0000068363

EXHIBITS

E-04204A-06-0783

PART 2 OF 5
BAR CODE # 0000068363

To review remaining parts please see the following:

PART 1 OF 5 BAR CODED #0000068370

PART 3 OF 5 BAR CODED #0000068364

PART 4 OF 5 BAR CODED #0000068365

PART 5 OF 5 BAR CODED #0000068366

EXHIBIT
S-5
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

REDACTED

SURREBUTTAL

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

AUGUST 24, 2007

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783

My Surrebuttal Testimony addresses the following issues:

- The Company's proposed revenue requirement.
- Adjustments to test year data.
- Rate base, including construction work in progress.
- Test year revenues (including number of customers and usage) and expenses.
- Depreciation rates.
- The Company's requested modifications to the Purchased Power and Fuel Adjustment Clause ("PPFAC") and Staff's recommendations for features to include in a new PPFAC for UNS Electric.
- The Company's proposed ratemaking treatment for a new peaking unit, the Black Mountain Generating Station ("BMGS").

My findings and recommendations for each of these areas are as follows:

- The Company's proposed revenue requirement of a base rate increase of $8.5 million is overstated. I recommend that UNS Electric be authorized a base rate increase of $3.668 million on adjusted fair value rate base.

- The following adjustments to UNS Electric's proposed original cost and fair value rate base should be made:

Summary of Staff Adjustments to Rate Base		**Original Cost**	**Fair Value**	
Adj. No.	Description	Increase (Decrease)	Increase (Decrease)	**Note**
B-1	Remove Construction Work in Progress	$ (10,761,154)	$ (10,761,154)	
B-2	Adjust CWIP for Plant in Service by End of Test Year	$ 442,255	$ 442,255	
B-3	Plant in Service Addition Subject to Reimbursement	$ -	$ -	Revised
B-4	Cash Working Capital - Lead/Lag Study	$ 196,450	$ 196,450	Revised
B-5	Accumulated Deferred Income Taxes	$ (161,555)	$ (161,555)	
	Total of Staff Adjustments	**$ (10,284,004)**	**$ (10,284,004)**	
	UNS Proposed Rate Base	$ 140,991,324	$ 177,802,341	
	Staff Proposed Rate Base	**$ 130,707,320**	**$ 167,518,337**	

- The following adjustments to UNS Electric's proposed revenues, expenses and net operating income should be made (amounts shown are impact on net operating income):

Summary of Staff Adjustments to Net Operating Income

Adj. No.	Description	Pre-Tax Revenue or Expense Adjustment	Net Operating Income Increase (Decrease)	Note
C-1	Revenue Adjustment for CARES Discount	$ (52,937)	$ 32,504	
C-2	Remove Depreciation & Property Taxes for CWIP	$ (689,512)	$ 423,374	
C-3	Depreciation & Property Taxes for CWIP Found to be In-Service in the Test Year	$ 26,582	$ (16,322)	
C-4	Fleet Fuel Expense	$ (62,197)	$ 38,190	Revised
C-5	Postage Expense	$ 17,503	$ (10,747)	
C-6	Normalize Injuries and Damages Expense	$ (159,063)	$ 97,668	
C-7	Incentive Compensation Expense	$ (44,001)	$ 27,017	
C-8	Supplemental Executive Retirement Plant (SERP) Expense	$ (83,506)	$ 51,274	
C-9	Stock Based Compensation Expense	$ (82,873)	$ 50,886	
C-10	Property Tax Expense	$ (59,747)	$ 36,686	
C-11	Rate Case Expense	$ (111,667)	$ 68,566	
C-12	Edison Electric Institute Dues	$ (8,470)	$ 5,201	
C-13	Other Membership and Industry Association Dues	$ (6,482)	$ 3,980	
C-14	Interest Synchronization	$ -	$ (177,611)	Revised
C-15	Depreciation Rates Correction	$ (63,105)	$ 38,748	
C-16	Emergency Bill Assistance Expense	$ 20,000	$ (12,280)	
C-17	Markup Above Cost in Charges from Affiliate, SES	$ (10,906)	$ 6,697	Added
C-18	Bad Debt Expense	$ (155,609)	$ 95,547	Added
C-19	Remove Double Count from Outside Services-Demand Side Management	$ (17,055)	$ 10,472	Added
C-20	Correct Year-End Accrual Expense Amount for Out-of-Period Expense	$ (6,256)	$ 3,841	Added
Total of Staff's Adjustments		$ (1,549,300)	**$ 773,690**	
	Adjusted Net Operating Income per UNS Electric		$ 8,742,011	
	Adjusted Net Operating Income per Staff		$ 9,515,701	

- The new depreciation rates proposed by UNS Electric presented in Dr. White's Direct Testimony Attachment REW-2 should be adopted for use in this case, as corrected in the response to data request STF 11.8. The depreciation rates proposed by UNS Electric were generally developed in a manner that is consistent with the Commission's rules for depreciation rates.

- Each of the new depreciation rates proposed by UNS Electric should be clearly broken out between (1) a service life rate and (2) a net salvage rate. By doing this, the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

- In my Direct Testimony, Staff recommended that a new PPFAC for UNS Electric should be developed along the lines of the APS PSA Plan of Administration Staff proposed for the Arizona Public Service Company in Docket Nos. E-01345A-05-0816 et al, after appropriate adjustments to fit UNS Electric's circumstances. Staff and UNS Electric agree that a new PPFAC for UNS Electric should become effective June 1, 2008, upon expiration of the Company's all requirements power contract with PWCC. The new PPFAC proposed by UNS Electric in Exhibit MJD-3 to Mr. DeConcini's Rebuttal Testimony deviates from Staff's proposal and contains objectionable features such as inclusion of costs that would more appropriately be addressed in base rates, as well as raising other concerns, and should therefore be rejected. Staff's Draft Proposed Plan of Administration for UNS Electric

Purchased Power and Fuel Adjustment Clause (which is a Redline of UNS Electric Exhibit MDC-3) should be adopted instead.

- The Black Mountain Generation Station ("BMGS") is a 90 MW peaking plant which is being constructed in Mohave County by an affiliate, and which the Company projects will be in service around June 1, 2008 when the PWCC PSA expires. The in-service date for this plant is too far outside of the test year to qualify for base rate treatment in the current UNS Electric rate case. Staff believes that a more reasonable alternative approach to addressing the ratemaking and cash flow impacts of meeting UNS Electric's power supply will need to be developed. UNS Electric's proposed base rate treatment for BMGS in the current case should be rejected for the reasons described in my testimony, including the uncertainties presently existing with respect to this plant.

I. INTRODUCTION

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

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. What is the purpose of the Surrebuttal Testimony you are presenting?

A. The purpose of my testimony is to address the revenue requirement and selected other issues, including changes to the Purchased Power and Fuel Adjustment Clause ("PPFAC") proposed by UNS Electric, Inc. ("UNS Electric" or "Company"), and the Company's proposed ratemaking treatment for a new peaking unit, the Black Mountain Generating Station ("BMGS") in the current rate case.

Q. Have you prepared any exhibits to be filed with your Surrebuttal Testimony?

A. Yes. Attachments RCS-6 through RCS-10 contain the results of my analysis and copies of selected documents that are referenced in my testimony.

Q. Are there outstanding data requests concerning the subject matter addressed in your Surrebuttal Testimony?

A. Yes. On August 16 and 17, 2007, Staff issued data request sets 20 and 21 to UNS Electric. As of the date of this writing (August 22, 2007) I had not received the Company's responses to those data requests.

II. REVENUE REQUIREMENT

Q. What issues are addressed in your Surrebuttal Testimony?

A. My testimony addresses the Company's proposed revenue requirement and selected other issues.

Q. What revenue increase has been requested by UNS Electric?

A. In its direct filing, UNS Electric requested an increase in base rate revenues of $8.507 million, or approximately 5.5 percent. As shown on Exhibit DJD-1, page 5 of 5, which was filed with UNS Electric witness Dallas Dukes' Rebuttal Testimony, the Company has revised its request to $8.487 million.

Q. What revenue increase does Staff recommend?

A. Staff recommends a revenue increase of $3.668 million on adjusted fair value rate base. The comparable base rate revenue increase calculated by Staff on original cost rate base is $3.647 million. This is shown on Schedule A of Attachment RCS-6, filed with my Surrebuttal Testimony. Attachment RCS-6 presents Staff's revised accounting schedules.

Return on Fair Value Rate Base

Q. How did Staff determine the return to be applied to the fair value rate base?

A. This is shown on Attachment RCS-6, Schedule D, and was addressed in my Direct Testimony and the Direct Testimony of Staff witness David Parcell.

Q. How did UNS Electric determine the rate of return to apply to fair value rate base in its filing?

A. As noted in my Direct Testimony, in UNS Electric's direct filing, as shown on Schedule A-1, the Company adjusted the return that is to be applied to fair value rate base

downward, consistent with long-standing Commission practice, such that the revenue requirement produced by both the original cost rate base and the fair value rate base would not result in an excessive return on equity to the utility. UNS Electric's calculation of return on fair value rate base in the instant case is also consistent with the way the return was applied to the fair value rate base in the original rate case filing of its affiliate, UNS Gas, in Docket No. G-04204A-06-0463.

Q. Has UNS Electric presented a revised fair value rate base calculation in its Rebuttal Testimony?

A. No. UNS Electric's rebuttal filing includes a recalculation of its proposed revenue requirement at Exhibit DJD-1 (filed with Mr. Dukes' Rebuttal Testimony). Page 1 of that exhibit shows that the Company is applying its requested rate of return to its calculated original cost rate base to derive its proposed amount of required net operating income.

Q. Does UNS Electric criticize Staff's calculation of the return on fair value rate base in its Rebuttal Testimony?

A. Yes. Mr. Grant's Rebuttal Testimony at page 3, lines 2-5 states that: "Staff has proposed a methodology that is mathematically equivalent to the 'backing in' method that was expressly rejected in a recent Arizona Court of Appeals ruling involving Chaparral City Water Company ("Chaparral decision"). Staff's methodology should be rejected and replaced with a methodology that actually gives credence to FVRB in setting rates." He makes a similar assertion at page 33 of his rebuttal.

Q. Please respond to Mr. Grant's criticism.

A. A recent Court of Appeals decision provided guidance for calculating the return on fair value rate base. Staff's calculation has carefully considered and applied such guidance,

whereas UNS Electric's filing has not. Moreover, Staff has selectively tested this methodology on some other Arizona utilities, and, in each instance tested, it produced a different revenue requirement than does the application of the rate of return to the utility's original cost rate base. More importantly, because there is appropriate economic and financial logic and support underlying the determination of the rate of return that Staff has applied to the FVRB, this approach cannot be dismissed as a mere superfluous mathematical exercise. The Court of Appeals clearly indicated that the Commission has the discretion to determine the appropriate methodology. Staff's position is that the proposed method of determining the rate of return that is applied to the FVRB is appropriate and is supported by valid economic and financial theory.

Q. Please elaborate upon the guidance that was provided by the Court of Appeals decision and how Staff's proposal has considered and reflected that guidance in its presentation in the current UNS Electric rate case.

A. First, the Court of Appeals specifically stated that the Commission was not bound to apply an authorized rate of return that was developed for use with an original cost rate base, without adjustment, to the fair value rate base. Page 9 of the Court of Appeals decision stated that: "Chaparral City … asks that the Commission be directed to apply the 'authorized rate of return' to the fair value rate base rather than to the OCRB, as Chaparral City contends was done here." At page 13, paragraph 17, the Court of Appeals decision states as follows: "The Commission asserts that it was not bound to use the weighted average cost of capital as the rate of return to be applied to the FVRB. The Commission is correct." Thus, the Court of Appeals clearly stated that the Commission is not bound to apply to the FVRB the same weighted average cost of capital that was developed for application to the OCRB.

At pages 13-14, paragraph 17, the Court of Appeals decision stated that: "... the Commission cannot ignore its constitutional obligation to base rates on a utility's fair value. The Commission cannot determine rates based on the original cost, or OCRB, and then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate of return. Such a method is inconsistent with Arizona law." At page 13, the decision states: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

In view of the Court of Appeals decision in the Chaparral City case, Staff has appropriately adjusted the weighted cost of capital to the utility's fair value rate base. David Parcell's Direct Testimony in the instant rate case describes Staff's revision to the return on fair value rate base calculations in view of the recent Court of Appeals decision.

On Attachment RCS-6, Schedule D, I have derived the adjusted weighted cost of capital for application to the FVRB based on the recommendation of Staff witness Parcell. On Schedule A of that exhibit, I have applied Staff's adjustment to the weighted cost of capital as described by Mr. Parcell in his Direct Testimony. The cost of capital applicable to the amount of FVRB that is in excess of the OCRB is zero, since that rate base is not reported on the utility's financial statements and therefore has not been financed by any source of capital (such as debt or equity) that is reported on the utility's financial statements. As explained by Mr. Parcell, the financing cost rate for items in rate base that have not been financed with debt or equity on the utility's books, is zero. As shown on Attachment RCS-6, Schedule A, the application of Staff's adjusted weighted cost of capital to the FVRB results in revenue increase of $3.668 million. In this instance, the

application of the adjusted weighted cost of capital to the FVRB produces a slightly higher revenue requirement than does the application of the unadjusted rate of return to OCRB.

III. RATE BASE

Q. In view of issues raised in UNS Electric's Rebuttal Testimony, have you made any revisions to Staff's proposed rate base?

A. Yes. After reviewing UNS Electric's Rebuttal Testimony, I have reflected adjustments for the following items:

- Staff is evaluating the removal of Staff Adjustment B-3 for a Customer Advance on a plant addition that was subject to reimbursement. UNS Electric witness Karen Kissinger explained in her rebuttal that the Company had received the advance, but had coded it incorrectly (to a different project) in its general ledger. Staff is awaiting the receipt of adequate supporting documentation to enable Staff's verification that the Customer Advance was recorded and netted against plant in service at the end of the test year. That documentation has been required in data request STF 20.50. If Staff determines that this adjustment is not necessary, it will be withdrawn.
- Updating cash working capital to reflect revised expenses on Schedule B-4.

Q. How does Staff's revised rate base compare with UNS Electric's proposed rate base?

A. A comparison of the proposed rate base identified in UNS Electric's rebuttal at Exhibit DJD-1, page 1 of 5, and Staff's recommended rate base on an Original Cost and Fair Value basis are presented below:

	UNSE (Revised)	Staff	Difference
Summary of Rate Base	Ex. DJD-1	Sch B (Revised)	
Original Cost Rate Base	$ 141,034,952	$ 130,707,320	$ (10,327,632)
Fair Value Rate Base	Not Updated	$ 167,518,337	N/A

The Company did not update its FVRB in Exhibit DJD-1.

The vast majority of the difference between the Company's proposed and Staff's recommended rate base relates to whether Construction Work in Progress should be included in rate base or not.

B-1 Construction Work in Progress

Q. As a result of UNS Electric's Rebuttal Testimony, has Staff revised its position concerning whether Construction Work in Progress should be included in UNS Electric's rate base in this case?

A. No. Staff continues to recommend that the $10.8 million of Construction Work in Progress ("CWIP") UNS Electric has proposed not be included in rate base because of the reasons described in my Direct and Surrebuttal Testimony. The Company has not justified including CWIP in rate base. Accordingly, Staff adjustment B-1 removes that amount of CWIP from rate base.

Q. Are you addressing any other aspects of the Company's proposal to include CWIP in rate base?

A. Yes. With respect to the issue of exclusion of CWIP from rate base, I am also addressing the related proposal of UNS Electric for inclusion of post-test-year plant in rate base, a Company proposal to continue accruing an Allowance for Funds Used During Construction ("AFUDC") on CWIP even if CWIP were to be included in rate base, and an issue concerning the appropriate ratemaking treatment of Customer Advances.

Q. Please summarize UNS Electric' rebuttal concerning the Company's proposal to include CWIP in rate base.

A. UNS Electric has proposed to include $10.761 million of "CWIP" in rate base. UNS Electric witness Kentton Grant presents the following reasons for why the Company believes CWIP should be included in rate base:

- While the rate base inclusion of CWIP is unusual in the sense that it has not been used for many years in Arizona, it is a tool that is available to the Commission for purposes of setting fair and reasonable rates.[1]
- Two Arizona Supreme Court cases in the 1970s discussed the inclusion of CWIP in rate base and indicated that the Commission could consider it in determining rates.[2]
- Mr. Grant selectively cites to certain cases in other jurisdictions where a state regulatory commission allowed a utility to include CWIP in rate base in order to maintain a utility's financial integrity.[3]
- There are "extraordinary circumstances" in the current case justifying the inclusion of CWIP in rate base because Mr. Grant claims "it will be very difficult, if not impossible, for the Company to earn its authorized rate of return over the next several years."[4]
- Inclusion of CWIP in rate base can be one means of addressing the "regulatory lag" issue for a utility with a large construction program.[5]
- An extension of time between rate case filings could be beneficial to the Company and its customers.[6]

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[1] Kentton Grant Rebuttal Testimony, page 9.
[2] Id., at page 9.
[3] Id, at pages 10-12.
[4] Id, at page 11.
[5] Id., at pages 16-17.
[6] Id., at pages 18. UNS Electric has not committed to any specific "stay out" period based on whether CWIP is or is not included in rate base in the current case.

Basically, these are not new arguments for inclusion of CWIP in rate base, but rather are a restatement of the Company's original request that CWIP be included in rate base in order to maintain the Company's financial integrity, to mitigate regulatory lag, to fund its rapid growth and to extend the period between rate cases.

Q. Mr. Grant's Rebuttal Testimony cites two Arizona Supreme Court cases in the 1970s that discussed the inclusion of CWIP in rate base. Has he demonstrated that the facts and circumstances of UNS Electric in the current case are similar to the specifics addressed in those cases?

