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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

REJOINDER 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, D. Bentley Erdwurm, Denise A. Smith, and Thomas N. Hansen and in the above-captioned docket.

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RESPECTFULLY SUBMITTED this 31st day of August 2007.

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
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UNS ELECTRIC, INC.

REJOINDER TESTIMONY

August 31, 2007

Rejoinder Testimony
of
James S. Pignatelli

BEFORE THE ARIZONA CORPORATION COMMISSION

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

Rejoinder Testimony of

James S. Pignatelli

on Behalf of

UNS Electric, Inc.

August 31, 2007

Q. Please state your name and address.

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

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

A. Yes I have.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my Rejoinder Testimony is to address: (i) the proposed Purchased Power and Fuel Adjustment Clause ("PPFAC") and anticipated increases in the costs of purchased power and fuel; (ii) the benefits of our proposal regarding the Black Mountain Generating Station ("BMGS"); and (iii) Staff's asserted "financial distress" standard regarding Construction Work in Progress ("CWIP").

Q. Mr. Pignatelli, why does the Company believe that the PPFAC is in the public interest?

A. The full requirements purchased power agreement with Pinnacle West Capital Corporation ("Pinnacle West") expires at the end of May 2008. Consequently, UNS Electric must arrange for replacement power and has, in fact, been engaged in acquiring replacement resources for some time now. The proposed PPFAC is an effective mechanism for the timely recovery of the costs of those resources. We currently estimate the cost of replacement power to be approximately 15% greater than the Pinnacle West contract price. The Company's request for a 5.5% increase in rates does not include any increase to the cost of purchased power and fuel. Accordingly, it is important for the financial health of UNS Electric that the PPFAC be in place to allow the Company to timely recover these increased purchase power and fuel costs. I believe a PPFAC that provides for the timely recovery of these costs not only protects the financial integrity of UNS Electric but sends realistic price signals to our customers.

Q. What is your response to RUCO's recommendation of a cap and a 90/10 sharing mechanism on the proposed PPFAC?

A. RUCO's recommendations regarding a cap and a sharing mechanism for the PPFAC are unacceptable. The costs recovered through the PPFAC are directly related to fuel and purchased power and do not include any profit to UNS Electric. The PPFAC is simply a pass-through of those costs and UNS Electric does not profit therefrom. A "cap" and a "sharing mechanism", as proposed by RUCO, would be confiscatory as each would deprive the Company of legitimate expenses it incurs directly related to the provision of electric service to customers. Also, the proposed sharing mechanism would send improper price signals to UNS Electric's customers.

Q. Are the cap and sharing mechanism that were imposed on the Arizona Public Service Company ("APS") PPFAC relevant in this case?

A. No, it is not because UNS Electric is in a substantially different situation than APS. The Company is undergoing the transition from a full requirements contract to building a portfolio to supply its load. UNS Electric owns very limited generation assets and will still need to purchase power to meet its customers' needs. In contrast, APS has a diversified portfolio of generation assets, including stable cost nuclear and coal facilities. I believe that these key differences are significant factors in Staff's recommendation against a cap or sharing mechanism for UNS Electric. As Mr. DeConcini stated in his Rebuttal Testimony "a cap could send the wrong message to over-emphasize short-term rate stability at the detriment of what is in the best long-term interest of our customers." (Rebuttal Testimony of Michael J. DeConcini at 14.)

Q. What is UNS Electric doing to stabilize future Company fuel and purchase power prices?

A. The Company has been procuring power in the wholesale markets on a forward basis. Additionally, the proposed purchase of the BMGS will save substantial costs over the long-run for generating capacity, transmission wheeling and ancillary services. Further, in the pending 40-252 / TEP Rate Case proceeding (consolidated Docket Nos. E-01933A-05-0650 and E-01933A-07-0402), TEP is proposing a hybrid plan whereby some of its coal generation would remain out of rate base and available for wholesale sales. This power could be made available to UNS Electric through a power agreement. Because it is coal generation, it can be provided at terms that are more stable than market prices of gas generated power.

Q. Has Staff recognized the benefits provided by the BMGS, including stabilizing the Company's future power costs?

A. No. Staff still seems uncertain whether the BMGS is an economical resource for UNS Electric and its customers. Staff's testimony seems to send mixed signals. In his Surrebuttal Testimony, Staff witness Ralph Smith says that, "Staff recognizes that there can be benefits to a utility owning its own generation". However, Mr. Smith then goes on to say that "[i]t is not known whether having UNS Electric purchase a peaking unit such as BMGS is the most economical alternative to obtain power for the short, intermediate or long-term." (Surrebuttal Testimony of Ralph Smith at 67.) But, I cannot find anywhere in the Staff testimony a substantive analysis to refute the benefits of the BMGS. On the other hand the testimony of UNS Electric witnesses Michael DeConcini and Kevin Larson demonstrates beyond a doubt that (i) the BMGS would be a key part of the Company's new energy portfolio; and (ii) rate base treatment of the BMGS would improve the Company's credit profile and ability to fund transmission and distribution projects.

Q. Staff suggests that a "financial distress" standard must be met to justify including CWIP in rate base. Do you agree with that proposed standard?

A. No, I do not. I believe such a standard is unrealistic and ignores the fact that utilities like UNS Electric need to be healthy financially in order to able to provide safe and reliable service. I think it is directly contrary to the public interest to allow a public utility to fall into "financial distress" before including CWIP in rate base or considering other ratemaking alternatives. I believe that the financial distress standard alluded to by Staff is vague. Furthermore, it seems to me that by the time a utility could demonstrate "financial distress," to satisfy Staff, the damage would already have been done to the utility's credit and access to capital. I believe that it is in the pubic interest to set rates that maintain a utility's financial integrity rather than attempting to restore it after it has been damaged. I think that this rate case is one in which CWIP should be included in rate base.

Q. Does this conclude your Rejoinder Testimony?

A. Yes.

Rejoinder Testimony
of
Thomas J. Ferry

BEFORE THE ARIZONA CORPORATION COMMISSION

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

Rejoinder Testimony of

Thomas J. Ferry

on Behalf of

UNS Electric, Inc.

August 31, 2007

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Thomas J. Ferry.

Q. Are you the same Thomas J. Ferry who filed Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my Rejoinder Testimony is to respond to the Surrebuttal Testimonies of Staff witness Julie McNeely-Kirwan regarding administration of CARES, Staff witness Bing E. Young regarding Line Extension policies and RUCO witness Rodney Moore regarding expense adjustments and Marshall Magruder's Surrebuttal Testimony regarding Billing Terms and Low-Income Programs.

II. RESPONSE TO STAFF WITNESS JULIE McNEELY-KIRWAN'S SURREBUTTAL TESTIMONY.

Q. What issues raised by Ms. McNeely–Kirwan in her Surrebuttal Testimony do you wish to address?

A. I will address the following issues raised by Ms. McNeely–Kirwan: (i) her recommendations for improved marketing of the CARES and Medical CARES programs and (ii) her request to include all CARES customer disconnects on the Company's semi-annual reports.

Q. Do you agree with Ms. McNeely–Kirwan's recommendations for CARES marketing?

A. Yes. The Company desires to clear up any possible confusion regarding the application of the CARES programs. Whether the Commission accepts the Company's recommendation regarding the design of CARES and Medical CARES plans or not, we will seek to improve all promotional and descriptive literature to clarify the programs for our customers.

Q. What is the Company's response to Ms. McNeely-Kirwan's request for modified Medical CARES reporting?

A. The Company agrees to separately report Medical CARES participation customer counts in the CARES semi-annual reports. But the Company believes it is following the Commission's administrative rules and feels that the requirement of reporting individual customer disconnects is impractical. As stated in my Rebuttal Testimony, the Company exercises extreme caution to prevent Medical CARES disconnections. Reporting individual disconnections of any kind semi-annually would not be of benefit to those customers and this requirement would be difficult for the Company to accurately administer.

Q. Does that conclude your response to the Surrebuttal Testimony of Ms. McNeely-Kirwan?

A. Yes, it does.

III. <u>RESPONSE TO STAFF WITNESS BING E. YOUNG'S SURREBUTTAL TESTIMONY.</u>

Q. What comments do you have on the Surrebuttal Testimony of Mr. Young?

A. Mr. Young continues to believe that UNS Electric is increasing the free footage allowance in the line extension rules. Mr. Young is incorrect. UNS Electric's current free allowance for a distribution line is 400 feet. The Company's current allowance for services is 150 feet plus one carry-over pole. As I indicated in my Direct Testimony, we will continue the 400 feet free allowance for distribution lines. However, the Company proposed to reduce the current service line allowance to only 100 feet. So Mr. Young is inaccurate when he states the Company is increasing the free footage allowance. I provided the specific provisions in the Company's proposed Rules and Regulations that detail this change. Should Staff want to amend the language to make it more clear that we are reducing the service line allowance, we would be open to doing so. However, the Company believes the substance of its proposed changes appropriately balance all important factors as I described in my Rebuttal Testimony.

Q. Does that conclude your response to the Surrebuttal Testimony of Mr. Young?

A. Yes, it does.

IV. <u>RESPONSE TO RUCO WITNESS RODNEY L. MOORE'S SURREBUTTAL TESTIMONY.</u>

Q. What is your response to Mr. Moore's recommended exclusion of expenses.

A. Mr. Moore has again ignored the Company's explanation of certain expenses as being reasonable and prudent. He mentions in his Surrebuttal Testimony that the Company has paid for liquor for the employees. I can only assume that he has concluded that a meal charged at a business with the word "bar" or "brewery" in its name means the Company has purchased liquor for its employees. There happens to be a restaurant in Kingman that has the word "bar" in its name. The Company has a strict policy about employees drinking alcohol during working hours and would not allow any liquor to be consumed at lunch. Mr. Moore again restates his objection to the Company including contributions to charitable organizations, even after we have agreed to an adjustment for those types of expenses in responses to Data Requests from Mr. Moore and again in my Rebuttal Testimony. I stand by my Rebuttal Testimony that the questioned expenses were reviewed by the Company and except for those previously accepted by the Company as unnecessary, are reasonable for the reasons stated.

Q. Do you have an issue with Mr. Moore's adjustment for MARC Training?

A. Yes, I do. I understand how Mr. Moore has concluded that MARC Training may have been a specialized training for UNS Gas as they were adapting to a new unionized environment. We believe this is the wrong conclusion because although MARC Training may have included Union/Supervisor relationship concepts, the majority of the training was on general supervisory skills. Second and more importantly, training employees is always an ongoing effort. While specific training may not reoccur each year, employees are constantly ongoing regular training as part of the normal course of their responsibilities.

Q. Do you have comments regarding the Operating Income Adjustment by Mr. Moore?

A. Yes, I do. The Company believes that the decision to move customer calls to a consolidated center was not only reasonable but in the best interest of our customers because of all of the increased call handling capabilities detailed previously in my Direct and Rebuttal Testimony. This was the only practical way to improve on unsatisfactory call handling issues which were destined to get worse as customer numbers increased. The other option would have required expensive infrastructure improvements at multiple sites as well as more employees.

Q. Does that conclude your response to the Surrebuttal Testimony of Mr. Moore?

A. Yes, it does.

V. RESPONSE TO WITNESS MARSHALL MAGRUDER'S SURREBUTTAL TESTIMONY.

Q. What comments do you have on the Surrebuttal Testimony of Mr. Magruder?

A. I will address the following issues raised by Mr. Magruder: (i) Billing Schedule and (ii) Medical CARES program.

Q. What is your response to Billing Schedule issues by Mr. Magruder?

A. Mr. Magruder's Surrebuttal Testimony on pages 32 through 34 is confusing and incorrectly reflects what the Company has requested. The Company's original objective was to revise the Billing Terms to match the terms of UNS Gas and Tucson Electric Power where practical. These changes were intended to avoid confusion for customers jointly served by UNS Electric and UNS Gas plus facilitate consistency in the common billing system recently adopted by the three different utilities while establishing common policies where it makes sense for the customer call center employees. The recommended Billing Terms include: (1) change the due date to 10 days after billing, (2) change the delinquent date to 15 days after the due date, which is 25 days after the billing date, (3) the notice of termination would be mailed to the customer after the delinquency date (again at least 25 days after the billing date), and (4) the termination notice allows another 5 days before the service disconnection process begins, which is in accordance with Commission Administrative Rules – A.A.C. R14-2-210.E. On page 2 of my Rebuttal Testimony, I stated that the Company would only assess late payment fees on delinquent accounts (those which payment had not been received by 25 days after the billing date).

Q. Do you have comments regarding Billing Statement recommendations by Mr. Magruder?

A. The Company is willing to consider recommendations to clarify the Rules and Regulations language but was unable to find the Billing Statement details referenced on page 35 of his Surrebuttal Testimony.

Q. What is your response to Mr. Magruder's concerns about the Low Income programs.

A. The Company disagrees with Mr. Magruder's statement that we have been unresponsive to Ms. McNeely-Kirwan's recommendations. Mr. Erdwurm proposed a different approach for the CARES and Medical CARES programs. I accepted all of the other recommendations for increasing awareness of low income programs in my Rebuttal Testimony and originally recommended the adoption of a Warm Spirits program for UNS Electric to match UNS Gas program in my Direct Testimony. The Company has also agreed through Ms. Denise Smith's Rebuttal Testimony to move $20,000 for bill assistance out of the Low Income Weatherization Program and into the proposed Warm Spirits Program.

Q. Do you agree that the Company has an obligation to provide back up power for Medical CARES customers?

A. No, I do not. UNS Electric makes every effort to supply reliable electric service to all of its customers. We cannot, however, guarantee uninterrupted service. The Company has the capability of taking outage reports from customers on a 24 hour, 7 day basis. Outage information is available on a recording which is updated regularly as facts are determined. Customers that advise us that they are dependent on medical equipment are advised to move to a different location if an extended outage will be a problem for them. We have no way of reliably tracking where these customers are on the system. We have no way of tracking if the customer's medical equipment has a back-up battery system. Customers with medical needs have the primary responsibility to know if power interruptions are an issue and to have some plan to either move locations or have adequate back-up. With all of this said, the Company has been recognized for its efforts of contacting emergency agencies during extended outages and have set up emergency relief stations for all customers. We have gone door to door to check on customers to keep them advised on the status of repairs in addition to the outage status recording.

Q. Does that conclude your response to the Surrebuttal Testimony of Mr. Magruder?

A. Yes, it does.

Q. Does this conclude your Rejoinder Testimony?

A. Yes, it does.

Rejoinder Testimony
of
Kentton C. Grant

BEFORE THE ARIZONA CORPORATION COMMISSION

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

Rejoinder Testimony of

Kentton C. Grant

on Behalf of

UNS Electric, Inc.

August 31, 2007

TABLE OF CONTENTS

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 who filed Direct and Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my Rejoinder Testimony is to respond to the Surrebuttal Testimony filed by the Commission Staff ("Staff") and the Residential Consumers Utility Office ("RUCO"). Specifically, I address the issues of financial integrity, the need for construction work in progress ("CWIP") in rate base, and the cost of capital to UNS Electric, Inc. ("UNS Electric" or the "Company").

Q. Please summarize your response to the Surrebuttal Testimony filed by Staff and RUCO.

A. Despite the volume of testimony filed on the issues of CWIP in rate base and the cost of capital, I found most of the testimony to be repetitive in nature, with only a few new arguments being offered by Staff and RUCO. No substantive analysis of UNS Electric's financial condition was provided, leading me to believe that financial integrity is not an issue of significant importance to either Staff or RUCO. This is unfortunate since UNS Electric will be required to attract large amounts of new capital over the next several years, the cost and availability of which will be greatly impacted by the outcome of this rate proceeding.

II. RESPONSE TO STAFF WITNESS RALPH C. SMITH'S SURREBUTTAL TESTIMONY.

Q. What issues raised by Mr. Smith in his Surrebuttal Testimony do you wish to address?

A. I will address the following issues raised by Mr. Smith: (i) his characterization of Staff's approach for calculating the rate of return (ROR) on fair value rate base ("FVBR"), (ii) his use of a "financial distress" standard for granting CWIP in rate base, (iii) his dismissal of other factors that point to the need for CWIP in rate base and (iv) his comments concerning regulatory lag and the appropriate use of financial forecasts in rate proceedings.

Q. On page 4 of his Surrebuttal Testimony, lines 4 through 7, Mr. Smith states that Staff's approach to calculating a ROR on FVRB "…cannot be dismissed as a mere superfluous mathematical exercise." Do you agree with this statement?

A. No, I do not. As I explained in my Rebuttal Testimony, Staff's approach is mathematically equivalent to the approach that was expressly disallowed by the Arizona Court of Appeals in a case involving Chaparral City Water Company. Despite his statement to the contrary, appearing on page 4 of his Surrebuttal Testimony (lines 1 through 4), Staff's approach does result in the same revenue requirement regardless of whether FVRB or original cost rate base ("OCRB") is used. It is only because of rounding that Staff has calculated a difference in the revenue requirement for UNS Electric. This $1,533 difference can be observed on Schedule A attached to Mr. Smith's Direct Testimony. This amount represents less than 0.001% of the $162 million revenue requirement identified by Staff, and only 0.04% of the $3.8 million revenue deficiency shown on Schedule A attached to Mr. Smith's Direct Testimony. Although I believe the Commission has wide discretion in setting a ROR on FVRB, Staff's approach is clearly unresponsive to the concerns raised in the Chaparral City Water Company ruling.

Q. Mr. Smith makes several references to "financial distress" in his discussion of the standard to be applied for granting CWIP in rate base. Is financial distress an appropriate standard to use?

A. No, it is not. According to a recent edition of Webster's unabridged dictionary, common definitions of "distress" include "an oppressed or distressed state, a painful situation, a state of danger or necessity, and an indication of weakness or incipient failure." Common synonyms include "suffering, misery, agony and dolor." To require a public utility to fall into such a financial state, before giving any consideration to CWIP in rate base or other ratemaking alternatives, is clearly inconsistent with the public interest. By the time a utility can demonstrate that it is in "financial distress," damage to the utility's credit and access to capital has already been done. The whole purpose of including CWIP in rate base is to support the utility's credit and access to capital, and to avoid the increased cost and reduced availability of capital associated with financial distress. If this same standard were applied in a medical setting, only those patients who become critically ill would be eligible for health care. By the time care is finally administered, it may be too late to save the patient.

Q. On page 12 of his Surrebuttal Testimony, lines 7 through 10, Mr. Smith states that "UNS Electric must show how it is different from the normal circumstances of a regulated public utility where CWIP has been excluded from rate base" and that it "has failed to do this." Do you agree with Mr. Smith on this point?

A. No, I do not. In both my Direct and Rebuttal Testimony I have provided extensive evidence concerning the negative financial impact of growth on UNS Electric and the extraordinary financial challenges facing this utility. I am not aware of any electric or gas utility whose growth in net plant investment comes close to approaching that of UNS Electric on a per customer basis – and Mr. Smith has not identified any such utilities. As demonstrated in Exhibit KCG-10 attached to my Rebuttal Testimony, this growth has a negative impact on the Company's financial results and highlights the need for timely and constructive rate relief. I am also not aware of any other electric utility that is facing the prospect of replacing 100% of its power supply and refinancing 100% of its long-term debt securities in the same year, a situation now faced by UNS Electric in 2008. If UNS Electric enjoyed healthy cash flows and an investment-grade credit rating going into this rate case, I could see how other parties might criticize a request to include CWIP in rate base. However, in light of the Company's strained cash flows and speculative-grade credit rating, it is disappointing that both Staff and RUCO oppose the Company's request to include CWIP in rate base.

Q. The inclusion of CWIP in rate base was recently considered and rejected by the Commission in the most recent Arizona Public Service Company ("APS") rate case. Can you point to any differences between the situation facing UNS Electric and that of APS?

A. Yes. Besides the obvious, such as size and financial wherewithal, there are several key differences that warrant examination. Based on my reading of Decision No. 69663 (June 28, 2007) – the opinion and order in the APS rate case – several factors were considered in rejecting the request for CWIP in rate base.

First, Staff was critical of the request because it was not presented in APS' Direct Testimony of APS, resulting in less time being available for discovery and analysis of the issue. That is not the case with UNS Electric, which included its request for CWIP in rate base in its original application and Direct Testimony.

Second, APS asked for CWIP in rate base in order to avoid being downgraded to a speculative-grade credit rating. UNS Electric already has a speculative-grade rating, and is attempting to improve its financial condition so it can eventually achieve an investment-grade credit rating.

Third, the financial forecast provided by APS was criticized because it included the results of operations for the transmission segment of its business, a sizable segment that falls under the rate jurisdiction of the Federal Energy Regulatory Commission ("FERC"). By contrast, due to the limited size and scope of its transmission assets, no wholesale transmission services are presently being provided by UNS Electric.

Lastly, Finding of Fact No.37 in Decision No. 69663 states that "APS failed to demonstrate that the near-term costs of customer growth are greater than the increased revenues generated by that growth." By contrast, I have presented clear evidence that the near-term cost of customer growth greatly exceeds the incremental revenues produced by that growth. In my Rebuttal Testimony on page 14, I described how Exhibit KCG-10 showed that new customers added approximately $1.2 million in annual delivery revenues for the year ending June 30, 2007 – while the Company's annual fixed costs increased by about $6.0 million. That means the Company experienced a $4.8-million increase in its annual revenue deficiency. Additionally, as demonstrated on Exhibit KCG-11 attached to my Rebuttal Testimony, the rate of growth in net plant investment at UNS Electric has exceeded that of APS – as well as that of Tucson Electric Power Company and Southwest Gas Corporation – by a substantial margin over the past three years on both an absolute and per-customer basis. The Company reemphasizes these key facts as Mr. Smith seemingly fails to recognize any of them in rejecting the Company's proposal.

Q. Do you have any comments regarding Mr. Smith's characterization of regulatory lag and the relevance of financial forecasts in the rate setting process?

A. Yes. Regarding the subject of regulatory lag, Mr. Smith appears to brush off any concerns over the time required to prepare and process a rate case by referring to past precedent and the existence of regulatory lag in other jurisdictions. On page 11 of his Surrebuttal Testimony, lines 11 through 15, Mr. Smith makes the following statement:

> "Regulatory lag refers to the difference in time between the test year and the rate effective date. My understanding is that it has always existed as an integral part of rate of return-based public utility regulation in Arizona, and for that matter virtually all states. It is not a new phenomenon which would require a change in basic regulatory policy."

While I agree with Mr. Smith that regulatory lag is a common phenomenon in many rate jurisdictions, he fails to recognize that changes to "basic regulatory policy" are sometimes warranted due to changing circumstances. Due to a rapidly expanding population and increasing electrical demands, electric utilities in Arizona, including UNS Electric, are struggling to cope with a surge in new transmission and distribution plant investment. At the same time, the regulatory lag period referred to by Mr. Smith is significantly longer in Arizona relative to that experienced in most other states. Even so, and as I indicated in Rebuttal Testimony, many other rate jurisdictions include CWIP in rate base.

The timeliness of cost recovery by utilities is also receiving renewed attention by the major credit rating agencies. For example, in an August 2007 publication entitled "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," Moody's Investors Service had the following observations:

> "...there are concerns arising from the sector's sizable infrastructure investment plans in the face of an environment of steadily rising operating costs. Combined, these costs and investments can create a continuous need for regulatory rate relief, which in turn can increase the likelihood for political and/or regulatory intervention. Conceivably, the combination of rising costs, higher infrastructure investment needs and larger or more frequent requests for rate relief could create pressure for future incremental rate relief from regulators, or at a minimum, raise the uncertainty level associated with expected recoveries – thereby directly affecting one of our primary rating drivers." (See page 1 of the Moody's publication, attached as Exhibit KCG-14.)

. . .

> "In our opinion, the rising costs and investment needs will have a direct impact on all three financial statements: income, cash flow and balance sheet. As a result, one of the biggest challenges for utility companies will be to seek and receive timely recovery of prudently incurred expenses. In addition, the substantial increases in capital expenditures will have a material impact on the sector's ability to generate free cash flow. While Moody's recognizes that the utility sector usually operates in a negative free cash flow environment, a concern could be raised if the level of negative free cash flow became large enough, or if regulatory lag was long enough, that the leverage were to increase materially." (See page 3 to Exhibit KCG-14.)

In the case of UNS Electric, assuming new rates are implemented in January 2008, the regulatory lag period will have lasted approximately 18 months from the test year ended June 30, 2006. From a financial perspective, that is a long time to wait when the cost of customer growth greatly exceeds the incremental revenues derived from that growth.

Regarding the use of financial forecast information, Mr. Smith cautions against using such information in this proceeding. Starting on page 10 of his Surrebuttal Testimony at line 23, Mr. Smith makes the following statement:

> "To the extent that Mr. Grant is attempting to use his revised financial forecasts as some kind of surrogate for a future test year, or as some kind of test of the reasonableness of the parties' differing recommendations, his comparisons to not appear to reflect the adjustments to rate base or expenses that contribute to Staff recommending a different level of revenue increase than has been requested by the Company."

I have two concerns with this statement. First, it appears that Mr. Smith may have misinterpreted the Company's intent regarding the use of financial forecast information. Second, he suggests that further adjustments to the financial forecasts are warranted, when in fact no such adjustments are warranted.

Q. Please explain.

A. Certainly. While UNS Electric would certainly support the opportunity to eliminate regulatory lag through the use of a future test year, the Company is fully aware of the fact that Arizona relies on a historical test year for setting rates. That is exactly what the Company used here. The test year ended June 30, 2006 formed the basis for UNS Electric's rate request, including known and measurable adjustments thereto, and the CWIP balance being requested in this case reflects the amount outstanding as of that date. There is simply no merit to Mr. Smith's insinuation that the Company's financial forecasts are being used somehow as a "surrogate" for a future test year. Rather, the financial forecasts are a necessary *component* to determining just and reasonable rates and a fair ROR on the Company's historical test year rate base.

Regarding the Company's use of financial forecast information to "test the reasonableness of the parties' differing recommendations," Mr. Smith is absolutely correct in making this assumption. Financial forecast information is invaluable in determining whether or not CWIP is needed in rate base to support a utility's financial integrity. This information is also helpful in ensuring that the allowed ROR and overall level of rate relief will be sufficient to support the utility's credit and access to capital. Mr. Smith errs, however, in his insistence that financial forecast information be adjusted to reflect the rate base and cost disallowances recommended by Staff and other parties. It is simply unrealistic to think that future costs will disappear just because ratemaking adjustments are made to historical test year costs. Additionally, the largest difference between the Company and Staff in terms of revenue requirement relates to CWIP in rate base and the allowed ROE, two items that only affect revenues on a going-forward basis. Since the financial forecasts presented in my Direct and Rebuttal Testimonies reflect the best estimates of management, and are consistent with the internal operating and capital budget outlooks prepared for the Company, there is no basis for adjusting these forecasts as suggested by Mr. Smith.

