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BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

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UNS ELECTRIC, INC.

REBUTTAL TESTIMONY

December 11, 2009

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
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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-09-0206

Rebuttal Testimony of

Michael J. DeConcini

on Behalf of

UNS Electric, Inc.

December 11, 2009

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Michael J. DeConcini. My business address is One South Church Avenue, Tucson, Arizona 85701.

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

A. Yes I have.

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

A. There are several UNS Electric witnesses who are filing Rebuttal Testimony in addition to me. All of our Rebuttal Testimony should be taken as a whole as our response to the other parties' Direct Testimony. However, there are a few items that I wish to emphasize.

First, the Commission Staff ("Staff") and the Residential Utility Consumers Office ("RUCO") continue to recommend increases that are insufficient to sustain the necessary levels of operation for UNS Electric. If their recommendations were adopted, UNS Electric would likely need to immediately file another request for a rate increase to ensure continuing reliability of service and continuing ability to obtain credit, debt and equity on reasonable terms.

Second, the Commission should adopt the Company's proposal concerning the Black Mountain Generating Station ("BMGS"). Acquiring BMGS is in the best public interest, because BMGS will provide the Company and its customers with numerous operational and financial benefits. For example, UNS Electric and its customers would secure a long-term source of economical peaking power with less reliance on the wholesale market for such power.

term source of economical peaking power with less reliance on the wholesale market for such power.

No party disputes the prudence of UNS Electric acquiring BMGS and having it in rate base. However, UNS Electric is not able to acquire BMGS without certainty regarding its cost recovery in rates. The purchase price of BMGS – although significantly lower than a market-based price – is too high for UNS Electric to finance. In order to solve this dilemma, the Company proposed a revenue-neutral rate reclassification, as a post-test year adjustment, to take effect upon Federal Energy Regulatory Commission ("FERC") approval to purchase BMGS from UniSource Energy Development Corporation ("UED") and shortly after ownership is transferred to UNS Electric.

Commission Staff does not support UNS Electric's proposal regarding BMGS. However, Commission Staff does not dispute that costs of BMGS are known and measurable and that BMGS, through its Purchase Power Agreement with UNS Electric, is used and useful. Further, Commission Staff agrees that the revenue-neutral rate reclassification would result in just and reasonable rates. In fact, Staff's only objection is one based solely on the timing of UNS Electric's purchase of BMGS.

As I explain in more detail, this transaction creates many benefits for the Company and its customers. Those benefits clearly outweigh Staff's sole concern about timing. RUCO recognizes the benefits of BMGS, understands the acquisition dilemma and supports the Company's proposal. The Commission should adopt the Company's proposal.

Third, the Company should be allowed to recover non-revenue-producing plant that is either currently serving customers or will be serving customers when rates established in this case go into effect. The purpose of this type of plant is to serve existing customers. It investments until mid-2012. This has a significant adverse impact on the Company's opportunity to earn its authorized rate of return.

Fourth, Staff and RUCO's recommendations regarding Cost of Capital and Rate of Return ("ROR") on Fair Value Rate Base ("FVRB") are inadequate, not commensurate with the level of risk the Company faces and contradict recent Commission orders.

Fifth, regarding its Purchased Power and Fuel Adjustor Clause, the Company reiterates its request to recover credit support costs as these are actual costs incurred by UNS Electric in the provision of electric service. The Company proposes, in response to suggestions in Staff Testimony, that $195,500 in annual credit support costs be recovered from base rates. Further, the Company maintains its request for an interest rate that reflects the actual cost of short-term borrowing from its joint revolving credit facility (3-month LIBOR plus 1.0%).

Sixth, I will briefly address rate design, time-of-use ("TOU") and low-income issues responding to both Staff and RUCO Direct Testimony on these topics.

Finally, I will respond to Direct Testimony provided by Chuck Essigs on behalf of the Arizona School Board Association ("ASBA") and the Arizona Association of School Business Officials ("AASBO").

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

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

A. There is no dispute, and all of the evidence justifies the importance and benefit of UNS Electric acquiring BMGS. For example, this is a generator that has been in commercial operation since May 30, 2008. Further, UNS Electric proposes a known and measurable value for BMGS of $62 million (equaling the total cost net depreciation). This reflects the net book value of the facility as of the end of the test year (December 31, 2008). We also propose a revenue-neutral rate reclassification that would go into effect only upon acquisition of BMGS by the Company. This rate reclassification would provide sufficient cash flow to service the debt arising from the acquisition of BMGS.

Staff argues that the Company chose not to acquire BMGS and that, since it does not own the facility, it should not be included in rate base. Staff's argument does not justify rate base exclusion of BMGS. First, the Company was not able to acquire BMGS after its last rate case. While UNS Electric received the financing authority it requested to acquire BMGS, the Commission rejected the Company's proposal to include BMGS in rates when it was acquired. As UNS Electric witness Mr. Kentton C. Grant explained in his Direct Testimony (at pages 9-10), an acquisition by UNS Electric of an asset the size of BMGS would have had a very detrimental impact on the Company's financial position and credit profile. The Company needed the rate base treatment it requested then (and requests now) to have the requisite earnings and cash flow to buy the facility. Further, the accounting deferral authorized in our prior rate case (Decision No. 70360 (June 27, 2008)) could not provide the cash rate relief necessary to acquire the plant. Staff ignores these important facts when it simply stated that "the Commission provided the Company with financing capability to purchase the plant."

Further, the rate reclassification requested here will not occur until *after* the Company acquires BMGS. In other words, the Company's rate reclassification request would not take effect until the Company owns BMGS. In addition, UNS Electric would promptly notify Staff regarding the transfer of ownership and the requirement to reclassify rates. This serves as additional assurance and protection that ownership would be obtained before the Company makes the requested reclassification.

Q. Can you please summarize the benefits BMGS would provide to UNS Electric and its customers?

A. BMGS will provide both financial and operational benefits to the Company and its customers. UNS Electric witnesses Messrs. Kentton C. Grant and Thomas A. McKenna detail these benefits in their respective pre-filed testimonies. Generally, the benefits BMGS would provide include:

- Securing a long-term source of economical peaking capacity;
- Improving UNS Electric's financial position;
- Reducing reliance on purchased-power and long-term lease agreements;
- Having full operational flexibility of the generator;
- Increasing reliability in UNS Electric's Mohave County load area;
- Allowing UNS Electric to better meet its peaking capacity and reserve needs; and
- Providing necessary must-run energy and minimizing transmission costs.

Q. Can UNS Electric acquire BMGS without the post-test rate base adjustment and related authorization to reclassify rates as it requests in this case?

A. No, it still cannot do so without the Company's requested rate treatment.

III. UNS ELECTRIC'S RATE BASE SHOULD INCLUDE NON-REVENUE PRODUCING PLANT THAT WILL SERVE EXISTING CUSTOMERS BEFORE THIS CASE IS CONCLUDED.

Q. What is the Company's overall reaction to Staff's and RUCO's recommendations regarding non-revenue producing plant?

A. It is unfortunate and disappointing that both parties recommend rejection of the Company's request to include plant: (1) where investment was made during the test year; (2) to serve existing customers; (3) that is either in service now or will be in service by the time an order is issued in this case; and (4) is prudently-incurred costs for plant that provides improved system reliability, operational flexibility and improved service. Further, both parties seem to impose unrealistically high burdens in order to allow such plant in rate base. Denying the opportunity to recover on this plant results in adverse impacts to the Company and necessitates the filing of a subsequent rate case in order to recover costs incurred for this plant.

Q. Is there precedent to support inclusion of post-test year plant in rate base?

A. Yes. UNS Electric witness Mr. Dallas Dukes describes several instances where the Commission allowed post-test year plant in rate base and equates those matters to the rate request.

Q. Does Staff point to any evidence contradicting the Company's testimony that the non-revenue post-test year plant is to serve existing customers?

A. No. Staff assumes there *could* be a mismatch between revenues and costs. The evidence is to the contrary, however. The plant at issue does not change how UNS Electric operates or maintains its system. Further, Staff has no support for its assumption that the plant at issue increases revenues to the Company. However, this plant would be necessary even if the Company experienced no growth subsequent to the test year.

Q. Please respond to RUCO's arguments against including post-test year plant in rate base.

A. It is clear that revenue neutral post-test year plant includes plant that is intended to serve existing customers without any material impacts to revenues and expenses. The Company has provided ample documentation, testimony and evidence demonstrating that the items UNS Electric seeks to include are not revenue-producing and do not result in any changes to how UNS Electric operates its system. UNS Electric witnesses Messrs. Thomas A. McKenna and Dallas J. Dukes detail this further in their Direct Testimony. Second, while the investments may not be extraordinary, that is not a reason to disallow post-test year plant. The Commission has, in the past, allowed utilities to include post-test year plant in rate base. Finally, RUCO ignores Commission regulations which allow for post-test year pro forma adjustments. There is no violation of the matching principle here. Applying a "uniform, consistent cut-off date as of the end of the test year" as RUCO suggests ignores Commission regulations and precedent.

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

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

A. As UNS Electric witness Martha B. Pritz explained in her Direct Testimony, the Company's 9.04% cost of capital recommendation is just and reasonable. This conclusion was based on an 11.4% cost of common equity capital and a 7.05% cost of long-term debt, with a capital structure consisting of 45.76% common equity and 54.26% long-term debt. The Company stands by its recommendations.

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

A. Staff recommends an overall cost of capital of 8.40%, based on a cost of equity of 10.00% and a cost of long-term debt of 7.05%, with a capital structure of 45.76% equity, and 54.26% long-term debt. RUCO recommends an overall cost of capital of 8.06%, based on a cost of equity of 9.25% and a cost of long-term debt of 7.05% and a hypothetical capital structure of 54.26% long-term debt and 45.76% equity. Neither Staff's nor RUCO's recommendations are sufficient or reasonable. In her Rebuttal Testimony, Ms. Pritz details the problems with both Staff's and RUCO's recommendations.

Q. Would you highlight some of those problems?

A. The awarded return on equity should be commensurate with the risk the Company faces. Staff and RUCO do not account for the increased business risks faced by UNS Electric. Nor does Staff or RUCO provide any analysis on how their recommendations affect the Company's cash flow or earnings. The Company is not proposing a new ratemaking methodology; rather, UNS Electric is requesting the Commission to look at these important factors within the regulatory framework established.

We try to secure capital on the best terms we can for UNS Electric, so that the Company can continue to provide reliable service. This is especially difficult in today's economic climate. It is even harder when the return on equity awarded is the same as that of far less riskier companies. The bottom line is that the Company will be at a competitive disadvantage when it comes to attracting capital compared to other utilities if either Staff's or RUCO recommendations are adopted. That disadvantage translates in financial costs to obtain capital which will ultimately be borne by rate payers. To put the Company in that position is not reasonable and does not benefit customers over the long term.

V. <u>RATE OF RETURN ON FAIR VALUE RATE BASE.</u>

Q. How does the Company respond to Staff and RUCO recommendations on rate of return on fair value rate base ("FVRB")?

A. Staff's and RUCO's recommendations squarely contradict the Commission's most recent decisions on fair value rate of return. In fact, both propose methodologies that have been rejected by the Commission in other cases. Both proposals are flawed for several reasons, as detailed by UNS Electric witness Mr. Grant in his Rebuttal Testimony. Staff witness David C. Parcell's primary recommendation that 0% return on the portion of FVRB that exceeds original cost rate base ("OCRB") is equivalent to the "backing in" method that has been discontinued. Further, neither Mr. Parcell's primary nor alternative recommendation were applied in Decision No. 70441 (July 28, 2008) ("Chaparral City Remand Order"), or Decision No. 71308 (October 21, 2009) ("Chaparral City Rate Order"). RUCO witness Dr. Ben Johnson recommends that the full rate of inflation be subtracted from both the cost of debt and again from the cost of equity. Dr. Johnson's method was not accepted by the Commission in either the Chaparral City Remand Order or the Chaparral City Rate Order.

Q. What rate of return on FVRB is the Company recommending?

A. Let me explain the rate of return by referring to alternative situations. If Staff's and RUCO's proposed negative adjustments to the revenue requirement are adopted, then the Company recommends that the methodology adopted by the Commission in Decision No. 70441 be adopted. This would lead to a ROR on FVRB of 8.08%. In the alternative, the Company recommends that the Commission use the methodology approved in Decision No. 71308, which would be a ROR on FVRB of 7.99%. The Company had proposed a 6.88% ROR on FVRB in its Direct Filing, and finds that ROR acceptable if the Commission rejects a majority of the proposed negative adjustments. If those adjustments are accepted, however, a 6.88% ROR is inadequate to allow UNS Electric to have an opportunity to earn its cost of capital and maintain its financial integrity, as Mr. Grant further details in his Rebuttal Testimony.

VI. <u>PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE ("PPFAC").</u>

Q. Please summarize Staff's recommendations regarding the PPFAC.

A. Staff recommends increasing the cap on the forward component of the PPFAC to $0.01845 per kWh. Staff rejects the Company's proposals to use the 3-month LIBOR rate plus 1 percent as the interest rate on PPFAC over- and under-collected balances. Staff also believes that credit support costs should not be recovered through the PPFAC and that those costs should be recovered through rate cases (and presumably through base rates).

Q. How does the Company respond to Staff's recommendations?

A. The Company does not oppose increasing the cap on the forward component of the PPFAC.

Regarding the PPFAC interest rate, the Company is only requesting an interest rate that reflects its actual cost of short-term borrowing at UNS Electric. The Company will continue to procure fuel and purchased power in a prudent manner.

In light of Staff witness Dr. Fish's testimony regarding credit support costs, the Company proposes to recover $195,500 in annual credit support costs as part of its non-fuel revenue requirement. Mr. Grant describes how this amount of recovery is reasonable, using the weekly average balance of wholesale credit support provided from August 10, 2008 through April 12, 2009.

VII. FUEL AND PURCHASED POWER POLICIES.

Q. At Page 69 of his Direct Testimony, Dr. Fish sets forth four specific recommendations regarding the Company's fuel and purchased power policies. Could you please address those recommendations?

A. Yes. Dr. Fish's first recommendation is to strengthen the relationship between fuel contract management and procurement. This recommendation appears to relate diesel procurement at the Valencia station. However, Dr. Fish does not set forth any particular guidance on what should be strengthened. The Company would certainly consider any specific recommendations to strengthen the relationship.

Q. Dr. Fish's second recommendation is to create internal auditing procedures regarding fuel and purchased power policies be created. Do you agree with this recommendation?

A. No. I believe his conclusion that procedures do not exist arises from the fact that UNS Electric's internal audit department did not perform such an audit for the test year period. However, the Company employs other audit procedures to ensure appropriate oversight of the power and fuel procurement processes.

Q. What audit procedures do the Company utilize?

A. UNS Electric's internal audit department tests the controls over the acquisition of purchased power and fuel annually as part of its responsibility to assess the effectiveness of the Company's internal controls over financial reporting as required under Section 404 of the Sarbanes-Oxley Act of 2002.

Q. The third recommendation proposes that the analysis of possible excess interstate capacity optimization by UNS Gas, Inc. ("UNS Gas") should be extended to UNS Electric fuel procurement. What is your response to this recommendation?

A. UNS Electric does not have any interstate pipeline capacity. UNS Gas is the provider of natural gas to the UNS Electric power plants.

Q. Finally, Dr. Fish recommends hedging for natural gas procurement for August, September, and October should be considered but not required. What is your response to this recommendation?

A. UNS Electric hedges gas pursuant to its hedging policy. Section 2.2.3 of this policy specifically addresses gas procurement during these months. The policy states that hedging is not required but should be considered during these three months.

VIII. RATE DESIGN, TIME-OF-USE, AND LOW-INCOME PROGRAMS.

Q. How would you characterize the testimony from Staff and RUCO on rate design and time-of-use ("TOU")?

A. Staff and the Company appear to largely agree on rate design issues, including increasing the rate differentials (between on-peak and off-peak) in its existing time of use ("TOU") rates. Staff also supports the introduction of new Super-Peak rates – setting a single hour during the day to be the peak hour. Staff does suggest a slightly different allocation approach for the revenue increases. The Company uses the same allocation methodology adopted in its last rate case. Company witness D. Bentley Erdwurm discusses this in more detail.

On the other hand, the Direct Testimony from Dr. Johnson for RUCO on rate design is troubling for several reasons. Dr. Johnson substantially understates the proposed residential customer charge by recommending it be decreased to $5.00 per month. In fact, Dr. Johnson appears to almost entirely ignore the actual embedded costs of metering, meter-reading, billing and customer service – which are fixed costs the Company incurs and independent of how much energy customers use. Further, Dr. Johnson's recommendations do not align the Company's need to recover its revenues with conservation and energy efficiency; they do the opposite. In other words, Dr. Johnson will drive UNS Electric's need to recover revenues towards energy consumption and away from conservation.

Dr. Johnson also seems to recommend against implementing the Super-Peak rate option – supporting a "real-time" rate instead. The Company is not necessarily opposed to implementing a "real-time option" in the future as a demand-side management program. Even so, the Super-Peak option the Company proposes in this case is less costly and easier for customers to understand and benefit from. Mr. Erdwurm details the Company's response to RUCO testimony regarding rate design.

Q. Has the Company's position on CARES and low-income programs changed in light of Staff and RUCO testimonies?

A. No. The Company is willing to expand low income programs to customers with household incomes between 150% and 200% of poverty, but *only if* those costs can be timely recovered from other retail customers. Further, Staff witness William C. Stewart proposes that CARES customers should receive the benefit of any downward adjustments to the PPFAC rate, but no upward adjustments beyond the PPFAC rate equaling zero. This is not equitable to other residential customers, in addition to being overly complicated. CARES customers already would receive the substantial benefit of having any PPFAC rate frozen at zero in addition to a substantial discount in the monthly customer charge, discounted power supply rate, and existing percentage discounts. It is not fair to shield them from all of the risk *and* provide them with the full benefit to the detriment of other customers who must incur those costs.

IX. <u>RESPONSE TO THE ASBA AND AASBO.</u>

Q. Have you reviewed the Direct Testimony of ASBA/AASBO witness Chuck Essigs.

A. Yes, I have.

Q. What is your response to Mr. Essig's Direct Testimony?

A. Mr. Essig's Direct Testimony seems to focus on helping school districts become more energy efficient and on installing renewable energy projects on school property. UNS Electric is certainly willing to engage Mr. Essigs, ASBA, AASBO in discussions about how to involve schools more in both renewable energy and energy efficiency. UNS

Electric proposes to consider specific renewable energy programs and projects for schools within its service territory in its next Renewable Energy Implementation Plan ("REIP"). UNS Electric would also be willing to work with ASBA/AASBO in designing a specific TOU rate for schools in its next rate case.

Q. Does that conclude your Rebuttal Testimony?

A. Yes, it does.

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Rebuttal Testimony of

Thomas A. McKenna

on Behalf of

UNS Electric, Inc.

December 11, 2009

TABLE OF CONTENTS

<u>EXHIBITS</u>

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Thomas A. McKenna. My business address is One South Church Avenue, Tucson, Arizona 85701.

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

A. My Rebuttal Testimony is filed on behalf of UNS Electric, Inc. ("UNS Electric" or "Company").

Q. What areas will you be discussing in your Rebuttal Testimony?

A. In my Rebuttal Testimony, I discuss:

- Staff's Direct Testimony regarding the Company's proposed treatment of the Black Mountain Generating Station ("BMGS");
- Staff's Direct Testimony regarding the Company's proposed Rules and Regulations; and
- Staff's Direct Testimony regarding engineering issues and the Company's response.

Q: Please summarize your Rebuttal Testimony.

A: First, the Company still believes acquiring BMGS is in the best interest of the Company and its customers, thereby making its proposed treatment for BMGS reasonable and appropriate.

Second, the Company agrees with all but one of Staff's recommendations on its Rules and Regulations. It is dropping its proposals for: (i) the Facilities Operating Charge; (ii) charging customers monthly minimums whose service is being reestablished or reconnected; and (iii) including certain language regarding accounting treatment in its line extension section. However, the Company does not believe it is appropriate to require itemization of materials, labor and other costs in line extension agreements beyond what is required by the Commission rules.

Third, I will comment on the testimony and recommendations offered by Staff witness W. Michael Lewis. While the Company agrees with the majority of Mr. Lewis' Direct Testimony, UNS Electric has comments about certain portions of his testimony relating to service quality and reliability. Further, the Company does not agree with including a listing of the worst performing circuits in an annual report for reasons I will explain later in my Rebuttal Testimony.

II. <u>RATE TREATMENT OF BLACK MOUNTAIN GENERATING STATION.</u>

Q. Please summarize the Company's requested rate treatment for BMGS.

A. UNS Electric is requesting that BMGS be included in its rate base. Specifically, the Company is requesting a post-test-year adjustment to rate base and a corresponding reclassification of rates as described in the Direct Testimonies of Messrs. Kentton C. Grant, Dallas J. Dukes and D. Bentley Erdwurm.

Q. Please summarize RUCO's Direct Testimony on the Company's requested treatment for BMGS?

A. RUCO supports the Company's proposal. RUCO witness, Dr. Ben Johnson recognizes and acknowledges UNS Electric's dilemma regarding its ability to acquire BMGS and believes the Company's proposal is reasonable.

Q. What was Staff's position on the proposed BMGS rate treatment?

A. Staff witness Dr. Thomas H. Fish recommends that the Commission deny the Company's requested rate base and ratemaking treatment of BMGS. Dr. Fish states (at pages 55-56 of his Direct Testimony) that, because the Company does not presently own BMGS, it should not be included in rate base as a post test year plant in service adjustment even if it is transferred to UNS Electric.

Q. What is your response?

A. Dr. Fish does not acknowledge or address our extensive testimony about why we have not been able to acquire BMGS to date and why we need the requested rate treatment to be able to finance the acquisition of BMGS. Further, Dr. Fish does not dispute that there are significant operational and financial benefits to UNS Electric, if it can acquire BMGS.

Dr. Fish also does not address many other pertinent facts regarding BMGS justifying its inclusion into rate base. For example, UniSource Energy Development Company ("UED") developed BMGS specifically for the needs of UNS Electric. The cost that UED would transfer to UNS Electric is a known and measurable amount. Moreover, by UED developing BMGS, UNS Electric was insulated from the risks of constructing the generating station. Further, if the Commission approves the transfer of BMGS, BMGS will then be owned by UNS Electric, creating several operational benefits, which I explain below, that will enhance UNS Electric's ability to provide safe and reliable electricity at just and reasonable rates to our customers.

Q. Why is the best long-term solution for both the Company and its customers the ratebasing of BMGS?

A. The best long-term solution for both the Company and its customers is the Company's recommended treatment in this case. As I stated in my Direct Testimony, UED has acquired these turbines at a substantial discount, and is willing to transfer this benefit to UNS Electric and its customers in exchange for recognition in rate base.

Q. Does Staff dispute the financial benefits of UNS Electric owning this generation?

A. No. Staff simply did not address those benefits, which were laid out in detail in Mr. Grant's Direct Testimony. Mr. Grant, in his Rebuttal Testimony, provides additional evidence as to why including BMGS in rate base is in the public interest from a financial perspective.

Q. Does Staff dispute the operational benefits of UNS Electric owning this generation as described in your Direct Testimony?

A. No. Staff does not dispute that BMGS will provide the operational benefits I detailed in my Direct Testimony, including:

- Flexibility to use instantaneous, load-following and emergency dispatch capabilities to provide required reserves and ancillary services, as well as the ability for full, unlimited, economic dispatch to optimize UNS Electric's portfolio. Purchase Power Agreements ("PPAs") simply do not provide the flexibility for full, unfettered dispatch rights that ownership provides;
- Reliability is enhanced through UNS Electric having the ability to fully control BMGS's maintenance and operation to ensure it meets high standards for adequacy and safety. Further, the Company avoids having to purchase significant wholesale capacity, transmission wheeling services and certain ancillary services;
- Efficiency is increased, as UNS Electric would own the exact type of unit needed to meet its particular requirements, and having a benchmark to compare future PPAs to determine the best overall value for the Company and its customers. UNS Electric would be able to meet its exact peaking capacity and reserve needs through owning BMGS; and

- BMGS's location minimizes transmission costs, and thereby delivery costs, while also providing must-run generation. Further, BMGS's location provides an additional benefit by having generation close to dual gas pipeline systems. Although UNS Electric is connected to only the Transwestern pipeline, it has the potential to tap into the El Paso pipeline with additional investment, giving it the potential for fuel redundancy.

Q. Dr. Fish, in his Direct Testimony, describes an issue with a broken blade that damaged one of the turbines. Can you describe what happened?

A. One of the third stage high pressure compressor blades separated at approximately the middle of the air foil. The separated piece then travelled through the remaining rows of compressor blades, causing some damage to those blades.

Q. When do you expect BMGS to be back to full operation?

A. BMGS should be back to being fully operable in February 2010.

Q. Dr. Fish states that Unit 1 is not currently operational in his Direct Testimony at page 54. Does that mean that Unit 1 will not be operational when this case is decided?

A. No. In fact, Staff witness W. Michael Lewis in his Direct Testimony at page 26 states that BMGS was "properly constructed and should be back to full operational levels once the repairs are made by UED." Since the facility was under warranty, there is no cost to UNS Electric or UED. In fact, BMGS may be fully operational when the evidentiary hearing for this case commences on February 4, 2010, depending on the repair schedule agreed to with GE.

Q. Will UED incur any costs due to the broken blade that are not covered by warranty?

A. No.

Q. Mr. Lewis also recommends that UNS Electric demonstrate that there are no limitations due to water availability on the required operations of both Unit #1 and Unit #2. How does UNS Electric respond?

A. As shown in Exhibit TAM-4, the plant water demand is 236.5 gallons per minute (gpm). The plant currently has well capacity of 425 gpm. The Company is also finishing a project that ties into the County water system that provides an additional 125 gpm water supply. This project will be done by the end of December 2009 and will give the plant total water availability up to 550 gpm. In addition, the plant has a 300,000 gallon water storage tank.

Q. Will the Company employ thermal scanning of the substation/switchyard bus and connected lines to the BMGS Facility, if it acquires the facility, as suggested by Mr. Lewis?

A. The Company currently uses thermal scanning annually in Santa Cruz County, and on a case-by-case basis in Mohave County, such as when a substation is de-energized for maintenance and re-energized, or when equipment, terminations or devices are suspect. If so ordered, the BMGS switchyard can be scanned annually, as well.

Q. Even with the broken blade, is BMGS still used and useful and serving customers?

A. Yes. The broken blade was discovered during routine maintenance in the fall, but operated during the peak summer months with the damage occurring in July 2009. In addition, Unit 2 is currently available for operation while the Unit 1 engine is in for repair. Because the plant is operational now, UNS Electric sees no reason to delay the Company's proposal to rate base BMGS.

Q. Overall, do you still believe rate basing BMGS is in the public interest?

A. Yes. As I stated in my Direct Testimony at page 16, BMGS provides power to UNS Electric through a five-year PPA tolling agreement approved by FERC. But by approving the rate base treatment UNS Electric requests, its customers would obtain the full benefit of turbines acquired at a substantial discount. Further, as I also explained in my Direct Testimony at page 17, there were few other resources found to offer the same benefits (e.g. quick start, full dispatchability) for as economical a price. UNS Electric customers do not receive the full operational benefits without rate base treatment. Because the plant is operational now, UNS Electric sees no reason to delay the Company's proposal to rate base BMGS.

III. RULES AND REGULATIONS.

Q. Have you reviewed Staff witness Mr. Kenneth C. Rozen's Direct Testimony in this case?

A. Yes. Mr. Rozen for Staff does not recommend adoption of the Facilities Operation Charge at this time, citing to significant issues regarding accounting treatment, rate design and policy. Mr. Rozen also does not support setting forth the accounting treatment of line extension payments in the Rules and Regulations, but further notes that those payments should be treated as Contributions In Aid of Contribution ("CIAC"). He also opposes requiring customers, whose service is being reestablished or reconnected, to pay monthly customer charges for the months during which service had been disconnected. Finally, he indicates that Staff does not oppose adding timeframes for repaying and refunding under-billed and over-billed amounts.