A. No.

Q. At page 10 of his Rebuttal Testimony, Mr. Grant recommends applying a "financial integrity test" which would determine whether CWIP should be included in rate base or not. Has UNS Electric demonstrated that including CWIP in rate base is necessary in order to preserve its financial integrity?

A. I don't believe so. UNS Electric is experiencing rapid growth in customers, but it is not in financial distress. Staff witness David Parcell describes in his Direct and Surrebuttal Testimony how Staff's recommendations concerning cost of capital should permit UNS Electric to raise capital on reasonable terms. At page 27 of his Rebuttal Testimony, at lines 8-12, Mr. Grant agrees with Mr. Parcell's conclusion that CWIP is not necessary for UNS Electric to attract capital, and concedes that: "over the short-term, assuming no significant changes occur in the capital markets, that UNS Electric could probably attract additional capital without having CWIP in rate base." Staff witness Alexander Igwe has recommended in his Direct Testimony that the Commission approve the Company's request for financing. Staff has also recommended adoption of a PPFAC mechanism for UNS Electric that includes a forward-looking component, which, prospectively, should

help match the Company's recovery of fuel and purchased power expense in the designated FERC accounts with the incurrence of such expense. Consequently, given the facts and circumstances of this case, the Company has not justified including CWIP in rate base and its request for CWIP in rate base should be denied.

Q. Please comment upon the use of financial projections by Mr. Grant as support for his arguments that CWIP should be included in rate base.

A. Mr. Grant appears to be relying on financial forecasts on pages 16 and 28-33 and elsewhere in his Rebuttal Testimony. I would caution against placing much reliance upon forecasts as the basis for ratemaking treatments, such as the CWIP issue in the current case. Forecasts are subject to change and can be inaccurate.[7]

At page 28 of his Rebuttal Testimony, Mr. Grant purports to recalculate his financial forecast and key financial indicators for UNS Electric based on inputting a $4.7 million reduction to the Company's requested revenue increase. However, to merely input a revenue difference without also reflecting the impact of the specific adjustments which cause that difference (i.e., without also reflecting the reasons for the difference) is questionable and unlikely to produce reliable forecasts that are meaningful and relevant for ratemaking purposes. In states that utilize future test years, where projections are made beyond the historical period, adjustments are not just made to revenues but to all of the components of the ratemaking formula which impact the level of revenues. In jurisdictions that utilize future test years, when adjustments are made for disallowed expenses, the disallowed expenses are removed from the future test year. To the extent that Mr. Grant is attempting to use his revised financial forecasts as some kind of

[7] Mr. Grant's rebuttal, at page 18, states that in 2003, the Company could not foresee the amount of capital investment needed to serve customer growth and system improvement needs, and that "it was difficult to predict the future impact of regulatory lag on UNS Electric."

surrogate for a future test year, or as some kind of test of the reasonableness of the parties' differing recommendations, his comparisons do not appear to reflect the adjustments to rate base or expenses that contribute to Staff recommending a different level of revenue increase than has been requested by the Company.

Q. Please discuss the issue of regulatory lag as it relates to the CWIP issue and to utility ratemaking in Arizona.

A. In Arizona, a historic test year with pro forma adjustments is used to establish utility rates. This approach has been employed for many years, and primarily without the inclusion of CWIP in utility rate base. The use of a test year, with appropriate adjustments, is intended to assure that the elements of the ratemaking formula are in balance. Regulatory lag refers to the difference in time between the test year and the rate effective date. My understanding is that it has always existed as an integral part of rate of return-based public utility regulation in Arizona, and for that matter virtually all states. It is not a new phenomenon which would require a change in basic regulatory policy. Moreover, there are other aspects of regulatory lag that benefit the Company. These include expired amortizations and accumulated depreciation. The Company continues to earn a return on and receives a recovery of assets that have already been recovered.

Q. Is inclusion of CWIP in rate base up to the discretion of the Commission?

A. Yes, it is. Staff's understanding is, in specific instances, the Commission has allowed a utility to include CWIP in rate base, but the Commission's general practice has been to <u>not</u> allow CWIP to be included in rate base.

Q. How does Staff view the "burden of proof" UNS Electric would have to meet in order to have CWIP included in rate base?

A. As I noted in my Direct Testimony, the burden of proof is on UNS Electric to prove its revenue requirement. Where the Commission has a very well-established policy, such as the exclusion of CWIP from rate base, UNS Electric bears the burden to demonstrate that it is different in significantly important respects than the comparable circumstances in the other utility rate cases over the past decades where CWIP was excluded from rate base. In other words, UNS Electric must show how it is different from the normal circumstances of a regulated Arizona public utility where CWIP has been excluded from rate base. In the current case, UNS Electric has failed to do this.

In this case, UNS Electric, Staff and RUCO have all acknowledged that the Commission's policy and practice has been to exclude CWIP from rate base. My Direct Testimony presented a number of reasons why CWIP has been excluded from rate base, which apply to CWIP in general as well as to UNS Electric in the current case. Mr. Grant's Rebuttal Testimony at page 34 does not refute these reasons. In fact, he indicates that two of the reasons are obvious: (1) that CWIP in rate base is not normally allowed by the Commission, and (2) that projects included in the test year CWIP balance were not in service as of the test year. He has also failed to demonstrate that post-test year revenue increases and expense reductions enabled by the CWIP have been properly identified and quantified by the Company and used as an offset to the revenue requirement impact of including CWIP in rate base. Consequently, the Company's proposal fails the matching principle. Nor has Mr. Grant demonstrated that UNS Electric is in financial distress, that it cannot continue to attract capital at favorable terms if CWIP continues to be excluded from rate base, or that UNS Electric is fundamentally different in terms of its customer

growth and regulatory lag situation than the other major utilities in Arizona which do not have CWIP included in rate base.

Q. Based on your review of the reasons presented by UNS Electric in its Direct and Rebuttal Testimony and other factors, should CWIP be included in rate base in the current case?

A. No. In general, Staff does not favor inclusion of CWIP in rate base unless the utility demonstrates compelling reasons to justify this exceptional ratemaking treatment. For the following reasons, Staff does not support UNS Electric' request for rate base inclusion of CWIP in the current case:

1) Inclusion of CWIP in rate base is an exception to the Commission's normal practice, and UNS Electric has not met its burden of proof showing why it requires such an exceptional ratemaking treatment. UNS Electric has not demonstrated that it is in financial distress, or that it would be unable to obtain financing at a reasonable cost if the normal practice of excluding CWIP from rate base is followed in the current case. Staff witness David Parcell addresses how Staff's recommendations should enable UNS Electric to continue to have access to financing at a reasonable cost. Mr. Parcell also addresses the determination of a fair rate of return that would allow UNS Electric to attract new capital on reasonable terms. In making his cost of capital recommendations, Mr. Parcell has been made aware of and has taken into consideration UNS Electric' proposal to include CWIP in rate base and Staff's recommendation that CWIP not be included in rate base in this case.

2) The CWIP was not in service at the end of the test year. As of June 30, 2006, the construction projects were not serving customers.

3) The Company has not demonstrated that its June 30, 2006 CWIP balance was for non-revenue producing and non-expense reducing plant. Much of the construction appears to be for plant related to serving customer growth, i.e., to be revenue producing. Test year revenues have been annualized to year-end customer levels. However, revenues have not been extended beyond the test year to correspond with customer growth. Hence, including the investment in rate base, without recognizing the incremental revenue it supports, would be imbalanced. Some of the facilities that are being constructed will be used subsequent to the test year ending June 30, 2006 to serve additional customers. It would not be appropriate to include the investment that will serve those new customers without also including the revenues that would be received from those customers. In other words, allowance of CWIP in rate base would result in a mismatch in the ratemaking process. Additionally, some of the plant being added could result in a reduction in maintenance expenditures which would not be reflected in the test period. The inclusion of CWIP in rate base, therefore, creates an imbalance in the relationships between rate base serving customers and the revenues being provided to the utility from customers who were taking service during the test year. Consequently, CWIP should not be allowed in rate base unless there are very compelling circumstances which would warrant an exception to the general rule.

4) UNS Electric accrues a return, representing its financing costs during the construction period, called AFUDC. This AFUDC return accounts for the utility's financing cost during the construction period.

5) Other large Arizona utilities are also facing customer growth and similar "regulatory lag" issues to UNS Electric. Yet, to the best of my knowledge, none of the large Arizona utilities have CWIP in rate base. UNS Electric has failed to demonstrate that

its circumstances are so different and unique that it requires a significantly different regulatory treatment for CWIP.

6) While the Company has stated that inclusion of CWIP in rate base could result in deferring the filing of its next rate case, the Company has made no specific enforceable commitments to a filing moratorium period.

In summary, in the current case, UNS Electric has not demonstrated convincingly that it requires an exception to the Commission's standard ratemaking treatment of excluding CWIP from rate base.

Q. If CWIP were to be included in rate base, as requested by the Company, what is the UNS Electric rebuttal position concerning whether the accrual of AFUDC should cease?

A. This issue is addressed in Mr. Grant's rebuttal at page 35-36. As Mr. Grant recognized on page 14, lines 10-12, of his Rebuttal Testimony in the recent UNS Gas rate case[8] (but fails to mention in his Rebuttal Testimony in the current UNS Electric rate case), "the accounting guidelines published by the FERC require utilities to subtract the amount of any CWIP allowed in rate base from the balance of future CWIP eligible for AFUDC accruals." However, contrary to these rules, Mr. Grant attempts to carve out an exception for UNS Electric to this required accounting for AFUDC. He states that, because there is only a small amount of AFUDC on the test year balance of CWIP, it would be unfair to require UNS Electric to cease accruing AFUDC on $10.8 million of CWIP on an ongoing basis. If the Commission grants the Company's request to include CWIP in rate base, Mr.

[8] Docket Nos. G-04204A-056-063 et al.

Grant requests that language be included in the order that authorizes the Company to continue accruing AFUDC on all eligible construction projects.

Q. Does Staff agree with this proposal by Mr. Grant to continue accruing AFUDC even if CWIP were to be included in rate base?

A. No. Mr. Grant's proposal to continue accruing AFUDC on CWIP should be rejected because it is contrary to the accepted accounting guidelines and would result in a double recovery of the financing cost of CWIP. The financing cost for CWIP can be addressed for ratemaking purposes in one of two ways: (1) through the inclusion of CWIP in rate base for a current cash return, or (2) through the accrual of AFUDC, which is added to the construction cost and is ultimately included in the cost of plant and depreciated. It would be improper to give UNS Electric both a cash return on CWIP through its inclusion in rate base and an AFUDC return. If CWIP were to be allowed in rate base, which the Staff is not recommending in this case, then AFUDC accruals on the amount of CWIP included in rate base must cease.

Q. Does Staff agree with UNS Electric' alternative proposal to include post-test year plant additions in rate base, if the inclusion of CWIP in rate base is denied?

A. No. Making the CWIP adjustment in a slightly different format, by adding post-test year plant into rate base, also suffers from the same flaws as the Company's proposal to include CWIP in rate base. It is imbalanced because it fails to capture any post-test year revenue growth and maintenance expense decreases enabled by the new plant. Consequently, for reasons similar to the ones described above, Staff does not agree with UNS Electric's proposed alternative of including post-test year plant additions in rate base.

Q. At pages 34-35 of his Testimony, Mr. Grant recommends removing Customer Advances of approximately $1.9 million from rate base, if CWIP is excluded. Does Staff agree with this UNS Electric proposal?

A. No. Customer Advances should be reflected as a deduction from rate base. Customer Advances represent non-investor supplied capital, and therefore should be reflected as a deduction to rate base. Mr. Grant has not cited any prior Arizona utility rate case in which CWIP was excluded from rate base and Customer Advances were not reflected as a reduction to rate base to recognize the non-investor provided cost-free capital. Nor is Staff aware of an instance for any major Arizona public utility where CWIP was excluded from rate base and Customer Advances were not reflected as a deduction to rate base. The Commission's rules (A.A.C. R14-2-103, Appendix B, Schedule B-1) require that Customer Advances be reflected as a deduction from rate base.

One additional reason why Customer Advances should be deducted from rate base is to prevent a double rate of return. In accruing AFUDC by applying the AFUDC rate to a CWIP balance, Customer Advances are typically not deducted from the construction cost base upon which AFUDC is computed. If the Customer Advances have not been specifically deducted in the AFUDC calculations (which would be contrary to the prescribed treatment for a utility following the AFUDC formula in the FERC Uniform System of Accounts), the non-investor provided cost-free capital in the form of Customer Advances needs to be reflected as a rate base deduction.

Consequently, the request by Mr. Grant to adjust the balance of Customer Advances, if CWIP is excluded from rate base, is contrary to precedent, would be improper for ratemaking purposes, and should be rejected.

Q. Does Staff's adjustment to remove CWIP from rate base affect UNS Electric's expenses?

A. Yes. UNS Electric had proposed to treat CWIP at the end of the test year as if it were plant in service. Consistent with that, UNS Electric proposed increases to depreciation and property tax expense. Consistent with Staff's recommendation that CWIP not be included in rate base, Staff adjustment C-2, which was described in my Direct Testimony, has removed the related UNS Electric adjustments for depreciation and property tax expense.

B-3 Plant in Service Addition Subject to Reimbursement

Q. Please discuss the Company's rebuttal concerning a Customer Advance related to the Tubac Golf Resort Overhead to Underground Conversion project.

A. As described in my Direct Testimony, Staff's inspection of the Tubac Golf Resort Overhead to Underground Conversion (task CE64023) with a cost of $236,874 had the appearance of a project that should be reimbursed, at least in significant part by the customer, since it involved the removal of an overhead 13 kV line and installation. UNS Electric had advised Staff that the project appeared to be reimbursable to some extent, but was not able to provide documentation of the customer reimbursement. Ms. Kissinger's rebuttal explained that the related Customer Advance had been recorded by the Company by the end of the test year (but had been mis-coded to a different project). However, her Rebuttal Testimony did not appear to include adequate documentation for Staff to verify this.

As indicated in my Direct Testimony, if the CIAC had been recorded by UNS Electric by June 30, 2006, the adjustment shown on Schedule B-3 would not be necessary and should be withdrawn. For purposes of recalculating the rate base and revenue requirement in

Attachment RCS-6, I have removed adjustment B-3. However, if the requested information is not provided, this adjustment may be restored.

Q. Based on the supporting information and explanations presented by UNS Electric in Ms. Kissinger's Rebuttal Testimony, is Staff withdrawing this adjustment?

A. Based on the explanations in Ms. Kissinger's Rebuttal Testimony, Staff is currently evaluating whether this adjustment should be withdrawn. Staff is awaiting the receipt of adequate supporting documentation, which has been requested in data request STF 20.50.

B-4 Cash Working Capital

Q. Have you revised Staff's calculation of the working capital allowance?

A. Yes. On Schedule B-4, Revised, I have updated Staff's calculation of cash working capital for the impact of revised operating expenses.

B-5 Accumulated Deferred Income Tax

Q. Is there a difference between Staff's and the Company's proposed amount of rate base deduction for Accumulated Deferred Income Taxes ("ADIT")?

A. Yes. Staff has made an adjustment (which was described in my Direct Testimony and shown on Schedule B-5) to decrease rate base by $161,555 for the impact of the following:

1) removal of the ADIT related to the Supplemental Executive Retirement Plan ("SERP")[9]; and
2) removal of the ADIT relating to stock-based compensation.[10]

[9] See Staff Adjustment C-8 that has removed the expense related to SERP.
[10] See Staff adjustment C-9 that removes the expense for stock-based compensation.

This adjustment to ADIT is necessary to properly coordinate the impact of Staff's related adjustments to operating expenses with the ADIT amount included in rate base. Whether the rate base adjustment to ADIT should be made is dependent upon whether the related adjustments to operating expense are used.

IV. ADJUSTMENTS TO OPERATING INCOME

Q. As a result of additional review of information, including the UNS Electric rebuttal, have you revised Staff's proposed net operating income?

A. Yes. Attachment RCS-6, Schedule C summarizes Staff's revised recommended net operating income. Schedule C.1, present Staff's recommended adjustments to test year revenues and expenses on an Arizona jurisdictional basis. The impact on state and federal income taxes associated with each of the recommended adjustments to operating income are also reflected on Schedule C.1. UNS Electric's originally proposed adjusted test year net operating income is $8.742 million[11], whereas Staff's revised recommended adjusted net operating income is $9.516 million. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1 Revenue Adjustment for CARES Discount

Q. Has any revision to Staff Adjustment C-1 be made as a result of the UNS Electric rebuttal?

A. No. This adjustment removes UNS Electric's proposed adjustment to reduce electric retail revenue by $52,937 relating to a change proposed by the Company concerning how the discounts for CARES customers are calculated. As explained in the testimony of Staff witness Julie McNeely-Kirwan, Staff disagrees with that Company proposal and recommends that the existing discount rate structure for CARES be retained. Staff has

[11] Mr. Dukes' Rebuttal Exhibit DJD-1 shows that the Company has revised this to $8.759 million.

reflected its recommendations concerning the CARES discounts in the Staff proposed rate design.

C-2 Remove Depreciation and Property Taxes for CWIP

Q. Was Staff Adjustment C-2 revised as a result of the UNS Electric Rebuttal Testimony?

A. No. This adjustment removes the pro forma amounts calculated by UNS Electric for depreciation and property taxes related to the Company's proposal to include CWIP in rate base. As explained above[12], Staff disagrees with the Company's proposal to include CWIP in rate base. Accordingly, Staff has also removed the pro forma depreciation and property tax expense adjustments proposed by UNS Electric. As shown on Schedule C-2, this reduces the Company's proposed expenses for depreciation by $449,816 and property taxes by $239,696, for a total reduction of $689,512.