Q. Does that conclude your response to the Surrebuttal Testimony of Mr. Smith?

A. Yes, it does.

III. <u>RESPONSE TO STAFF WITNESS DAVID C. PARCELL'S SURREBUTTAL TESTIMONY.</u>

Q. What comments do you have on the Surrebuttal Testimony of Mr. Parcell?

A. My comments will be brief, as most of the points raised by Mr. Parcell on the cost of capital were addressed in my Rebuttal Testimony. However, I feel compelled to comment on his misunderstanding of the relationship between UNS Electric and its parent company, UniSource Energy Corporation ("UniSource Energy").

Q. What misunderstanding are you referring to?

A. Mr. Parcell continues to believe that UNS Electric somehow derives most of its financial strength from UniSource Energy. In discussing the cost of capital to UNS Electric on pages 4 and 5 of his Surrebuttal Testimony, Mr. Parcell makes numerous references to the Company's corporate affiliates including UniSource Energy, Tucson Electric Power Company ("TEP"), UNS Gas, Inc. ("UNS Gas") and UniSource Energy Services ("UES"), the intermediate holding company that owns both UNS Electric and UNS Gas. He cites the financial linkages between UNS Electric and its parent companies, as well as the decision not to merge UNS Electric into TEP, as reasons for dismissing the company-specific risks facing UNS Electric. In doing so, I believe that Mr. Parcell has confused the risk of investing in UNS Electric with the risk of investing in UniSource Energy, and has subtly attempted to shift the issue of financial integrity to the parent company and away from the operating utility where it rightfully belongs.

Q. Please describe the linkages between UNS Electric and its corporate affiliates.

A. UNS Electric is a public service corporation owned by UES, an intermediate holding company owned by UniSource Energy. Due to lender requirements, UES provided a guarantee for the repayment of long-term debt and credit facility borrowings at both UNS

Electric and UNS Gas. Other than the UES guarantee, no other guarantees have been provided to UNS Electric by any corporate affiliate including UniSource Energy. UNS Electric is a separate corporation having its own assets and obligations that are clearly segregated from its affiliates. It is responsible for procuring purchased power, natural gas and other materials and services on its own credit. And although UES has guaranteed the Company's long-term debt and credit facility borrowings, UNS Electric's debt securities were rated separately from UNS Gas and received different terms and conditions when the existing long-term notes were issued in 2003. The only other corporate transactions between UNS Electric and its affiliates involve the provision of administrative and operating support services by TEP, the participation by UNS Electric in a consolidated tax sharing agreement, and the infusion of additional equity capital from time to time by UniSource Energy and UES. Although these linkages and corporate affiliations serve to strengthen the financial standing of UNS Electric, they are clearly limited in terms of their scope and size.

Q. On page 5 of his Surrebuttal Testimony, lines 1 through 4, Mr. Parcell refers to a potential merger of UNS Electric with TEP as a means of reducing the cost of capital to UNS Electric. Is such a merger feasible?

A. No, it is not. As indicated in the response to Staff Data Request No. STF 4.7, TEP is an issuer of tax-exempt local furnishing bonds, of which $359 million are currently outstanding. An additional $221 million of local furnishing bonds that were repurchased in 2005 also remain eligible for re-issuance. As an issuer of local furnishing bonds TEP is restricted to providing retail service within a two-county area. If UNS Gas or UNS Electric were to merge with TEP, TEP would no longer qualify as an issuer of local furnishing bonds, thereby causing the redemption or defeasance of these low cost bonds. As a consequence, TEP would experience a substantial increase in its cost of debt. Since this would clearly not be in the interest of TEP or its customers, the merger scenario referenced by Mr. Parcell is simply not feasible at this time.

Q. Is the linkage between UNS Electric and its other corporate affiliates relevant to an assessment of financial integrity and cost of capital?

A. No, it is not. Unless the utility has somehow been harmed as a result of the parent/subsidiary relationship, which is clearly not the case for UNS Electric, the issue of who owns the utility is largely irrelevant. The cost of capital is a function of the risk to which it is exposed, and not on the identity of the investor providing capital. Likewise, it is the utility that is responsible for providing service and attracting the capital and other resources needed to provide that service, and not the parent company holding an equity interest in the utility. Although a substantial portion of UNS Electric's capital has obviously come from UniSource Energy in the form of equity contributions, as well as from the retention of earnings that otherwise could have been paid out as dividends, this continuing financial support is clearly premised on the ability of UNS Electric to earn a reasonable ROR on its invested capital.

Q. Does that conclude your response to Mr. Parcell's Surrebuttal Testimony?

A. Yes, it does.

IV. RESPONSE TO RUCO WITNESS MARYLEE DIAZ CORTEZ'S SURREBUTTAL TESTIMONY.

Q. What comments do you have on the Surrebuttal Testimony of Ms. Diaz Cortez?

A. Since I did not find any new arguments on the issue of CWIP in rate base in the Surrebuttal Testimony of Ms. Diaz Cortez, I have no further comments to make. I would instead refer to the Rebuttal Testimony I filed earlier in response to Ms. Diaz Cortez' Direct Testimony, and to my earlier response in this Rejoinder Testimony to Mr. Smith, whose arguments overlap with those of Ms. Diaz Cortez.

Q. Does that conclude your response to Ms. Diaz Cortez' Surrebuttal Testimony?

A. Yes, it does.

V. RESPONSE TO RUCO WITNESS WILLIAM RIGSBY'S SURREBUTTAL TESTIMONY.

Q. Do you have any comments on the Surrebuttal Testimony filed by Mr. Rigsby?

A. Yes, I do. I will focus my comments on the following issues: (i) Mr. Rigsby's interpretation of recent developments in the financial markets, (ii) his continued justification of abnormally low growth rates in the discounted cash flow ("DCF") model, (iii) his dismissal of regulatory lag and the impact of growth on UNS Electric and (iv) his conclusion regarding the sufficiency of RUCO's rate recommendation in light of the *Hope* and *Bluefield* court decisions.

Q. Does Mr. Rigsby discuss recent developments in the financial markets?

A. Yes, he does. On pages 6 through 8 of his Surrebuttal Testimony he discusses the recent turmoil experienced in the financial markets. In his discussion he refers to recent "borrowing crises," "a turbulent week on Wall Street" and markets that may "fail to settle down." (See page 7 of his Surrebuttal Testimony, lines 1, 4 and 11.) At the end of this discussion, on page 8 of his Surrebuttal Testimony, he then points to a recent reduction in the yield on U.S. Treasury Bills as a reason for reducing the cost of equity estimate obtained from his application of the Capital Asset Pricing Model ("CAPM").

Q. Do you concur with Mr. Rigsby's observations and conclusions?

A. While I certainly agree with his observation that the financial markets have been in a state of turmoil over the past several weeks, I disagree with his conclusion that the cost of equity for UNS Electric would somehow decrease as a result of this turmoil. What Mr. Rigsby has observed is a re-pricing of risk in the financial markets, with a flight to quality by investors that has benefited U.S. Treasury securities and pummeled most other financial assets. Although he is correct in pointing out the substantial reduction in required yields on short-term U.S. Treasury securities, Mr. Rigsby failed to mention the substantial increase in required risk premiums that has occurred in the corporate debt and equity markets. Such an increase, in my opinion, would more than offset any reduction to U.S. Treasury yields when updating a risk premium model such as the CAPM.

Q. How has this recent financial turmoil affected the required risk premiums on utility securities?

A. The risk premiums demanded by investors have increased substantially. The best evidence of this is the widening of credit spreads, or the difference in required rates of return on long-term utility bonds and long-term U.S Treasury bonds. Based on market data available through Reuters financial service, the average credit spread for ten-year utility bonds having a Triple-B credit rating (Baa or BBB) widened from 141 basis points to 178 basis points between September 29, 2006 (the date referenced on page 20 of my Direct Testimony) and August 23, 2007. This increase of 37 basis points (0.37%) reflects the increased risk premium now required by investors for these bonds. Consistent with the previously mentioned flight to quality, the impact on speculative-grade utility bonds has been much more severe. The observed credit spread for ten-year utility bonds having a Double-B credit rating (Ba or BB) widened from 220 basis points to 345 basis points over this same period, an increase of 125 basis points (1.25%). Since the required yield on ten-year U.S. Treasury bonds has dropped by only 2 basis points (0.02%) over this same period of time, it is apparent that the cost of both debt and equity capital for utilities with speculative-grade ratings has increased substantially since my Direct Testimony was filed.

This disproportionate increase to the cost of capital, relative to investment-grade utilities, also demonstrates the prudence of targeting and maintaining an investment-grade credit rating for UNS Electric.

Q. What comments do you have regarding Mr. Rigsby's discussion of long-term DCF growth rates?

A. Mr. Rigsby dedicates nearly five pages of his Surrebuttal Testimony to a defense of the dividend growth rates used in his constant growth DCF model and to a further critique of the growth rates used in my multi-stage DCF model. Regardless of whether the constant growth or multi-stage version of the DCF model is used, it is obvious that the results obtained are highly sensitive to the growth rates selected. Unfortunately, as discussed in my Rebuttal Testimony, Mr. Rigsby's use of abnormally low growth rates results in cost of equity estimates as low as 6.6% for his comparable company group. By contrast, my use of five-year growth rates reflecting company-specific projections, followed by the use of an industry-wide growth rate that closely approximates the expected long-term growth rate in the U.S. economy, results in cost of equity estimates that are much more reasonable when compared with (i) recent ROE allowances for other electric utilities, (ii) required yields on investment-grade utility bonds and (iii) the results that Mr. Rigsby and I obtained for the same group of companies using the CAPM. For this reason, I recommend once again that Mr. Rigsby's DCF analysis be given little or no weight in this proceeding.

Q. On page 15 of his Surrebuttal Testimony, lines 1 through 10, Mr. Rigsby downplays the significance of regulatory lag and growth for UNS Electric. Does he offer any new arguments on this subject?

A. No, he does not. However, on page 16 of his Surrebuttal Testimony, lines 1 through 11, he now cites a probable slowing of growth in Mohave County as a positive factor for UNS Electric.

Q. Do you agree that a slowing of growth in the Company's service territory would be a positive development for UNS Electric?

A. If a slowdown in customer growth were accompanied by a reduction in capital spending, then I would agree with Mr. Rigsby on this point. However, based on preliminary planning for fiscal years 2008 through 2012, it does not appear that capital spending for UNS Electric will decrease even if a decline in customer growth occurs. The primary reason for this is the increased cost of system reinforcement work that UNS Electric is now planning for. As a result, the financial forecasts presented in my Direct and Rebuttal Testimony may be overly optimistic. If a significant slowdown in customer and sales growth occurs, with no commensurate decrease to the Company's capital spending requirements, the end result would be lower earnings and cash flow relative to the forecasts previously presented.

Q. On page 15 of his Surrebuttal Testimony, Mr. Rigsby states his belief that RUCO's rate recommendation will satisfy the capital attraction standards set forth in the *Hope* and *Bluefield* decisions. What evidence does he offer in this regard?

A. The only evidence I could find was on page 15, lines 14 through 16, where he states that "RUCO believes that the rates it is recommending in this case will provide the Company with the opportunity to recover its operating expenses and provide a return on its invested capital." Unfortunately, I could find no other analysis or discussion in his testimony regarding the *adequacy* of that return. As discussed in my Rebuttal Testimony, RUCO's rate recommendation is expected to result in an earned ROE of only 2.6% in 2008 assuming a full year of rate relief. This expected return is so low that it cannot even compete with the 4.09% risk-free rate on U.S. Treasury bills cited by Mr. Rigsby on page 8, line 7 of his Surrebuttal Testimony. Under RUCO's rate recommendation, UniSource Energy would be better off investing in short-term U.S. Treasury bills than investing additional equity capital in UNS Electric.

Q. Does that conclude your Rejoinder Testimony?

A. Yes, it does.

EXHIBIT

KCG-14

Special Comment

August 2007

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Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector

Summary

While the rating outlooks for the vast majority of the North American regulated electric utility companies remain stable, a number of "storm clouds" appear to be gathering on the horizon which could have negative credit implications over the intermediate-term. The stable outlook is primarily based on the consistency of key financial credit ratios reported over the past few years, an expected continuation of relatively strong financial metrics over the next 6 to 18 months, our views regarding timely regulatory recoveries of prudently incurred costs and investments and an overall focus on regulated operations by management. One of the most significant factors incorporated into our outlook is a view that most utility management teams will maintain healthy and constructive relationships with their state regulatory authorities and that most state regulatory authorities prefer to regulate financially healthy utilities within their states.

However, there are concerns arising from the sector's sizable infrastructure investment plans in the face of an environment of steadily rising operating costs. Combined, these costs and investments can create a continuous need for regulatory rate relief, which in turn can increase the likelihood for political and/or regulatory intervention. Conceivably, the combination of rising costs, higher infrastructure investment needs and larger or more frequent requests for rate relief could create pressure for future incremental rate relief from state regulators, or at a minimum, raise the uncertainty level associated with expected recoveries — thereby directly affecting one of our primary rating drivers. This potential for increased regulatory uncertainty and pressure for rate relief might peak several years from now, at precisely the time when many companies are completing their base-load generation construction projects or other non-discretionary infrastructure investment projects and the potential for rate shock to consumers would be highest.

Moody's Investors Service
Global Credit Research

Furthermore, despite the clear and present challenges currently facing the industry over the near, intermediate and longer-term horizons, some utility parent holding companies continue to pursue overly biased shareholder reward policies in the form of high dividend payout targets, annual dividend rate increases and common equity repurchase programs. While these financial policies may be rooted in capital efficiency philosophies, and companies obviously work for shareholders, Moody's observes that these shareholder reward strategies are currently being established in the face of increasing business and operating risks that are clearly articulated in the public SEC disclosures, and, in our opinion, typically result in a permanent increase to leverage and fixed obligations. If utility companies experience construction cost overruns, lengthy delays, quasi-permanent recovery deferrals or other adverse regulatory rulings, a deterioration of credit quality could result. Should this situation materialize, Moody's would be concerned over the potential prospect that regulators may harbor little sympathy for companies seeking financial relief if they previously chose a policy that overly benefited shareholders, given the lost opportunity costs associated with strengthening a balance sheet.

Moody's acknowledges the longer-term aspect of the risks associated with these storm clouds and the uncertainty associated with potential downside scenario assessments. At this time, the unknowns associated with the investment plans and regulatory relationships are not sufficient enough to cause direct implications to near-term credit ratings. However, Moody's will continue to assess the constructiveness of the regulatory relationships between utility companies and their respective regulatory commissioners. In our opinion, the relationships with regulators could conceivably counterbalance any potential deterioration of key financial credit ratios, especially if the deterioriation is expected to be relatively temporary. In addition, Moody's expects most utility companies to approach their financing plans with a balanced mix of debt and equity to fund their capital expenditures. If however, the business and operating risks for a utility appear to be increasing at a more significant pace, or the regulatory relationships appear to take a more adversarial tone, the rating outlook would likely change, even if the key financial credit ratios were maintained at current levels.

In this Special Comment, Moody's will explore several of these downside risks to credit quality and articulate our views regarding these risks and how we may incorporate them into our credit analysis.

Summary of Rising Business and Operating Risks

The storm clouds referenced in this report essentially point to a potential increase in the business and operating risk profile for the sector. In our opinion, the rising costs and investment needs will have a direct impact on all three financial statements: income, cash flow and balance sheet. As a result, one of the biggest challenges for utility companies will be to seek and receive timely recovery of prudently incurred expenses. In addition, the substantial increases in capital expenditures will have a material impact on the sector's ability to generate free cash flow. While Moody's recognizes that the utility sector usually operates in a negative free cash flow environment, a concern could be raised if the level of negative free cash flow became large enough, or if regulatory lag was long enough, that the leverage were to increase materially. Furthermore, shareholder dividends could conceivably begin to outpace earnings growth, if the regulatory relationship were to become more confrontational.

Income Statement	Revenues	Will rate relief stay current given potential for rising regulatory/political intervention?
	Fuel & Purchased Power	Rising – need for timely recovery
	Operations & Maintenance	Rising expenses to maintain existing assets
	SG&A	Rising – healthcare / work force
	Interest	What happens to interest rates?
	Taxes	Rising
Cash Flow Statement	Net income	Rising with rate relief and attempts for cost containment
	Depreciation & Amortization	Lower than capital expenditures
	Working Capital/Other	Impact of deferred costs / Liquidity impact
	Capital Expenditures	Rising significantly (plus environmental compliance risk)
	Dividends	Rising. Consistent with earnings. A fixed obligation.
Balance Sheet	Regulatory Assets	Increasing
	Debt	Rising – to fund negative FCF
Increasing regulatory / political intervention risks		
Increasing risks associated with environmental compliance/ Carbon legislation		

Comparable Company Analysis

Moody's regularly utilizes comparable company analysis as part of our fundamental credit research, which we typically refer to as peer groups. These peer groups can be created based on a specific rating category (for example, all Baa1 parent holding companies) or by business composition (for example, all transmission and distribution "T&D" utilities). In this Special Comment, Moody's will summarize the financial results of a much broader peer group than we would typically use for a specific rated entity. In addition, we acknowledge that there may be occasions where a particular company's extraordinary event may skew an annual average (which we may not adjust for), so we have attempted to minimize the effect by also assessing a 5-year average and a 4-year Compound Annual Growth Rate (CAGR) from 2002 to 2006.

The companies included in the peer groups for the bulk of this Special Comment are listed in the tables below. The companies that comprise any additional peer groups, which include companies characterized by region or other industrial, non-utility peer groups, are listed in Appendix A.

Utility Parent Companies	Senior Unsecured Rating*
Allegheny Energy, Inc.	Ba2
ALLETE, Inc.	Baa2
Ameren Corporation	Baa2
American Electric Power Company	Baa2
Aquila, Inc.	Ba3
Avista Corp.	Ba1
Black Hills Corporation	Baa3
Central Vermont Public Service Co.	Ba2**
Cinergy Corp.	Baa2
Cleco Corporation	Baa3
CMS Energy Corporation	Ba1
Constellation Energy Group, Inc.	Baa1
Dominion Resources Inc.	Baa2
DPL Inc.	Baa3
DTE Energy Company	Baa2
Duke Energy Corporation	Baa2
Duquesne Light Holdings, Inc.	Ba1
E. ON U.S. LLC	A3
Edison International	Baa2
El Paso Electric Company	Baa2
Empire District Electric Company	Baa2
Entergy Corporation	Baa3
Exelon Corporation	Baa2
FirstEnergy Corp.	Baa3
FPL Group, Inc.	(P)A2
Great Plains Energy Incorporated	(P)Baa2
Hawaiian Electric Industries, Inc.	Baa2
IDACORP, Inc.	Baa2
Integrys Energy Group, Inc.	A3
IPALCO Enterprises, Inc.	Ba1***
MidAmerican Energy Holdings Co.	Baa1
OGE Energy Corp.	Baa1
Otter Tail Corporation	A3
Pepco Holdings, Inc.	Baa3
PG&E Corporation	Baa3
Pinnacle West Capital Corporation	Baa3
PNM Resources, Inc.	Baa3
PPL Corporation	Baa2
Progress Energy, Inc.	Baa2
PSEG Energy Holdings L.L.C.	Ba3
Public Service Enterprise Group	Baa2
Puget Energy, Inc.	Ba1
SCANA Corporation	A3
Sempra Energy	Baa1
Sierra Pacific Resources	B1
Southern Company (The)	A3
TECO Energy, Inc.	Ba1
TXU Corp.	Ba1
TXU US Holdings Company	Baa3
UniSource Energy Corporation	Ba1***
Westar Energy, Inc.	Baa3
Wisconsin Energy Corporation	A3
Xcel Energy Inc.	Baa1

** Long-term Issuer Rating used where Senior Unsecured is not available.*
*** Preferred Stock*
**** Senior Secured*
***** First Mortgage Bond*

Integrated Utilities	Senior Unsecured Rating*
Alabama Power Company	A2
Appalachian Power Company	Baa2
Arizona Public Service Company	Baa2
Black Hills Power, Inc.	Baa2
Central Illinois Light Company	Ba1
Cleco Power LLC	Baa1
Columbus Southern Power Company	A3
Consumers Energy Company	(P)Baa2
Dayton Power & Light Company	Baa1
Detroit Edison Company (The)	Baa1
Duke Energy Carolinas, LLC	A3
Duke Energy Indiana, Inc.	Baa1
Duke Energy Ohio, Inc.	Baa1
Entergy Arkansas, Inc.	Baa2
Entergy Gulf States, Inc.	Baa3****
Entergy Louisiana, LLC	Baa2
Entergy Mississippi, Inc.	Baa3
Entergy New Orleans, Inc.	Ba2
Florida Power & Light Company	A1
Georgia Power Company	A2
Green Mountain Power Corporation	Baa1****
Gulf Power Company	A2
Hawaiian Electric Company, Inc.	Baa1
Idaho Power Company	Baa1
Indiana Michigan Power Company	Baa2
Indianapolis Power & Light Company	Baa2
Interstate Power and Light Company	A3
Kansas City Power & Light Company	A3
Kansas Gas & Electric Co.	Baa2***
Kentucky Power Company	Baa2
Kentucky Utilities Co.	A2
Louisville Gas & Electric Company	A2
Madison Gas and Electric Company	Aa3
MidAmerican Energy Company	A2
Mississippi Power Company	A1
Monongahela Power Company	Baa3
Nevada Power Company	B1
Northern States Power Company (MN)	A3
Northern States Power Company (WI)	A3
Ohio Power Company	A3
Oklahoma Gas & Electric Company	A2
Pacific Gas & Electric Company	Baa1
PacifiCorp	Baa1
Portland General Electric Company	Baa2
Progress Energy Carolinas, Inc.	A3
Progress Energy Florida, Inc.	A3
Public Service Company of Colorado	Baa1
Public Service Company of New Hampshire	Baa2
Public Service Company of New Mexico	Baa2
Public Service Company of Oklahoma	Baa1
Puget Sound Energy, Inc.	Baa3
Savannah Electric and Power Company	A2
Sierra Pacific Power Company	B1
South Carolina Electric & Gas Company	A2
Southern California Edison Company	A3
Southwestern Electric Power Company	Baa1
Southwestern Public Service Company	Baa1
Tampa Electric Company	Baa2
Tucson Electric Power Company	Baa3
Union Electric Company	Baa1
Virginia Electric and Power Company	Baa1
Wisconsin Electric Power Company	A1
Wisconsin Power and Light Company	A2
Wisconsin Public Service Corporation	A1

T&D Utilities	Senior Unsecured Rating*
AEP Texas Central Company	Baa2
AEP Texas North Company	Baa1
Atlantic City Electric Company	Baa1
Baltimore Gas and Electric Company	Baa2
CenterPoint Energy Houston Electric	Baa3
Central Hudson Gas & Electric Co	A2
Central Illinois Light Company	Ba1
Central Illinois Public Service	Ba1
Central Maine Power Company	A3
Cleveland Electric Illuminating	Baa3
Commonwealth Edison Company	Ba1
Connecticut Light and Power Company	Baa1
Consolidated Edison Company of NY	A1
Delmarva Power & Light Company	Baa2
Duquesne Light Company	Baa2
Illinois Power Company	Ba1
Jersey Central Power & Light Company	Baa2
Metropolitan Edison Company	Baa2
New York State Electric and Gas	Baa1
NSTAR Electric Company	A1
Ohio Edison Company	Baa2
Orange and Rockland Utilities	A2
PECO Energy Company	A3
Pennsylvania Electric Company	Baa2
Pennsylvania Power Co.	Baa2
Potomac Edison Company (The)	Baa3
Potomac Electric Power Company	Baa2
PPL Electric Utilities Corporation	Baa1
Public Service Electric and Gas	Baa1
Rochester Gas & Electric Corporation	Baa1
San Diego Gas & Electric Company	A2
Texas-New Mexico Power Company	Baa3
Toledo Edison Company	Baa3
TXU Electric Delivery Company	Baa2
West Penn Power Company	Baa3
Western Massachusetts Electric Co.	Baa2

T&D Parent Companies	Senior Unsecured Rating*
AES El Salvador Trust	Baa3
CenterPoint Energy, Inc.	Ba1
CILCORP Inc.	Ba2
Consolidated Edison, Inc.	A2
Energy East Corporation	Baa2
Northeast Utilities	Baa2
NorthWestern Corporation	Ba2
NSTAR	A2
UIL Holdings Corporation	Baa3

Rising Operating Cost Structure

In general, Moody's believes that the North American regulated utility sector is facing a long-term period of rising operating costs, which include fuel and purchased power, operating and maintenance (O&M) costs, and selling, general and administrative (SG&A) expenses. The ability to recover these rising costs on a timely basis through rate relief has increasingly become a significant determinant to credit quality and highlights the importance for utility management teams to maintain constructive relationships with state regulatory authorities and provide reliable service to end-use customers.

The stable rating outlook for the sector is largely premised on our belief that these costs will be recovered on a reasonably timely basis. However, for those companies that are incurring large, multi-year deferral balances, Moody's may begin to incorporate a higher risk profile, which would create pressure to maintain a stronger balance sheet and cash flow coverage metrics. The size of these potential balances should become more clear over the next 18 to 24 months.

FUEL AND PURCHASED POWER

The largest and most volatile expense on the income statement is fuel and purchased power, which has averaged approximately 48% of revenues over the past 5 years for the integrated electric utility group. The trend has been rising, with these costs averaging 51.4% of revenues in 2006, compared with 43.7% in 2002. As noted in Table 1 below, the average gross margin for the integrated electric utilities has declined from 56% in 2002 to 49% in 2006, a decline of roughly 13%, while the gross margin of T&D utilities has remained reasonably steady.

Table 1

Gross Margin as a % Revenue

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	56%	54%	54%	49%	49%	52%	-3.3%
T&D Utility	45%	46%	46%	45%	45%	45%	—
Utility Parent	56%	53%	51%	49%	49%	52%	-3.3%
T&D Parent	49%	48%	46%	41%	43%	45%	-3.2%

Moody's acknowledges that an assessment of gross margin is somewhat misleading for the utility sector, especially when considering the pass-through nature of many fuel and purchased power costs. For example, if a utility collects $100 in revenue and spends $50 on fuel, its gross margin would be 50%. If however, that same utility experienced a doubling of its fuel costs — to $100 — which was directly passed-on to customers, its revenues would be $150 and its gross margin would fall to 33%.

With respect to these gross margins, Moody's notes that the vast majority of utilities do not earn margins on their fuel and purchased power expenses, but instead enjoy specific rate riders to address these costs as direct pass-through items to end-use customers. Our concern with these pass-through rate riders, however, reside with the timing differences between when a company needs to procure its fuel and purchased power and when it collects the costs from ratepayers. Due to the extremely volatile nature of natural gas, oil and power commodity prices, many companies can very quickly find themselves in a significant under-recovery position, which could stress liquidity. Examples of utilities which have experienced large deferred fuel and purchased power costs include Alabama Power, Georgia Power, Virginia Electric and Power and Arizona Public Service.

