UNS Electric, Inc. ("UNSE") in Decision No. XXXXX [DATE]. The PPFAC provides for the recovery of fuel and purchased power costs from the date of that decision forward.

The PPFAC described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs to set a rate that is then reconciled to actual costs experienced. This POA describes the application of the PPFAC.

2. DEFINITIONS

Applicable Interest – Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15.

Base Cost of Fuel and Purchased Power – An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost embedded in the base rates as approved by the Commission in UNSE's most recent rate case. The Base Cost of Fuel and Purchased Power revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at $X.XXXX per kWh effective on [DATE].

Forward Component –An amount expressed as a rate per kWh charge that is updated annually on June 1 of each year and effective with the first billing cycle in June. The Forward Component for the PPFAC Year will adjust for the difference between the forecasted fuel and purchased power costs expressed as a rate per kWh less the Base Cost of Fuel and Purchased Power generally expressed as a rate per kWh embedded in UNSE's base rates. The result of this calculation will equal the Forward Component, expressed as a rate per kWh.

Forward Component Tracking Account – An account that records on a monthly basis UNSE's over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue; plus Applicable Interest. The balance of this account as of the end of each PPFAC Year is, subject to periodic audit, reflected in the next True-Up Component calculation. UNSE files the balances and supporting details underlying this Account with the Commission on a monthly basis via a monthly reporting requirement.

Mark-to-Market Accounting – Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load – Native load includes customer load in the UNSE control area for which UNSE has a generation service obligation.

PPFAC – The Purchased Power and Fuel Adjustment Clause approved by the Commission in Decision No. XXXXX that tracks changes in the cost of obtaining power supplies based upon

forward-looking estimates of fuel and purchased power costs that are eventually reconciled to actual costs experienced as described herein.

PPFAC Rate - The combination of two rate components, the Forward Component and True-Up Component.

PPFAC Year - A consecutive 12-month period beginning each June 1 and lasting through May 31 the following year. The PPFAC will initially be set to zero on the date the Commission issues a decision in this proceeding (Decision No. XXXXX). The first year of the PPFAC will begin on June 1, 2008 and end on May 31, 2009.

System Book Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by UNSE to serve both Native Load and off-system sales, less the costs associated with applicable special contracts and Mark-to-Market Accounting adjustments. Wheeling costs and broker's fee are included.

Off-System Wholesale Sales Revenue - The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the UNSE system, using UNSE-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale - The portion of load from Native Load wholesale customers that is served by UNSE.

True-Up Component - An amount expressed as a rate per kWh charge that is updated annually on June 1 of each year and effective with the first billing cycle in June. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PPFAC Year tracking account balances to be refunded/collected from customers in the coming year's PPFAC rate.

True-Up Component Tracking Account – An account that records on a monthly basis the account balance to be collected or refunded via the True-Up Component rate as compared to the actual True-Up Component revenues, plus Applicable Interest; the balance of which at the close of the preceding PPFAC Year is, subject to periodic audit, then reflected in the next True-Up Component calculation. UNSE files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of UNSE's electricity over transmission facilities owned by others.

3. PPFAC COMPONENTS

The PPFAC Rate will consist of two components designed to provide for the recovery of actual, prudently incurred fuel and purchased power costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PPFAC Year (each June 1 through May 31 period shall constitute a PPFAC Year) fuel and purchased power costs and those embedded in base rates.

2. The True-Up Component, which tracks the differences between the PPFAC Year's actual fuel and purchased power costs and those costs recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PPFAC Year.

The PPFAC Year begins on June 1 and ends the following May 31. The first full PPFAC Year in which the PPFAC rate shall apply will begin on June 1, 2008 and end on May 31, 2009. Succeeding PPFAC Years will begin on each June 1 thereafter.

For the period from when the Commission issued Decision No. XXXXX in this case – until June 1, 2008 – the Base Cost of Fuel and Purchased Power rate established in that decision will be in effect.

On or before December 31 of each year, UNSE will submit a PPFAC Rate filing, which shall include a proposed calculation of the components for the PPFAC Rate. This filing shall be accompanied by supporting information as Staff determines to be required. UNSE will supplement this filing with True-Up Component filing on or before April 1 in order to replace estimated balances with actual balances, as explained below.

A. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) the fuel and purchased power costs embedded in base rates and (2) the forecasted fuel and purchased power costs over a PPFAC Year that begins on June 1 and ends the following May 31. UNSE will submit, on or before December 31 of each year, a forecast for the upcoming PPFAC year (June 1 through May 31) of its fuel and purchase power costs. It will also submit a forecast of kWh sales for the same PPFAC year, and divide the forecasted costs by the forecasted sales to produce the cents per kWh unit rate required to collect those costs over those sales. The result of subtracting the Base Cost of Fuel and Purchased Power from this unit rate shall be the Forward Component.

UNSE shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record UNSE's over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue. This account will operate on a PPFAC Year basis (i.e. June 1 to the following May 31), and its balances will be used to administer this PPFAC's True-Up Component, which is described immediately below.

Should an unusual event occur causing a drastic change in forecasted fuel and energy prices – such as a hurricane or other calamity – UNSE has the discretion to apply for an adjustment to the forward component. Such an adjustment would only last until May 31 and would not be implemented unless approved by Staff and upon notice to the Commission.

B. True-Up Component Description

The True-Up Component in any current PPFAC Year is intended to refund or recover the balance accumulated in the Forward Component Tracking Account (described above) during the previous PPFAC year. Also, any remaining balance from the True-Up Component Tracking Account as of May 31 would roll over into the True-Up Component for the coming PPFAC year starting June 1. The sum of projected Forward Component Tracking Account and True-Up Component Tracking Account balances on May 31 is divided by the forecasted PPFAC year kWh sales to determine the True-Up Component for the coming PPFAC year.

UNSE shall maintain and report monthly the balances in a True-Up Component Tracking Account, which will reflect monthly collections or refunds under the True-Up Component and the amounts approved for use in calculating the True-Up Component.

Each annual UNSE filing on December 31 will include an accumulation of Forward Component Tracking Account balances and True-Up Component Tracking Account balances for the preceding June through November and an estimate of the balances for December through May (the remaining six months of the current PPFAC Year). The UNSE filing shall use these balances to calculate a preliminary True-Up Component for the coming PPFAC Year. On or before April 1, UNSE will submit a supplemental filing that recalculates the True-Up Component. This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the December 31 filing.

The December 31 filing's use of estimated balances for December through May (with supporting workpapers) is required to allow the PPFAC review process to begin in a way that will support its completion before June 1. The April 1 updating will allow for the use of the most current balance information available before the PPFAC would go into effect. In addition to the April 1 update filing, UNSE monthly filings (for the months of November through April) of Forward Component Tracking Account balance information and True-Up Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected True-Up Component unit rate required for the next PPFAC Year.

The True-Up Component Tracking Account will measure the changes each month in the True-Up Component balance used to establish the current True-Up Component as a result of collections under the True-Up Component in effect. It will subtract each month's True-Up Component collections from the True-Up Component balance. The True-Up Component Account will also include Applicable Interest on any balances. UNSE shall file the amounts and supporting calculations and workpapers for this account each month.

4. CALCULATION OF THE PPFAC RATE

The PPFAC rate is the sum of the two components; i.e., Forward Component and True-Up Component. The PPFAC rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PPFAC rate by May 31, the proposed PPFAC rate (as amended by the updated April 1 filing) shall go into effect on June 1. The PPFAC rate shall be applicable to UNSE's retail electric rate schedules (except those specifically exempted) and is adjusted annually. The PPFAC Rate shall be applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge that is the same for all customer classes.

The PPFAC rate shall be reset on June 1 of each year, and shall be effective with the first June billing cycle unless suspended by the Commission. It is not prorated.

5. FILING AND PROCEDURAL DEADLINES

A. December 31 Filing

UNSE shall file the PPFAC rate with all Component calculations for the PPFAC year beginning on the next June 1, including all supporting data, with the Commission on or before December 31 of each year. That calculation shall use a forecast of kWh sales and of fuel and purchased power costs for the coming calendar year, with all inputs and assumptions being the most current available for the Forward Component. The filing will also include the True-Up Component calculation for the year beginning on the next June 1, with all supporting data. That calculation will use the same forecast of sales used for the Forward Component calculation.

B. April 1 Filing

UNSE will update the December 31 filing by April 1. This update will replace estimated Forward Component Tracking Account balances, the True-Up Component Tracking Account balances with actual balances and with more current estimates for those months (March, April and May) for which actual data are not available. Unless the Commission has otherwise acted on the UNSE calculation by June 1, the PPFAC rate that UNSE proposed will go into effect on June 1.

C. Additional Filings

UNSE will also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PPFAC.

D. Review Process

The Commission Staff and interested parties will have an opportunity to review the December 31 and April 1 forecast, balances, and supporting data on which the calculations of the two PPFAC components have been based. Any objections to the December 31 calculations must be filed within 45 days of the UNSE filing. Any objections to the April 1 calculations must be filed within 15 days of the UNSE filing (i.e. by April 15.)

E. Extraordinary Circumstances

Should an unusual event occur that causes a drastic change in forecasted fuel and energy prices – such as a hurricane or other calamity – UNSE will have the authority to request an adjustment to the forward component reflecting such a change. Staff must review and either approve, modify or deny UNSE's request within 30 days. This adjustment will only last until May 31, or the end of the current PPFAC Year.

6. VERIFICATION AND AUDIT

The amounts charged through the PPFAC will be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded in the True-Up Component for the following year (i.e. starting the next June 1.)

7. CALCULATIONS

A. Schedule 1: PPFAC Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PPFAC columns and then complete the following in each respective column:

1. On Line 1, enter the Forward Component from Schedule 2, Line 8.
2. On Line 2, enter the True-Up Component from Schedule 4, Line 5.
3. On Line 3, enter the sum of Lines 1 and 2 to calculate the total PPFAC Rate.
4. Calculate the Increase/(Decrease) in rates and % Change by respective lines: Proposed Rates Less Current Rates equals Increase/(Decrease) with result divided by Current Rate to determine % of Increase/(Decrease).

Reflect notes as appropriate.

B. Schedule 2: PPFAC Forward Component Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PPFAC columns and then complete the following in each respective column:

1. On Line 1, enter the Projected Fuel and Purchased Power Costs for the coming year.
2. On Line 2, enter 90% of the Projected Off-System Sales Revenue (entered as a negative value) for the coming year.
3. On Line 3, enter the PPFAC Adjustments to Fuel and Purchased Power Costs for the coming year.
4. On Line 4, enter the sum of Lines 1 through 3 to arrive at the Net Fuel and Purchased Power Costs.
5. On Line 5, enter the Projected Native Load Sales (MWh), including Wholesale Native Load Customers for the coming year.
6. On Line 6, enter the derivation of the Net Fuel and Purchased Power Costs divided by the Projected Native Load Sales to arrive at the Projected Average Net Fuel Cost per kWh.
7. On Line 7, enter the Authorized Base Cost of Fuel and Purchased Power Rate per kWh.
8. On Line 8, enter the sum of Line 6 less Line 7 to arrive at the Forward Component rate per kWh; and then carry forward resultant value to Schedule 1, Line 1.

Reflect notes as appropriate.

C. Schedule 3: Forward Component Tracking Account

Enter the appropriate: effective dates for the PPFAC Forward Component currently being tracked; year for the column headed "Cycle Billing Month"; and Base Rate and Forward Component in columns h and i. On lines 1 through 12 under the Cycle Billing Month, January through December for each respective column complete the following:

1. On Lines 1 to 12, enter the monthly PPFAC Retail Energy Sales (MWh) and the monthly Wholesale Native Load Energy Sales in columns a and b, respectively. The sum of columns a and b equals the Total Native Load Energy Sales in column c. Currently, Wholesale Native Load Energy Sales include Traditional Sales-for-Resale and any Supplemental Sales.
2. On Lines 1 to 12, enter the monthly System Book Fuel and Purchased Power Costs and 90% of the monthly System Book Off-System Sales Revenue in columns d and e, respectively:

   - The sum of column d minus e equals the monthly Net Native Load Power Supply Costs in column f.
   - The off-system sales margin is embedded in the Net Native Load Power Supply Cost. The costs associated with the off-system sales are included in the System Book Fuel and Purchased Power Costs.

- When the System Book Off-System Sales Revenue is subtracted from the System Book Fuel and Purchased Power Costs, the difference between the off-system sales costs and revenue ends up in the Net Native Load Power Supply Cost. That difference is the off-system sales margin.
- A list of the items included in the PPFAC sales and costs described above will be included in the PPFAC reporting schedules filed with the Commission each month.