C-3 Depreciation and Property Taxes for CWIP Found to Be In-Service in the Test Year

Q. Was Staff adjustment C-3 revised as a result of the UNS Electric rebuttal?

A. No. This adjustment relates to rate base adjustment B-2. As described above in conjunction with Staff adjustment B-2, Staff's engineering and used-and-useful review revealed that a project that UNS Electric had included in CWIP was actually in service in May, 2006, and thus qualifies as plant in service. This adjustment increases recorded test year expenses to provide for depreciation and property taxes related to a project that UNS Electric had included in CWIP, Rhodes Homes (task 8009729), with a cost of $442,255 that was inspected by Staff on June 6, 2007, and was found to be in service on May 26, 2006, which was prior to the end of the test year.

[12] See above discussion in conjunction with Staff Adjustment B-1.

Q. Does UNS Electric appear to agree with this adjustment in principle?

A. Yes. While UNS Electric would prefer to have all CWIP included in rate base (a proposal with which Staff disagrees), the Company has indicated in Ms. Kissinger's Rebuttal Testimony at pages 3-4 that it accepts Staff Adjustments B-3 and C-3 for recognizing plant that was placed into service by the end of the test year, and the related impact on expense.

C-4 Fleet Fuel Expense

Q. Have you revised Staff Adjustment C-4 for fleet fuel expense?

A. Yes. The documentation presented in Mr. Dukes' rebuttal workpapers on page UNSE(0783)10597 shows a total fleet fuel expense of $585,210 for the 12-month period July 2006 through June 2007, one full year after the test year. That workpaper, which is reproduced in Attachment RCS-8, also shows total gallons of 207,310 for that 12 month period. This actual information calls into question the accuracy of the Company's proposed pro forma calculation method (which was also followed by Staff and RUCO in their respective direct filings) for adjusting the quantity of gallons purchased. The Company's as-filed direct adjustment, and the Staff and RUCO pro forma calculations, which had accepted that part of the Company's calculation, resulted in pro forma gallons purchased of approximately 214,500 gallons. If the cost per gallon is going to be adjusted for a full year of post-test year pricing, the related pro forma quantity of gallons of fuel purchased should also be adjusted to correspond with the price data. Accordingly, as shown on Schedule C-4, revised, Staff has revised this adjustment to use 207,310 gallons at $2.82 per gallon, for a pro forma fleet fuel cost of $585,210.

UNS Electric's originally proposed adjustment is reduced by $62,197, as shown on Schedule C-4 (Revised).

C-5 Postage Expense

Q. Is there any remaining dispute between UNS Electric and Staff concerning normalized postage expense?

A. No. UNS Electric has adopted the adjustment shown on Schedule C-5, which increased UNS Electric's proposed amount of postage expense by $17,503 to reflect a known increase that became effective in May 2007.

C-6 Normalize Injuries and Damages Expense

Q. Has UNS Electric agreed with a portion of Staff Adjustment C-6?

A. Yes. In Mr. Dukes' Rebuttal Testimony at page 5, lines 16-25, UNS Electric agrees that the workers' compensation portion of injuries and damages expense is abnormally high during the test year and should therefore be reduced by $79,978. At page 5, lines 20-22, Mr. Dukes states that: "It does appear that the test-year amount of $173,456 is abnormally high due to the timing of when activity was actually expensed."

Q. Does Staff accept the adjustment proposed by Mr. Dukes of $79,978 for the workers' compensation portion of injuries and damages?

A. No. Mr. Dukes proposed adjustment is based on a test year expense of $173,456 for workers' compensation, which appears to understate the actual test year expense and is inconsistent with information provided by the Company concerning test year workers' compensation expense in response to data requests, such as STF 3.102 and STF 11.16.

Moreover, the remaining expense in Account 925, after making Mr. Dukes' proposed adjustment would appear to substantially exceed a normalized level.

Q. What other concerns does Staff have about the amount of injuries and damages expense proposed by UNS Electric?

A. Staff has continuing concerns about the total of Account 925 for the test year not being representative of normal, ongoing activity, and with respect to the remaining items in the account, including the Company's expense for Directors' and Officers' Liability ("D&O") Insurance, which is recorded in Account 925 and has been increasing substantially, from $22,032 in 2004, to $88,605 in 2005, to $130,330 in 2006, as listed in the responses to data requests STF 3.102 and STF 11.16. Mr. Dukes' Rebuttal Testimony at page 4, lines 25-26, explains that "that dramatic increase was caused by the fact that this coverage was not allocated to UNSE in 2004 and only partially in 2005." Staff is reviewing the workpapers and supporting documentation that UNS Electric has supplied after the filing of Mr. Dukes' Rebuttal Testimony, but has not yet completed that review. Staff has also reviewed the total amount recorded in Account 925 for the 12 month period following the test year, i.e., for the 12 months ending June 30, 2007, however, and that amount supports the overall reasonableness of Staff's recommended normalized allowance.

Q. What was the total amount in Account 925 for the 12 months ending June 30, 2007?

A. The total amount of expense in Account 925 for the 12 months ending June 30, 2007 listed on Company workpaper UNSE(0783)10737 was $398,032.

Q. How does that amount compare with Staff's recommended normalized amount?

A. Staff's recommended normalized amount for this account is $403,340, as shown on Schedule C-6. The Company's actual expense for the 12 months following the test year of $398,032 is $5,308 <u>less</u> than Staff's recommended normalized allowance.

Q. What do you recommend?

A. I continue to recommend a normalized level of expense for Account 925 of $403,340.

C-7 Incentive Compensation

Q. As a result of UNS Electric's Rebuttal Testimony, is any revision being made to Staff Adjustment C-7?

A. No. This adjustment removes 50% of the expense related to the various incentive compensation programs in effect at UNS Electric. In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50% of the incentive compensation expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals; however, there is no assurance that the award levels included in the Company's proposed expense for the test year will be repeated in future years.

The adjustments to expense for each of UNS Electric's incentive compensation programs are shown on Schedule C-7. The adjustment reduces O&M expense by $42,448. A related impact on payroll tax expense reduces that by $1,553.

Q. What is the UniSource Energy Corporation's Performance Enhancement Program?

A. UNS Electric participates in the same incentive compensation arrangement, the Performance Enhancement Plan ("PEP"), as its affiliate, UNS Gas. As explained in the Company's supplemental response to data request STF 11.5 in the recent UNS Gas rate case, Docket Nos. G-04204A-06-0463 et al, the utility's non-union employees participate in UniSource Energy Corporation's PEP. UniSource Energy Services ("UES") is a

subsidiary of UniSource Energy Corporation and the parent company of UNS Electric. The structure of the PEP determines eligibility for certain bonus levels by measuring UES' performance in three areas: (1) financial performance; (2) operational cost containment; and (3) core business and customer service goals. Levels of achievement in each area are assigned percentage-based "scores." Those scores are combined to calculate the final payout. The amount made available for bonuses pursuant to the PEP formula may range from 50 percent to 150 percent of the targeted payment level. The financial performance and operational cost containment components each make up 30 percent of the bonus structure, while the core business and customer service goals account for the remaining 40 percent. Additional information concerning the PEP was discussed in my Direct Testimony.

Q. What arguments does Mr. Dukes present in his Rebuttal Testimony for why the costs of UniSource Energy Corporation's Performance Enhancement Program should be fully charged to ratepayers?

A. At page 6 of his rebuttal, Mr. Dukes claims that the evidence he discusses in his Rebuttal Testimony shows that UNS Electric's total employee compensation including the PEP program is reasonable. At page 7 of his rebuttal, he claims that the PEP program costs "are actually a net savings to customers." He claims that "the goals and targets of the current PEP program are also heavily weighted toward providing benefits to customers." At page 8, he claims that "if the PEP program is eliminated, there would be considerable increased pressure on base compensation." At page 9 of his rebuttal, Mr. Dukes claims that direct savings result because PEP is not part of base compensation, and "the impact of reduced compounding wage increases that would be based on a higher base pay total is another benefit." At page 10, he cites a Commission Decision No. 69663 in a recent Arizona Public Service Company rate case where cash-based incentive compensation

expense was allowed. At pages 10-11 of his rebuttal, Mr. Dukes claims that UNS Electric's PEP incentive compensation is different than the Southwest Gas Corporation ("SWG") Management Incentive Plan ("MIP") because the SWG MIP appears limited to management personnel, whereas UNS Electric's PEP plan covers all non-union employees. He claims that the PEP is based on broader and more wide-ranging factors, of which financial performance is only part of the consideration. Finally, on pages 11-13, he selectively cites to a few decisions from other regulatory commissions where the cost of a utility incentive compensation program was allowed to be included in rates.

Q. Has Mr. Dukes demonstrated that PEP is a net savings to customers?

A. No. Mr. Dukes has not demonstrated that base salaries were reduced when PEP was implemented. Moreover, base salaries have continued to increase each year. Thus, the PEP expense is an additional cost to the base salaries and other employee benefits.

Q. How does the weighting of the PEP goals affect your analysis of how the incentive compensation cost should be shared between shareholders and ratepayers?

A. The specific design of the incentive compensation program is one factor to be considered in determining the appropriate sharing of the cost between shareholders and ratepayers. The PEP program uses financial performance measures weighted at 30 percent, operational cost containment weighted at 30 percent, and customer service goals weighted at 40 percent. Shareholders benefit from financial performance, and also benefit between rate cases from any operational cost containment that is produced. While a 60/40 or some other sharing allocation could be used for ratemaking purposes, the 50/50 sharing recommended by Staff considers that there is benefit to both shareholders and to customers, and is a reasonable allocation.

Q. Has the Company made PEP payouts even where the specified goals were not met?

A. Apparently yes. As explained in the Company's supplemental response to data request STF 11.5(c) in the recent UNS Gas rate case, Docket G-04204A-06-0463:

> "In 2005, PEP had a similar structure as 2004 with two primary goals. However, the primary financial goal was now a combined financial measure for UNS Electric, UNS Gas and TEP. The second primary goal measured UNS Electric financial performance, customer and reliability goals, integration goals, and safety and employee goals. Similar to the prior year, each of the two primary goals was weighted equally and PEP only paid if the primary financial goal was met. As stated in the response to STF 11.5 b, the 2005 primary financial goal was not met."

Even though the primary financial goal under the PEP was not met in 2005, incentive bonuses were paid. As explained in the utility's supplemental response to STF 11.5(b): in the recent UNS Gas rate case, Docket No. G-04204A-06-0463, which describes the same UniSource Energy PEP in which UNS Electric also participates:

> "... the financial performance goal, which was a trigger under the PEP program for UNS Electric, UNS Electric and Tucson Electric Power Company ("TEP"), was not met. The financial performance goal was not met, in part, because of unplanned outages at the coal generating units which required TEP to purchase power on the open market. In discussions with the Board of Directors, the desire was to recognize employee achievements distinct from financial measures. The Board deemed it appropriate to implement a Special Recognition Award to employees for achievements in 2005. Normally, PEP is paid at 50% to 150% of target; the Special Recognition Aware was paid at approximately 42% of the target for each of the operating companies."

Q. What evidence does Mr. Dukes rely upon for his claim that the compensation of employees who receive PEP incentive bonuses is reasonable?

A. At page 8 of his Rebuttal Testimony he references and appears to be relying upon Confidential Exhibit DJD-3 for this conclusion. However, that exhibit does not appear to include an evaluation of the compensation for all employees who are eligible to receive

PEP. After receiving Mr. Dukes' Rebuttal Testimony, Staff has requested clarification and additional information in discovery; however, responses have not yet been received.

Q. What does Mr. Dukes state is the Company's compensation philosophy?

A. At page 8, lines 12-13, Mr. Dukes states that: "The Company's compensation philosophy is to pay at approximately 50% of market rate for its employees."

Q. Is there evidence that this policy has not been followed?

A. At least with respect to executives, yes. In Confidential Attachment RCS-10, I have attached a copy of the "UniSource Energy Executive Compensation – Competitive Compensation Review" dated October 25, 2005 that was prepared by Frederic W. Cook & Co., Inc. (which was provided in a supplemental response to STF 22.10 in the recent UNS Gas rate case). That document indicates that **[REDACTED]**.

Q. At page 10 of his rebuttal, Mr. Dukes cited Commission Decision No. 69663 from a recent APS rate case where cash-based incentive compensation expense was allowed after it was not opposed by Staff in that case. Did Mr. Dukes' rebuttal fully address the analysis of incentive compensation contained in Commission Decision No. 69663?

A. No. It appears that Mr. Dukes may have cherry-picked one paragraph from that decision. However, in his Rebuttal Testimony, Mr. Dukes failed to mention that there was a disallowance made for incentive compensation in the APS rate case or the Commission's reasoning for that disallowance. In making the disallowance in the APS case, the Commission adopted a recommendation by Staff to disallow that company's stock-based compensation. Page 36 of Decision 69663 indicates that the Commission rejected an argument by APS that the Commission not look at how compensation is determined or its individual components:

> "APS argues that the issue is whether APS compensation, including incentives, is reasonable. APS does not believe that the Commission should look at how that compensation is determined or its individual components, but rather should just look at the total compensation. The Company argues that the interests of investors and consumers are not in fundamental conflict over the issue of financial performance, because both want the Company to be able to attract needed capital at a reasonable cost."
>
> "We agree with Staff that APS' stock-based compensation expense should not be included in the cost of service used to set rates. Contrary to APS' argument that we should not look at how compensation is determined, we do not believe rates paid by ratepayers should include costs of a program where an employee has an incentive to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate." As testified to by Staff witness Dittmer and set out in Staff's Initial brief, "enhanced earnings levels can sometimes be achieved by short-term management decisions that may not encourage the development of safe and reliable utility service at the lowest long-term cost. ... For example, some maintenance can be temporarily deferred, thereby boosting earnings. ... But delaying maintenance can lead to safety concerns or higher subsequent 'catch-up' costs." [cite omitted] To the extent that Pinnacle West shareholders wish to compensate APS management for its enhanced earnings, they may do so, but it is not appropriate for the utility's ratepayers to provide such incentive and compensation."

Thus, in Decision No. 69663, the Commission did make an adjustment to disallow a portion of that utility's incentive compensation expense.

Q. At pages 10-11 of his rebuttal, Mr. Dukes claims that UNS Electric's PEP incentive compensation is different than SWG Management Incentive Plan ("MIP") because the SWG MIP appears limited to management personnel, whereas UNS Electric's PEP plan covers all non-union employees. Please respond.

A. The specific forms of incentive compensation may differ somewhat in the coverage or structure between utilities regulated by the Commission. Again, Staff is not proposing an adjustment to the UNS Electric incentive compensation solely because an adjustment was made to SWG's incentive compensation. Rather, based on the factual situation in the current case, a 50/50 sharing of the UNS Electric's PEP incentive compensation expense

would appear to be fair and more appropriate than charging such expense 100 percent to ratepayers.

Q. Did the Commission disallow a portion of APS's and SWG's incentive compensation in each of their respective most recent rate cases?

A. Yes. The Commission disallowed a portion of APS's incentive compensation expense in Decision No. 69663 and disallowed a portion of SWG's incentive compensation in Decision 68487.

Q. Is Staff's recommended treatment of the PEP incentive compensation for UNS Electric consistent with the recommendation for this expense in the recent UNS Gas rate case?

A. Yes, it is. Staff sees no basis at this time for revising the recommendation that the cost of PEP be shared between ratepayers and shareholders.

Officer's Long-Term Compensation Program

Q. At pages 13-14 of his rebuttal, Mr. Dukes claims that long term incentive costs allocated to the Company from TEP for executive oversight of UNS Electric "represent a portion of the Officers' total compensation that is variable and put at risk, but are an integral part of a competitive compensation program. This *total compensation* is targeted at the median of the peer group as reviewed by an independent consultant on behalf of the Compensation Committee of the Board of Directors." He further claims that: "No party states that the package is unreasonable or excessive, or that refutes the evidence the Company provided that the costs are at the median of market and are necessary, reasonable and prudent cost incurred to attract and retain the Officer's (sic) of TEP and UNS Electric." Please respond.

A. Contrary to these assertions by Mr. Dukes, as shown in Attachment RCS-10, a recent executive compensation study shows the total compensation of officers **[REDACTED].** At page 8, lines 12-13 of his rebuttal, Mr. Dukes stated that: "The Company's compensation philosophy is to pay at approximately 50% of the market rate for its employees." Compensation that is substantially in excess of 50% of the market rate could presumably be viewed as unreasonable and even excessive. In addition to the reasons described in my Direct Testimony for disallowing this cost, an additional argument could be made that the compensation is in excess of 50% of the market rate, and consequently is excessive and should be borne by shareholders and not charged to ratepayers.

C-8 Supplemental Executive Retirement Program Expense

Q. In response to UNS Electric's Rebuttal Testimony, is any revision being made to Staff Adjustment C-8?

A. No. Staff's adjustment removes 100% of the expense for the Supplemental Executive Retirement Plan ("SERP"). The SERP provides supplemental retirement benefits for select executives. Generally, SERPs are implemented for executives to provide retirement benefits that exceed amounts limited in qualified plans by Internal Revenue Service ("IRS") limitations. Companies usually maintain that providing such supplemental retirement benefits to executives is necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can also limit the Company 401(k) contributions such that the Company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

In Decision No. 68487, February 23, 2006, an SWG rate case, the Commission adopted a recommendation by RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of Order 68487 that:

> "Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers."

The SERP expense at UNS Electric is not distinguishable in any material way from the SERP expense that was disallowed in the recent SWG rate case. Consequently, I continue to recommend the adjustment to remove UNS Electric's expense for the SERP, which is shown on Schedule C-8 and reduces O&M expense by $83,506.

C-9 Stock Based Compensation

Q. Has any revision been made to Staff Adjustment C-9 as the result of UNS Electric's rebuttal?

A. No. This adjustment decreases test year expense by $82,873 for the removal of stock-based compensation to officers and employees. The expense of providing stock options and other stock-based compensation to officers and employees beyond their normal levels of compensation should be borne by shareholders and not by ratepayers. The Commission recently disallowed APS's stock-based incentive compensation expense in Decision No. 69663.