Recovery of deferred fuel costs over an extended time period during which fuel costs are rising weakens the overall credit profile of utilities, due to the increasing mismatch between cost incurrence and cost recovery. Moreover, Moody's believes utilities may find themselves having a more difficult time seeking other base rate or incremental fuel relief in such an environment. End-use customers and intervener groups are also less likely to be sympathetic to the factors driving the rate increases during regulatory proceedings making the management of relationships with regulators and other interested parties challenging. (Moody's acknowledges that most large industrial customers recognize the fuel rates and the pass-through nature of the fuel riders and tend to be less concerned with this particular issue).

SELLING, GENERAL AND ADMINISTRATIVE EXPENSES

In addition to fuel costs, the fundamental operating cost structure appears to be rising as well. Industry consulting groups and data collection agencies can demonstrate a clear trend in rising costs on a per-customer basis. However, over the past 5 years, this trend can not be demonstrated through our financial analysis, as the level of SG&A expenses as a percentage of revenues appears to remain relatively stable at roughly 11% for the integrated electrics and roughly 9% for the T&D utilities.

Table 2

SG&A expenses as a % revenue

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	11%	10%	12%	11%	10%	11%	-2.4%
T&D Utility	10%	8%	9%	9%	9%	9%	-2.6%
Utility Parent	11%	9%	10%	9%	9%	10%	-4.9%
T&D Parent	16%	10%	11%	10%	11%	12%	-8.9%

OPERATING MARGIN

However, the concern over a steadily rising operating cost structure is evident in the average operating margins. As noted in the table below, the operating margin as a percentage of revenue has steadily fallen for the integrated utilities from approximately 18% in 2002 to approximately 15% in 2006. The deterioration is also evident for the T&D utilities, which have fallen from approximately 16% in 2002 to approximately 13% in 2006.

Table 3

Operating Margin as a % revenue

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	18%	17%	17%	15%	15%	16%	-4.5%
T&D Utility	16%	16%	16%	15%	13%	15%	-5.1%
Utility Parent	14%	15%	15%	15%	15%	15%	1.7%
T&D Parent	13%	12%	17%	11%	11%	13%	-4.1%

In general, the vast majority of the operating costs related to regulated utility operations are recoverable through base rates, and most regulatory authorities are aware of the rising costs facing the industry. While operating margin is less helpful to credit analysis, it does provide a view of profitability. Any sustained deterioration of the sector's profitability could negatively bias our sector rating outlook.

INTEREST EXPENSE

Interestingly, the average interest expense as a percentage of revenue appears to remain relatively stable at approximately 5% for the integrated electrics, having fallen from roughly 6.3% in 2002. For the T&D utilities, interest expense as a percentage of revenue fell from approximately 6.4% in 2002 to 5.75% in 2006. As debt levels and interest rates reverse the declining trend of the last several years, interest expense as a percentage of revenues may begin to increase, depending on cost of capital recovery proceedings.

Table 4

Interest Expense as a % revenue

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	6%	6%	6%	5%	5%	6%	-4.5%
T&D Utility	6%	6%	6%	5%	6%	6%	—
Utility Parent	8%	8%	8%	6%	7%	7%	-3.3%
T&D Parent	7%	7%	7%	6%	6%	7%	-3.8%

In summary, the majority of the expenses "above the line" are expected to be recovered through the regulated rate-making process, although some of this recovery could be impacted by regulatory lag. Utility companies should recover these costs and expense deferrals (such as those associated with fuel and purchased power) in a reasonably timely manner. As such, the primary credit implications associated with the costs and expenses, and recoveries associated with regulatory lag, relate to working capital and liquidity.

In general, a vast majority of utility companies maintain a relatively healthy amount of liquidity capacity that helps them mitigate the loss of financial flexibility from any delayed regulatory response to cost recoveries. We have also observed, over the past few years, a trend away from bilateral facilities and more towards committed, fully syndicated multi-year facilities without MAC clauses beyong initial closing on the facility. We view this development as a credit positive.

Larger Capital Expenditure Programs

Although industry estimates vary widely, there appears to be an expectation that the utility sector will make significant infrastructure investments over the next few years, including investments in generation, transmission and distribution assets as well as environmental mitigation. In fact, there has been a considerable increase in the projected estimates of capital expenditures in the public disclosure for year-end 2006 versus year-end 2005.

Given the relatively non-discretionary nature of the announced capital expenditure plans (such as environmental compliance, new generation build and transmission upgrades), Moody's expects a significant portion of these plans to translate into actual investments. However, we note that the timing associated with some of the announcements appears to be relatively aggressive. For example, a number of companies in the sector have announced plans to build new base load generation, such as coal or new nuclear plants. In our opinion, these projects will take approximately 50–60 months for construction, after the necessary permitting process has been completed. In addition, many T&D utilities (as well as integrated electrics) have announced new transmission projects beyond simple maintenance of the existing system. In our opinion, there will likely be significant resistance from numerous intervener groups which could potentially delay some of these projects.

There are many ways to evaluate the increase in capital expenditure plans, the most notable of which is the public disclosure in the annual SEC filings. This increasing level of investment has actually started to materialize in the financial statements as utility companies geared up over the past few years for the increases in maintenance and new projects. This increase is apparent in a ratio of capital expenditures to cash flow from operations, as noted in the table below and is arguably related to the expiration of many rate-freeze periods when capital expenditures may have been smaller.

Table 5

Capital Expenditures / CFO

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	83%	99%	78%	410%*	110%	93%	7.3%
T&D Utility	78%	72%	69%	72%	129%	84%	13.4%
Utility Parent	79%	77%	71%	113%	126%	93%	12.4%
T&D Parent	90%	55%	83%	144%	113%	97%	5.9%

** Excluded from 5-yr. average. Outlier primarily attributed to Entergy subsidiaries.*

Capital expenditure as a percentage of annual depreciation expense has also been increasing, and Moody's observes that the investments are beginning to be made in very long-lived assets with long book depreciation lives.

Table 6

Capital Expenditures / Depreciation Expense

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	286%	148%	157%	166%	200%	191%	-8.6%
T&D Utility	120%	134%	151%	172%	189%	153%	12.0%
Utility Parent	164%	147%	140%	153%	195%	160%	4.4%
T&D Parent	174%	152%	165%	165%	192%	170%	2.5%

One of the more alarming ratios that highlight the increased spending and its potential impact on credit quality is cash flow, adjusted for working capital items less dividends, as a percentage of capital expenditures. Prospectively, Moody's would expect these ratios to continue to decline over the next few years, depending on how much of the expected investment actually materializes and what recovery arrangements are in place.

Table 7

CFO Pre-W/C – Dividends / Capital Expenditures

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	101%	101%	102%	88%	76%	94%	-6.9%
T&D Utility	134%	127%	136%	95%	65%	111%	-16.6%
Utility Parent	114%	122%	123%	103%	96%	112%	-4.2%
T&D Parent	94%	104%	103%	108%	72%	96%	-6.5%

As these cash outlays begin to flow through the statement of cash flows, many companies will begin to stress their key financial credit metrics, regardless of any regulatory recovery mechanisms, due to timing differentials and the sheer size of the projects. If the expected deterioration to the financial statements materializes or if the financing plans associated with the increased expenditures primarily encompass the use of debt, negative rating actions could result. For example, SCANA Corporation and its principal utility subsidiary, South Carolina Electric and Gas, were recently placed on review for potential downgrade in part due to its announced increased spending plans driven by higher construction and material costs, new nuclear permitting costs and a change in the associated financing plans of said projects which will now be done soley with the issuance of additional debt. This is clearly a more aggressive financing policy than the company utilized previously. Otter Tail Corporation is another example of a company that has recently experienced a negative rating action (outlook changed to negative from stable) as a result of an expected deterioriation to key financial credit metrics.

Potential For Regulatory and/or Legislative Intervention

An environment of rising operating costs and capital investment needs should increase the frequency of requests for rate relief from state regulatory authorities. In Moody's opinion, these requests appear to be occurring annually or bi-annually now that many rate-freeze periods have expired. Eventually, rate-payers may resist these increases, depending on the magnitude of the increase. Additionally, individual state legislatures may feel the need to intervene to either help address the situation or revise the current rules and regulations.

Not all intervention is negative to credit quality, however. In fact, it appears that many states have recently seen regulatory or legislative intervention that has proven quite beneficial to the utility sector. In general, higher rates make future increases harder to obtain and so many utilities and regulators are beginning to pursue a series of smaller annual increases in an effort to avoid a more dramatic rate shock.

States with More Constructive Recent Regulatory or Legislative Actions	States with Less Constructive Recent Regulatory or Legislative Actions
Wisconsin	Maryland
Virginia	Illinois
Iowa	Arkansas
Florida	Arizona
Louisiana	
Nevada	
North Carolina	
South Carolina	

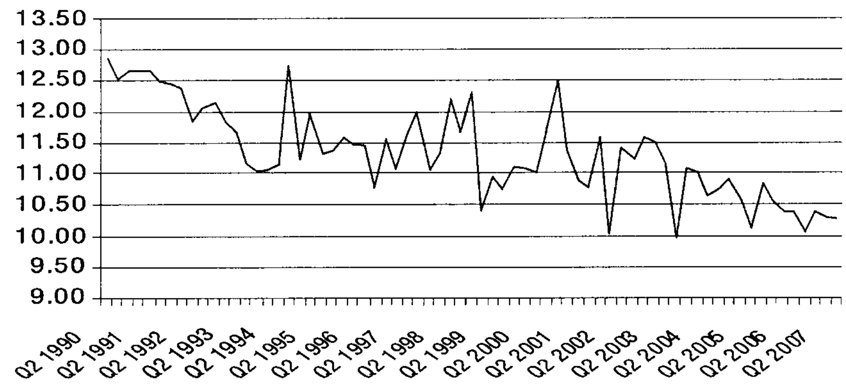
From a credit perspective, the intervention risk could also be affected by management's desire to attain pre-approvals on investments or other cash recovery mechanisms or assurances prior to committing to a particular investment. A future regulatory risk could arise over the intermediate- to longer-term where regulatory authorities find it beneficial to allow for pre-approval or other assurances for recovery but subsequently prescribe a lower allowed equity return reflecting the lower risk profile of the investment.

Table 8

Net Income / Average Equity

	2002	2003	2004	2005	2006	4-yr Avg	3-yr CAGR
Integrated Utility	n/a	11%	11%	10%	10%	11%	-3.1%
T&D Utility	n/a	13%	12%	11%	9%	11%	-11.4%
Utility Parent	n/a	10%	9%	10%	11%	10%	-3.2%
T&D Parent	n/a	12%	11%	9%	12%	11%	—

The chart below is a graphical depiction of average awarded ROE's as calculated by the Edison Electric Institute which shows a similar trend to our analysis in Table 8.

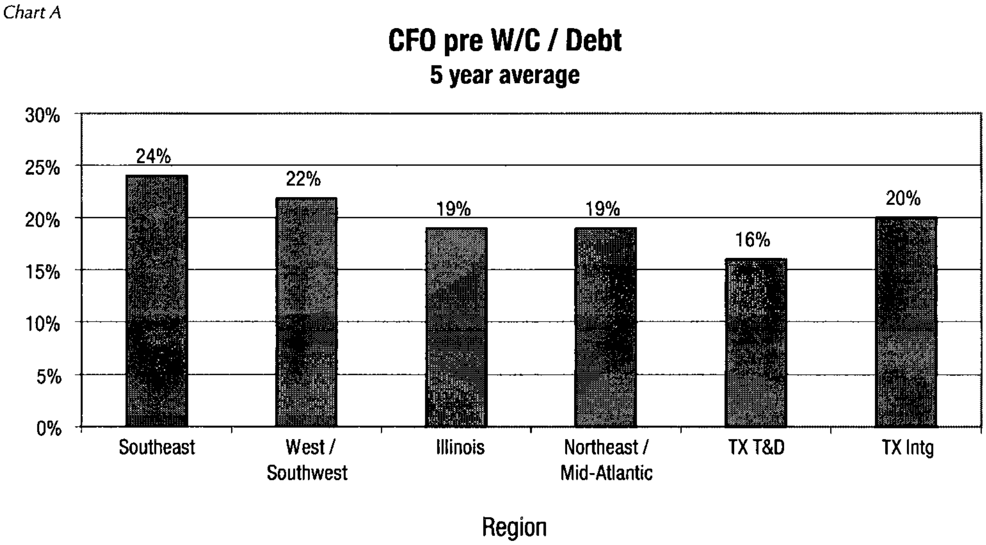


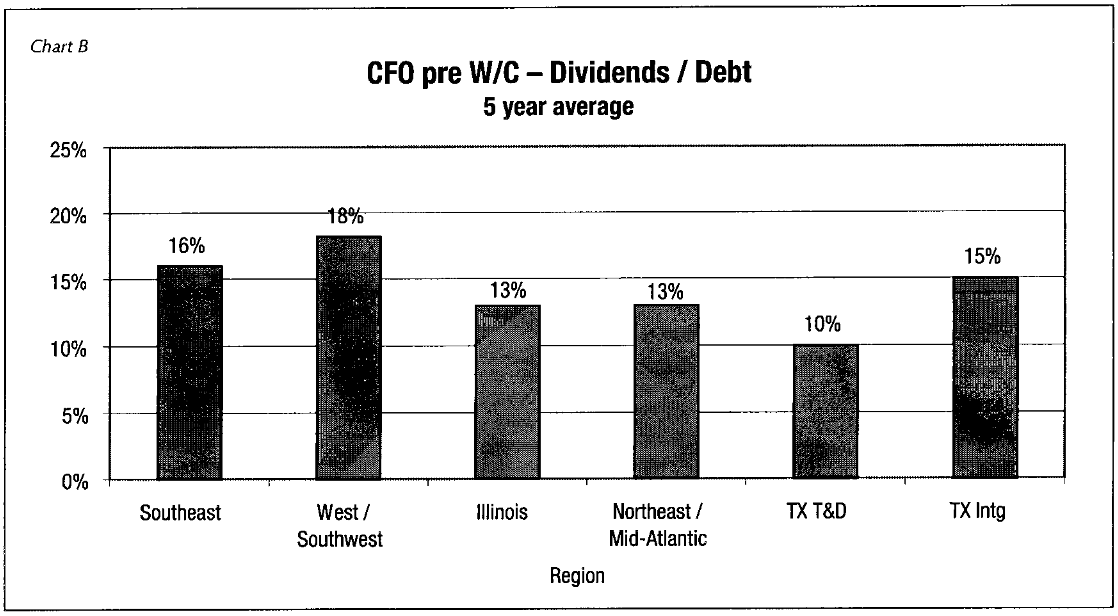
Source: EEI Q2 2007 Financial Update.

Given current macroeconomic market conditions, Moody's believes there are several regulatory commissions that are actively targeting progressively lower equity returns, presumably on the premise that utilities are lower-risk businesses than industrial companies. Consequently, the equity market valuations being ascribed to the regulated utility sector, which are at all-time highs, are likely to reverse themselves in the future. This potential outcome might lead many regulators to question why more companies did not look to access relatively cheap equity at this time, knowing they were entering a phase of significant infrastructure investment.

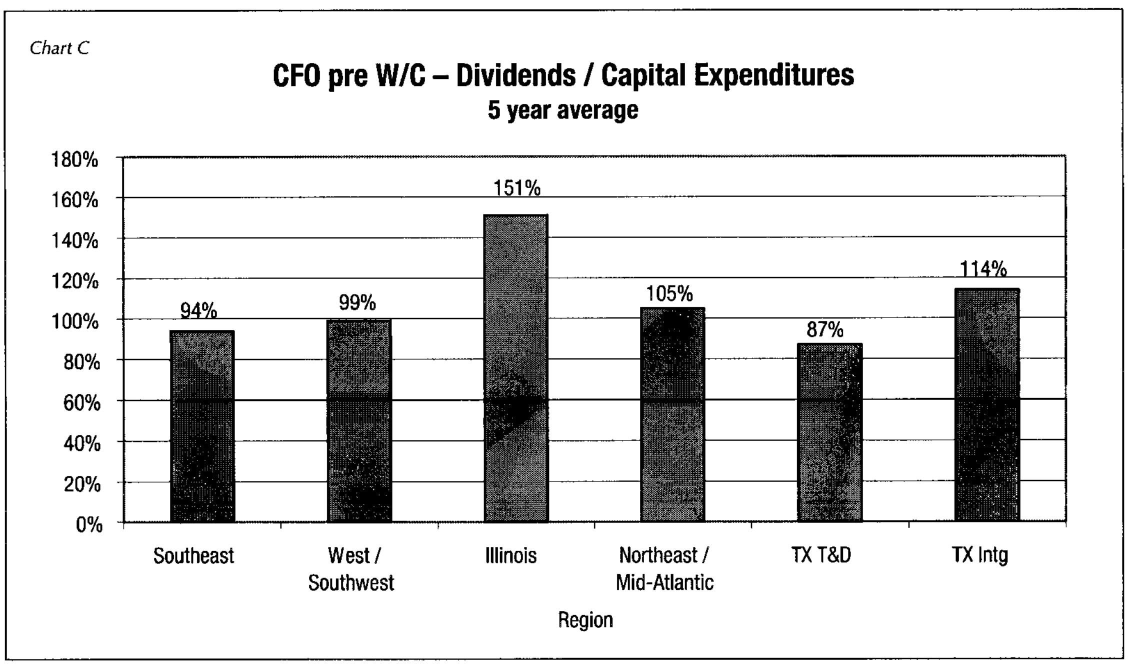
Moody's believes there is a discernable difference between individual state regulatory commissions, their relationship with the utilities they regulate and individual states' prior attempts to deregulate the industry. As noted in the charts below, the states in the southeastern region of the United States and in the West / Southwest, have produced, on average over the past 5 years, higher credit metrics than the states in the Northeast / Mid-Atlantic region, where most utilities divested their generation assets, or perhaps transferred those assets into a less-regulated, affiliate entity. Interestingly, in addition, it appears as if the average metrics for the utilities in the West/Southwest peer group may be experiencing some lift from California.

Chart A





As demonstrated in these charts, the T&D-related utilities in Illinois and the Northeast / Mid-Atlantic region tend to produce a lower level of cash flow to adjusted total debt than their integrated peers, given their rating category. Theoretically, this makes sense given the lower business and operating risk profile associated with many of these T&D utilities, as they generally do not have the more risky generation assets within the vertically integrated utility structure. However, many of these utilities need to procure their power supplies on the open market or through bi-lateral agreements with power generators or merchant energy companies. While these costs are generally passed through to end-use consumers through various rate-rider mechanisms, there could be very significant and potentially devastating consequences to credit quality if regulators, legislators, or other political leaders intervene over rapidly rising prices. This case is most prominent in Illinois where the legislators, not the regulators, lead the intervention, in part due to the steep increase in rates that went into effect this past January after a 10-year rate freeze.



Generous Shareholder Rewards Policies Appear Inconsistent With Increasing Business and Operating Risk Profiles

In general, Moody's observes that most companies and industries that are facing increasing business and operating risk profiles tend to institute corporate finance strategies that are designed to bolster the balance sheet in an effort to address rising uncertainties in a more conservative manner. In the regulated utility sector, some companies appear to be more focused on competing for investor attention by instituting overly generous shareholder reward policies. These shareholder reward polices typically include steady and predictable annual dividend rate increases and equity repurchase programs.

Over the past few years, Moody's has observed a trend where many utility companies are beginning to slowly increase both their leverage and dividend obligations or reinstitute the payment of dividends, such as CMS Energy (dividend only) or Dominion Resources. Moody's generally considers dividends as a fixed expense given the historical reluctance of issuers to either cut or halt the dividends except when confronted with an extremely dire financial situation. Several companies have also raised their dividend payout targets in an effort to attract or retain investor interest. While Moody's recognizes the importance of issuers maintaining strong equity interest given the capital intensive nature of the industry and the need to tap the equity markets from time-to-time to help maintain their metrics, Moody's would also prefer to see a more consistent balance between protection of creditors and shareholder rewards in an effort to defend a particular rating. In the table below, Moody's observes that the average dividend payout for the sector has declined for the integrated utilities and increased for the T&D parent companies.

Table 9

Dividend Payout Ratio (Dividends / Net Income)

	2002	2003	2004	2005	2006	4-yr Avg	3-yr CAGR
Integrated Utility	n/a	82%	75%	44%	68%	67%	-6.0%
T&D Utility	n/a	139%	77%	89%	134%	110%	-1.2%
Utility Parent	n/a	69%	74%	44%	56%	61%	-6.7%
T&D Parent	n/a	69%	69%	139%	106%	96%	15.2%

A majority of the integrated electric utilities in our coverage universe are subsidiaries of parent holding companies. As such, many of the utilities incorporate financial policies that are designed to achieve a leverage target consistent with the allowed regulated equity ratio or regulated capital structure. As a result, some of these subsidiaries are actually demonstrating a reasonably consistent retained cash flow to debt ratio. The same can not be said for the T&D utilities, which have had steadily declining retained cash flow to debt ratios since 2004.

Table 10

CFO pre W/C – Dividends / Debt

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	16%	17%	17%	15%	17%	16%	2.0%
T&D Utility	13%	13%	16%	14%	10%	13%	-8.3%
Utility Parent	12%	14%	14%	13%	14%	13%	5.2%
T&D Parent	9%	10%	11%	12%	9%	10%	—

From a credit perspective, these shareholder reward programs could have implications in companies' dealings with regulators or legislators. Regulatory authorities may feel less sympathetic to companies that might find themselves in increasingly stressful financial conditions as they recall the equity repurchases or other shareholder rewards of the past few years. Under this scenario, it is conceivable that regulators may ask management why it would implement these programs in the face of increasing business and operating risks; especially as it relates to building new base-load generation facilities. This leads us back to the issues of constructive regulatory relationships and timely recovery of costs.

Comparison to Other Regulated, Capital Intensive Industries

Moody's compared the integrated electric utilities and T&D utilities to a selected group of peer industries. These peers are large, capital-intensive industries that are also affected by significant amounts of regulation — for example, environmental or safety-related regulation — or are affected by commodity cycles or weather. For each comparable sector, we selected a small group of companies that we believe constitute a reasonable representation for the peer group average. A list of the companies selected for the peer group is included in Appendix A.

Table 11

CFO pre W/C + Interest / Interest

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Steel	9.2x	6.6x	19.9x	18.0x	22.3x	15.2x	24.8%
Major Oil	8.0x	13.5x	15.1x	18.0x	18.6x	14.6x	23.5%
Shipping	6.3x	7.3x	8.4x	8.3x	7.9x	7.7x	5.8%
Chemicals	5.3x	7.0x	7.5x	7.7x	7.6x	7.0x	9.4%
Integrated Utility	4.9x	5.1x	5.4x	5.0x	4.9x	5.1x	0
Divr. Nat. Gas	4.5x	4.9x	4.9x	4.0x	5.7x	4.8x	6.1%
Paper	3.5x	4.4x	4.6x	4.6x	5.5x	4.5x	12.0%
Railroads	3.8x	4.0x	4.3x	4.7x	5.5x	4.5x	9.7%
T&D Utility	4.1x	4.1x	5.0x	5.0x	3.7x	4.4x	-2.5%
Utility Parent	3.5x	3.7x	3.9x	3.8x	4.0x	3.8x	3.4%
Airlines	3.2x	4.1x	3.5x	3.2x	4.0x	3.6x	5.7%
T&D Parent	2.9x	3.2x	3.3x	3.4x	3.1x	3.2x	1.7%

Table 12

CFO pre W/C / Debt

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Major Oil	34%	58%	70%	95%	98%	71%	30.3%
Steel	31%	20%	92%	83%	120%	69%	40.3%
Chemicals	25%	27%	34%	39%	42%	33%	13.9%
Shipping	22%	29%	34%	37%	35%	31%	12.3%
Paper	15%	22%	22%	23%	31%	23%	19.9%
Integrated Utility	24%	25%	25%	21%	22%	23%	-2.2%
Divr. Nat. Gas	19%	21%	22%	18%	29%	22%	11.2%
T&D Utility	20%	19%	23%	21%	16%	20%	-5.4%
Railroads	17%	18%	20%	23%	28%	21%	13.3%
Utility Parent	16%	18%	18%	18%	19%	18%	4.4%
T&D Parent	12%	13%	15%	16%	15%	14%	5.7%
Airlines	10%	13%	11%	11%	18%	13%	15.8%

One of the more interesting differentiation factors between these large capital intensive industrial sector peers and the utility industry is the ability of the industrials to capitalize on commodity prices. This is most evident with the major oil and steel companies. Oil companies, in general, do not hedge their production the way utilities hedge, and as a result the significant rise in oil prices has resulted in a dramatic impact on earnings and cash flows. Similarly, steel companies have benefited from increased demand and higher prices.

Table 13
CFO pre W/C – Dividends / Debt

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Steel	25%	17%	87%	73%	96%	60%	40.0%
Major Oil	25%	46%	57%	76%	82%	57%	34.6%
Shipping	19%	25%	30%	32%	31%	27%	13.0%
Chemicals	19%	22%	27%	31%	32%	26%	13.9%
Railroads	16%	17%	18%	21%	25%	19%	11.8%
Paper	11%	17%	18%	18%	25%	18%	22.8%
Divr. Nat. Gas	14%	17%	18%	13%	24%	17%	14.4%
Integrated Utility	16%	17%	17%	15%	17%	16%	1.5%
T&D Utility	13%	13%	16%	14%	10%	13%	-6.4%
Airlines	10%	13%	11%	11%	18%	13%	15.8%
Utility Parent	12%	14%	14%	13%	14%	13%	3.9%
T&D Parent	9%	10%	11%	12%	9%	10%	—

Moody's also observes that there is a noticeable consistency among the regulated industries with respect to annual credit ratios versus the more volatile industrial sectors. That being said, Moody's also notes that the industrial peers, many of whom are bailing hay while the sun shines, are not overly leveraging their balance sheets when times are good. Theoretically, this may be due to the inherent acknowledgement that the cyclical nature of the industry sector may eventually turn around again, and some industrial companies are less enthusiastic to an increased level of leverage if they believe future cash flows may be stressed.