Q. What is the Company's response to Staff's recommendation against the Facilities Operation Charge?

A. The Company withdraws its request for a Facilities Operation Charge. While UNS Electric does not necessarily agree with all of Mr. Rozen's testimony and concerns about the Facilities Operation Charge, the Company understands that there are some reasons why this may not be the proper time to implement such a charge. Should the Company decide to propose such a charge in a future rate case, it will discuss the proposal with Staff at that time.

Q. What about Staff's recommendation that the Company not specify the accounting treatment in its line extension policy?

A. The Company understands that it is not precluded from seeking a particular accounting treatment if the Rules and Regulations are silent on the issue. With that understanding, the Company agrees to remove the language that concerns Staff.

Q. Does the Company agree with Staff's recommendation against charging customers monthly minimums whose service is being reestablished or reconnected?

A. Yes. UNS Electric agrees to delete the language allowing monthly minimums to be charged to customers whose service is reestablished or reconnected, even those customers who were disconnected for non-payment or who failed to comply with the Company's pricing plans within the preceding 12-month period. This also includes those customers who had ordered a service disconnection within the preceding 12-month period.

Q. What is the Company's response to Mr. Rozen's recommendation to revise Subsection 9.B.1.e. and that line extension agreements include itemized material costs, labor and other itemized costs?

A. The Company has concerns regarding this recommendation. Subsection 9.B of the UNSE Line Extension Rules itemizes the Minimum Written Agreement Requirements for line extensions. The requirements currently in the UNS Electric rules and regulations are directly from A.A.C. R14-2-207. The Company does not believe itemizing estimated costs from our normal materials estimating system will lead to an Applicant better understanding the cost estimates. This is partially because most customers are unfamiliar with materials used in power line construction and the engineering thereof. Those materials, however, are based on engineering standards using materials specified by the utility that support safe and reliable service. Even if the Company were to itemize all materials, it could not sacrifice the need to ensure safe and reliable construction and operation with an Applicant's desire to minimize costs of an extension. Finally, any line extension agreement must also a description and sketch of the requested extension. The Company believes this provides the Applicant enough detail to understand what is being required and why.

Q. Are there any other parts of Mr. Rozen's Direct Testimony you want to respond to at this time?

A. No.

Q. Are there any other requests regarding the Rules and Regulations?

A. Yes. The Company proposes to remove the word "Residential" from the title of Subsection 4.A. so that it reads "Information for Customers." Further, the Company will correct some typographical errors in Subsections 11.I.2. (to read "The outgoing Customer *will* be responsible for all electric services provided and/or consumed up to the scheduled turn-off-date."), 11.J.1. (so that the eighth sentence reads "Any notices which *the* Company is required to send to a Customer who has elected an Electronic Billing service may be sent by electronic means at the option of the Company."), and 12.E. (so that the title reads "Timing of *Terminations* with Notice").

IV. QUALITY OF SERVICE, RELIABILITY AND OTHER ENGINEERING ISSUES.

Q. Mr. McKenna, did you review the Direct Testimony of Staff witness of Mr. W. Michael Lewis?

A. Yes. My understanding of his Direct Testimony is that he found UNS Electric's system to be satisfactory overall. Although Mr. Lewis noted the distribution system provides service quality and reliability of an average to below average compared to other electric utility systems similar in size and service area characteristics, Mr. Lewis also noted that the duration of service outages decreased significantly in 2009, and that revising circuit configurations, replacing older circuits and standardizing the Company's distribution substations over the normal course of business, should decrease both outage frequencies and service restoration times.

Q. How does the Company respond to Mr. Lewis' testimony on service quality and reliability?

A. The Company finds Mr. Lewis' testimony to be generally accurate. However, the responses beginning on page 7, lines 11 through 22, are only partially accurate. The Company has collected outage data and calculated reliability indices for the UNS Electric distribution systems since the purchase of the electric assets from Citizens in 2003. Calculation of Major Event Day indices was not undertaken for UNS Electric until 2009 due to the lack of historical data required to create the statistical threshold as specified by the IEEE Standard 1366-2003. Clear Weather indices were calculated recently and are under consideration for implementation across the entire Company.

In addition to Mr. Lewis' Direct Testimony at page 8, lines 2 through 12, the Company would also like to note that UNS Electric does not own or operate the transmission in the Kingman and Lake Havasu service areas. This can result in extended outage times on the distribution system while the transmission owners troubleshoot and attempt to restore service.

Q. Mr. Lewis notes, on page 11 of his Direct Testimony, that the reported SAIFI and CAIDI values for Major Event Disturbances is superior to what he calls "Clear Weather" periods for UNS Electric. Can you explain why that is?

A. The outages that are excluded from the distribution indices in order to produce the Clear Weather indices are only those outages caused by storms. Outages that are excluded from the distribution indices in order to produce the Major Event Day indices are any outages that occur on any days that are deemed a Major Event Day using criteria defined in the IEEE Standard 1366-2003. Because Major Event Days can have any cause, the same outages will not necessarily be removed from both indices to perform both sets of calculations. In the case of UNS Electric, the Major Event Days impacted many more customers and resulted in many more customer outage minutes than did the outages that were caused by storms. Therefore, the Major Event Day indices will be superior in comparison to the Clear Weather indices.

Q. Can you describe what the Company is doing to improve its service quality and reliability in its service territory?

A. Consistent with Mr. Lewis' Direct Testimony at page 19, the Company is making a significant effort to standardize and upgrade equipment from the older Citizens installations, as follows:

- TEP engineers, working on behalf of UNS Electric, conduct a volt-amperes reactive ("VAR") study for Santa Cruz County as needed. The 2009 study included a complete inventory of existing capacitors on the Santa Cruz distribution system and recommendations for replacements, control installations, and new capacitor installations;

- TEP engineers are creating a model of the Kingman and Lake Havasu sub-transmission systems to aid the UNS Electric engineers in their system analysis;
- Fiber communications are being built out incrementally in Mohave County, and radio-based communications are being extended to outlying substations. These efforts will result in better system operator awareness of the electric system in Mohave and timelier operator response; and
- A 69kV breaker has been added to sectionalize a 69kV circuit. Another 69kV sectionalizing breaker is in design engineering and more are being studied. These breakers allow long 69kV circuits to be split into parts so that circuit problems do not cause an outage on the entire circuit. There is also a program underway to replace old oil-filled 69kV breakers with modern SF6 breakers.

Q. Mr. Lewis recommends that UNS Electric include a listing of the worst performing circuits and steps to mitigate these poor performing circuits in an annual report. Does the Company agree with that recommendation?

A. No. While personnel are developing a method to determine "worst performing circuits" for UNS Electric, the Company does not agree that submission of an annual report should be required. This is because circuits may appear at the top of the list for many reasons, some of which are not quickly or easily mitigated. Submission of an annual report implies that regular rotation of these "worst circuits" should be expected. In reality, it may not be practical to address the worst circuits in order of performance because the underlying causes of poor performance may take significant time and effort relative to other circuits.

Q. What other observations did Mr. Lewis make in his Direct Testimony?

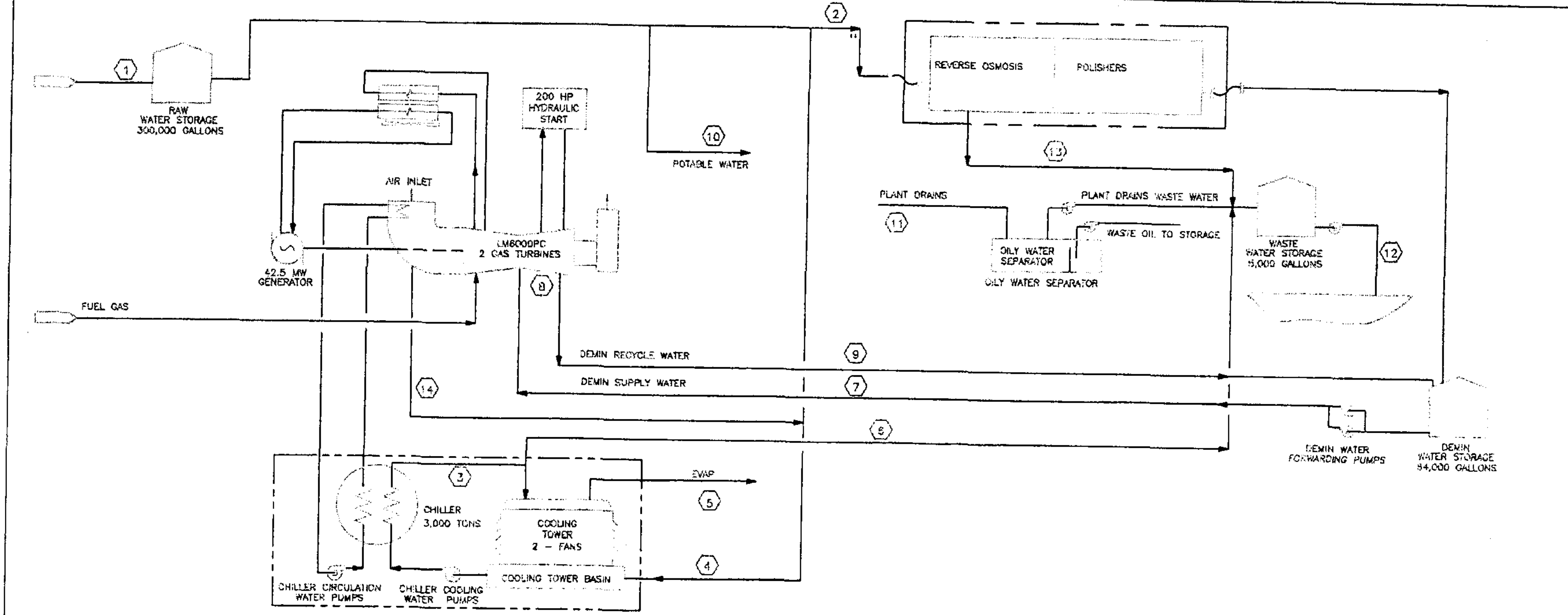
A. Notably, Mr. Lewis concluded at pages 13-15 of his Direct Testimony that the Call Center operates effectively and its procedures are adequate to maintain acceptable restoration even in the Mohave service areas. This further justifies inclusion of the costs for the Call Center sponsored by Mr. Dallas J. Dukes in his pre-filed testimonies.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

EXHIBIT

TAM-4



WOOD GROUP POWER SOLUTIONS, INC
PROCESS WATER BALANCE, RO UNIT
UNISOURCE ENERGY SERVICES
BLACK MOUNTAIN GENERATING STATION

T08150 | 50001 | 5 | C

RWC 12/8/06

WOOD GROUP

WATER BALANCE

2 LM6000PC SPRINT WITH RO UNIT AND EVAPORATION POND

WATER BALANCE WITH RO UNIT, DESIGN BASIS - 82°F AND 62% RELATIVE HUMIDITY

STREAM NUMBER	RAW WATER		COOLING TOWER				DEMINERALIZED WATER				WASTE WATER			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
DESCRIPTION	RAW WATER PUMPS	FEED TO TREATING	CIRCULATION	MAKE UP	EVAPORATION	BLOW DOWN	DEMIN MAKE CIRCULATION	DEMIN WATER USAGE	DEMIN WATER RECYCLE	POTABLE WATER	PLANT DRAINS	WATER TO POND	RO UNIT REJECT	CONDENSATE COOLING TOWER
FLOW, LB/HR	105,554	77,061	2,114,654	41,234	28,739	12,495	84,966		34,894	2,999	2,499	41,983	26,989	12,741
FLOW, GPM	211	154	4,231	83	58	25	170		70	6	5	84	54	25.5
DEMINERALIZED WATER														
NOX CONTROL, LB/HR								42,210						
NOX CONTROL, GPM								84.5						
SPRINT, LB/HR								7,862						
SPRINT, GPM								15.7						
PUMP CAPACITY, GPM	220		4,231				170							
PUMP HORSEPOWER	10		100				7.5	100.18						

NOTES: COLUMN 1, TOTAL RAW WATER REQUIRED FOR THE PLANT IS COLUMN 1 PLUS COLUMN 14 = 236.5 GPM
COLUMN 4, TOTAL WATER FOR MAKE UP TO THE COOLING TOWER WILL INCLUDE CONDENSATE FROM THE LM6000 INLET COOLING, ITEM 14 .
COLUMN 11, PLANT DRAINS INCLUDES WASTE WATER FROM WASH DOWN, POTABLE AND DOMESTIC USAGE

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

Rebuttal Testimony of

Kentton C. Grant

on Behalf of

UNS Electric, Inc.

December 11, 2009

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

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

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

A. My Testimony is filed on behalf of UNS Electric, Inc ("UNS Electric" or the "Company").

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

A. The purpose of my Rebuttal Testimony is to rebut portions of the Direct Testimony of Mr. David C. Parcell and Dr. Thomas H. Fish filed by the Arizona Corporation Commission Staff ("Staff"), as well as portions of the Direct Testimony of Mr. William A. Rigsby and Dr. Ben Johnson filed by the Residential Utility Consumers Office ("RUCO"). The subject matter addressed in my Rebuttal Testimony includes: (i) the proposed purchase and rate base treatment of the Black Mountain Generating Station ("BMGS"), (ii) the determination of a fair rate of return ("ROR") on fair value rate base ("FVRB"), (iii) the ability of UNS Electric to have an opportunity to earn its cost of capital, and (iv) the recovery of wholesale credit support costs and the interest rate applicable to the Company's purchased power and fuel adjustor clause ("PPFAC").

Q. Please summarize the essential points presented in your Rebuttal Testimony.

A. Certainly. With respect to the proposed purchase of the BMGS, Staff witness Dr. Thomas Fish recommends that the Company's post-test year adjustment to rate base be denied even if UNS Electric were to subsequently acquire ownership of the facility. The only substantive basis offered by Dr. Fish in support of his recommendation is the fact that UNS Electric does not currently own the BMGS, a situation that could be remedied if the proposed post-test year adjustment is approved. Additionally, in spite of the fact that Staff is recommending denial of the Company's proposed rate treatment, Staff witness Mr. David Parcell goes on to describe certain "interim financing" alternatives that UNS Electric could still use to purchase the BMGS. For the reasons offered earlier in my Direct Testimony, as well as in the last UNS Electric rate case, it would be irresponsible to even consider these "interim" financing alternatives without some reasonable assurance of cost recovery for the BMGS.

Regarding the ROR on FVRB, Staff witness Mr. Parcell and RUCO witness Dr. Ben Johnson each propose calculation methods that were extensively considered and rejected by the Commission in Decision No. 70441 (July 28, 2008) involving Chaparral City Water Company. The calculation method proposed by Mr. Parcell is also vastly different from the method proposed by Staff and adopted by the Commission in a subsequent Chaparral City Water Company rate case (Decision No. 71308 (October 21, 2009)). Even the method proposed by Dr. Johnson is different from the position taken by RUCO in that same case. Although each of these witnesses offers a theoretical explanation as to why their respective methods should be adopted, neither witness provides any discussion of the practical effects of their recommendations on the financial condition of UNS Electric. Unfortunately, it appears that both Staff and RUCO have decided to ignore the Commission's prior determinations on the ROR to be applied to FVRB, as well as their own stated positions in prior cases, in order to obtain a result that provides short-term rate benefits while adding long-term financial costs to UNS Electric and its customers.

If the Commission accepted the low recommendations of ROR on FVRB, as well as other adjustments made by Staff and RUCO to the Company's revenue requirement, UNS

Electric would continue to significantly under-earn its cost of capital. UNS Electric estimates that the $7.5 million rate increase recommended by Staff would result in an earned return on equity ("ROE") of only 8% in 2011, the first full year under new rates. RUCO's recommended $4.5 million rate increase is projected to result in a ROE of only 6%. Such a result would jeopardize the Company's financial integrity to the long-term detriment of both customers and shareholders.

Finally, with respect to the modest changes proposed by UNS Electric to its PPFAC, Dr. Fish fails to provide any substantive basis for denying the Company's request. However, based on his observation that the Company could seek recovery of wholesale credit support costs through non-fuel base rates instead of through the PPFAC, UNS Electric has revised its proposed non-fuel revenue requirement to include these costs which amount to $195,500 on an annualized basis.

II. PROPOSED PURCHASE OF THE BMGS.

A. Rebuttal of Staff Witness Dr. Thomas H. Fish.

Q. What position does Dr. Fish take with respect to the Company's proposed rate treatment of the BMGS?

A. Dr. Fish recommends that the Commission deny UNS Electric's proposed rate base treatment of the BMGS. The primary reason offered by Dr. Fish is that UNS Electric does not currently own the BMGS. As discussed on page 55 of his Direct Testimony, he further recommends that the proposed post-test year adjustment to rate base be denied even if UNS Electric were to subsequently acquire the BMGS from the present owner, UniSource Energy Development Company ("UED"). Although Dr. Fish does not offer a specific reason for denying rate base treatment of the facility upon transfer of ownership, his testimony implies that he is not satisfied with the actions taken to date to effectuate such a transfer. Additionally, based on statements made on pages 50-51 of his Direct Testimony, he appears to imply that UNS Electric has abdicated its responsibility to make a decision regarding ownership of the BMGS, and is now requesting that the Commission "direct" the Company to purchase the BMGS.

Q. Has UNS Electric abdicated its responsibility to make a decision on acquiring the BMGS?

A. No. UNS Electric is simply asking the Commission to approve its proposal to purchase the BMGS and to place that facility into rate base upon completion of the purchase. As evidenced by the testimony filed in this rate case, as well as in the last UNS Electric rate case, the Company's management has already determined that it would be best for UNS Electric and its customers to proceed with a purchase of the BMGS. However, the acquisition of such a large asset is simply not feasible for a company as small as UNS Electric without some assurance of timely rate relief. This financial predicament is described extensively in my Direct Testimony, as well as in the testimony presented by UNS Electric in its last rate case. In order to resolve this dilemma, UNS Electric has proposed a revenue-neutral rate reclassification that would be effective upon the transfer of the BMGS to UNS Electric.

Q. On page 56 of his Direct Testimony, Dr. Fish asserts that the Commission provided UNS Electric with "the financing capability to purchase the plant," but that the Company "chose not to do so." Is this assertion accurate?

A. No. What was provided in UNS Electric's last rate case, as reflected in Decision No. 70360 (May 27, 2008), was (i) financing authority to raise debt and equity capital in connection with a purchase of the BMGS, and (ii) ordering language that may have permitted the accounting deferral of certain costs associated with owning and operating the BMGS prior to its inclusion in rate base. While the receipt of a Commission financing order is certainly a prerequisite to raising capital, the *authority* to raise capital does not necessarily mean that UNS Electric has the *capability* to raise capital. And as described extensively in my Direct Testimony, as well as in the testimony presented by the Company in its last rate case, the "financing capability" of UNS Electric depends on cash flow and timely rate relief, and not on the receipt of non-cash accounting deferrals.

Q. Has Dr. Fish or any other Staff witness addressed the cash flow and financial integrity concerns identified by the Company?

A. No. As I set forth in my Direct Testimony, UNS Electric does not have sufficient cash flow at this time – or even with the requested $13.5 million rate increase – to service the additional capital required to purchase the BMGS. Absent a post-test year adjustment to rate base and the proposed revenue-neutral rate reclassification, an acquisition of the BMGS is simply not feasible from a financial perspective. Staff does not dispute this fact.

Q. What rationale did Dr. Fish offer in support of his recommendation to deny a post-test year adjustment to rate base, even if UNS Electric were to subsequently purchase the BMGS from UED?

A. Other than a general discussion of the actions taken by the Commission in the last UNS Electric rate case, and an inaccurate portrayal of the choices available to the Company, Dr. Fish provides no explanation for his recommended denial of rate treatment upon purchase of the facility.

B. <u>Rebuttal of Staff Witness Mr. David C. Parcell.</u>

Q. What comments did Mr. Parcell have to offer with respect to the Company's proposed purchase and rate base treatment of the BMGS?

A. In his Direct Testimony, Mr. Parcell offered just a few comments on the financing of the BMGS. Mr. Parcell correctly points out that UED financed the construction of the BMGS through contributions and loans received from its parent company, UniSource Energy Corporation ("UniSource Energy"), which used its own revolving credit facility and cash on hand to fund these contributions and loans to UED. Mr. Parcell is also correct when he states that UNS Electric received financing authority to purchase the BMGS from UED as part of Commission Decision No. 70360, but that the Company has yet to issue any securities authorized in that decision. However, in his discussion of "interim" financing alternatives that may be available to the Company, Mr. Parcell seems to imply that such alternatives would still be feasible regardless of how the BMGS is treated from a rate making perspective in this proceeding. This implication is problematic from at least two perspectives. First, it is not clear from Mr. Parcell's testimony just how long he expects such "interim" financing to remain outstanding. Second, he fails to address the significant financial repercussions associated with entering into any "interim" financing alternatives prior to a determination of the rate treatment for the BMGS.

Q. What "interim" financing alternatives does Mr. Parcell mention in his testimony?

A. On page 20 of his Direct Testimony he lists two alternatives. The first potential source of interim financing he mentions "would be the transfer of the assets and liabilities within the UniSource framework to UNS Electric." The second potential source he mentions is the Company's "access to a revolving credit facility...which it shares with UNS Gas."

Q. What is your view of the "interim" financing alternatives described by Mr. Parcell?

A. While these two financing alternatives do exist, and have for some time, it would be irresponsible for UNS Electric and UniSource Energy to exercise either one or both of these options in the absence of any prospective rate base treatment for the BMGS.

With respect to the option of using the $60 million revolving credit facility that UNS Electric shares with its sister company, UNS Gas, Inc. ("UNS Gas"), any large draw on that facility for a purchase of the BMGS would preclude the use of that facility for other needs such as seasonal working capital requirements, the posting of letters of credit and cash collateral in support of wholesale energy procurement, and the potential funding of deferred fuel and purchased power costs under the Company's PPFAC. Additionally, since the Company's revolving credit facility is shared with UNS Gas, that company would also be precluded from using the credit drawn by UNS Electric. UNS Electric's credit profile would also decline until such time that the BMGS is placed into rate base, since there would an increase in debt without any corresponding increase in cash flow. Since the Company's credit rating is already at the lowest investment grade level of Baa3, UNS Electric would face a strong probability of having its credit downgraded to junk bond status as a result of using its revolving credit facility to purchase the BMGS well before the Commission determines rate treatment for this facility.

The second option -- a "transfer" of the BMGS from UED to UNS Electric -- would essentially be equivalent to UNS Electric receiving an enormous capital contribution from UniSource Energy for which any recovery on the investment would be delayed for several years at best (i.e. the conclusion of the *next* UNS Electric rate case). Moreover, if such a transfer of the BMGS were to occur, the purchased power contract between UNS Electric and UED would presumably cease to exist, thereby eliminating the only source of BMGS fixed cost recovery to UniSource Energy. Thus, until the facility were placed into rate base, the consolidated earnings, cash flow and credit metrics for UniSource Energy would be weakened, and the earned ROE recorded for UNS Electric would fall even further from the anemic levels currently being realized. Without any assurance of cost recovery at UNS Electric, it is difficult to view this "interim" financing alternative as being feasible or fair to UniSource Energy.

Q. Do you have any further comments on this portion of Mr. Parcell's Direct Testimony?

A. Yes. I would like to highlight and respond to some comments made by Mr. Parcell concerning UNS Electric's inability to finance a purchase of the BMGS. In particular, the following statements appear on page 19 of his Direct Testimony, lines 7-13:

> "It is also my understanding that UNS Electric is maintaining that it cannot afford to finance the purchase of this plant due to the relatively small size of the Company and the relatively large size of this generation facility. It is also my understanding that UNS Electric indicates that it would have a problem getting a lender to commit to providing debt capital to fund a portion of this potential purchase without assurance that the plant will be in rate base and thus provide a source of interest and principal repayment."

I would simply like to point out that Mr. Parcell is correct in his understanding. The management of UNS Electric is not willing to "bet the company" with a purchase of the BMGS without a reasonable assurance of cost recovery. Likewise, it is difficult to fathom a prospective lender making a loan to the Company for the purchase of an operating asset providing no contribution to cash flow for an extended period of time.

C. Rebuttal of RUCO Witness Ben Johnson, Ph.D.

Q. Did RUCO address the Company's proposal regarding the BMGS?

A. Yes, RUCO acknowledges the dilemma facing UNS Electric regarding the acquisition of the BMGS and supports the Company's proposal for the post-test year rate base adjustment and related revenue-neutral rate reclassification. This position is significant because RUCO did not support our similar proposal for the BMGS in the last rate case.

Q. Do you have any other comments regarding Dr. Johnson's proposed treatment of the BMGS?

A. Yes. It appears that Dr. Johnson applied the same ROR on FVRB to the Company's proposed investment in the BMGS as he applied to the non-BMGS rate base for UNS Electric. As described in the next section of my testimony, this results in a ROR that is much lower than the cost of capital that will be required to purchase the BMGS. Since there is only a minimal difference between (i) the original cost of the BMGS and (ii) the fair value of that facility as traditionally determined by the Commission, the overall ROR on FVRB should reflect a weighted average of the ROR on non-BMGS rate base and the cost of capital for the BMGS portion of rate base.

III. RATE OF RETURN ON FAIR VALUE RATE BASE.

A. Rebuttal of Staff Witness David C. Parcell.

Q. What does Mr. Parcell recommend regarding the ROR on fair value rate base?

A. Mr. Parcell's primary recommendation is that the Commission should apply a 0% return on the portion of FVRB that exceeds the original cost rate base ("OCRB"). Mr. Parcell refers to this portion of the FVRB as the "fair value increment." In other words, Mr.

Parcell recommends no return at all on the fair value increment. Thus, the revenue requirement is entirely determined by the ROR on original cost. This approach is nearly identical to the now-discredited "backing in" method formerly used by the Commission, where the revenue requirement was determined by applying the weighted average cost of capital to the original cost rate base, with a "fair value rate of return" being determined simply as a fall out number.

Q. Is Mr. Parcell's recommendation consistent with recent Commission decisions?

A. No. Mr. Parcell presented this same recommendation in the remanded Chaparral City Water Co. case.[1] The Commission did not adopt Mr. Parcell's recommendation in its remand order, Decision No. 70441 (July 28, 2008) ("Chaparral City Remand Order"). Mr. Parcell also repeated this recommendation in the recent Southwest Gas rate case, and again the Commission did not adopt it in the Commission's rate order, Decision No. 70665 (December 24, 2008). The Commission also recently issued Decision No. 71308 (October 21, 2009) in Chaparral City Water's most recent rate case ("Chaparral City Rate Order") in which the Commission adopted a fair value methodology based on the Chaparral City Remand Order. Mr. Parcell's proposal is not consistent with that decision either.

Thus, Mr. Parcell's recommendation has been rejected at least twice by the Commission. Indeed, even Staff seems to concede that this recommendation is inappropriate because Staff uses Mr. Parcells alternate recommendation for its revenue requirement.[2]

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[1] Docket No. W-02113A-04-0616.

[2] See Direct Testimony of Dr. Thomas Fish, Schedule THF-A1, line 6 and footnote *.

Q. What approach did Staff use in calculating its revenue requirement?

A Staff used an "alternative" recommendation proposed by Mr. Parcell. However, Mr. Parcell had presented this alternative recommendation to the Commission in the Chaparral City remand case but the Commission did not adopt his alternate recommendation in that case.[3]

The alternate recommendation being made by Mr. Parcell in this proceeding is also the same as the alternate method he proposed in the recent Southwest Gas rate case and the pending UNS Gas rate case. In the Southwest Gas rate case, his proposal was adopted in a modified form by the Commission. However, in doing so the Commission noted that: (1) the Chaparral City Remand Order (Decision No. 70441) was not issued by the time of the hearing in the Southwest Gas case; (2) no party presented a method similar to the method approved in the Chaparral City remand case; and (3) the utility agreed to the basics of Mr. Parcell's approach, disputing only the method of determining the risk-free rate.[4] The Commission determined that for these three reasons the method approved in the Chaparral City remand order was not available in the Southwest Gas case.