At page 8, lines 12-13 of his rebuttal, Mr. Dukes states that: "The Company's compensation philosophy is to pay at approximately 50% of the market rate for its employees." Compensation that is substantially in excess of 50% of the market rate could presumably be viewed as unreasonable and even excessive. As shown in Attachment RCS-10, a recent executive compensation study suggests that the total compensation of officers **[REDACTED].**

C-10 Property Tax Expense

Q. What response in rebuttal did UNS Electric present to Staff Adjustment C-10?

A. UNS Electric's Rebuttal Exhibit DJD-1, page 5 of 5 indicates that UNS accepts Staff's adjustment. This adjustment reflects the known statutory assessment ratio of 23.5 percent

applicable for 2008, when rates in this case are expected to become effective. The Arizona State Legislature passed House Bill No. 2779 which set a new rate schedule for property tax assessments. The new assessment rate schedule provides for decreasing the 25 percent rate applicable in 2005 in 0.5 percent steps each year until a 20 percent rate is attained in 2015. The Company's calculation used a 24 percent assessment rate and thus failed to recognize the impact of this known tax change prospectively. Staff's recommended adjustment reduces UNS Electric's proposed property tax expense by $59,747.

C-11 Rate Case Expense

Q. Please discuss the allowance for rate case expense.

A. UNS Electric's filing requests an amount of $600,000 for rate case expense normalized over a three year period, for an annual allowance of $200,000 per year. Staff recommends an annual allowance of $88,333 per year, based on a total of $265,000 normalized over three years. The total amount of rate case expense requested by UNS Electric of $600,000 and the annual allowance of $200,000 per year over a three-year period appears to be excessive and would represent an unreasonable burden on ratepayers. The amount of $600,000 requested by UNS Electric is over 2.5 times as high as the amount of rate case expense allowed by the Commission in the Southwest Gas rate case, which was $235,000 in total, and which was normalized over a three-year period. Although Southwest Gas is a larger utility than UNS Electric, the current UNS Electric rate case has similarities to the Southwest Gas rate case in terms of both the scope of issues in the cases, and the majority of each application being sponsored by in-house or affiliated company staff. Staff Adjustment C-11 reduces the $200,000 annual amount that was requested in the Company's original filing for rate case expense by $111,667 to provide for an annual allowance of $88,333 per year.

Q. Does the fact that this is the first rate case for UNS Electric justify a $600,000 rate case expense?

A. No. While the current case may be the first rate case for this utility operation under its current ownership, it isn't the first rate case for this utility. This electric utility had periodic, recurring rate cases under its prior ownership by Citizens Utilities. The transfer of ownership should not be an excuse for charging ratepayers for what appear to be excessive amounts of rate case cost.

Q. At page 16-17 of his rebuttal, Mr. Dukes claims that SWG is not comparable to UNS Electric, because of the way in which SWG and TEP charge for shared services. Why does Staff view the SWG allowance for rate case expense to be a good guideline for UNS Electric?

A. Staff used the SWG rate case allowance as a reasonable benchmark for UNS Gas in that utility's recent rate case, Docket No G-04204A-06-463 et al. Moreover, the current UNS Electric rate case is similar to and presents many of the same issues, such as revisions to a PGA/PPFAC mechanism, adjustments to operating expenses for incentive compensation and SERP, etc., that were recently addressed by the Commission in Docket No. G-01551A-04-0876, a rate case involving a large gas distribution utility in the state, Southwest Gas Corporation. Consequently, Staff believes that the Southwest Gas case provides a reasonable benchmark for what a reasonable allowance for rate case cost should be in the current UNS Electric rate case.

Q. Is the current UNS Electric rate case the best forum for reviewing whether the allocation of TEP shared services cost should be revised?

A. No. Staff believes that the allocation of TEP shared services costs can best be reviewed in the current rate case that TEP has filed in Docket Nos. E-01933A-05-0402 et al. Staff

would caution against attempting to allocate substantially higher amounts of TEP shared services cost to UNS Electric in the current case, where it cannot be adequately verified that such costs are being removed from TEP's expenses.

C-12 Edison Electric Institute Dues

Q. Please respond to UNS Electric's Rebuttal Testimony concerning Edison Electric Institute ("EEI") dues.

A. At page 17 of his rebuttal, Mr. Dukes concedes that "based on the historical standard of excluding lobbying cost we (UNS Electric) should have excluded the EEI Utility Air Regulatory Group ("UARG") dues. He argues against the exclusion of 49.93 percent of the EEI regular dues, however, on the grounds that the Company has provided extensive information on the benefits to customers through its EEI membership. He provided that information in Exhibit DJD-5 to his Rebuttal Testimony.

Q. What is provided in Mr. Dukes' Rebuttal Exhibit DJD-5?

A. It basically is a reproduction of the Company's response to data request STF 11.11. The benefits claimed by Mr. Dukes are apparently those listed in the response to STF 11.11, parts a and c. Those subparts had requested a listing of what EEI did during the test year to represent the interests of its members in advocating positions in the legislative and regulatory arenas and a statement of "exactly what advocacy activities before Congress and government agencies EEI engaged in during the test year." Neither UNS Electric nor its affiliates have performed a study or evaluation of whether its ratepayers are receiving a benefit from the EEI membership that is commensurate with the cost.[13]

[13] See, e.g., response to STF 11.11(f).

Q. Why should 49.93 percent of the regular EEI dues be disallowed?

A. Staff's adjustment reduces test year expense by $8,470 to reflect removal of 49.93 percent of EEI core dues and 100 percent of the EEI UARG dues. Staff's adjustment reflects the removal of 49.93 percent of EEI core dues based upon a classification by NARUC category for EEI Core Dues activities for the year ended December 31, 2005. This is shown on Schedule C-12, page 2. EEI Core Dues relating to the following activities should be excluded from rates:

- Legislative Advocacy
- Regulatory Advocacy
- Advertising
- Marketing
- Public Relations

The sum of EEI Core Dues activities for these NARUC categories totals 49.93 percent, as shown on Schedule C-12, page 2.

Q. What is the purpose of the NARUC-designated categorization of EEI expenditures?

A. The purpose of the NARUC-designated categorization of EEI expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities. Certain expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not

be to their benefit. The NARUC-designated categories of EEI expenditures are thus intended to be helpful to state utility regulatory commissions.

Q. Has Mr. Dukes addressed the NARUC categories of EEI expenses?

A. Not really. He appears to agree that the lobbying portion of EEI regular dues should be disallowed.

Q. Was this same percentage for the EEI core dues disallowance recently used in any other electric utility rate cases?

A. Yes. The Arkansas Public Service Commission in Docket No. 06-101-U, an Entergy Arkansas, Inc., rate case, in Order No. 10 (6/15/07) adopted a similar adjustment to reflect the disallowance of 49.93 percent of EEI core dues. This 49.93 percent disallowance of EEI core dues corresponds to the above-identified activity categories.

C-13 Other Membership and Industry Association Dues

Q. Has UNS Electric accepted Staff's proposed adjustment for Other Membership and Industry Association Dues.

A. Yes. Mr. Dukes' Rebuttal Exhibit DJD-1, page 3 of 6, states that: "UNS accepts … the adjustment for $6,482 (C-13) for other membership and industry association dues."

C-14 Interest Synchronization

Q. Have you updated Staff's interest synchronization adjustment?

A. Yes. The interest synchronization adjustment applies the weighted cost of debt to the calculation of test year income tax expense. After adjustments, my proposed rate base differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The revised calculation of the

interest synchronization adjustment is shown on Schedule C-14 of Attachment RCS-6. This adjustment increases income tax expense by the amount shown on Schedule C-14 and decreases the Company' achieved operating income by a similar amount.

C-15 Depreciation Rates Correction

Q. Has UNS Electric accepted Staff Adjustment C-15 to correct depreciation expense?

A. Yes. UNS Electric has accepted Staff's adjustment to reduce annualized depreciation expense by $63,105 to correct the Company's proposed depreciation rate for transportation equipment. See Mr. Dukes' Rebuttal Exhibit DJD-1, page 5, and the Rebuttal Testimony of UNS Electric witness Karen Kissinger at page 2.

C-16 Emergency Bill Assistance Expense

Q. Has UNS Electric accepted Staff Adjustment C-16?

A. Yes. UNS Electric has accepted Staff's adjustment to increase test year expense to be included in the base rate revenue requirement determination by $20,000 to provide for an increase requested by the Company for emergency bill assistance.

Adjustments Not Quantified in Staff's Direct Filing

Q. Have you adjusted Staff's revenue requirement calculation for certain adjustments that were not quantified in Staff's direct filing?

A. Yes. As described below, I have adjusted Staff's revenue requirement calculation for adjustments to certain operating expenses that were not quantified in Staff's direct filing, but which have now been quantified. The need for Adjustment C-17 was discussed in my Direct Testimony. Adjustments C-18 through C-20 merely reflects Staff's acceptance of certain corrections and revisions for three items that UNS Electric has agreed with in its Rebuttal Testimony. Each of these adjustments is discussed below.

C-17 Markup Above Cost for Charges from Affiliate, Southwest Energy Services

Q. Your Direct Testimony at pages 42-43 described the need for an adjustment to remove a 10 percent mark-up above cost related to charges to UNS Electric for services provided by the affiliated company, Southwest Energy Services. Have you quantified an adjustment for this?

A. Yes. As shown on Schedule C-17, I have removed $10,906 of expense, which is the test year amount of mark-up related to SES charges that was stated in the Company's supplemental response to data request STF 15.1. UNS Electric's supplemental response to STF 15.1 identified that amount, but also stated that: "The mark-up represents 6.5% of the total billings." I should note that the $10,906 used in this adjustment may be understated and appears to represent considerably less than 6.5% of the total test year direct and indirect billings to UNS Electric from the affiliate, SES. Staff has issued a follow up data request STF 21.3 to obtain further information concerning this.

C-18 Bad Debt Expense

Q. Please describe your adjustment to Bad Debt Expense.

A. This adjustment was made to reflect Staff's acceptance of UNS Electric's revision to its Bad Debt Expense adjustment as referenced in Mr. Dukes' Rebuttal Testimony at pages 21 and 22. Mr. Dukes agreed with RUCO's adjustment to Bad Debt Expense to the extent that RUCO used net write-offs in its adjustment versus gross write-offs as the Company did in its initial adjustment. In addition, Mr. Dukes' used a three-year average of net write-offs in his revised Bad Debt Expense calculation. Therefore, as shown on Schedule C-18, I have reduced Bad Debt Expense by $155,609.

C-19 Remove Double Count from Outside Services - Demand Side Management ("DSM")

Q. Please explain your adjustment to Outside Services as it relates to DSM expenses.

A. This adjustment was made to reflect Staff's agreement with an error correction identified at page 27 of Mr. Dukes' Rebuttal Testimony related to the removal of test year expense related to DSM activity. RUCO recommended the removal of $49,920 from Outside Services that the Company paid to ECOS Consulting pursuant to it developing the Residential New Construction DSM Program (Energy Smart Homes)[14]. Mr. Dukes agreed that the amount should be removed as the Company is proposing to recover such costs separately through a DSM charge. Mr. Dukes indicated in his Rebuttal Testimony that $32,865 of these costs were already included in the Company's DSM and Renewables adjustment, but that the remaining costs should also be removed. Therefore, as shown on Schedule C-19, I have removed the remaining expense $17,055 from the Company's test year expense.

C-20 Correct Year-End Accrual Expense Amount

Q. Please explain your adjustment to Year-End Accruals.

A. This adjustment was made to reflect Staff's agreement with the Company's and RUCO's removal of a prior period expense that was incurred in April 2004, but not recorded by the Company to expense until August 2005, as referenced in Mr. Dukes' Rebuttal Testimony at page 22. Therefore, as shown on Schedule C-20, I have removed $6,256 from test year expense.

[14] See Direct Testimony of RUCO witness Marylee Diaz Cortez at page 30.

Additional Adjustments Proposed by Company in Rebuttal

Q. Has UNS Electric proposed some additional adjustments in its Rebuttal filing?

A. Yes. UNS Electric witness Dukes proposes additional adjustments to increase test year operating expense for an overtime adjustment and for an additional payroll increase.

Q. Didn't the Company already have adjustments for payroll and overtime in its Direct filing?

A. Yes, it did. In UNS Electric's original filing, Mr. Dukes proposed an adjustment to increase payroll and overtime expense by $107,433.

Q. Was that adjustment contested by Staff or RUCO?

A. No. The adjustments for payroll and overtime in UNS Electric's direct filing were not contested by Staff. Mr. Dukes' Rebuttal Exhibit DJD-1, page 2 of 5, indicates that both Staff and RUCO accepted the Company's originally filed payroll expense adjustment of $107,433.

Q. How does the Company's newly proposed adjustment that was filed with the Company's Rebuttal on August 14, 2007 compare with the $107,433 payroll increase amount that was in the Company's original filing and was accepted by both Staff and RUCO?

A. As shown on Mr. Dukes' Rebuttal Exhibit DJD-1, page 2 of 5, the Company's new adjustment is now an increase of $339,184. This is an increase of $231,751 over the $107,433 payroll increase amount that was in the Company's original filing and was accepted by both Staff and RUCO. It more than triples the Company's original adjustment.

Q. Had Staff requested in discovery of UNS Electric to have the Company identify revisions and corrections to its filing?

A. Yes. In data request STF 3.88 Staff requested the following information: "As the Company discovers errors in its filing identify such errors and provide documentation to support any changes. Please update this response as additional information becomes available." The purpose of such discovery was to avoid surprise revisions.

Q. Did the Company identify any revisions and corrections to its filing in response to STF 3.88 related to payroll or overtime expense?

A. No. A copy of the Company's response to STF 3.88 is included in Attachment RCS-8. No adjustments to payroll or overtime expense were identified in that response.

Company's Proposed Overtime Adjustment

Q. At page 20 of his Rebuttal Testimony, Mr. Dukes asserts that he accepted Staff's adjustment for overtime expense in the UNS Gas case. In his Rebuttal, he is now proposing to revise the Company's overtime expense to use the same calculation for normalized overtime that was used in the UNS Gas case. Do you agree that an adjustment to overtime expense should be made for the UNS Electric using the same method you used to calculate an overtime adjustment for UNS Gas?

A. No. My analysis shows that while an adjustment to overtime expense was necessary for UNS Gas, the overtime reflected in UNS Electric's original filing is within a range of the results produced by the same calculations for normalized overtime that I used to calculate an overtime adjustment for UNS Gas. Consequently, no overtime adjustment is necessary for UNS Electric. My analysis of overtime expense for both companies is presented in Attachment RCS-9.

Q. Please discuss your analysis of overtime in the UNS Gas case and your similar analysis of overtime in the UNS Electric case.

A. Calculations considered in proposing an adjustment to test year overtime for UNS Gas and not proposing an adjustment to test year overtime for UNS Electric are presented in Attachment RCS-9. Pages 2 and 3 of Attachment RCS-9 reproduce, for ease of reference, my analysis of an overtime adjustment in the UNS Gas case, specifically, Schedule C-9, pages 1 and 2 from my revenue requirement exhibit (Attachment RCS-2), in that case. As shown, my recommendation for an adjustment to the Company's filed amount of overtime expense in the UNS Gas rate case was based upon two calculations, both of which confirmed the need for a downward adjustment. Schedule C-9, page 1, showed a reduction to overtime of $123,010 and Schedule C-9, page 2, showed a reduction of overtime expense of $138,876.

In contrast, the same two calculations for UNS Electric, which are shown on pages 4 and 5 of Attachment RCS-9, produced different results, one (on page 4) showed an increase of $64,222 and the other (on page 5) showed a $50,981 decrease. These workpapers were prepared under my supervision prior to Staff's direct filing in this case. Attachment RCS-9, page 6, lists the overtime results used, which were from Mr. Dukes' payroll expense workpapers. Consequently, because the results of my overtime analysis for UNS Electric bracketed the amount of overtime presented in UNS Electric's filing, I concluded that no adjustment to UNS Electric's filed overtime adjustment was necessary.

Q. Have you reflected Mr. Dukes' new proposed adjustment for overtime?

A. No. As described above, my analysis of overtime expense, which is presented in Attachment RCS-9, and which followed the same analysis format that I used in the UNS Gas case, indicates that the overtime expense in UNS Electric's original filing is within a

range of reasonableness (i.e., it was bracketed by the results of the two alternative calculations I performed). Consequently, no additional adjustment to overtime for UNS Electric is necessary.

Company's Proposed Revision to Payroll Expense Adjustment

Q. Have you reflected Mr. Dukes' new proposed adjustment for payroll expense?

A. No. Due to the timing of when this adjustment was presented, coupled with the size of the change, I have not been able to fully evaluate whether Mr. Dukes' more than tripling of the Company's previously filed payroll and overtime expense adjustment, which had been accepted by both Staff and RUCO, is appropriate.

Q. Has Staff issued some discovery to obtain additional information that might be helpful in evaluating the Company's new revision to its payroll adjustment?

A. Yes. After receiving the Company's Rebuttal Testimony, Staff issued data request sets 20 and 21 to UNS Electric. Some of that requested information, which had not yet been received or reviewed as of the date of this writing, might be helpful in evaluating the Company's revised payroll expense adjustment.

V. DEPRECIATION RATES

Q. What recommendations did you make in your Direct Testimony concerning the depreciation rates proposed by UNS Electric?

A. I recommended that the new depreciation rates proposed by UNS Electric be adopted, subject to correcting an error in the rates for transportation equipment.

I also recommended that each of the new depreciation rates proposed by UNS Electric should be clearly broken out between (1) a service life rate and (2) a net salvage rate. By

doing this, the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

Q. Has UNS Electric's rebuttal caused you to change either of these recommendations?

A. No. UNS Electric agreed with my recommended correction to the depreciation rates for transportation equipment. Additionally, UNS Electric has offered no valid reason why it should not be required to clearly break out the depreciation rates between (1) a service life rate and (2) a net salvage rates, which will enable tracking of the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

VI. CHANGES TO PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

Q. What recommendations did Staff make in your Direct Testimony concerning the revised PPFAC that UNS Electric had proposed?