3. On Lines 1 to 12, calculate the PPFAC Retail Power Supply Costs, column g by dividing the PPFAC Retail Energy Sales in column a by the Total Native Load Energy Sales in column c, then multiply the product by the Net Native Load Power Supply Costs in column f.
4. On Lines 1 to 12, calculate the amount recovered via the Commission approved embedded base fuel and purchased power rate by multiplying the Retail Energy Sales in column a by the Commission approved Base Cost of Fuel and Purchased Power rate entered in the above column heading the result which is entered in column h.
5. On Lines 1 to 12, calculate the amount recovered via the Forward Component rate by multiplying said rate by the Retail Energy Sales in column a, the result which is entered in column i.
6. On lines 1 to 12, calculate the respective level of (Over)/Under Collection in column j by subtracting the Base Rate Power Supply Recovery and the Forward Component Recovery from the PPFAC Retail Power Supply Costs, columns g and h, respectively.

An interest rate, based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, is applied each month to the previous month's Tracking Account Balance. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the UNSE customer deposit rate.

The (Over)/Under Collection, the Interest and the prior month's Tracking Account Balance produce the current month's balance.

D. Schedule 4: PPFAC True-Up Component Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PPFAC-2 columns and then complete the following in each respective column:

1. On Line 1, enter the Forward Component Tracking Account Balance from Schedule 3, Line13, column i.
2. On Line 2, enter the True-Up Component Tracking Account Balance from Schedule 5, Line 8.
3. On Line 3, enter the sum of Lines 1, and 2 to arrive at the Total (Refundable)/Collection Amount Balance.
4. On Line 4, enter the respective Projected Energy Sales (MWh).
5. On Line 5, enter the Applicable True-Up Component rate by dividing Line 3 by Line 4.

Reflect notes as appropriate.

E. Schedule 5: True-Up Component Tracking Account

Enter the appropriate: effective dates for the PPFAC Prior True-Up Component being tracked:

On Line 8, for May and Line 1 for June, enter the True-Up Component balance as of June 1, 20XX. On Line 2, (Prior period PPFAC True-Up Component Calculation From Schedule 4, Line 4) for June enter any true-up for the use of prior period estimates, (i.e. prior estimated March, April and May True-Up Component rate application revenues to subsequent actual data), the sum of Lines 1 and 2, to reflect the Adjusted True-Up Component Beginning Balance as of June 1, 20XX.

Each month, the Applicable True-Up Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable True-Up Component rate. The revenue is subtracted from the Adjusted Beginning Balance.

Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the PPFAC Year.

Reflect notes as appropriate.

8. COMPLIANCE REPORTS

UNSE shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PPFAC. A UNSE Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PPFAC Rate Calculation (Schedule 1); Forward Component and True-Up Component Calculations (Schedules 2 and 4); Annual Forward Component and, True-Up Component Tracking Account Balances (Schedules 3 and 5). Additional information will provide other relative inputs and outputs such as:
    a. Total power and fuel costs.
    b. Customer sales in both MWh and thousands of dollars by customer class.
    c. Number of customers by customer class.
    d. A detailed listing of all items excluded from the PPFAC calculations.
    e. A detailed listing of any adjustments to the adjustor reports.
    f. Total off-system sales revenues.
    g. System losses in MW and MWh.

h. Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from UNSE for questions.

UNSE shall also provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports must be provided confidentially.

A. Information for each generating unit will include the following items:
   1. Net generation, in MWh per month, and 12 months cumulatively.
   2. Average heat rate, both monthly and 12-month average.
   3. Equivalent forced-outage rate, both monthly and 12-month average.
   4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
   5. Total fuel costs per month.
   6. The fuel cost per kWh per month.

B. Information on power purchases will include the following items per seller (information on economy interchange purchases may be aggregated):
   1. The quantity purchased in MWh.
   2. The demand purchased in MW to the extent specified in the contract.
   3. The total cost for demand to the extent specified in the contract.
   4. The total cost of energy.

C. Information on off-system sales will include the following items:
   1. An itemization of off-system sales margins per buyer.
   2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:
   1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
   2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.

E. UNSE will also provide:
   1. Monthly projections for the next 12-month period showing estimated (Over)/undercollected amounts.
   2. A summary of unplanned outage costs by resource type.
   3. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
   4. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate protective agreement. UNSE will keep

fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PPFAC within XX years of those costs being incurred. Any costs flowed through the PPFAC are subject to refund, if those costs are found to be imprudently incurred.

9. ALLOWABLE COSTS

A. Accounts

The allowable PPFAC costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PPFAC. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

B. Other Allowable Costs

In addition to the fuel and purchased power costs in the above mentioned FERC accounts, the following costs will also be recovered through the PPFAC:

- Energy procurement, scheduling and management fees allocated to UNSE from TEP.
- Credit costs necessary to support fuel and purchased power contracts
- Any and all federal and/or state carbon taxes applied to UNSE's generation or fuel and purchased power contracts
- Outside legal expenses incurred to litigate fuel and purchased power matters on behalf of UNSE's customers, such as pipeline and transmission rate cases and contract disputes
- Amortized interstate pipeline and electric transmission interconnection costs

UNS Electric, Inc.
Schedule 1
Purchased Power and Fuel Adjustment Clause (PPFAC) Rate Calculation Effective June 1, 20XX
($/kWh)

Line No.	PPFAC Rate Calculation		Current June 1, 20XX [1]	Proposed June 1, 20XX	Increase / (Decrease) $.000000/kWh	%
1	Forward Component Rate - FC (Sch. 2, L8)		$ -	$ -	$ -	0.00%
2	True Up Component Rate - HC (Sch. 4, L5)[2]		$ -	$ -	$ -	0.00%
3	PPFAC Rate June 1, 20XX and 20XX	(L1+L2+L8)	$ -	$ -	$ -	0.00%

Notes:

[1] See June 1, 20XX PPFAC Filing.

[2] A Historical Component is a true up related to respective prior period PPFAC activity.

UNS Electric, Inc.
Schedule 2
PPFAC Forward Component Rate Calculation Effective June 1, 20XX
($ in thousands; Forward Component Rate in $/kWh)

Line No.	PPFAC Forward Component Rate - Calculation	Current June 1, 20XX [1]	Proposed June 1, 20XX	Increase / (Decrease) $ Values	%
1	Projected Fuel and Purchased Power Costs	$ -	$ -	$ -	0.00%
2	Projected Off-System sales Revenue Credit[2]	$ -	$ -	$ -	0.00%
3	PPFAC Ajustments to Fuel and Purchased Power Costs3	$ -	$ -	$ -	0.00%
4	Net Fuel and Purchased Power Cost (L1 through L3)	$ -	$ -	$ -	0.00%
5	Projected Native Load sales (MWhs)	0	0	-	0.00%
6	Projected Average Net Fuel Costs $/kWh (L4/L5)	$ -	$ -	$ -	0.00%
7	Authorized Base Cost of Fuel and Purchased Power Rate $/kWh	$ -	$ -	$ -	0.00%
8	Forward Component Rate June 1, 20XX and 20XX $/kWh (L6 - L7)	$ -	$ -	$ -	0.00%

Notes:

[1] See June 1, 20XX PPFAC Filing.

[2] Off-System Sales revenues are credited at 90% as approved by the Commission in Decision No. xxxxx

[3] Includes mark-to-market accounting adjustments.

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

UNS Electric, Inc.
Schedule 3
Forward Component Tracking Account - (PPFAC Prior Forward Component Rate in effect from June 1, 20XX to May 31, 20XX
($ in thousands; Forward Component Rate and Base Rate in $/kWh)

Line No.	20XX Cycle Billing Month	(a) PPFAC Retail 1 Energy Sales (MWh)	(b) Wholesale [2] Native Load Energy Sales (MWh)	(c) Total Native Load Energy Sales (MWh)	(d) System [3] Book Fuel and Purchased Power Costs	(e) System Book[4] Off-System Sales Revenue	(f) Net Native Load Power Supply Costs	(g) PPFAC Retail Power Supply Costs	(h) Base Rate Power Supply Recovery	(i) Forward [6] Component Recovery	(j) (Over)/Under Collections	(k) Interest [5]	(l) Tracking [7] Account Balance
				(a + b)			(d - e)	(a/c*f)	(a*0.0XXXXX)	(a*0.00XXXX) (a*0.00XXXX)	(g - h - i)	(i * rate/12)	(j + k + l)
1	June	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	July	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	August	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	September	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	October	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	November	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	December	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	January	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	February	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	March	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	April	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	May	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Total	-	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Interest rate [5]		0.00%										

Notes:

[1] PPFAC Retail Energy Sales are the calender month's MWh sales. Cumulative Retail Energy Sales of XXXXXX MWhs under rate schedule XX were excluded from the PPFAC Calculations.

[2] Includes traditional sales-for-resale and supplemental sales.

[3] Includes native load and off-system fuel and purchased power and mark-to-market accounting adjustments.

[4] Includes off-system revenue at 100% per Decision xxxx less mark-to-market accounting adjustments.

[5] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15.

[6] Forward Component Rates $/kWh Effective June 1, 20XX to May 31, 20XX $ - June 1, 20XX to May 31, 20XX $ -

[7] Tracking Account Balance Line 13 carried to Schedule 4, Line 1.

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

UNS Electric, Inc.
Schedule 4
PPFAC True Up Component Rate Calculation Effective June 1, 20XX
($ in thousands; True Up Component Rate in $/kWh)

Line No.	PPFAC Historical Component Rate - Calculation	Current June 1, 20XX [1]	Proposed June 1, 20XX	Increase / (Decrease) $ Values	Increase / (Decrease) %
1	Forward Component Tracking Account Balance (From Schedule 3, L13, Cl L) [2,3]	$ -	$ -	$ -	0.00%
2	True Up Component Tracking Account Balance (From Schedule 5, L8) [4,5]	$ -	$ -	$ -	0.00%
3	Total True Up Amount to be (refunded)/Collected Balance (L1+L2) [6]	$ -	$ -	$ -	
4	Projected Native Load Sales (MWh)	0	0	-	0.00%
5	Applicable True Up Component Rate for Apr 1, 20XX & 20XX ($/kWh) (L3 / L4)	$ -	$ -	$ -	0.00%

Notes:

[1] See June 1, 20XX PPFAC Filing.

[2] Current Forward Component Tracking Account Balance as of December 31, 20XX.

[3] Includes interest for December, January and February

[4] Current Historical Component Tracking Account Balance as of March 31, 20XX.

[5] Because the actual amount of revenue to be received in March, April & May from application of the prior Applicable True Up Component is not available at the time of filing, Schedule 5 will reflect as necessary estimates for those periods as well as true-up calculations for the prior period estimates, See Schedule 5 for more detail.

[6] Beginning Balance as of June 1, 2010 - to be carried forward to subsequent period PPFAC, True Up Component Tracking account Balance, Schedule 5, L1.

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

UNS Electric, Inc.
Schedule 5
True Up Component Tracking Account - Prior PPFAC True Up Component Rate in Effect June 1, 20XX through May 31, 20XX
($ in thousands; Historical Component Rate in $/kWh)

Line No.		20XX Data									20XX data		20XX data		
		May	June	July	August	September	October	November	December	January	February	March	April	May
1a	TU Beginning Balance as of June 1, 20XX and thereafter.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1b	FC tracking Account Balance as of May 31, 20XX	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Revenue True-up from March-May Estimate [2]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	TU Adjusted Beginning Balance (L1 + L2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Applicable True Up Component Rate ($/kWh) [3]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Retail Billed Sales (MWhs)[4]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Less Revenue from Application TU (L4 x L5) [5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Monthly Interest (Line3 * Int Rate/12) [6]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	TU Ending Balance; (L3 - L6 + L7)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

[1] Beginning Balance as of April 1, 20XX - carried forward April 1, 20XX PPFAC Filing, Historical Component Calculation Schedule, Schedule 4, L2.

[2] True-up is the result of using estimated revenue for March through May since the actual amount was not available at the time of prior period PPFAC filing - No true-up since no rate applied in Prior April 20XX Filing.

[3] Historical Component, Prior Period PPFAC, Sch. 4, L5.

[4] Sales amounts are for energy billed beginning with the first billing cycle of April 20XX.

[5] Generally, Line 4 x Line 5 = Line 6; however, differences may occur due to billing adjustments.