These three reasons do not apply to this case: (1) the Chaparral City Remand Order, as well as the subsequent Chaparral City Rate Order, is available for guidance; (2) UNS Electric is presenting the methods approved in each of those cases; and (3) the Company does not concede the appropriateness of Mr. Parcell's alternative recommendation. Thus, I believe the Commission should follow the method approved in the Chaparral City Remand Order, Decision No. 70441, or in the alternative, the method that was adopted by the Commission in the subsequent Chaparral City Rate Order, Decision No. 71308.

[3] See Decision No. 70441 at 36-37.
[4] See Decision No. 70665 at 32-33.

Q. What is your view of Mr. Parcell's alternative recommendation for calculating the ROR on FVRB?

A. I strongly disagree with the alternative recommendation. First, as described below in Section IV of my Rebuttal Testimony, it results in a revenue requirement that is simply too low to support UNS Electric's financial integrity. Second, it represents an unwarranted and unsupported departure from the calculation methodology approved by the Commission in Decision No. 70441, as well as the modest refinement to that methodology recommended by Staff and approved by the Commission in Decision No. 71308. Third, it is based solely on Mr. Parcell's belief that the fair value of utility property should be given little, if any, weight in setting retail rates. Fourth, his alternative method identifies the lowest possible cost of capital, the inflation adjusted ROR on risk-free U.S. Treasury securities, as the highest possible ROR the Commission should consider applying to his "fair value increment" of rate base. Fifth, his selection of a 1.5% ROR to be applied to his "fair value increment," equal to one-half of the inflation adjusted risk-free rate, is arbitrary since it represents the midpoint of a fairly wide range of values he deems to be appropriate (zero to 3.0%), and is completely unsupported by any analysis of the financial impact his recommendation would have on UNS Electric. And finally, as I explain below, Mr. Parcell's calculation of a 5.99% ROR on FVRB, using a 1.50% ROR on the "fair value increment," is mathematically incorrect.

Q. What mathematical result should Mr. Parcell have obtained using a 1.50% ROR on Staff's "fair value increment" of rate base?

A. As corrected, the table appearing at the bottom of page 57 of his Direct Testimony should have reflected a weighted average return on the "FVRB Increment" of 0.49% instead of 0.34% (32.79% x 1.50% = 0.49%, not 0.34%), resulting in an overall ROR on FVRB of 6.14% instead of 5.99% (5.65% + 0.49% = 6.14%). This mathematical correction, when applied to Staff's FVRB of $257.8 million increases Staff's proposed revenue requirement by $633,000:

Difference between 6.15% and 5.99% ROR on FVRB

= $257.8 mil. x 0.15% x 1.6363

= $0.63 mil.

Q. Relative to methodologies recently approved by the Commission, and the high end of a "range" recommended by Mr. Parcell, what impact does his 5.99% ROR recommendation have on UNS Electric's revenue requirement?

A. His decision to apply a 5.99% ROR to the Company's FVRB resulted in a substantial reduction to the overall revenue requirement. For example, had Mr. Parcell instead chosen the full inflation adjusted risk-free rate he identified, 3.0%, as the cost rate to apply to his "fair value increment," he would have derived a ROR on FVRB of 6.63%:

	% of Capital Structure	Cost	Weighted Average Cost
Long-Term Debt	36.45%	7.05%	2.57%
Common Equity	30.76%	10.00%	3.08%
Fair Value Increment	32.79%	3.00%	0.98%
Total	100.00%		6.63%

When applied to Staff's FVRB of $257.8 million, and adjusted by Staff's gross revenue conversion factor, this difference in the ROR on FVRB has the following impact on UNS Electric's overall revenue requirement:

Difference between 6.63% and 5.99% ROR on FVRB

= $257.8 mil. x 0.64% x 1.6363

= $2.70 mil.

Alternatively, had Mr. Parcell used the same calculation methodology adopted by the Commission in Decision No. 70441, where the ROR on FVRB was derived by adjusting the cost of equity downward by the expected rate of inflation, he would have obtained a 7.48% ROR on FVRB using his 10.0% cost of equity capital and the 2.0% inflation rate referenced on page 56 of his Direct Testimony:

	% of Capital Structure	Modified Cost *	Weighted Average Cost
Long-Term Debt	54.24%	7.05%	3.82%
Common Equity	45.76%	8.00%	3.66%
Total	100.00%		7.48%

* Note:Modified cost of equity = 10.0% - 2.0% = 8.0%.

When applied to Staff's FVRB of $257.8 million, and adjusted by Staff's gross revenue conversion factor, this difference in the ROR on FVRB has the following impact on UNS Electric's overall revenue requirement:

Difference between 7.48% and 5.99% ROR on FVRB

= $257.8 mil. x 1.49% x 1.6363

= <u>$6.29 mil.</u>

Finally, had Mr. Parcell used the same methodology recommended by Staff and adopted by the Commission in Decision No. 71308, in which both the cost of debt and cost of equity are adjusted by one-half of the inflation rate, he would have also obtained a 7.40% ROR on FVRB:

	% of Capital Structure	Modified Cost *	Weighted Average Cost
Long-Term Debt	54.24%	6.05%	3.28%
Common Equity	45.76%	9.00%	4.12%
Total	100.00%		7.40%

* Note: Modified cost of debt = 7.05% - 1.0% = 6.05%.
Modified cost of equity = 10.0% - 1.0% = 9.00%.

When applied to Staff's FVRB of $257.8 million, and adjusted by Staff's gross revenue conversion factor, this difference in the ROR on FVRB has the following impact on UNS Electric's overall revenue requirement:

Difference between 7.40% and 5.99% ROR on FVRB

= $257.8 mil. x 1.41% x 1.6363

= $5.95 mil.

Q. Mr. Grant, in your Direct Testimony you proposed a 6.88% ROR on FVRB, before inclusion of the BMGS in rate base, even though you demonstrated that UNS Electric could have supported a higher value of approximately 8.0%. Is it your position that the ROR on FVRB in this proceeding should be limited to a maximum value of 6.88%?

A. No. This reduction was a voluntary measure. As described on page 30 of my Direct Testimony, the ROR of 6.88% was selected on the basis that this was the minimum value required to produce an overall revenue requirement that would allow UNS Electric an opportunity to earn its cost of capital and maintain its financial integrity. Even if there are negative adjustments to the revenue requirement proposed by Staff and RUCO, we still have the same overall revenue requirement to maintain financial integrity. Therefore, to maintain financial integrity, the ROR on FVRB could be determined using the method approved by the Commission in Decision No. 71308, or in the alternative, the method approved earlier by the Commission in Decision No. 70441.

Q. In light of the substantial revenue requirement adjustments recommended by Staff, what ROR would you recommend be applied to UNS Electric's FVRB?

A. I would recommend using a ROR derived using the methodology adopted by the Commission in Docket No. 71308. As described in my Direct Testimony, this ROR would be equal to 7.99% if the Commission were to approve the Company's proposed cost of capital. Alternatively, as discussed previously, this ROR would be equal to 7.40% if the Commission were to apply this methodology to Staff's proposed cost of capital.

B. Rebuttal of RUCO Witness Dr. Ben Johnson.

Q. What is your general impression of Dr. Johnson's testimony regarding the ROR on FVRB?

A. Dr. Johnson recommends that the ROR on FVRB be derived by subtracting the full estimated rate of inflation from the cost of debt and then subtracting the same full rate of inflation *again* from the cost of equity. Such an adjustment is seriously flawed from both a theoretical and practical perspective. Additionally, it is worth mentioning that this methodology has already been considered and rejected by the Commission in Decision No. 70441, and is also different from the approach advocated by RUCO in the follow-up Chaparral City Water Company rate case (Decision No. 71308). In that case, RUCO supported the approach previously adopted by the Commission in Decision No. 70441, where a full rate of inflation was subtracted *only* from the equity portion of the cost of capital.

Q. Please explain how Dr. Johnson's recommended approach is flawed from a theoretical perspective.

A. Certainly. The Commission has traditionally determined that FVRB should be calculated using a 50% weighting of original cost rate base ("OCRB") and a 50% weighting of reconstruction cost new depreciated ("RCND") rate base. As recognized by the Commission in Decision No. 71308, RCND is impacted by inflation, whereas OCRB is stated in original nominal dollar terms. Since only 50% of FVRB is impacted by inflation, the Commission determined that the ROR on FVRB should be determined by subtracting only 50% of an inflation rate from the weighted average cost of capital. If the full rate of inflation were deducted from the weighted cost of capital, as advocated by Dr. Johnson, this method would result in an adjustment that overstates the impact of inflation on capital costs and would produce an unreasonably low ROR on FVRB.

Q. On page 56 of his Direct Testimony, Dr. Johnson asserts that reproduction costs tend to grow faster than the rate of inflation, and as a result, the inflation rate does not need to be cut in half when adjusting the cost of capital. What is your response to this point?

A. First, I would note that Dr. Johnson provided no data whatsoever in support of his assertion that reproduction costs grow faster than the rate of inflation. Second, even if this phenomenon were true, it should be recognized that there will always be a mismatch between the historical cost of inflation embedded in the RCND and the forward-looking rate of inflation embedded in the cost of capital. There is simply no perfect way to eliminate the "double counting" of inflation that is embedded in both the FVRB and the cost of capital. As discussed in Decision No. 71308, the Commission has already considered this issue in detail and determined that the best approach is to reduce the weighted average cost of capital by 50% of the inflation rate that is embedded in the cost of capital. Therefore, Dr. Johnson's assertions should be rejected by the Commission.

Q. On page 55 of his Direct Testimony, Dr. Johnson states his belief that the inflation rate adjustment should not be based purely on forward looking expectations for inflation. Do you agree with his position on this?

A. No. When making an adjustment to the cost of capital for inflation, it is important that the adjustment be based on the inflation rate embedded in the cost of capital. And since the cost of capital is forward looking, by definition one would need to determine the inflation adjustment based on forward looking expectations for inflation. The mixing of historical inflation rates with forward looking cost of capital estimates, as suggested by

Dr. Johnson, is akin to mixing apples and oranges with the intention of making pure orange juice.

Q. What are some of the practical problems with Dr. Johnson's recommended method for determining the ROR on FVRB?

A. First and foremost, the ROR he derives is insufficient to support the financial integrity of UNS Electric. Thus, even if his theoretical arguments were sound, the end result does not comport with the fundamental goal of allowing a utility an opportunity to earn its cost of capital and attract new capital on reasonable terms. Additionally, since Dr. Johnson made no adjustment to the ROR on FVRB when adding the BMGS to rate base, UNS Electric would not be able to fully recover the cost of capital that will be needed to finance a purchase of that facility.

Q. What does Dr. Johnson have to say regarding the practical effects of rate making on UNS Electric?

A. Dr. Johnson has quite a bit to say. For example, on page 4 of his Direct Testimony, lines 22-24, he states that "While there is no expectation that earnings will exactly match the allowed rate of return, it is not in the public interest for the Company to achieve earnings that are far below its cost of capital – particularly if this pattern were to be sustained for several more years into the future." On page 7 of his testimony he also points out that UNS Electric's bond rating and credit metrics are "a legitimate concern, particularly since the UNS Electric ratings are currently near the low end of the industry range, and any further degradation could put the Company below the 'investment grade' categories." Finally, on pages 14-15 of his testimony, Dr. Johnson offers a potential solution to the Company's "weak earnings," suggesting that the Commission allow "a slightly higher return on the fair value rate base that would otherwise be approved."

Q. Is this the same rate making solution that the Company has proposed in its effort to realize a fair rate of return on its invested capital?

A. Yes. However, instead of increasing the ROR on FVRB relative to what would otherwise be justified based on Commission precedent (i.e., Decision Nos. 70441 and 71308), UNS Electric has, based on facts and circumstances of this case, actually discounted its requested ROR on FVRB.

Q. Mr. Grant, what is your concern regarding the ROR that Dr. Johnson applied to the Company's proposed investment in the BMGS?

A. The ROR he applied (5.96%) is simply too low relative to cost of capital that will be needed to finance a purchase of the BMGS. As discussed on pages 15-16 of my Direct Testimony, the ROR on FVRB for the BMGS should reflect the Company's weighted cost of capital. This is important not only from a practical standpoint, it is also important from a theoretical standpoint since OCRB and FVRB are nearly identical for the BMGS as presented in the Company's rate filing. As described on page 16 of my Direct Testimony, if the Commission were to include the BMGS in rate base as a post-test year adjustment, I recommend that the ROR on total FVRB (including both BMGS and non-BMGS investments) be determined by using a weighted average of (i) the ROR applied to non-BMGS rate base using the method approved in Decision No. 71308, and (ii) the ROR on BMGS rate base using the Company's weighted average cost of capital.

Q. Mr. Grant, do you have any final comments on the testimony offered by Dr. Johnson on the ROR to be applied to FVRB?

A. Yes. I would simply like to point out that of the five different calculation methods presented on Schedule BJ-10 attached to his testimony, only two of these methods ("Method 2" and "Method 5") reflect the Commission's fully-informed discussion and determination of this issue found in Decision Nos. 70441 and 71308. By contrast, "Method 1" represents the flawed approach favored by Dr. Johnson, "Method 3" is essentially equivalent to the now-discredited "backing-in method" formerly used by the Commission, and "Method 4" represents the same flawed approach being advocated by Staff witness Mr. David Parcell. Finally, I would also like to note that all of the calculations shown on Scheduled BJ-10 rely on an unrealistically low cost of equity as recommended by RUCO witness Mr. William Rigsby. UNS Electric witness Ms. Martha Pritz will address Mr. Rigsby's unreasonable recommendation in more detail

IV. <u>ABILITY OF UNS ELECTRIC TO EARN ITS COST OF CAPITAL.</u>

A. <u>Rebuttal of Staff Witness Mr. David C. Parcell.</u>

Q. Did any Staff witness directly address the Company's ability to actually earn its cost of capital?

A. No. However, Mr. Parcell makes several references to the importance of allowing a utility to earn a reasonable ROR, and on page 41 of his Direct Testimony, lines 9-12, he asserts that his cost of capital recommendation "provides the company with a sufficient level of earnings to maintain its financial integrity."

Q. What is the basis for Mr. Parcell's conclusion that his recommendation will result in a sufficient level of earnings for UNS Electric?

A. Mr. Parcell makes reference to a pre-tax interest coverage ratio calculated on Schedule 14 attached to his Direct Testimony. As discussed by Mr. Parcell on page 41 of his Direct Testimony, lines 12-14, he believes the referenced coverage ratio is consistent with a credit rating of BBB or higher. However, if Mr. Parcell's statements are read carefully, it is apparent that he is not offering an opinion as to whether or not UNS Electric will actually be able to achieve the level of earnings and pre-tax interest coverage portrayed on Schedule 14. Instead, he refers to the coverage ratio on Schedule 14 as "the pre-tax coverage that would result if UNS Electric earned my cost of capital recommendation." Importantly, Mr. Parcell *assumes* that UNS Electric will be able earn the 10.0% cost of equity he recommends, but offers no evidence that the Company will actually be able to do so.

Q. Does Mr. Parcell express an opinion regarding the importance of allowing a utility to earn its cost of capital?

A. Yes, based on the numerous statements found throughout his Direct Testimony on this subject, it appears that he attaches great importance to this regulatory goal. For example, on page 5 of his Direct Testimony, lines 15-17, he states that "From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments." Likewise, on pages 5-8 of his Direct Testimony, he devotes considerable attention to a discussion of the Hope and Bluefield decisions rendered by the U.S. Supreme Court, and makes a specific reference to the "end result" doctrine established by the Hope decision. As discussed by Mr. Parcell on page 7 of his Direct Testimony, lines 4-6, this "end result" doctrine maintains that "the methods utilized to develop a fair return are not important as long as the end result is reasonable." On this same page, lines 10-13, he goes on to state that "The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk." Finally, on page 53 of his Direct Testimony, in a discussion of the linkage between rate base and the cost of capital, Mr. Parcell states that "This link is important since financial theory indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility." Based on these statements from Mr. Parcell's Direct Testimony, as well as his belief that his cost of capital recommendation "provides the company with a sufficient level of earnings to maintain its financial integrity," it appears on the surface that Mr. Parcell believes that UNS Electric should be provided with an opportunity to actually earn its cost of capital.

Q. Did Mr. Parcell offer any analysis regarding the Company's ability to earn its cost of capital?

A. No. Despite the fact that Staff is recommending a rate increase that is 44% lower than what UNS Electric has requested, and despite evidence presented in my Direct Testimony that the Company requires all of the rate relief requested in order to earn its cost of capital, Mr. Parcell does not provide any analysis or evidence to support his assumption that the Company will be able to do so.

Q. Has the Company been able to earn its cost of capital since its last rate increase was implemented in June 2008?

A. No. The Company realized an earned ROE of only 4.6% in calendar year 2008, versus an ROE of 10.0% authorized in UNS Electric' last rate case. For the twelve months ended September 30, 2009, which reflects a full year under the rates approved in 2008, the Company's earned ROE was 6.9%.

Q. Will UNS Electric have an opportunity to earn its cost of capital if Staff's revenue requirement is adopted?

A. No. The Company estimates that it will be able to earn a ROE of only 7.9% if Staff's revenue requirement is adopted. UNS Electric will certainly have no reasonable opportunity to earn even the 10% ROE recommended by Staff.

Q. How did you arrive at an estimate of UNS Electric' earned ROE under Staff's revenue requirement?

A. This calculation is very straightforward. Since Staff's recommended rate increase is $6.0 million lower than the Company's requested increase, this represents the approximate difference in pre-tax earnings available to UNS Electric in 2011, the first full year under new rates. Applying a 39% composite income tax rate to this value produces an after-tax earnings difference of $3.7 million. Subtracting this amount from the Company's forecasted 2011 earnings of $11.6 million and ending common equity balance of $107.5 million (see table on page 18 of my Direct Testimony) results in forecasted 2011 earnings of $7.9 million and a return on average equity of 7.9% under Staff's rate recommendation.

Q. When estimating the earned ROE resulting from Staff's revenue requirement, should the expenses and capital base of the Company also be adjusted in the forecast?

A. No. In making their reductions to UNS Electric's revenue requirement, Staff assumes that certain expenses and investments are somehow not needed for the provision of retail electric service. However, these expenses and investments do not disappear simply because Staff assumes they are not needed. The other adjustments Staff made to UNS Electric's revenue requirement relating to the cost of equity capital and the ROR on FVRB also have no bearing on what the Company will be required to spend on operating costs and capital projects in the years to come. In the context of the "end result" test referenced by Mr. Parcell, the adjustments made by Staff to test year expenses and rate base have no relevance except for their impact on future operating revenues. It is the practical effect of Staff's recommendation on UNS Electric that should be considered, as opposed to a backward-looking analysis based solely on historical data and assumed spending reductions.

Q. Does Mr. Parcell's pre-tax coverage ratio analysis constitute an "end results" test?

A. No. For example, if a utility regulator is too aggressive with expense and rate base adjustments, a utility could be forced into bankruptcy – yet Mr. Parcell's approach would lead one to conclude that the bankrupt utility is financially healthy on an adjusted basis. Indeed, if Mr. Parcell were to apply the same approach he does in his testimony in this case, it appears he would testify that the bankrupt utility was able to attract debt and equity capital at reasonable rates and that it would be able to earn returns consistent with companies of similar risk. A test that shows a bankrupt utility is financially sound is no test at all.

Q. Based on the financial impact of Staff's rate recommendations, do you believe that the adoption of Staff's revenue requirement will result in earnings that are sufficient to support UNS Electric' financial integrity?

A. No, I do not. If Staff's revenue requirement is adopted, it is obvious that UNS Electric will not be provided with a reasonable opportunity to either earn its cost of capital or attract new capital on reasonable terms.

B. <u>Rebuttal of RUCO Witness Mr. William A. Rigsby.</u>

Q. What does Mr. Rigsby have to say about UNS Electric's ability to actually earn its cost of capital?

A. Like Mr. Parcell, Mr. Rigsby's Direct Testimony does not say much in this regard, despite making several references to the importance of providing a utility with an opportunity to actually earn its cost of capital. The closest Mr. Rigsby comes to opining on the prospective earnings of UNS Electric is a statement he makes on page 47 of his Direct Testimony, lines 24-31:

> I believe that my recommended cost of equity will provide UNSE with a reasonable rate of return on the Company's invested capital...As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my DCF analysis has produced such a return.

Mr. Rigsby's statement on page 8 of his Direct Testimony, beginning on line 17, also touches on his belief regarding the Company's ability to earn a reasonable ROR:

> The FVROR that RUCO is recommending meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers.

Q. What financial analysis does Mr. Rigsby offer to support his conclusion that UNS Electric will be provided with a "reasonable rate of return"?

A. None whatsoever. Nowhere does Mr. Rigsby evaluate the Company's ability to actually earn its cost of capital under RUCO's rate recommendation. Instead, all he offers are blanket assurances that the ROR recommended by RUCO will meet the requirements of Hope and Bluefield, and that the Company will be provided with a reasonable ROR.

Q. Will UNS Electric have an opportunity to earn its cost of capital if RUCO's revenue requirement is adopted?

A. No. The rate increase recommended by RUCO is $9.0 million less than that requested by UNS Electric. On an after-tax basis this equates to approximately $5.5 million in lost income to the Company. After adjusting the forecasted net income and ending common equity balances for 2011 presented in the table on page 18 of my Direct Testimony, I estimate that UNS Electric will be able to earn a ROE of only 6.0% if RUCO's revenue requirement is adopted. This ROE is so low that it even falls below the Company's 7.05% cost of debt that Mr. Rigsby recommends as being reasonable.

Q. Did any other witness for RUCO comment on the Company's ability to earn its cost of capital?

A. No. Although RUCO witness Ben Johnson discusses the need to consider the Company's financial condition and its relatively weak credit rating in setting rates, he did not provide a forward-looking analysis of the Company's financial condition.

Q. Based on the financial impact of RUCO's rate recommendations, do you believe that the adoption of RUCO's revenue requirement will result in earnings that are sufficient to support UNS Electric's financial integrity?

A. No, I do not. If RUCO's revenue requirement is adopted, UNS Electric simply will not be provided with an opportunity to either earn its cost of capital or attract new capital on reasonable terms.

V. CHANGES TO PURCHASED POWER AND FUEL ADJUSTOR CLAUSE.

A. Rebuttal of Staff Witness Dr. Thomas H. Fish.

Q. Mr. Grant, did Staff witness Thomas Fish concur with the Company's proposed change to the interest rate on balances of under- and over-recovered PPFAC costs?

A. No, he did not. Other than pointing out that the proposed interest rate would not be consistent with the interest rate currently applicable to UNS Gas and Southwest Gas Company, the only rationale he offered (at page 47 of his Direct Testimony) is that "a higher rate could provide a disincentive to reduce bank balances and become less inclined to take all possible measures to reduce the cost of purchased power and fuel to its customers."

Q. Do you agree with the rationale offered by Dr. Fish?

A. No. Such a minor change to the PPFAC interest rate would have no impact whatsoever on the fuel and wholesale power procurement practices of UNS Electric. By requesting an interest rate that reflects the actual cost of short-term borrowing at UNS Electric, the Company is simply trying to recover its reasonable costs. And during periods when PPFAC costs are over-recovered, such as presently exists, customers would actually benefit more from the proposed change in the PPFAC interest rate.

Q. Did Dr. Fish agree with the Company's request to include costs of wholesale credit support in the PPFAC?

A. No, he did not. On page 49 of his Direct Testimony he states that since the costs of wholesale credit support are not recorded in FERC Accounts 501, 547, 555 or 565, the Company should not be permitted to recover such costs through the PPFAC. However, he goes on to note that the Company "has another way to recover those costs" by requesting their recovery "through rate cases."

Q. Did Dr. Fish express any concern over the reasonableness or necessity of such costs?

A. No.

Q. Why did the Company request that such costs be recovered through the PPFAC?

A. First, these costs are directly related to the fuel and wholesale power procurement function. Second, the level of credit support will vary from season to season and year to year depending on the size of the Company's payable balances and the market value of forward energy purchases committed to by UNS Electric.

Q. If the Company's request to include these costs in the PPFAC is denied, what level should be included in UNS Electric's non-fuel base rates?

A. As shown in Exhibit KCG-4 attached to my Direct Testimony, the Company was required to provide substantial credit support to the fuel and wholesale power procurement function shortly after the full requirements contract with Pinnacle West Capital Corporation expired in May 2008. This requirement for wholesale credit support, consisting of cash collateral placed in escrow and letters of credit issued for the benefit of suppliers, is expected to continue as the Company's fuel and purchased power needs increase over time. For purposes of determining an appropriate amount to include in base rates, I recommend using the weekly average balance of wholesale credit support provided over the period August 10, 2008 through April 12, 2009, as reflected in Exhibit KCG-4, and multiplying that average weekly balance by the 1.15% annual cost rate for credit support discussed in my Direct Testimony. Based on an average weekly balance of $17 million for this period, I recommend that $195,500 in annual credit support costs be included in the Company's non-fuel revenue requirement.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

Rebuttal Testimony of

Martha B. Pritz

on Behalf of

UNS Electric, Inc.

December 11, 2009

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Martha B. Pritz. My business address is One South Church Avenue, Tucson, AZ 85701.

Q. What is the Purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to rebut portions of the Direct Testimony of Mr. David C. Parcell filed by the Arizona Corporation Commission ("Commission") Staff ("Staff"), as well as portions of the Direct Testimony of Mr. William A. Rigsby filed by the Residential Utility Consumers Office ("RUCO"). The main topic addressed in my Rebuttal Testimony is the cost of common equity capital used in calculating the weighted average cost of capital ("WACC") of UNS Electric, Inc. ("UNS Electric" or the "Company").

II. COST OF COMMON EQUITY CAPITAL.

A. Rebuttal of Staff Witness Mr. David C. Parcell.

Q. Please summarize your assessment of Mr. Parcell's Direct Testimony.

A. While Mr. Parcell agrees with the Company's recommendations regarding the cost of debt and capital structure, he recommends a lower cost of common equity resulting in a lower weighted average cost of capital. He suggests a cost of equity of just 10.0%, 140 basis points below the 11.4% recommended by the Company. Because Mr. Parcell uses a cost of equity of just 10.0%, his recommended WACC is only 8.4%, 64 basis points below that determined by the Company. The cost of equity recommended by Mr. Parcell is low due to the use of inappropriate inputs in several of the methods upon which he relies. In addition, one of the methods he uses, the Comparable Earnings method, does not provide relevant information for reasons discussed below.

Q. Please comment on Mr. Parcell's use of the discounted cash flow ("DCF") method of estimating the cost of equity for UNS Electric.

A. Mr. Parcell has chosen to use the constant growth form of the DCF model for which dividend yield and expected rate of dividend growth are the inputs. Mr. Parcell presents several weak sets of data as indicators of dividend growth in his DCF calculation, resulting in too low an estimate of the Company's cost of equity.

Q. Why do you consider some of the sets of data "weak"?

A. To calculate the growth rate, Mr. Parcell used an average of five growth rates, including two based solely on historical data. One historical data set shows historical retention growth and another shows historical growth in earnings, dividends and book value. Both sets of figures are taken from the Value Line Investment Survey ("Value Line"). Mr. Parcell also includes Value Line's forward-looking estimates of the same measures. Since Value Line's analysts would have taken historical data into account in preparing the forward-looking estimates, the inclusion of historical data again as a separate data source is redundant and produces a downward-biased estimate of growth for the groups of companies he examined.

Q. Had Mr. Parcell not included the historical data in his estimates of average growth rates, would his calculated range of DCF rates have been closer to the rate calculated by the Company?

A. Yes, by excluding the historical data, Mr. Parcell's range of DCF outcomes would have been closer to that of the Company. The range would have been 9.9% to 10.7% instead of the 9.4% to 10.1% shown in his Direct Testimony.

Q. Is there anything else about the various growth rates included in Mr. Parcell's calculation of average growth that concerns you?