A. I recommended that the PPFAC proposed by UNS Electric in its direct filing be rejected and, instead, a new PPFAC for UNS Electric should be developed, based on the PSA that Staff had recommended for APS in its recent rate case, Docket Nos. E-01345-05-0816 et al.

Q. Does UNS Electric appear to agree with that recommendation?

A. In principle, yes. UNS Electric rebuttal witness, Mr. DeConcini, has revised the Company's proposed PPFAC to contain features modeled on the PSA that Staff had recommended for APS.

Q. Weren't there some significant differences in the PSA that Staff had recommended for APS and the PSA that the Commission ultimately adopted for APS?

A. Yes, there were some significant differences including (1) the inclusion of a 90/10 sharing provision and (2) a 4 mill annual cap in the Commission approved APS PSA.

Q. What reasons did the Commission state for maintaining a 90/10 sharing provision in the APS PSA?

A. At page 111, Decision No. 69663 stated concerning the APS PSA that: "a prospective adjustor should also contain a sharing provision to provide an incentive for the Company to keep its fuel and purchased power costs as close to base rates as possible."

At pages 106-107 of Decision No. 69663, the Commission stated:

> "We believe that maintaining an incentive mechanism with the opportunity for some 'sharing' of the savings or costs of the purchased power and fuel costs is appropriate. Although the 90/10 sharing may be a 'blunt instrument,' apparently it did hit the mark and has worked to insure that APS is diligent in its fuel procurement. [cite omitted] As pointed out by RUCO, it is not a 'penalty provision' but an incentive mechanism to align APS' interest in acquiring fuel with the interests of APS' customers who pay the costs that APS incurs. However, we do agree with APS' recommendations to modify which costs are subject to the sharing requirement. We agree with APS that the fixed or demand element of long-term Purchase Power Agreements acquired through competitive procurement and renewable energy purchases not otherwise recoverable through the EPS/RES should be excluded from the sharing requirement."

Q. Does Staff recommend a 90/10 sharing provision in the UNS Electric PPFAC?

A. No. Staff recognizes that such sharing mechanisms can provide an incentive to utilities in procuring fuel and purchased power under the right circumstances. However, Staff believes the circumstances are somewhat different for UNS Electric than for APS, and

therefore, it would be premature to include the 90/10 sharing provision that was developed for APS, in the UNS Electric PPFAC at this time.

Q. Please describe some of the differences between APS' and UNS Electric's situation for fuel and purchase power procurement that are believed to be significant with respect to whether a 90/10 sharing mechanism should be imposed.

A. APS owns a substantial and diversified mix of generation resources, including base load nuclear and coal units with relatively low and historically stable fuel costs. APS is subject to fuel cost volatility, primarily through its exposure to natural gas and purchased power price fluctuations, but not nearly to the degree that UNS Electric would be once its full requirements contract expires.

Unlike APS, which owns substantial generation, UNS Electric has been dependent upon a full requirement Purchase Power Agreement ("PPA"). When that PPA expires, UNS Electric will have to acquire power to serve its load. Because its full requirements PPA is expiring, the UNS Electric's fuel and purchase power costs after that contract expires may be significantly different than they have been while that PPA was in effect.

Thus, unlike the APS situation, which was more in the nature of a continuation of similar circumstances in terms of that utility's fuel and purchase power procurement, the UNS Electric situation represents a significant change once the full requirements PPA expires.

Moreover, there is no indication that UNS Electric would have the same degree of influence and control over its fuel and purchase power costs that APS may have over its power costs. For UNS Electric, the power cost in base rates reflects the current full requirements PPA. It is probably unrealistic in UNS Electric's situation to have an

expectation that the Company would be able to keep its fuel and purchase power costs close to the power costs included in its base rates, because the power procurement situation after May 31, 2008 for this utility would be significantly different.

It is probably also unrealistic to believe that UNS Electric would anticipate a similar degree of power cost price stability than APS would have, since UNS Electric does not have the base load nuclear and coal generating units or other generating assets that APS owns. Currently, UNS Electric owns very limited generation.

Consequently, Staff believes that imposing the APS 90/10 sharing mechanism on the UNS Electric PPFAC at this time and under such circumstances would be inadvisable and unfair to UNS Electric and its ratepayers.

Q. Under what circumstances could a 90/10 sharing provision in a PPFAC be unfair to ratepayers?

A. Under circumstances where power costs have decreased due to general power market conditions, ratepayers would not receive the full amount of cost savings produced by such market-related price declines. Depriving ratepayers of the full benefit of power cost decreases that were outside of the control of the utility and occur due to general market fluctuations seems unfair and inappropriate.

Q. Are there other reasons why Staff does not favor a sharing mechanism at this time for UNS Electric's PPFAC?

A. Yes. Staff believes that an effective incentive would by definition be something that would motivate the utility to do something that it would not otherwise do, or to do something better. Staff does not believe that a 90/10 sharing provision would necessarily

have that result for UNS Electric. Given UNS Electric's situation, a 90/10 sharing mechanism would not necessarily improve the utility's fuel and purchase power procurement decisions. It could even have a detrimental result on procurement decisions by emphasizing short-term price stability over long-term lowest cost procurement.

Moreover, creating a sharing provision that produces reward/penalty amounts that are not directly related to the utility's power procurement efforts does not seem appropriate. Because energy markets can be volatile and prices can change significantly, in UNS Electric's situation, sharing results could be produced through uncontrollable market fluctuations, rather than as a direct result of utility fuel procurement decisions. Even if the Company made fully prudent and well planned purchases, under a 90/10 sharing provision, the volatility of energy markets that is beyond the Company's control could cause the Company to absorb power cost increases or cause its customers to not fully receive cost decreases.

Staff is concerned that including an APS-type 90/10 sharing provision for UNS Electric's initial PPFAC would not improve upon the incentive the Company already has to procure fuel and power at a reasonable cost, and could likely result in the seemingly unfair result of the Company absorbing cost increases that are beyond its ability to control, or, conversely, preventing ratepayers from fully receiving the benefits of power cost decreases that result from energy market fluctuations, that are again, beyond the control or influence of UNS Electric.

For the reasons described above, Staff does not favor incorporating an APS-like 90/10 sharing provision into the UNS Electric PPFAC at this time.

Q. If some type of sharing provision were to be included the UNS Electric PPFAC should it apply to <u>all</u> fuel and purchased power costs?

A. No. As described above, Staff does not believe that a sharing provision should be included in the UNS Electric PPFAC at this time. However, if one were to be included, similar to the provisions in Decision No. 69663 for APS, it should not apply to the fixed or demand elements of long-term purchased power agreements acquired through competitive procurement or to renewable energy purchases.

Q. You have said that Staff does not favor including a sharing provision in the UNS Electric PPFAC at this time. Please explain the time element.

A. As noted above, UNS Electric's fuel and purchase power procurement situation will be significantly different for the period beyond May 31, 2008, when its full requirements PPA expires. Because of that impending change, at this time, the Company's fuel and purchased power cost history does not appear to provide a good benchmark for crafting an appropriate incentive mechanism. Moreover, as described above, the APS situation is significantly different and does not represent a good comparison with UNS Electric, since APS owns substantial and diversified generation, including base load coal and nuclear, where UNS Electric does not.

Although Staff does not recommend a sharing provision for the UNS Electric PPFAC at this time because of the unique situation that exists at this utility, it would probably be reasonable to reconsider whether an appropriate sharing mechanism could be developed and applied to the UNS Electric PPFAC after a few years of experience have occurred with the new PPFAC and the Company's procurement decisions under it. The UNS Electric circumstances at present appear to be particularly inappropriate for an APS-type 90/10 sharing mechanism. However, this does not mean that some type of sharing

provision, tailored to providing an incentive toward improved fuel and purchased power procurement decisions, should never be considered for the UNS Electric PPFAC. Indeed, it might be appropriate to impose a well-conceived incentive mechanism on UNS Electric in the future after a baseline has been established with this utility's power procurement. Potentially one or two years of experience under the new PPFAC could be sufficient to provide a baseline from which appropriate power procurement incentives could be developed.

Q. You also noted that one of the differences between what Staff had recommended and what the Commission adopted for the APS PSA was a 4 mill annual cap. What did Decision No. 69663 state with respect to the 4 mill annual cap that the Commission imposed on the APS PSA?

A. Page 112 of Decision No. 69663 stated that:

> "APS proposed to modify the PSA by eliminating the four mil cumulative 'lifetime' cap on the Annual PSA Adjustor and replace it with a four mil annual cap. Staff's proposal was to eliminate the cap entirely. The Commission finds that the four mil cap should be an annual, not a lifetime cap. In other words, the PSA adjustor rate could not increase, or decrease, in any one year, more than four mills from the existing PSA adjustor rate. This level, combined with the higher base cost of fuel we are adopting in this Order, and the other changes to the PSA as described above, will significantly improve APS' cash flow, while at the same time protecting ratepayers from potential large spikes in the PSA."

Q. Please address whether a cap, such as the 4 mil annual cap, should be included in the UNS Electric PPFAC.

A. The purpose of an annual cap is to protect ratepayers from large spikes in the PPFAC. For UNS Electric, the new PPFAC would commence effective June 1, 2008. Currently, we do not have reliable information on what UNS Electric forecasts its fuel and purchase power

costs to be for periods after June 1, 2008.[15] We do not know if imposing a 4 mil annual cap would prevent UNS Electric from timely recovery of its fuel and purchased power costs after June 1, 2008 and result in large deferrals. The purpose of a forward looking component in the PPFAC, as recognized by the Commission in Decision No. 69663, is to make the recovery of the utility's power costs timelier, thereby improving the Company's cash flow. An annual cap set too low could defeat that objective.

Q. Does Staff recommend an annual cap for the UNS Electric PPFAC?

A. No, not at this time. With respect to whether or not an annual cap should be imposed, I generally agree with the observations made by Mr. DeConcini on page 14, lines 16-24 of his Rebuttal Testimony:

> "It is understandable that the Commission applied a cap to APS' PSA as APS has a well-established system consisting of significant stable cost nuclear and coal facilities. UNS Electric, on the other hand, is in the process of acquiring and developing its resource requirements and it would not be appropriate to force a cap on the PPFAC rate in this period of flux. A cap could send the wrong message to over-emphasize short-term rate stability at the detriment of what is in the best long-term interest of our customers. That is, putting caps and collars for rate stability in the short-term can lead to large deferrals that can negatively impact both the Company – making it a riskier investment – and its customers – who have to pay for those cost deferrals eventually."

Consequently, Staff does not recommend imposing an annual cap on the PPFAC during what Mr. DeConcini refers to as "this period of flux."

[15] Information has been requested in Staff data requests set 20, but responses have not yet been received.

Q. Do you believe that the PPFAC proposed by Staff fairly balances the interests of the utility and its ratepayers and provides adequate incentive to the company to seek the most economical sources of fuel and purchased power?

A. Yes. Under the PPFAC proposed by Staff, UNS Electric does not receive any return on its prudently incurred fuel and purchased power costs. Staff does not believe that UNS Electric would have anything to gain by not seeking out the most economical sources of fuel and purchased power. Staff believes that its proposed PPFAC, which includes provisions for a prudence review, provides UNS Electric with adequate incentives to procure reliable sources of fuel and energy at reasonable prices, and to hedge an appropriate amount of fuel and purchased power to provide stability in price.

Q. Please discuss the inclusion of prudently incurred hedging costs in the PPFAC.

A. Page 15 of the Staff proposed Plan of Administration for the APS PSA specifies that: "Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA." I believe that allowing UNS Electric to recover prudent direct costs of contracts it uses for hedging system fuel and purchased power under its PPFAC would also be appropriate. UNS Electric's actual hedging costs, like its power costs, should, of course, be subject to review for prudence and reasonableness.

Q. Has UNS Electric proposed to recover broker's fees in the PFPAC?

A. Yes. At page 15 of his rebuttal testimony, Mr. DeConcini proposes to include broker's fees, as well as credit costs and legal costs, in the PFPAC.

Q. Were broker's fees allowed to be included in the APS PSA?

A. No. Decision No. 69663 states at page 107 that: "APS has not demonstrated any reason why we should change the costs that are allowed to be recovered in the adjustor, and we find that the level of broker fees that APS will collect in its base rates is reasonable. Accordingly, the broker fees in excess of the level already included in base rates will not flow through to the adjustor." Footnote 61 on page 107 of Decision No. 69663 noted that: "Staff continues to believe that broker fees are not allowable PSA costs."

Q. Since UNS Electric has not incurred the broker's fees and the types of "other costs" in the past that Mr. DeConcini seeks to include in the PFPAC, what avenue would be available to the Company to recover such future costs if they are not included in the PFPAC?

A. If the fluctuations in those costs, along with the fluctuations in all of UNS Electric's other non-PPFAC includable costs become significant, the Company could request recovery in base rates. Basically, they would be treated as any other utility operating expenses that fluctuate between rate cases.

Q. Has UNS Electric provided information on the levels of such "other costs" it is expecting?

A. No. Such information has been requested in Staff data request set 20, but responses have not yet been received.

Q. Should the PPFAC be limited to expenses that are recorded in FERC accounts 501, 547, 555 and 565 and prudent hedging costs?

A. Yes. This is consistent with Staff's recommendation for UNS Electric and consistent with the PSA for APS that was recommended by Staff, and appears to be consistent with the

PSA for APS that was approved by the Commission. The FERC Accounts 501, 547, 555 and 565 that should be included in the PPFAC for UNS Electric are basically the same accounts that the Plan of Administration included for recovery by APS under the APS PSA.[16]

Mr. DeConcini's attempt on Exhibit MJD-3, page 11, to add an additional category of "other allowable costs" for inclusion in the PPFAC, and his related proposal at page 15, lines 1-8 of his rebuttal testimony to include broker's fees, credit costs and legal fees in the PPFAC, should be rejected.

As shown on Attachment RCS-7, under item 9-B, "Other Allowable Costs," I have revised this provision of the Plan of Administration accordingly to read: "None without pre-approval from the Commission in an Order."

Q. What interest rate should be applied to the monthly PPFAC bank balance, and where is the applicable interest rate addressed in Staff's proposed Plan of Administration?

A. Staff recommends using an interest rate, based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, applied each month to the previous month's balance. This is essentially the same recommendation for the carrying cost rate that Staff proposed in the APS PSA Plan of Administration.[17] The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the customer deposit rate.

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[16] Page 15 of the APS Plan of Administration listed the accounts included for the APS PSA as these four FERC accounts, and, for APS, also Account 518, Nuclear Fuel. UNS Electric does not have any nuclear generation and does not record expense in Account 518.

[17] See, e.g., Attachment RCS-4 (attached to my Direct Testimony), pages 10, 11 and 13 of the Staff Proposed Plan of Administration for APS.

Staff's proposed Plan of Administration addresses the definition of Applicable Interest on page 1, under "Definitions" to provide that Applicable Interest is "Based on on-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15. The interest rate is adjusted annually on the first business day of the calendar year."

Q. How does the carrying cost rate Staff recommends compare with UNS Electric's proposed interest rate for customer deposits?

A. As shown on Exhibit TJF-1 to Direct Testimony of Thomas J. Ferry, in the red-lined version of the Rules and Regulations, page 16 of 109, section 3, UNS Electric has proposed in its rate case to use the one-year Treasury constant maturities rate for customer deposits. This is the same interest rate that Staff recommends be applied to compute carrying charges on the monthly PPFAC bank balances.

Q. Are Staff and the Company in agreement concerning the effective date for a new PPFAC mechanism for UNS Electric?

A. Yes. As stated on page 8 of Mr. DeConcini's Rebuttal Testimony, UNS Electric proposes that the new PPFAC Mechanism begin June 1, 2008 upon the expiration of the PWCC PSA.

Q. Where and how is this provided for in Staff's proposed Plan of Administration?

A. This is provided for on page 3 of Staff's proposed Plan of Administration, which states: "The PPFAC Year begins on June 1 and ends the following May 31. The first full PPFAC Year in which the PPFAC rate shall apply will begin on June 1, 2008 and end on May 31, 2009. Succeeding PPFAC Years will begin on each June 1, thereafter."

Q. Your Direct Testimony identified a number of principal features that should be considered in the design or modification of UNS Electric's PPFAC. Please describe how each of these features is covered in Staff's proposed Plan of Administration for the UNS Electric PPFAC.

A. Attachment RCS-7 to my Surrebuttal Testimony presents a redlined revision to Mr. DeConcini's Exhibit MJD-3 to reflect Staff's recommendations. The following principal features have been considered in the manner described below:

- There should be an opportunity for Commission review of proposed charges before they become applicable. Review and Commission approval modeled after the APS PSA is provided for in Staff's proposed Plan of Administration as follows. Section 5 provides for filing and procedural deadlines. Section 8 provides for compliance reporting. Section 3-A provides, in the definition of the Forward Component, that: "Should an unusual event occur causing a drastic change in forecasted fuel and energy prices – such as a hurricane or other calamity – UNSE has the discretion to apply for an adjustment to the forward component. Such an adjustment would not be implemented unless approved by the Commission." Section 5-E provides further that: "Should an unusual event occur that causes a drastic change in forecasted fuel and energy prices – such as a hurricane or other calamity – UNSE will have the ability to request an adjustment to the forward component reflecting such a change. The Commission may provide for the change over such period as the Commission determines appropriate."
- There should be a clear provision for the reconciliation of revenues and costs. Staff's proposed Plan of Administration provides for this in the filing and procedural deadlines specified in Section 5, the verification and audit provisions specified in Section 6, and the compliance reporting specified in Section 8.