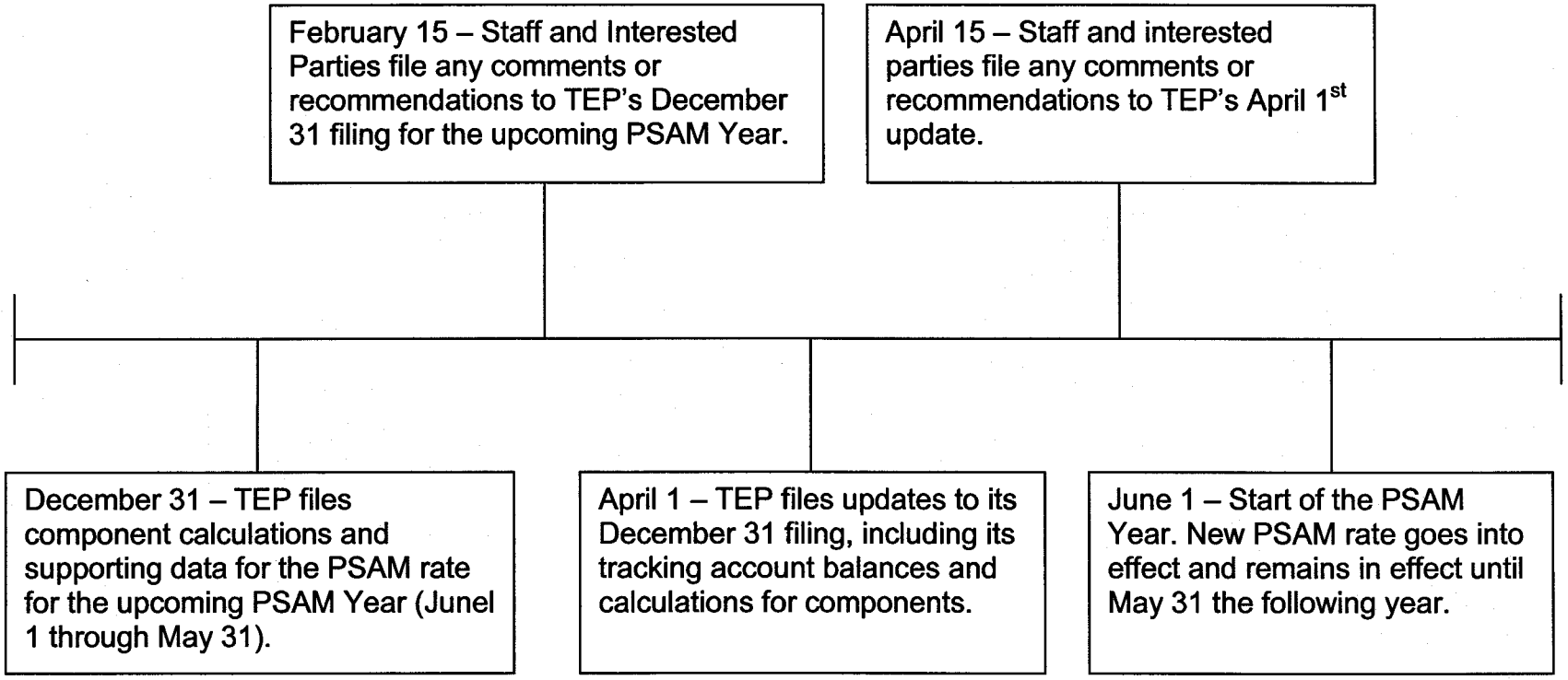
[6] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15. 0.00%

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

EXHIBIT

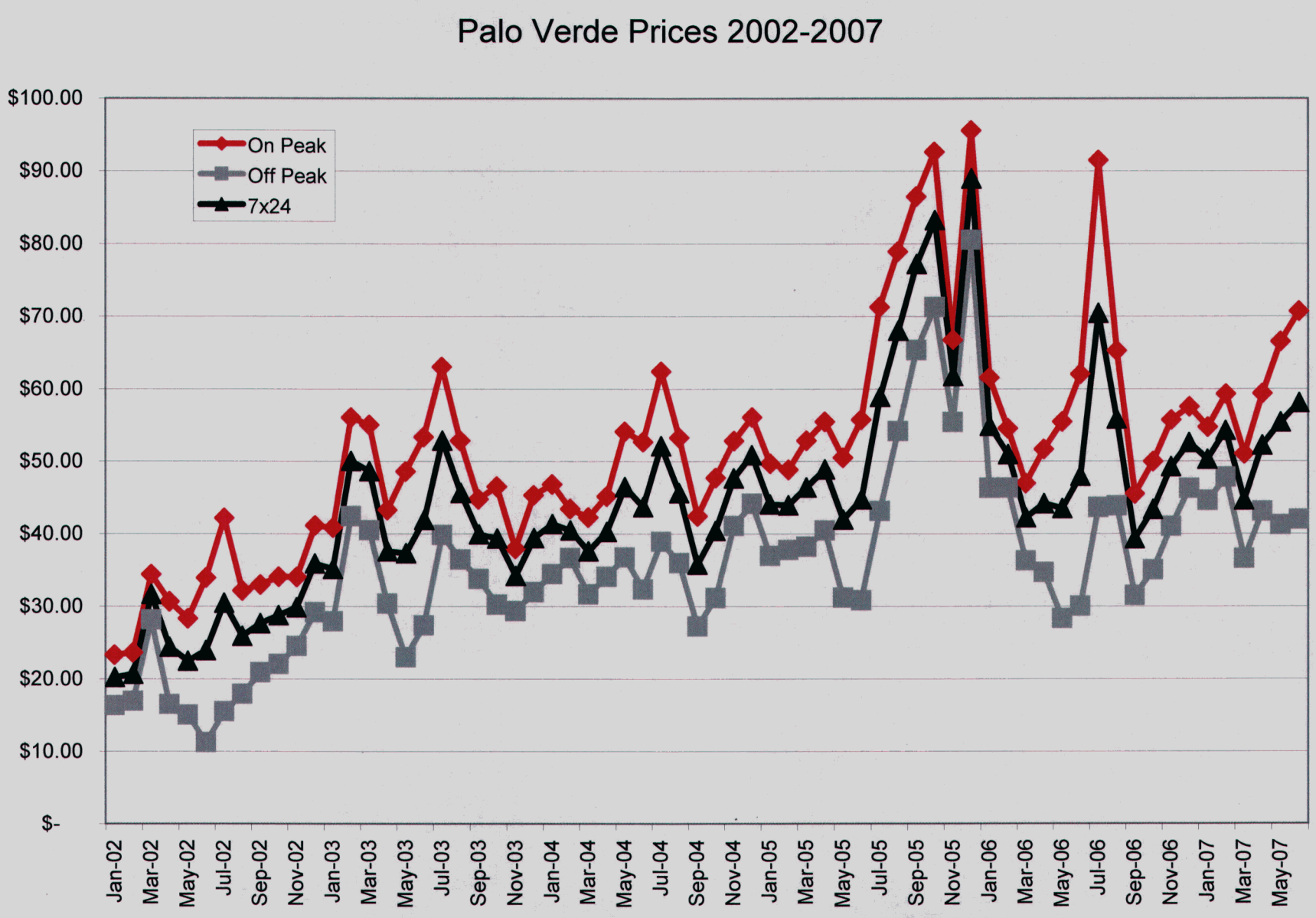
MJD-4

PURCHASED POWER & FUEL ADJUSTMENT CLAUSE TIMELINE



EXHIBIT

MJD-5


Palo Verde Prices 2002-2007
On Peak
Off Peak
7x24
$100.00
$90.00
$80.00
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04
Jul-04
Sep-04
Nov-04
Jan-05
Mar-05
May-05
Jul-05
Sep-05
Nov-05
Jan-06
Mar-06
May-06
Jul-06
Sep-06
Nov-06
Jan-07
Mar-07
May-07

Rebuttal Testimony
of
Edmond A. Beck

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-783

Rebuttal Testimony of

Edmond A. Beck

on Behalf of

UNS Electric, Inc.

August 14, 2007

Q. Please state your name and address.

A. My name is Edmond A. Beck. My business address is Tucson Electric Power Company ("TEP"), P.O. Box 711, Tucson, Arizona 85702.

Q. Are you the same Edmond A. Beck that filed Direct Testimony in this case?

A. Yes.

Q. Have you reviewed Marshall Magruder's Direct Testimony in this case?

A. Yes I have.

Q. Can you please give your overall impression of Mr. Magruder's Direct Testimony?

A. Mr. Magruder discusses at length issues related to reliability. The specific issues he raises are addressed in other dockets at the Commission. In fact, there has been extensive testimony and hearings on many of the issues he tries to – again – raise here. We do not believe that it is appropriate to try and re-litigate those issues in this rate case.

Q. Even so, are there any items within his reliability testimony you feel should be addressed in this case?

A. Yes, there are several items where Mr. Magruder's Direct Testimony is inaccurate. First, Mr. Magruder seems to indicate that UNS Electric rate base should not take into consideration expenses that were incurred by Citizens prior to UNS Electric taking control. This is incorrect. If infrastructure was installed to serve customers, whether by Citizens or by UNS Electric, the costs incurred should be considered as part of the rate base. Second, Mr. Magruder equates electrical load growth to population growth. His "equation" is inaccurate. While there is a correlation between the two – UNS Electric has experienced a larger increase in load than population growth. This is a common phenomenon that most

electric utilities experience. The use per customer ("UPC") has been growing in the recent past.

Third, Mr. Magruder may have experience with military use of turbines in the U.S. navy but this does not equate to electric utility operation of turbines. Electric utilities operate the equipment in a more controlled manner to reduce maintenance and extend service life. Also generation capabilities are based on various ratings. Nameplate ratings are the output at the terminals of a generator at a given elevation. There is an adjustment to output based on variations in elevation. Also, when a unit is installed in a plant auxiliary load should be subtracted from the adjusted nameplate rating to get a "nominal" capability. Auxiliary load includes the equipment required to operate the turbine such as pumps and fans. In a Navy installation aboard a ship a turbine is not exposed to the impacts of interconnection across a transmission grid that plays on role in the use of the turbines.

So, while Mr. Magruder may have experience with the general concepts regarding turbine operations, it is a far cry to then proclaim to have extensive expertise in how generation works within a transmission grid. It takes substantial time, training and actual experience working in the utility industry for someone to reach the point where he or she can "plan" transmission. None of Mr. Magruder's experience involves ensuring that utility customers receive reliable energy and planning generation, transmission and distribution that affects an interstate and regional grid.

Q. Does that conclude your Rebuttal Testimony?

A. Yes.

Rebuttal Testimony
of
D. Bentley Erdwurm

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783

Rebuttal Testimony of

D. Bentley Erdwurm

on Behalf of

UNS Electric, Inc.

August 14, 2007

TABLE OF CONTENTS

I. Introduction 1

1. Customer Charges 2
2. Purchased Power Allocation 6
3. Inclining Block Rates (Inverted Block) 9
4. Super-Peak Time-of-Use / Alternative Design 11
5. Mandatory TOU 12
6. Large Power Service Demand Charge for less than 69 kv 14
7. Systemwide Rates (Santa Cruz and Mohave) 15
8. CARES and Medical Cares 15
9. Miscellaneous Service Fees 17

Exhibits:

Exhibits DBE-2 Response to Staff Data Request 16.3

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is D. Bentley Erdwurm. My business address is One South Church Avenue, Tucson, AZ 85701.

Q. Are you the same D. Bentley Erdwurm who filed Direct Testimony in this case?

A. Yes.

Q. What is the Purpose of your rebuttal testimony?

This testimony:

1. Corrects an inadvertent error in the classification of transformer costs, which leads to a lowering of proposed customer charges;
2. Switches the allocation of purchased power from 100% average and peaks, to a mix of average and peaks and energy;
3. Supports the conservation-oriented inclining block structure for residential and smaller commercial customers;
4. Supports the "super-peak" approach to time-of-use rate design, and offers an alternative to shave one hour off the winter evening peak;
5. Supports the proposed requirement that time-of-use be mandatory for new and moving residential and small commercial time of use customers, and mandatory for all larger commercial and industrial customers;
6. Supports lowering the Large Power Service demand charges on customers receiving service at less than 69 kV;
7. Supports combining Santa Cruz and Mohave rates;
8. Proposes to retain the Medical CARES program as separate from the general CARES program; and

9. Supports the Company's position on miscellaneous service fees.

1. Customer Charges.

Q. Do you desire to amend your customer charge recommendations in this case?

A. Yes. In the class cost-of-service study filed with the Company's direct case, transformers were inadvertently classified as a customer-related cost. This was a mistake; transformers should have been classified as a demand-related cost, rather than a customer related cost. The Company intended to set customer charges at cost-based levels using a "bare-bones" approach. By "bare-bones", I mean a customer charge covering only the costs for metering, meter-reading, billing, and the service drop. The Company has recalculated residential and small commercial customer charges using the bare-bones approach as shown in the following table:

	Cost from **Direct Test.**	Direct Testimony. **Cust. Charge**	Cost **As amended**	Adjusted **Cust. Charge**
Residential	$12.63	$ 8.00	$ 7.71	$ 7.70
Sm. Gen. Service	$17.74	$12.00	$12.25	$12.00 (no charge from direct)

UNS Electric notes that reductions in proposed customer charges will necessitate increases in energy charges ($/kWh) to maintain full revenue recovery.

Q. Did Staff and RUCO address the customer classification issue in their respective Direct Testimonies?

A. Yes. Ms. Marylee Diaz Cortez for RUCO – in her Direct Rate Design Testimony on page 3 at lines 11 through 13 – states that she did not agree that a portion of the current commodity charge should be shifted to the fixed monthly minimum. But Staff witness Frank W. Radigan – in his Direct Testimony on page 16 at lines 7 through 24 – states that

"while the CCOSS (class cost of service study) presented by the Company does justify the increase in the customer charge proposed for most service classifications, it should also be noted that a large portion of the costs allocated to the customer component is for line transformers." Given that Mr. Radigan thought that the Company was attempting to estimate a customer component of distribution plant often classified as non-coincident peak and demand-related, he suggested that in future cases the Company should – at least for comparative purposes – apply what is typically called the "zero intercept method" (Mr. Radigan refers to it as the "minimum intercept method" in his Direct Testimony) for calculating customer components.