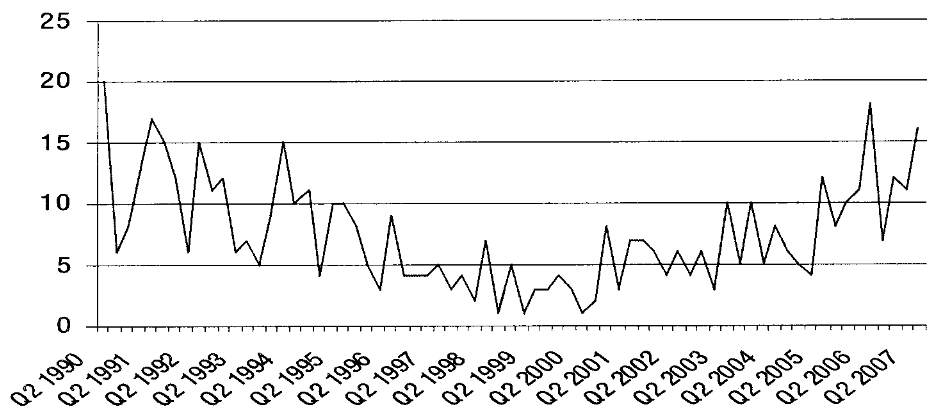
Table 14
CFO pre W/C – Dividends / Capital Expenditures

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Steel	191%	62%	419%	333%	365%	274%	17.6%
Chemicals	148%	217%	224%	216%	168%	195%	3.2%
Paper	135%	215%	213%	173%	220%	191%	13.0%
Shipping	109%	154%	212%	242%	173%	178%	12.2%
Major Oil	96%	146%	157%	175%	163%	147%	14.2%
Railroads	121%	117%	120%	127%	137%	124%	3.2%
Utility Parent	114%	122%	123%	103%	96%	112%	-4.2%
T&D Utility	134%	127%	136%	95%	65%	111%	-16.6%
T&D Parent	94%	104%	103%	108%	72%	96%	-6.8%
Integrated Utility	101%	101%	102%	88%	76%	94%	-6.9%
Divr. Nat. Gas	69%	113%	113%	63%	91%	90%	7.2%
Airlines	56%	76%	72%	84%	105%	79%	17.0%

Conclusion

The regulated electric utility sector is currently facing a period of rising expenses, huge needs to invest in its infrastructure and significant needs to address steadily increasing environmental mandates. As a result, the sector will most likely be very active with state regulators in seeking rate relief, which could strain the reasonably constructive relationships they have enjoyed over the last few years. In addition, legislators may view the sector as an easy target with which to score political points, and may intervene to protest the steadily rising costs associated with lighting, heating and cooling constituent's homes or businesses.

The chart below depicts the number of rate cases filed by utilities as calculated by the Edison Electric Institute.



Source: EEI 2Q 2007 Financial Update

However, none of the issues currently facing the industry are new. In fact, the utility sector has faced an environment with eerily similar uncertainties in the past. The risk, in our opinion, is whether or not the experiences of the past will be repeated in the future. The most significant risk might be future disallowances of investments that were made with an understanding that those investments were prudent and necessary at the time they were made.

Our concern is that even in states with reasonably constructive CWIP or other construction recovery mechanisms, over the life of construction, only approximately 10% – 20% of the total project costs would be recovered. If the balance of the costs, in this case 80% – 90%, were added to rate base in year 5 or 6, rate shock could be meaningful for some utilities. If this scenario materializes, Moody's would be concerned if the regulatory relationship is more confrontational, potentially increasing the risk for large deferrals or disallowances, as had been sometimes the case in previous years. In addition, while Moody's did not spend any material attention to the risks associated with carbon legislation or carbon tax issues in this report, we believe the issues over carbon could be substantial for utility companies over the next several years.

From a credit perspective, it is unclear what impact these storm clouds on the horizon may have on the utility sector. The risks that are currently being highlighted are sufficiently far enough out on the horizon that there appears to be little threat of imminent rating action especially if key financial credit ratios remain at current levels. However, Moody's has raised a question on many occasions as to whether or not utility companies should be re-doubling their efforts to strengthen balance sheets and bolster liquidity capacity, given the potential risks over the intermediate and longer-term horizons.

From a rating perspective, Moody's expects to carefully monitor utility investment plans, the associated financing plans related to those investments and the potential those investments could have on future rate cases. While we recognize that there are significant needs that need to be addressed — in terms of generation capacity, fuel diversity, transmission and distribution upgrades and enhancements and substantial uncertainties associated with increasingly stringent environmental mandates — credit quality could suffer if key financial ratios were to deteriorate meaningfully or if the deterioration appeared to be sustained for an extended period of time.

Déjà vu All Over Again

The following excerpts are from an annual report published by a large, multi-state utility holding company. Can you guess what year the report was published?

A. 2005
B. 1996
C. 1970
D. 1964

"...inflationary pressures pushed the costs of doing business progressively higher and compelled ...our operating companies to ask for rate increases."

"... difficulties as fuel shortages and environmental concerns..."

"...operating expenses reached new heights, primarily because of significant increases on the costs of fuel and of purchased power....Labor and materials costs, too, were higher than ever before."

"Construction of generation plants and other needed facilities continues to carry high priority in the...planning for the future, as do research and development activities aimed at finding ways to protect more effectively the quality of air and water in our service area."

"...subnormal hydroelectric generating conditions."

"Contributing to...higher construction costs are the environment-protection facilities associated with the production of electric power."

"Public concern over fuel shortages, power supply inadequacies, need for increased revenues, and ecological considerations — more visible than usual through increased national news coverage — amplified the concern already being shown by the nation's producers of electric power."

"...it is probable that about half of the new generation installed...on the system...will be nuclear."

"In the long run, the development of "clean coal" — through gasification or solvent refining — probably will provide the most feasible solution to the challenging problem of controlling stack effluents."

Answer: C. 1970 The Southern Company

Related Research

Special Comments:

Moody's Comments on the Credit Implications Associated with North American Utility Consolidation, December 2006 (# 101392)

Moody's Comments on the Back to Basics Strategy for the North American Electric Utility Sector, November 2006 (# 100660)

Criteria for Assessing Director Independence, October 2006 (# 100302)

Covenants and Ring-Fencing for Wholly-Owned Subsidiaries, May 2007 (# 102983)

Environmental Regulations Increase Capital Costs for Public Power Electric Utilities, June 2007 (# 103616)

Regulation Of Greenhouse Gases: Substantial Credit Challenges Likely Ahead For U.S. Public Power Electric Utilities, June 2007 (# 103356)

Rating Methodologies:

Global Regulated Electric Utilities, March 2005 (# 91730)

Global Integrated Oil & Gas, October 2005 (# 94696)

Global Steel Industry, October 2005 (# 94683)

Global Paper & Forest Products Industry, June 2006 (# 95092)

Global Chemicals and Allied Products, February 2002 (# 74324)

North American Diversified Natural Gas Transmission And Distribution Companies, March 2007 (# 102513)

Industry Outlook:

U.S. Electric Utilities, December 2006 (# 101304)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

Appendix A

Company	Senior Unsecured Rating
Airlines	
Southwest Airlines	Baa1
AMR Corporation	B2
Continental Airlines	B2
JetBlue Airways	B2
Major Oils	
Exxon Mobil Corporation	Aaa
BP plc	Aa1
Royal Dutch Shell plc	Aa1
Chevron Corporation	Aa2
Conoco Phillips	A1
Marathon Oil	Baa1
Diversified Natural Gas	
Equitable Resources	A2
KeySpan Corporation	A3
Consolidated Natural Gas	Baa1
National Fuel Gas	Baa1
CenterPoint Energy Resources Corp	Baa3
Southern Union	Baa3
Williams Companies	Ba2
El Paso Corp	Ba3
Questar	—
Paper	
Sonoco Products Company	Baa1
Weyehaeuser Company	Baa2
International Paper	Baa3
Temple-Inland	Baa3
Railroads	
Burlington Northern Santa Fe	Baa1
Norfolk Southern Corp	Baa1
CSX Corporation	Baa2
Union Pacific Corp	Baa2
Shipping	
United Parcel Service	Aaa
FedEx Corp	Baa2
Con-way Incorporated	Baa3
Overseas Shipping Corp	Ba1
Chemicals	
E.I. DuPont de Nemours & Company	A2
Praxair, Inc.	A2
Dow Chemical Company	A3
Monsanto Company	Baa1
Steel	
Nucor Corporation	A1
United States Steel	Baa3
Steel Dynamics	Ba1
AK Steel Holdings Corp	B1

Southeast	West/Southwest	Illinois	Northeast/Mid-Atlantic	TX T&D	TX Integrated
Alabama Power	Arizona P.S.	Ameren CIPS	Baltimore G&E	AEP Central	El Paso Electric
Appalachian Power	Nevada Power	Commonwealth Ed	Boston Ed	AEP North	ETR- Gulf States
Cleco Power	P.S. Colorado	Illinois Power	Central Hudson	CEHE	SPS
Duke Carolinas	P.S. New Mexico	PECO	Central Main Power	TNMP	SWEPCo
ETR - LA	PG&E		Con. Ed	TXU Delivery	
ETR - MS	San Diego G&E		Connecticut L&P		
FP&L	Sierra Pacific Power		Delmarva P&L		
Georgia Power	SoCal Edison		JCP&L		
Gulf Power	Tucson Electric		Mass. Electric		
Kentucky Power			Met. Ed		
Kentucky Utilities			NYSEG		
Louisville G&E			Penn. Electric		
Mississippi Power			Potomac Electric		
Monongahela Power			PPL Electric		
PGN - Carolina			PSE&G		
PGN - Florida			Rochester G&E		
Savannah Electric					
Virginia Electric					
Tampa Electric					
South Carolina E&G					

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Rejoinder 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

Rejoinder Testimony of

Kevin P. Larson

on Behalf of

UNS Electric, Inc.

August 31, 2007

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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 who filed Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my Rejoinder Testimony is to respond to Staff and RUCO's Surrebuttal Testimony regarding Black Mountain Generating Station ("BMGS").

II. RESPONSE TO STAFF WITNESS RALCH C. SMITH'S SURREBUTTAL TESTIMONY.

Q. Have you read the Surrebuttal Testimony of ACC Staff witness Ralph C. Smith regarding BMGS?

A. Yes.

Q. Has Staff's position on the Company's proposed ratemaking treatment of BMGS changed?

A. No. Mr. Smith states in his Surrebuttal Testimony on page 63 at lines 22 through 23 that "Staff continues to believe that the inclusion of BMGS in rate base in the current rate case would be premature and inadvisable for several reasons."

Q. Does Staff provide an economic analysis of UNS Electric's proposed rate treatment of BMGS?

A. No. Staff still seems uncertain whether BMGS is an economical resource for UNS Electric and its customers. Mr. Smith states in his Surrebuttal Testimony on page 67 at lines 2 through 4 that "[i]t is not known whether having UNS Electric purchase a peaking unit such as BMGS is the most economical alternative to obtain power for the short, intermediate or long-term."

Q. Does Staff provide an economic analysis of owning generation versus acquiring energy needs through purchased power contracts?

A. No. However, Mr. Smith states in his Surrebuttal Testimony on page 67 at line 1 that "Staff recognizes that there can be benefits to a utility owning its own generation."

Q. Has the Company provided an economic analysis that compares ownership of generation versus acquiring energy needs through purchased power contracts?

A. Yes. Exhibit KPL-3 to my Direct Testimony provides a comparison of the non-fuel revenue requirements for a 90 MW peaking facility such as BMGS with a purchased power contract. The revenue requirements associated with ownership decline over time, whereas the cost of the purchased power contract increases over time. Based on the assumptions in my analysis, the cost of ownership is approximately $12 million less than the purchased power option on a net present value basis over 30 years. The ownership of generation contributes to a stable and declining non-fuel revenue requirement relative to purchased power over the long-run.

Q. Has the Company provided an economic analysis of its proposed rate-making treatment of BMGS?

A. Yes. Exhibit KPL-2 to my Direct Testimony summarizes the projected impact of the generating facility on the utility's income and cash flow. Operating cash flow and net income are positively impacted if all or most of the non-fuel revenue requirement is reflected in rates at the time of commercial operation. It is readily apparent that rate base treatment of owned generation would provide UNS Electric with a significant source of internally generated funds that would improve the Company's credit profile and its ability to fund transmission and distribution projects.

Q. Does Staff provide any new recommendations regarding the Company's proposed rate treatment of BMGS?

A. No. Although Mr. Smith's indicates on the last page of the summary of his Surrebuttal Testimony that "Staff believes that a more reasonable alternative approach to addressing the ratemaking and cash flow impacts of meeting UNS Electric's power supply will need to be developed.", he does not describe what that alternative would entail. The Company believes that it has fully developed a reasonable approach to meeting UNS Electric's power supply needs that provides tangible financial and operating benefits to the Company and its customers.

III. <u>RESPONSE TO RUCO WITNESS MARYLEE DIAZ CORTEZ'S SURREBUTTAL TESTIMONY</u>

Q. Have you read the Surrebuttal Testimony of RUCO witness Marylee Diaz Cortez regarding BMGS?

A. Yes.

Q. Has RUCO's position on the Company's proposed ratemaking treatment of BMGS changed?

A. No. Similar to her Direct Testimony, Ms. Diaz Cortez states in her Surrebuttal Testimony on page 6 at lines 18 through 19 that "The Company's proposal for BMGS is premature and violates all ratemaking principles."

Q. Does the Company share RUCO's opinion that UNS Electric's proposed rate treatment of BMGS violates all ratemaking principles?

A. No. I address each of RUCO's concerns about ratemaking principles in my rebuttal testimony. UNS Electric recognizes that its proposed ratemaking treatment for BMGS is not typical; however, the Company believes it is in the public interest for the Commission to adopt the Company's proposal to acquire BMGS, so that customers can begin realizing the financial and operating benefits of BMGS beginning June 1, 2008. The Company has provided substantial technical and financial information justifying this treatment in this case. Unfortunately, RUCO fails to recognize the Company's circumstances and the supporting information.

IV. CONCLUSION.

Q. Do you have any concluding thoughts?

A. Yes. UNS Electric is approaching a critical juncture. On May 31, 2008, the Company's full requirements energy supply agreement with PWCC expires. On June 1, 2008, UNS Electric will need to have a portfolio of supply-side resources in place to serve its entire service territory of over 95,000 customers. BMGS represents an opportunity for UNS Electric to add owned generation to its resource portfolio and provide some long-term price stability to its customers. The Company has provided ample evidence showing the financial and operating benefits of owning BMGS in the course of these proceedings and UNS Electric believes its proposed rate-making treatment of BMGS is in the public interest because it is in the long-term benefit to both the Company and its customers.

The Company has agreed to put the following safeguards in place: (i) the maximum amount of construction costs that will be reflected in the rate reclassification will be no greater than $60 million. The Company will not seek recovery of construction costs over $60 million until its next rate case; (ii) if BMGS is completed at a cost less than $60 million, the Company will reduce the size of the rate reclassification in proportion with the final cost; and (iii) UNS Electric will file a project completion report with the Commission upon completion of the project and prior to making the rate reclassification.

UNS Electric is fully aware that the prudence of the construction costs of BMGS can be addressed in the Company's next rate case. However, we believe the information provided in our direct filing in December 2006 has given and still gives the Commission ample opportunity to review all aspects of BMGS. While not typical ratemaking treatment, the Company believes that the benefits of a post-test-year adjustment for BMGS are in the public interest.

Q. Does this conclude your Rejoinder Testimony?

A. Yes.

Rejoinder 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

Rejoinder Testimony of

Karen G. Kissinger

on Behalf of

UNS Electric, Inc.

August 31, 2007

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 who filed Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my Rejoinder Testimony is to address the Surrebuttal Testimonies filed by RUCO witnesses Rodney L. Moore and Marylee Diaz Cortez, submitted in response to my previous Rebuttal Testimony.

Q. What is your general assessment of their Surrebuttal Testimony?

A. After reading their surrebuttal it is clear to me that they have either ignored or failed to understand the information that I conveyed in my Rebuttal Testimony.

Q. Please describe the portions of Mr. Moore's Surrebuttal Testimony with which you disagree.

A. Beginning on line 15 of page 4, Mr. Moore continues to support an adjustment increasing the end-of-test year balance of Accumulated Depreciation deducted from rate base, based on incorrect calculations. Moreover, beginning at line 17 on page 5, Mr. Moore addresses an accounting adjustment identified in the Notes to Financial Statements for the year 2005. This was filed as part of an exhibit with my Direct Testimony. Mr. Moore attempts to establish an incorrect distinction between the $2 million correction posted to Accumulated

Depreciation in 2005 – as I covered in my Rebuttal Testimony – with the $0.5 adjustment to depreciation expense described in the aforementioned Notes to Financial Statements.

Mr. Moore's position regarding Accumulated Depreciation – as stated in his Direct and Surrebuttal Testimonies – should be rejected. There is no basis upon which to accept the proposed adjustment. The fact remains that his calculations were not made in the same manner by which the Company computes and accounts for depreciation expense, as required by the FERC Uniform System of Accounts. His calculations also fail to reflect the $2 million correcting adjustment recorded to Accumulated Depreciation in 2005.

Further, Mr. Moore's comment on page 5 of his Surrebuttal Testimony regarding the 2005 depreciation correction adjustment is misplaced. The $2 million adjustment referred to in my Rebuttal Testimony was the adjustment made to Accumulated Depreciation; the $0.5 million footnote disclosure referred to by Mr. Moore was the reported effect on 2005 Depreciation Expense. Mr. Moore failed to make this important distinction in his testimonies. The difference between those two amounts reflects the portion of the $2 million accounting adjustment that the Company applied to construction work orders in accordance with its Transportation Clearing accounting procedure. Mr. Moore identified and apparently agreed to this – as indicated beginning at line 19 on page 11 of his Surrebuttal Testimony.

Q. Please describe the portions of Ms. Diaz Cortez's Surrebuttal Testimony with which you disagree.

A. I disagree with her position concerning Accumulated Deferred Income Taxes reflected in rate base and with the issue of computing income tax expense. She fails to understand my Rebuttal Testimony on these two issues and simply does not reconcile her position with

Commission Decision No. 55774 or the controlling FERC Uniform System of Accounts ("USOA").

Q. Please explain the Accumulated Deferred Income Taxes issue.

A. In her Direct Testimony, Ms. Diaz Cortez proposed to exclude the Accumulated Deferred Income Taxes associated with Contributions in Aid of Construction ("CIAC") because of her perceived failure of the Company to remove CIAC from rate base. In attempting to illustrate her point she noted in her direct testimony that she can see no evidence that the Company has reflected an Account No. 271 in determining its rate base.

In my Rebuttal Testimony, I explained that Account No. 271, CIAC, does not exist in the FERC USOA, and that her reference to Account 271 came from the NARUC Uniform System of Accounts used by water and wastewater utilities subject to Commission jurisdiction. I presented the relevant CIAC accounting requirements from the FERC USOA in my Rebuttal Testimony and showed that we are required to directly credit the related plant or construction work in progress accounts upon receipt of CIAC. The Company has done just that; thus, there is no separate account to deduct from rate base as believed by Ms. Diaz Cortez. Finally, my Rebuttal Testimony included a discussion regarding Decision No. 55774 and the related Staff Report directing self-pay companies to include the deferred tax asset associated with CIAC to rate base. Both items are attached to my Rebuttal Testimony as exhibits.

Unfortunately, Ms. Diaz Cortez confuses the issue by discussing the existence of an Account 271 in the NARUC USOA for Electric companies. She offers no other justification for her proposed exclusion. But as I described above and showed in my Rebuttal Testimony, Decision No. 55774 and the Staff Report govern this issue.

Q. Should the Commission accept the proposed ADIT-CIAC exclusion from rate base?

A. Absolutely not. To do so would be to double count the CIAC already excluded from rate base, and is contrary to past Commission directives. Ms. Diaz Cortez's discussion about the existence of an Account 271 in the NARUC USOA for Electric Utilities is not relevant. As stated in my Rebuttal Testimony, A.A.C. R14-2-212.G requires electric utilities under the Commission's jurisdiction to follow the FERC USOA. There is no requirement for electric utilities to use the NARUC USOA, and to do so would be violating Commission rules. Therefore, Ms. Diaz Cortez proposal should be rejected.

Q. Please explain your disagreement with Ms. Diaz Cortez's Surrebuttal Testimony concerning the computation of income tax expense.

A. Initially, the issue of computing income tax expense was addressed by Mr. Moore. Ms. Diaz Cortez addresses this issue in her Surrebuttal Testimony. In my Rebuttal Testimony I noted that the method used by RUCO was incorrect in that it only addressed the *current* component of income tax expense and failed to consider the *deferred* tax component. Income tax expense is correctly comprised of *both* components. RUCO's method makes no distinction between current and deferred income taxes.

My Rebuttal Testimony highlights that RUCO's tax calculations fail to consider that some of their adjustment amount are not fully deductible in computing income taxes, and that there is no way to assure that the deferred component of income tax expense is in accordance with the degree of income tax normalization the Commission authorized and as the Internal Revenue Code requires. Finally, the method of computing taxes by RUCO does not permit a correct reflection of deferred (*i.e.* non-cash) and current income taxes in the lead/lag study of cash working capital.

Beginning at line 21 on page 17 of her Surrebuttal Testimony, Ms. Diaz Cortez asserts that there is nothing wrong with the RUCO computational method. She further states – in her Surrebuttal Testimony at line 2 on page 18 – that "it is standard practice in ratemaking to account for income tax on a current basis" and continues with "the accounting for tax timing differences is appropriately reflected for ratemaking purposes in the rate base". That does not accurately describe the ratemaking process. Revenue requirements are based on an income tax expense component that includes both current and deferred elements, and some of the most contentious ratemaking issues involved the determination of a proper deferred component of income tax expense. Its existence and proper computation cannot be ignored if the goal is to truly establish a proper measure of revenue requirements and assure that the income tax normalization rules of the Internal Revenue Code are properly complied with.

Q **To what specific income tax normalization rules are you referring?**

A. The requirements of the Internal Revenue Code require consistency in the manner by which depreciation expense, income tax expense, and accumulated deferred income taxes are computed in ratemaking. Specifically, Section 168(i)(9)(B) of the Internal Revenue Code states that the normalization requirements are violated if a procedure or adjustment that is inconsistent with the normalization requirements is used for ratemaking purposes. To adjust accumulated book depreciation without correspondingly adjusting accumulated deferred income taxes and to adjust book depreciation expense without correspondingly recomputing deferred income tax expense, as have been done by RUCO, are types of the inconsistencies addressed in the aforementioned Internal Revenue Code citation.

Q. **Should the Commission accept the income tax computational methodology advanced by Mr. Moore and Ms. Diaz Cortez?**

A. No. RUCO's approach should be rejected. RUCO's attempted justification for their computational method fails to consider any of the arguments presented in my Rebuttal Testimony and does not accurately depict the manner in which income taxes have traditionally been computed for ratemaking purposes.

Q. Does this conclude your Rejoinder Testimony?

A. Yes it does.

Rejoinder 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 RELATED FINANCING.	DOCKET NO. E-04204A-06-0783

Rejoinder Testimony of

Dallas J. Dukes

on Behalf of

UNS Electric, Inc.

August 31, 2007

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Exhibits:

Exhibit DJD-6: Summary of Pro Forma Adjustments and Revisions to Pro Forma Adjustments

Exhibit DJD-7: Fleet Fuel Expense

Exhibit DJD-8: UNS Electric, Inc. FERC 925 Injuries and Damages

Exhibit DJD-9 - Confidential: UniSource Energy Executive Compensation Competitive Compensation Review

Exhibit DJD-10: Outside Services - DSM

Exhibit DJD-11: Page 123.1 of the FERC Form 1 for 2003

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Dallas J. Dukes and my business address is One South Church Avenue, Tucson, Arizona, 85702.

Q. Are you the same Dallas Dukes who filed Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. Mr. Dukes, have you reviewed the Surrebuttal Testimony filed by the Commission Staff and Intervenors in this case?

A. Yes, I have. Please see Exhibit DJD-6 for a summary of pro forma adjustments and revisions to pro forma adjustments as proposed by Staff, RUCO and the Company.

II. RESPONSE TO STAFF WITNESS RALPH C. SMITH'S SURREBUTTAL TESTIMONY.

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

Q. Mr. Dukes do you have any comments regarding Mr. Smith's revised adjustment for fleet fuel expense?

A. Yes. Mr. Smith has relied upon my rebuttal workpaper UNSE (0783)10597 to derive his latest revised fleet fuel expense level. However, the $585,210 he references is not the complete fleet fuel expense for the twelve months ending June 2007 as Mr. Smith interpreted the workpaper. That amount represented the fuel that was invoiced to the Company through four different fleet card providers that includes gallons purchased information directly on the invoice. Those amounts were used to derive an average cost per gallon. However there were additional fleet fuel purchases during that twelve month period. The additional purchases were made via the Company's Pro-Card and were not used in that evaluation because it takes additional time and research to obtain the amount of gallons purchased information. The actual Fleet Fuel expense for the twelve months ended June 2007 was $599,075 as shown on Exhibit DJD-7. The amount the Company proposed in its Rebuttal filing and accepted by RUCO of $605,498 remains the Company's recommended level of fleet fuel expense. That represents $2.82 per gallon – the agreed-upon weighted average cost – times 214,716 gallons.

B. <u>Normalized Injuries and Damages Expense (Staff Adjustment C-6).</u>

Q. Has Mr. Smith addressed his adjustment for Injuries and Damages expense in his Surrebuttal testimony?

A. Yes. Mr. Smith continues to support a simple three-year average of the entire FERC Account 925; with the intention of providing a pro forma expense level of $403,340. As stated in my Rebuttal Testimony, I disagree with this position because it significantly understates the normal and recurring levels of expense. The years 2004 through 2005 are not reflective of current expense levels for general liability insurance expense and Officers and Directors liability insurance expense. I showed in my Rebuttal Testimony how these expenses increased because of increases in insurance premiums, and that Officers and Directors liability insurance expense becoming fully allocated to UNS Electric. These are the known and actual costs for these expenses, which are reasonable expenses for the Company to incur. Regarding workers compensation expense, I agreed that a reduction was appropriate to reflect normal and recurring expense. Mr. Smith's proposal for a three-year average of the entire FERC Account is not warranted and will not accurately reflect these costs going forward. As I describe below, that reduction should have been $98,161. I am making that change in my Rejoinder Testimony.

Mr. Smith is proposing a reduction to the test year of $159,063 to reduce it to the three-year average. But Mr. Smith's application is faulty for several reasons. First, because he applies this adjustment to the Company's adjusted amounts to arrive at his adjusted test-year operating income. Because he starts with the Company's adjusted test-year expenses, he is actually recommending a reduction in test-year activity of $222,315 and an ending expense level of only $340,088. The Company's adjusted test-year level already included a reduction of $63,252 to FERC Account 925 to adjust worker's compensation expense to a cash basis. Mr. Smith would need to reverse that adjustment first to accurately reflect his intent to reduce test-year activity.