A. Yes, in the case of the retention growth figures used, the median and mean values for the proxy groups are very low – ranging from 2.8% down to only 1.8%. Since Mr. Parcell has chosen to use a single-stage DCF model, he's asserting that these rates are valid indicators of growth for an infinite number of periods into the future. Furthermore, the retention growth figures are stated in nominal terms. If expected inflation were subtracted from these amounts to get indicated real growth, the rates would be lower still, even negative in some cases. When one considers that real gross domestic product ("GDP") growth has been 3.3% per year for the period from 1929 to 2008, the growth figures presented by Mr. Parcell are unreasonable.

Q. Had Mr. Parcell not included the retention growth data in his estimates of average growth rates, would his calculated range of DCF rates have been closer to the rate calculated by the Company?

A. Yes, by excluding the earnings retention data, Mr. Parcell's range of DCF outcomes would have been closer to that of the Company. The range would have been 10.3% to 11.1% instead of the 9.4% to 10.1% shown in his Direct Testimony.

Q. Please respond to Mr. Parcell's comments on your application of the DCF model.

A. Mr. Parcell is concerned that I did not use historical growth along with forward-looking estimates of growth in arriving at a short-term growth rate for my multi-stage DCF model. As stated above, it is safe to say that analysts providing forward-looking growth estimates will have already considered historical growth in determining the outlook for a company. To average forward-looking growth estimates with historical growth overemphasizes the impact of historical growth. Furthermore, Dr. Roger Morin, in his textbook, *New Regulatory Finance,* explains, "Past growth rates in earnings or dividends may be misleading, since past growth rates may reflect changes in the underlying relevant variables that cannot reasonably be expected to continue in the future, or may fail to capture known future changes."[1]

In short, while companies' historical growth rates (dividend per share growth, earnings growth, and book value per share growth) contain information that should be considered in forming forward-looking projections, blindly plugging unadjusted historical growth rates into a DCF model does not lead to a meaningful estimate of future dividend growth.

Q. Please address Mr. Parcell's concern that analysts' forecasts of growth rates might be biased, subject to conflicts of interest, or optimistic.

A. I used data from three sources. The first, Value Line, is an independent firm. The other two, Zacks Investment Research ("Zacks") and SNL Financial ("SNL"), compile data from a number of analysts in order to avoid bias. By giving weight to all three of these sources in determining a short-term growth rate, the likelihood of any material bias was avoided.

In addition, regulation that became effective in the early 2000s has reduced the likelihood of analysts' projections reflecting conflicts of interest. In a recent paper, *Conflicts of interest and analysts behavior: Evidence from recent changes in regulation*, the authors conclude, "...the recent efforts of regulators have helped neutralize analysts' conflicts of interest."[2]

Also, regardless of whether some analysts' forecasts of growth may have been high (or low) in the past, there is an abundance of academic research that has shown analysts'

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[1] Morin, *New Regulatory Finance* (Public Utilities Reports, Inc. 2006) at 292.

[2] Hovakimian (Baruch College) and Saenyasiri (Arizona State University), *Conflicts of interest and analyst behavior: Evidence from recent changes in regulation* (2009) at 24. Paper is available at http://ssrn.com/abstract=1133102.

forecasts of earnings growth to be superior to estimates based on historical growth. Cragg and Malkiel, in *Expectations and the Structure of Share Prices*, compared analysts' growth forecasts to forecasts based on historical growth and found that, "... on balance the security analysts tended to produce stronger predictions."[3]

A study by Brown and Rozeff published in *The Journal of Finance* concludes, "Given rational market expectations, our evidence of analyst superiority over time series models means that analysts' forecasts should be used in studies of firm valuation, cost of capital and stock price changes until forecasts superior to those of the analysts are found."[4]

Finally, it is unlikely that any optimism that has been shown in analysts' estimates of growth would be a significant factor in a relatively stable industry such as regulated utilities.

Q. Mr. Parcell suggests that rather than using historical GDP growth as a one of the data points in determining a long-term growth rate for your DCF model, one could also consider projections of GDP growth. Would that greatly change the cost of equity indicated by the DCF model?

A. No, it would not. I arrived at a 6.5% long-term growth figure by considering the 5-year earnings growth projections for the proxy group of companies (6.5%), the outlook for the electric utility industry (8.6%), and an estimate of GDP growth (5.4%). These three figures average approximately 6.8%, but I selected the slightly lower estimate of 6.5%. If I were to replace my estimate of GDP growth with the average of the projections proposed by Mr. Parcell, this would still produce an average growth rate slightly above 6.5%.

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[3] Cragg and Malkiel, *Expectations and the Structure of Share Prices* (University of Chicago Press 1982) at 85.
[4] Brown and Rozeff, "The Superiority of Analyst Forecasts as Measures of Expectations: Evidence From Earnings," *The Journal of Finance* Vol. XXXIII (1978): 13.

Q. Please summarize any concerns you have regarding Mr. Parcell's use of the Comparable Earnings ("CE") method of estimating cost of equity.

A. The comparable earnings method suffers from a shortcoming that makes it inappropriate for determining forward-looking cost of equity expectations. Also, Mr. Parcell apparently has no qualms about restricting UNS Electric's return on equity in order to produce a market to book value ratio much lower than that of its peers.

Q. Why are CE-based returns inappropriate for determining forward-looking cost of equity expectations?

A. One of the problematic aspects of the CE approach is that it attempts to identify investors' opportunity cost, which Mr. Parcell explains is "the prospective return available to investors from alternative investments of similar risk", but it tries to do so using historical accounting returns. Accounting returns do not reflect the always-changing, market-based returns sought by investors based on alternative investments opportunities. Likewise, comparing the market value of stock to an accounting-based book value is of limited value in a cost of capital analysis. Mr. Parcell includes prospective as well as historical returns in his calculations, but the problem associated with using accounting-based returns on equity ("ROE") persists.

In his recommendation, Mr. Parcell states, "An earned return of 9.5 percent to 10.5 percent should thus result in market-to-book ratios of over 100 percent."Apparently Mr. Parcell believes that a market-to-book ratio that is more than a few percentage points over 100% is excessive. He also states clearly that anything over 150% is "indicative of earnings that exceed the utility's reasonable cost of capital", yet 3 of the 4 average market-to-book ratios he cites (using his two proxy groups and two time periods) are above 150%.

Q. Please address Mr. Parcell's capital asset pricing model ("CAPM") analysis.

A. Mr. Parcell arrives at a CAPM-indicated range of 7.6 to 8.3% using a risk-free rate of 4.28%, Value Line betas for companies in the proxy groups, and a risk premium that was determined by averaging three estimates. While the risk-free rate and the beta values do not cause concern, the risk premium calculation does.

Q. Before discussing your concern about the risk premium calculation, are there any errors in the CAPM estimate that should be noted?

A. Yes. In Schedule 9 of Mr. Parcell's testimony, the beta value for NorthWestern Corp. is shown as zero. Based on Yahoo! Finance, the value should be shown as 0.65. Once that change is made, the mean CAPM rate for the Pritz Comparable Company Group is 8.0% instead of the 7.6% shown on the schedule, which would bring the CAPM range from 7.6- 8.3% to 8.0-8.3%.

Q. Now, please explain why the risk premium used by Mr. Parcell causes concern.

A. Of the three estimates Mr. Parcell averaged to arrive at a risk premium, two incorrectly rely on a comparison of S&P 500 returns to *total* returns for long-term government bonds. A more appropriate comparison would be of S&P 500 returns to long-term government bond *income* returns. In its 2009 Ibbotson SBBI Valuation Yearbook, Morningstar states:

> "Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation… Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return. The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss."

Of the two estimates of the risk premium that incorrectly use total bond returns, one of the estimates suffers from a second problem in that it is calculated using geometric means of historical returns. It is inappropriate to use the geometric mean of an historical data series if the result is to be used as a forward-looking estimate.

Q. Why is it wrong to use a geometric mean of historical return data in estimating forward looking returns or risk premia?

A. While a geometric mean is useful in describing returns for historical periods, it is well-accepted in financial theory that the arithmetic mean of an historical data series is a stronger estimate of future returns. For example, in the textbook *Investments*, by Bodie, Kane and Marcus, the authors state, "There is a general property: geometric averages never exceed arithmetic averages, and the difference between the two becomes greater as the variability of period-by-period returns becomes greater."[5]

They also state, "The geometric average has considerable appeal because it represents exactly the constant rate of return we would have needed to earn in each year to match actual performance over some past investment period. It is an excellent measure of *past* performance. However, if our focus is on future performance, then the arithmetic average is the statistic of interest because it is an unbiased estimate of the portfolio's expected future return (assuming of course, that the expected return does not change over time.) In contrast, because the geometric return over a sample period is always less than the arithmetic mean, it constitutes a downward-biased estimator of the stock's expected return in any future year."[6]

Furthermore, Morningstar, Inc. ("Morningstar"), which Mr. Parcell uses as his source of data for calculations of arithmetic and geometric means, provides its own Long-Horizon

[5] Bodie, Kane, Marcus, *Investments* (Richard D. Irwin, Inc. 1989) at 721.
[6] Bodie, Kane, Marcus, *Investments* (Richard D. Irwin, Inc. 1989) at 721-722.

Expected Equity Risk Premium (Historical) based solely on arithmetic mean returns. In the documentation provided in Morningstar's *Ibbotson SBBI 2009 Valuation Yearbook*, it clearly states that only arithmetic mean returns are appropriate in determining risk premia: "The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number."[7]

While I agree with Mr. Parcell that investors have access to both geometric and arithmetic means for returns over various timeframes, I would also point out that investors have access to financial literature, like that shown above, that would lead them to use the arithmetic averages to form forward expectations.

Q. Is the Long-Horizon Expected Equity Risk Premium (Historical) provided by Morningstar the 6.5% used in the Company's CAPM?

A. Yes, it is.

Q. Had Mr. Parcell calculated the risk premium without including the geometric mean -- in other words by averaging the other two risk premiums he presented -- what would the impact be on the CAPM results for the two proxy groups used?

A. The CAPM results would have indicated a range of 8.4-8.8% instead of 8.0-8.3% (as corrected).

[7] *2009 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook* (Morningstar, Inc. 2009) at 59.

Q. Had Mr. Parcell used the one risk premium that he calculated that had neither the total return problem nor the geometric mean problem, what total CAPM rate of equity would result?

A. A range of 8.7 to 9.1% would have been indicated, using the two proxy groups (as corrected).

Q. Can you comment on the relationship of the CAPM range recommended by Mr. Parcell and the average yield on public utility bonds?

A. The average yield on public utility bonds as of September 2009 was 5.6%. The CAPM range recommended, 8.0-8.3% (as corrected), is only 2.4-2.7% above that. At first glance, it appears that investors would be compensated for the additional risk of an equity investment relative to the risk of a debt instrument. However, an examination of historical relationships between allowed ROEs and utility bond yields proves that wrong. As shown in my Direct Testimony, the average premium for the period from January 2006 through January 2009 was 4.0%, well above the 2.4-2.7% based on Mr. Parcell's CAPM analysis.

Q. Based on the fact that the CAPM-based rates are so very low (so low as to fail to represent investor expectations) with respect to other cost of equity estimates provided by parties to the rate case, should they be given much, if any, weight in the final determination of a return on equity?

A. No, they should not. As calculated, and without any adjustments, the CAPM-indicated rates should not be given weight in the determination of a return on equity. This is consistent with the approach taken by Mr. Parcell. While he states that the results from his CAPM analysis should not be disregarded, his ROE recommendation appears to be based only on the results of the other methods he used. The entire return range Mr. Parcell calculated using CAPM is well below the ranges indicated by his other methods.

Q. Would you please address the questions Mr. Parcell raised about the assumptions and inputs you used for CAPM.

A. Yes. His first concern is the use of the arithmetic average, rather than geometric average, of historical differences between large company stock returns and long-term Treasury bonds. I addressed the topic at length above in stating my own concerns about Staff's CAPM calculation.

Q. What about his concern with your use of "income returns" rather than "total returns" for Treasury bonds?

A. As discussed in my review of Mr. Parcell's CAPM equity risk premium, total returns are not an estimate of a riskless rate of return. Income returns show returns that are not distorted by price risk. Therefore, Treasury bond income returns are the appropriate data for use in estimating risk premia.

Q. Please respond to Mr. Parcell's concern about the use of a risk premium adjustment.

A. As stated in my Direct Testimony, the CAPM-indicated cost of equity at that time (before any risk premium adjustment) was 8.4%. As that was only 50 basis points above the average bond yields for Baa-rated (low investment grade) public utility bonds as of January 2009, it was clear that 8.4% would not be an equity return acceptable to investors. Since investors take on more risk as they move from Treasury bonds to utility bonds and then to utility stocks, it was clearly necessary to adjust the risk premium applicable to equity investment. In doing so, I used the spreads between 30-year Treasury yields and Baa-rated public utility bond yields as a conservative estimate of the additional amount that would be required by an equity investor at the time my analysis was performed.

Since that time, spreads between 30-year Treasury yields and Baa-rated public utility bond yields have narrowed to a more normal level. The problem remains, however, that an updated CAPM-based estimate of the cost of equity is still too low with respect to Baa-rated utility bond yields to be acceptable to investors.

Q. If the Company had ignored CAPM and simply based its final recommendation of ROE on the other methods it employed, as Mr. Parcell did, would the indicated return have been higher or lower?

A. Had the company based its recommendation for allowed ROE only on the results of the DCF and bond yield plus risk premium methods, the indicated return would have been approximately 60 basis points higher – about 12.0%.

Q. By adjusting the CAPM return initially calculated and including this result in its determination of the cost of equity, did the Company actually recommend a lower return than it would have without adjusting CAPM?

A. Yes.

Q. Did Mr. Parcell comment on the Company's use of the bond yield plus premium method?

A. Yes. Mr. Parcell notes that in my Direct Testimony, I compared average allowed ROEs and yields on public utility bonds for the period 2006 – January 2009 to determine a premium that was then added to the yield for appropriately-rated utility bonds, which in this case is Baa. He observes that yields on Baa public utility bonds are now about 6.1%, down from the 7.9% rate seen at the time my Direct Testimony was prepared. Using this lower bond yield, the cost of equity indicated is 10.2%.

Q. How would a 10.2% ROE compare to the actual allowed ROEs from the last several years?

A. Using data from SNL, the average allowed ROEs for electric utilities are as follows:

2006 – August 2009 - 10.4%

January – August 2009 - 10.5%

Given that UNS Electric is a smaller, riskier company than many of the companies included in the allowed ROE data above, and given that UNS Electric's debt rating is the lowest possible investment grade rating, one would expect that investors would require a return higher than the averages observed.

Q. The average Baa public utility bond yield was 7.9% for January 2009 and 6.1% for September 2009. What was the average Baa public utility bond yield for the period from January 2006 through January 2009 (the same period for which the risk premium was calculated)?

A. 6.7%.

Q. What cost of equity would result if the January 2006 to January 2009 average Baa public utility bond yield were used in the bond yield plus risk premium calculation along with the 4.07% risk premium for the same time-frame?

A. 10.8%.

Q. Is your original recommendation still reasonable in light of risks faced by UNS Electric relative to larger, publicly traded companies?

A. Yes, it is.

B. Rebuttal of RUCO Witness Mr. William A. Rigsby.

Q. Please summarize your assessment of Mr. Rigsby's Direct Testimony.

A. Mr. Rigsby's determinations of the appropriate cost of debt and capital structure for UNS Electric were the same as those proposed by the Company. On the other hand, his recommendation of 9.25% for the cost of equity is far below that proposed by the Company. Mr. Rigsby uses both a CAPM analysis and a single-stage DCF model in reaching his recommendation. In each case, inappropriate inputs to the models result in greatly understated ROEs.

Q. Please discuss Mr. Rigsby's use of the CAPM, starting with the risk-free rate of return he used.

A. Mr. Rigsby determined a risk-free rate using an average of yields on a 5-year Treasury instrument on the basis that the 5-year timeframe approximates the timeframe for a company's filing of rate cases. The average yield he used was 2.41%.

Q. Is that consistent with recommendations made in financial literature regarding an appropriate Treasury instrument?

A. No. As Roger Morin explains in his textbook, *New Regulatory Finance*, "As a proxy for the risk-free rate, long-term rates are the relevant benchmarks when determining the cost of common equity rather than short-term or intermediate-term interest rates." Mr. Morin goes on to explain that "The expected common stock return is based on long-term cash flows, regardless of an individual's holding time period."

Q. Had Mr. Rigsby used a long-term Treasury yield in his CAPM model, would the range of returns he estimated have been higher or lower?

A. The range would have been higher. As can be seen from the information provided by Mr. Rigsby on his Attachment C, the average 30-year Treasury rate for the period from August 12, 2009 through September 20, 2009, the same period he used, was 4.25%, 184 basis points higher than the average yield on 5-year Treasuries. Using the correct risk-free rate in his model would have added 184 basis points to the indicated ROE.

Q. Do you agree with Mr. Rigsby's calculation of the market risk premium?

A. No, I strongly disagree with his calculation for several reasons. First, he has chosen to compare S&P 500 returns to *intermediate-term* Treasury *total* returns rather than *long-term* Treasury *income* returns. Both the use of intermediate-term Treasury returns and the use of total returns are inappropriate. Second, in determining the equity risk premium, Mr. Rigsby included geometric means of historical data series, which is also inappropriate.

The data Mr. Rigsby used in his equity risk premium analysis came from Morningstar's Ibbotson SBBI 2009 Yearbook. That very publication, while it includes tables of short-, intermediate-, and long-term risk premia, states that, "Although the equity risk premia of several horizons are available, the long-horizon equity risk premium is preferable for use in most business-valuation settings, even if an investor has a shorter time horizon. Companies are entities that generally have no defined life span; when determining a company's value, it is important to use a long-term discount rate because the life of the company is assumed to be infinite."[8]

[8] *2009 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook* (Morningstar, Inc. 2009) at 57.

The same publication specifies, "Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. ...The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return."[9] While the publication provides widely-used tables of risk premia, in none of the tables is the premia calculated based on *total* Treasury returns, only Treasury *income* returns.

My biggest disagreement with Mr. Rigsby's method is that he uses *both* arithmetic and geometric means of historical S&P 500 and government bond returns. Only arithmetic means are appropriate in determining a forward-looking rate of return on equity. In addition to the information I provided in rebutting Mr. Parcell's use of geometric means, I add the following from Roger Morin's *New Regulatory Finance* textbook. "The best estimate of expected returns over a given future holding period is the arithmetic average. ...only arithmetic means are correct for forecasting purposes and for estimating the cost of capital."[10]

Q. If the risk-free rate and equity risk premium were corrected as explained above, would the indicated return on equity have been higher or lower?

A. It would have been significantly higher. The low end of the range determined by Mr. Rigsby would have to be excluded because it was based on geometric means of historical data. Starting with the 6.83% return on equity that was calculated using arithmetic averages, one would have to correct the risk-free rate, which would add 184 basis points. Correcting the selection of Treasury instruments and the measure of returns on Treasuries would add another 40 basis points. The resulting return on equity would be 9.07%, not 6.83%.

[9] *2009 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook* (Morningstar, Inc. 2009) at 58.
[10] Morin, *New Regulatory Finance* (Public Utilities Reports, Inc. 2006) at 116-117.

Q. How much weight did Mr. Rigsby give his CAPM-based estimate of return on equity in making his final recommendation?

A. While Mr. Rigsby presents the results of both his DCF and CAPM models, his final recommendation appears to give very little weight to the CAPM model because his recommendation is well above even the high end of the CAPM-indicated range.

Q. In his comments on your CAPM methodology, Mr. Rigsby notes the use of an upward adjustment to the equity risk premium. His concern is that the adjustment was based on a spread between 30-year Treasuries and Baa/BBB rated debt that occurred over a brief period of time. Would you please comment on that?

A. Of course. At the time I was preparing my Direct Testimony, the turmoil in the financial markets had created the abnormally wide spreads. The spreads have since returned to more normal levels, but that could not have been assumed at the time.

Q. He also questions the need for an adjustment to CAPM.

A. Without an adjustment, the CAPM-indicated cost of equity at that time was 8.4%. It was clear that an 8.4% equity return would not be acceptable to investors as that was only 50 basis points above the average bond yields for Baa-rated public utility bonds as of January 2009. Rather than give the CAPM results little or no weight in my final recommendation of a cost of equity, I chose to make an adjustment based on the unusually high credit spreads seen at that point. As stated above, adjusting and including the CAPM results resulted in my recommending a return that was lower than it would have been had I just averaged the results from the other two methods I used to establish the Company's cost of equity.

Q. What else does Mr. Rigsby point out about the differences between your CAPM analysis and his?

A. He notes significant differences that result from my use of only arithmetic means versus his use of both geometric and arithmetic. He also notes the difference in the Treasury instruments used to estimate a risk-free rate. In addressing Mr. Rigsby's CAPM analysis, I've explained that my choices of inputs for the model were sound.

Q. Please summarize your view of RUCO's DCF analysis.

A. In RUCO's DCF analysis, a dividend yield of 5.4% was used along with a growth rate of 4.15%. While I do not have concerns about the calculation of the dividend yield, I do have several concerns about the calculation of the growth rate.

Q. What are your concerns regarding the growth rate?

A. First, I note that Mr. Rigsby calculated a growth rate that includes an external stock financing component. He cites Dr. Myron J. Gordon's textbook, *The Cost of Capital to a Public Utility*, as the source of the growth rate formula and states that Dr. Gordon is "the individual responsible for the development of the DCF or constant growth model". Then, instead of using the formula as presented by Dr. Gordon, he makes an adjustment based on an assumption that utilities' market-to-book ratios will tend to move toward 1.0. The market-to-book ratios shown in Mr. Parcell's Schedule 10, covering 18 years worth of data for a number of utilities, clearly demonstrate this is not the case. Had Mr. Rigsby stayed with the accepted form of the calculation, his average growth rate would have been 31 basis points higher. A bigger concern, however, is that his work papers show a comparison of the growth rate he calculated to published growth estimates from Value Line and Zacks for his proxy group of companies. These estimates were 4.04% and 6.44%, respectively. Had Mr. Rigsby given these widely-available estimates weight by averaging them with the rate he calculated, his average growth rate would have been 73 basis points higher, even without any correction to the rate he calculated. He offers no explanation as to why he did not use the data he had gone to the trouble to compile.

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

A. Yes. Mr. Rigsby points out that UNS Electric's capital structure includes more debt that the average of those companies included in his proxy group. He states that the higher level of debt would cause investors to view UNS Electric as a riskier investment and notes that investors would require a higher return than that recommended based on the proxy group. I would note, however, that he fails to mention UNS Electric's inability to pay a dividend which would also drive investors to require a higher return. He goes on to say that he made no upward adjustment in his recommended rate, instead preferring to believe that the fair value rate of return ("FVROR") recommended by another RUCO witness, Dr. Johnson, would be adequate. He offers no analysis to support this statement.

Q. What comments did Mr. Rigsby have regarding your DCF analysis?

A. Mr. Rigsby mistakenly states that the 6.5% long-term growth rate in my model is based on the five-year growth rate estimates from Value Line, Zacks and SNL. In fact, in determining a long-term growth rate, I considered estimates of growth for my proxy group of companies, the electric utility industry, and the United States economy as a whole.

He also suggests that more emphasis should be placed on the near-term growth than the longer-term rate "that is carried out into perpetuity." He seems to be overlooking the fact that perpetual dividend growth is a fundamental assumption for both the single-stage version of the DCF model he used and the multi-stage model I used.

Q. Does that conclude your testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

Rebuttal Testimony of

Karen G. Kissinger

on Behalf of

UNS Electric, Inc.

December 11, 2009

TABLE OF CONTENTS

Exhibits

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Karen G. Kissinger. My business address is One South Church Avenue, Tucson, AZ 85701.

Q. What is the Purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to: (i) update pro forma property taxes to reflect the most current available rates, and (ii) address the property tax adjustment recommended by RUCO Witness, Dr. Ben Johnson.

II. SUPPLEMENTAL PROPERTY TAX ADJUSTMENT.

Q. Please explain the Supplemental Property Tax Adjustment.

A. As indicated on page 8 of my Direct Testimony, pro forma property taxes in the rate case filing were computed using the final adjusted plant in service and inventory balances in rate base at December 31, 2008, a 21% assessment ratio scheduled to become effective January 1, 2010, and an average property tax rate based on the property tax bills received in September 2008. At that time, I proposed to update the pro forma calculation when more current information became available.

The supplemental property tax adjustment is a revised calculation of pro forma property tax using the average tax rate implicit in the tax bills received in September 2009, resulting in a change in our pro forma property tax expense. In the initial filing, an adjustment reducing annual property tax expense by $7,358 was proposed for UNS Electric, Inc. ("UNS Electric" or "Company") rate base and property tax expense of $419,305 was calculated for Black Mountain Generating Station ("BMGS"). After recalculating pro forma property taxes, the pro forma adjustment for UNS Electric rate base is no longer a decrease, but instead is an increase of property tax expense above recorded 2008 amounts by $105,181. The revised calculation for BMGS is property tax expense of $434,148. Supporting workpapers for this adjustment are included in Exhibit KGK-2 Support for Company Proposed Adjustments.

Q. Why has there been an increase in the amount of property tax expense requested in rates?

A. In 2006, the Arizona State Legislature passed, and the Governor signed, legislation that set the State equalization property tax rate at zero for three years, starting with tax year 2006. No action was taken by the Legislature to extend the zero rate and effective January 1, 2009 a state equalization property tax rate of $0.3306 per $100 of assessed value was passed by the Legislature and approved by the Governor. This rate is applied to the value of taxable property as of January 1, 2008.

Q. Are there additional adjustments needed to the pro forma property tax expense?

A. Not at this time.

III. RUCO's PROPOSED PROPERTY TAX ADJUSTMENT.

Q. Have you reviewed the property tax recommendation of RUCO witness Dr. Johnson?

A. Yes, I have.

Q. **Did Dr. Johnson compute property taxes in the same manner as the Company?**

A. Dr. Johnson used the same overall computational methodology, but he proposed using the 22% assessment ratio applicable to the 2009 property tax year rather than the 21% assessment ratio applicable to the 2010 property tax year.

Q. **Do you agree with Dr. Johnson's computation?**

A. I do not agree with the use of the 22% assessment ratio applicable to the 2009 property tax year. Property taxes for the 2009 property tax year are calculated based on plant in service at December 31, 2007. The lien date for the 2009 property tax year is January 1, 2008.

Rate base in this case includes plant in service as of December 31, 2008. This is the basis for the property tax calculation proposed by both the Company and RUCO. Since it is known and measurable that the property taxes paid on plant in service at December 31, 2008 will be for the 2010 tax year and reflect the use of the 21% assessment ratio, it is appropriate to use that assessment ratio to determine pro forma property tax expense.

Q. **Should the 21% assessment ratio for the 2010 tax year also be used to calculate property taxes for Black Mountain Generating Station?**

A. Yes, it should. BMGS was placed in service in 2008. The first year for which property taxes are payable is the 2010 tax year. Therefore, it is appropriate to use the 21% assessment ratio for 2010 to calculate pro forma property tax expense for BMGS.