Mr. Radigan further notes – in his Direct Testimony on page 16 at lines 9 through 14 – that the "1992 NARUC Electric Utility Cost Allocation Manual recognizes that there are various ways to allocate the distribution costs between a demand component and a customer component and it believes that the most accurate method is the use of the minimum intercept method. Under the minimum intercept method, a regression calculation is performed to determine the amount of equipment necessary to just supply service to a customer that uses no power. The zero intercept method gives the percent breakdown of costs that should be classified as customer costs."

The recalculated customer charges in the table above are based on the bare-bones method, which was the originally-intended approach. In the future filings, however, the Company also will present the results of the zero intercept – which Mr. Radigan refers to as the minimum intercept method – for comparative purposes.

Q. Please briefly discuss the zero intercept and minimum system methods.

A. Mr. Radigan gave a brief description of the zero intercept method in his Direct Testimony. As mentioned, a regression line is used; the cost to serve a "hypothetical" customer using

no power is estimated as the "y" value (y is the dependent variable "cost to serve") corresponding to an "x" value of zero (x is the independent variable "customer size based on usage"). Mr. Radigan correctly notes that this theoretical approach does have support. Critics of the zero intercept approach point out that it pushes the limits of the regression technique. Typically, regression estimates are most accurate near the "center" of the observed data. When one moves to cases of customers with no usage – well below the minimum usage level seen in actual data – ones expectation of accuracy falls since none of the "real" data is close to the "what-if" scenario. To rectify this problem, some analysts use a "minimum system" approach to estimate customer-related costs. Analysts supporting the minimum system inquire as to what is the smallest capacity system that can be built with materials commercially available today. This small system cannot be scaled back further if usage falls. We can say, therefore, that the cost to build the minimum system is all customer-related.

Q. Why did you base the corrected customer charges on the "bare bones" approach?

A. I wanted to be consistent with past Commission precedent for Tucson Electric Power Company ("TEP"), another UniSource Energy Corporation ("UniSource Energy") affiliate. "Bare-bones" has been a workable approach for TEP since the early 1990's. For TEP, the bare-bones approach isolates a very select and limited group of costs which almost all parties agree are customer-related fixed costs (*i.e.*, metering, meter reading, billing and the service drop), and recovers these costs through fixed monthly customer charges. Arguments over "gray-area" issues (*e.g.*, whether part of the distribution system is customer-related) are avoided, and time can be devoted to other issues in the case. An added "bonus" of the bare-bones approach is that under rate unbundling for direct access, three of the customer charge components (*i.e.*, metering, meter reading, and billing) may be provided by third party providers. Companies using the bare-bones approach are well-prepared to present unbundled rate components, since these calculations are all part of the

bare-bones "workpapers".

Second, the "bare-bones" approach produces some of the lowest monthly customer charges of any standard approach. This elicits an initial positive reaction from many customers, who often – and incorrectly – view the customer charge as a "payment for nothing", and from the Commission, which has historically been more than willing to keep this visible and easy-to-describe charge low. Moreover, holding the line on customer charges helps mitigate percentage increases to the small low-use customers, which helps encourage reduced consumption.

Keep in mind, however, that lower customer charges are not always "better" from the standpoint of matching cost to revenues. Making sure costs and revenues match should always be the paramount goal in rate design. But the "bare-bones" customer charge has worked for TEP in the past. In the recent TEP case filed in July 2007, I also proposed "bare-bones" customer charges. For TEP, historically there has been enough revenue stability under "bare-bones" rate design to insure that fixed costs are covered with both higher than normal and lower than normal actual usage. Based on the particulars in this case, I have no reason to believe that the "bare-bones" customer charge approach will not work for UNS Electric, another Arizona electricity distributor serving primarily low desert communities and our sister electric company under UniSource Energy.

Q. You state that matching cost and revenues is the key goal in rate design. Can this be in conflict with the "bare-bones" approach?

A. Yes. In the UNS Gas case filed in 2006, I discussed the advantages of customer charges that exceeded "bare-bones" charges. In the UNS Gas case, I argued that there was a disconnect between distribution costs and usage levels; within a class, distribution cost to serve was not necessarily correlated with gas usage. Location within the system was often

more relevant to distribution costs. In the UNS Gas case, holding customer charges at low levels would have resulted in relatively high volumetric charges. High-use customers within a class would therefore be paying more than their cost to serve. In the UNS Gas case, I noted that Flagstaff gas customers often subsidize low-use, low desert gas customers. This is inequitable, and part of why I said that lower customer charges are not always best. The specifics of each case must be examined to determine the best way to set customer charges.

2. <u>Purchased Power Allocation (Average And Peaks V. Energy).</u>

Q. Does Mr. Radigan question the use of average and peaks for allocating Purchased Power (Accounts 555 and 565)?

A. Yes. In the initial filing, Accounts 555 and 565 were allocated on the basis of average and peaks. Mr. Radigan discusses the effect on cost allocation and class rates of return of changing this allocation to energy. Specifically in his Direct Testimony from page 6 at line 24 through page 7 at line 7 – Mr. Radigan indicates that more study of the Company's purchased power cost could help in choosing a best allocation method. Given what Mr. Radigan perceives are unresolved issues in the class costs of service study, he recommends that the study not serve as a basis for the proposed revenue increase by class.

Q. Please comment on the issues raised by Mr. Radigan with respect to Purchased Power

A. If UNS Electric had the facilities such that it could generate its own power requirements, a portion of production costs – including return on net generation plant and the associated income tax, property taxes related to production plant, and non-fuel O&M expenses – would then be allocated on average and peak and fuel would have been allocated on energy. If the portions were based on TEP, then 50% of production cost ("capacity") would be based on average and peaks and 50% of production costs ("fuel") would be based

on energy. I believe TEP's 50%/50% split in production cost between capacity and fuel is at least close to the capacity/fuel split of a hypothetical system that would serve UNS Electric. This is because both TEP and UNS Electric service territories have similar weather characteristics and somewhat similar system load factors. But to the extent that UNS Electric system actually has a slightly lower system load factor than TEP, I would expect more peaking plants and fewer baseload plants than if the load factor matched the TEP load factor. A lower load factor system would therefore result in lower capacity-related costs (per kWh) and higher fuel costs (per kWh). This means that the "capacity" portion to be allocated based on average and peaks would be less than the 50% applicable to TEP.

Q. Do you desire to amend your allocation approach for Purchased Power?

A. Given that the UNS Electric system does have a lower load factor than TEP, and less (as a percentage) of the type of high load factor industrial load that is found in the TEP service territory, I proposed the future use of a purchase power allocation factor that is 40% average and peaks and 60% energy. This factor will apply to Accounts 555 and 565, and represents a change in allocation from 100% average and peaks, as filed. The 40% "capacity", 60% "fuel" assumption is not based on a specific study, but is instead an attempt to "fine-tune" the approach presented in my Direct Testimony.

Q. Does this change affect the base rate fuel component allocation?

A. Yes. The base rate fuel component will decrease for relatively lower load factor classes, and increase for higher load factor classes. The total recovered through the component is unaffected. For example, the residential component as filed was $0.077178. The recalculated number based on the revised allocation is $0.073771, a 4.4% decrease.

Q. Allocating purchased power on 100% energy was another option you could have chosen. Why did you choose in your Direct Testimony 100% average and peaks instead of 100% energy?

A. The use of average and peaks recognizes the importance of both demand and energy (*i.e.*, load factor) when determining the costs to serve customers. Customers who are lower load factor – that is require relatively large power requirements for short duration – typically pay a higher price per kWh. This follows from simple microeconomic theory because a fixed (capacity) cost is spread over relatively few kWh. That is, average fixed costs rise as sales decrease (or conversely, average fixed costs decline as sales increase). For example, assume that $1.44 in monthly fixed cost must be collected from each of two customers, Customer A and Customer B, on a volumetric basis. Further assume that A is a 1 kW 100% load factor customer using 720 kWh in a 30-day month. B is a 1 kW 10% load factor customer using 72 kWh in a 30-day month. The volumetric charge applicable to A would be 2 mils ($0.002) per kWh, while the volumetric charge for B would be 2 cents ($0.020) per kWh. The volumetric charge for the high load factor customer A is only one-tenth the charge applicable to the low-load factor customer B.

Q. Mr. Radigan says your "theory" is out of touch with today's purchased power markets. Do you agree?

A. No. Mr. Radigan uses an overly simplistic argument that UNS Electric currently buys power from Pinnacle West Capital Corporation ("PWCC") on a volumetric basis at a fixed price per MWh. This is not inconsistent with my claim that the average price of purchased power is influenced by load factor. When PWCC agreed to sell power to UNE Electric, PWCC was well aware of UNS Electric's load characteristics. Had PWCC been selling a 100% load factor block of power with the same level of peak demand, the average price of this high-load factor block would likely have been lower than the average price of the UNS Electric purchased power. In other words, the fixed price per MWh is likely determined by

looking at the overall load factor for the service area UNS Electric now serves. The fact that today's marketplace is deregulated – as Mr. Radigan indicates in his Direct Testimony on page 5 at lines 9 through 10 – only makes me more comfortable in my assertion that the high-load-factor block should be priced at a lower level. This is because as markets become more competitive, prices tend to be driven closer to long-run average costs of providing the service, and high-load factor service is less expensive to provide since average fixed costs decline as sales increase (*i.e.*, as the load factor increases the valleys (times with lower usage) are "filled in".)

3. <u>Inclining (Inverted) Block Rate Structure.</u>

Q. Have Staff and RUCO supported the implementation of your proposed tiered inverted (*i.e.*, inclining) block structure?

A. RUCO supports immediate implementation of the inverted block structure. Ms. Diaz Cortez noted that UNS Electric currently has a flat-rate structure for residential and small commercial customers, and that UNS Electric's proposed rate structure would send a stronger price signal based on the higher unit price beyond a set kWh level (*e.g.*, 400 kWh for residential customers.)

Mr. Frank Radigan for Staff agrees with the inverted block concept in principle. Unfortunately, Mr. Radigan recommends against implementation in this case. This is because – as he states in his Direct Testimony on page 13 at lines 13 through 14 – "of the relatively small recommended rate increase and the increases in the customer charge." Mr. Radigan's argument and Staff's position is very puzzling, because of Staff's recommendations for tiered-inverted-block rate structures for other utilities. For instance, in Decision No. 67093 (June 30, 2004), regarding several Arizona American Water Company ("AAWC") districts, the Commission adopted Staff's recommendation for a

tiered-inverted-block rate design because it believed such encouraged water conservation.[1] The Commission maintained the inverted-block rate design for AAWC's Paradise Valley district in Decision No. 68858 (June 28, 2006). The Commission also approved Staff's tiered-inverted-block rate design for Arizona Water Company's Western Group in Decision No. 68302 (November 14, 2005).[2] We have taken the desire for inverted block rate structure to heart and propose a conservation-oriented rate design while mindful of the need for revenue stability and foregoing any request for any type of "elasticity adjustment." But now Staff appears to have changed its tune somewhat. The fact that this is an electric rate case does not mean a tiered-inverted-block rate structure cannot be implemented. If conservation is an important goal to the Commission, then Mr. Radigan's argument seems to be against policy.

Consequently, I was taken aback by Mr. Radigan's reasoning against implementing a tiered-inverted-block rate design for UNS Electric. Further, Mr. Radigan frets over a customer charge increase coupled with a first block (1st 500 kWh) energy charge decrease because, for example, the percentage increase for a no-usage bill would be larger than the percentage increase for a low-use, first block bill (e.g., a 350 kWh/month bill), but may be smaller than the increase for a high-use, upper block bill (e.g., a 4,000 kWh/month bill). But customers face varying percentage increases – depending on usage – for other utilities. I do not think our customers will be too traumatized by some variation in percentage increases. The inverted block rate is a good rate design change for UNS Electric, and I believe that most stakeholders can handle the pro-conservation change for the better.

In addition, I am typically more concerned about rate design changes when the overall increase is relatively high, given that some customers will be affected by an increase

[1] Page 42 and Finding of Fact No. 53.
[2] Pages 40 through 43 and Finding of Fact No. 40.

associated with the rate design change as well as a share of the large overall increase. This "compounded increase" can create the type of rate shock that should be of concern to all involved. Given that Mr. Radigan has characterized the Company's overall increase as relatively small, the Commission should also approve consolidating rates for Mohave and Santa Cruz County, which was supported by RUCO and "praised but postponed" by Mr. Radigan.

4. <u>"Super-Peak" Time-of-Use; Alternative Rate Design.</u>

Q. Do RUCO and Staff support the TOU periods you have chosen?

A. Yes. I believe it's fair to say the Company, RUCO, and Staff support the type of super-peak rates (limited number of on-peak hours) as proposed in the UNS Electric case. Based on a Staff data request attached as Exhibit DBE-2, there seems to be some interest in shortening the winter evening peak period. The Company would not object to moving the hour from 5 p.m. to 6 p.m. to the off-peak period. The winter evening peak period would then be 6 p.m. to 9 p.m.