Second, in his Surrebuttal Testimony, Mr. Smith uses workpaper UNSE(0783)10737 – attached to my Testimony as Exhibit DJD-8 – to support this overall average level. He points out that the expense level for the twelve months ended June 2007 for FERC Account 925 is $398,032 and is therefore supportive of his suggested pro forma expense. However, he overlooks the fact that the twelve months ending June 2007 has negative worker's compensation expense recorded in the amount of ($46,740). Obviously, it is not realistic to expect worker's compensation expense to be negative on a normal and recurring basis. This negative amount is as a result of the over-accrual of worker's compensation expense within the test year. I agreed with Mr. Smith on this point in my Rebuttal Testimony. Because the accruals were too large in the test year, the worker's compensation liability account was overstated and thus was adjusted in the following year by reducing worker's compensation expense.

Finally, Page 2 of Exhibit DJD-8 attached to my Rejoinder Testimony provides additional analysis and support for my revised pro forma adjustment for Injuries and Damages expense. As you can see, if you replace the worker's compensation expense level in the twelve months ended June 2007 with a normalized level of expense of $75,295 – based on a three-year average of the expense for 2004 through 2006 – you come up with an expense level of $520,066 for that period as opposed to $398,032. If you do the same for the test year, you come up with an expense level of $464,242 as opposed to $562,403. In simple terms, the mid-year test year had an abnormally high level of expense for worker's compensation expense because of the timing of accruals. The accrued liability was corrected in the following twelve months and then there was an abnormally low level of worker's compensation expense for that twelve-month period.

Q. Have you revised your adjustment as presented in your Rebuttal Testimony?

A. Yes. In my Rebuttal Testimony I inadvertently compared the three-year average of expense unadjusted compared to an adjusted test year level. I am correcting that here. So, instead of $79,978, the adjustment to normalize worker's compensation expense should be a reduction of $98,161. That will reduce the test-year level of injuries and damages expense of $562,403 (as shown on Exhibit DJD-8, page 1 of 2) to $464,242 (as shown on Exhibit DJD-8, page 2 of 2). That amount is still $55,824 less than the normalized level for the twelve months following the test year (*i.e.* through June 30, 2007); and it is $36,198 less than the twelve months ended December 2006. It is reflective, however, of normal and recurring levels.

C. <u>Incentive Compensation (Staff Adjustment C-7 through C-9).</u>

1. <u>Performance Enhancement Plan ("PEP")</u>.

Q. Mr. Dukes would you briefly summarize Mr. Smith's position regarding the Company's PEP expenses.

A. Yes. Essentially, Mr. Smith continues to argue that incentive programs, like the Company's PEP program, benefit customers and shareholders and therefore the expense should be equally shared.

Q. Do you agree with Mr. Smith's position?

A. No, I do not. I believe he continues to ignore the reality that to attract and retain skilled employees **"total cash compensation"** has to be set at a competitive level. The PEP is part of total cash compensation. The Company currently targets the median of the market for total cash compensation and has provided evidence in support of the Company's review of such. If the Company is denied recovery of these costs, it is reasonable to assume that there will be pressure to eliminate the incentive program and provide market level total cash compensation completely through base wages; with no portion being variable in future proceedings. It stands to reason that the Company will attempt to modify its compensation programs to optimize the opportunity to recover its actual cost to provide market-based wages.

However, I believe that the program currently being provided by the Company provides a greater benefit to the customer rather than just paying market-based wages in the form of base salary, with no portion of compensation being at-risk.. As I have previously stated in my Rebuttal Testimony, by putting a portion of employee pay at-risk through a variable pay program, the Company can use that as a tool to affect the behavior of eligible employees and to provide and promote additional benefits to customers without increasing cost.

- It provides a tool to help the Company retain the more skilled and more productive employees, which benefits the customers.
- It helps to reduce the compounding cost of base wage increases, which also reduces the cost of benefits that are directly linked to base wages, which benefits customers.
- It is based on targeted goals and objectives designed to benefit customers and shareholders.

This is simply a better way to structure compensation and provides additional benefits to the customers. I provided examples of how other state commissions recognize incentive compensation as a valuable tool that provides benefits to customers. Those jurisdictions did not simply penalize the Company 50% of expenses for incentive compensation if those programs provided benefit to the customer by keeping and retaining qualified employees and motivating customers to provide reliable service at reasonable rates. This compensation directly and indirectly benefits the customers and it should be recovered through rates as a result. There is no evidence that the PEP payouts were exorbitant or unreasonable. Therefore, the Company should be allowed to recover the prudent and reasonable cost levels associated with the program.

Q. On page 28 of Mr. Smith's Surrebuttal Testimony he questions your statement that the compensation of employees is reasonable, do you have any comments?

A. Yes. Mr. Smith refers to my Confidential Exhibit DJD-3 and questions whether it provides an evaluation of the compensation for all employees who are eligible to receive PEP. The document referred to by Mr. Smith, provides an evaluation of all UNS Electric employees eligible to receive PEP, with the exception of the Vice Presidents and General Managers. The evaluation of those two positions was provided to Staff through the discovery process. Staff was also provided through the discovery process – and Mr. Smith has attached it to his testimony as Confidential Attachment RCS-10 – the most recent evaluation of Executive compensation. Therefore, Staff was provided evaluations for all positions eligible for PEP that were charged to UNS Electric.

Q. On page 29 of Mr. Smith's Surrebuttal Testimony he questions your statement that the Company's compensation philosophy is to pay at approximately 50% of market. Do you have any comments?

A. Yes. Mr. Smith's questioning is directed at Executive compensation and is based on his review of the "UniSource Energy Executive Compensation – Competitive Compensation Review", which he has attached to his Testimony as Confidential Attachment RCS-10. But Mr. Smith ignores the fact that none of this information challenges the PEP as an unreasonable or exorbitant expense. In addition, in the most recent UNS Gas case Staff requested a comparison of Officers actual compensation during the test year as compared to the median level discussed within his Attachment RCS-10. That request was not made in the UNS Electric case; however I have attached Confidential Exhibit DJD-9 to my testimony that provides that information. As you can clearly see, the actual compensation of the Officers during the test year was actually significantly below the median of the peer group. None of Mr. Smith's commentary challenges the fact that the personnel receiving this compensation provide customer benefits through reliable service at reasonable rates. And none of what Mr. Smith cites justifies Staff's proposal to only allow 50% of PEP recovery through rates.

Q. Do you have any additional comments about Staff's proposed adjustment for PEP?

A. Yes. Staff's proposed adjustment for PEP is a reduction of 50% of the Company's proposed PEP pro forma adjustment. I believe it was the intention of Staff to propose a 50% reduction of PEP expense (test year amount plus the Company's adjustment), not to just revise the Company's pro forma adjustment. This means that the Staff's adjustment would need to be modified to reduce the Company's expenses an additional $33,771 if accepted.

2. **Officer's Long Term Incentive Program.**

Q. Did Mr. Smith address the Officer's Long Term Incentive Program ("LTIP") in his Surrebuttal Testimony?

A. Yes. He again discusses the "UniSource Energy Executive Compensation – Competitive Compensation Review", which he has attached to his Testimony as Confidential Attachment RCS-10.

Q. Do you have any additional comments about the LTIP?

A. Yes. In Mr. Smith's Surrebuttal Testimony on page 30 at lines 17 through 23, he includes an excerpt from the most recent rate decision for Arizona Public Service Company ("APS") Decision No. 69663 (June 28, 2007):

> As testified to by Staff witness Dittmer and set out in Staff's initial brief, "enhanced earnings levels can sometimes be achieved by short-term management decisions that may or many not encourage the development of safe and reliable utility service at the lowest long term cost. …For example, some maintenance can be temporarily deferred, thereby boosting earnings. …But delaying maintenance can lead to safety concerns or higher subsequent 'catch-up' costs."
>
> See Decision No. 69663 at 36.

Mr. Smith added this language along with other excerpts from the order in support of his position to exclude stock-based compensation (Staff Adjustment C-9). But the findings of the Commission in that order support the Company's position. The LTIP is an important part of a balanced compensation package and is included for the reasons including the one Staff witness Dittmer pointed out in the APS case. The program is designed to put a portion of each Executive's compensation at-risk based on long-term operating performance. This provides balance to the short-term goals of the PEP plan and provides an incentive to not sacrifice the future for the present. It invests Officers in the long-term success of the Company. This is particularly the case for the higher-ranking Officers who have a much greater proportion of their compensation at-risk.

3. Supplemental Executive Retirement Plan ("SERP").

Q. Did Mr. Smith address the Supplemental Executive Retirement Plan in his Surrebuttal Testimony?

A. Yes. Mr. Smith again cites the most recent rate decision for Southwest Gas Corporation ("SWG") – Decision No. 68478 (February 23, 2006) – where the Commission disallowed the recovery of SERP expense.

Q. Are there any additional comments you would like to make about the Supplemental Executive Retirement Plan?

A. Yes. I would like to reiterate why a program like SERP is necessary. In a recent decision involving the Nevada Power Company ("NPC"), which I cite in my Rebuttal testimony, the Nevada Public Utility Commission found that SERP expenses could be fully recovered. Factors considered by the Nevada Commission included that the plan does not enhance benefits, but only restores benefits to the equivalent level of the other employees. Additionally, information presented in the Decision was the evidence in the record of a database of 2004 executive benefit practices, The evidence was of a Towers Perrin data base reporting that 96% of energy/utility companies offered SERP. And that a similar review of a 2006 executive database, Towers Perrin reported 93% of general industry companies offer SERP. I respectfully disagree with the recent findings of the Commission to deny recovery of these normal and recurring costs of providing utility. As shown by the information provided in the NPC decision, it would be a significant disadvantage to the Company in its efforts to retain and to attract Executives if it did not offer SERP to insure that those individuals' benefits are on par with their own coworkers and equivalent to what they can obtain elsewhere. These are not abnormal or special benefits that should be paid by the Shareholders; but are a normal and recurring cost of providing utility service.

4. Stock Based Compensation.

Q. Did Mr. Smith address the Stock Based Compensation Plan in his Surrebuttal Testimony?

A. Yes. Mr. Smith again refers to the "UniSource Energy Executive Compensation – Competitive Compensation Review", which he has attached to his Testimony as Confidential Attachment RCS-10. Also, as I discussed earlier, Mr. Smith cites the recent APS rate case decision in which APS was denied recovery of stock based compensation and the Commission referenced a concern that the program could promote short-term decision making. Again, as I mentioned earlier, this is supportive of the Company's position. Stock-based compensation or equity compensation is primarily awarded in the form of stock options, the ultimate value of which is based on the future strength and performance of the Company and are primarily awarded as a result of each individual Executive's LTIP goals; and as such promote long-term employee retention, ownership and long-term operating performance.

D. Rate Case Expense (Staff Adjustment C-11).

Q. Do you have any comments about Staff's recommended level of rate case expense to be recovered?

A. Yes. I am perplexed by Staff's and RUCO's disregard for the fact that UNS Electric is being provided rate case support services "at cost" by a separate regulated Arizona utility – Tucson Electric Power Company ("TEP"). Both Staff and RUCO are essentially promoting subsidization of UNS Electric customers by TEP. These incremental costs incurred by UNS Electric from TEP for rate case support are just that - incremental - and are not included in test year activity and/or in any other pro forma adjustments. Staff and RUCO continue to use SWG as a proxy for what a normal amount of rate case expense is, but they make no attempt to normalize or adjust SWG costs to reflect the fact that SWG rate case expense was for outside consultants only. This rate case expense did not include the major real cost of litigating a rate case, which were allocated to the SWG's Arizona division and included in base rates for that division. The clear evidence is that SWG could not litigate a rate case for $265,000 if it did not have its shared service departments cost built into its base rates.

E. Payroll Adjustment.

Q. Did the Company propose a change to its originally filed payroll expense adjustment in it Rebuttal filing?

A. Yes. After reviewing Staff's Direct Testimony and accepting their adjustments for a postage rate increase that became effective in early 2007, and property tax rate changes that are effective in 2008, the Company realized that it had overlooked the obvious payroll rate increase that became effective January 2007. These rates were applied to test-year employee levels and do not consider employee level increases after the end of the test year, but only the additional wage increase to each employee existing at the end of the test year.

Q. Has Staff opposed this new adjustment?

A. It is not completely clear from Mr. Smith's Surrebuttal Testimony, but Staff did not include it in their cost of service (pending receipt and analysis of responses to Staff Data requests sets 20 and 21. Staff seems to be insinuating through Mr. Smith's Surrebuttal Testimony that this is an error that we did not inform them of at an earlier date in response to Staff Data request STF 3.88. But Staff accepted the Company's revised bad debt expense adjustment that was actually correcting an error that was not reported prior to the Company's Rebuttal Filing and which Staff had the same amount of time to evaluate. The payroll adjustment is simply increasing normalized payroll by an additional 3% for the rate increase effective January 2007. It is based on known and measurable wage rate increases and should be allowed.

F. **Overtime Adjustment.**

Q. **Did the Company propose a change to its originally filed overtime expense adjustment in it Rebuttal Filing?**

A. Yes. As I testify to in my Rebuttal Testimony, the Company had accepted a proposed method for calculating normalized overtime expense by Mr. Smith in the UNS Gas case. This took place after the direct case had been filed in the UNS Electric case. It was my assumption that Mr. Smith would use the same methodology in his direct filing in this case as well. Mr. Smith did not propose any adjustment to the overtime expense in his Direct Testimony and therefore the Company proposed the revised level in the Rebuttal Testimony.

Q. **Has Staff opposed this new adjustment?**

A. Yes. Mr. Smith asserts that his analysis shows that the method that UNS Gas used in its direct filing produced too high an overtime amount, but the same method in the UNS Electric case produced an amount that was just right. However, the method he proposed in the UNS Gas case produced an amount that was just right, but when applied to UNS Electric produces an amount that is too high. While each case stands on its own merits, the methodology used for UNS Gas and for UNS Electric should be the same. In the UNS Gas rate case, UNS Gas agreed with the methodology proposed by Mr. Smith. But for UNS Electric, Mr. Smith now recommends the methodology he rejected in UNS Gas, without any reason distinguishing UNS Electric from UNS Gas – other than it produces a lower amount. The bottom line is that the method Mr. Smith recommended for UNS Gas is reasonable for both UNS Gas and UNS Electric; it gives the proper result in the UNS

Electric case. The methodology used to determine the overtime adjustment for these two companies should be consistent. It appears to be selective analysis to say that the method works for UNS Gas but now does not work for UNS Electric.

II. RESPONSE TO RUCO WITNESS MARYLEE DIAZ CORTEZ'S SURREBUTTAL TESTIMONY.

A. Bad Debt Expense (RUCO Adjustment No. 6).

Q. Mr. Dukes do you have any comments regarding Ms. Diaz Cortez's position on Bad Debt expense?

A. Yes. Ms. Diaz Cortez and I are in agreement that the Company mistakenly used gross bad debt expense as opposed to net bad debt expense. The Company corrected that in its Rebuttal Testimony and their revised adjustment was accepted by Staff. However, Ms. Diaz Cortez is still in disagreement on the Company's use of an average write-off rate as opposed to test year level only. Ms. Diaz Cortez argues that an average should only be used when "*specific abnormal conditions are identified in the test year data*". However, she ignores the fact that the bad debt expense incurred by a small company like UNS Electric does tend to fluctuate significantly year over year and the test year itself was not reflective of the historical years or most recent activity. Below is a chart of the actual bad debt expense for the three calendar years 2004 – 2006, the test year and the twelve months ending June 2007. You can see from the chart that bad debt expense can fluctuate significantly over varying time periods and calendar year 2005 appears to be abnormally low ($198,703 less than the next year level), which of course has impacted the test year level. You can also see that the pro forma level the Company is requesting, $423,929, is in line with normal and recurring levels. If anything, it is conservative because it gives equal weight to the abnormally low year of 2005, which is not as likely to recur. You can also see by the large jump in the twelve months ended June 2007, that it can be very volatile and is likely to be much higher in the near future.

Bad Debt Expense for UNS Electric

2004	$ 426,405
2005	$ 296,428
2006	$ 495,131
Test Year	$ 356,982
June 2006 to June 2007	$ 715,267

B. A&G Capitalization (RUCO Adjustment No. 10).

Q. Mr. Dukes do you have any comments regarding Ms. Diaz Cortez's position on A&G Capitalization?

A. Yes. Ms. Diaz Cortez's argument is puzzling; she continues to equate this adjustment with some type of double recovery. This is an inaccurate depiction. As I point out in my Rebuttal Testimony, this is known and measurable change in the capitalization "rate" for shared services departments that impacts expenses prospectively. This rate change took place after the test year and therefore the cost capitalized from inception of the Company (August 2003) through the end of the test year were accurate and based on the best information at that time. It is normal for capitalization rates for shared service, operational and construction departments to change over time. If Ms. Diaz Cortez's argument were correct then it would stand to reason that had the capitalization rate increased; Ms. Diaz Cortez would be arguing that the prospective adjustment should be added to rate base. I find it hard to imagine that she would argue to add dollars not yet spent to rate base; as she should not be arguing to remove dollars already properly capitalized.

C. Corporate Cost Allocations (RUCO Adjustment No. 12).

Q. Mr. Dukes do you have any comments regarding Ms. Diaz Cortez's position on Corporate Cost Allocations?

A. Yes. Ms. Diaz Cortez and others continue to make a subjective determination on who benefits the most from certain expenses. But the fact is that the expenditure is a reasonable expenditure for the Company to incur and that the expenditure benefits the customers. Almost every expenditure of an investor owned Utility can be interpreted to benefit shareholder and customer in one way or another. But it is not appropriate to simply split the costs between shareholders and customers if the customer benefits and the cost is related to providing electric utility service. These expenses allocated to UNS Electric are normal, necessary and recurring expenses related to running a utility. All investor owned utilities large or small have to produce and print annual reports and all of them have Boards of Directors that need materials prepared and printed. These are necessary costs of doing business. These are just normal expenses associated with running an investor owned utility. They are neither perks nor excessive expenses. They are not incurred to solely or primarily to benefit shareholders.

D. Valencia Turbine Fuel (RUCO Adjustment No. 14).

Q. Mr. Dukes do you have any comments regarding Ms. Diaz Cortez's position on the Valencia Turbine Fuel adjustment?

A. Yes. It appears that we are primarily disagreeing on where these expenses should be recovered within future rates. The Company is attempting to quantify all cost that are PPFAC-reconcilable, based on the best current information and then establish a "Base Power Supply Rate" to be included in the customer's rate structures on first day that the rates go into effect. The Company is also proposing that the PPFAC rate be set at zero on day one and then be established based on a forward looking basis to be effective June 2008. Mr. Michael J. DeConcini has testified to the Company's proposal regarding the PPFAC. Ultimately, under either RUCO's proposed method or the Company's proposed method, only the actual Valencia fuel cost will be recovered from customers. Essentially, the Company is requesting that the known and measurable amount incurred within the test year be used to establish what it believes to be the most representative base power supply rate possible on day one – with the best information currently known.

E. Outside Services Adjustment (RUCO Adjustment No. 21).

Q. Mr. Dukes do you have any comments regarding Ms. Diaz Cortez's position on the Outside Services adjustment?

A. Yes. In the backup workpapers to my Rebuttal testimony (Bates No. UNSE(0783)10704 - UNSE(0783)10705), I provided Ms. Diaz Cortez with detailed workpapers that clearly show that invoices totaling $32,865 she is proposing to exclude from cost of service have already been removed by the Company in our DSM & Renewable adjustment, and that only the additional $17,055 addressed in my Rebuttal testimony for an invoice omitted from the original pro forma adjustment in error should be the additional amount excluded from test year expense. I am not sure why she was unable to discern this in her review of the workpapers, but I have attached those workpapers and additional information in Exhibit DJD-10. It is clearly identified within the exhibit that the $32,865 has already been excluded from test year expense. To remove these expenses again would be improper.

Q. Please explain the information contained in Exhibit DJD-10.

A. Exhibit DJD-10 is composed of a summary page with notes. This summary page is followed by Bates No. UNSE(0783)10704 - UNSE(0783)10705 as provided in the backup workpapers for my rebuttal testimony (in response to the adjustment proposed by Ms. Diaz

Cortez). These pages are followed by three pages of the DSM pro forma adjustment as originally filed (Bates No. UNSE(0783)02038, 02039 and 02096, which show the original amount of FERC 908 expense that was removed from test year expense.

Q. Please demonstrate again that the UNSE does not need to remove $32,865 of DSM outside services expense from the cost of service.

A. On the first page of Exhibit DJD-10, the invoices totaling $32,865 are clearly outlined. This summary page was taken from the original pro forma adjustment spreadsheet as included in Bates No. UNSE(0783)02038- UNSE(0783)02103 and in the Excel spreadsheet provided in response to RUCO Data Request 1.10. Because the spreadsheet was over 30 pages, I have limited the data displayed to the outside services invoices that Ms. Diaz Cortez has identified as totaling her adjustment of $49,920. The total of $136,139 is the total for FERC 908 from the original spreadsheet. The first five invoices totaling $32,865 are the invoices included in the $136,139 that was removed from test year expense in the original pro forma. It can be seen clearly that the total DSM expense in FERC 908 of $136,139 on the summary page matches the amount that was removed for FERC 908 in the original pro forma adjustment pages as attached in Bates No. UNSE(0783)02038, 02039 and 02096.

Going back to the summary page of Exhibit DJD-10, the invoice of $17,055 that was omitted from the original pro forma adjustment is shown. As explained on the summary page, this invoice was not included in the original DSM expense removed from test year expense because the query used was based on tasks specifically identified as related to DSM activities. This invoice had been incorrectly recorded in the GL without a correct DSM task and thus was not included in the query. This information was previously provided to Ms. Diaz Cortez in Bates No. UNSE(0783)10704 - UNSE(0783)10705 provided in my Rebuttal testimony as noted above. It can be clearly seen on Bates No.

UNSE(0783)10704-10705 that this was explained and that the invoice of $17,055 did not have a task number.

In summary, I agree with Ms. Diaz Cortez that the total expense of $49,920 was the correct amount of DSM outside services expense that should have been removed from test year expense. We removed $32,865 of DSM outside services expense in our original pro forma adjustment and I have proposed to remove the remaining $17,055 of DSM outside expense in my rebuttal testimony. Ms. Diaz Cortez is incorrect that the full $49,920 remains to be excluded from test year expense.

III. RESPONSE TO RUCO WITNESS RODNEY L. MOORE'S SURREBUTTAL TESTIMONY.

A. Pension and Benefits Adjustment (RUCO Adjustment No. 2).

Q. Mr. Dukes do you have any comments regarding Mr. Moore's position on his Pension and Benefit adjustment?

A. Yes. Mr. Moore is attempting to exclude costs here that are primarily related to the recognition of employee service, safety accomplishments and other goal achievements by individual or groups of employees. As I previously explained, this weighting of expenses by who benefits the most and then excluding normal and recurring expenses is a very difficult measure to administer. The fact is that these are reasonable expenses for a utility to incur. An employee who reaches the milestone of twenty-five years of service has provided that service to the customers benefit – in that the customers benefit from that employees knowledge, expertise and experience on the job. Rewarding employees for good service better enables UNS Electric to retain the best and the brightest employees so that they can *continue* to provide this service to the customer's benefit. I believe the recognition of employees and the rewarding of employees on a normal and recurring basis is beneficial to customers and is a normal and recurring expense that should be encouraged and recognized. It should not be excluded from cost of service.

B. Incentive Compensation (RUCO Adjustment No. 4).

Q. Has Mr. Moore addressed his adjustment for Incentive Compensation in his Surrebuttal testimony?

A. Yes. Mr. Moore continues to defend his position of eliminating incentive compensation expense from the test year.

Q. Do you have any additional comments about Mr. Moore's position?

A. Yes. I have addressed Mr. Moore's arguments previously in my Rebuttal Testimony, and earlier in my Rejoinder Testimony above. However, I would like to address a few of his points. First, Mr. Moore is arguing that the PEP was not even awarded in 2005 and therefore no recovery should be allowed. That ignores the fact that half of the PEP expense in the test year is related to the 2006 plan (because the test year ended on June 30, 2006); The fact is the UNS Electric Board of Directors approved the plan itself, the measures, the goals and the payout of the PEP program. The Board was the entity that recognized the achievements of the employees in 2005 toward the PEP measures and awarded the payout, despite not meeting an initial funding threshold measure. The Board subsequently eliminated this measure going forward. But the payments were actually made and have been made every year at varying levels, but some level of variable pay has been made. So the payments are normal and recurring.

Secondly, Mr. Moore is arguing against the use of an historical average to arrive at an adequate recurring level of incentive compensation expense based on strict adherence to the "Historical Test-Year Principal." Yet at the same time he argues to also exclude the test-year expense awarded as incentive compensation. That appears to be taking contradictory positions within one adjustment. I believe the averaging is the appropriate treatment, because it gives the customers the most representative cost level within cost of service.

Third, Mr. Moore continues to argue that the entire program is flawed because it only rewards a segment of the employee base. I find this argument very puzzling. It implies that part of the workforce cannot have an impact on results. That is entirely incorrect and it implies that even if a program can be shown as cost effective and as producing results, if it does not apply to the entire workforce, then it should not be used. That is not a sound business practice. UNS Electric would like to make the PEP program a part of every employees' compensation program because of all of the benefits that are associated with it, but has been unable to do so with the union workforce. However, that shouldn't mean that the program should be abandoned. The program still provides all of the benefits I testified about earlier and impacts customer service, customer cost and reliability of the system.

C. Rate Case Expense (RUCO Adjustment No. 5).

Q. Has Mr. Moore addressed his adjustment for Rate Case expense in his Surrebuttal testimony?

A. Yes. Mr. Moore continues to defend his position of basically comparing UNS Electric to SWG while ignoring the clear differences. I disagree with RUCO's proposed adjustment for the same reasons as I discuss earlier in my Rejoinder Testimony addressing Staff's rate case expense adjustments.

D. <u>Postage Expense (RUCO Adjustment No. 8).</u>

Q. Has Mr. Moore addressed his adjustment for Postage expense in his Surrebuttal testimony?

A. Yes. Mr. Moore continues to defend his position of basically only allowing recovery of test year levels adjusted for known rate changes. Again RUCO is arguing that the cost of postage expense does not fluctuate enough to merit normalization treatment and again RUCO ignores the information provided to them within workpapers. The postage expense has varied from $415,524 to $257,881 to $365,567 over the past three years, all the while customer counts and customer's bills mailed have steadily increased. This is because customer count is not the only driver of these costs. This is why the Company normalized these expenses and Staff accepted our adjustment modified to reflect the postage rate increase in 2007.

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

Q. Has Mr. Moore addressed his adjustment for SERP expense in his Surrebuttal testimony?

A. Yes. Mr. Moore continues to defend his proposed elimination of SERP cost incurred by the Company during the test year.

Q. Do you have any additional comments about Mr. Moore's position?

A. Yes. I have addressed most of Mr. Moore's arguments in my Rebuttal Testimony and in responding to Mr. Smith's arguments earlier in my Rejoinder Testimony. For all of those reasons, I continue to disagree with Mr. Moore's position.