Q. **Does this conclude your Rebuttal Testimony?**

A. Yes, it does.

EXHIBIT

KGK-2

INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2008

REVISED FOR REBUTTAL

ADJUSTMENT NAME:	Property Tax Expense
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	December 11, 2009
PREPARED BY:	Gail Boswell
REVIEWED BY:	Jay Rademacher

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
408	Taxes Other Than Income - Production	$12,350	
408	Taxes Other Than Income - Transmission	$69,856	
408	Taxes Other Than Income - Distribution	$23,223	
408	Taxes Other Than Income - General		$248
	ENTRY TOTAL	**$105,429**	**$248**
	NET ENTRY		$105,181

Reason for Adjustment

Adjusts property tax expense to reflect 12/31/08 Plant in Rate Base, 2009 property tax rates, and the Arizona statutory assessment ratio in effect for Tax Year 2010

INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2008

REVISED FOR REBUTTAL

ADJUSTMENT NAME:	Property Tax Expense - BMGS
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	December 11, 2009
PREPARED BY:	Gail Boswell
REVIEWED BY:	Jay Rademacher

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
408	Taxes Other Than Income - Production	$434,148	
408	Taxes Other Than Income - Transmission		
408	Taxes Other Than Income - Distribution		
408	Taxes Other Than Income - General		
	ENTRY TOTAL	**$434,148**	**$0**

NET ENTRY $434,148

Reason for Adjustment

Adjusts property tax expense to reflect 12/31/08 Plant in Rate Base, 2009 property tax rates, and the Arizona statutory assessment ratio in effect for Tax Year 2010 for Black Mountain Generating Station

UNS Electric, Inc.
Property Taxes - Lead
Test Year Ended 12/31/2008

Source: G. Boswell, 12/11/09

REVISED FOR REBUTTAL

	Generation	Transmission	Distribution	General / Intangible	Total
Utility Plant in Service Taxes					
1 Recalculated Utility Plant in Service Taxes	205,119	453,020	2,467,740	165,722	3,291,601
2 Less: Recorded Property Taxes	(192,769)	(383,164)	(2,444,517)	(165,970)	(3,186,420)
3 Property Tax Expense Adjustment	12,350	69,856	23,223	(248)	105,181

UNS Electric, Inc.
Property Taxes - Utility Property
Test Year Ended 12/31/2008

REVISED FOR REBUTTAL

Source: G. Boswell, 12/11/09

	Generation Valencia	Transmission	Distribution	General / Intangible	Total
Utility Plant in Service Taxes					
Total Net Plant in Service - Rate Base	15,571,882	24,475,884	125,889,870	15,230,537	181,168,173
Less: Non-Taxable Licensed Transporation in Rate Base				(6,551,740)	(6,551,740)
Less: Land Cost & Rights of Way in Rate Base*	173,596	(798,609)	(777,344)	(17,270)	(1,419,627)
Less: Environmental Property in Rate Base	-	-	(11,232,485)	-	(11,232,485)
Less: Non-Taxable WAPA portion of N Havasu Sub			(4,255,251)		(4,255,251)
Less: CWIP in Rate Base**	-	-	-	-	-
Less: Net Book Value of Generation	(15,745,478)				(15,745,478)
Plus: Full Cash Value of Generation	10,720,618				10,720,618
Plus: Land FCV Per AZ Dept of Revenue			5,474,725		5,474,725
Plus: Materials & Supplies in Rate Base			8,261,763		8,261,763
Plant in Service Full Cash Value	10,720,618	23,677,275	123,361,278	8,661,527	166,420,698
Assessment Ratio	21.0%	21.0%	21.0%	21.0%	
Taxable Value	2,251,330	4,972,228	25,905,868	1,818,921	34,948,347
Average Tax Rate (Updated to 2009 Actual Rates)	9.1110%	9.1110%	9.1110%	9.1110%	
Property Tax	205,119	453,020	2,360,284	165,722	3,184,145
Environmental Property in rate Base	0	0	11,232,485	0	11,232,485
Statutory Full Cash Value Adjustment	50%	50%	50%	50%	
Environmental Full Cash Value	0	0	5,616,243	0	5,616,243
Assessment Ratio	21.0%	21.0%	21.0%	21.0%	
Taxable Value	0	0	1,179,411	0	1,179,411
Average Tax Rate	9.1110%	9.1110%	9.1110%	9.1110%	
Property Tax	0	0	107,456	0	107,456
Total Property Taxes	**205,119**	**453,020**	**2,467,740**	**165,722**	**3,291,601**

*RW are not subject to property tax and Land FCV (Line 9) rather than land cost is subject to property tax.

**Property Tax on CWIP in rate base will be calculated as part of a separate adjustment.

UNS Electric, Inc.
Environmental Property
Test Year Ended 12/31/2008

Source: G. Boswell, 12/11/09

			Distribution
1	Environmental Cost	19A	29,731,594
2	Total Rate Base Cost	6A	333,221,584
3	Total Acq Adj in Rate Base Net of A/A	7G	(52,886,708)
4	Total Reserve in Rate Base	7F	(154,445,007)
5	Total Reserve & Acq Adj		(207,331,715)
6	Allocated Reserve/Acq Adj	lines 1/2 x 5	(18,499,109)
7	Net Environmnetal Property in Rate Base	lines 1+6	11,232,485

UNS Electric, Inc.
Property Taxes - Utility Property
Test Year Ended 12/31/2008

REVISED FOR REBUTTAL

Source: G. Boswell, 12/11/09

		Generation Black Mountain Generating Station
	Utility Plant in Service Taxes	
1	Plus: Full Cash Value of Generation	22,690,956
2	Plus: Land FCV Per AZ Dept of Revenue	
3	Plus: Materials & Supplies in Rate Base	
4	Plant in Service Full Cash Value	22,690,956
5	Assessment Ratio	21.0%
6	Taxable Value	4,765,101
7	Average Tax Rate	9.1110%
8	Property Tax	434,148

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

Rebuttal Testimony of

Dallas J. Dukes

on Behalf of

UNS Electric, Inc.

December 11, 2009

TABLE OF CONTENTS

Exhibits:

I. INTRODUCTION.

Q. Please state your name and address.

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

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

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

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

A. I address certain adjustments that Staff witness Dr. Thomas H. Fish recommends in his Direct Testimony. I address several errors in computation and compilation of pro forma adjustments and schedules sponsored by Dr. Fish. I also address adjustments that Residential Utility Consumer Office ("RUCO") witness Dr. Ben Johnson proposes in his Direct Testimony. While I agree with some of their adjustments, a significant number of adjustments made by Staff and RUCO are inappropriate and other adjustments are not supported by the evidence in this case. In my testimony, I explain why the Commission should reject Staff's and RUCO's adjustments as they would not result in just and reasonable rates. I further explain why UNS Electrics' revenue requirements, expenses, and adjustments are reasonable based on the evidence presented in this matter.

Q. Have you revised any of the adjustments that you sponsored in your Direct Testimony?

A. Yes, I have. I have made changes to the following adjustments that originally appeared in my Direct Testimony:

Working Capital: This adjustment to rate base is revised from ($3,794,846) to ($3,925,045) to reflect the impact of the proposed Rebuttal adjustment by Company Witness, Kentton Grant, for recovery of credit cost associated with Wholesale Credit Support, the proposed Rebuttal adjustment by Company Witness Karen Kissinger for property tax expense and my proposed Rebuttal adjustment for Fleet Fuel expense.

Fleet Fuel Expense: This adjustment to operating expense is revised from $0.00 to ($56,333) to reflect a three year average for Fleet Fuel Expense. This adjustment is necessary to normalize the test year level of expense using fixed, known and measurable information. The test year reflected and average cost of about $3.65 per gallon and the three year average is $3.00 per gallon which is more representative of current prices being incurred by UNS Electric and the expected cost to be incurred over the life of the rates established in this case.

Income Taxes: This adjustment to operating expense is revised from to reflect the other pro forma adjustments.

Other than those adjustments (and the flow through impacts of those revisions), I reiterate the adjustments in my Direct Testimony.

Attached to my Rebuttal Testimony is Exhibit DJD-1, which is a spreadsheet that sets forth a comparison of the positions of the parties on the Revenue Requirement and their related adjustments. The spreadsheet also identifies the Company's revised position on its proposed adjustments.

Q. How do those revisions affect the Revenue Requirement?

A. Given these revised adjustments, our revenue requirement would increase as much as $144,701 on an original cost basis above the amount requested in the Application. However, as indicated in Exhibit DJD-1, the Company is not requesting a revenue requirement higher than proposed in its Application and noticed to our customers.

II. <u>COMPUTATION AND COMPILATION CORRECTIONS TO STAFF'S DIRECT FILING.</u>

Q. Are there computation and compilation errors that you have identified within Staff's adjustments and Schedules filed November 6, 2009?

A. Yes. I have provided an attachment, Exhibit DJD-2, which summarizes and explains the computation and compilation errors identified in several of Dr. Fish's pro forma adjustments and sets forth the appropriate computation and compilation corrections.

Q. What do you mean by compilation corrections?

A. An example would be Staff's Cash working capital proposal for UNS Electric. The Company's original pro forma adjustment reduced test year rate base by $2,810,346. Dr. Fish calculated test year cash working capital as a rate base reduction of $2,749,321. Dr. Fish's Schedules are based on his proposed incremental changes to the Company's final numbers that are then adjusted to his proposed pro forma levels. But because Dr. Fish's reduction of test year rate base is less than the reduction proposed by the Company, his incremental pro forma adjustment should have resulted in an increase to the Company's proposed rate base level. However, Schedule THF B-2 shows Dr. Fish's adjustment as a decrease to the Company's proposed rate base, when it should have been an increase. Because of this compilation error, Staff's pro forma rate base is understated by $122,050. I provided an example of this particular difference in a chart below for illustrative purposes.

Cash Working Capital	
$ (2,810,346)	Company Proposed Reduction to Rate Base - Direct
$ (2,749,321)	Staff's Proposed Reduction to Rate Base – Direct
$ 61,025	Staff's Reduction is $61,000 Less
$ (2,810,346)	Staff Started with Company's Pro Forma Rate Base
$ (61,025)	Staff Incorrectly Reduced the Rate Base by the Difference
$ (2,871,371)	Cash Working Capital Reflected in Staff's Schedule B
$ (2,749,321)	Staff's Intended Pro Forma Reduction
$ (122,050)	Staff's Inadvertent Error

Q. What other corrections did you identify?

A. They are explained in more detail within Exhibit DJD-2, but they consist of the following:

1. Correction to Staff's calculation of cash working capital - for formula errors with the worksheet, incomplete recognition of adjustments proposed by Staff and to recognize the proper direction of the adjustment to increase the Company's rate base, not decrease it.
2. Correction of Staff's Schedule A to use a 6.14% fair value rate of return. On page 27, of Staff witness Mr. David C. Parcell's Direct Testimony he recommends a weighted average fair value rate of return of 5.99%. The supporting capital structure provided by Mr. Parcell, on page 57 of his Direct Testimony, actually calculates out to 6.14% (Mr. Grant details this in his Rebuttal Testimony). When this correct rate of return is transferred to Schedule A, it results in an additional $387,149 being added to Staff's fair value adjustment – prior to income tax gross-up.
3. Correction for the calculation of incentive compensation expense -- the wrong test year expense level was used in Staff's calculation.
4. Correction for the calculation of call center expense adjustment -- the incorrect June 2006 test year expense level was used in Staff's calculation.

5. Correction for the calculation of industry association dues -- the percentage disallowed was applied to the incorrect test year expense level.

6. Correction for the calculation of outside legal expense. Staff calculated the difference between their proposed pro forma level and the test year amount and included that amount within its schedules as the adjustment. The adjustment, however, should have been the difference between Staff's and the Company's pro forma outside legal cost calculations because Staff started with the Company's adjusted numbers.

7. Correction for the bad debt expense adjustment proposed by Staff. Staff calculated a pro forma bad debt expense of $869,550, the Company calculated pro forma bad debt expense of $764,063. Staff's incremental adjustment to our filed position should have been an increase in Company's pro forma expenses of $105,487 – not a decrease of that amount.

8. The associated income tax and payroll tax corrections after flowing through the corrections.

Q. If these computation and compilation corrections were made to Staff's filing without changing their filed positions what would be the impact to their recommended revenue increase for UNS Electric?

A. Staff's recommendation would increase approximately $1.2 million.

III. <u>FIXED, KNOWN AND MEASURABLE.</u>

Q. Why are you discussing the fixed, know and measurable concept in your Rebuttal testimony?

A. RUCO witness, Dr. Johnson, proposes the disallowance of several adjustments proposed by the Company for known and measurable rate changes that went into effect after test year end, but were applied to test year ending levels. The adjustments were a disallowance of the 2010 payroll increase, the 2009 pension and benefit loading rate cost increase and the proposed decrease in property tax expense due to a reduction in the assessment ratio effective tax year 2010.

Q. Why is Dr. Johnson opposing these adjustments to test year ending levels?

A. The central theme of the argument is RUCO's desire to limit pro forma adjustments to test year normalization and to apply a strict cut-off for fixed, known and measureable adjustments outside the test year.

Q. Is his proposed treatment consistent with recent Commission Orders?

A. No. It is inconsistent with the Commission's positions in the last UNS Electric Decision No. 70360 (May 27, 2008), as well as the last three Southwest Gas Decisions, the last Tucson Electric Power Company ("TEP") decision and recent Arizona Public Service Company ("APS") decisions. Also, Commission rules and regulations do not limit pro forma adjustments as Dr. Johnson would have the Commission do here. The purpose of pro forma adjustments is to reflect a normal or more realistic relationship going forward between revenues, expenses and rate base. Simply enforcing a strict cut-off without considering those adjustments and what expenses, revenues and the related rate base changes will actually be going forward when rates are in effect could yield unreasonable results.

Q. Can you summarize what you believe is the Commission's position with regards to such adjustments to test year ending levels for known and measureable changes outside of the test year?

A. Yes. The Commission has allowed such adjustments as long as they are based on test year levels (such as employee counts, plant in service and mailing levels) and is for a known and measureable rate changes (such as wage increases, property tax rate decreases, postage rate increases, and capitalization rate changes). This is consistent with Commission rules and regulations.

Q. Could a Utility take this concept to the extreme and request, for example, a pro forma adjustment for approved wage rate increase for the next five years and provide fixed, known and measureable rate changes?

A. A Utility could request such treatment, but recent Commission decisions have only allowed the next known rate change that coincides with the anticipated year the new rates will go into effect. Ultimately, it is the Commission's decision and it has the discretion to decide if adjustments that are known and measurable should be considered and how far removed from the test year should adjustments be considered. Based on the most recent Commission decisions, UNS Electric believes its request is consistent, reasonable and creates no mismatches.

Q. Has RUCO consistently applied Dr. Johnson's recommendation of not going beyond the test year in recent filings and/or in this case?

A. Not in my opinion. In the last UNS Electric case and the most recent UNS Gas case RUCO witnesses proposed property tax expense reductions based on assessment reductions beyond the test year and out to the next year that coincides with the anticipated initial effective year of the new rates. An extensive discussion of this concept is in the direct testimony of RUCO witness, Ralph Smith in the most recent UNS Gas case (pages 53-55) – where he provides a table summarizing such treatment and recent Commission Decisions.

Dr. Johnson is also inconsistent within this case. He says that the wage rate increase in effect January 1, 2009 is equivalent to December 31, 2008 (test year end) and thus is known and an acceptable adjustment. But, the pension and benefit (P&B) loading rate that went into effect January 1, 2009 that is charged to UNS Electric from TEP to recover those employee benefit cost, is not known and is not acceptable. The P&B loading rate applies to pro forma payroll expense and is based on a test-year-ending level of employees. Clearly, the P&B for the year 2009 will be known and measurable at the time of the hearing on this case in 2010.

IV. REBUTTAL TO RATE BASE ADJUSTMENTS.

A. Post Test Year Non Revenue Plant in Service.

Q. Does either Staff or RUCO agree with the Company's inclusion of Post Test Year Non Revenue Plant in Service within rate base?

A. No. Both Staff's witness, Dr. Fish, and RUCO's witness, Dr. Johnson, objected to including Post Test Year Non Revenue Plant in rate base.

Q. What is the basis for Dr. Fish and Dr. Johnson's removal of the Company's Post Test Year Non Revenue Plant in Service adjustment?

A. Both Dr. Fish and Dr. Johnson assert that the investment in the Post Test Year Plant are ordinary investments that may improve the Company's efficiency and help reduce operating expenses or could even serve additional load and produce additional revenue in the future. Dr. Johnson also argues that ultimately these investments will be included in ratebase in future proceedings. Therefore, both agree that the investments should not be given extraordinary post-test year treatment. They should only be included in rate base when in service within the confines of an historical test year.

Q. Do you agree with Dr. Fish or Dr. Johnson's recommendations to deny the Company's request to include Post Test Year Non Revenue Plant in Service within rate base?

A. No. The Commission has broad discretion in the setting of just and reasonable rates and has included similar post test year adjustments in rate base in past proceedings.

Q. Why do you believe the Company should be afforded such treatment in this case?

A. First, the Company is required to provide safe and reliable electricity to present and future customers within its service territory. Second, the Company is requesting recovery only on the portion of its post test year plant investment made prior to test year end (*i.e.* any investment made on or before December 31, 2008). Third, as Company witness Mr. Grant explains in his Direct Testimony, if the Company were awarded 100% of its request rate increase, it would still not earn its requested rate of return in the first full year of new rates – and its return would decline each year afterward until new rates were established in a subsequent UNS Electric rate case.

Despite the fact that the Company is not earning a reasonable return and does not anticipate earning its requested return even if given its full requested increase - the Company continues to invest in system replacements, improvements and new equipment to provide safe reliable service to its customers. The Company is requesting that these non-revenue-producing items be included in rate base because the purpose of those items is to provide safe and reliable service to existing UNS Electric's customers. As such, those items should be a part of the cost of service recovered from customers.

Q. Can an argument be made that some of these investments may reduce cost or may be used to serve additional customers that could be added in the future?

A. Yes. But, not to any extent that can be identified as material in nature or measureable at the time of the investment and when these rates are being established. The vast majority of the investments are in the replacement of distribution system assets for reasons of maintaining service levels and reliability. The other major portion of the investment is for tools, communication equipment and system control upgrades.

These investments are necessary to avoid system interruptions and failures. They would be needed regardless of whether the Company adds any new customer load. They are independent of growth. The Company must maintain and operate its system to provide reliable service to its existing customers and these replacements and infrastructure improvements are a normal part of business. By the time this rate case is concluded, these items will be in operation and working to preserve good service for the customer. The Company's request is simply for a reasonable opportunity to recover the cost of and return on these investments in a timelier manner in providing service to existing customers. To have the Company wait over three years to begin recover on and of these investments unduly harms the Company. The fact that these investments are not unusual or comprise a large percentage of its overall rate base is not a reason to disallow them. In fact, allowing those items puts the Company in a better position to avoid being at the point where it is in extraordinary circumstances and needs to request more unusual treatment.

Q. How did UNS Electric determine which plant was revenue-neutral and would not result in materially identifiable cost savings?

A. The Plant accounting group and operational personnel of UNS Electric reviewed the projects and indentified investments that had been made in projects that were not being installed for the purpose of serving additional load or to produce additional revenue and that would have been invested in regardless of customer growth.

Q. Can you describe past Commission decisions that have approved post-test year plant in rate base and how those decisions relate to UNS Electric's request in this case.

A. Yes. I will describe three cases regarding Arizona Water Company, Rio Rico Utilities Inc. and Chaparral City Water Company.

In Decision No. 66849 (March 19, 2004), the Commission approved post-test year plant up to 12 months after the end of the test year for Arizona Water Company. In that case, the plant at issue was intended to provide service to customers existing at the end of the test year, was in service a reasonable time before the hearing so it could be inspected, and was not funded by CIAC or AIAC. The Commission approved inclusion of post test-year plant consistent with how it has treated such plant in prior cases (*i.e.*, up to 12 months after the end of the test year). For UNS Electric, the plant at issue is to serve existing customers, and would be needed regardless of whether the Company added zero customers or 1,000. It was not financed by CIAC and AIAC and the majority was available for inspection before Staff and RUCO submitted their pre-filed Direct Testimony. Most of the post test-year plant UNS Electric requests be included will be in service on or before December 31, 2009.

In Decision No. 67279 (October 5, 2004), the Commission approved approximately $900,000 of post-test year plant because "the preponderance of the evidence indicates that the post test year plant that the Company seeks to include in rate base was installed to serve existing test year customers, was required for system reliability, and that there would not be a material impact on revenue or expenses." (page 7). The Commission further stated that its own rules and regulations contemplated pro forma adjustments "to allow for plant placed in service post test year to be included in rate base." (Id.) In this case, there is no dispute that the approximate $7.263 million of post-test year plant was installed to serve existing test year customers and primarily for the purpose of maintaining service levels and system reliability.

In Decision No. 68176 (September 30, 2005), the Commission approved over $2.9 million of post-test year plant in rate base for Chaparral City Water Company. In justifying the Shea Water Treatment Plant expansion costs (over $2 million) the Commission explained "[we] find that the weight of the evidence in this proceeding supports the Company's that the Shea WTP expansion, which the Company paid for during the test year, and has been used and useful since March of 2004, allows the Company to reliably meet test year peak demands during the summer months with CAP water, which is a renewable resource we wish to encourage, while retaining the ability to take individual modules off line for repairs and to meet emergency needs" (Decision No. 68176 at 5). The Commission also supported inclusion of this plant because it provided for additional operational flexibility. The Commission also approved an inclusion of costs for a 16-inch transmission main because it was "used and useful since November 2004, providing operational flexibility and improved service to customers." Notably, because the installation of the transmission main does not change the way the system would be operated, the Commission did not find that the weight of the evidence demonstrated a reduction in operating cost with the transmission main. The test year in that case ended December 31, 2003. Here, UNS Electric is seeking to include post-test year plant costs for facilities that improve operational flexibility and service reliability. Much of this plant will be in service within a year after the end of the test year. Similar to Chaparral City Water Company, how UNS Electric would operate and maintain its system has not and would not change with these facilities.

These are only a sampling of some of the cases that approved post-test year plant for utilities. The Commission also approved inclusion of post test-year plant in rate base for Paradise Valley Water Company in Decision No. 61831 (July 20, 1999) and for Bella Vista Water Company in Decision No. 65350 (November 1, 2002). While UNS Electric understands that the precedent is not binding, it should be considered persuasive authority justifying UNS Electric's request as being neither unusual nor uncommon. UNS Electric's request contains many of the same characteristics as the requests in those cases justifying inclusion.

Q. Is there any requirement that the percentage of post-test year plant to be included in rate base be at a certain level related to total rate base?

A. No. There is no such requirement in the Commission's rules and there is no decision that I am aware of that makes reference to any percentage requirement when determining whether post-test year plant should be included.

Q. Is there any requirement that the post-test year plant be unusual or outside of normal and ongoing improvements made to improve service?

A. No. Some decisions reference a need to meet emergencies as a reason to justify inclusion of post-test year plant. But there is no decision that I am aware of that states post-test year plant should only be included to address an emergency. Further, from a policy perspective, it seems counter-productive to award a company that waits to make necessary repairs, while penalizing UNS Electric for making improvements to prevent and avoid service interruptions.

V. REBUTTAL TO OPERATING INCOME ADJUSTMENTS.

A. Payroll and Payroll Tax Expense.

Q. Did Staff or RUCO object to the Company's payroll adjustments?

A. Staff did not object to the Company's payroll adjustments in their Direct Testimony. RUCO proposed the exclusion of a portion of the Company's payroll adjustment. Dr. Johnson (at page 33) took exception to the Company increasing test year annualized payroll for the wage increase that will take effect January 2010.

Q. What are Dr. Johnson's reasons for excluding the January 2010 increase from the adjustment?

A. Dr. Johnson believes that the increase is too far from the end of the test year and not known at this time. He essentially is making the same argument that RUCO witnesses made in each of the last UNS Electric case and the last three Southwest Gas Corporation rate filings. The Commission adopted the payroll adjustments in those cases, despite RUCO's opposition.

Q. Do you agree with Dr. Johnson's rationale?

A. No. The evidentiary hearing in this case commences February 4, 2010. The actual pay rate increases will be known at that time. These increases are being applied to employee levels as of the end of test year and coincide with the effective year of the new rates. Therefore, the payroll adjustments do not create any mismatch of revenue and expenses.

B. Incentive Compensation Expense.

1. Performance Enhancement Program ("PEP").

Q. Did Staff or RUCO reduce the pro forma PEP cost contained within the Company's requested revenue requirements?

A. Yes. Both Dr. Fish and Dr. Johnson recommended that the pro forma level of PEP expense be reduced by half on the basis that the program benefits both shareholders and customers and thus should be shared equally. RUCO did not actually quantify such an adjustment, but did discuss their position on page 43 of Dr. Johnson's Direct Testimony.

The Company strongly disagrees with the "who benefits" analysis as a tool for what percentage of recovery to be afforded to the Company. That same type of analysis could be applied to any number of expense items. For example, payroll expense for operation personnel – the customers clearly benefit from employees operating and maintaining the system to provide safe reliable service – but the shareholders benefit as well as employees keep the system operational so the business can generate sales and make a profit for the owners. Clearly, the payroll cost of operational employees should not be proportioned based on who benefits.

The decision to allow recovery should be based on whether the costs are prudently incurred, reasonable and if the costs are incurred to provide reliable service to customers. If those criteria are all met, then the costs should be fully recoverable. Neither Staff nor RUCO contend that the overall compensation, including the PEP, is unreasonable or imprudent. To allow only partial recovery based on proportion of benefit only assures a much greater possibility that the income generated by the Company will not yield the return it is authorized to earn.

Q. Are Staff and RUCO's adjustments consistent with prior Commission orders?

A. Yes and no. The Commission's position on the recovery of incentive compensation program cost has varied, somewhat inconsistently, based on the nature of the incentive compensation. UNS Electric' incentive compensation is a cash-based incentive program available to all non-union employees. The Commission allowed full recovery of a similar program for APS in Decision No. 69663 (June 28, 2007). However, I acknowledge that the Commission previously allowed only 50% recovery of the PEP in the last UNS Gas and UNS Electric rate cases, relying primarily on how it treated the Southwest Gas Management Incentive Program in the previous two Southwest Gas rate cases. The Southwest Gas program is not comparable to the UNS Electric PEP because Southwest Gas limits the program only to a certain level of managers. Our PEP covers all non-union employees. UNS Electric continues to believe that given the nature of its PEP, it should be allowed full recovery of the PEP expense.

Q. Does the Commission's position in the recent APS rate case support your position?

A. Yes. The Commission provided for full recovery of APS' Cash-based Incentive Compensation plan expenses in Decision No. 69663 (page 37) stating:

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

Q. Can you provide more detail as to why you disagree with Staff and RUCO?

A. Certainly. The evidence I discuss below shows that UNS Electric' total employee compensation including the PEP program is reasonable and to deny recovery is to ensure that UNS Electric will not have a reasonable opportunity to recover its operating cost. Again, neither Staff nor RUCO assert that the total employee compensation including PEP is unreasonable. In effect, UNS Electric is being penalized simply for its compensation structure.

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

The goals or targets of the current PEP program are also heavily weighted toward providing benefits to customers. The program uses operational cost containment, customer service goals and financial performance measures in setting the PEP level. The benefits of the current program goals and objectives merit full recovery of the expense as it provides benefits to the customers and doesn't provide for unreasonable salary and wage expense.

Q. Do either Staff or RUCO believe that UNS Electric should eliminate the PEP program or state that it is not beneficial to customers?

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

Q. Does the UNS Electric PEP program resemble APS' Variable Cash Compensation Plan?

A. Similar to the APS Plan, the PEP rewards certain performance if the desired results, which are based on objective criteria, are achieved. The actual amount of the award depends upon the achieved results. The intent of the plan is to: link pay with business performance and personal contributions to results; motivate participants to achieve higher levels of performance; communicate and focus on critical success measures; reinforce desired business behaviors, as well as results; and to reinforce an employee ownership culture.

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

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

Q. What would happen if the PEP program is terminated?

A. If the PEP program is eliminated, there would be considerable increased pressure on base compensation. Employee base compensation would eventually have to be increased toward market to allow the Company to compete in attracting and retaining a skilled workforce. It is not reasonable to assume that the Company would be able to continue to attract employees at compensation rates well below the market median, without the PEP. So, Staff's recommendation will drive base compensation upward so that little to no compensation is variable or at risk. If such a result came to fruition, UNS Electric employees would not be as incentivized to meet performance based criteria designed to directly benefit UNS Electric customers.

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

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

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

Q. **Are the arguments you present on the Company's disagreement for disallowance of full recovery of PEP compensation essentially the same as you provided in the most recent UNS Gas case and the prior UNS Electric case?**

A. Yes. The arguments are essentially unchanged. The Company recognizes that recent Commission Decisions rejected the Company's position. The Company believes, however, that the PEP program is instrumental to saving costs for customers. The costs for the program are reasonable and prudent – and are all directly related to providing service to the customer. Therefore, the Company respectfully disagrees with the Commission's with the past orders for UNS Electric and UNS Gas on this issue.