Q. The data request from Staff asked to see a rate design with the last two hours (7 p.m. to 9 p.m.) removed from the winter evening peak. Would this be acceptable to the Company?

A. No. That rate design is a recipe for disaster, as it could create an intensified peak at the conclusion of the on-peak period. Many residential customers' loads are actually peaking at 7:00 p.m. To switch from "peak" to "off-peak" at this moment could encourage load spiking, as hundreds of heating systems switch on over a period of minutes. Even if the system as a whole does not reach a daily peak, certain "pockets" of the distribution system (especially those containing a large percentage of "late-peaking" residential customers) could reach a localized peak. Higher localized peaks could result in more distribution

spending.

5. <u>Mandatory Time-of-Use.</u>

Q. Do Staff and RUCO support UNS Electric's mandatory time-of-use proposal?

A. RUCO supports implementing mandatory TOU for new and moving residential and smaller commercial customers. Ms. Diaz Cortez noted that UNS Electric needs to start from "ground zero" because UNS Electric does not currently have TOU rates.

Staff witness Mr. Radigan – in another puzzling position – is against mandatory TOU rates and questions the cost effectiveness of time-of-use for these customers because of metering costs.

Q. Mr. Radigan – in his Direct Testimony from page 8 line 21 through page 9 line 26 – discusses how the cost for a new TOU meter outweighs the benefit some customers would enjoy with TOU rates. Do you agree?

A. I do not agree with Mr. Radigan's conclusions, though he does make a valid point about the need to consider cost-benefit analyses. He views the issue from a short-run perspective, and reaches a predictable, anti-conservation conclusion. At present, there is a positive cost differential between a non-TOU meter and a TOU meter. Mr. Radigan correctly points out that the meter premium (he appears to have used the full meter cost instead of the differential between TOU and non-TOU.) can be multiplied by a carrying charge factor (also known as a fixed charge rate ("FCR") or a capital recovery factor ("CRF")) like 15% to annualize the TOU premium. So, considering only short term costs and benefits, it may be difficult for customers to shift enough energy from peak to fully justify TOU from a pure cost perspective. Mr. Radigan's analysis notwithstanding, his conclusion is flawed because metering is moving toward full time-of-use functionality and

communications capabilities. Prudency requires Mr. Radigan to take into account these intermediate term technology improvements. As the cost of storing information falls exponentially, the cost differential between time-of-use and non-time-of-use disappears. There will be no such thing as a non-time-of-use meter. Radigan's argument against mandatory time-of-use quickly collapses.

Q. So, you still support mandatory TOU for new and moving residential and small commercial customers, or any TOU for smaller residential and small commercial customers?

A. Yes, because I look at the problem from a long-term perspective. With technology improvements and the expansion of smart metering, the cost-differential between a meter with TOU capabilities and non-TOU meters will disappear – for the simple reason that all meters will be TOU capable. Non-TOU meters will eventually go the way of the black and white television; they will become extinct.

In the meantime, I do not want to segment our customers into those for which TOU is available, and those we will not offer it to. That certainly does not seem to be sound policy. UNS Electric, and UniSource Energy's other electric utility, TEP are both trying to expand acceptance of TOU. For the interim period and until the cost differential disappears, we must be content that there may be some cross subsidies among customers. But some subsidization already exists between customer classes, so this factor should not be an impenetrable barrier to implementing TOU rates.

Q. Has the Commission previously taken a longer run view with respect to issues involving conservation, demand side management, and renewables?

A. Yes. Clearly, Decision No. 69127 (November 14, 2006) that approved the Renewable Energy Standard and Tariff ("RES") Rules is a classic example of the Commission taking a

long-term view at promoting renewables, even when not economical in the short-term. We propose that the same type of longer-term view apply to implantation of the Company's TOU proposals.

6. Large Power Service Demand Charges - Less Than 69 kV.

Q. In your Direct Testimony, why did you propose a lower demand charge for large commercial and industrial service less than 69 kV?

A. The differential in demand charges for service over 69 kV and under 69 kV is too high. I have done no study to determine a more exact differential for UNS Electric; however, for Arizona Public Service Company, an analogous differential is around $4.72 per kW-month (see APS' E-34, page 1 of 4, delivery charge differential secondary to transmission), as opposed to the large $8.65 ($24.75-$16.10) per kW month differential that currently exists for UNS Electric. The differential represents the cost for the Company to provide the transformation services to reduce voltage levels. While I do not know, absent a study, how the APS cost of transformation compares to the UNS Electric cost of transformation, I have no reason to believe it would vary by more than 50%. Even increasing APS' $4.72 per kW-month by 50% would support a differential of no more than $7.08.

Q. Mr. Radigan for Staff opposes your proposal for a lower demand charge for large commercial and industrial service less than 69 kV. Please discuss.

A. Mr. Radigan's concerns are understandable. Even though I was unable to provide results from a specific study in response to Mr. Radigan's data requests, I hope that Staff reconsiders its position in light of my answer above. Given the size of the current differential, the rate design change would probably need to be accomplished over two cases. The $8.65 differential could be narrowed to $7.00 now, which would still provide an opportunity for a refinement based a specific study in a future case.

Q. Is there a practical reason to lower the demand charge for customers less than 69 kV?

A. Yes. The current design imposes significant costs on low-load factor customers. There is no cost-justification for this.

7. <u>Combining Santa Cruz and Mohave Rates.</u>

Q. Have Staff and RUCO supported the Company's proposal to combine the Santa Cruz and Mohave rates?

A. RUCO and Ms. Diaz Cortez support the Company's proposal to combine rates in this case. Unfortunately, Staff and Mr. Radigan balk at implementing a beneficial proposal. Mr. Radigan opposes consolidation here, but supports it in general, which makes little sense. It is another puzzling position in a series of puzzling positions Staff and Mr. Radigan take in this case. Mr. Radigan's hypersensitivity to change runs counter to the public interest – and is particularly odd because Mr. Radigan has already conceded that the overall increase is relatively small. This is the opportune time to implement UNS Electric's proposal, which provides a distinct benefit to Santa Cruz County customers with little, if any, noticeable impact to Mohave County customers. Maintaining the status quo is certainly not in the public interest, since it perpetrates an inequity that could easily be eliminated.

8. <u>Cares and Medical Cares.</u>

Q. Do you wish to expand your proposals for the CARES program?

A. Yes. Currently, CARES and Medical CARES are offered as separate programs. In my Direct Testimony, I proposed simplifying the programs such that no distinction would be made between CARES and Medical CARES. The Company has reconsidered this position, and concluded that customers with medical needs should receive a somewhat larger discount. The small incremental administrative effort to provide the separate

Medical CARES program is justified by the positive impact we can have on our lower-income customers with medical needs.

Q. How do you propose to differentiate the Medical CARES program from CARES?

A. I propose a $10.00 per-month discount for Medical CARES, as opposed to the $8.00 per-month discount proposed for CARES generally. This additional discount will approximately maintain the incremental discount that Medical CARES customers currently receive in excess of CARES customers generally. I propose that both CARES and Medical CARES be flat discounts unrelated to usage.

Q. What happens under your proposal if the $8.00 CARES or $10.00 Medical CARES discount exceeds the monthly bill?

A. In this circumstance, the discount is limited to the monthly bill; the monthly bill is never made negative by the discount. Therefore, it is more precise to characterize the Company's proposed discount for CARES as the lesser of $8.00 or the monthly bill, and the proposed discount for Medical CARES as the lesser of $10.00 or the monthly bill.

Q. Has RUCO supported your position on flat discounts, as opposed to usage-based discounts for CARES?

A. Yes. Ms. Diaz Cortez for RUCO realizes that it is good public policy to decouple receipt of a low-income discount from usage. Requiring a low-income customer to use more energy in order to receive a needed discount is an anachronism ready for immediate phase-out.

9. Miscellaneous Service Fees.

Q. How did you determine the proposed service fees that you supported in your direct testimony?

A. The fees generally were cost-based. In some cases however, fee increases were reduced in the interest of gradualism, and the proposed fee fell short of the cost-based fee.

Q. In their respective Direct Testimonies, do Staff and RUCO support the Company's proposed limited fee increases, or do they support the full cost-based fees?

A. Staff supported the limited fee increases, but RUCO proposed increasing service fees to match actual cost-of-service,

Q. Since RUCO supports higher cost-of-service based fees, is the Company seeking to amend its service fee proposal?

A. No. The Company will stick to its original proposal in the interest of gradualism. From the Company's standpoint, changing the fee structure is a zero-sum game. UNS Electric neither gains nor loses when the fees are reset during the context of a rate case. Fees are an "other revenue item." Increasing the fees while holding all other items constant, requires reducing sales revenue to hold total revenue at the required level. At issue is fairness in how costs are split out among customers. Ms. Diaz Cortez states – in her Direct Testimony on page 21 at lines 2 through 12 – that "these services should be priced at their actual cost. If they are not, it will have the effect of having the general body of ratepayers subsidizing the customers who utilize these services."

Q. Do you share Ms Diaz Cortez's concern regarding unfair cross subsidies among customers?

A. Yes. I share her concerns about cross subsidies, and I agree that ideally fees should be set

at cost. However, I believe that the Company's fee proposals are the appropriate step in this case. Fees are either at cost or moving toward cost. The largest increases can be implemented over two general rate cases. Full cost-of-service fees will be proposed in the next general rate case.

Q. Though you favor the Company's original proposal, would you object to moving to fully cost based fees now as RUCO proposes?

A. No. The Company could live with either approach.

Q. Does this conclude your Rebuttal Testimony?

A. Yes it does.

EXHIBIT

DBE-2

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S SIXTEENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
July 13, 2007

UNS Witness D. Bentley Erdwurm (CCOSS and Rate Design)

STF 16.3 How would the TOU rates proposed by the Company change if the TOU periods for the Winter Billing Months on-peak would run from 6:00 a.m. - 10:00 a.m. and from 5:00 p.m. to 7:00 p.m. (7:00 p.m. – 9:00 p.m. would be off-peak)?

a. If exact amounts are not known, provide the Company's best estimates and show in detail how such estimates were calculated.

RESPONSE: This analysis was not prepared in the rate case, and is not readily available. However, UNS Electric will provide the response to this data request as soon as the compilation is complete. The Company does wish to note, however, that a design with this specific two-hour winter peak evening period (i.e., without the hours ending 8:00 p.m. and 9:00 p.m.) is flawed for the reasons discussed in response to STF 16.2 (load spikes), and the Company would oppose the approval of this specific design. The design could actually result in the creation of a new peak demand at the beginning of the off-peak period. Moreover, it would be contrary to the distribution considerations discussed in STF 16.2. A more attractive alternative is to either eliminate the evening winter peak period (and only have a morning peak period), or shave an hour off the beginning of the evening peak period (i.e., the hour ending at 6:00 p.m.; the winter evening peak period would run from 6:00 p.m. – 9:00 p.m.). The Company would not oppose a three-hour winter peak evening period with a peak from 6:00 p.m. – 9:00 p.m.. The Company will also include this design for the residential class in the analysis to be submitted when completed.

RESPONDENT: Bentley Erdwurm

WITNESS: Bentley Erdwurm

SUPPLEMENTAL RESPONSE: In this Supplemental Response, the Company will refer to the Staff's rate design absent the last two hours of the peak period as "Design A". "Design B" is the three hour winter evening peak absent 5:00 p.m. to 6:00 p.m. As indicated in the initial Response to this data request, the Company believes Staff's Design A is flawed and opposes its implementation. The design differences are reflected in the Differentials on the filed tariff sheets.

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S SIXTEENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
July 6, 2007

As filed, the winter on-peak Differential is +$0.00288 and the winter off-peak Differential is -$0.01212. These Differentials reflect a 1.5 cent spread between on- and off-peak.

With Design A and a 1.5 cent spread between on- and off-peak, the winter on-peak Differential is +$0.00454 and the winter off-peak Differential is -$0.01046.

With Design B and a 1.5 cent spread between on- and off-peak, the winter on-peak Differential is +$0.00358 and the winter off-peak Differential is -$0.01142.

With Design A and a 2 cent spread between on- and off-peak, the winter on-peak Differential is +$0.00811 and the winter off-peak Differential is -$0.01189.

With Design B and a 2 cent spread between on- and off-peak, the winter on-peak Differential is +$0.00684 and the winter off-peak Differential is -$0.01316.

The Company has offered designs with both 1.5 cent and 2 cent spreads to reflect the fact that there are fewer on-peak hours in Designs A and B (i.e., seven winter on-peak hours as opposed to eight winter on-peak hours as filed). The Company believes that Design B is a very acceptable alternative to its filed rate, and it would not oppose the elimination of the 5:00 p.m. to 6:00 p.m. hour from the winter on-peak. Please see STF 16.3 on the enclosed CD for detail. The Excel spreadsheet on the enclosed CD is <u>not</u> identified by Bates numbers.

RESPONDENT: Bentley Erdwurm

WITNESS: Bentley Erdwurm

Rebuttal Testimony
of
Denise A. Smith

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783

Rebuttal Testimony of

Denise Smith

on Behalf of

UNS Electric, Inc.