F. <u>Overhead Line Maintenance (RUCO Income Statement Adjustment 18)</u>.

Q. Has Mr. Moore addressed his adjustment for Overhead Line Maintenance expense in his Surrebuttal testimony?

A. Yes. Mr. Moore continues to defend his proposed normalization of overhead line maintenance cost incurred by the Company during the test year.

Q. Do you have any additional comments about Mr. Moore's position?

A. Yes. In Mr. Moore's Surrebuttal testimony he implies that the Company's response to RUCO 2.12 was somehow incomplete or knowingly inaccurate. Below is the question RUCO 2.12 and it clearly request the year-end balances for 2003 through 2006 for FERC 593.

> <u>Operating Income</u> – Please provide the year-end balances for 2003, 2004, 2005 and 2006 for FERC account 593 – Maintenance of Overhead Lines and also please provide the month-end balances of this account for each month of the test year.

RUCO was provided the information they requested. It is common knowledge to the parties of this case that the year of 2003 is a partial year and that any income statement accounts would only represent just activity from August 11, 2003 through December 31, 2003. UNS Electric did not acquire these assets until August 11, 2003.

Mr. Moore also refers to the 2003 FERC Form 1 and says there is no footnote or notation to indicate that it represents a partial year. That is just untrue, throughout the report it indicates that the Company began operation on August 11, 2003. Specifically, on page 123.1 there is a note that specifically states that all statements are reflective of activity for the period August 11, 2003 through December 31, 2003. Please see exhibit DJD-11 to see page 123.1 of the FERC Form 1 for 2003. The test-year level is reflective of normal and recurring levels and Mr. Moore's normalization adjustment should be ignored based on the inherit error in the computation.

G. <u>Payroll Expense (RUCO Income Statement Adjustment 25)</u>.

Q. Has Mr. Moore addressed the adjustment for Payroll expense the Company proposed in its Rebuttal Testimony?

A. Yes. Mr. Moore argues that it is reaching out beyond the test year and should not be accepted. I disagree with Mr. Moore's argument based on the reasons I provided in responding to Staff's Surrebuttal Testimony. I also find Mr. Moore's argument contradictory to his own proposed adjustment to reflect a property tax assessment rate that won't be in effect until 2008, which is well beyond the effective date of the wage rate increases already in place.

Q. Does this conclude your Rejoinder Testimony?

A. Yes.

EXHIBIT

DJD-6

UNS ELECTRIC, INC.

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2006

	As Filed 12/15/06 UNSE	Surrebuttal 8/24/07 ACC	Surrebuttal 8/24/07 RUCO	Rejoinder 8/31/07 UNSE	Summary	UNSE 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)	-	-	(2,295,112)	-	RUCO decreased 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; RUCO Adj. 3)	10,761,154	-	(299)	10,761,154	Staff & RUCO excluded 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 the 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 increased 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 Revised)		-	-	-	Staff removed Adjustment B-3 for a customer advance on a plant addition that was subject to reimbursement pending receipt of workpapers. Staff is awaiting the receipt of adequate supporting documentation to verify that the customer advance was recorded and netted against plant in service at the end of the test year. Documentation was provided in the response to Staff Data Request STF 20.50. The original Staff adjustment reduced rate base by $236,874.	Kissinger
Accumulated Deferred Income Taxes (Staff Adj B-5; RUCO Adj. 4 & 5)	(2,235,928)	(2,397,483)	(3,008,060)	(2,235,928)	Staff removed 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
Working Capital - Cash Working Capital (Staff Adj B-4 Revised; RUCO Adj. 6 Revised)	(3,104,100)	(2,907,650)	(1,524,443)	(3,058,862)	Changes result from proposed rate base and operating expense adjustments.	Kissinger
Total Adjustments	14,555,412	4,271,408	4,601,484	14,600,650		
Pro Forma OCRB	140,991,324	130,707,320	128,742,285	141,036,562		
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	$11,746,759	$11,166,869	$13,950,796		

UNS ELECTRIC, INC.

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2006

	As Filed 12/15/06 UNSE	Surrebuttal 8/24/07 ACC	Surrebuttal 8/24/07 RUCO	Rejoinder 8/31/07 UNSE	Summary	UNSE 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)	285,424	285,424	334,072	285,424	RUCO increased Service Fees for after-hours service from $75 to $125, creating an increase of $48,648 in revenue. UNSE disagrees. M. Diaz Cortez states that UNSE did not object to the increase (page 11 of her surrebuttal testimony); this is not correct - UNSE did not accept the adjustment (rebuttal testimony of Bentley Erdwurm pages 17-18).	Erdwurm
CARES Revenue (Staff Adj C-1; RUCO Adj 22)	(52,937)	-	(56,564)	(56,564)	Staff removed 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. RUCO agrees with UNSE and accepted the UNSE rebuttal adjustment.	Erdwurm
Total Adjustments to Operating Revenues	3,072,309	3,125,246	3,117,330	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)	82,965	82,965	71,353	82,965	RUCO decreased 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)	(63,252)	(222,315)	(143,230)	(98,161)	Staff intended to reduce injuries & damages expense by $159K by normalizing the test year using a 3-year average through December 2006. Staff added this reduction to UNSE's original adjustment and actually reduced expenses by $222K. RUCO accepted UNSE use of the 3-year average and reduces test year worker's compensation expense by $79,978, but did not use the incremental change of $16,726 in the adjustment - RUCO added the $79,978 to the $63,252 beginning adjustment. UNSE revised the pro forma to correct the calculation presented in rebuttal testimony.	Dukes
Incentive Compensation (Staff Adj C-7; RUCO Adj 4)	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. They inadvertently only reduced UNSE's adjustment and not total PEP expenses. 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

	As Filed 12/15/06 UNSE	Surrebuttal 8/24/07 ACC	Surrebuttal 8/24/07 RUCO	Rejoinder 8/31/07 UNSE	Summary	UNSE Witness
Operating Expense Adjustments (cont'd)						
Rate Case Expense (Staff Adj C-11), (RUCO Adj 5)	200,000	88,333	83,667	200,000	Staff recommended 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 recommended 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 (Staff Adj C-18; RUCO Adj 6)	222,556	66,947	19,518	66,947	Staff accepted UNSE revised adjustment using a 3-year average of actual net write-off rates. RUCO disagreed with the use of a 3-year average and continued to decrease bad debt expense by $203,038 based on actual expense for the test year.	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 Revised; RUCO Adj 7 Revised)	73,661	11,464	31,136	31,752	Staff decreased Fuel Expense based on UNSE revised workpapers supplied with DJD-1. Staff accepted the adjusted average fuel cost of $2.82 per gallon, but adjusted the gallons purchased from 214,497 to 207,310. RUCO accepts the UNSE revised pro forma adjustment using a fuel cost of $2.82 per gallon reflecting the most recent weighted average cost of fuel using all seasons (there is rounding of $616 between RUCO and UNSE calculation due to RUCO using a hard coded $2.82 and the UNSE calculation was a link to the unrounded/calculated amount per gallon).	Dukes
Postage Expense (Staff Adj C-5; RUCO Adj 8)	66,283	83,786	28,327	83,786	Staff increased 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 change in the postal rates and included it 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)	140,677	134,421	134,421	134,421	RUCO reduced 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. Staff accepted the UNSE rebuttal 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; RUCO Adj 23)	(2,000)	(16,952)	(15,759)	(13,759)	Staff removed 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. RUCO accepts the UNSE 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). RUCO did not use the incremental change of $11,759 in the adjustment - RUCO added the $13,759 to the $2,000 beginning adjustment.	Dukes
A&G Expense Capitalized (RUCO Adj. 10)	301,187	301,187	-	301,187	RUCO reversed 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.	Dukes
Depreciation & Property Tax for CWIP (Staff Adj C-2; RUCO Adj 11)	689,512	-	-	689,512	Staff & RUCO excluded the 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

	As Filed 12/15/06 UNSE	Surrebuttal 8/24/07 ACC	Surrebuttal 8/24/07 RUCO	Rejoinder 8/31/07 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)	97,152	97,152	87,142	95,285	RUCO decreased 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. UNSE revises the pro forma presented in rebuttal to correct for an error in the calculation presented in rebuttal testimony (additional reduction of expense of $44 based on $500 invoice @ 8.86%).	Dukes
Valencia Turbine Fuel (RUCO Adj 14)	266,198	266,198	-	266,198	RUCO removed 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.	Dukes
Depreciation & Property Taxes for CWIP in Plant in Service @ Year End (Staff Adj C-3)	-	26,582	-	-	Staff increased 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)	-	(83,506)	(83,506)	-	Staff & RUCO removed 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 removed 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.	Dukes
Emergency Bill Assistance Expense (Staff Adj C-16; RUCO Adj 24)	-	20,000	20,000	20,000	Staff increased 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. RUCO accepted the UNSE rebuttal adjustment.	Dukes
SES Markup Above Cost (Staff Adj C-17)	-	(10,906)	-	-	Staff reduced the revenue requirement by the 10% markup in the charges from SES.	Ferry
Inappropriate Expenses (RUCO Adj 17)	-	-	(73,620)	(10,013)	RUCO removed 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)	-	-	(267,678)	-	RUCO decreased 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, because the 2003 year was a partial year and distorts the calculation.	Dukes & Ferry
Customer Service Cost Allocation (RUCO Adj 19)	-	-	(66,797)	-	RUCO decreased 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

	As Filed 12/15/06 UNSE	Surrebuttal 8/24/07 ACC	Surrebuttal 8/24/07 RUCO	Rejoinder 8/31/07 UNSE	Summary	UNSE Witness
Operating Expense Adjustments (cont'd)						
Non-Recurring / Atypical Expenses (RUCO Adj 20)	-	-	(14,251)	-	RUCO decreased 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) (Staff Adj C-19; RUCO Adj 21)	-	(17,055)	(49,920)	(17,055)	RUCO decreased 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. Staff accepted the UNSE rebuttal adjustment.	Dukes
Depr. and Amort. Exp. Annualization (Staff Adj C-15; RUCO Adj 13)	582,981	519,876	324,306	519,876	Staff reduced 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. RUCO accepted Staff's adjustment for transportation equipment, but RUCO's depreciation calculation is affected by RUCO's beginning adjusted plant numbers.	Kissinger
Property Taxes (Staff Adj C-10; RUCO Adj. 15)	(130,301)	(190,048)	(487,012)	(190,048)	Staff reduced 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 accepted revised assessment rate of 23.5%, but the calculation is affected by RUCO's adjustment to accumulated depreciation. UNSE accepts Staff's adjustment.	Kissinger
Income Taxes (Staff Adjustment "All C's"; RUCO Adj 22)	(1,444,412)	(668,802)	(61,659)	(1,360,798)	All changes are recalculations based on other pro forma adjustments.	Kissinger
Total Adjustments to Operating Expense	3,465,253	2,744,499	1,811,917	3,433,621		
Total Net Adjustments	(392,944)	380,747	1,305,413	(364,939)		
Adjusted Operating Income	$8,742,011	$9,515,701	$10,440,368	$8,770,016		
Operating Income Deficiency	$5,204,310	$2,231,058	$726,501	$5,180,780		
Gross Revenue Conversion Factor	1.634626	1.634626	1.636983	1.634626		
Increase in Gross Revenue Requirement	$8,507,097	$3,646,946	$1,189,270	$8,468,638		Kissinger

8/30/2007 10:40 AM

EXHIBIT

DJD-7

Transaction Detail - All Sources

Co: 033mpany, Expenditure Type: 129, GL Period Name: JUL-06, AUG-06, SEP-06, OCT-06, NOV-06, DEC-06, JAN-07, FEB-07, MAR-07, APR-07, MAY-07, JUN-

Co: 033 | Exp Type: 129 ← Fleet Fuel Expense

GL Period	FERC	Query Source	Task Number	PA Transaction Source	PA Expenditure Comment	GL JE Name	DR	CR	Net Amount	PA Perio
JUL-06	0000	Payables	E618905			Purchase Invoices USD	7,241.97		7,241.97	Jul
JUL-06	0000	Payables	E648905			Purchase Invoices USD	42.76		42.76	Jul
JUL-06	0000	Payables	ETR6004			Purchase Invoices USD	41,199.48		41,199.48	Jul
JUL-06	0000	Payables	ETR6404			Purchase Invoices USD	12,653.68		12,653.68	Jul
JUL-06	0921	Projects	E600921	PVS Net - Procard Charges	HESS 09453		38.30		38.30	Jul
JUL-06	0588	Projects	E610588	PVS Net - Procard Charges	CHEVRON 0202405		75.18		75.18	Jul
JUL-06	0588	Projects	E610588	PVS Net - Procard Charges	CHEVRON 0207031		36.09		36.09	Jul
JUL-06	0588	Projects	E610588	PVS Net - Procard Charges	EXXONMOBIL59 01039916		32.02		32.02	Jul
JUL-06	0000	Projects	E618905	PVS Net - Procard Charges	TRVXTON STATION		110.60		110.60	Jul
JUL-06	0000	Projects	E618905	PVS Net - Procard Charges	NORTHERN ENERGY #412		209.67		209.67	Jul
JUL-06	0000	Projects	E618905	PVS Net - Procard Charges	AIRWAY AVENUE CAR WASH		113.81		113.81	Jul
JUL-06	0908	Projects	E61A908	PVS Net - Procard Charges	SHELL OIL 60541220549		48.55		48.55	Jul
JUL-06	0598	Projects	E620598	PVS Net - Procard Charges	EXXONMOBIL59 07599996		53.66		53.66	Jul
JUL-06	0000	Projects	E628905	PVS Net - Procard Charges	CHEVRON 0094781		45.82		45.82	Jul
JUL-06	0000	Projects	E628905	PVS Net - Procard Charges	CHEVRON 0211955		47.35		47.35	Jul
JUL-06	0000	Projects	E628905	PVS Net - Procard Charges	SHELL OIL 93004128588		3.01		3.01	Jul
JUL-06	0901	Projects	E640901	Transportation Fuel Issues			285.49		285.49	Jul
JUL-06	0000	Projects	ETR6004	PVS Net - Procard Charges	FLYING J/CFJ		75.00		75.00	Jul
AUG-06	0930	Payables	E630930			Purchase Invoices USD	9.00		9.00	Aug
AUG-06	0000	Payables	ETR6004			Purchase Invoices USD	39,868.80		39,868.80	Aug
AUG-06	0000	Payables	ETR6404			Purchase Invoices USD	12,530.06		12,530.06	Aug
AUG-06	0921	Projects	E600921	PVS Net - Procard Charges	FLYING J/CFJ		6.12		6.12	Aug
AUG-06	0921	Projects	E600921	PVS Net - Procard Charges	SHELL OIL 57440039907		10.69		10.69	Aug
AUG-06	0588	Projects	E610588	PVS Net - Procard Charges	CHEVRON 0202499		76.27		76.27	Aug
AUG-06	0588	Projects	E610588	PVS Net - Procard Charges	CHEVRON 0207129		19.01		19.01	Aug
AUG-06	0588	Projects	E610588	PVS Net - Procard Charges	HAVASU SUPERFUELS		32.01		32.01	Aug
AUG-06	0592	Projects	E610592	PVS Net - Procard Charges	USA TRAVEL CENTER		80.00		80.00	Aug
AUG-06	0000	Projects	E618905	PVS Net - Procard Charges	SMITHS #9190 Q74		21.99		21.99	Aug
AUG-06	0000	Projects	E618905	PVS Net - Procard Charges	NORTHERN ENERGY #412		263.24		263.24	Aug
AUG-06	0000	Projects	E618905	PVS Net - Procard Charges	MEADVIEW GAS		162.00		162.00	Aug
AUG-06	0000	Projects	E618905	PVS Net - Procard Charges	AAA SAFE STORAGE		48.57		48.57	Aug
AUG-06	0000	Projects	E628905	PVS Net - Procard Charges	CHEVRON 0211955		42.12		42.12	Aug
AUG-06	0000	Projects	E628905	PVS Net - Procard Charges	CIRCLE K 05537 Q04		45.90		45.90	Aug
AUG-06	0000	Projects	E628905	PVS Net - Procard Charges	TEXACO 0305657		15.30		15.30	Aug
AUG-06	0901	Projects	E640901	Transportation Fuel Issues			541.39		541.39	Aug
SEP-06	0000	Payables	ETR6004			Purchase Invoices USD	47,180.19		47,180.19	Sep
SEP-06	0000	Payables	ETR6404			Purchase Invoices USD	13,278.98		13,278.98	Sep
SEP-06	0921	Projects	E600921	PVS Net - Procard Charges	EXXONMOBIL26 09612Q19		10.57		10.57	Sep
SEP-06	0921	Projects	E600921	PVS Net - Procard Charges	LOVE S COUNTRY00002Q01		6.76		6.76	Sep
SEP-06	0921	Projects	E600921	PVS Net - Procard Charges	SHELL OIL 57440039907		8.56		8.56	Sep
SEP-06	0000	Projects	E618905	PVS Net - Procard Charges	SMITHS #9190 Q74		70.02		70.02	Sep

Transaction Detail - All Sources

Co: 033mpany, Expenditure Type: 129, GL Period Name: JUL-06, AUG-06, SEP-06, OCT-06, NOV-06, DEC-06, JAN-07, FEB-07, MAR-07, APR-07, MAY-07, JUN-

Co: 033 | Exp Type: 129

GL Period	FERC	Query Source	Task Number	PA Transaction Source	PA Expenditure Comment	Gl JE Name	DR	CR	Net Amount	PA Period
SEP-06	0000	Projects	E618905	PVS Net - Procard Charges	NORTHERN ENERGY #412		249.27		249.27	Sep
SEP-06	0901	Projects	E640901	Transportation Fuel Issues			99.10		99.10	Sep
OCT-06	0000	Payables	ETR6004			Purchase Invoices USD	11,270.49		11,270.49	Oct
OCT-06	0000	Payables	ETR6404			Purchase Invoices USD	10,175.78		10,175.78	Oct
OCT-06	0921	Projects	E600920	PVS Net - Procard Charges	CHEVRON 0213144		49.87		49.87	Oct
OCT-06	0921	Projects	E600920	PVS Net - Procard Charges	CIRCLE K 05302 QC1		34.50		34.50	Oct
OCT-06	0921	Projects	E600920	PVS Net - Procard Charges	UNION 76 00041Q65		4.56		4.56	Oct
OCT-06	0921	Projects	E600921	PVS Net - Procard Charges	LOVE S COUNTRY00002Q01		16.71		16.71	Oct
OCT-06	0000	Projects	E618905	PVS Net - Procard Charges	AIRWAY AVENUE CAR WASH		302.72		302.72	Oct
OCT-06	0908	Projects	E61A908	PVS Net - Procard Charges	UNION 76 00041Q65		45.15		45.15	Oct
OCT-06	0908	Projects	E61A908	PVS Net - Procard Charges	EXXONMOBIL26 09732926		28.23		28.23	Oct
OCT-06	0908	Projects	E61A908	PVS Net - Procard Charges	CHEVRON 0213231		18.01		18.01	Oct
OCT-06	0000	Projects	E628905	PVS Net - Procard Charges	SHELL OIL 93002996732		23.12		23.12	Oct
OCT-06	0901	Projects	E640901	Transportation Fuel Issues			250.32		250.32	Oct
NOV-06	0000	General Ledger				J342 TEP/UNE/UNG Manual A A	24,969.94		24,969.94	Nov
NOV-06	0000	Payables	ETR6004			Purchase Invoices USD	36,695.71		36,695.71	Nov
NOV-06	0000	Payables	ETR6404			Purchase Invoices USD	9,890.54		9,890.54	Nov
NOV-06	0921	Projects	E600920	PVS Net - Procard Charges	EXXONMOBIL59 07433667		26.26		26.26	Nov
NOV-06	0921	Projects	E600920	PVS Net - Procard Charges	CHEVRON 0210232		44.75		44.75	Nov
NOV-06	0921	Projects	E600920	PVS Net - Procard Charges	CHEVRON 0202499		46.00		46.00	Nov
NOV-06	0921	Projects	E600921	PVS Net - Procard Charges	LOVE S COUNTRY00002Q01		25.80		25.80	Nov
NOV-06	0930	Projects	E600930	PVS Net - Procard Charges	C & T OIL #3		11.21		11.21	Nov
NOV-06	0930	Projects	E600930	PVS Net - Procard Charges	EXXONMOBIL26 09732926		13.49		13.49	Nov
NOV-06	0000	Projects	E618905	PVS Net - Procard Charges	AIRWAY AVENUE CAR WASH		76.14		76.14	Nov
NOV-06	0000	Projects	E618905	PVS Net - Procard Charges	CHEVRON 0209914		55.07		55.07	Nov
NOV-06	0000	Projects	E618905	PVS Net - Procard Charges	FLYING J/CFJ		39.00		39.00	Nov
NOV-06	0000	Projects	E618905	PVS Net - Procard Charges	NORTHERN ENERGY #412		153.75		153.75	Nov
NOV-06	0000	Projects	E618905	PVS Net - Procard Charges	SHELL OIL 54539790029		25.10		25.10	Nov
NOV-06	0000	Projects	E628905	PVS Net - Procard Charges	SHELL OIL 93004128588		113.86		113.86	Nov
NOV-06	0000	Projects	E628905	PVS Net - Procard Charges	EXXONMOBIL59 01132Q19		4.48		4.48	Nov
NOV-06	0000	Projects	E628905	PVS Net - Procard Charges	EXXONMOBIL26 09612653		59.91		59.91	Nov
NOV-06	0000	Projects	E628905	PVS Net - Procard Charges	CHEVRON 0209914		15.01		15.01	Nov
NOV-06	0901	Projects	E640901	Transportation Fuel Issues			190.28		190.28	Nov
NOV-06	0000	Projects	ETR6004	PVS Net - Procard Charges	QT #444 05004Q05		169.16		169.16	Nov
DEC-06	0000	General Ledger				J343 - Reverses "J342 TEP/UNE		24,969.94	<24,969.94>	Dec
DEC-06	0000	Payables	ETR6004			Purchase Invoices USD	42,421.27		42,421.27	Dec
DEC-06	0000	Payables	ETR6404			Purchase Invoices USD	8,820.92		8,820.92	Dec
DEC-06	0000	Projects	E618905	PVS Net - Procard Charges	NORTHERN ENERGY #412		181.70		181.70	Dec
DEC-06	0000	Projects	E618905	PVS Net - Procard Charges	USA TRAVEL CENTER		49.49		49.49	Dec
DEC-06	0582	Projects	E620582	PVS Net - Procard Charges	SHELL OIL 93004128588		11.12		11.12	Dec
DEC-06	0000	Projects	E628905	PVS Net - Procard Charges	CHEVRON 0207577		55.31		55.31	Dec

Transaction Detail - All Sources

Co: 033mpany, Expenditure Type: 129, GL Period Name: JUL-06, AUG-06, SEP-06, OCT-06, NOV-06, DEC-06, JAN-07, FEB-07, MAR-07, APR-07, MAY-07, JUN-

Co: 033 | Exp Type: 129

GL Period	FERC	Query Source	Task Number	PA Transaction Source	PA Expenditure Comment	GL JE Name	DR	CR	Net Amount	PA Period
DEC-06	0000	Projects	E628905	PVS Net - Procard Charges	CIRCLE K 06674 Q04		21.82		21.82	Dec
DEC-06	0901	Projects	E640901	Transportation Fuel Issues			143.53		143.53	Dec
DEC-06	0000	Projects	UNETELE	PVS Net - Procard Charges	SAFEWAY FUEL 10020170		16.61		16.61	Dec
DEC-06	0000	Projects	UNETELE	PVS Net - Procard Charges	SHELL OIL 60541220549		1.18		1.18	Dec
DEC-06	0000	Projects	UNETELE	PVS Net - Procard Charges	SHELL OIL 93004148673		49.02		49.02	Dec
JAN-07	0000	General Ledger				J342 TEP/UNG/UNE AP Manua /	24,805.56		24,805.56	Jan
JAN-07	0000	Payables	ETR6004			Purchase Invoices USD	30,997.04		30,997.04	Jan
JAN-07	0000	Projects	E618905	PVS Net - Procard Charges	NORTHERN ENERGY #412		207.33		207.33	Jan
JAN-07	0000	Projects	E618905	PVS Net - Procard Charges	EXXONMOBIL26 09628272		156.31		156.31	Jan
JAN-07	0000	Projects	E618905	PVS Net - Procard Charges	CHEVRON 0210842		73.69		73.69	Jan
JAN-07	0000	Projects	E628905	PVS Net - Procard Charges	AMERIGAS PROPANE		94.91		94.91	Jan
JAN-07	0000	Projects	E628905	PVS Net - Procard Charges	SHELL OIL 93004128588		52.00		52.00	Jan
JAN-07	0901	Projects	E640901	Transportation Fuel Issues			41.02		41.02	Jan
FEB-07	0000	General Ledger				J343 - Reverses "J342 TEP/UNG		24,805.56	<24,805.56>	Feb
FEB-07	0000	Payables	ETR6004			Purchase Invoices USD	36,674.87		36,674.87	Feb
FEB-07	0000	Payables	ETR6404			Purchase Invoices USD	17,578.94		17,578.94	Feb
FEB-07	0921	Projects	E600921	PVS Net - Procard Charges	QT 461 05004Q05		4.88		4.88	Feb
FEB-07	0921	Projects	E600921	PVS Net - Procard Charges	LOVE S COUNTRY00002Q01		77.07		77.07	Feb
FEB-07	0921	Projects	E600921	PVS Net - Procard Charges	FLYING J/CFJ		7.02		7.02	Feb
FEB-07	0921	Projects	E600921	PVS Net - Procard Charges	EXXONMOBIL59 01152Q19		4.67		4.67	Feb
FEB-07	0921	Projects	E610923	PVS Net - Procard Charges	EXXONMOBIL26 09639Q19		8.75		8.75	Feb
FEB-07	0000	Projects	E618905	PVS Net - Procard Charges	NORTHERN ENERGY #412		284.20		284.20	Feb
FEB-07	0000	Projects	E618905	PVS Net - Procard Charges	PILOT		28.89		28.89	Feb
FEB-07	0921	Projects	E620923	PVS Net - Procard Charges	CHEVRON 0211955		60.29		60.29	Feb
FEB-07	0921	Projects	E620923	PVS Net - Procard Charges	TERRIBLES #148		4.37		4.37	Feb
FEB-07	0000	Projects	E628905	PVS Net - Procard Charges	SMITHS #9188 Q74		50.77		50.77	Feb
FEB-07	0901	Projects	E640901	Transportation Fuel Issues			172.06		172.06	Feb
FEB-07	0000	Projects	ETR6404	PVS Net - Procard Charges	CHEVRON 0209114		55.62		55.62	Feb
MAR-07	0000	General Ledger				J342 A/P Accrual Adjustment USI	9,480.11		9,480.11	Mar
MAR-07	0000	Payables	ETR6004			Purchase Invoices USD	24,759.66		24,759.66	Mar
MAR-07	0000	Payables	ETR6404			Purchase Invoices USD	8,934.48		8,934.48	Mar
MAR-07	0921	Projects	E600921	PVS Net - Procard Charges	EXXONMOBIL59 01152Q19		5.96		5.96	Mar
MAR-07	0921	Projects	E600921	PVS Net - Procard Charges	LOVE S COUNTRY00002Q01		19.96		19.96	Mar
MAR-07	0921	Projects	E600921	PVS Net - Procard Charges	MARIPOSA Q17		21.21		21.21	Mar
MAR-07	0592	Projects	E610592	Project Journal	UNSE Transfer PA3070307		3.78		3.78	Mar
MAR-07	0000	Projects	E618905	PVS Net - Procard Charges	NORTHERN ENERGY #412		265.57		265.57	Mar
MAR-07	0000	Projects	E618905	PVS Net - Procard Charges	TEMPLE BAR RESORT		8.80		8.80	Mar
MAR-07	0000	Projects	E628905	PVS Net - Procard Charges	SHORT STOP MINI MART L		4.84		4.84	Mar
MAR-07	0901	Projects	E640901	Transportation Fuel Issues			149.45		149.45	Mar
MAR-07	0921	Projects	ETP0923	PVS Net - Procard Charges	EXXONMOBIL26 09639261		14.59		14.59	Mar
APR-07	0000	General Ledger				J342 A/P Accrual Adjustment USI	27,874.48		27,874.48	Apr