- There should be an opportunity for an independent Commission review of prudence and reasonableness in all areas that drive the costs collected under the PPFAC. The content of these reviews and the issues they address should be subject to examination and comment by the affected stakeholders. The ultimate purpose of such reviews is to enable the Commission to make an informed determination of what, if any, costs resulted from ineffective or imprudent utility performance, and what, if any, adjustments should be made to future recoveries and over what periods of time. Staff's proposed Plan of Administration provides for verification and audit of the amounts charged through the PPFAC as follows: "The amounts charged through the PPFAC will be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded in the True-Up Component for the following year (i.e. starting the next June 1.)" The monthly compliance reports specified in Section 8 of Staff's proposed Plan of Administration should also be helpful to the Staff, Commission and RUCO in monitoring the Company's PPFAC rate and the costs.
- The PPFAC should provide a reliable mechanism for assuring reasonably prompt recovery of prudent and reasonable fuel and energy costs. Ideally, a well designed PPFAC would avoid situations where delayed recovery of prudent and reasonable fuel and energy costs would have material financial consequences (e.g., through increased financing costs or restraints on access to financial resources). Put another way, the PPFAC should, by providing for reasonably prompt recovery of prudent and reasonable fuel and energy costs, help to maintain the utility's financial benchmarks

that promote the ability to secure financing at costs favorable to customers. Staff's Plan of Administration provides for recovery of prudent and reasonable fuel in two components, a forward component and a true-up component, as defined in Section 3, over an annual period running from June 1 through May 31 of each year, with the first full PPFAC year to begin on June 1, 2008. As explained above, Staff does not favor imposing an APS-type 90/10 sharing provision or 4-mill cap on the UNS Electric PPFAC at this time for a number of reasons, including that such provisions would be contrary to the objective of providing a reliable mechanism for assuring reasonably prompt recovery of UNS Electric's prudent and reasonable fuel and energy costs.

Q. Are there any other considerations for the PPFAC?

A. Yes. The Commission may want to include a provision designed to provide the utility with an incentive to procure fuel and purchased power at the lowest cost consistent with providing reliable electric service. Incentive provisions can be appropriate under the right circumstances. However, as described above, Staff does not recommend imposing a 90/10 sharing mechanism or a 4 mil annual cap on the UNS Electric PPFAC at this time.

Q. Are there some aspects of the detailed descriptions in Mr. DeConcini's Exhibit MJD-3, Section 7 "Calculations" that appear to be inaccurate or inconsistent with the PPFAC proposed by UNS Electric?

A. Yes. For example, Exhibit MJD-3, Section 7 "Calculations," item 2 under B on page 6, and item 2 under C on page 6, each refer to 90 percent of Off-System Sales Revenue. Page 16, lines 20-21, of Mr. DeConcini's rebuttal testimony states that: "Although UNS Electric does not anticipate substantial short-term off-system wholesale revenue, to the extent they exist, UNS Electric will credit the revenues to the PPFAC." The references to 90 percent in Exhibit MJD-3, Section 7, noted above, do not appear to be consistent with

UNS Electric's proposal to fully credit short-term off-system wholesale revenue to the PPFAC, or with the Company's recommendation that no 90/10 sharing be applied to PPFAC costs.

Q. Does Staff agree with UNS Electric that short-term off-system wholesale revenue should be credited against the PPFAC?

A. Yes. To the extent they exist, UNS Electric should be required to fully credit short-term off-system wholesale revenues to the PPFAC.

Q. Has Staff requested the Company to provide illustrative examples of the calculations that are to be filed on Schedules 1 through 5 which are listed in Section 7 of the PPFAC Plan of Administration?

A. Yes. Staff data request STF 20.3 has requested that the Company provide illustrative examples of those schedules using estimated information. Staff reserves the right to suggest modifications to such schedules or other aspects of the PPFAC after reviewing the Company's responses to outstanding discovery. Staff recommends that the specific details of the PPFAC Schedules listed in Section 7 of the Plan of Administration be developed after the parties have reviewed illustrative examples of those schedules using estimated information, such as were requested in data request STF 20.3.

Q. If the Staff-proposed PPFAC is adopted for UNS Electric, what rate impacts could this be expected to produce?

A. That is not known at this time. Staff has requested information in data request set 20 concerning the potential magnitude of the PPFAC True-Up component and details for specific cost items.

Q. Please summarize Staff's recommendations concerning the development of a new PPFAC mechanism for UNS Electric.

A. The new PPFAC for UNS Electric should be based upon the Plan of Administration detailed in Attachment RCS-7 to my Surrebuttal Testimony. This has been developed along the lines of the APS PSA Plan of Administration that Staff proposed for the APS in Docket Nos., E-01345A-05-0816 et al. For the reasons described in my testimony, Staff's proposed Plan of Administration does not include an APS-type 90/10 sharing mechanism or a 4 mill annual cap. Staff's recommended Plan of Administration removes an open-ended provision for "other includible costs" that Mr. DeConcini had included in his Exhibit MJD-3 on page 11. Staff recommends that the includable costs should be restricted to costs included in the following four FERC accounts: 501, 547, 555, and 565, plus the prudent direct costs of contracts used for hedging system fuel and purchased power costs. There should be no other costs included in the new PPFAC. The new PPFAC for UNS Electric should become effective June 1, 2008, upon expiration of the Company's all requirements power contract with PWCC.

VII. COMPANY'S PROPOSED RATEMAKING TREATMENT FOR A NEW PEAKING UNIT, BLACK MOUNTAIN GENERATING STATION

Q. As a result of the UNS Electric rebuttal, has the Staff revised its opposition to including the Black Mountain Generating Station ("BMGS") in rate base in the current UNS Electric rate case?

A. No. Staff continues to believe that inclusion of BMGS in rate base in the current rate case would be premature and inadvisable for several reasons.

Q. What is the BMGS, and what ratemaking treatment is the Company requesting for it in the current rate case?

A. The BMGS is a 90 MW peaking facility under development at a site in Mohave County. BMGS consists of two LM 6000 combustion turbines. It is being developed by an affiliated company, UniSource Energy Development Company ("UEDC"). UNS Electric witness Kevin Larson states (at pages 2 and 4 of his Direct Testimony) that UEDC has negotiated a turnkey construction contract for the project totaling $46 million. UEDC is in the process of obtaining permits and making other arrangements to meet a projected operating date of May 2008. The Company estimates additional costs of permitting, site improvements, obtaining water supply, connecting to a gas pipeline, making substation improvements, providing project supervision and paying interest on borrowed funds of $14 million to $19 million. In total, UNS Electric estimates BMGS will cost $60 to $65 million.

The Company's Rebuttal Testimony appears to represent no change in position to UNS Electric's original proposal related to BMGS. UNS Electric requests that the Commission include the BMGS in its rate base effective as of June 1, 2008 as set forth in the testimony of Company witness Kevin Larson. As explained on page 3 of Mr. Larson's Direct Testimony: "the Company is requesting a post-test year adjustment to rate base and a corresponding reclassification of rates effective June 1, 2008, or at a later date if commercial operation is delayed beyond June 1, 2008." The Company's proposed post-test year adjustment would add approximately $10 million to the non-fuel (base rate) revenue requirement, assuming a $60 million completion cost. As Mr. Larson further explained (on page 3 of his Direct Testimony): "On the effective date of this adjustment, UNS Electric would increase the average base delivery charge to customers by approximately 0.6 cents per kWh, and make a corresponding decrease of 0.6 cents per

kWh to the base power supply rate." He states that, initially, this proposal will be "revenue neutral" to UNS Electric. Other features of the Company's proposed ratemaking treatment for BMGS include (per Mr. Larson's Direct Testimony, at page 4):

- If actual project costs exceed $60 million, UNS Electric will not seek rate base treatment of any cost difference until the Company's next rate case.
- Following the purchase of the project by UNS Electric and upon commercial operation of the facility, the Company would provide the Commission with a project completion report, detailing the cost of completion and the results of pre-commercial testing.
- Thirty days after such report is filed, or on June 1, 2008 if the project is completed prior to May 1, 2008, the Company would implement the rate reclassification described above.

Q. What has the Company said it would do if the Commission rejects its proposal for a post-test year adjustment to rate base?

A. At page 5 of his Direct Testimony, Mr. Larson states that UNS Electric could elect to enter into a purchased power agreement ("PPA") with its affiliate, UEDC. He states that the terms of the PPA would be subject to approval by the Commission and by FERC. Bypassing these approvals is not necessarily a good idea. Approval of PPAs with affiliated parties is intended to provide a safeguard for ratepayers to prevent abuses.

Q. Does Staff support the Company's requested ratemaking treatment for BMGS in the current rate case?

A. No. For several reasons, Staff views the Company's requested ratemaking treatment for this plant is premature and inappropriate in the current rate case.

Q. Please summarize why Staff recommends that BMGS not be added to rate base in the current UNS Electric rate case.

A. There are several concerns with approving rate base treatment of BMGS in the current rate case, including the uncertainties relating to the plant. One of the primary deficiencies is that the plant is not expected to be in commercial operation until May or June of 2008. This is well beyond the end of the test year in the current UNS Electric rate case, and is several months beyond even the scheduled hearing. Consequently, this plant addition does not qualify as a pro forma adjustment to plant in service.

In the current UNS Electric rate case, BMGS would not qualify for an exception to the inclusion of CWIP in rate base because only minimal, if any, costs have been incurred by UNS Electric in the test year. As of the end of the test year, it appears the Company had not incurred any cost for BMGS construction. The response to STF 11.2 states that none of the Company's end-of-test-year CWIP balance includes BMGS cost. Additionally, Staff's engineering report, which reported on the results of a site visit made in June 2007 among other things, revealed very little work has apparently been done at the plant site. It appears that costs related to BMGS construction are being recorded on the books of the affiliate, UEDC, rather than on UNS Electric's books.

Additionally, there is uncertainty regarding the total cost of the plant. There is uncertainty regarding whether the ownership of the plant would be at the utility, UNS Electric, or with the affiliate, UEDC. There is uncertainty regarding whether it would be more economical for UNS Electric and its ratepayers for the utility to own the plant or to obtain power by some other means. Given the substantial uncertainties regarding BMGS, Staff believes it would be premature and inappropriate to approve the Company's request for rate base inclusion.

Staff recognizes that there can be benefits to a utility owning its own generation. However, it is not known whether having UNS Electric purchase a peaking unit such as BMGS is the most economical alternative to obtain power for the short, intermediate or long-term.

In terms of the impact on cash flow, the Company's proposal is to have BMGS included in rate base by a "revenue neutral" rate reclassification that apparently would not result in any net rate adjustment. It is unclear how the Company's proposed "revenue neutral" rate reclassification would result in a substantial improvement in the Company's cash flow if it were to be implemented in a truly "revenue neutral" manner that did not result in a substantial net rate increase. It is unclear whether UNS Electric ownership of BMGS would reduce purchased power and fuel costs by $10 million per year. Thus, what UNS Electric has proposed as being initially "revenue neutral" may end up producing large customer rate increases that have not been estimated with accuracy at this time. Staff has issued a set of data requests (set 20) which attempted to elicit additional information on the potential rate impacts on UNS Electric customers with BMGS ownership versus other alternatives. As of the date of this writing (August 23, 2007) responses had not yet been received.

In conclusion, the Company's requested rate base inclusion of BMGS in the current case is premature and would bypass too many regulatory safeguards. The Company's proposed rate base inclusion of BMGS in the current case should be rejected. Staff believes that the ratemaking treatment of BMGS would most appropriately be addressed in the context of UNS Electric's next rate case.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

Attachment RCS-6

Staff Revised Accounting Schedules

Accompanying the Surrebuttal Testimony of Ralph C. Smith

Schedule	Description	Pages	Note
	Revenue Requirement Summary Schedules		
A	Calculation of Revenue Deficiency (Sufficiency)	1	Revised
A-1	Gross Revenue Conversion Factor	1	Revised
B	Adjusted Rate Base	1	Revised
B.1	Summary of Adjustments to Rate Base	1	Revised
C	Adjusted Net Operating Income	1	Revised
C.1	Summary of Net Operating Income Adjustments	4	Revised
D	Capital Structure and Cost Rates	1	Revised
	Rate Base Adjustments		
B-1	Remove Construction Work in Progress	1	
B-2	Adjust CWIP for Plant in Service by End of Test Year	1	
B-3	Plant in Service Addition Subject to Reimbursement	1	Revised
B-4	Cash Working Capital - Lead/Lag Study	1	
B-5	Accumulated Deferred Income Taxes	1	
	Net Operating Income Adjustments		
C-1	Revenue Adjustment for CARES Discount	1	
C-2	Remove Depreciation & Property Taxes for CWIP	1	
C-3	Depreciation & Property Taxes for CWIP Found to be In-Service in the Test Year	1	
C-4	Fleet Fuel Expense	2	Revised
C-5	Postage Expense	1	
C-6	Normalize Injuries and Damages Expense	1	
C-7	Incentive Compensation Expense	1	
C-8	Supplemental Executive Retirement Plant (SERP) Expense	1	
C-9	Stock Based Compensation Expense	1	
C-10	Property Tax Expense	1	
C-11	Rate Case Expense	1	
C-12	Edison Electric Institute Dues	2	
C-13	Other Membership and Industry Association Dues	1	
C-14	Interest Synchronization	1	Revised
C-15	Depreciation Rates Correction	4	
C-15.1	Depreciation Rates Correction - Details of Company's Pre-Correction Calculation		[RCS-2]
C-15.2	Depreciation Rates Correction - Details of Calculation Using Corrected Rates		[RCS-2]
C-16	Emergency Bill Assistance Expense	1	
C-17	Markup Above Cost in Charges from Affiliate, Southwest Energy Services	1	Added
C-18	Bad Debt Expense	1	Added
C-19	Remove Double Count from Outside Services-Demand Side Management	1	Added
C-20	Correct Year-End Accrual Expense Amount for Out-of-Period Expense	1	Added
	Total Pages, Including Content Listing	41	

[RCS-2] Depreciation Rates Correction Support was filed in Attachment RCS-2 with Mr. Smith's direct testimony. That additional supporting detail has not changed, and is therefore not being re-filed with Mr. Smith's surrebuttal.

UNS Electric Inc.
Computation of Increase in Gross Revenue Requirement

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule A Revised

Line No.	Description	Reference	UNS Proposed Original Cost (A)	UNS Proposed Fair Value (B)	Staff Proposed Original Cost (C)	Staff Proposed Fair Value (D)
1	Adjusted Rate Base	Sch. B	$ 140,991,324	$ 177,802,341	$ 130,707,320	$ 167,518,337
2	Rate of Return	Sch. D	9.89%	7.84%	8.99%	7.02%
3	Operating Income Required		$ 13,946,320	$ 13,946,320	$ 11,746,759	$ 11,759,787
4	Net Operating Income Available	Sch. C	$ 8,742,011	$ 8,742,011	$ 9,515,701	$ 9,515,701
5	Operating Income Excess/Deficiency		$ 5,204,309	$ 5,204,309	$ 2,231,058	$ 2,244,086
6	Gross Revenue Conversion Factor	Sch. A-1	1.6346	1.6346	1.634626	1.634626
7	Overall Revenue Requirement		$ 8,507,097	$ 8,507,097	$ 3,646,946	$ 3,668,242

Notes and Source

Cols. A & B taken from UNS Electric, Inc. filing, Schedule A-1

UNS Electric, Inc.
Computation of Gross Revenue Conversion Factor

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule A-1 Revised

Line No.	Description	Company Proposed (A)	Staff Proposed (B)
1	Gross Revenue	100.00%	100.00000%
2	Less: Uncollectible Revenue	0.36792%	0.36792%
3	Taxable Income as a Percent	99.63%	99.63208%
4	Less: Federal and State Income Taxes	38.46%	38.46%
5	Change in Net Operating Income	61.18%	61.17609%
6	Gross Revenue Conversion Factor	1.6346	1.634626

Notes and Source

Col.A: UNS Electric Inc. Filing, Schedule C-3
Col.B:

Components of Revenue Requirement Increase (Revised)

	Amount	Percent
Net Income	$ 2,231,059	61.18%
Federal and State Income Taxes	$ 1,402,469	38.46%
Uncollectibles	$ 13,418	0.37%
Total Revenue Increase	$ 3,646,946	100.00%

UNS Electric, Inc.
Original Cost and RCND Adjusted Rate Base

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B Revised

Line No.	Description	Original Cost As Adjusted by UNS (A)	Original Cost Staff Adjustments (B)	Original Cost As Adjusted by Staff (C)	RCND As Adjusted by UNS (D)	RCND Staff Adjustments (E)	RCND As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 390,513,651	$ (10,318,899)	$ 380,194,752	$ 612,326,062	$ (10,318,899)	$ 602,007,163
2	Less: Accumulated Depreciation	$ (159,524,693)	$ -	$ (159,524,693)	$ (257,585,628)	$ -	$ (257,585,628)
3	Net Utility Plant in Service	$ 230,988,958	$ (10,318,899)	$ 220,670,059	$ 354,740,434	$ (10,318,899)	$ 344,421,535
4	Citizens Acquisition Discount	$ (93,273,341)	$ -	$ (93,273,341)	$ (150,061,415)	$ -	$ (150,061,415)
5	Less: Accum. Amort. - Citizens Acq. Discount	$ (11,224,066)	$ -	$ (11,224,066)	$ (18,123,969)	$ -	$ (18,123,969)
6	Net Citizens Acquisition Discount	$ (82,049,275)	$ -	$ (82,049,275)	$ (131,937,446)	$ -	$ (131,937,446)
7	Total Net Utility Plant	$ 148,939,683	$ (10,318,899)	$ 138,620,784	$ 222,802,988	$ (10,318,899)	$ 212,484,089
8	Customer Advances for Construction	$ (8,692,444)	$ -	$ (8,692,444)	$ (9,559,141)	$ -	$ (9,559,141)
							$ -
9	Customer Deposits	$ (3,778,419)	$ -	$ (3,778,419)	$ (3,778,419)	$ -	$ (3,778,419)
							$ -
10	Accumulated Deferred Income Taxes	$ 1,154,833	$ (161,555)	$ 993,278	$ 1,780,258	$ (161,555)	$ 1,618,703
11	Total Deductions	$ (11,316,030)	$ (161,555)	$ (11,477,585)	$ (11,557,302)	$ (161,555)	$ (11,718,857)
12	Allowance for Working Capital	$ 3,367,671	$ 196,450	$ 3,564,121	$ 3,367,671	$ 196,450	$ 3,564,121
							$ -
13	Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -
							$ -
14	Regulatory Liabilities	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Rate Base	$ 140,991,324	$ (10,284,004)	$ 130,707,320	$ 214,613,357	$ (10,284,004)	$ 204,329,353