August 14, 2007

TABLE OF CONTENTS

I. Introduction 1

II. Demand-Side Management 3

A. Explanation of New DSM Portfolio Filing 3

B. Response to Mr. Magruder's Direct Testimony 7

1. Citizens Advisory Council 7
2. Similar Comments Shown on Multiple DSM Programs 7
3. Education and Outreach 10
4. Direct Load Control 13
5. Low-Income Weatherization 17
6. Energy Smart Home 17
7. Residential HVAC Program 18
8. Shade Tree Program 20
9. Commercial Facilities Efficiency Program 21

C. Response to Staff Witness Jerry Anderson's Direct Testimony 21

D. Response to RUCO Witness Marylee Diaz Cortez's Direct Testimony 22

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Denise A. Smith. My business address is 4350 E. Irvington Road, Tucson, Arizona.

Q. What is your employment position?

A. I am the Director of Conservation and Renewable Programs at Tucson Electric Power Company ("TEP"), UNS Gas, Inc. ("UNS Gas") and UNS Electric, Inc ("UNS Electric" or the "Company"), collectively referred to as the "UniSource Energy Companies".

Q. Please describe your education and professional background.

A. I graduated from Northern Arizona University ("NAU") in 1991 earning a Bachelor of Science degree in Mathematics with an extended major in Statistics and then completed graduate work in Statistics at NAU. During my tenure at TEP, I completed a Masters of Business Administration at the University of Phoenix. After leaving NAU, I was hired by Pima Association of Governments in 1992 in the Travel Reduction Program, which reduces vehicle emissions by targeting major employers to reduce employee's travel to and from work.

I was hired in 1996 by TEP as a Demand-Side Management ("DSM") Analyst, developing, analyzing and researching new DSM and energy-related market programs. In addition, I implemented and reported progress of existing DSM programs and then transitioned them into market-transformation programs. In 1999, I moved into the Pricing and Rates Department, developing cost of service and revenue requirement models. In 2002, I was promoted to the Director of the Pricing and Rates Department. I then accepted the position of Director of Conservation Services. Most recently my position was expanded to include

Renewable Programs. I manage the successful TEP Guarantee Home Program and, for the past year, have been researching and developing new DSM programs for all three UniSource Energy Companies.

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

A. My Rebuttal Testimony is filed on behalf of UNS Electric.

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

A. The purpose of my Rebuttal Testimony is to respond to certain recommendations made by Mr. Marshall Magruder, RUCO and Commission Staff with regard to DSM matters.

Q. Did you file Direct Testimony in this proceeding?

A. No, I did not. However, due to my close involvement in the proposal, analysis, monitoring and reporting of DSM programs for UNS Electric, I was asked to respond to Intervenors' Direct Testimony regarding DSM matters.

Q. Please summarize your Rebuttal Testimony.

A. My Rebuttal Testimony focuses on Mr. Magruder's recommendations about the DSM programs themselves. For ease of review, my Rebuttal Testimony tracks Mr. Magruder's Direct Testimony on these issues. There are several areas where Mr. Magruder is incorrect and inaccurate, while also contradicting what Staff recommended in its DSM Report issued February 7, 2005 in Docket No. E-00000-02-0051 (hereinafter "Staff DSM Report").

In general, UNS Electric agrees with Staff's and RUCO's recommendations about DSM. However, UNS Electric is requesting that a few of Staff's and RUCO's recommendations be modified. I discuss those requested modifications in more detail later in my Rebuttal Testimony.

II. DEMAND-SIDE MANAGEMENT.

A. Explanation of New DSM Portfolio Filing.

Q. Is UNS Electric asking for approval of DSM Programs in this docket?

A. No. UNS Electric was advised by Arizona Corporation Commission ("Commission") Staff during the UNS Gas Rate Case proceeding (Docket No. G-04204A-06-0463) to file for DSM Program Portfolio approval – and the specific program plans contained therein – in a separate docket. Consistent with that request, UNS Electric filed its DSM Program Portfolio on June 13, 2007 in Docket No. E-04204A-07-0365 ("UNS Electric DSM Docket"); that filing is incorporated herein by reference.

Q. If UNS Electric is not asking for approval of DSM Programs in this docket, why is DSM Rebuttal Testimony being filed?

A. UNS Electric is filing Rebuttal Testimony addressing DSM for two reasons: (1) to address issues raised in Mr. Magruder's Direct Testimony; and (2) to request approval of a DSM cost recovery mechanism in this rate case. UNS Electric incorporated its DSM Portfolio in this Docket to provide sufficient information for the Commission to make appropriate recommendations for DSM cost recovery. The actual DSM Program Portfolio and specific program plans will be approved, or modified, by the Commission in the UNS Electric DSM Docket.

Q. Have there been changes to the original DSM Programs filed with Mr. Thomas J. Ferry's Direct Testimony in this Docket?

A. Yes. As stated above, UNS Electric filed its comprehensive DSM Program Portfolio *to replace* the original filing on December 15, 2006. UNS Electric determined the replacement DSM Program Portfolio was necessary to prevent similar concerns as those addressed from Staff, as well as other Intervenors, in light of TEP's Motion to Amend

Decision No. 62103 (Docket No. E-01933-05-0650) (hereinafter referred to as the "62103 Amendment Proceeding") – as well as comments from Staff witness Ms. Julie McNeely-Kirwan during the UNS Gas Rate Case. In those cases, Staff requested more detailed program descriptions with a separate filing and requested that both TEP and UNS Gas explore more DSM Program options. So, UNS Electric is attempting to address both Staff requests through filing its DSM Program Portfolio in the UNS Electric DSM Docket.

Q. What information was included in UNS Electric's DSM Program Portfolio?

A. UNS Electric refined the previous program descriptions based on Staff's recommendations and the Company considered more program options for its DSM Portfolio. We updated the avoided costs numbers to be consistent for all UniSource Energy Companies' DSM evaluations. In addition, we added programs and provided greater detail in the documentation for the cost-benefit calculations. An analysis of the Low Income Weatherization ("LIW") Program was also completed to identify energy savings associated with measures installed through that Program. UNS Electric also updated the program descriptions with the information requested by Ms. McNeely-Kirwan in the UNS Gas Rate Case and Ms. Barbara Keene for Staff in the 62103 Amendment Proceeding and included information requested on the overall DSM portfolio.

Q. Can you explain the difference in programs filed during Mr. Ferry's Direct Testimony and programs filed on June 13, 2007 in the separate DSM Program Portfolio docket?

A. The programs identified in Mr. Ferry's Direct Testimony included:

1. Time-Of-Use
2. Direct Load Control
3. Low-Income Weatherization
4. Energy Smart Home Program

5. Shade Tree Program
6. Education and Outreach

The specific DSM program plans filed in the UNS Electric DSM Docket include:

1. Direct Load Control
2. Low-Income Weatherization
3. Energy Smart Home Program
4. Shade Tree Program
5. Education and Outreach
6. Residential HVAC
7. Commercial Facilities Efficiency Program

The major program components and changes are outlined below:

Direct Load Control: The Program Plan for Direct Load Control provides comprehensive program detail, cost-benefit analysis, and plans for marketing and evaluation. UNS Electric has decided to initially limit the type of control to thermostats with radio frequency control in the Lake Havasu area.

Low-Income Weatherization: The Program Plan for Low-Income Weatherization ("LIW") provides comprehensive program detail and we included a cost-benefit analysis. UNS Electric also agreed with Staff to move $20,000 for bill assistance out of the Low-Income Weatherization Program and into the proposed UNS Electric Warm Sprit Program as also agreed upon in the UNS Gas Rate Case.

Energy Smart Home Program: UNS Electric evaluated the benefits of EPA's Energy Star Home Program and decided to use these National Standards for the Energy Smart

Home Program. The Program Plan for Energy Smart Homes also provides comprehensive program detail, cost-benefit analysis and plans for marketing and evaluation.

Shade Tree Program: The Program Plan for the Shade Tree Program also provides comprehensive program detail, cost-benefit analysis and plans for marketing and evaluation.

Education and Outreach: The Program Plan for Education and Outreach ("E&O") is a market transformation program that provides comprehensive program detail about residential and commercial education, the on-line energy audit and academic education. It also has been updated to include education for the newly designed Time-of-Use ("TOU") Rate options. The TOU Program itself has been eliminated from the list of specific DSM Programs, even though it is an important part of UNS Electric's DSM strategy. As it is essentially a rate design issue, Mr. D. Bentley Erdwurm addresses TOU rates in his Direct and Rebuttal Testimonies.

Residential HVAC: This program was added to the DSM Program Portfolio to provide more DSM options to existing residential customers. The Residential HVAC program promotes the installation of high-efficiency air conditioning and heat pump systems in existing homes in UNSE's service region. For equipment replacements, the program promotes the selection of high-efficiency equipment that exceeds the federal minimum efficiency standard of 13 SEER and quality installation practices

Commercial Facilities Efficiency Program: This program was added to the DSM Program Portfolio to provide more DSM options to existing commercial customers. The Commercial Program encourages commercial customers to install high-efficiency lighting equipment and controls, HVAC equipment, and energy-efficient refrigeration system

retrofits in their facilities. The program will encourage contractors to promote the program and provide turn-key installation services to customers, and will provide training and education through seminars and brochures.

B. Response to Mr. Magruder's Direct Testimony.

1. Citizens Advisory Council.

Q. Do you have any response to the comments by Mr. Magruder regarding the Citizens Advisory Council ("CAC"), which has, as one of its duties, to discuss DSM planning for the community?

A. The CAC was formed in 1999 as a result of Decision No. 61793 (June 29, 1999) but the list of issues brought before the CAC predominantly dealt with a second transmission line and reliability. None of the CAC membership ever questioned or chose to discuss DSM planning. Further, no member of the CAC has requested a meeting to discuss DSM planning issues – or any other issues for that matter – since 2002.

2. Similar Comments Shown on Multiple DSM Programs.

Q. In his Direct Testimony, Mr. Magruder refers to "UNSE lost revenue recovery". Is UNS Electric requesting lost revenue recovery from DSM programs?

A. No. The only reference to UNS Electric lost revenue recovery in program documents filed in UNS Electric's DSM Portfolio filing relates to the calculation of program cost effectiveness. Specifically, lost revenues are a necessary component in the calculation of the Ratepayer Impact Measure ("RIM") test. This test determines the impact on rates to all UNS Electric customers. While the Commission does not require this test, it is important for all parties to understand that a RIM result of less than one will put upward-pressure on rates. Thus UNS Electric chose to include the calculation in all DSM Programs.

Q. In his Direct Testimony, Mr. Magruder requests that the cost effectiveness of UNS Electric DSM Programs be recalculated using formulas included in his Direct Testimony. Do you agree?

A. No. The Benefit/Cost calculations that UNS Electric used meet the guidelines the Commission recommended and the methods outlined in the California Standard Practice Manual. UNS Electric believes this is the most accurate and consistent methodology to calculate cost effectiveness. If the Commission requests that UNS Electric use an alternate method for these calculations, UNS Electric will utilize at alternate method.

Q. In his Direct Testimony, Mr. Magruder requests that more items be included in the environmental benefits table (*e.g.*, potable water, ozone and mercury.) Do you have any comments?

A. Yes. Potable water has not been included in the UNS Electric environmental benefit table because UNS Electric has calculated the avoided capacity using a Simple-Cycle Turbine which requires minimal water consumption. In addition, utility electric generating units do not emit ozone. Furthermore, neither Santa Cruz County nor Mohave County currently exceed the National Ambient Air Quality Standard for Ozone, nor are they projected to do so in the foreseeable future. Similar to the case for potable water, mercury emission reductions are not included in the UNS Electric environmental benefit table because UNS Electric avoided capacity would be served by a Simple-Cycle Turbine which has no mercury emissions.

Q. Mr. Magruder states in his Direct Testimony that the line loss factor and rates used in benefit/cost calculations do not meet proposed values. Do you have any comments?

A. Yes. Proposed rate schedules are not yet approved by the Commission. Until UNS Electric receives Commission approval, proposed values are just that - proposed. UNS Electric believes it would be inappropriate to utilize other values until the Commission

approves the proposed rate schedules. For line-loss factors UNS Electric also includes those reported to the Commission during most recent rate case.

Q. In his Direct Testimony, Mr. Magruder suggests that Marketing and Advertising dollars be eliminated from each program in the DSM Portfolio and be replaced by the general education dollars budgeted in the E&O Program. Do you agree?

A. No. Significant and direct marketing and advertising is necessary to increase participation for each individual program. Marketing and advertising costs for each program must also be included in the total program costs to calculate the cost tests for each program. There are separate budgets for each program in the DSM Portfolio and marketing costs must be accounted for accordingly. Individual Program budgets for Marketing and Advertising cover development and delivery of marketing messages for each program through a range of strategies including, but not limited to:

- Promotions on the UNS Electric website;
- Bill stuffers mailed to existing UNS Electric customers;
- Advertising in major newspapers and other selected print media in the UNS Electric service region;
- Providing information through UNS Electric's customer care center;
- Developing marketing pieces, including brochures and other collateral pieces, to promote the benefits of each program; and
- Assisting with responding to customer inquiries about the program.