2. <u>Supplemental Executive Retirement Plan ("SERP").</u>

Q. **Did Staff or RUCO take exception to the SERP expense contained within the test year?**

A. Yes. Both parties oppose any recovery of SERP expense allocated to UNS Electric, asserting that SERP expense is simply an excess benefit provided to select executives. The Company strongly opposes this representation. This expense and program is not an "excess" benefit or cost. It is the cost required to keep retirement benefits equal as a percentage of compensation for eligible employees.

Q. Do you agree with their adjustments to remove 100% of the SERP expenses allocated to UNS Gas?

A. No, I do not. They both have relied upon recent Commission decisions that disallowed the recovery of SERP expenses. The SERP program is a portion of the compensation and benefits package made available to UniSource officers. The level of compensation, incentives and benefits are all determined by the Compensation Committee of the Board that is comprised of independent Board members.

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

Q. Is SERP an excess benefit?

A. No. It simply keeps those individuals whose compensation level exceeds deductibility levels equal to those individuals whose compensation does not. The intention of the plan is to keep them equal.

Q. Are the arguments you present on the Company's disagreement for disallowance of full recovery of SERP expense essentially the same as you provided in the most recent UNS Gas case and the prior UNS Electric case?

A. Yes. The arguments are essentially unchanged. The Company recognizes that those recent Commission Decisions rejected the Company's position – but respectively continue to disagree for the reasons laid out above and continues to request recover of what they believe to be prudent and reasonable cost incurred in providing service to its customers.

C. <u>Rate Case Expense.</u>

Q. Did Staff or RUCO dispute the Company's pro forma rate case expense?

A. Yes. Staff and RUCO reduced the Company's proposed rate case expense based on the $300,000 rate case expense recovery over three years provided in the last UNS Electric rate case.

Q Do you agree with Staff and RUCO's recommendation of a normalized annual allowance of $100,000?

A. No. To the date of this testimony UNS Electric has already incurred over $436,000 in external rate case cost through the use of substantial TEP employee time (which is allocated to UNS Electric) and outside counsel. The final cost after hearing, briefing and open meeting will be in excess of UNS Electric' initial $500,000 estimate. These costs are the incremental real cost associated with filing a rate case by a utility that does not have its own regulatory counsel or rates group on hand and built into base rates.

Q. Do you have any other comments on this issue?

A. Yes. We are seeking less than the actual cost to the Company for rate case expenses. Rate cases are complicated proceedings involving numerous internal personnel (as shown by the witnesses in this case and the personnel assisting in preparing testimony and data request responses) and outside counsel and consultants. There is a significant amount of discovery that takes place. There are three rounds of testimony prepared by the Company. There is a hearing and then post-hearing briefing, exceptions and open meeting. UNS Electric must compensate TEP for the use of its personnel to avoid any subsidization of

UNS Electric by TEP. It also does not make economic sense for UNS Electric to develop its own stand-alone rate case team given the variety of issues arising in an electric rate case, such as procurement practices to personnel costs. UNS Electric believes that it is handling its rate cases in the most cost efficient manner possible and should be compensated for its actual costs.

D. <u>Membership Dues Expense – Edison Electrical Institute Dues.</u>

Q. Did Staff or RUCO reduce the Company's pro forma industry association dues expense?

A. Yes. Staff proposed an adjustment.

Q. Do you agree with Dr. Fish's adjustment to reduce the Company's test-year level of industry association dues?

A. Partially. Dr. Fish reduces all unadjusted industry association dues within the test year – which doesn't even include Edison Electric Institute ("EEI") dues. His basis for this adjustment is the prior UNS Electric rate case. In that decision, the Commission disallowed 49.93% of EEI dues because they were related to legislative advocacy, regulatory advocacy, advertising, marketing and public relations. The Commission determined that since these activities did not benefit ratepayers, the cost should not be borne by ratepayers.

Q. What part of Dr. Fish's adjustment do you disagree with?

A. Dr. Fish's adjustment has two errors. First, he applied the disallowance of 49.93% to the wrong amount of industry dues expense. He used total test year dues expense of $81,699 per FERC Form 1, Page 335. The Commission only applied the previous disallowance to EEI dues. Second, a pro forma adjustment for EEI dues was prepared and filed by the

Company, which Dr. Fish appears to have ignored. Instead of applying the reduction to EEI dues, Dr. Fish incorrectly applied that reduction to all industry dues such as the Western Electric Coordinating Council ("WECC"), which makes up almost $70 thousand of the $82 thousand test year total. The WECC dues are mandatory costs that UNS Electric has to incur to serve its customers. Dr. Fish's reduction, which eliminates about 50% of these normal and recurring cost should be backed out. Once that is done, I anticipate that the Staff Adjustment will be similar to the Company's adjustment.

Q. What was the Company's pro forma adjustment for EEI dues?

A. Test year expense was increased by $11,172 in the Miscellaneous Expense pro forma, which represented the Company's position on allowable test year EEI dues of the $12,800 incurred. Test year expense was increased in the pro forma adjustment because the EEI dues were actually not included in the UNS Electric starting test year expense as a result of a posting error; instead, the total dues of $12,800 remained on the books of TEP.

Q. Are you recommending an alternative level of expense in your Rebuttal filings for EEI dues?

A. No. But if the prior position of the Commission is applied to this case the disallowance of 49.93% of EEI dues would mean that only $6,409 would be added to test year expense for EEI dues rather than the $11,172 being requested by the Company. Or in the format of the Staff as a reduction to the Company's position $4,763 should be removed from the Company's pro forma expense level, not the incorrect amount of $40,792 proposed by Dr. Fish.

E. **Call Center Expense.**

Q. Did either Staff or RUCO reduce the Company's Call Center expense?

A. Only Staff proposes an adjustment to the Call Center expense -- RUCO did not contest the Call Center expense of $880,553. Staff reduced the Call Center expense being allocated to UNS Electric from TEP. TEP's Call Center serves UNS Electric, UNS Gas and TEP. Dr. Fish asserts that the increase in the expense level being allocated to UNS Electric is not commensurate with an increase in call volume and therefore is inappropriate. However, he did not dispute that the actual Call Center expense incurred by UNS Electric was inaccurate. Dr. Fish adjusted test year expense back to what he believed to be the level approved in the last rate case, which is based on a June 2006 test year.

Q. Do you agree with Dr. Fish's adjustment to reduce the test year expense for the Call Center?

A. No. Dr. Fish argues that the Company should not be permitted to recover the increase in Call Center expense since the last rate case. However, Dr. Fish ignores the fact that the primary costs of the call center - the systems to provide the service, wages and benefit cost associated with the employees of the call center have gone up significantly since the last test year. Wages alone have gone up over 3% annually and benefit cost have gone up over 10% annually in the last three years.

Q. Is Dr. Fish's adjustment calculated correctly?

A. No. Dr. Fish calculates his cost disallowance by comparing test year call center expense invoiced by TEP to the Company (based on data provided in response to Staff Data Request STF 3.30) to the allocated Call Center expense as calculated by RUCO in the prior UNS Electric rate case. The problem is that RUCO's calculation in the prior case did not represent test year actual expense for the last rate case – the actual test year expense for the

Call Center that was included in the revenue requirement approved by the Commission in the prior rate case was $781,077, as invoiced and expensed in the prior rate case test year.

Q. **What is the impact if Dr. Fish's adjustment is corrected to reflect the actual expense amounts from the prior rate case?**

A. Dr. Fish reduced test year expense by $281,582. His adjustment would be $99,456 had he used the correct expense in his calculation. However, even that adjustment is still improper because it simply does not reflect the actual Call Center expense incurred in the current test year.

Q. **Has Call Center expense decreased since the last rate case?**

A. No. The invoiced expense of $880,553 for the current test year indicates an approximate 4% annual increase in expense over the invoiced expense of $781,077 from the prior rate case test year. This is a reasonable increase given the increased investment, increased wage cost and increased benefit cost associated with the center. Therefore, the adjustment made by Dr. Fish should not be allowed and the test year Call Center expense of $880,533 should remain unadjusted.

F. <u>Bad Debt Expense.</u>

Q. **Mr. Dukes, do you agree with Dr. Fish's recommendation regarding Bad Debt Expense?**

A. No. Dr. Fish contends that test year bad debt expense is overstated. He believes this is the case because the Company's three-year Average Retail Expense Rate of 0.4718% for bad debt expense is based on gross revenue, but is applied to adjusted test year revenue. Evidently, Dr. Fish perceives an inconsistency in this calculation. However, this is the same bad debt expense methodology approved by the Commission in ACC Decision No.

70360 in the prior UNS Electric rate. This is also the same methodology that the Commission approved in prior rate orders for UNS Gas (Decision No. 70011) and TEP Decision No. 70628). Dr. Fish seems to be unaware that his analysis of bad debt expense calculation is inconsistent with prior Commission decisions. I believe that an historical percentage of bad debt expense as a percentage of gross revenue applied to adjusted pro forma revenue is a reliable indicator of bad debt expense to be included in cost of service.

Q. Has Dr. Fish presented his proposed pro forma adjustment to the Company's test year expense correctly in his schedules?

A. No. In addition to using an inconsistent method of calculating bad debt expense, Dr. Fish has included his proposed incremental pro forma adjustment (per Schedule THF C-12) to the Company's test year bad debt expense backwards in Schedule THF C-2. The Company's original pro forma adjustment reduced test year bad debt expense by $436,441. Dr. Fish calculated a pro forma bad debt expense resulting in a reduction of test year expense of $330,954. Because Dr. Fish's reduction of test year expense is $105,487 less than the reduction proposed by the Company, his incremental pro forma adjustment should be an increase to test year expense. However, Schedule THF C-2 shows Dr. Fish's adjustment as a decrease to test year expense. Because of this error, Staff's pro forma expense is understated by $210,974.

Q. Are there any other errors in the Bad Debt Expense pro forma adjustment prepared by Dr. Fish?

A. Yes. Schedule THF C-12 for the bad debt expense pro forma intends to use unadjusted retail revenues on Line 1, but the line label indicates the amount is adjusted. In addition, the gross revenues of $184,304,880 on Line 1 of Schedule THF C-12 that are referenced to Staff Schedule C-1 do not tie to the gross retail revenues of $184,572,743 from that schedule (total operating revenues less Sales for Resale). The difference between the incremental adjustment as proposed by Dr. Fish and the corrected adjustment using the actual gross retail revenue per Schedule C-1 is $2,065.

Q. Did RUCO contest the Company's Bad Debt expense?

A. No, it did not.

G. <u>Outside Legal Expense.</u>

Q. Mr. Dukes, do you agree with the recommendation of Dr. Fish regarding Outside Legal Expense?

A. No. Dr. Fish calculated his adjustment based on a three-year average legal expense that I do not agree with. In addition, his pro forma adjustment calculation includes errors.

Q. Please explain why you disagree with Dr. Fish's calculation of the three-year average?

A. The Company pro forma adjustment employed a three-year average legal expense composed of years 2005 through 2007. The expense for 2007 used in the average excluded amounts for prior UNS Electric rate case legal expense. Dr. Fish calculated his three-year average legal expense using 2005, 2006 and the 2008 test year. He excluded the reduced 2007 legal expense of $180,906 used by the Company and instead included test year legal expense of $28,830 in his calculation. Dr. Fish stated in his Direct Testimony at page 29, line 14, that the 2007 expense should be excluded because it is a "non-representative value". Dr. Fish did not provide any substantive reason that the 2007 legal expense of $180,906 is non-representative.

Q. Should Dr. Fish's revision to the three-year average be accepted?

A. No. His calculation does not allow adjusted test year expense to reflect a normal and recurring level of legal costs. In addition, the Company's adjusted test year expense was prepared and calculated in the same manner that was approved by the Commission for UNS Gas (Decision No. 70011), as noted in my Direct Testimony (at Page 25, Lines 19-20) and as corrected in response to RUCO Data Request 6.3. Dr. Fish's calculation is again inconsistent with prior Commission orders.

Q. What errors were included in Dr. Fish's proposed adjustment to test year legal expense?

A. His calculation had two errors. The first error is that, although Mr. Fish intended to make an incremental reduction to the Company's adjusted test year legal expense as filed, he included his total adjustment to unadjusted test year expense in Schedule THF C-2 as though it were incremental. Dr. Fish compared his $87,572 of allowed test year expense (using his three-year average as noted previously) to the actual test year expense of $28,830, resulting in an increase of $58,742 to unadjusted test year expense. If his adjustment had been presented correctly on an incremental basis, the expense reduction that should have been included in Schedule THF C-2 is $50,962. This amount is the difference between Dr. Fish's allowed expense of $87,572 (his three-year average) and the adjusted test year expense of $138,264 (the Company's three-year average).

Q. What is the second error Dr. Fish's proposed adjustment to legal expense?

A. The second error is a typographical mistake in Dr. Fish's three-year average in Schedule THF C-8. The schedule shows $87,552, when the correct result of the calculation is $87,572. As a result, the pro forma adjustment in Schedule THF C-8 of $58,722 is misstated and should be $58,742. However, as noted above, these amounts are incorrect when carried forward to Schedule C-2 because they are not incremental changes.

Q. Do these errors in Dr. Fish's pro forma adjustment have any impact on whether you accept the adjustment to the Company's test year expense?

A. No. Regardless of the amounts filed by Dr. Fish, or whether the amounts are correct, I do not agree with his proposed adjustment. As I noted previously, the Company has presented test year legal expense in accordance with prior Commission-approved methodology and to reflect a normal and recurring level of legal costs.

Q. Has RUCO proposed an adjustment to the Company's proposed normalized outside legal cost?

A. Yes. RUCO proposed using the three year average of 2006 thru 2008 with adjustments to exclude rate case support.

Q. Do you agree with RUCO's recommendation?

A. I would not oppose the Commission accepting RUCO's proposed pro forma level as it is provides for a reasonable level of normalized recovery being built into rates for outside legal cost.

H. <u>Fleet Fuel Expense.</u>

Q. Did Staff or RUCO reduce the Company's pro forma fleet fuel expense?

A. Yes. Staff proposed to reduce the Company's pro forma expense to reflect the reduced cost of fuel currently being incurred by the Company. RUCO did not contest the Company's Fleet Fuel expense.

Q. Do you agree with Staff's proposed adjustments to reduce fleet fuel expense?

A. No. I can agree that the test year level of expense may need to be adjusted given the extreme volatility of fuel expense, but I do not agree with the adjustments proposed by Staff.

Q. Please explain your concerns with Staff's proposed adjustment.

A. Staff used indexed rates from AAA.com website representing the year to date average cost for a gallon of gasoline and for a gallon of diesel. The problem with using these prices from a website for 2009: (1) they don't represent real cost incurred by UNS Electric in their more rural service territories, and (2) fuel prices are volatile and are already increasing as 2010 approaches.

Q. What is the Company's suggestion for adjusting test year fuel expense?

A. Fuel prices are highly volatile. The Company recommends using the three year average to normalize the cost based on recent actual cost incurred by UNS Electric. UNS Electric primary service territories are not located in Arizona's major urban communities. Consequently, UNS Electric's actual fuel cost tends to be higher than fuel costs in Tucson and Phoenix. The average price per gallon of fuel incurred by UNS Electric over the past three years and through September of this year within its service territory is $3.00 per gallon. This amount is known, measurable and provides compelling evidence of UNS Electric' normalized fuel expense. By applying the three year average cost to the three year average consumption the Company is suggesting a $56,333 reduction in test year fuel cost. If this three year average is not used, then the actual test year expenses should be used as reflected in UNS Electric' original Application. In no event should Staff's internet cost projections be used, as it is simply not reflective of actual cost incurred by UNS Electric.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

EXHIBIT

DJD-1

UNS ELECTRIC, INC.
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2008
INCLUDING BLACK MOUNTAIN GENERATING STATION

	UNSE	ACC	RUCO	UNSE		
	As Filed	As Filed	As Filed	Revised		
	4/30/09	11/6/09	11/6/09	12/11/09	Summary	Witness
Original Cost Rate Base - Unadjusted	$164,679,539	$164,679,539	$164,679,539	$164,679,539		Dukes
Rate Base Adjustments						
Acquisition Discount Adjustment	8,355,383	8,355,383	8,355,383	8,355,383	No change	Dukes
Post-Test Year Non-Revenue Plant in Service (Staff & RUCO)	7,263,614	-	-	7,263,614	Staff & RUCO disallowed Post-Test Year Non-Revenue Plant in Service.	Dukes
Accumulated Deferred Income Taxes	(684,777)	(684,777)	(684,777)	(684,777)	No change	Kissinger
Working Capital (Staff & RUCO)	(3,794,846)	(3,855,871)	(3,794,846)	(3,925,045)	Staff & RUCO adjusted cash working capital for the impact of the proposed adjustments to operating revenue and expense.	Dukes
BMGS Plant in Service (Staff)	61,970,352	-	61,970,482	61,970,352	Staff disallowed all BMGS pro formas. RUCO allowed all of BMGS in the revenue requirement.	Grant
BMGS Working Capital (Staff)	(580,420)	-	(580,420)	(580,420)	Staff disallowed all BMGS pro formas. RUCO allowed all of BMGS in the revenue requirement.	Grant
Total Adjustments	72,529,306	3,814,735	65,265,822	72,399,107		
Pro Forma OCRB	237,208,845	168,494,274	229,945,361	237,078,646		
Proposed Rate of Return	9.04%	8.40%	8.06%	9.04%	Staff ROE 10% (midpoint of 9.5% & 10.5%); RUCO ROE 9.25%, Company ROE 11.4%	Grant
Required Operating Income	$21,443,680	$14,153,519	$18,533,596	$21,431,910		

UNS ELECTRIC, INC.
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2008
INCLUDING BLACK MOUNTAIN GENERATING STATION

	UNSE	ACC	RUCO	UNSE		
	As Filed	As Filed	As Filed	Revised		
	4/30/09	11/6/09	11/6/09	12/11/09	Summary	Witness
Original Operating Income - Unadjusted	$9,786,382	$9,786,382	$9,786,382	$9,786,382		
Operating Income Adjustments						
Operating Revenue Adjustments						
Retail Revenue & Purchased Power Annualization	10,733,456	10,733,456	10,733,456	10,733,456	No change	Dukes
Wholesale Rev & Purch Power	(10,168,115)	(10,168,115)	(10,168,115)	(10,168,115)	No change	Dukes
Weather Normalization	(1,017,300)	(1,017,300)	(1,017,300)	(1,017,300)	No change	Erdwurm
Customer Energy Annualization & Customer Demand Normalization	(2,820,565)	(2,820,565)	(2,820,565)	(2,820,565)	No change	Erdwurm
Normalization of Rev & Exp for Fuel and PPFAC	(29,192,263)	(29,192,263)	(29,192,263)	(29,192,263)	No change	Dukes
CARES Discounts (Staff)	(61,797)	-	(61,797)	(61,797)	Staff disallowed the UNSE operating revenue adjustment for CARES discounts.	Erdwurm
DSM & Renewables Revenue & Expense	(1,458,039)	(1,458,039)	(1,458,039)	(1,458,039)	No change	Dukes
Total Adjustments to Operating Revenues	(33,984,623)	(33,922,826)	(33,984,623)	(33,984,623)		
Operating Expense Adjustments						
Retail Revenue & Purchased Power Annualization	(956,469)	(956,469)	(956,469)	(956,469)	No change	Dukes
Wholesale Rev & Purch Power	(10,168,115)	(10,168,115)	(10,168,115)	(10,168,115)	No change	Dukes
Weather Normalization	(830,613)	(830,613)	(830,613)	(830,613)	No change	Erdwurm
Customer Energy Annualization & Customer Demand Normalization	(1,079,814)	(1,079,814)	(1,079,814)	(1,079,814)	No change	Erdwurm
Normalization of Rev & Exp for Fuel and PPFAC	(19,024,147)	(19,024,147)	(19,024,147)	(19,024,147)	No change	Dukes
DSM & Renewables Revenue & Expense	(1,626,826)	(1,626,826)	(1,626,826)	(1,626,826)	No change	Dukes
Payroll Expense (RUCO)	220,252	220,252	79,628	220,252	RUCO disallowed the increase for the expected 3% wage increase for 2010.	Dukes
Payroll Tax Expense (RUCO)	55,054	55,054	35,430	55,054	RUCO adjusted payroll tax expense related to the disallowed 2010 payroll expense increase.	Dukes
Pension & Benefits (RUCO)	210,866	210,866	-	210,866	RUCO disallowed the increase for expected pension & benefits expense as of January 1, 2009 since it was "anticipated" and thus estimated.	Dukes
Post Retirement Medical	161,929	161,929	161,929	161,929	No change	Dukes
Incentive Compensation - PEP Expense (Staff)	-	(132,159)	-	-	Staff disallowed 50% of incentive compensation expense in accordance with ACC Decision No. 70360 in the prior UNSE rate case.	Dukes
Payroll Tax - PEP Expense (Staff)	-	(10,110)	-	-	Staff reduced payroll tax expense related to the disallowed incentive compensation expense.	Dukes
SERP Expense (Staff)	-	(102,142)	-	-	Staff disallowed 100% of SERP expense in accordance with ACC Decision No. 70360 in the prior UNSE rate case.	Dukes

UNS ELECTRIC, INC.
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2008
INCLUDING BLACK MOUNTAIN GENERATING STATION

	UNSE	ACC	RUCO	UNSE		
	As Filed	As Filed	As Filed	Revised		
	4/30/09	11/6/09	11/6/09	12/11/09	Summary	Witness
Call Center Expense (Staff)	-	(281,582)	-	-	Staff disallowed the increase in call center expense over the amount presented in the UNSE prior rate case, citing a decrease in call center call volume.	Dukes
Rate Case Expense (Staff & RUCO)	138,890	72,223	72,223	138,890	Staff and RUCO disallowed $200,000 of the $500,000 proposed test year rate case expense.	Dukes
Bad Debt Expense (Staff)	(436,441)	(541,928)	(436,441)	(436,441)	Staff reduced bad debt expense for "inconsistency" in application of the bad debt ratio based on gross revenues that was applied to adjusted revenues.	Dukes
Interest on Customer Deposits	(145,701)	(145,701)	(145,701)	(145,701)	No change	Dukes
Workers Compensation	(115,528)	(115,528)	(115,528)	(115,528)	No change	Dukes
Miscellaneous Expenses - Other (Staff & RUCO)	(451,888)	(412,348)	(484,460)	(451,888)	Staff reduced industry association dues by 49.93% as approved by the ACC in Decision No. 70360 in the prior rate case, but applied the percentage to total dues per FERC Form 1 and incorrectly did not include amounts for the EEI dues expense that UNSE added to test year expense (in addition to the FERC Form 1 amount). RUCO disallowed 40% of the $12,800 of the total EEI dues as presented in the original UNSE pro forma adjustment (UNSE added $11,172 of the EEI dues to the test year). RUCO also reduced the UNSE pro forma for postage expense by disallowing the May 2009 postage increase as being too far outside of the test year.	Dukes
Miscellaneous Expenses - Outside Legal Expense (Staff & RUCO)	109,434	(29,620)	76,503	109,434	Staff reduced outside legal expense to reflect a 3-year average expense based on 2005, 2006 and 2008, citing 2007 expense as non-representative (Staff's calculation had errors in the their pro forma adjustment calculation). RUCO reduced outside legal expense to reflect a 3-year average expense based on 2006, 2007 and 2008.	Dukes
Fleet Fuel (Staff)	-	(75,798)	-	(56,333)	Staff reduced test year expense for lower average gasoline & diesel fuel prices based on 2009 fuel price data. UNSE added a pro forma adjustment to reduce test year expense to reflect the average fuel cost based on data from 2007 through October 2009.	Dukes
Wholesale Credit Support	-	-	-	195,500	UNSE added a pro forma adjustment to increase test year expense for wholesale credit support.	Grant
A&G Expense Capitalized	(229,429)	(229,429)	(229,429)	(229,429)	No change	Dukes
Depr & Property Tax for Post TY Non-Rev. Plant in Service (Staff & RUCO)	442,526	-	-	442,526	Staff and RUCO disallowed Post-Test Year Non-Revenue Plant in Service.	Kissinger
Depr & Amort Expense Annualization	(507,792)	(507,792)	(507,792)	(507,792)	No change	Kissinger
Property Tax Expense (RUCO)	(7,358)	(7,358)	144,026	105,181	RUCO adjusted the property tax assessment ration from 21% to 22%. UNSE revised property tax expense to reflect property tax rates for 2009 (a revision from the original adjustment based on property tax rates for 2008).	Kissinger
Income Taxes (Staff & RUCO)	39,582	521,441	39,582	(55,652)	Changes are recalculations based on other pro forma adjustments. Staff's calculation of revised income tax expense used the incorrect tax rate and excluded the impact of cash working capital and synchronized interest.	Kissinger

UNS ELECTRIC, INC.