Transaction Detail - All Sources

Co: 033mpany, Expenditure Type: 129, GL Period Name: JUL-06, AUG-06, SEP-06, OCT-06, NOV-06, DEC-06, JAN-07, FEB-07, MAR-07, APR-07, MAY-07, JUN-

Co: 033 | Exp Type: 129

GL Period	FERC	Query Source	Task Number	PA Transaction Source	PA Expenditure Comment	GI JE Name	DR	CR	Net Amount	PA Period
APR-07	0000	General Ledger				J343 - Reverses "J342 A/P Accru		9,480.11	<9,480.11>	Apr
APR-07	0000	Payables	E618905			Purchase Invoices USD	55.02		55.02	Apr
APR-07	0000	Payables	ETR6004			Purchase Invoices USD	16,754.34		16,754.34	Apr
APR-07	0921	Projects	E600921	PVS Net - Procard Charges	CHEVRON 0109876		21.35		21.35	Apr
APR-07	0921	Projects	E600921	PVS Net - Procard Charges	CHEVRON 0209914 Q61		9.76		9.76	Apr
APR-07	0921	Projects	E600921	PVS Net - Procard Charges	PIC N RUN 10008Q65		16.74		16.74	Apr
APR-07	0921	Projects	E600921	PVS Net - Procard Charges	SHELL OIL 57541309902		19.77		19.77	Apr
APR-07	0000	Projects	E618905	PVS Net - Procard Charges	TA #094 KINGMAN AZ		1.79		1.79	Apr
APR-07	0000	Projects	E618905	PVS Net - Procard Charges	NORTHERN ENERGY #412		272.57		272.57	Apr
APR-07	0000	Projects	E618905	PVS Net - Procard Charges	CIRCLE K 01569 Q04		26.65		26.65	Apr
APR-07	0598	Projects	E620598	PVS Net - Procard Charges	EXXONMOBIL 96386Q19		6.00		6.00	Apr
APR-07	0901	Projects	E640901	Transportation Fuel Issues			77.36		77.36	Apr
MAY-07	0000	General Ledger				J342 A/P Accrual Adjustment USI	11,736.74		11,736.74	May
MAY-07	0000	General Ledger				J343 - Reverses "J342 A/P Accru		27,874.48	<27,874.48>	May
MAY-07	0000	Payables	E648905			Purchase Invoices USD	1,640.23		1,640.23	May
MAY-07	0000	Payables	ETR6004			Purchase Invoices USD	68,714.56		68,714.56	May
MAY-07	0000	Payables	ETR6404			Purchase Invoices USD	21,923.09		21,923.09	May
MAY-07	0921	Projects	E600921	PVS Net - Procard Charges	LOVE S COUNTRY00002Q01		24.57		24.57	May
MAY-07	0921	Projects	E600921	PVS Net - Procard Charges	EXXONMOBIL 96129Q19		12.83		12.83	May
MAY-07	0921	Projects	E600921	PVS Net - Procard Charges	EXXONMOBIL 11521Q19		12.29		12.29	May
MAY-07	0921	Projects	E600921	PVS Net - Procard Charges	DANNY'S FMLY CAROUSEL		14.99		14.99	May
MAY-07	0000	Projects	E608905	PVS Net - Procard Charges	SAMSCLUB #6241		20.93		20.93	May
MAY-07	0000	Projects	E618905	PVS Net - Procard Charges	CHEVRON 0211955		45.29		45.29	May
MAY-07	0000	Projects	E618905	PVS Net - Procard Charges	NORTHERN ENERGY #412		258.58		258.58	May
MAY-07	0901	Projects	E640901	Transportation Fuel Issues			177.90		177.90	May
JUN-07	0000	General Ledger				J342 A/P Accrual Adjustment USI	15,590.35		15,590.35	Jun
JUN-07	0000	General Ledger				J343 - Reverses "J342 A/P Accru		11,736.74	<11,736.74>	Jun
JUN-07	0000	Payables	E648905			Purchase Invoices USD		1,640.23	<1,640.23>	Jun
JUN-07	0000	Payables	ETR6004			Purchase Invoices USD	42,285.79		42,285.79	Jun
JUN-07	0000	Payables	ETR6404			Purchase Invoices USD	12,770.03		12,770.03	Jun
JUN-07	0921	Projects	E600921	PVS Net - Procard Charges	LOVE S COUNTRY00002Q01		27.99		27.99	Jun
JUN-07	0921	Projects	E600921	PVS Net - Procard Charges	SHELL OIL 60635220120		15.35		15.35	Jun
JUN-07	0000	Projects	E618905	PVS Net - Procard Charges	#412 NORTHERN ENERGY		160.74		160.74	Jun
JUN-07	0000	Projects	E618905	PVS Net - Procard Charges	EXXONMOBIL 10399160		26.55		26.55	Jun
JUN-07	0000	Projects	E618905	PVS Net - Procard Charges	NORTHERN ENERGY #412		95.51		95.51	Jun
JUN-07	0000	Projects	E628905	PVS Net - Procard Charges	EXXONMOBIL 96466479		30.31		30.31	Jun
JUN-07	0901	Projects	E640901	Transportation Fuel Issues			148.10		148.10	Jun
Total							699,582.47	100,507.06	599,075.41	

EXHIBIT

DJD-8

UNS ELECTRIC, INC.
FERC 925 ACTIVITY

	Test Year				
	TME 6/30/07	**TME 6/30/06**	**TME 12/31/06**	**TME 12/31/05**	**TME 12/31/04**
50000 Wages 0925 Injuries & Damag	$30,000.19	$42,228.58	$49,669.25	$12,250.13	$9,888.49
50010 Vacation & Sick 0925 Injuries & Damag	$0.00	$0.00	$0.00	$0.00	$395.31
50250 Workers' Compen 0925 Injuries & Damag	$20,710.62	$3,593.23	$12,803.12	$11,443.99	$16,187.54
51500 Materials & Sup 0925 Injuries & Damag	($380.00)	$7,848.94	($713.73)	$13,167.10	$8,117.29
52000 Outside Service 0925 Injuries & Damag	$0.00	$0.00	$0.00	$0.00	$780.50
52020 Outside Serv-Co 0925 Injuries & Damag	$14,803.70	$10,670.09	$13,266.79	$1,681.50	$581.63
52100 Outside Service 0925 Injuries & Damag	$0.00	$7,392.70	$498.00	$17,549.22	$10,876.67
55000 Transportation 0925 Injuries & Damag	$103.71	$165.65	$207.48	$134.75	$1,692.78
56000 Facilities Rent 0925 Injuries & Damag	$860.81	$862.52	$778.65	$524.60	$393.62
78000 Officers & Dire 0925 Injuries & Damag	**$138,852.00**	**$120,071.83**	**$130,329.56**	**$88,604.79**	**$22,032.32**
78010 General Liabili 0925 Injuries & Damag	**$221,929.49**	**$203,527.90**	**$202,092.70**	**$180,051.76**	**$169,604.93**
78040 Workers' Compen 0925 Injuries & Damag	**($46,739.53)**	**$173,456.03**	**$81,037.33**	**$31,579.70**	**$113,266.73**
78100 Injuries & Dama 0925 Injuries & Damag	$17,888.81	($7,824.88)	$10,063.93	$0.00	($1,228.77)
79010 Travel 0925 Injuries & Damag	$0.00	$406.83	$406.83	$0.00	$0.00
79070 Printing & Mail 0925 Injuries & Damag	$0.00	$0.00	$0.00	$0.00	$0.00
79120 Postage 0925 Injuries & Damag	$0.00	$0.00	$0.00	$0.00	$0.00
79200 Other A&G Expen 0925 Injuries & Damag	$0.00	$0.00	$0.00	$0.00	$0.00
79300 A&G Expense Tra 0925 Injuries & Damag	$1.95	$3.73	$0.35	$4.74	$0.00
	$398,031.75	$562,403.15	$500,440.26	$356,992.28	$352,589.04

	2004	**2004/2005 Δ**	**2005/2006 Δ**
78000 Officers & Dire 0925 Injuries & Damag	$22,032.32	$66,572.47	$41,724.77

1. 2004 amount low because allocation to UNSE did not start until July 2004 - using invoice for AEGIS

2. 2005 amount increase - 1) full year amount , 2) additional invoice added in Jul 05 to the allocation for EIM (Energy Insurance Mutual) for a total increase of $29,227.98. 3) % amount to be allocated to UNSE increased from 7.71% to 8.13% - (Three Factor Mass Formula being used)

3. 2006 amount increase due to increase in insurance premiums and increase in % to UNSE through Mass formula (from 8.13% to 8.86%)

UNS ELECTRIC, INC.
FERC 925 ACTIVITY

	TME 6/30/07	Test Year TME 6/30/06	TME 12/31/06	TME 12/31/05	TME 12/31/04	
50000 Wages 0925 Injuries & Damag	$30,000.19	$42,228.58	$49,669.25	$12,250.13	$9,888.49	
50010 Vacation & Sick 0925 Injuries & Damag	$0.00	$0.00	$0.00	$0.00	$395.31	
50250 Workers' Compen 0925 Injuries & Damag	$20,710.62	$3,593.23	$12,803.12	$11,443.99	$16,187.54	
51500 Materials & Sup 0925 Injuries & Damag	($380.00)	$7,848.94	($713.73)	$13,167.10	$8,117.29	
52000 Outside Service 0925 Injuries & Damag	$0.00	$0.00	$0.00	$0.00	$780.50	
52020 Outside Serv-Co 0925 Injuries & Damag	$14,803.70	$10,670.09	$13,266.79	$1,681.50	$581.63	
52100 Outside Service 0925 Injuries & Damag	$0.00	$7,392.70	$498.00	$17,549.22	$10,876.67	
55000 Transportation 0925 Injuries & Damag	$103.71	$165.65	$207.48	$134.75	$1,692.78	
56000 Facilities Rent 0925 Injuries & Damag	$860.81	$862.52	$778.65	$524.60	$393.62	
78000 Officers & Dire 0925 Injuries & Damag	**$138,852.00**	**$120,071.83**	**$130,329.56**	**$88,604.79**	**$22,032.32**	
78010 General Liabili 0925 Injuries & Damag	**$221,929.49**	**$203,527.90**	**$202,092.70**	**$180,051.76**	**$169,604.93**	**04-06 Average**
78040 Workers' Compen 0925 Injuries & Damag	**$75,294.59**	**$75,294.59**	**$81,037.33**	**$31,579.70**	**$113,266.73**	**$75,294.59**
78100 Injuries & Dama 0925 Injuries & Damag	$17,888.81	($7,824.88)	$10,063.93	$0.00	($1,228.77)	
79010 Travel 0925 Injuries & Damag	$0.00	$406.83	$406.83	$0.00	$0.00	
79070 Printing & Mail 0925 Injuries & Damag	$0.00	$0.00	$0.00	$0.00	$0.00	
79120 Postage 0925 Injuries & Damag	$0.00	$0.00	$0.00	$0.00	$0.00	
79200 Other A&G Expen 0925 Injuries & Damag	$0.00	$0.00	$0.00	$0.00	$0.00	
79300 A&G Expense Tra 0925 Injuries & Damag	$1.95	$3.73	$0.35	$4.74	$0.00	
	$520,065.87	$464,241.71	$500,440.26	$356,992.28	$352,589.04	

	2004	2004/2005 Δ	2005/2006 Δ
78000 Officers & Dire 0925 Injuries & Damag	$22,032.32	$66,572.47	$41,724.77

1. 2004 amount low because allocation to UNSE did not start until July 2004 - using invoice for AEGIS

2. 2005 amount increase - 1) full year amount , 2) additional invoice added in Jul 05 to the allocation for EIM (Energy Insurance Mutual) for a total increase of $29,227.98. 3) % amount to be allocated to UNSE increased from 7.71% to 8.13% - (Three Factor Mass Formula being used)

3. 2006 amount increase due to increase in insurance premiums and increase in % to UNSE through Mass formula (from 8.13% to 8.86%)

EXHIBIT

DJD-9

CONFIDENTIAL

EXHIBIT

DJD-10

UNS Electric, Inc.- Test Year Ended June 30, 2006
Transaction Detail - All Sources
File: DSM-Renewables Account Transaction Detail.DIS Sheet: DSM-All
Run Date: 25-SEP-06 01.48.16 PM

BATES #UNSE(0783)02038 - 02103 WAS PROVIDED IN BACKUP FOR DSM PRO FORMA ADJUSTMENT FOR RUCO DATA REQUEST 1.10

DETAIL BELOW = BATES #UNSE(0783)02064 - 02096 - PROVIDED IN BACKUP FOR DSM PRO FORMA ADJUSTMENT
DATA HAS BEEN REORGANIZED & SORTED TO SIMPLIFY VIEWING - NOT ALL ROWS ARE DISPLAYED; NOTES HAVE BEEN ADDED

FERC	Acct	Task Number	Query Source	Gl JE Name	Gl Je Batch Name	Gl Je Batch Description	GL Period	Net Amount
908	52000	E61A908	Payables	Purchase Invoices USD	2030 Payables 7927733: A 77996	Journal Import Payables 7927733:	Feb-06	$3,597
908	52000	E61A908	Payables	Purchase Invoices USD	2010 Payables 7825083: A 77149	Journal Import Payables 7825083:	Feb-06	$17,055
908	52000	E62A908	Payables	Purchase Invoices USD	2030 Payables 7927733: A 77996	Journal Import Payables 7927733:	Feb-06	$3,597
908	52000	E61A908	Payables	Purchase Invoices USD	1886 Payables 7028041: A 70219	Journal Import Payables 7028041:	Dec-06	$4,309
908	52000	E62A908	Payables	Purchase Invoices USD	1886 Payables 7028041: A 70219	Journal Import Payables 7028041:	Dec-06	$4,309
DSM Outside Services as originally filed and removed from test year expense								**$32,866**

<u>**Invoice not included in DSM Outside Services as originally filed and therefore not removed from test year expense (see Bates UNSE(0783)10705)**</u>

This invoice was not included in the FERC 908 DSM expense removed from test year expense in the original pro forma adjustment and therefore should be adjusted out of test year expense; this occurred because the expense query was based on DSM tasks and this invoice was recorded incorrectly in the GL without a task.

FERC	Acct	Task Number	Query Source	Gl JE Name	Gl Je Batch Name	Gl Je Batch Description	GL Period	Net Amount
908	52000	n/a	Payables	Purchase Invoices USD	ECOS Consulting		Feb-06	$17,055
					Total DSM Outside Services			**$49,920**
Total FERC 908 expense as originally filed and removed from test year expense								**$136,139**

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	DSM
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	October 23, 2006
PREPARED BY:	Janet Zaidenberg-Schrum JZS
CHECKED BY:	Dallas Dukes D
REVIEWED BY:	

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	
408	Taxes Other Than Income Taxes		$5,283	a
546	Operation Supervision & Engineering		$68,254	b
549	Miscellaneous Other Power Generation		$107,473	c
588	Miscellaneous Distribution Expenses		$7,022	d
908	Customer Assistance Expenses		$144,338	e
909	Informational and Instructional Advertising Expenses		$49,875	f
920	Administrative & General Salaries		$107	g
923	Outside Services Employed		$12,529	h
925	Injuries and Damages		$25	i
926	Employee Pension & Benefits		$20,902	j
931	Rents		$526	k
587	Customer Installations Expense		$42,533	6.1a
	ENTRY TOTAL	$0	$458,867	

Reason for Adjustment

To reduce operating expenses for amounts related to DSM activities; these are to be evaluated independently.

Original Pro Forma

10/23/2006 11:29 AM

UNSE(0783)02038

UNS Electric, Inc.
DSM & Renewables - Expense Detail
Test Year Ended June 30, 2006

Description	Amount	FERC	Note
Renewables - EPS	$1,876	408	2.18a
Renewables - EPS	$68,254	546	b
Renewables - EPS	$107,473	549	c
Renewables - EPS	$7,022	588	d
Renewables - EPS	$107	920	e
Renewables - EPS	$1,004	923	f
Renewables - EPS	$4	925	g
Renewables - EPS	$7,457	926	h
	$193,197		
Weatherization	$29	408	3.4a
Weatherization	$584	908	b
Weatherization	$112	926	c
	$725		
DSM Administration	$345	408	4.2a
DSM Administration	$7,615	908	b
DSM Administration	$11,525	923	c
DSM Administration	$4	925	d
DSM Administration	$1,293	926	e
	$20,782		
DSM	$3,033	408	5.33 a
DSM	$136,139	908	b
DSM	$49,875	909	c
DSM	$17	925	d
DSM	$12,040	926	e
DSM	$526	931	f
	$201,630		
Total	$416,334		

Summary By FERC Account

FERC 408	$5,283	a
FERC 546	$68,254	b
FERC 549	$107,473	c
FERC 588	$7,022	d
FERC 908	$144,338	e
FERC 909	$49,875	f
FERC 920	$107	g
FERC 923	$12,529	h
FERC 925	$25	i
FERC 926	$20,902	j
FERC 931	$526	k
	$416,334	

Original Pro Forma

10/19/2006 3:11 PM

UNS Electric, Inc.- Test Year Ended June 30, 2006
Transaction Detail - All Sources
File: DSM-Renewables Account Transaction Detail.DIS Sheet: DSM-All
Run Date: 25-SEP-06 01.48.16 PM

GL Period Name: JUL-05, AUG-05, SEP-05, OCT-05, NOV-05, DEC-05, JAN-06, FEB-06, MAR-06, APR-06, MAY-06, JUN-06, Co: 033mpeny, &Account, &Subaccount, Co: 033st Center, Task: E61WEB9, E61WEBA, E62WEB9, E62WEBA, E64WEB9, E64WEBA, E61RSE9, E61RSES, E62RSE9, E62RSES, E64RSE9, E64RSES, E61CSE9, E61CSES, E62CSE9, E62CSES, E64CSE9, E64CSES, E61CUS9, E61CUST, E62CUS9, E62CUST, E64CUS9, E64CUST, E64ACE9, E64ACED, E61ACE9, E61ACED, E62ACE9, E62ACED, E61A908, E61A909, E62A909, E62A908, E64A909, E64A908, &Expenditure Type, &Project Number, &Location, &Activity, &Business Center, &Cash Type, &Service Product Code, &FERC Account

FERC	Acct	Task Number	Query Source	PA Transaction Source	PA Expenditure Comment	Gl JE Name	Gl Je Batch Name	Gl Je Batch Description	GL Period	DR	CR	Net Amount
	50300	E64RSES	Projects	BURDENS					5-Jul	$8		$8
	50300	E64RSES	Projects	BURDENS					5-Aug	$931		$931
	50300	E64RSES	Projects	BURDENS					5-Sep		$330	($330)
	50300	E64RSES	Projects	BURDENS					5-Oct	$3		$3
	50300	E64RSES	Projects	BURDENS					5-Nov	$7		$7
	50300	E64RSES	Projects	BURDENS					5-Dec	$4		$4
	50300	E64RSES	Projects	BURDENS					6-Jan	$3		$3
	50300	E64RSES	Projects	BURDENS					6-Feb	$24		$24
	50300	E64RSES	Projects	BURDENS					6-Mar		$4	($4)
	50300	E64RSES	Projects	BURDENS					6-Apr	$9		$9
	50300	E64RSES	Projects	BURDENS					6-May	$9		$9
										$12,624	$584	$12,040
931	55010	E61A908	Payables			Purchase Invoices USD	1929 Payables 7323042: A 72897	Journal Import Payables 7323042:	6-Jan	$142		$142
	55010	E61RSES	Payables			Purchase Invoices USD	1786 Payables 6617887: A 68401	Journal Import Payables 6617887:	5-Nov	$121		$121
	55010	E61RSES	Payables			Purchase Invoices USD	1866 Payables 6929931: A 69402	Journal Import Payables 6929931:	5-Dec	$132		$132
	55010	E61RSES	Payables			Purchase Invoices USD	1929 Payables 7323042: A 72897	Journal Import Payables 7323042:	6-Jan	$132		$132
										$526		$526
								Total		$212,211	$10,582	$201,629

FERC 408	$3,033	a
FERC 908	$136,139	b
FERC 909	$49,875	c
FERC 926	$17	d
FERC 928	$12,040	e
FERC 931	$526	f
	$201,630	

Original Rebuttal

UNSE(0783)~~02096~~533

UNS Electric, Inc.- Test Year Ended June 30, 2006

RUCO Adjustment for Outside Services for DSM Programs

Source: DSM Pro Forma Adjustment detail & query of activity in FERC 908 (GL 52000) for activity with no task.

FERC	Acct	Task Number	Query Source	Gl JE Name	Vendor	GL Period	Net Amount	Notes
908	52000	E62A908	Payables	Purchase Invoices USD	ECOS Consulting	Dec-06	$4,308.71	Included in DSM pro forma expenses removed
908	52000	E61A908	Payables	Purchase Invoices USD	ECOS Consulting	Dec-06	$4,308.72	Included in DSM pro forma expenses removed
908	52000	E61A908	Payables	Purchase Invoices USD	ECOS Consulting	Feb-06	$3,596.67	Included in DSM pro forma expenses removed
908	52000	E62A908	Payables	Purchase Invoices USD	ECOS Consulting	Feb-06	$3,596.67	Included in DSM pro forma expenses removed
908	52000	E61A908	Payables	Purchase Invoices USD	ECOS Consulting	Feb-06	$17,054.62	Included in DSM pro forma expenses removed
				Subtotal			$32,865.39	
908	52000	\1	Payables	Purchase Invoices USD	ECOS Consulting	Feb-06	$17,054.61	Omitted from DSM pro forma expenses removed a See Note \1 below.
							$49,920.00	RUCO adjustment to test year expense

\1 Task is missing from GL data when invoice entered into A/P system. As a result, $17,054.61 was not included in the DSM expense removed from the revenue requirement for separate evaluation.

Dukes Rebuttal
14
UNSE(0783)10704

Transaction Detail - All Sources
File: UNSE DSM-DSM FERC 908 Outside Services RUCO.DIS Sheet: DSM-Builder Program
Run Date: 25-JUL-07 01.09.42 PM

GL Period Name: JUL-05, AUG-05, SEP-05, OCT-05, NOV-05, DEC-05, JAN-06, FEB-06, MAR-06, APR-06, MAY-06, JUN-06, Co: 033mpany, Account: 52000, FERC Account: 0908

Co: 033

Task

FERC	Acct	Exp Type	Task Number	[illegible]	[illegible]	GL Period	DR	CR	Net Amount
0908	52000	155	E61A908	Payables	Purchase Invoices USD	DEC-05	4,308.72		4,308.72
0908	52000	155	E61CSES	Payables	Purchase Invoices USD	DEC-05	2,812.50		2,812.50
0908	52000	155	E62A908	Payables	Purchase Invoices USD	DEC-05	4,308.71		4,308.71
0908	52000	155	E61CSES	Payables	Purchase Invoices USD	JAN-06	2,077.50		2,077.50
0908	52000	155		General Ledger	J962 Jan-06 Inv. With Feb Adjustment USD	JAN-06	7,193.34		7,193.34
0908	52000	155	E61A908	Payables	Purchase Invoices USD	FEB-06	20,651.29		20,651.29
0908	52000	155	E62A908	Payables	Purchase Invoices USD	FEB-06	3,596.67		3,596.67
				General Ledger	J909 - Reverses "J962 Jan-06 Inv. With Feb Adjustment USD"08-MAR-06 14:22:04	FEB-06		7,193.34	<7,193.34>
0908	52000	155		Payables	Purchase Invoices USD	FEB-06	17,054.61		17,054.61
Total							62,003.34	7,193.34	64,810.00

Dukes Rebuttal
14.1
UNSE(0783)10705

EXHIBIT

DJD-11

NOTES TO PAGES 120-122

Page 120 – Instruction 1:
Cash and cash equivalents include cash on hand and highly liquid investments with original maturities of three months or less.

The "Cash and Cash Equivalents at End of Year" on page 121 reconciles to the following amounts on the Comparative Balance Sheet on page 110.

Cash (Account 131)	$ 11,423,738
Temporary Cash Investments (Account 136)	0
Total Cash and Cash Equivalents at Year End	11,423,738

Page 120, Instruction 3:

Income Taxes Paid	$ 573,000

Page 122, Instruction 2:
See Note 6, Commitments and Contingencies in the Notes to Financial Statements.

NOTE 1. NATURE OF OPERATIONS

UNS Electric, Inc. (UNS Electric) procures, transmits and distributes electricity to 81,000 retail electric customers in the Mohave county of Northern Arizona and the Santa Cruz county of Southern Arizona. UniSource Energy Services, Inc. (UES), an intermediate holding company, established UNS Electric on April 14, 2003, and owns all of the common stock of UNS Electric. UniSource Energy Corporation (UniSource Energy) owns all of the common stock of UES.

On August 11, 2003, UNS Electric completed the purchase of the Arizona electric system assets from Citizens Communications Company (Citizens). The operating results of UNS Electric have been included in UES' consolidated financial statements since the acquisition date. The operating results in the attached "Statement of Income For The Year", "Statement Of Retained Earnings For The Year" and "Statement Of Cash Flows" are for the period of August 11, 2003 through December 31, 2003.