Q. Throughout Mr. Magruder's Direct Testimony, he recommends the DSM adjustor be calculated by dividing the number of customers into the program budget for a per customer charge. Do you agree?

A. No. UNS Electric, Staff and RUCO all agree in this proceeding through their respective Direct Testimonies that the DSM adjustor be determined on a kWh basis.

3. Education and Outreach.

Q. Mr. Magruder describes on page 16 at lines 24 through 27 in his Direct Testimony, that the E&O Program provides all the external media exposures, training, and marketing support for all UNS Electric DSM Programs. Do you have response to his description?

A. Yes. There is very little chance that $170,000 can provide all external media exposures, training, and marketing support for all UNS Electric DSM Programs plus the general education described here. The E&O Program simply provides general energy efficiency education to raise awareness about energy use and opportunities for saving energy. Items included in the E&O Program are the annual summer cooling tips and winter heating tips, general energy efficiency and conservation campaign, and promotion of the on-line Energy Advisor to answer energy use questions. The budget for these items totals $54,000 for the media campaign plus $11,000 for the license fee for the on-line Energy Advisor. The E&O Program budget also includes academic education through various school programs for $15,000. UNS Electric will also develop education and out-reach regarding the benefits of TOU rates from the E&O budget. The first year budget to promote the benefits of TOU rates is $90,000. UNS Electric will incorporate messages or 'tags' on many of these general energy efficiency messages to announce individual DSM programs so that the E&O education campaigns compliment separate messages and campaigns for individual DSM programs. The E&O Program does not include Marketing and Advertising for *any* specific DSM Program.

Q. In his Direct Testimony on page 18 at item 3.2.e, Mr. Magruder states that "The ACC Staff's definition of types of Demand-Side Management Programs does not include EC programs, thus without change, this program might NOT be included as a DSM program." Do you agree?

A. No. When selecting the programs for the DSM Program Portfolio, UNS Electric relied on the DSM definition in the Staff DSM Report. I believe the E&O Program meets the current definition of Energy Efficiency as outlined in the Staff DSM Report at page 3:

> "Energy Efficiency is products, services, or **practices aimed at saving energy** in end-use application generally by substituting technically more advanced (compared to what is presently used in a specific situation) equipment or **practices to produce the same or an improved level of end-use service with less energy use."** **[emphasis added.]**

Ultimately, The Commission will make the final recommendation on the program inclusion.

Q. On page 20, lines 16 through 18 in his Direct Testimony, Mr. Magruder requests that UNS Electric "change the Staff's Draft DSM Report definition for the types of DSM Programs" to agree with his recommended definitions. Do you agree?

A. No. UNS Electric participated in workshops with Staff and other stake-holders to determine the proposed DSM Policy ultimately included in the Staff DSM Report. UNS Electric believes no further definition as suggested by Mr. Magruder in his Direct Testimony from pages 16 through 17 is necessary. Moreover, UNS Electric has no authority to modify the Staff-recommended definitions.

Q. In his Direct Testimony, Mr. Magruder makes recommendations regarding the Education and Outreach Program. Is UNS Electric open to considering any of his recommendations?

A. Yes. UNS Electric believes all activities described in the E&O Program were designed to meet the needs of UNS Electric customers and influence a change in behavior that results in energy or demand reduction. UNS Electric is either open to considering or are already offering some of the recommendations in Mr. Magruder's Direct Testimony. For instance, UNS Electric is already proceeding with:

- Availability of speakers to civic organizations upon request – in response to Mr. Magruder's recommendation in his Direct Testimony on page 18, item 3.2.f.1.b – as long as resources exist to fulfill the request;
- Development of quarterly eNewsletters with energy information included – in response to Mr. Magruder recommendation in his Direct Testimony on page 19, item 3.2.f.3; and
- Availability of telephone energy assistance is available to all ratepayers – in response to Mr. Magruder's recommendation in his Direct Testimony on page 19 at item 3.2.f.4 through the call center or Account Managers.

Another important note is that UNS Electric is unable to provide 15-minute interval data without use of AMI/AMR ("automated meter intelligence / automated meter reading"). Therefore, UNS Electric is not able to consider the recommendation in Mr. Magruder's Direct Testimony at this time – at Section 3.2, item 7 on page 20.

Q. On pages 18 through 20 in his Direct Testimony, Mr. Magruder makes recommendations on measurement and evaluation on the E&O Program. Do you have any comments?

A. Yes. UNS Electric currently tracks the number of on-line energy audits started by commercial and residential customers. The Company also tracks the number of schools and school children who attend energy presentations and receive learning kits, and it further tracks the presentations to civic and business presentations including the number of people in attendance. But it is difficult to determine kWh and kW savings from a possible 'behavior" modification, so cost effectiveness on education and outreach programs can be costly to evaluate and results can be misleading. UNS Electric is considering some additional monitoring and evaluation methods to determine if each marketing effort identified in the E&O Program has resulted in a positive impact to alter consumer behavior.

4. <u>Direct Load Control ("DLC").</u>

Q. On page 23 at item 3.3.e.2 of his Direct Testimony, Mr. Magruder seemingly compares UNS Electric's proposed DLC Program to a Florida Power and Light Company ("FPL") DLC Program. He further states that FPL "has a 15-minute OFF cycle not more than once every four hours." Do you have any comments regarding his comparison?

A. Yes. Mr. Magruder is incorrect. FPL cycle strategy is comparable to UNS Electric's proposed DLC Program in that FPL utilizes a 50% cycle strategy – not the 15 minutes once during every 4 hours that Mr. Magruder described.

FPL uses a 50% cycle strategy (15 minutes each half hour) over a maximum duration of 3 hours within any 24-hour period. UNS Electric has proposed a 50% cycle strategy over a maximum duration of 4 hours within any 24-hour period. The longer duration in the UNS

Electric proposed DLC program is necessary to extend the potential cycle time through hours when system peak is registered. During times of extreme demand the FPL program may actually exceed the 50% Off cycle. Inserted below is the actual text from the FPL website related to its DLC program. (the 'On Call Program'):

> *"For example, air conditioning and central heaters may be put on a 15-minute savings cycle or an extended savings cycle. The 15-minute option cycles appliances off for 15 minutes each half hour for up to a total of three hours."*
>
> *"* During times of extreme demand, cycle time may be extended to a maximum of 17.5 minutes. During power system emergencies (e.g. extreme weather conditions and capacity shortages as determined by FPL), the cycle schedule and duration of the interruption may be extended.'*
>
> (http://www.fpl.com/residential/savings/residential_on_call.shtml).

Q. Do you agree that the 50% cycle time should be reduced from two hours per four-hour cycle to 15 minutes per four-hour cycle as Mr. Magruder recommends on page 25 at item 3.3.f.3 of his Direct Testimony?

A. No. UNS Electric has evaluated the cost-effectiveness of the DLC program and remains committed to the 50% cycle strategy and the 4-hour duration to meet peak demand requirements as presented in the UNS Electric DSM Docket. The 50% cycle strategy is utilized by many utilities around the country including the very success FPL program cited by Mr. Magruder. As recognized on page 23 of Mr. Magruder's Direct Testimony at item 3.3.e.2, the reduction from 120 minutes to 15 minutes "off" cycle during the four-hour duration would result in an 87.5% reduction in the demand impact produced by each participant in the DSLC program (from 2.5 kW to 0.32125 kW) and would not meet the TRC test required by the Commission.

Q. On page 24 at item 3.3.e.5 of his Direct Testimony, Mr. Magruder again mentions the FPL DLC program, stating "... FPL avoided about $3 billion with a DR program installed and paid by FPL (not ratepayer) company expense." Do you have any comments?

A. Yes. Mr. Magruder is incorrect when he stated that ratepayers do not provide the funding the cost for the FPL DLC Program. UNS Electric contacted the Senior Load Management Field Technician for FPL's On-Call Program. UNS Electric was essentially advised that FPL's On-Call Program, like all other FPL energy-conservation-approved programs, have all been filed and approved by the Florida Public Service Commission ("FLSC") – to be recovered through its Energy Conservation Cost Recovery "ECCR" clause and that more information can be found on FPSC's website.

To verify that the ECCR is similar to the Company's proposed DSM Adjustor, UNS Electric conducted some additional research. The best description of the ECCR administered by the Florida Power Service Commission was found on the web site for Gulf Power Company: http://www.gulfpower.com/pricing/pdf/ecc.pdf.

Q. Do you agree that Cares-M customers required to have electric powered life-support equipment be excluded from participating in a DLC program as Mr. Magruder recommends on page 24 at item 3.3.f.1 of his Direct Testimony?

A. Yes.

Q. Do you agree with Mr. Magruder's recommendation to add more Demand Response or "DR" options mentioned on page 25 at items 3.3.f.4 a through e of his Direct Testimony?

A. UNS Electric is willing to consider only items proven to meet cost-effectiveness tests. Mr. Magruder provides no evidence that his recommendations are cost-effective under any test.

If the Commission wishes to expand the options, those options can be considered in the UNS Electric DSM Docket.

Q. On page 25 at item 3.3.f.4 of his Direct Testimony, Mr. Magruder requests that UNS Electric revise the DLC Participation Agreement. Do you have any comments?

A. Yes. UNS Electric is willing to consider revisions to the Draft Participation Agreement during the implementation phase after the DLC Program receives Commission approval for implementation.

Q. On page 25 at items 3.3.f.6 and 3.3.f.7 of his Direct Testimony, Mr. Magruder suggests 'incentives', 'bonus' and other changes to the Participant Agreement. Do you agree?

A. No. UNS Electric believes that providing the communicating thermostat to the customer will be enough incentive to encourage participation in the program. Any additional incentives or bonus would add unnecessary costs and may cause the program to fail benefit/cost analysis. If the Commission wishes for UNS Electric to include additional costs it would be considered during the separate proceedings to approve the DSM Program Portfolio.

Q. Do you agree with Mr. Magruder's recommendation that UNS Electric should use only "Off-the shelf, proven equipment and DLC hardware and software"?

A. No. DLC technologies are not mature and the range of DLC technology options available commercially today is a small fraction of those that will be available in the future. Because of the anticipated rapid expansion of improved DLC technologies in the future, UNS Electric is investigating a number of equipment options but has not chosen the equipment at this time. The option UNS is exploring would integrate DLC with the UNS strategy for AMI/AMR, thereby gaining efficiency from the equipment and communication structure.

It would also provide the necessary data to accurately calculate saving from a DLC customer plus increase customer satisfaction through more information on their energy use. If the Commission wishes to limit the options open to UNS Electric this would be considered during the separate hearings to approve the DSM Program Portfolio.

5. Low-Income Weatherization.

Q. On pages 28 at item 3.4.f.2 of his Direct Testimony, Mr. Magruder suggests eliminating $2,552 from the total budget. What is your response?

A. The $2,552 dollar entry was placed in the incorrect line of the detail budget. This dollar amount should relate to "Rebate Processing" and be distributed to the agencies to help cover the cost of this activity. Therefore, UNS Electric does not agree that the $2,552 should be removed from the total budget.

6. Energy Smart Home.

Q. On page 30 at items 3.5.e.1 and f.1 of his Direct Testimony, Mr. Magruder discusses reducing high recurring costs and improving the return to customers to 45% in 2009. Do you have any comments?

A. Yes. The calculation included in Mr. Magruder's Direct Testimony on page 30 is not accurate. The total Direct Implementation costs submitted for this program are $243,600, *not* $161,312 as stated in Mr. Magruder's testimony. Utilizing the actual direct costs for the program to calculate the return to customers, UNS Electric's return to customers is 58% in the first year (243,600/420,000).

Q. On page 30 at item 3.5.f. 2 of his Direct Testimony, Mr. Magruder suggests that annual goals for the Energy Smart Home should be increased. What is your response to his suggestion?

A. UNS Electric will make every attempt possible to increase the number of participants in the Energy Smart Home Program. UNS Electric would be thrilled to reach 42%, or higher, participation by 2012. But UNS Electric does not have ultimate control over how many residents decide to participate. For the purpose of planning, UNS Electric would rather be conservative in its estimates of participation. If program participation exceeds the estimated percentages in the Energy Smart Program Plan, UNS Electric will inform the Commission through UNS Electric's semi-annual DSM Report.

Q. On page 30 at item 3.5.e. 3 of his Direct Testimony, Mr. Magruder requests a sample Partner Agreement. Do you have any comments?

A. Yes. The partner agreement with Energy Star is an agreement between Energy Star and the Builder. UNS Electric does not develop this agreement, but it can be found on the Energy Star web-site (www.energystar.gov). Agreements between UNS Electric and the builder have not yet been developed but will be developed in the coming months.

7. <u>Residential HVAC Program.</u>

Q. In his Direct Testimony at item 3.6.f.1 on page 33, Mr. Magruder makes the recommendation to remove $35,952 of subcontractor expenses and $12,000 of internal marketing expenses from the total program budget. Do you agree with his recommendations?