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED DECEMBER 31, 2008

INCLUDING BLACK MOUNTAIN GENERATING STATION

	UNSE	ACC	RUCO	UNSE		
	As Filed	As Filed	As Filed	Revised		
	4/30/09	11/6/09	11/6/09	12/11/09	Summary	Witness
BMGS PPA Adjustment (Staff)	(10,960,779)	-	(10,960,779)	(10,960,779)	Staff disallowed all BMGS pro formas. RUCO allowed all of BMGS in the revenue requirement.	Dukes
BMGS O&M Expense (Staff)	1,158,464	-	1,158,464	1,158,464	Staff disallowed all BMGS pro formas. RUCO allowed all of BMGS in the revenue requirement.	Dukes
BMGS Depr & Amort Expense Annualization (Staff)	1,649,496	-	1,649,496	1,649,496	Staff disallowed all BMGS pro formas. RUCO allowed all of BMGS in the revenue requirement.	Kissinger
BMGS Property Tax Expense (Staff)	419,305	-	420,211	419,305	Staff disallowed all BMGS pro formas. RUCO allowed all of BMGS in the revenue requirement.	Kissinger
BMGS Income Taxes (Staff)	2,079,821	-	2,079,821	2,079,821	Staff disallowed all BMGS pro formas. RUCO allowed all of BMGS in the revenue requirement.	Kissinger
Synchronize Income Taxes (RUCO)	-	-	114,778	-	RUCO adjusted synchronized interest related to interest on debt as a separate expense instead of including it in the income tax adjustment.	N/A
Total Adjustments to Operating Expense	(39,855,281)	(35,035,714)	(40,534,023)	(39,698,809)		
Total Net Adjustments	5,870,658	1,112,888	6,549,400	5,714,186		
Adjusted Operating Income	$15,657,039	$10,899,270	$16,335,782	$15,500,568		
Operating Income Deficiency	$5,786,641	$3,254,249	$2,197,814	$5,931,342		
Fair Value Addition (Pre-Tax)	$2,463,680	$1,339,997	$579,160	$2,318,979	Assuming acception of the Company's pro forma adjustments and fair value rate base - the Company has limited the fair value addition so as to not exceed the requested increase noticed to customers.	Grant
Fair Value Operating Income Deficiency	$8,250,321	$4,594,246	$2,776,974	$8,250,321		
Gross Revenue Conversion Factor	1.6363	1.6363	1.6363	1.6363		Kissinger
Increase in Gross Revenue Requirement	$13,500,000	$7,517,565	$4,543,963	$13,500,000		

EXHIBIT

DJD-2

UNS ELECTRIC, INC.
RATE CASE DOCKET NO. E-04204A-09-0206
TEST YEAR ENDED DECEMBER 31, 2008
CORRECTIONS TO STAFF PRO FORMA ADJUSTMENTS, SCHEDULES, & DIRECT TESTIMONY

Description	As Filed	Corrected	Difference	Explanation
Pro Forma Adjustments & Schedules - Rate Base				
Cash Working Capital	($61,025)	$79,556	$140,581	Staff included the adjustment to cash working capital as calculated in Schedule THF B-3 in the wrong direction in Schedule THF B-2 (and Schedule THF B-1). The adjustment as calculated was a smaller decrease cash working capital than originally filed by UNSE, which should have resulted in an incremental increase, not a decrease as presented by Staff. In addition, this calculation had several other errors, as noted below. Staff incorrectly omitted the impact of the decrease in rate base for the removal of Post-Test Year Non-Revenue Producing Plant, the impact of the adjustment for cash working capital, the impact of the CARES revenue adjustment on revenue-related taxes, the impact of income tax expense based on the incremental O&M adjustments, and the impact of synchronized interest from the cash working capital calculation (these impacts assume use of the UNSE cash working capital & current income tax calculation). Staff also removed a rounding adjustment from a Lead/Lag Factor for Property Taxes that UNSE had included to ensure that the entire calculation tied out (the manual adjustment was +.0013499) and Staff Schedule THF B-3 had a formula error in the "Adjusted Amount" column for property tax, which affected the cash working capital calculation. The "Corrected" amount is based on the UNSE calculation model with Staff cash WC errors corrected.
Total Original Cost Rate Base Corrections	($61,025)	$79,556	$140,581	
Fair Value Rate Base As Filed by Staff			$257,827,428	From Schedule THF A-1
Corrected Fair Value Rate Base			$257,968,009	Inclusive of the Cash Working Capital correction - which is equal for fair value.
Fair Value ROR Recommended by Staff	6.01%	6.14%	0.13%	The Proposed FVROR presented on page 27, Direct Testimony of Staff Witness, David C. Parcell, has an error in the calculation 32.79% x 1.50% = 0.49%, not 0.34%. The correction would change the FVROR to 6.14% as opposed to 5.99%. Dr. Fish's Schedule A actually calculated the additional fair value dollars to equate to a 6.01% return on fair value rate base, not 5.99%. This is the correction to the 6.14% recommended by Witness Parcell.
Additional Fair Value Adjustment			$335,358	
Addl Required Revenue for Original Cost Adj - Cash WC		8.4%	$11,809	
			$347,167	
Gross Revenue Conversion Factor			1.6363	
Addditional Revenue			$568,070	

UNS ELECTRIC, INC.
RATE CASE DOCKET NO. E-04204A-09-0206
TEST YEAR ENDED DECEMBER 31, 2008
CORRECTIONS TO STAFF PRO FORMA ADJUSTMENTS, SCHEDULES, & DIRECT TESTIMONY

Description	As Filed	Corrected	Difference	Explanation
Pro Forma Adjustments & Schedules - Revenue Impacts				
Incentive Compensation PEP	($132,159)	($127,063)	$5,096	Staff incorrectly used the FERC Form 1 book-to-tax reconciling amount for incentive compensation to reduce test year expense instead of the actual test year book expense as provided in response to Staff Data Request STF 1.62.
PEP Payroll Tax Expense	($10,110)	($9,720)	$390	
Call Center Expense	($281,582)	($99,456)	$182,126	Staff incorrectly used $598,951 of call center expense calculated by RUCO in the prior UNS Electric rate case as the basis for comparison with the $880,553 of current test year expense obtained from invoices. The correct amount of prior rate case expense is $781,077 based on invoices provided in data request responses in that proceeding, which indicates an average 4% yearly growth in expense over the prior test year.
Industry Association Dues	($40,792)	($4,763)	$36,029	Staff's pro forma adjustment included two errors. Staff incorrectly used total Industry Association Dues of $81,699 per FERC Form 1 rather than the EEI dues of $12,800 as provided in the UNS Electric pro forma adjustment (as filed) as the basis for applying the disallowed dues percentage of 49.93%. In ACC Decision No. 70360, the ACC approved the disallowance of 49.93% of EEI dues, not total industry association dues. A second error is that Staff also neglected to include the UNSE pro forma adjustment for EEI dues in Staff's adjustment, since the EEI dues were not included in the $81,699 (because the dollars of EEI dues expense remained on TEP books as a result of a posting error during the test year (UNSE increased expense for the allowable portion of the $12,800 of EEI dues in the pro forma adjustment as filed).
Outside Legal Expense	($58,722)	($50,692)	$8,030	Staff's pro forma adjustment included two errors. The first error is that the actual pro forma adjustment reducing legal expense by $58,722 (should be $58,742) is presented as an incremental adjustment but is really the difference between Staff's 3-year average and the UNSE actual test year expense of $28,830 prior to the UNSE pro forma adjustment that increased test year expense to UNSE's 3-year average expense of $138,264. Staff intended for this to be an incremental adjustment, and if it had been done correctly, the adjustment would have been an incremental reduction of test year expense of $50,692, which is the difference between Staff's allowable 3-year average expense of $87,572 and the UNSE 3-year average expense of $138,264. The second was a typo in the 3-year average expense of $87,572 as noted in Dr. Fish's written testimony (see note below for errors in testimony text), but incorrectly shown as $87,552 in Schedule THF C-8 and Schedule THF C-2.

UNS ELECTRIC, INC.
RATE CASE DOCKET NO. E-04204A-09-0206
TEST YEAR ENDED DECEMBER 31, 2008
CORRECTIONS TO STAFF PRO FORMA ADJUSTMENTS, SCHEDULES, & DIRECT TESTIMONY

Description	As Filed	Corrected	Difference	Explanation
Bad Debt Expense	($105,487)	$105,487	$210,974	Staff included the proposed adjustment as presented in Schedule THF C-12 in the wrong direction in Schedule THF C-2. The adjustment was a smaller decrease in test year expense than originally filed by UNSE, which should have resulted in an incremental increase, not a decrease as presented by Staff.
Normalized Income Tax Expense - Correction to Staff's As Filed Calculation	$481,859	$606,035	$124,176	Recalculated normalized income tax expense based on the adjusted operating income before income taxes in Staff's filing of $13,502,396 less sychronized interest of $6,436,481 times the effective tax rate 38.598%. This gives you a normalized income tax expense of $2,727,302 -vs- Company's pro forma level of $2,121,267. Staff's incremental adjustment should have been $606.035.
Normalized Income Tax Expense - Incremental Change for Corrections in this Summary	$606,035	$433,110	($172,925)	Recalculated normalized income tax expense based on the adjusted operating income after <u>corrections above</u> which produces operating income before income tax of $13,059,751 less sychronized interest of $6,441,851 times the effective tax rate 38.598%. This gives you a normalized income tax expense of $2,554,377 -vs- Staff's corrected pro forma level of $2,727,302.
Total Expense Corrections	$459,042	$852,938	$393,896	Total Increase to Expense (Decrease in Operating Income)
Gross Revenue Conversion Factor			1.6363	
Additional Revenue			$644,532	
Total of the Additional Increase			$1,212,602	

<u>Errors Testimony Text & Schedule Presentation</u>

Operating revenue deficiency of $4,574,216 as stated on Page 7, Line 8, is incorrect and does not match the amount on Schedule A-1 of $4,594,246.

The legal expense adjustment of $58,722 as stated on Page 28, Line 19, is incorrect and follows the incorrect pro forma amount in Schedule THF C-8. However, the Staff 3-year average expense allowed of $87,572 on Page 28, Line 25, is correct, but the pro forma Schedule THF C-8 incorrectly shows $87,552. In addition, the adjustment of $58,722 on Page 29, Line 3, is stated incorrectly.

On Schedule THF C-1, the amounts for Staff's incremental adjustments carry over to the wrong lines from Schedule THF C-2; however, the adjusted totals are correct.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

Rebuttal Testimony of

D. Bentley Erdwurm

on Behalf of

UNS Electric, Inc.

December 11, 2009

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is D. Bentley Erdwurm. My business address is One South Church Avenue, Tucson, Arizona 85701.

Q. What is the Purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to Arizona Corporation Commission ("Commission") Staff ("Staff") and Residential Utility Consumer's Office ("RUCO") testimony on rate design and cost of service. The key issues are:

CARES:

Both Staff witness Mr. William C. Stewart and RUCO witness Dr. Ben Johnson presented Direct Testimony on the CARES program for low-income customers. Staff has recommended that low-income programs be expanded and that CARES customers be allowed to benefit from downward purchased power and fuel adjustor clause ("PPFAC") adjustments but be shielded from upward PPFAC adjustments. RUCO opposes the expansion of low-income programs because of the detrimental impact on other customers on the system. UNS Electric is not necessarily opposed to offering some type of discounts to customers with household incomes between 150% and 200% of poverty under appropriate circumstances. However, expansion of the program could be costly and UNS Electric stands by its position that its support of expanded low income programs is contingent on program costs being fully recovered from other retail customers on a timely basis. UNS Electric opposes Staff's proposal for CARES customers to be subject only to downward adjustments of the PPFAC rate without also being subject to upward adjustments. UNS Electric maintains its proposal for CARES customers to have a PPFAC rate frozen at $0 per kWh.

Additionally, Dr. Thomas H. Fish, witness for Staff, recommends disallowance of a $61,797 adjustment to operating income, because he believes that it constitutes a double recovery of weather and customer annualization adjustments applicable to CARES. There is no double recovery and the Company's proposed adjustment should be accepted.

Residential Customer Charges and Inverted Block Rates:

Staff is supportive of UNS Electric's proposed residential rate design. UNS Electric disagrees strongly with RUCO's proposed rate design. RUCO proposes that residential customer charges decrease, rather than increase as proposed by UNS Electric. RUCO supports adding a third residential rate tier and making the rate more inverted – that is, making the spread between the lower tier price per kWh and the upper tier price per kWh greater. RUCO does not provide any analysis on the impact of its rate design on revenue when, in fact, its proposed residential rate design deprives UNS Electric of a reasonable opportunity to earn its approved return. RUCO's rate design creates a mismatch between revenue collection and cost incursion. Moreover, RUCO's proposal is counter to the energy efficiency policy objectives of the Commission.

Time of Use ("TOU"):

UNS Electric proposes increasing the rate differentials (between on-peak and off-peak) in its existing TOU rates. UNS Electric also proposes a new Super-Peak option where a single hour is priced at a significantly higher rate. Staff supports the Company's proposals. RUCO, however, believes there is need for more analysis before increasing the rate differentials. The Company believes increasing the differentials will encourage more customers to shift load from peak periods and should result in larger savings for customers who keep their peak usage relatively low. RUCO is also concerned about the Super-Peak option and proposes changes that would bring real-time pricing elements into the TOU program. The Company plan as proposed will be less expensive to implement and easier to understand than real-time pricing, and therefore should be implemented as proposed. Even so, implementation of UNS Electric's proposed Super-Peak option will not preclude future implementation of a real time pricing program because the programs are not mutually exclusive.

II. RESIDENTIAL RATE DESIGN.

Q. Please briefly describe UNS Electric's current residential rate.

A. UNS Electric's residential rate is structured as follows:

- A Monthly Customer Charge at $7.50 per month; and
- An inclining (inverted) block (tier) rate structure with a first, lower-priced tier applicable to consumption up to 400 kWh per month, and a second, higher-priced tier applicable to consumption in excess of 400 kWh per month.

Q. When was the inverted block rate structure implemented?

A. The structure was implemented June 1, 2008, in compliance with Decision No. 70360 (May 27, 2008) in UNS Electric's last general rate case.

Q. What is the purpose of an inclining block rate structure?

A. The tiered structure was implemented to encourage conservation by making the incremental price electricity rise at higher usage levels. Moreover, the structure allows customers to purchase up to 400 kWh - energy for the most basic needs - at a reduced price.

Q. UNS Electric proposes to increase the residential monthly customer charge to $8.00 from $7.50. How does that charge compare to the residential customer charges of other Arizona electric utilities?

A. The $8.00 residential customer charge is in line with the customer charges of other electric utilities, including:

- Arizona Public Service Company ("APS") ($7.50 per month for non-Time of Use rate plans to $15.00 per month for TOU rates. A substantial percentage of APS residential customers are TOU customers);
- Tucson Electric Power Company ("TEP") ($7.00 per month for non-TOU to $8.00 per month for TOU); and
- Salt River Project ("SRP") ($12.00 per month for non-TOU to $15.00 per month for TOU in some months).

UNS Electric is also proposing an $8.00 monthly residential charge for its proposed residential TOU rates.

Considering the number of residential customers – both non-TOU and TOU – and the number of customers served by the three aforementioned companies, the proposed UNSE residential monthly customer charge of $8.00 is actually *less than* the weighted average customer charge paid by residential customers of the three companies listed above.

A. <u>Response to RUCO Witness Dr. Ben Johnson – Residential Rate Design</u>.

Q. Dr. Johnson has proposed that the residential customer charge be decreased from $7.50 per month to $5.00 per month, and has proposed adding a third rate block priced at two cents per kWh over the first rate block. Do you agree with these residential rate design recommendations?

A. No. The Company appreciates Dr. Johnson's acknowledgement that progress has been made in promoting conservation in rates. Dr. Johnson, however, has not adequately considered the adverse potential impact of his proposals on UNS Electric's financial condition. Dr. Johnson's proposals do not align UNS Electric's need to have a reasonable opportunity to recover its revenue requirement with efforts to promote energy efficiency and conservation – including development of enhanced Demand Side Management ("DSM") programs.

The Company incurs fixed costs for establishing and maintaining service. These actual embedded costs include costs of metering, meter-reading, billing and customer service, and customer-specific equipment at the customer's premises. Dr. Johnson is attempting to incorporate marginal costing principles into unbundled rates that instead should reflect the average embedded costs of providing customer-related services. By doing so, his proposed residential customer charge is substantially understated and does not cover the costs of items that are typically classified as customer-related and appropriate for inclusion in the customer charge.

Dr. Johnson's methodology is also inconsistent with methodologies previously used to derive customer charges for UNS Electric. The Company's customer charge methodology is an accepted embedded average cost approach that restrains the size of customer charges. The cost-of-service methodology was not an issue in the last general rate case for UNS Electric or TEP.

Q. What concerns do you have with Dr. Johnson's proposal?

A. Dr. Johnson seeks to radically shift recovery away from the customer charge to the energy charge. In doing so, he significantly understates the residential customer charge. This results in a mismatch between revenue collection and cost causation. Shifting customer-related costs to energy (per kWh) charges leads to the Company under-recovering when sales are relatively low, regardless of whether low sales are attributable to weather, the economy, conservation and energy efficiency or other factors. Likewise, over-recoveries result when sales are relatively high. Maintaining a cost-based residential customer charge – like the one proposed by UNS Electric – helps mitigate periodic swings in revenue because of volatility in usage. In short, it is important that a rate design that promotes conservation also gives some measure of revenue stability for the Company.

Q. Doesn't Dr. Johnson's rate design provide customers a greater incentive to conserve, as he states on pages 18 and 21 of his Direct Testimony?

A. Yes, but the problem is that his rate design proposal will also preclude providing UNS Electric a reasonable opportunity to earn its approved return. UNS Electric's proposed residential rate design provides a balance between the conservation goal and providing the Company a fair opportunity to recover its costs. Dr. Johnson's residential rate design proposal, in contrast, ignores customer-related costs that the Company incurs for every customer that receives service from UNS Electric. I believe Dr. Johnson's rate design is confiscatory in its approach.

Q. Why is Dr. Johnson's proposed residential rate design confiscatory?

A. When recovery of costs is shifted from customer charges to energy charges (*i.e.* volumetric charges), these costs will go unrecovered if kWh sales levels are below the test-year levels used to design rates. Simply put, no sales equals no recovery. Given that the Commission is considering energy efficiency rules that would impose aggressive targets to reduce energy consumption, it would become difficult (if not impossible) for any electric utility to recover its fixed costs through energy charges. What makes Dr. Johnson's proposal especially troubling is how radical a shift in recovery he is proposing from the customer charges to the energy charges.

Dr. Johnson has loaded up cost recovery on kWh sales in excess of 800 kWh per month. In other words, a significant portion of the Company's revenues will be obtained through a third tier. Under Dr. Johnson's approach, sales in this third tier (the highest priced tier) will decline more than lower tier sales. Sales revenue from the third tier will not be collected, as a significant portion of third tier sales will be effectively eliminated; thus, the Company cannot recover its revenue requirement. In short, with Dr. Johnson's proposal, sales of electricity will decline to the point that the Company will have no opportunity to achieve its revenue requirement and earn a reasonable return. Again, no sales equals no recovery.

UNS Electric is further at risk taking into account how leveraged UNS Electric's earnings already are to volumetric (kWh) sales and energy consumption, and how a seemingly small reduction in volumetric sales can greatly reduce those earnings. For example, a reduction in kWh sold of just 3% across all classes (except lighting) can lead to a pre-tax earnings reduction of approximately $1.6 million per year. Dr. Johnson provides no detailed analysis to quantify the potential for substantial loss of earnings within his pre-filed testimony. He also did not propose an adjustment to normalized sales that would reflect the anticipated reduction in load due to conservation resulting from his proposed rate design.

Q. **What is the effect of a rate structure where the vast majority of costs are recovered through volumetric rates as Dr. Johnson suggests?**

A. Under the current rate and regulatory structure, sales reductions for any reason (including conservation and energy efficiency) mean margin loss to UNS Electric. Dr. Johnson's residential rate design recommendations exacerbate the problem. His proposed rate design will drive UNS Electric's need to recover its revenues towards increasing use of power and away from conservation.

Q. **What would you recommend to the Commission in order to align the goal of conservation with the Company's need to have an opportunity to recover its costs of providing service?**

A. UNS Electric needs a rate structure that recognizes it is a provider of electric service, and not simply a seller of a commodity. That rate structure should also align important policy goals (*e.g.*, conservation and efficiency) with a financially-healthy public service corporation. Avoiding artificially low customer charges – and implementing customer charges that more fully recover costs – is consistent with that new business model. Customer charge increases are one of the simplest ways to move profitability away from energy consumption and sales. In other words, the Commission should make the correct level of fixed cost recovery (revenue collected to recover fixed costs) more independent of sales being at a certain level. The Company believes that effective conservation programs occur through DSM and energy efficiency. Dr. Johnson's rate design, however, would create a significant disincentive for the Company to aggressively pursue creative and effective conservation programs.

Q. Do you have comments about other aspects of Dr. Johnson's Direct Testimony?

A. Yes. Dr. Johnson makes a specific recommendation not to classify as customer-related two cost components, Account 904 "Uncollectible Accounts" and Account 431 "Customer Deposit Interest". The calculation of customer-related costs serves as the cost-of-service basis for proposed customer charges.

Q. What is the Company's response?

A. UNS Electric agrees with Dr. Johnson's position on Uncollectible Accounts. The Company is not opposed to Dr. Johnson's proposal regarding Interest on Customer Deposits, so long as the same approach applies to the Customer Deposits themselves, a credit to rate base. However, these are minor issues. These modifications to the class cost of service study result in changing the residential customer charge calculation from $7.65 to $7.74 (an increase of nine cents). UNS Electric's proposal to increase the residential customer charge from $7.50 to $8.00 per month remains unchanged.

Q. Please comment on Dr. Johnson's testimony regarding the relationship between average total price of electricity and usage.

A. Dr. Johnson, in his Direct Testimony at pages 20-21, discusses and makes calculations regarding average price per residential kWh. He does this to show that he would like to see an increase in the average *total* price (total price includes both customer and energy charges measured as cost per kWh) as usage increases over a greater range of usage – and not just an increase in the volumetric price (energy charges only) as usage increases. But requiring average total price (including only the energy charges) to increase with usage over the entire range of usage is only possible if the customer charge is set to zero. That proposal would be extreme and Dr. Johnson does not go that far in his recommendations.

However, a pro-conservation residential rate design requires only that customers see an increasing volumetric price (energy charges only). UNS Electric's proposed residential inclining block residential rate accomplishes exactly this. Specifically, the incremental price (*i.e.* marginal price) of electricity increase as residential usage increases into the second tier.

Consumption decisions are most influenced by marginal cost – meaning that an additional unit of product is consumed only when marginal utility (benefit) to the consumer is greater than or equal to marginal cost to the consumer. In this case, marginal cost is UNS Electric's energy charge – the incremental price. Dr. Johnson's lengthy discussion of average total price (includes both customer and energy charges) – moves the focus away from the more appropriate incremental volumetric price. UNS Electric proposes a rate design where the volumetric charge (the energy charge) is greater in the second tier; the marginal cost to the consumer increases as usage increases. This makes UNS Electric's rate design pro-conservation - despite Dr. Johnson's testimony about average total price.

B. <u>Summary of Staff Rate Design Recommendations.</u>

Q. Has Staff supported UNS Electric's residential rate design proposals?

A. Yes. Staff witness Mr. William C. Stewart, unlike Dr. Johnson at RUCO, has supported the Company's residential rate design and customer charge proposals. However, Mr. Stewart's Direct Testimony does diverge from the UNS Electric position on the issue of the distribution of the rate increase across classes ("Revenue Spread") and the treatment of the CARES rate. I discuss this issue in more detail in the next section.

III. REVENUE SPREAD.

Q. Please discuss "revenue spread" across classes.

A. UNS Electric proposed that all classes receive an equal percentage increase in adjusted test-year revenue (9.21% based on the Company's request), with the exception of CARES customers, who receive a 9.41% *decrease*. This approach is consistent with what was approved in UNS Electric's last rate case – Decision No. 70360 (May 27, 2008) – and with the recent TEP rate case settlement – approved in Decision No. 70628 (December 1, 2008). However, both Staff and RUCO now express an interest in seeing revenue changes vary by rate class. UNS Electric is not necessarily opposed to varying percentage increases, so long as the maximum percentage increase assigned to any class is no more than 200% of the system average percentage increase. This helps avoid the risk of rate shock.

IV. CARES AND LOW-INCOME.

Q. What are Staff and RUCO positions regarding expanding the low-income program?

A. Staff supports the expansion of the low-income program from 150% to 200% of poverty level, and RUCO opposes the expansion. UNS Electric at this time is not taking a position in favor of or opposed to the expansion of the low-income programs, since no consensus has been reached on the issue. Additionally, UNS Electric is not opposed to some minor changes in the structure of the CARES program, as long as the Company can recover associated revenue shortfalls.

Q. Please discuss UNS Electric's response to Staff's CARES and low-income proposals.

A. At pages 7-8 of his testimony, Staff witness Mr. William C. Stewart agrees with the notion of expanding low-income program eligibility to customers whose income is 200%

of the poverty level. UNS Electric is not necessarily opposed to offering some type of discounts to customers with household incomes between 150% and 200% of poverty under appropriate circumstances. However, expansion of the program could be costly and UNS Electric stands by its position that its support of expanded low income programs is contingent on program costs being fully recovered from other retail customers on a timely basis. This is a prudent approach and eliminates the potential that any expansion of the program is confiscatory. Assuming new low-income discounts averaging $140 per customer per year, and 2,500 new participants, UNS Electric stands to lose $350,000 annually in pretax earnings. I assume that Staff agrees that expanded program costs should be recovered from other retail customers in a timely manner.

Additionally, UNS Electric is not opposed to some minor changes in the structure of the CARES program, as long as the Company can recover associated revenue shortfalls.

Q. **Please respond to Staff's recommendation concerning CARES customers and UNS Electric's PPFAC.**

A. Mr. Stewart for Staff, at page 7 of his Direct Testimony, proposes that CARES customers be subject to downward PPFAC adjustments, but that upward adjustments be capped. Given that CARES customers already enjoy a discount in base rates, such a proposal seems overly complicated and unfair to regular residential customers. It is unfair that other customers incur the costs for freezing the PPFAC rate at a rate no greater than zero for CARES customers, if the downward adjustments (*i.e.*, "negative rates" as Mr. Stewart puts it) are passed on to CARES customers. CARES customers cannot incur all of the benefit and none of the risk because other customers (mostly middle class customers) bear the entire burden with none of the reward. UNS Electric maintains its proposal to freeze the PPFAC rate at zero for CARES customers when new rates become effective.

Q. Staff Witness Dr. Thomas H. Fish recommends disallowance of a $61,797 adjustment to operating income because he believes that it constitutes a "double recovery" of customer annualization and weather normalization adjustments applicable to CARES. Do you disagree with Dr. Fish?

A. Yes. The Company's customer annualization and weather normalization adjustments for CARES customers were calculated using the regular residential rate RES 01 rather than the lower CARES rates. Consequently, the net customer and weather adjustment for CARES – a positive revenue adjustment - is higher (i.e., more positive) than it would have been had lower CARES rates been used in the calculation. The use of this larger customer and weather adjustment results in adjusted test-year CARES revenue being overstated relative to what it would have been had lower CARES rates been used in the adjustment calculation. In reality CARES customers *will* pay lower CARES rates, *not* the regular residential rate RES 01, and CARES revenue (based on adjusted sales) will be lower than the stated adjusted test-year CARES revenue. Absent any adjustment to recognize the lower CARES rates, UNS Electric will face a revenue shortfall. The $61,797 adjustment is necessary to offset this revenue shortfall. The $61,797 adjustment is the *only* adjustment recognizing that sales to CARES customers will in fact be discounted relative to regular residential rate RES 01. The adjustment is not a "double recovery" – it is a necessary step in the overall adjustment process. The $61,797 adjustment is appropriate and should be approved.

V. <u>COST ALLOCATION.</u>

Q. Has Staff or RUCO raised issues regarding the allocation of production or transmission cost?

A. Staff has not taken issue with the Company's position. Dr. Johnson discusses some of the problems in trying to allocate joint costs. I agree with Dr. Johnson that there is no single correct way to allocate a joint cost. I also agree that the Average and Peak method, as described in my Direct Testimony, is a far better approach for production plant allocation than a purely peak-oriented methodology. Dr. Johnson's discussion of production and transmission cost allocation notwithstanding, he does not appear to be recommending changes in UNS Electric's production and transmission cost allocation approaches. His point appears to be that the Commission has some flexibility to deviate from the results of the cost allocation study in the design of rates. UNS Electric does not disagree with that, but does disagree with what seems to be Dr. Johnson's abandonment of cost of service as a basis to formulate customer charges.

In several places in his testimony, Dr. Johnson notes that UNS Electric purchases the majority of its power requirements from the wholesale market and that the portion that is self-generated is relatively small. In the last rate case, the Commission ordered that purchased power be allocated solely on energy and not on average and peaks. UNS Electric used 100% energy as the basis for purchased power allocation in this proceeding. Staff witness Mr. Stewart acknowledges at page 4, lines 1-9, of his Direct Testimony that the Company did allocate purchase power on an energy basis, as directed. Only a relatively small amount of production capacity costs are allocated based on average and peaks. The Average and Peaks method was accepted for that purpose in UNS Electric's last general rate case, and in TEP's rates cases since the early 1990's.

VI. TIME-OF-USE.

Q. Please comment on the Staff and RUCO position on UNS Electric's time-of-use rate proposals.

A. UNS Electric has proposed increasing the rate differentials (between on-peak and off-peak) in its existing time-of-use rates. This results in larger savings for customers who are able to keep their peak usage relatively low. The Company has also proposed some Super-Peak rates that for summer billing months set a single hour during the day to be the peak hour. Staff has recommended approval of these rates.

On the other hand, Dr. Johnson for RUCO has some concerns, and believes there is the need for more analysis on the size of the on peak / off-peak differential. He also inquired about the terms and conditions of the Super-Peak rates, and questioned whether the Super-Peak Rates should not be designed more as a real-time pricing type program. I will clarify some issues of concern below.

Q. Please discuss the Company's goals and objectives for the Super-Peak rate.

A. In layman's terms, this rate was designed to offer the maximum benefit in our efforts to reduce demand in the most critical periods. By pricing a single summer hour at a very high price, the customer will be motivated to dramatically reduce usage – even air conditioning on a hot summer day – for that one hour. The Super-Peak rate is geared for the hot desert climate in UNS Electric's service territory. Even on the hottest days, customers are motivated to reduce energy consumption in the peak hour with the right price signal. There will be some additional usage in the following hour, of course, but the Super-Peak will likely result in eliminating (and not just shifting) some usage during the on-peak period.

The rate was also designed to be revenue neutral for residential customers. So, if all customers maintained usage at current levels over all hours, even the super-peak hour, residential revenue will remain unchanged. Super-Peak subscribers, however, will likely reduce usage during the super-peak hour. That means that the customer will likely save money. The Super-Peak customer saves money while also reducing usage and easing the burden on UNS Electric's system. At a minimum, load is shifted from peak times, which reduces the need for additional infrastructure.

Q. Please describe why you believe implementing a "Super-Peak" TOU option will advance the goals of reducing demand and implementing demand response.