Notes and Source

Cols. A and D: UNS Electric Inc. filing, Schedule B

Fair Value Calculation (Per Company)

Original Cost	$ 140,991,324	
RCND	$ 214,613,357	
Total	$ 355,604,681	
Average (Fair Value)	$ 177,802,341	See Sch. A

Fair Value Calculation (Per Staff)

Original Cost	$ 130,707,320	
RCND	$ 204,329,353	
Total	$ 335,036,673	
Average (Fair Value)	$ 167,518,337	See Sch. A

UNS Electric, Inc.
Summary of Rate Base Adjustments

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B.1 Revised

Line No.	Description	Staff Adjustments	CWIP	Rhode Homes Line Extensions	Customer Advances for Construction	Cash Working Capital	ADIT	N/A
			B-1	B-2	B-3 Revised	B-4 Revised	B-5	B-6
1	Gross Utility Plant in Service	$ (10,318,899)	$ (10,761,154)	$ 442,255				
2	Less: Accumulated Depreciation	$ -						
3	Net Utility Plant in Service	$ (10,318,899)	$ (10,761,154)	$ 442,255	$ -	$ -	$ -	$ -
4	Citizens Acquisition Discount	$ -						
5	Less: Accum. Amort. - Citizens Acq. Discount	$ -						
6	Net Citizens Acquisition Discount	$ -						
7	Total Net Utility Plant	$ (10,318,899)	$ (10,761,154)	$ 442,255	$ -	$ -	$ -	$ -
8	Customer Advances for Construction	$ -		$ -				
9	Customer Deposits	$ -						
10	Accumulated Deferred Income Taxes	$ (161,555)					$ (161,555)	
11	Total Deductions	$ (161,555)	$ -	$ -	$ -	$ -	$ (161,555)	$ -
12	Allowance for Working Capital	$ 196,450				$ 196,450		
13	Regulatory Assets	$ -						
14	Regulatory Liabilities	$ -						
15	Total Rate Base	$ (10,284,004)	$ (10,761,154)	$ 442,255	$ -	$ 196,450	$ (161,555)	$ -

UNS Electric, Inc.
Adjusted Net Operating Income

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C Revised

Line No.	Description	As Adjusted by UNS (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Electric Retail Revenues	$ 156,651,860	$ 52,937	$ 156,704,797
2	Sales for Resale	$ 246,016	$ -	$ 246,016
3	Other Operating Revenues	$ 1,589,014	$ -	$ 1,589,014
4	Total Operating Revenues	$ 158,486,890	$ 52,937	$ 158,539,827
	Operating Expenses			
5	Purchased Power	$ 106,224,185	$ -	$ 106,224,185
6	Other O&M Expenses	$ 26,423,248	$ (709,028)	$ 25,714,220
7	Depreciation & Amortization	$ 11,812,574	$ (494,656)	$ 11,317,918
8	Taxes Other Than Income Taxes	$ 3,447,533	$ (292,679)	$ 3,154,854
9	Income Taxes	$ 1,837,339	$ 775,610	$ 2,612,949
10	Total Operating Expenses	$ 149,744,879	$ (720,753)	$ 149,024,126
11	Net Operating Income	$ 8,742,011	$ 773,690	$ 9,515,701

Notes and Source

Col. A: UNS Electric, Inc. filing, Schedule C-1
Col. B: Staff Schedule C.1

UNS Electric, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2006

Line No.	Description	Stafff Adjustments	CARES Discount	Remove Depreciation & Property Taxes for CWIP	Depreciation & Property Taxes for CWIP Found in Service	Fleet Fuel Expense	Postage Expense
			C-1	C-2	C-3	C-4 Revised	C-5
	Operating Revenues						
1	Electric Retail Revenues	$ 52,937	$ 52,937				
2	Sales for Resale	$ -					
3	Other Operating Revenues	$ -					
4	Total Operating Revenues	$ 52,937	$ 52,937	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Purchased Power	$ -					
6	Other O&M Expenses	$ (709,028)				$ (62,197)	$ 17,503
7	Depreciation & Amortization	$ (494,656)		$ (449,816)	$ 18,265		
8	Taxes Other Than Income Taxes	$ (292,679)		$ (239,696)	$ 8,317		
9	PRE-TAX OPERATING EXPENSES	$ (1,496,363)	$ -	$ (689,512)	$ 26,582	$ (62,197)	$ 17,503
10	PRE-TAX OPERATING INCOME	$ 1,549,300	$ 52,937	$ 689,512	$ (26,582)	$ 62,197	$ (17,503)
11	Income Taxes	$ 775,610	$ 20,433	$ 266,138	$ (10,260)	$ 24,007	$ (6,756)
12	TOTAL OPERATING EXPENSES	$ (720,753)	$ 20,433	$ (423,374)	$ 16,322	$ (38,190)	$ 10,747
13	OPERATING INCOME	$ 759,377	$ 32,504	$ 423,374	$ (16,322)	$ 38,190	$ (10,747)

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per UNS Electric filing, Schedule C-3

UNS Electric, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2006

Line No.	Description	Injuries and Damages Expense	Incentive Compensation Expense	SERP Expense	Stock Based Compensation Expense	Property Tax Expense	Rate Case Expense
		C-6	C-7	C-8	C-9	C-10	C-11
	Operating Revenues						
1	Electric Retail Revenues						
2	Sales for Resale						
3	Other Operating Revenues						
4	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Purchased Power						
6	Other O&M Expenses	$ (159,063)	$ (42,448)	$ (83,506)	$ (82,873)		$ (111,667)
7	Depreciation & Amortization						
8	Taxes Other Than Income Taxes		$ (1,553)			$ (59,747)	
9	PRE-TAX OPERATING EXPENSES	$ (159,063)	$ (44,001)	$ (83,506)	$ (82,873)	$ (59,747)	$ (111,667)
10	PRE-TAX OPERATING INCOME	$ 159,063	$ 44,001	$ 83,506	$ 82,873	$ 59,747	$ 111,667
11	Income Taxes	$ 61,395	$ 16,984	$ 32,232	$ 31,987	$ 23,061	$ 43,101
12	TOTAL OPERATING EXPENSES	$ (97,668)	$ (27,017)	$ (51,274)	$ (50,886)	$ (36,686)	$ (68,566)
13	OPERATING INCOME	$ 97,668	$ 27,017	$ 51,274	$ 50,886	$ 36,686	$ 68,566

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per UNS Electric filing, Schedule C-3

UNS Electric, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2006

Line No.	Description	Edison Electric Institute Dues	Other Membership Dues	Interest Synchro-nization	Depreciation Rates Correction	Emergency Bill Assistance	SES Markup Above Cost
		C-12	C-13	C-14 Revised	C-15	C-16	C-17 Added
	Operating Revenues						
1	Electric Retail Revenues						
2	Sales for Resale						
3	Other Operating Revenues						
4	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Purchased Power						
6	Other O&M Expenses	$ (8,470)	$ (6,482)			$ 20,000	$ (10,906)
7	Depreciation & Amortization				$ (63,105)		
8	Taxes Other Than Income Taxes						
9	PRE-TAX OPERATING EXPENSES	$ (8,470)	$ (6,482)	$ -	$ (63,105)	$ 20,000	$ (10,906)
10	PRE-TAX OPERATING INCOME	$ 8,470	$ 6,482	$ -	$ 63,105	$ (20,000)	$ 10,906
11	Income Taxes	$ 3,269	$ 2,502	$ 177,611	$ 24,357	$ (7,720)	$ 4,209
12	TOTAL OPERATING EXPENSES	$ (5,201)	$ (3,980)	$ 177,611	$ (38,748)	$ 12,280	$ (6,697)
13	OPERATING INCOME	$ 5,201	$ 3,980	$ (177,611)	$ 38,748	$ (12,280)	$ 6,697

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per UNS Electric filing, Schedule C-3

UNS Electric, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2006

Line No.	Description	Bad Debt Expense	Outside Services-DSM	Correct Year-End Accrual Expense
		C-18 Added	C-19 Added	C-20 Added
	Operating Revenues			
1	Electric Retail Revenues			
2	Sales for Resale			
3	Other Operating Revenues			
4	Total Operating Revenues	$ -	$ -	$ -
	Operating Expenses			
5	Purchased Power			
6	Other O&M Expenses	$ (155,609)	$ (17,055)	$ (6,256)
7	Depreciation & Amortization			
8	Taxes Other Than Income Taxes			
9	PRE-TAX OPERATING EXPENSES	$ (155,609)	$ (17,055)	$ (6,256)
10	PRE-TAX OPERATING INCOME	$ 155,609	$ 17,055	$ 6,256
11	Income Taxes	$ 60,062	$ 6,583	$ 2,415
12	TOTAL OPERATING EXPENSES	$ (95,547)	$ (10,472)	$ (3,841)
13	OPERATING INCOME	$ 95,547	$ 10,472	$ 3,841

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per UNS Electric filing, Schedule C-3

UNS Electric, Inc.
Capital Structure & Cost Rates

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule D

Line No.	Capital Source	Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
	UNS - Proposed				
1	Short-Term Debt	$ 5,000	3.97%	6.36%	0.25%
2	Long-Term Debt	$ 59,486	47.18%	8.22%	3.88%
3	Common Stock Equity	$ 61,587	48.85%	11.79%	5.76%
4	Total Capital	$ 126,073	100.00%		9.89%
	ACC Staff - Proposed				
5	Short-Term Debt	$ 5,000	3.96%	6.36%	0.25%
6	Long-Term Debt	$ 59,545	47.21%	8.16%	3.85%
7	Common Stock Equity	$ 61,587	48.83%	10.000%	4.88%
8	Total Capital	$ 126,132	100.00%		8.99%
9	Difference				-0.90%
10	Weighted Cost of Debt				4.10%
	ACC Staff - Proposed Cost of Capital for Fair Value Rate Base				
11	Short-Term Debt	$ 5,181,370	3.09%	6.36%	0.20%
12	Long-Term Debt	$ 61,704,939	36.83%	8.16%	3.01%
13	Common Stock Equity	$ 63,821,011	38.10%	10.000%	3.81%
	Capital financing OCRB	$ 130,707,321			
14	Appreciation above OCRB not recognized on utility's books	$ 36,811,017	21.98%	0% [a]	0.00%
15	Total capital supporting FVRB	$ 167,518,338	100.00%		7.02%

Notes and Source

Lines 11-15, Col.A:

Fair Value Rate Base	$ 167,518,337	Schedule A
Original Cost Rate Base	$ 130,707,320	Schedule A
Difference	$ 36,811,017	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

[a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

UNS Electric, Inc.
Remove Construction Work in Progress

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B-1

Line No.	Description	Amount	Reference
1	Remove Construction Work in Progress	$ (10,761,154)	A & B

Notes and Source

A: UNS Electric Filing, Schedule B-2, page 2, line 1
B: Testimony of Staff witness Ralph Smith

UNS Electric, Inc.
Adjust CWIP for Plant in Service by End of Test Year

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B-2

Line No.	Description	Plant Account	Amount	Reference
1	Adjustment to Plant in Service for Rhode Homes Line Extensions	365	$ 442,255	A
2	Adjustment to Customer Advances for Construction			A
3	Net Rate Base Adjustment		$ 442,255	

Notes and Source

A: Staff memorandum concerning its Preliminary Field Assessment of Used and Useful Review for UNS Electric as it relates to the Rhode Homes overhead line extensions

Line 2: Letter of Agreement dated March 2, 2006 indicates the customer will pay to the Company a total Customer Advance of $360,117
The Company's response to data request STF 15.4(f) and (g) indicate that, as of June 30, 2006, UNS Electric had received Customer Advances totaling $360,117 for this project, and no additional Customer Advances for this project have been received subsequent to June 30, 2006.

UNS Electric, Inc.
Plant in Service Addition Subject to Reimbursement

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B-3 (Revised)

Line No.	Description	Amount	Reference
1	Adjustment to Contributions in Aid of Construction	$ (236,874)	Notes A & B
	Decrease to Plant in Service	Withdrawn, subject to obtaining supporting documentation	

Notes and Source

A: Staff memorandum concerning its Preliminary Field Assessment of Used and Useful Review for UNS Electric as it relates to the Tubac Golf Resort Overhead to Underground Conversion

The Company's response to STF 15.4(d) states that: "this customer requested work was paid 100% by the customer as a Contribution in Aid of Construction."

B Adjustment withdrawn based on explanation in UNS Electric witness Karen Kissinger's rebuttal testimony at pages 4-5 subject to obtaining adequate supporting documentation, which was requested in data request STF 20.50

UNS Electric, Inc.
Cash Working Capital - Lead/Lag Study
For the Test Year Ending 6/30/06

Line No.	Description	FERC	Per UNS Electric Pro Forma Test Year Amount		Staff Adjustments	Staff Adjusted	Expense Lag Days		Net Lag Days (RevLag - Col. D)	Lead/Lag Factor (Col. E/365)	Cash Working Capital Required (Col. F X Col.C)
	(A)		(A)		(B)	(C)	(D)		(E)	(F)	(G)
	Operating Expenses:				Revised	Revised					Revised
	Non-Cash Expenses -										
1	Bad Debts Expense	904	$ 579,538	1a	(155,609)	423,929					$ -
2	Depreciation	403/404	15,594,232	1.2a	(494,656)	15,099,576					-
3	Amortization	406	(3,781,658)	1.2b	-	(3,781,658)					-
4	Deferred Income Taxes		494,521	1.3a		494,521					-
	Other Operating Expenses -										
5	Salaries and Wages (UNSE Direct Employees)	Multi	4,571,466	2.2a		4,571,466	23.33	D.	12.26	0.0336	153,601
6	Incentive Pay (UNSE Direct Employees)	Multi	98,247	3a	(17,962)	80,285	267.00	D.	(231.41)	(0.6340)	(50,901)
7	Purchased Power		106,021,950	1b		106,021,950	33.79	E.	1.80	0.0049	519,508
8	Transmission Other		7,009,878	1c		7,009,878	40.67	F.	(5.08)	(0.0139)	(97,437)
9	Meter Reading		730,556	1d		730,556	33.67	G.	1.92	0.0053	3,872
10	Customer Records & Collection Expenses (excluding alloc.)	903	2,982,604	1e-4b	-	2,982,604	34.94	H.	0.65	0.0018	5,369
11	Office Supplies and Expenses	921	535,854	1.1a		535,854	50.89	I.	(15.30)	(0.0419)	(22,452)
12	Injuries and Damages	925	512,417	1.1b	(159,063)	353,354	70.52	J.	(34.93)	(0.0957)	(33,816)
13	Pension & Benefits	926	1,172,133	1.1c	-	1,172,133	51.37	K	(15.78)	(0.0432)	(50,636)
14	Support Services (Direct Labor, Burdens, System Allocation)		5,631,155	4a	(190,865)	5,440,290	44.77	L.	(9.18)	(0.0252)	(137,095)
15	Property Taxes	408	3,096,371	1.3b	(291,126)	2,805,245	213.00	M.	(177.41)	(0.4861)	(1,363,630)
16	Payroll Taxes	408	348,088	1.3c	(1,553)	346,535	19.87	M.	15.72	0.0431	14,936
17	Current Income Taxes		1,342,818	1.3d		3,520,897	41.42	M.	(5.83)	(0.0160)	(56,334)
18	Interest on Customer Deposits	431	217,492	1.3e		217,492	182.50	Q.	(146.91)	(0.4025)	(87,541)
19	Other Operations and Maintenance	Multi	2,587,216	X	(185,529)	2,401,687	41.21	N.	(5.62)	(0.0154)	(36,986)
20	Total Operating Expenses		149,744,878		(1,496,363)	150,426,594					
	Other Cash Working Capital Elements:										
21	Interest on Long-Term Debt		5,819,157	8a	(460,157)	5,359,000	90.22	O.	(54.63)	(0.1497)	(802,242)
22	Revenue Taxes and Assessments	Calc	$ 13,983,561	P.	329,752	14,313,313	45.71	M.	(10.12)	(0.0277)	(396,479)
23	Total Cash Working Capital - Calculated										$ (2,438,263)
24	Total Cash Working Capital - Per UNS Electric Filing, Schedule B-5, page 3 of 3										(2,634,713)
25	Adjustment to Cash Working Capital										196,450

Notes and Source
UNS Electric filing, Schedule B-5, page 3 of 3
RUCO 1.10 2005 UNSE Lead-Lag Summary.xls
Revenue Lag, in days 35.59
Col.B: Staff workpapers for CWC calculation

Line 17, Col.C, Current income taxes:

26	Per UNS Electric, Current Income Taxes	$ 1,342,818	Col.A, line 17
27	Staff adjustments to Current Income Taxes	$ 775,610	Schedule C.1
28	Staff adjusted Current Income Taxes before Revenue Increase	$ 2,118,428	Schedule C
29	Income taxes for revenue increase	$ 1,402,469	Schedule A-1
30	Total current income taxes for CWC calculation	$ 3,520,897	

Total Income Taxes		Current Inc Taxes		Deferred Inc Taxes
2,612,949	-	$ 2,118,428	=	$ 494,521
Schedule C		Line 28		Col. A, Line 4

Line 22, Revenue Based Taxes

31	Revenue adjustments	$ 52,937	Schedule C
32	Staff recommended rate increase	$ 3,646,946	Schedule A, filtered through CWC macro
33	Revenue adjustments	$ 3,699,883	
34	Revenue based taxes	0.0891249	B-4 W/P 2
35	Adjustment to revenue based taxes	$ 329,752	

UNS Electric, Inc.
Accumulated Deferred Income Taxes

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B-5

Line No.	Description	Account	Amount	Reference
1	SERP	190	$ (97,217)	A
2	Stock Based Compensation	190	$ (64,338)	A
3	Total Adjustment to ADIT		$ (161,555)	

Notes and Source

A: Staff has removed SERP and Restricted Stock from operating expenses and allocated incentive compensation expense 50/50 to shareholders and ratepayers. This adjustment coordinates the corresponding ADIT amounts with those recommendations.