A. No. Although UNS Electric may administer the program internally, subcontractors will be used for various items including program design and development, verification of equipment efficiency, inspections, rebate processing and data entry. If subcontractors do

not complete these items, all the work would then be completed by UNS Electric employees. Mr. Magruder needs to understand that the detailed budgets have been placed in categories based on estimated allocations that are common to other utility DSM programs. Actual costs may vary among subcategories. Regarding the $12,000 of marketing costs, Mr. Magruder suggests be eliminated, those costs include payments to the HVAC Contractors, as outlined in the program description under Products and Services, at Attachment 5 page 4 of UNS Electric's DSM Program Portfolio filed June 13, 2007. As I discussed earlier in my Rebuttal Testimony, the E&O Program does not include marketing for specific programs. The recommended budget by UNS Electric must remain at the level UNS Electric proposes to ensure successful implementation.

Q. In his Direct Testimony at item 3.6.f.2 on page 33, Mr. Magruder questions 17 and 18 SEER incentives. Do you have any comments?

A. Yes. Mr. Magruder misunderstands the information UNS Electric included in its DSM Program Portfolio at Appendix 3. UNS Electric recognizes that some equipment with 17 and 18 SEER ratings are available, but the choices are not great and the cost is high. Appendix 3 is used to estimate the size and efficiency of equipment that would most likely be installed in this program. Because the likelihood of having any 17 to 18 SEER equipment installed is slim, the analysis shows a zero for that category. If the Commission wishes for UNS Electric to escalate rebates for 17 and 18 SEER equipment above the recommended $100/ton, it can be considered in the UNS Electric DSM Docket.

Q. In his Direct Testimony also at item 3.6.f.2 on page 33, Mr. Magruder suggests that savings in therms should be included for heat pumps. Do you have any comments?

A. Yes. UNS Electric followed the Staff DSM Report to determine the baseline equipment. In that Report on page 19 regarding Fuel Neutrality, it clearly states: "For those installations/applications that have multiple fuel choices, ***the baseline used in the cost***

effectiveness analysis shall utilize the same fuel source as the installation/application." [emphasis added] Therefore, UNS Electric followed this procedure in calculating program savings and assumed in the cost-benefit analysis a high-efficiency heap pump would replace an older heat pump.

8. Shade Tree Program.

Q. In his Direct Testimony at item 3.7.a on page 33, Mr. Magruder states that "UNS Electric does not have an assessment of the impact of reducing loads or energy savings potential through shading from trees." Is this true?

A. No. UNS Electric has estimated savings based on the calculation of energy savings on a detailed report compiled by Gregory McPherson and James R. Simpson, Desert Southwest Community Tree Guide – Benefits, Costs and Strategic Planting, 2004. UNS Electric also used the assessment from the same report that indicates no calculations of demand savings. UNS Electric's DSM Portfolio at Appendix 3 of Attachment 6 outlines the estimated energy savings.

Q. In his Direct Testimony at item 3.7.d on page 34, Mr. Magruder states that the program "has a repeated and not relevant section on Monitoring and Evaluation. It is not expected that UNS Electric field personnel will check customer's yards to verify UNS Electric "shade trees"." Do you agree?

A. No. The Monitoring and Evaluation section is repeated in several programs but is relevant. Because of the Measurement and Evaluation requirements recommended in the Staff DSM Report, UNS Electric will field-inspect installation of a statistical sample of trees installed through this Program. This was clearly stated in UNS Electric's DSM Portfolio on page 3 of Attachment 6: "**Field verification** – UNS Electric will conduct field verification of the installation of a sample of measures throughout the implementation of the program."

Q. On page 35 at item 3.7.f.1 of his Direct Testimony, Mr. Magruder recommends that the Commission not approve this program. Do you have any comments?

A. Yes. UNS Electric believes the Shade Tree Program provides significant energy and environmental benefits to customers. Whether the Shade Tree Program will be rejected based on the information provided by Mr. Magruder (3.7.e.1), however, is a matter for discussion by the Commission during the UNS Electric DSM Docket.

9. Commercial Facilities Efficiency Program.

Q. In his Direct Testimony at item 3.8.e.1 on page 38, Mr. Magruder assumes that all participants will receive the maximum of $10,000 and the customers allowed to participate will be limited to 28.5 customers. Do you have any comments?

A. Yes. UNS Electric believes that most customer rebates will be significantly lower than $10,000. UNS Electric added the incentive cap to prevent one or two customers from consuming the entire budget for the program.

Q. On page 38 at item 3.8.e.3 of his Direct Testimony, Mr. Magruder requests a sample of proposals, agreements and report formats. How do you respond to his requests?

A. Development of forms, agreements, and proposals has not yet been developed but will be in the coming months for Commission approval.

C. Response to Staff Witness Jerry Anderson's Testimony.

Q. Does UNS Electric agree with comments made by Mr. Anderson?

A. Yes. UNS Electric agrees with the Jerry Anderson's comments and recommendations in his Direct Testimony.

Q. Are there areas that UNS Electric agreed to modify regarding the Direct Testimony of Tom Ferry concerning its DSM Program?

A. Yes. UNS Electric has agreed to modify two major points in UNS Electric's DSM Portfolio Filing:

- UNS Electric recommended in its portfolio filing that the $20,000 allocated to the Emergency Bill Assistance component of the LIW be re-categorized into the proposed Warm Sprits Program and that it not be funded with DSM funds.
- UNS Electric recommended in its portfolio filing that UNS Electric's TOU pricing plans not be considered as DSM, and that these activities not be funded with DSM funds.

D. <u>Response to Ms. Marylee Diaz Cortez's Testimony.</u>

Q. Does UNS Electric agree with comments made by RUCO's witness Marylee Diaz Cortez?

A. Generally, yes. But I need to make one correction regarding her Direct Testimony on DSM Programs. Ms. Diaz Cortez indicated that the existing program budget was $460,000 annually; in fact, that figure is only $175,000 annually for existing DSM programs plus an additional $70,000 annually for LIW.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

Rebuttal Testimony
of
Thomas N. Hansen

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783

Rebuttal Testimony of

Thomas N. Hansen

on Behalf of

UNS Electric, Inc.

August 14, 2007

Q. Please state your name and address.

A. My name is Thomas N. Hansen. My address is 255 South Washington, St. Johns, Arizona, 85936.

Q. What is your employment position?

A. I am the Vice President, Environmental Services, Conservation and Renewable Energy for Tucson Electric Power Company ("TEP" or the "Company").

Q. On whose behalf are you filing your direct testimony in this proceeding?

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

Q. Please summarize your educational and professional background.

A. I received a Bachelor of Science degree in Electrical Engineering with an emphasis in Computer Science from Lehigh University in 1971. In 1972, I received a Masters of Science degree in Electrical Engineering with emphasis in inertial guidance, laser communications and rocket propulsion systems with a minor in geophysics from Stanford University. I was employed by Bechtel Power Corporation from 1972 to 1984, designing, building and operating electric generation stations of fossil, nuclear and renewable fuel sources, totaling over 6,500 MW of generation capacity. I was hired in 1984, by Alamito Company to manage its generation assets in Arizona and New Mexico, as well as generating plants later acquired in numerous other locations. I had different levels of management responsibility for about 3,500 MW of fossil and renewable fueled generation through 1992. I was hired in 1992 by TEP as Vice President of Power Production and served in that role through 1994 when I accepted the role of Vice President and Technical Advisor to the Chief Executive Officer, developing the technologies needed to transition the TEP generation portfolio to one that is more distributed, and less dependent upon

imported sources of primary energy. I served in that role until 2007 when I was named to my current position as Vice President of Environmental Services, Conservation and Renewable Energy. I have held a Registered Electrical Engineering License in California since 1973 and a similar license in Arizona since 1975, as well as a Registered Mechanical Engineering License in Arizona since 1979. From 1982 through 1984, I held all electrical, mechanical, instrumentation, steamfitting and plumbing New Mexico contractors' licenses as the qualifying party for Bechtel in New Mexico.

Q. Did you file Direct Testimony on behalf of UNS Electric in this Docket?

A. No, I did not.

Q. Have you reviewed the Direct Testimony filed by the Commission Staff and other parties to this rate case?

A. Yes, I have.

Q. What is the purpose of your Rebuttal Testimony?

A. I will respond to the Direct Testimony of Marshall Magruder concerning Environmental Portfolio Standard ("EPS") and Renewable Energy Standard and Tariff ("REST") issues.

Q. Do you agree with Mr. Magruder's assertions concerning UNS Electric's performance relative to the EPS annual renewable energy percentage requirements?

A. No, I do not. First, while no Arizona electric utility has met their EPS annual renewable energy goals in any year of the EPS, UNS Electric has provided its customers with a percentage of renewable energy generally at par with other Arizona utilities that have been required to implement the EPS. From its adoption in 2001, the EPS was not sufficiently funded to allow any utility to meet the EPS annual solar energy requirements. During the test year, UNS Electric met 40.68% of its EPS requirements with 6,577 MWh of renewable

energy provided to its customers. That is far more than the 0.6% of its EPS requirements set forth in Mr. Magruder's Direct Testimony.

Second, Mr. Magruder incorrectly suggests at page 55 of his Direct Testimony, without any supporting evidence, that the UNS Electric EPS program does not have the attention of UNS Electric management, that the EPS program is not ISO 14400 certified, and that UNS Electric lacks commitment to develop renewable energy. In fact, the UNS Electric EPS program has received equal attention from the same management group that provides the TEP EPS program management. The UNSE SunShare program is actually growing at faster rates of participation on a per capita basis than the TEP SunShare program in 2007. Moreover, Mr. Magruder sets forth no evidence of any kind that ISO 14400 certification provides for a better renewable energy program.

Third, Table 14 on page 55 of Mr. Magruder's Direct Testimony is incorrect – by several orders of magnitude – in its conclusions in the fourth, fifth and sixth columns ("solar power," "actual percent renewable" and "annual renewable deficit"). Mr. Magruder first assumes incorrectly that all EPS energy is to be solar energy, which of course only 60% must be solar energy; and second his calculation fails to account for EPS multiplying credits which reduce the solar capacity requirement by a factor of at least two in calculating the fourth column. In then calculating the fifth column, Mr. Magruder uses an incorrect capacity to energy conversion factor of 153.kWh AC per kW-DC of nameplate capacity, when that number historically is closer to 1,300. Using historically correct multiplying and conversion factors to correct the 2006 line of Magruder Table 14 gives:

Magruder Table 14 for 2006 year:

Year	UNSE/Citizens Total Retail Sales (MWh)	EPS Percent Renewable Electricity	Needed to meet EPS Standard (MWh)	Solar Generated (MW)	Actual Percent Renewable	Annual Renewable Deficit (MWh)
2006	1,711,420	1.05%	16,919	110.6	0.00646%	-16,818

Should be:

Year	UNSE/Citizens Total Retail Sales (MWh)	EPS Percent Renewable Electricity	Needed to meet EPS Standard (MWh)	Solar Generated (MW)	Actual Percent Renewable	Annual Renewable Deficit (MWh)
2006	1,711,420	1.05%	4,792	3.686	40.68%	-4,738

Moreover, Mr. Magruder has not provided any supporting assumptions or evidence that would engender a full understanding of what the table purports to represent or to allow verification of what he is asserting.

Finally, Mr. Magruder confuses energy and capacity at a number of places throughout his Direct Testimony, making it nearly impossible to respond to the specific claims of insufficient solar energy production. His claim of "52 solar panels" having been installed by UNS Electric in Kingman and Lake Havasu is flat wrong. As visual observation would attest, there are 320 solar modules installed and owned by UNS Electric at those locations capable of generating over 8,000 watts of power. Mr. Magruder also wrongly asserts that there is no solar generation in Santa Cruz County. In fact there are several solar generation systems in Santa Cruz County, including a pilot production 20 kW DC dual axis tracking system and at least two on-grid homeowner installed units along with at least two off-grid solar installations installed in Santa Cruz County. UNS Electric SunShare personnel have traveled to Santa Cruz County numerous times in the past four years to discuss new solar

opportunities with every interested customer who has asked for a visit, and several customers who did not previously inquire about solar who UNS Electric felt could support solar installations on their facilities, such as the City of Nogales and the International Wastewater Treatment Plant.

Q. Do you agree with Mr. Magruder's recommendations for the transition of UNS Electric's EPS program to an REST program?

A. No. Mr. Magruder makes three recommendations for such a transition, none of which are appropriate. First, he mentions previous revisions to the GreenWatts program in his first recommendation. In fact, it was the SunShare program, not the GreenWatts program, which was upgraded and expanded by the Commission in December 2006. UNS Electric will include a proposal to again upgrade and expand the SunShare program in its upcoming REST compliance program filing. Moreover, Mr. Magruder's second and third recommendations – to present an implementation plan by January 1, 2008 and to commence implementation of the sample REST tariff surcharge within 30 days of "approval of this docket" – will also be addressed by UNS Electric in its REST compliance filing. I would note these latter two recommendations of Mr. Magruder do not comport with the timing provisions of the REST Rules.

Q. Does this conclude your testimony?

A. Yes it does.