A. The demand for electricity is very inelastic in the Company's hot desert service territory during peak times (*e.g.*, a hot summer day in the mid to late afternoon). Demands are inelastic when the percentage change in quantity demanded is less than the percentage change in price. In other words, the change in the price will not affect significantly the amount of a product that is bought or consumed. On that hot summer afternoon, consumers will use approximately the same amount of electricity when faced with low to moderate price changes.

The demand for peak-period electricity is especially inelastic. With this inelastic demand, a substantial price jolt is necessary to push consumption away from the peak. Compared with goods with more elastic demand – where sales respond to price changes - a greater percentage change in price is needed to cause a given shift in consumption. The question is how much of a price hike will be necessary to change the customer's usage patterns.

Under UNS Electric's proposed Super-Peak rate, the summer peak price is set high enough to elicit a price-elasticity response from the participating customer. A lower peak price may also be effective in shifting load away from the peak, but the true degree of price inelasticity at the most critical times – and UNS Electric's ability to ascertain the level to which the peak price can be decreased – will remain unknown until the Super-Peak rate is implemented. It is possible that an even higher peak price would be necessary and appropriate to achieve the desired load shift. The implementation of

Super-Peak option will be a very useful experiment to help quantify price elasticity at the most critical peak periods. We can "study" this issue at length, but we ultimately will not have good elasticity estimates for *this* service territory over a wider range of prices until we implement the rate. The only meaningful results will come with the implementation of a Super-Peak option, which can then be adjusted and refined once the Company collects the necessary data. The aggressive conservation and load shifting targets being considered by the Commission may necessitate the consideration of innovative, but heretofore untested new programs that may require some "fine-tuning" in the future. Super-Peak TOU is such a program.

Q. How difficult will it be to implement the Super-Peak option?

A. As proposed by UNS Electric, Super-Peak will be easy to implement and does not require expensive communications equipment installation. It is also incredibly easy for customers to understand and implement. It allows customers with programmable thermostats to, for example, set summer thermostats between 85 and 90 degrees during the peak hour and rely on fans. UNS Electric believes that customers will be willing and able to adjust their lifestyles so as to capitalize on the rate.

Q. Does Dr. Johnson agree with the Company's approach?

A. Dr. Johnson prefers a real-time rate with a price that varies with specific circumstances. At this time, Dr. Johnson's rate will be more costly to implement and harder for the customer to benefit from and to understand. Pre-programming thermostats would not be as effective. Also, we do not believe that residential customers have time to watch monitors telling them how expensive usage will be at a particular time.

Q. Does this mean the Company is forever opposed to a real-time pricing option at some time in the future?

A. No. The Company may consider a real-time pricing rate as part of its DSM programs. UNS Electric does not see a real time pricing rate and the Super-Peak rates as mutually exclusive alternatives. In time, UNS Electric could potentially implement both programs. These rates may appeal to different customer groups.

Q. How will a customer's peak hour be chosen under the Super-Peak rate?

A. A customer's peak hour will be based on the last two digits of his street address, an objective, non-changing metric. A non-changing metric prevents the customer from calling back to get a different peak hour. Having the customer choose his own peak hour creates an "adverse selection" issue that Dr. Johnson recognized and that I discuss below. The "last two digits" peak hour selection criterion is also easy to implement. Exhibit DBE-4 shows the peak hour associated with each of the 100 two-digit address combinations ("00" through "99"). Exhibit DBE-5 shows proposed tariffs with the Exhibit DBE-4 peak hour / address combination information included.

Q. Please explain the adverse selection concern you noted in your previous answer.

A. Dr. Johnson correctly noted that the Company is concerned about the issue of adverse selection that could occur if the customer chose the peak hour. If customers could choose the peak hour, then they would choose the hour in which they were already restricting usage. Consequently, there would be less beneficial load shifting if customers could pick their own hour. Since the Super-Peak rates are optional, a customer assigned an hour he sees as undesirable has the regular TOU rate as an additional rate option.

Q. Will the Company need to close subscription for certain Super-Peak hours, or change the selection criteria if too many customers end up on one or two of the peak hours?

A. The Company does not know the extent that a customer will accept the Super-Peak rate based on the summer peak hour assigned. This may result in certain summer peak hours being over-subscribed or under-subscribed. Under these circumstances, the Company may discuss with Commission Staff changes to the peak-hour selection criterion. As mentioned, the Super-Peak tariffs may require some fine-tuning in the future. The possible need for such fine tuning is referenced in the Super-Peak tariffs attached as Exhibit DBE-5. The resolution to some questions may need to wait until the program has been in place for a year or more. UNS Electric will keep the Staff informed as situations arise or resolve themselves.

Q. Please comment on Dr. Johnson's proposal to study the size of the on-peak to off-peak differential in the regular TOU rate.

A. As in the Super-Peak design, the regular TOU rates are designed to be revenue neutral with the regular Non-TOU rates – assuming usage remains the same. So, the larger differentials proposed offer enhanced saving opportunities for customers who can reduce on-peak consumption. The differential deliberately is not cost-based, but is instead designed to elicit the type of price elasticity response that will contribute to significantly reducing peak demand, which is a rate design goal.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

DBE-4

UNS Electric, Inc.

Peak-Hour Selection Criterion for Super-Peak Proposals
Last 2 digits of Street Address will Determine Peak Hour for the Address.

Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour
00	5-6 pm	25	4-5 pm	50	3-4 pm	75	2-3 pm
01	4-5 pm	26	5-6 pm	51	5-6 pm	76	5-6 pm
02	3-4 pm	27	3-4 pm	52	4-5 pm	77	4-5 pm
03	2-3 pm	28	2-3 pm	53	2-3 pm	78	3-4 pm
04	5-6 pm	29	4-5 pm	54	3-4 pm	79	2-3 pm
05	4-5 pm	30	5-6 pm	55	5-6 pm	80	5-6 pm
06	3-4 pm	31	3-4 pm	56	4-5 pm	81	4-5 pm
07	2-3 pm	32	2-3 pm	57	2-3 pm	82	3-4 pm
08	5-6 pm	33	4-5 pm	58	3-4 pm	83	2-3 pm
09	4-5 pm	34	5-6 pm	59	5-6 pm	84	5-6 pm
10	3-4 pm	35	3-4 pm	60	4-5 pm	85	4-5 pm
11	2-3 pm	36	2-3 pm	61	2-3 pm	86	3-4 pm
12	5-6 pm	37	4-5 pm	62	3-4 pm	87	2-3 pm
13	4-5 pm	38	5-6 pm	63	5-6 pm	88	5-6 pm
14	3-4 pm	39	3-4 pm	64	4-5 pm	89	4-5 pm
15	2-3 pm	40	2-3 pm	65	2-3 pm	90	3-4 pm
16	5-6 pm	41	4-5 pm	66	3-4 pm	91	2-3 pm
17	4-5 pm	42	5-6 pm	67	5-6 pm	92	5-6 pm
18	3-4 pm	43	3-4 pm	68	4-5 pm	93	4-5 pm
19	2-3 pm	44	2-3 pm	69	2-3 pm	94	3-4 pm
20	5-6 pm	45	4-5 pm	70	3-4 pm	95	2-3 pm
21	4-5 pm	46	5-6 pm	71	5-6 pm	96	5-6 pm
22	3-4 pm	47	3-4 pm	72	4-5 pm	97	4-5 pm
23	2-3 pm	48	2-3 pm	73	2-3 pm	98	3-4 pm
24	5-6 pm	49	4-5 pm	74	3-4 pm	99	2-3 pm

Examples:

5288 W. Oak's Peak Hour would be 5-6 pm, becase "5288" ends in "88."
1 W. Oak's Peak Hour would be 4-5 pm, becase "1" ends in "01."

EXHIBIT

DBE-5

EXHIBIT DBE-5

Clarifying Revisions to Proposed Super-Peak Tariffs

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Available as an optional rate to Customers served under the Company's Pricing Plan RS, Residential Service.

This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

Service is restricted to private single family dwellings or individually metered apartments.

Not applicable to three phase service, resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single phase, 60 hertz, at one standard voltage.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge Components of Delivery Services:
Customer Charge, Single Phase service and minimum bill $ 8.00 per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All energy charges below are on a per kWh basis for all summer and winter months.

Summer	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
First 400 kWh				
Super-Peak	$0.020070	$0.488770	Varies	$0.508840
Shoulder Peak	$0.020070	$0.074812	Varies	$0.094882
Off-Peak	$0.020070	$0.054158	Varies	$0.074228
All Additional kWhs				
Super-Peak	$0.030084	$0.488770	Varies	$0.518854
Shoulder Peak	$0.030084	$0.074812	Varies	$0.104896
Off-Peak	$0.030084	$0.054158	Varies	$0.084242

Winter	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
First 400 kWh				
On-Peak	$0.020070	$0.159138	Varies	$0.179208
Off-Peak	$0.020070	$0.041894	Varies	$0.061964
All Additional kWhs				
On-Peak	$0.030084	$0.159138	Varies	$0.189222
Off-Peak	$0.030084	$0.041894	Varies	$0.071978

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local Delivery Energy and Production not included in Power Supply.

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

TIME-OF-USE PERIODS

Summer TOU periods:

Weekdays except Memorial Day, Independence Day (July 4), and Labor Day. If Independence Day falls on Saturday, the Weekend schedule applies on the preceding Friday, July 3. If Independence Day falls on Sunday, the Weekend schedule applies on the following Monday, July 5.

Super-Peak: Either:
Version A: 2:00 p.m. to 3:00 p.m., or
Version B: 3:00 p.m. to 4:00 p.m., or
Version C: 4:00 p.m. to 5:00 p.m.; or
Version D: 5:00 p.m. to 6:00 p.m.

Shoulder-Peak: Either:
Version A: 3:00 p.m. to 6:00 p.m., or
Version B: 2:00 p.m. to 3:00 p.m. and 4:00 p.m. to 6:00 p.m., or
Version C: 2:00 p.m. to 4:00 p.m. and 5:00 p.m. to 6:00 p.m., or
Version D: 2:00 p.m. to 5:00 p.m.

Off-Peak: 12:00 a.m. (midnight) to 2 p.m. and 6:00 p.m. to 12:00 a.m. (midnight)

Weekends (Saturday and Sunday), Memorial Day, Independence Day (or July 3 or July 5, under above conditions), and Labor Day.

On-Peak:	*(There are no On-Peak weekend hours)*
Shoulder-Peak:	*(There are no Shoulder-Peak weekend hours)*
Off-Peak:	All weekend hours.

The Version (i.e., A, B, C, or D) available to a specific customer shall be determined on the basis of the last two digits of the customer's street address. A matrix of address digits and summer peak hours is found below. The "two-digit" rule helps promote load diversity, a beneficial result of a demand response program. The Company shall evaluate subscription to each Version to determine whether certain peak hours are under-subscribed or over-subscribed. In the event that an optimal mix of peak hours is not developing, the Company will notify the Commission Staff and may seek modifications to the selection criterion.

Winter TOU periods:
Winter weekdays except Thanksgiving Day, Christmas Day, and New Years Day. If Christmas Day and New Years Day fall on Saturdays, the Weekend schedule applies on the preceeding Fridays, December 24 and December 31. If Christmas Day and New Years Day fall on Sundays, the Weekend schedule applies on the following Mondays, December 26 and January 2.

On-Peak:	6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak:	There are no shoulder peak periods in the winter.
Off-Peak:	12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight).

WinterWeekend days (Saturday and Sunday), Thanksgiving Day, Christmas Day (or December 24 or December 26, under above conditions), and New Years Day (or December 31 or January 2, under above conditions).

On-Peak:	*(There are no On-Peak weekend hours)*
Shoulder-Peak:	*(There are no Shoulder-Peak weekend hours)*
Off-Peak:	All weekend hours.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan RES-01 SuperPeak TOU
Residential Service SuperPeak Time-of-Use – Weekends Off-Peak

Criterion for Selecting Summer Peak Hour in Time-of-Use Super-Peak Proposals
Last 2 digits of Street Address will Determine Peak Hour for the Address.

Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour
00	5-6 pm	25	4-5 pm	50	3-4 pm	75	2-3 pm
01	4-5 pm	26	5-6 pm	51	5-6 pm	76	5-6 pm
02	3-4 pm	27	3-4 pm	52	4-5 pm	77	4-5 pm
03	2-3 pm	28	2-3 pm	53	2-3 pm	78	3-4 pm
04	5-6 pm	29	4-5 pm	54	3-4 pm	79	2-3 pm
05	4-5 pm	30	5-6 pm	55	5-6 pm	80	5-6 pm
06	3-4 pm	31	3-4 pm	56	4-5 pm	81	4-5 pm
07	2-3 pm	32	2-3 pm	57	2-3 pm	82	3-4 pm
08	5-6 pm	33	4-5 pm	58	3-4 pm	83	2-3 pm
09	4-5 pm	34	5-6 pm	59	5-6 pm	84	5-6 pm
10	3-4 pm	35	3-4 pm	60	4-5 pm	85	4-5 pm
11	2-3 pm	36	2-3 pm	61	2-3 pm	86	3-4 pm
12	5-6 pm	37	4-5 pm	62	3-4 pm	87	2-3 pm
13	4-5 pm	38	5-6 pm	63	5-6 pm	88	5-6 pm
14	3-4 pm	39	3-4 pm	64	4-5 pm	89	4-5 pm
15	2-3 pm	40	2-3 pm	65	2-3 pm	90	3-4 pm
16	5-6 pm	41	4-5 pm	66	3-4 pm	91	2-3 pm
17	4-5 pm	42	5-6 pm	67	5-6 pm	92	5-6 pm
18	3-4 pm	43	3-4 pm	68	4-5 pm	93	4-5 pm
19	2-3 pm	44	2-3 pm	69	2-3 pm	94	3-4 pm
20	5-6 pm	45	4-5 pm	70	3-4 pm	95	2-3 pm
21	4-5 pm	46	5-6 pm	71	5-6 pm	96	5-6 pm
22	3-4 pm	47	3-4 pm	72	4-5 pm	97	4-5 pm
23	2-3 pm	48	2-3 pm	73	2-3 pm	98	3-4 pm
24	5-6 pm	49	4-5 pm	74	3-4 pm	99	2-3 pm

Examples:
5288 W. Oak's Peak Hour would be 5-6 pm, becase "5288" ends in "88."
1 W. Oak's Peak Hour would be 4-5 pm, becase "1" ends in "01."

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling):

Meter Services	$3.097 per month
Meter Reading	$0.862 per month
Billing & Collection	$3.661 per month
Customer Delivery	$0.380 per month
	$8.00 per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Delivery Services- Energy 1st 400 kWhs	
Transmission	$0.002299
Sub-Transmission	$0.004813
Local Delivery Energy	$0.012643
Production not included in Power Supply	$0.000315
Delivery Services - Energy All Additional kWhs	
Transmission	$0.002299
Sub-Transmission	$0.004813
Local Delivery Energy	$0.022657
Production not included in Power Supply	$0.000315

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply Summer	
On-Peak	$0.488770
Shoulder-Peak	$0.074812
Off-Peak	$0.054158
Base Power Supply Winter	
On-Peak	$0.159138
Off-Peak	$0.041894
PPFAC (see Rate Rider-1 for current rate)	Varies

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan SGS-10 SuperPeak TOU
Small General Service SuperPeak Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

To any customer where the monthly usage is not more than 7,500 kWh in any two (2) consecutive months. Customers who use more than 7,500 kWh for two (2) or more consecutive months shall not be eligible for this pricing plan and shall take service under the Large General Service pricing plan. However, service is available for customer-owned, operated, and maintained area, street, or stadium lighting, and for firm irrigation service with a maximum monthly demand less than 25 kW

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single phase, 60 hertz at one standard voltage. Three phase for eligible loads over 5 kW.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge Components of Delivery Services:
Customer Charge, Single Phase service and minimum bill $ 12.50 per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All energy charges below are on a per kWh basis for all summer and winter months.

Summer	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
First 400 kWh				
Super-Peak	$0.032440	$0.423680	Varies	$0.456120
Shoulder Peak	$0.032440	$0.072649	Varies	$0.105089
Off-Peak	$0.032440	$0.046759	Varies	$0.079199
All Additional kWhs				
Super-Peak	$0.042454	$0.423680	Varies	$0.466134
Shoulder Peak	$0.042454	$0.072649	Varies	$0.115103
Off-Peak	$0.042454	$0.046759	Varies	$0.089213

Winter	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
First 400 kWh				
On-Peak	$0.032440	$0.136759	Varies	$0.169199
Off-Peak	$0.032440	$0.038539	Varies	$0.070979
All Additional kWhs				
On-Peak	$0.042454	$0.136759	Varies	$0.179213
Off-Peak	$0.042454	$0.038539	Varies	$0.080993

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local Delivery Energy and Production not included in Power Supply.

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

TIME-OF-USE PERIODS

The Summer periods below apply to all summer days:

Super-Peak: Either:
Version A: 2:00 p.m. to 3:00 p.m.;
Version B: 3:00 p.m. to 4:00 p.m.;
Version C: 4:00 p.m. to 5:00 p.m.; or
Version D: 5:00 p.m. to 6:00 p.m.

Shoulder-Peak: Either:
Version A: 3:00 p.m. to 6:00 p.m.;
Version B: 2:00 p.m. to 3:00 p.m. and 4:00 p.m. to 6:00 p.m.;
Version C: 2:00 p.m. to 4:00 p.m. and 5:00 p.m. to 6:00 p.m.; or
Version D: 2:00 p.m. to 5:00 p.m.

Off-Peak: 12:00 a.m. (midnight) to 2 p.m. and 6:00 p.m. to 12:00 a.m. (midnight)

The Version (i.e., A, B, C, or D) available to a specific customer shall be determined on the basis of the last two digits of the customer's street address. A matrix of address digits and summer peak hours is found below. The "two-digit" rule helps promote load diversity, a beneficial result of a demand response program. The Company shall evaluate subscription to each Version to determine whether certain peak hours are under-subscribed or over-subscribed. In the event that an optimal mix of peak hours is not developing, the Company will notify the Commission Staff and may seek modifications to the selection criterion.

The Winter periods below apply to all winter days:

On-Peak	6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak:	There is no shoulder peak periods in the winter.
Off-Peak:	12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight)

Criterion for Selecting Summer Peak Hour in Time-of-Use Super-Peak Proposals
Last 2 digits of Street Address will Determine Peak Hour for the Address.

Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour
00	5-6 pm	25	4-5 pm	50	3-4 pm	75	2-3 pm
01	4-5 pm	26	5-6 pm	51	5-6 pm	76	5-6 pm
02	3-4 pm	27	3-4 pm	52	4-5 pm	77	4-5 pm
03	2-3 pm	28	2-3 pm	53	2-3 pm	78	3-4 pm
04	5-6 pm	29	4-5 pm	54	3-4 pm	79	2-3 pm
05	4-5 pm	30	5-6 pm	55	5-6 pm	80	5-6 pm
06	3-4 pm	31	3-4 pm	56	4-5 pm	81	4-5 pm
07	2-3 pm	32	2-3 pm	57	2-3 pm	82	3-4 pm
08	5-6 pm	33	4-5 pm	58	3-4 pm	83	2-3 pm
09	4-5 pm	34	5-6 pm	59	5-6 pm	84	5-6 pm
10	3-4 pm	35	3-4 pm	60	4-5 pm	85	4-5 pm
11	2-3 pm	36	2-3 pm	61	2-3 pm	86	3-4 pm
12	5-6 pm	37	4-5 pm	62	3-4 pm	87	2-3 pm
13	4-5 pm	38	5-6 pm	63	5-6 pm	88	5-6 pm
14	3-4 pm	39	3-4 pm	64	4-5 pm	89	4-5 pm
15	2-3 pm	40	2-3 pm	65	2-3 pm	90	3-4 pm
16	5-6 pm	41	4-5 pm	66	3-4 pm	91	2-3 pm
17	4-5 pm	42	5-6 pm	67	5-6 pm	92	5-6 pm
18	3-4 pm	43	3-4 pm	68	4-5 pm	93	4-5 pm
19	2-3 pm	44	2-3 pm	69	2-3 pm	94	3-4 pm
20	5-6 pm	45	4-5 pm	70	3-4 pm	95	2-3 pm
21	4-5 pm	46	5-6 pm	71	5-6 pm	96	5-6 pm
22	3-4 pm	47	3-4 pm	72	4-5 pm	97	4-5 pm
23	2-3 pm	48	2-3 pm	73	2-3 pm	98	3-4 pm
24	5-6 pm	49	4-5 pm	74	3-4 pm	99	2-3 pm

Examples:
5288 W. Oak's Peak Hour would be 5-6 pm, becase "5288" ends in "88."
1 W. Oak's Peak Hour would be 4-5 pm, becase "1" ends in "01."

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling):

Meter Services	$4.381 per month
Meter Reading	$1.434 per month
Billing & Collection	$6.061 per month
Customer Delivery	$0.624 per month
	$12.50 per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Delivery Services- Energy 1st 400 kWhs	
Transmission	$0.001889
Sub-Transmission	$0.003993
Local Delivery Energy	$0.026252
Production not included in Power Supply	$0.000306
Delivery Services - Energy All Additional kWhs	
Transmission	$0.001889
Sub-Transmission	$0.003993
Local Delivery Energy	$0.036266
Production not included in Power Supply	$0.000306

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply Summer	
On-Peak	$0.423680
Shoulder-Peak	$0.072649
Off-Peak	$0.046759
Base Power Supply Winter	
On-Peak	$0.136759
Off-Peak	$0.038539
PPFAC (see Rate Rider-1 for current rate)	Varies

TERMS AND CONDITIONS

Service under this schedule is for the exclusive use of the Customer and shall not be resold or shared with others.

Customers who qualify for service under this pricing plan must remain on the pricing plan for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach.

Standby, supplemental or breakdown service shall not be rendered under this pricing plan.

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

To any customer where the maximum monthly demand is less than 1,000 kW.

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single or three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises. Customers may choose time-of-use service as well.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER, ENERGY AND DEMAND CHARGES

Customer Charge Components of Delivery Services:
Customer Charge, Single Phase service and minimum bill $ 16.00 per month

Demand Charge Component is unbundled into Delivery Services-Demand
Demand Charge $13.353 per kW per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All energy charges below are on a per kWh basis for all summer and winter months.

Summer	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
All kWh				
Super-Peak	$0.004254	$0.363690	Varies	$0.367944
Shoulder Peak	$0.004254	$0.064326	Varies	$0.068580
Off-Peak	$0.004254	$0.046221	Varies	$0.050475

Winter	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
All kWh				
On-Peak	$0.004254	$0.121221	Varies	$0.125475
Off-Peak	$0.004254	$0.032503	Varies	$0.036757

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local DeliveryEnergy and Production not included in Power Supply.

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

TIME-OF-USE PERIODS

The Summer periods below apply to all summer days:

Super-Peak:	Either:	Version A: 2:00 p.m. to 3:00 p.m.; Version B: 3:00 p.m. to 4:00 p.m.; Version C: 4:00 p.m. to 5:00 p.m.; or Version D: 5:00 p.m. to 6:00 p.m.
Shoulder-Peak:	Either:	Version A: 3:00 p.m. to 6:00 p.m.; Version B: 2:00 p.m. to 3:00 p.m. and 4:00 p.m. to 6:00 p.m.; Version C: 2:00 p.m. to 4:00 p.m. and 5:00 p.m. to 6:00 p.m.; or Version D: 2:00 p.m. to 5:00 p.m.
Off-Peak:	12:00 a.m. (midnight) to 2 p.m. and 6:00 p.m. to 12:00 a.m. (midnight)	

The Version (i.e., A, B, C, or D) available to a specific customer shall be determined on the basis of the last two digits of the customer's street address. A matrix of address digits and summer peak hours is found below. The "two-digit" rule helps promote load diversity, a beneficial result of a demand response program. The Company shall evaluate subscription to each Version to determine whether certain peak hours are under-subscribed or over-subscribed. In the event that an optimal mix of peak hours is not developing, the Company will notify the Commission Staff and may seek modifications to the selection criterion.

The Winter periods below apply to all winter days:

On-Peak:	6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak:	There is no shoulder peak periods in the winter.
Off-Peak:	12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight).

Criterion for Selecting Summer Peak Hour in Time-of-Use Super-Peak Proposals
Last 2 digits of Street Address will Determine Peak Hour for the Address.

Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour
00	5-6 pm	25	4-5 pm	50	3-4 pm	75	2-3 pm
01	4-5 pm	26	5-6 pm	51	5-6 pm	76	5-6 pm
02	3-4 pm	27	3-4 pm	52	4-5 pm	77	4-5 pm
03	2-3 pm	28	2-3 pm	53	2-3 pm	78	3-4 pm
04	5-6 pm	29	4-5 pm	54	3-4 pm	79	2-3 pm
05	4-5 pm	30	5-6 pm	55	5-6 pm	80	5-6 pm
06	3-4 pm	31	3-4 pm	56	4-5 pm	81	4-5 pm
07	2-3 pm	32	2-3 pm	57	2-3 pm	82	3-4 pm
08	5-6 pm	33	4-5 pm	58	3-4 pm	83	2-3 pm
09	4-5 pm	34	5-6 pm	59	5-6 pm	84	5-6 pm
10	3-4 pm	35	3-4 pm	60	4-5 pm	85	4-5 pm
11	2-3 pm	36	2-3 pm	61	2-3 pm	86	3-4 pm
12	5-6 pm	37	4-5 pm	62	3-4 pm	87	2-3 pm
13	4-5 pm	38	5-6 pm	63	5-6 pm	88	5-6 pm
14	3-4 pm	39	3-4 pm	64	4-5 pm	89	4-5 pm
15	2-3 pm	40	2-3 pm	65	2-3 pm	90	3-4 pm
16	5-6 pm	41	4-5 pm	66	3-4 pm	91	2-3 pm
17	4-5 pm	42	5-6 pm	67	5-6 pm	92	5-6 pm
18	3-4 pm	43	3-4 pm	68	4-5 pm	93	4-5 pm
19	2-3 pm	44	2-3 pm	69	2-3 pm	94	3-4 pm
20	5-6 pm	45	4-5 pm	70	3-4 pm	95	2-3 pm
21	4-5 pm	46	5-6 pm	71	5-6 pm	96	5-6 pm
22	3-4 pm	47	3-4 pm	72	4-5 pm	97	4-5 pm
23	2-3 pm	48	2-3 pm	73	2-3 pm	98	3-4 pm
24	5-6 pm	49	4-5 pm	74	3-4 pm	99	2-3 pm

Examples:
5288 W. Oak's Peak Hour would be 5-6 pm, becase "5288" ends in "88."
1 W. Oak's Peak Hour would be 4-5 pm, becase "1" ends in "01."

DETERMINATION OF BILLING DEMAND
The monthly billing demand shall be the higher of:
(i) the highest measured fifteen (15) minute integrated reading of the demand meter during the on-peak and shoulder hours of the billing period,
(ii) one-half the highest measured fifteen (15) minute integrated reading of the demand meter during the off-peak hours, or
(iii) the contract capacity.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling):

Meter Services	$8.772 per month
Meter Reading	$1.282 per month
Billing & Collection	$5.394 per month
Customer Delivery	$0.552 per month
	$16.00 per month

Demand Charge Component is unbundled into Delivery Services-Demand

Demand Charge $13.353 per kW per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Delivery Services- Energy – All kWh	
Transmission	$0.001507
Sub-Transmission	$0.003224
Local Delivery Energy (negative charge)	($0.000768)
Production not included in Power Supply	$0.000291

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply Summer	
On-Peak	$0.363690
Shoulder-Peak	$0.064326
Off-Peak	$0.046221
Base Power Supply Winter	
On-Peak	$0.121221
Off-Peak	$0.032503
PPFAC (see Rate Rider-1 for current rate)	Varies

TERMS AND CONDITIONS

Standby, supplemental or breakdown service shall not be rendered under this pricing plan except for Qualifying Facilities or Independent Power Producers that have entered into a Service or Purchase Agreement with the Company.

Customers who qualify for service under this pricing plan must remain on the pricing plan for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach.

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

Service under this pricing plan is for the exclusive use of the Customer and shall not be resold or shared with others, unless authorized by the Company.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.