The purchase price and the allocation of the assets acquired and the liabilities assumed based on their estimated fair market values as of the acquisition date are as follows for the electric system assets:

Purchase Price:	-Thousands of Dollars-
Cash Paid	$ 82,765
Transaction Costs	1,950
Total Purchase Price	**$ 84,715**

Allocation of Purchase Price:	-Thousands of Dollars-
Property, Plant & Equipment	$ 90,815
Current Assets	17,952
Other Assets	580
Current Liabilities	(20,385)
Deferred Credits and Other Liabilities	(4,247)
Total Purchase Price	**$ 84,715**

Rejoinder 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

Rejoinder Testimony of

Michael J. DeConcini

on Behalf of

UNS Electric, Inc.

August 31, 2007

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Michael J. DeConcini. My business address is One South Church Avenue, Tucson, Arizona.

Q. Are you the same Michael J. DeConcini who filed Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my Rejoinder Testimony is to address Commission Staff's Witness Ralph C. Smith's Surrebuttal Testimony on UNS Electric's revised Purchased Power and Fuel Adjustment Clause ("PPFAC") as filed in my Rebuttal Testimony. I also address the Surrebuttal Testimony of RUCO witness Marylee Diaz Cortez on this same topic.

Q. Please summarize your Rejoinder Testimony?

A. UNS Electric is in agreement with the majority of Mr. Smith's recommendations on the proposed PPFAC and POA, the only exception being the "Other Allowable Costs" category. The Company requests that the Commission include UNS Electric's procurement, scheduling and management costs in the "Other Allowable Costs". The Company disagrees with Ms. Diaz Cortez's testimony that a PPFAC using a historical rolling average, an annual cap, and a sharing provision is a better mechanism. With regards to the Black Mountain Generating Station ("BMGS"), the Company stands by the Direct and Rebuttal Testimonies that Mr. Kevin P. Larson and I submitted supporting the specific treatment of BMGS requested by the Company.

II. RESPONSE TO STAFF WITNESS RALPH C. SMITH'S SURREBUTTAL TESTIMONY.

Q. Please Summarize Mr. Smith's Rebuttal Testimony on UNS Electric's PPFAC filed in Mr. DeConcini's Rebuttal Testimony?

A. Mr. Smith recommends several changes to the PPFAC Plan of Administration ("POA") filed by UNS Electric. Further Mr. Smith states that application of either a 90/10 sharing provision or an annual cap similar to APS' would be inappropriate for UNS Electric at this time.

Q. Do you agree with Mr. Smith's view that the inclusion of a 90/10 sharing mechanism and annual cap would be inappropriate for UNS Electric?

A. Yes. Mr. Smith's comments and analysis accurately reflect the Company's position on these issues. In the Company's current transitional period from a full requirements contract to building a portfolio of resources and contracts to supply its load, it would be inappropriate to apply either an annual cap or a 90/10 sharing provision for the following reasons:

- The power cost in base rates reflects the current full requirements PPA.
- Currently, UNS Electric owns only a small amount of generation that is used for peak power and reliability (must run and voltage stability). UNS Electric's fuel and purchased power costs will be significantly different than the full requirements PPA after its expiration and would not exhibit the stability of a vertically integrated utility with significant, stable cost, base load resources.
- As Mr. Smith states in his Surrebuttal Testimony at page 49 at lines 19 through 21, the application of the sharing mechanism in the APS situation "was more in the nature of a continuation of similar circumstances in terms of the utility's fuel and purchase power procurement, the UNS Electric situation represents a significant

change once the full requirements PPA expires."

- Mr. Smith and the Company agree that an annual cap for the UNS Electric PPFAC is not appropriate at this time. We generally agree with Mr. Smith's explanations in his Surrebuttal Testimony – pages 53 through 54 – with respect to why UNS Electric should not have an annual cap on its PPFAC.

Q. What is Mr. Smith's position on "other allowable costs" included in the UNS Electric's PPFAC?

A. Mr. Smith believes that these costs should not be recovered in the Company's PPFAC.

Q. How does Mr. Smith propose that these costs be recovered?

A. Mr. Smith states that the Company could request recovery of these costs in base rates and that they would be treated as any other utility operating expenses that fluctuate between rate cases.

Q. Do you agree?

A. No. Theses costs are directly related to fuel and purchased power procurement, and as such, should be included in the PPFAC. UNS Electric has not incurred these costs in the past due to its full requirements PPA. Waiting until the next rate case for recovery of these costs could put an unfair financial burden on the Company.

Q. Can the Company accurately forecast these costs?

A. Not all of them. In response to Staff's Data Request No. STF 20.4, the Company provided a forecast of its procurement, scheduling and management costs as it would be allocated from TEP's Wholesale Energy group. This group will perform all the procurement and scheduling functions for TEP and UNS Electric and will allocate costs in proportion to the two companies' loads. The other costs are case or situation dependent which TEP cannot estimate with any degree of certainty at this point.

Q. What has Mr. Smith recommended for changes to the "Other Allowable Costs" section of the POA?

A. Mr. Smith recommends that they be stricken and replaced with "None without pre-approval from the Commission in an Order".

Q. Does the Company request any such pre-approval in this case?

A. Yes. Given that the Company has provided a forecast of the procurement, scheduling and management fees in response to STF 20.4, the Company requests that recovery of these costs be pre-approved in this Rate Case. The Company's response to STF 20.4 is attached as Exhibit MJD-6.

Q. Has Mr. Smith made any additional changes to the POA filed by the Company?

A. Yes. Mr. Smith provided a red-line of the POA filed by the Company. The changes he made are summarized below:

- Interest rate clarification – clarifies that the interest rate shall be adjusted annually on the first business day of the new year.
- Commission Approval for unusual event – clarifies that the Company would need Commission approval prior to amending the Forward Component in the case of an unusual event within the PPFAC Year and clarifies that the Commission could order recovery over such period as the Commission determines appropriate.
- Commission Decision for new PPFAC rates – adds language that a Commission decision, if necessary, would need to occur prior to the June 1 implementation of new PPFAC rates.
- Specific calculations - should be determined upon review of illustrative schedules.
- Credit of wholesale revenue – the POA indicated 90% of wholesale revenues will

be credited to the PFPAC, while my Rebuttal Testimony indicated 100%.

- Prudence review - adds clarity that the Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PPFAC at any time.
- Other Allowable Costs – indicates that no other costs, beyond those recorded in FERC Accounts 501, 547, 555 and 565, will be allowed without pre-approval from the Commission in an Order.

Q. Please address the Company's position on these changes?

A. These changes as proposed by Mr. Smith are all acceptable to the Company, with the exception of his recommendation regarding Other Allowable Costs. I have addressed the Company's position on this recommended change in my Rejoinder Testimony above.

Regarding Mr. Smith's recommendation on specific calculations, the Company will be pleased to work with Staff on development of definitive schedules and specific calculations.

Regarding Mr. Smith's recommendation on crediting wholesale revenues to the PPFAC, the Company agrees. This inconsistency was an error on the Company's part. The POA should have indicated that 100% of revenues from short-term off-system wholesale sales, to the extent they exist, will be credited to the PPFAC.

III. <u>RESPONSE TO RUCO WITNESS MARYLEE DIAZ CORTEZ'S SURREBUTTAL TESTIMONY.</u>

Q. What is Ms. Diaz Cortez's position on the PPFAC filed in the Company's Rebuttal Testimony?

A. Ms. Diaz Cortez believes the historical twelve-month rolling average PPFAC as originally proposed by the Company to be a superior methodology.

Q. What is Ms. Diaz Cortez reasoning for this opinion?

A. Ms. Diaz Cortez states – in her Surrebuttal Testimony on page 7, line 20, through page 8, line 2 – that "the rolling average methodology, as modified by RUCO, provides a number of safeguards and protections including a cap on the magnitude by which the surcharge can move in a given year, and a 90/10 sharing mechanism that is designed to incent the Company to control its fuel and purchased power costs.

Q. Do you agree?

A. No. It is both the Company's and Staff's position that caps and a sharing mechanism would be inappropriate at this time.

Q. Please comment on Ms. Diaz Cortez's statement on page 8 lines 10 through 13 of her Surrebuttal Testimony that "UNS Electric is subject primarily to market prices and purchased power contracts. The historical price of these procurements is a more accurate measure of these costs than market projections?"

A. Ms. Diaz Cortez is correct that UNS Electric is subject to market prices and purchased power contracts. However, historical prices can be significantly different and, in fact, less accurate than projections for UNS Electric as it converts from historical costs based on the expiring full requirements PPA to market power purchases, contracts, and asset acquisitions. Further, actual historical costs incurred by the Company are used to true-up the market projections.

Q. Does this conclude your Rejoinder Testimony?

A. Yes.

EXHIBIT

MJD-6

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TWENTIETH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
August 21, 2007

STF 20.4 Refer to Exhibit MJD-3, the UNS Electric, Inc. Purchased Power and Fuel Adjustment Clause Plan of Administration filed with Mr. DeConcini's rebuttal testimony. For each item of "Other Allowable Costs" on page 11, provide the following information:

a. A complete description of UNS Electric's understanding of whether such costs are included in the APS PSA upon which the UNS Electric PPFAC was modeled? Include supporting documents relied upon for your understanding.

b. A listing, by account, by calendar year (or portion of calendar years 2003 through 2007), of the actual expenses incurred by UNS Electric for each item of "Other Allowable Costs" on page 11, from the inception of ownership of UNS Electric in August 2003 through June 30, 2007.

c. A listing, by account, of the anticipated, estimated, and/or forecast expenses incurred by UNS Electric for each item of "Other Allowable Costs" on page 11, for each of the following periods: (1) calendar 2007, (2) calendar 2008, (3) calendar 2009, (4) calendar 2010, (5) June 1, 2008 through May 31, 2009, and (6) June 1, 2009 through May 31, 2010. Provide the Company's best estimates. To the extent that the requested estimated or forecast information is not available in exactly the form requested (by FERC account), provide the best information the Company has, and provide it in the form that the Company has it in.

RESPONSE:

a. UNS Electric understands that because Arizona Public Service Company ("APS") had an existing PPFAC that was operational, APS recovers the requested "Other Allowable Costs" in its base rates, rather than in the PSA. However, UNS Electric is transitioning from a full requirements agreement into a supply portfolio, and these costs will be incurred. Due to the full requirements agreement, these costs were not in UNS Electric's test-year, and therefore not in the base rates, but will be an actual cost incurred related to replacing the full requirements agreement.

b. These costs have not been incurred to date because UNS Electric has been served under a full requirements Power Supply Agreement with Pinnacle West Capital Corporation ("Pinnacle West").

c. Costs for scheduling/administration of wholesale purchases are as follows: (1) for 2007 - $0; (2) for 2008 - $259,368; (3) for 2009 - $273,563; (4) for 2010 - $281,783; (5) for June 1, 2008 through May 31, 2009 - $268,783; and (6) for June 1, 2009 through May 31, 2010 - $276,978. These scheduling/administration costs could either be accounted for in Account 555 (Purchased Power) or FERC O&M Accounts depending on allocation methodology. UNS Electric cannot anticipate the timing of legal or credit costs with any certainty and none are included in the estimate above. Legal fees and credit costs would continue to be recorded in FERC Accounts 923 and 431, respectively.

RESPONDENT: David Hutchens

WITNESS: Michael DeConcini

Rejoinder Testimony of D. Bentley Erdwurn

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

Rejoinder Testimony of

Bentley Erdwurm

on Behalf of

UNS Electric, Inc.

August 31, 2007

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Bentley Erdwurm, and my business address is 1 South Church Avenue, Tucson, Arizona, 85701.

Q. Are you the same Bentley Erdwurm who filed Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my Rejoinder Testimony is to support the Company's:

- Mandatory Time-of-Use Proposals.
- Purchased Power Allocation.
- Mohave and Santa Cruz County Rate Consolidation.
- Inverted (Inclining) Block Rate Design.
- Proposed Large Power Service Demand Charges; Under 69 kV.
- CARES and Medical CARES.

II. MANDATORY TIME-OF-USE RATES.

Q. Are mandatory time-of-use rates in the public interest?

A. Yes. For residential and smaller commercial customers, time-of-use ("TOU") rates combined with the inverted (inclining) rate structure provide an incentive to customers to shift load from higher-cost to lower-cost time periods. These rate design positions are supported by RUCO witness Diaz-Cortez, and are consistent with past Commission orders in cases involving Tucson Electric Power Company ("TEP") – UniSource Energy's other electric utility – as well as for some Arizona American Water service areas and Arizona Water Company's Western Group. Moreover, Staff has in the past encouraged TEP to increase subscription to its TOU programs.

Q. Is the mandatory TOU program still opposed by Mr. Radigan of Staff?

A. Yes. Mr. Radigan has taken some very reactionary and obstructionist positions in this proceeding, which are contrary to stated Commission policy. If implemented, Mr. Radigan's position will "stop the clock" on TOU's progress. In my Rebuttal Testimony, I indicated that cost-benefit analysis was relevant to the evaluation of TOU programs. However, I never indicated that more information was needed to cost-justify the programs proposed in UNS Electric's direct and rebuttal testimony.

Further, Mr. Radigan seems unaware of the history of TOU in Arizona. The experimental phase for TEP occurred from 1991 through 1994, with the evaluation of TEP's Residential TOU Rate No. 21, and the subsequent expansion of TOU programs with the implementation of Residential Time-of-Use Rate No. 70 and the later implementation of General Service Time-of-Use Rate No. 76. The conclusion drawn from TEP's experimentation with its Rate No. 21 is the importance of choosing peak, off-peak, and shoulder hours and designing TOU prices that reduce both the percentage of peak energy consumption as well as peak demand. Overly-long peak periods in Arizona's desert climate can result in demand spikes during the last hours of the on-peak period. Demand spikes push costs up, because they can accelerate capacity expansion plans. Super-peak rates, with peak hours limited the most critical hours, help avoid demand spikes. TEP Rates 70 and 76, as well as the UNS Electric proposed TOU rates are all examples of super-peak rates.

Q. Are TOU rates also well established at other Arizona electric utilities?

A. Yes. Arizona Public Service Company currently has over 40% of its residential load on TOU. Salt River Project also has an extensive and well-established TOU program. The Public Utility Regulatory Policy Act ("PURPA"), which supported consideration of TOU, was passed in 1978, almost thirty years ago. TOU is an important program that should not be placed on hold.

Q. Mr. Radigan claims – in his Surrebuttal Testimony on page 4 at lines 4 through 6 – that there is no cost justification for the proposed TOU rates. Do you agree?

A. No. The proposed increase in the relative price of peak energy should – other things being constant – cause a shift in consumption away from peak energy and toward off-peak and shoulder energy. That reduces energy costs. Assuming that peak demand does not spike, the average cost of providing energy will fall. Cost reductions benefit customers. This supports immediate mandatory TOU implementation.

III. <u>POWER SUPPLY ALLOCATION.</u>

Q. Do differences still exist between you and Mr. Radigan of Staff on Power Supply Allocation?

A. Yes. Mr. Radigan's preference is to allocate purchased power costs on a 100% volumetric (kWh) basis. I prefer to split the allocation of purchase power between volumetric (kWh) and the average and peaks method. I provided detail of this method in my Rebuttal Testimony. Mr. Radigan bases his method on the simple fact that the current full requirements power supply contract with Pinnacle West Capital Corporation ("PWCC") is collected from UNS Electric by a single, kWh-based charge. This overly simplistic argument is flawed, because had UNS Electric exhibited a much lower system load factor at the time of the price negotiation, Pinnacle West most likely would have required a higher price per kWh to compensate it for underutilized fixed capital investment. Volumetric contract pricing does not imply that load factor is absent from cost causation. The importance of load factor supports my allocation based in part on average and peaks.

Q. How will the upcoming expiration of the PWCC full requirements power supply agreement affect Mr. Radigan's argument?

A. The expiration neutralizes Mr. Radigan's argument on purchased power allocation. Given this coming uncertainty, a prudent approach is to look at how generation is allocated for a vertically integrated utility. My proposed technique, which uses both kWh and average and peaks, strikes this balance.

IV. <u>MOHAVE AND SANTA CRUZ COUNTY RATE CONSOLIDATION AND UNS ELECTRIC'S PROPOSED INVERTED BLOCK RATE DESIGNS.</u>

Q. Do differences still exist between you and Mr. Radigan of Staff on Mohave – Santa Cruz Rate Consolidation and Inverted Block Designs?

A. Unfortunately yes. Our two proposals -- which RUCO also supports -- are rejected by Mr. Radigan to avoid a situation where some customers pay slightly higher bills while other customers pay slightly lower ones. The Company maintains its position as articulated in my Direct and Rebuttal Testimonies. I recommend Commission acceptance of these programs.

V. <u>LARGE POWER SERVICE DEMAND CHARGES; UNDER 69 kV.</u>

Q. Do differences still exist between you and Mr. Radigan over Large Power Service Demand Charges?

A. Yes. As I have indicated, UNS Electric has not performed a study on appropriate demand charge differentials here. However, the current demand charge for large commercial and industrial customers taking service at less than 69 kV is high relative to demand charges for commercial and industrial customers with 69 kV deliveries. All the cost justification notwithstanding, the current "less than 69 kV" demand charge is incredibly oppressive to larger, low load factor customers. This should cause the Commission concern. Such a high demand charge could potentially prevent a new, low load factor commercial customer from locating within the UNS Electric Service territory.

VI. CARES AND MEDICAL CARES.

Q. Staff Witness McNeely-Kirwan of Staff proposes in her surrebuttal (Executive Summary, point 1) that the current CARES and Medical CARES structure should be retained. Please comment.

A. I disagree. The Company's position is detailed in the Company's rebuttal testimony. Simply put – needy customers should not be required to use more energy to fully enjoy the discounts. RUCO agrees with the Company's position. Mr. Ferry in his Rejoinder Testimony further addresses Ms. McNeely-Kirwan's list of recommendations on CARES and Medical CARES.

Q. Does this conclude your Rejoinder Testimony?

A. Yes it does.

Rejoinder 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

Rejoinder Testimony of

Denise A. Smith

on Behalf of

UNS Electric, Inc.

August 31, 2007

TABLE OF CONTENTS

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. Are you the same Denise Smith who filed Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. On whose behalf are you filing your Rejoinder Testimony in this proceeding?

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

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my Rejoinder Testimony is to respond to certain comments Mr. Marshall Magruder makes in his Surrebuttal Testimony.

II. RESPONSE TO MR. MAGRUDER.

Q. How does UNS Electric respond to questions, comments, and allegations made by Mr. Magruder in his Surrebuttal Testimony regarding Demand-Side Management Programs?

A. While UNS Electric has agreed with Mr. Magruder on a few select specific items, the Company disagrees in general with Mr. Magruder's DSM recommendations and allegations. UNS Electric remains committed to its selection of DSM programs, the cost-benefit analysis, and the individual program designs in the DSM Portfolio Program filed on June 13, 2007. The Company's position with regard to Mr. Magruder's objections and recommendations are fully described in my Rebuttal testimony.

Q. On page 15 of Mr. Magruder's Surrebuttal Testimony he recommends a DSM integration plan to summarize goals and objectives and centralized cost accounting of DSM programs. Do you agree?

A. Yes. This information has been provided in the June 13th filing in Docket No. E-04204A-07-0365 and can be found in the DSM Portfolio Plan.

Q. On page 22 of his Surrebuttal Testimony, Mr. Magruder assumes that UNS Electric will implement and incorporate recommendations that UNS Electric did not specifically respond to in Rebuttal Testimony. Is that accurate?

A. No. Just because UNS Electric did not respond to each of the myriad of specific items in Mr. Magruder's Direct Testimony, Supplemental Direct Testimony, or Surrebuttal Testimony does not indicate that we agree with his recommendations.

Q. Mr. Magruder claims UNS Electric's DLC program includes "potentially life-threatening structural flaws." Do you agree?

A. No. First Mr. Magruder provides no reference or documentation to support his inflammatory allegation. Second, the UNS Electric DLC program is voluntary and provides for a customer override of a control event. Third, one advantage with the two-way communication is UNS Electric can build an individual thermal load profile for each home. Thus, any excessive temperature increase in an individual home can be mitigated.

Q. Does this conclude your Rejoinder Testimony?

A. Yes.

Rejoinder 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

Rejoinder Testimony of

Thomas N. Hansen

on Behalf of

UNS Electric, Inc.

August 31, 2007

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Thomas N. Hansen.

Q. Are you the same Thomas N. Hansen who filed Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my Rejoinder Testimony is to respond to Mr. Magruder's Surrebuttal Testimony regarding the Renewable Energy Program.

II. UNS ELECTRIC RENEWABLE ENERGY PROGRAMS.

Q. Do you agree with the Surrebuttal Testimony of Mr. Magruder in his Part VII – Issue 5, Environmental Portfolio Standard ("EPS") and Renewable Energy Standard and Tariff ("REST") Surcharges?

A. No. While Mr. Magruder did recognize and correct many inaccuracies in his testimony, he did not provide any additional information in his Surrebuttal Testimony to challenge or change the statements made in my Rebuttal Testimony. For example, while the Magruder Surrebuttal Testimony discusses ISO 14400 certification and adds ISO 9000 certification to the discussion, there is still no evidence or example provided to create a link between such certifications and improved environmental compliance for electric utilities. In the remainder of my Rejoinder Testimony I will respond to specific points raised by Mr. Magruder, including:

- The structural insufficiency of funding for the EPS included in the EPS rule;

- Mr. Magruder's revised Table 14;
- Mr. Magruder's apparent misunderstanding of the UNS Electric's SunShare program approved by the Commission on December 21, 2006;
- Mr. Magruder's four final REST recommendations.

Q. Has the structural program design insufficiency of EPS funding been the primary cause of failure of any Arizona utility to meet the EPS requirements?

A. Absolutely. During the EPS rulemaking process, many parties provided testimony that the EPS surcharge was very likely insufficient to generate the revenues needed for meeting the EPS annual solar energy requirements, given the relatively high initial cost of solar generation. The Commission recognized this structural program design flaw and in response, Decision No. 63364 on page 4 at lines 18 through 20 states "It is not the Commission's intent that the ratepayers of Arizona pay the surcharge and also be faced with high deferred costs if it turns out the surcharge is not sufficient to allow an utility that is taking prudent measures to meet the portfolio percentage." Thus, utilities were allowed to only spend the EPS surcharge funds towards meeting compliance with EPS goals. If shareholder funds were to be spent towards EPS compliance, they could not be recovered through future rates. Additionally, the surcharge caps in the EPS rule were set as maximums which could not be increased, even by the Commission. See Decision No. 63364 at page 13, lines 26 and 27. Two utilities, APS and TEP were allowed to use existing DSM program funding in their EPS programs. This nearly doubled the amount of funds available. Even so, the funding was still not sufficient to meet EPS goals for those two utilities. UNS Electric has not had the benefit of any additional funding source and has been consistently dismayed, not excited as Mr. Magruder opines, that it has not been able to meet the EPS annual renewable energy goals. But given the limited funding that could be spent on the EPS program, the funds did not allow the goals to be met. This was recognized unanimously by the EPS Cost Evaluation Working Group in its report entitled

"Costs, Benefits, and Impacts of the Arizona Environmental Portfolio Standard" submitted on June 30th, 2003. Specifically, the Executive Summary at page 2 of that report states: "However, given the limited revenues available under the EPS rule, no utilities will be able to meet the annual renewable energy targets established by the EPS on the existing timeline."

Clearly, this statement shows that the EPS had a structural program design funding flaw, which did not provide sufficient funding for the solar generation portion of the EPS goals to be met. UNS Electric has met all of its EPS non-solar goals in every year of the EPS program for which UNS Electric filed the annual report. Yet, Mr. Magruder continues to beat the dead horse of UNS Electric being noncompliant with the EPS solar goals, without regard to the structural program design funding flaw in the EPS that resulted in inadequate EPS program funding. No utility has ever met the EPS annual solar energy requirements. Mr. Magruder fails to note any of these facts in his testimony.

Q. Is the revised Table 14 Mr. Magruder provided in his Surrebuttal Testimony a valid reflection of the status of UNS Electric compliance with the EPS?

A. Not at all. The revised Table 14 does not reflect: a) that not all EPS energy was to be from solar resources, and b) that multiplying factors were an essential part of the EPS program formula. Thus, the revised Table 14 has no more bearing on EPS compliance than the original Table 14. Any comparisons drawn between Table 14 and EPS compliance are inherently invalid. Moreover, my objections to the use of Table 14, even as revised, are not resolved.

Q. Is there any significant difference between the current UNS Electric and TEP SunShare program offerings that would support increased interest by UNS Electric residential customers in the first six months of 2007?

A. No. UNS Electric's residential SunShare program approved by the Commission on December 21, 2006 is effectively identical to the Option 3 residential program offered by TEP, and only marginally different from UNS Electric's SunShare program offered prior to December 21, 2006. The increased per capita interest in the UNS Electric program in the first six months of 2007 is a result of the increase in incentive rates offered in 2007. Other changes made to UNS Electric's SunShare program in December 2006, including the increase in the incentive rates and minor revisions to equipment qualifications are identical to the Option 3 residential TEP incentive rates and equipment qualifications revisions made in November of 2006. UNS Electric has supported and continues to support its SunShare program to its customers to the extent that EPS annual SunShare expenditure limits have nearly been reached already in 2007. To spend additional funds to provide outreach support to a program that has nearly exceeded its spending cap in mid year, would not be cost effective or prudent. We do appreciate Mr. Magruder recognizing that UNS Electric has administered its EPS program in a most cost effective manner to maximize the funds available for customer incentives.

Q. Would you please respond to the four recommendations made by Mr. Magruder in his Surrebuttal Testimony?

A. Certainly.

- *Magruder Recommendation #1: That [UNS Electric] continue to invigorate its "SunShare" program, as upgraded on 21 December 2006 and as expanded in its REST Implementation Plan expected filing during September 2007.* UNS Electric looks forward to Commission approval of its REST Implementation Plan.

- *Magruder Recommendation #2: That [UNS Electric] present in its REST Implementation Plan details on how it will transition from EPS to REST, as required by the ACC Decision No. 69127 and its rules in Appendix A of this Decision to comply with or exceed all REST requirements, summarized in Table 15 or as presented by [UNS Electric] to the Commission in its REST Implementation Plan.* While UNS Electric does not accept Mr. Magruder's Table 15 as the definitive REST compliance annual energy requirement definition, UNS Electric plans to file an REST Implementation Plan for Commission approval.

- *Magruder Recommendation #3: That [UNS Electric] present its REST Tariff not later than 14 October 2007 and implemented as required by the resultant Commission Order or Decision.* Since October 14, 2007, is a Sunday, UNS Electric shall present its REST Tariff on or before October 12th for consideration and approval by the Commission. UNS Electric shall not implement the REST Tariff prior to such an approval order of the Commission.

- *Magruder Recommendation #4: That all future ACC REST Reports be routed through and signed by Mr. Hansen, whose job title reflects this area, before submission to the ACC and Docket Control.* I have reviewed past UNS Electric EPS reports before submission to the Commission. We expect to continue that practice while I enjoy my current position responsibilities.

Q. Does this conclude your Rejoinder Testimony?

A. Yes, it does.