	Account and Description	Per Books (1)	UNS Electric Adjustment (2)	UNS Electric Adjusted		Staff Adjustment
	Account 190					
4	SERP	$ 99,736	$ (2,519)	$ 97,217	a	$ (97,217)
5	Restricted Stock	$ 28,728	$ (1,970)	$ 26,758	b	$ (26,758)
6	Dividend Equivalents	$ 37,661	$ (1,844)	$ 35,817	c	$ (35,817)
7	Stock Options	$ -	$ 1,763	$ 1,763	d	$ (1,763)
8	Stock Based Compensation related ADIT	$ 66,389	$ (2,051)	$ 64,338		$ (64,338)

(1) Response to STF 3.60
(2) UNS Electric ADIT workpapers
a: UNS Electric workpaper "Pro Forma ADIT - Account 190" "SERP 12G"
b: UNS Electric workpaper "Pro Forma ADIT - Account 190" "Restricted Stock 12F"
c: UNS Electric workpaper "Pro Forma ADIT - Account 190" "Dividend Equivalents 12C"
d: UNS Electric workpaper "Pro Forma ADIT - Account 190" "Stock Options 12H"

UNS Electric, Inc.
Revenue Adjustment for CARES Discount

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Remove Company Revenue Adjustment for Company's Proposed Revisions to CARES Discounts	$ 52,937	A&B

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 1, line 1
B: Testimony of Staff witness Julie McNeely-Kirwan

UNS Electric, Inc.
Remove Depreciation & Property Taxes for CWIP

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-2

Line No.	Description	Account	Amount	Reference
1	CWIP Related Depreciation Expense	403	$ (449,816)	A
2	CWIP Related Property Tax Expense	408	$ (239,696)	A
3	Total Adjustments		$ (689,512)	

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 4, lines 7 and 8

UNS Electric, Inc.
Depreciation & Property Taxes for CWIP Found to be In-Service in the Test Year

Docket No. E-04204A-06-0783
Schedule C-3

Test Year Ended June 30, 2006

Line No.	Description	Account	Amount	Reference
1	Rhode Homes Related Depreciation Expense	403	$ 18,265	A
2	Rhode Homes Related Property Tax Expense	408	$ 8,317	B
3	Total Adjustments		$ 26,582	

A: Depreciation Rate taken from Attachment REW-2, Statement A, from Dr. White's testimony

		Plant Account	Amount	Depreciation Rate	Depreciation Expense
4	Rhode Homes Overhead Line Extensions (see Sch. B-2)	365	$ 442,255	4.13%	$ 18,265

B: **Calculation of Property Tax Expense**

5	Rhode Homes Overhead Line Extensions	$ 442,255	
6	Less: Accumulated Depreciation	$ (18,265)	
7	Subtotal	$ 423,990	
8	Assessment Ratio	23.5%	
9	Taxable Value	$ 99,638	
10	Mohave Property Tax Rate	8.3471%	per Company's Property Tax adjustment workpaper
11	Property Tax Expense	$ 8,317	

UNS Electric, Inc.
Fleet Fuel Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-4 (Revised)

Line No.	Description	Amount	Reference
1	UNS Electric Adjustment to Fleet Fuel Expense	$ 73,661	A
2	Staff Recommended Pro Forma Adjustment to Fleet Fuel Expense	$ 11,464	B
3	Adjustment to Fleet Fuel Expense	$ (62,197)	L2 - L1

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 3, lines 5 and 6

B: Per Company's workpapers showing calculation of Fleet Fuel Expense adjustment UNSE(0783)10597:
(Dallas Dukes' rebuttal workpapers for fleet fuel expense)
Actual fleet fuel expense invoices for July 2006 through June 2007

4	Gallons purchased	207,310	UNSE(0783)10597
5	Weighted average price per gallon	$ 2.82	UNSE(0783)10597
6	Pro forma fuel expenditures	$ 585,210	UNSE(0783)10597
7	Test year expenditures	$ 573,746	
8	Staff Recommended pro forma adjustment to Fleet Fuel Expense	$ 11,464	L6-L7

C: **Line 6 Compare Amounts taken from the Company's response to STF 11.24**

		Gallons	Fuel Cost	Weighted Average Cost/Gal
9	Wright Express (September 2006 - May 2007)	51,891	$ 139,467	$ 2.69
10	Kingman Gascard (September 2006 - May 2007)	71,885	$ 192,615	$ 2.68
11	Parker Oil (February through May 2007)	7,775	$ 22,304	$ 2.87
12	Weighted Average	131,551	$ 354,386	$ 2.69

UNS Electric, Inc.
Adjustment to Fleet Fuel Expense (supplemental worksheet)
Allocation of Staff adjustment to FERC accounts

Docket No. E-04204A-06-0783
Schedule C-4 (Revised)

Test Year Ended June 30, 2006

Co	Acct	Expense Type	FERC Account	DR	CR	Net Amount	% of Total	O&M Adjustment	Staff Adjustment
33	55000	403	546	$7,634.11		$7,634.11	0.85%	$98	($530)
33	55000	403	548	$1,198.26		$1,198.26	0.13%	$15	($83)
33	55000	403	549	$188.36		$188.36	0.02%	$2	($13)
33	55000	403	551	$9,428.90		$9,428.90	1.05%	$121	($655)
33	55000	403	553	$17,592.83		$17,592.83	1.96%	$225	($1,222)
33	55000	403	554	$9,332.50		$9,332.50	1.04%	$119	($648)
33	55000	403	557	$2,550.60		$2,550.60	0.28%	$33	($177)
33	55000	403	562	$3,237.60		$3,237.60	0.36%	$41	($225)
33	55000	403	563	$472.61		$472.61	0.05%	$6	($33)
33	55000	403	566	$2,075.77		$2,075.77	0.23%	$27	($144)
33	55000	403	570	$7,633.80		$7,633.80	0.85%	$98	($530)
33	55000	403	571	$395.23		$395.23	0.04%	$5	($27)
33	55000	403	580	$8,414.78		$8,414.78	0.94%	$108	($584)
33	55000	403	581	$54,108.09		$54,108.09	6.04%	$693	($3,758)
33	55000	403	582	$4,099.30		$4,099.30	0.46%	$52	($285)
33	55000	403	583	$33,150.21		$33,150.21	3.70%	$424	($2,303)
33	55000	403	584	$65,053.92		$65,053.92	7.26%	$833	($4,518)
33	55000	403	585	$165.43		$165.43	0.02%	$2	($11)
33	55000	403	586	$98,161.79		$98,161.79	10.96%	$1,257	($6,818)
33	55000	403	587	$1,717.22		$1,717.22	0.19%	$22	($119)
33	55000	403	588	$43,342.83		$43,342.83	4.84%	$555	($3,010)
33	55000	403	590	$9,421.61		$9,421.61	1.05%	$121	($654)
33	55000	403	592	$53,782.89		$53,782.89	6.01%	$689	($3,736)
33	55000	403	593	$93,650.75		$93,650.75	10.46%	$1,199	($6,505)
33	55000	403	594	$18,195.04		$18,195.04	2.03%	$233	($1,264)
33	55000	403	595	$8,141.32		$8,141.32	0.91%	$104	($565)
33	55000	403	596	$8,089.99		$8,089.99	0.90%	$104	($562)
33	55000	403	598	$171.22		$171.22	0.02%	$2	($12)
33	55000	403	901	$24,434.41		$24,434.41	2.73%	$313	($1,697)
33	55000	403	902	$13,012.92		$13,012.92	1.45%	$167	($904)
33	55000	403	903	$132,933.49		$132,933.49	14.85%	$1,702	($9,233)
33	55000	403	905	$1,969.74		$1,969.74	0.22%	$25	($137)
33	55000	403	908	$7,737.47		$7,737.47	0.86%	$99	($537)
33	55000	403	909	$7,376.08		$7,376.08	0.82%	$94	($512)
33	55000	403	910	$181.63		$181.63	0.02%	$2	($13)
33	55000	403	920	$0.00		$0.00	0.00%	$0	$0
33	55000	403	921	$111,418.51		$111,418.51	12.44%	$1,426	($7,739)
33	55000	403	925	$165.65		$165.65	0.02%	$2	($12)
33	55000	403	930	$34,835.19		$34,835.19	3.89%	$446	($2,421)
				$895,472.05	$0.00	$895,472.05		$11,464	($62,196)

Staff adjustment amount from page 1: $11,464 $ (62,197)

UNS Electric, Inc.
Postage Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-5

Line No.	Description	Amount	Reference
1	UNS Electric Annualized Postage Expense	$ 341,321	A
2	Recommended Staff Annualized Postage Expense	$ 358,824	B
3	Adjustment to Annualized Postage Expense	$ 17,503	L2 - L1

Notes and Source

A: Per Company workpaper used in calculating its Postage Expense adjustment

B:

4	UNS Electric Annualized Postage Expense	$ 341,321
5	Postage increase effective 5/14/07 (.41/.39)	1.05
6	Staff adjusted annualized Postage Expense	$ 358,824

UNS Electric, Inc.
Normalize Injuries and Damages Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-6

Line No.	Description	Amount	Reference
1	UNS Electric Test Year Injuries and Damages Expense	$ 562,403	A
2	Staff Recommended Normalized Injuries and Damages Expense	$ 403,340	B
3	Adjustment to Injuries and Damages Expense	$ (159,063)	L2 - L1

Notes and Source

A: Amount taken from UNS Electric's response to STF 3.101

B: Amounts taken from UNS Electric's response to STF 3.101

January through December 2004	$ 352,589
January through December 2005	$ 356,992
January through December 2006	$ 500,440
Total	$ 1,210,021
Normalized over three years	3
Staff Recommended Normalized Injuries and Damages Expense	$ 403,340

FERC Account 925

UNS Electric, Inc.
Incentive Compensation Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-7

Line No.	Description	Amount	Reference
1	Staff Adjustment to UES's Performance Enhancement Plan (PEP)	$ (17,962)	A
2	Staff Adjustment to UES's Other Incentive Comp	$ (24,486)	B
3	Total Adjustment to Incentive Compensation Expense	$ (42,448)	
4	Adjustment to Taxes Other Than Income	$ (1,553)	B

Notes and Source

A: Per Company's workpapers showing calculation of Incentive Compensation adjustment (except where noted)

FERC Acct	FERC Account Description	Company Amount	Disallowance Percentage	Staff Adjusted Amount
	Performance Enhancement Plan			
581	Distribution - Load Dispatching	$ 292	50%	$ 146
588	Distribution - Miscellaneous Expense	$ 3,428	50%	$ 1,714
593	Distribution - Maintenance of Overhead Lines	$ 3,612	50%	$ 1,806
901	Customer Accounting - Supervision	$ 5,374	50%	$ 2,687
903	Customer Records & Collection Expense	$ 585	50%	$ 293
909	Informational & Instructional Advertising Expense	$ 2,139	50%	$ 1,070
920	A&G Salaries	$ 20,491	50%	$ 10,246
		$ 35,921		$ 17,962
408	Taxes Other Than Income	$ 3,105	50%	$ 1,553
B: Per UNS Electric Inc.'s response to STF 3.83				
920	Deferred Compensation Plan	$ 9,035	50%	$ 4,518
923	Officer's Long Term Incentive Plan	$ 39,935	50%	$ 19,968
		$ 48,970		$ 24,486

UNS Electric, Inc.
Supplemental Executive Retirement Plant (SERP) Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-8

Line No.	Description	Amount	Reference
1	Remove Supplemental Executive Retirement Plan Expense	$ (83,506)	A

Notes and Source

A: Per the Company's response to STF 3.83

FERC 923

UNS Electric, Inc.
Stock Based Compensation Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-9

Line No.	Description	Amount	Reference
1	Remove Stock Based Compensation Expense	$ (82,873)	Note A

Notes and Source

A: Per Company's response to STF 10.11

Stock Option Expense	$	62,904
Performance Share Expense	$	19,969
Total	$	82,873

UNS Electric, Inc.
Property Tax Expense

Docket No. E-04204A-06-0783
Schedule C-10

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	UNS Electric Proposed Decrease to Property Tax Expense	$ (130,301)	A
2	Staff Proposed Decrease to Property Tax Expense	$ (190,048)	B
3	Adjustment to Property Tax Expense	$ (59,747)	L2 - L1

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 5, line 8

B: Amounts taken from Company workpapers used to calculate its property tax expense adjustment

	Utility Plant in Service Taxes	Generation	Transmission	Distribution	General/ Intangible	Total
4	Total Net Plant in Service - Rate Base	$ 18,471,624	$ 15,073,774	$ 99,401,194	$ 16,474,253	$ 149,420,845
5	Less: Non-Taxable Licensed Transportation in Rate Base	$ -	$ -	$ -	$ (3,834,788)	$ (3,834,788)
6	Less: Land Cost & Rights of Way in Rate Base	$ (408,603)	$ (681,822)	$ (695,700)	$ (30,719)	$ (1,816,844)
7	Less: Environmental Property in Rate Base	$ -	$ -	$ (5,563,286)		$ (5,563,286)
8	Less: Non-Taxable WAPA Portion of N Havasu Sub			$ (4,674,822)		$ (4,674,822)
9	Less: CWIP in Rate Base	$ (777,167)	$ (1,234,041)	$ (7,840,042)	$ (951,066)	$ (10,802,316)
10	Less: Net Book Value of Generation	$ (17,285,854)				$ (17,285,854)
11	Plus: Full Cash Value of Generation	$ 7,943,440				$ 7,943,440
12	Plus: Land FCV per AZ Department of Revenue			$ 1,551,539		$ 1,551,539
13	Plus: Materials and Supplies in Rate Base			$ 5,650,559		$ 5,650,559
14	Plant in Service Full Cash Value	$ 7,943,440	$ 13,157,911	$ 87,829,442	$ 11,657,680	$ 120,588,473
15	Assessment Ratio	23.5%	23.5%	23.5%	23.5%	
16	Taxable Value	$ 1,866,708	$ 3,092,109	$ 20,639,919	$ 2,739,555	$ 28,338,291
17	Average Tax Rate	9.6858%	9.6858%	9.6858%	9.6858%	
18	Property Tax - Subtotal	$ 180,806	$ 299,495	$ 1,999,141	$ 265,348	$ 2,744,790
19	Environmental Property in Rate Base	$ -	$ -	$ 5,563,286	$ -	
20	Statutory Full Cash Value Adjustment	50%	50%	50%	50%	
21	Environmental Full Cash Value	$ -	$ -	$ 2,781,643	$ -	
22	Assessment Ratio	23.5%	23.5%	23.5%	23.5%	
23	Taxable Value	$ -	$ -	$ 653,686	$ -	
24	Average Tax Rate	9.6858%	9.6858%	9.6858%	9.6858%	
25	Property Tax - Subtotal	$ -	$ -	$ 63,315	$ -	$ 63,315
26	Total Property Taxes	$ 180,806	$ 299,495	$ 2,062,456	$ 265,348	$ 2,808,105
27	Less: Recorded Property Taxes Excluding Call Center	$ (101,364)	$ (395,121)	$ (2,266,077)	$ (222,391)	$ (2,984,953)
28	Property Tax Expense Adjustment (subtotal)	$ 79,442	$ (95,626)	$ (203,621)	$ 42,957	$ (176,848)
29	Less: Estimated Property Tax Related to PHFFU					$ (13,200) *
30	Property Tax Expense Adjustment					$ (190,048)

***Plant Held for Future Use**

	Transmission	Distribution	Total
Original Cost	$ 320,000	$ 120,000	$ 440,000
Estimated Property Tax Rate	3.0%	3.0%	
Estimated Property Tax Expense	$ 9,600	$ 3,600	$ 13,200

2008 Arizona Statutory Assessment Ratio 23.5%

FERC Account 408

UNS Electric, Inc.
Rate Case Expense

Docket No. E-04204A-06-0783
Schedule C-11

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	UNS Electric Rate Case Expense per Company Filing	$ 200,000	A
2	Staff Recommended Rate Case Expense	$ 88,333	B
3	Adjustment to Rate Case Expense	$ (111,667)	L2 - L1

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 3, line 6

B:	Staff Recommended Rate Case Expense	$ 265,000	Note 1
	Normalized Over Three Years	3	
	Staff Recommended Normalized Rate Case Expense	$ 88,333	

(1) Reflects an escalation of approximately 4% over the allowance recommended by Staff in the recent UNS Gas rate case

UNS Electric, Inc.
Edison Electric Institute Dues

Docket No. E-04204A-06-0783
Schedule C-12

Test Year Ended June 30, 2006

Line No.	Description	Test Year Amount (A)	Company Adjustment (B)	Company Adjusted Amount (C)	Staff Adjustment (D)	Staff Adjusted (E)
1	Regular Dues	$ 10,000	$ (2,000)	$ 8,000	$ (2,993) a	$ 5,007
2	2005 UARG	$ 24,071	$ -	$ 24,071	$ (2,675) b	$ -
3	2006 UARG	$ 2,802	$ -	$ 2,802	$ (2,802)	$ -
4	Total Test Year EEI Dues	$ 36,873	$ (2,000)	$ 34,873	$ (8,470)	$ 5,007
5	Journal Entry to Correct 2005 UARG per G/L	$ (21,396)	$ -	$ (21,396)	$ -	$ -
6	Adjusted Test Year EEI Dues	$ 15,477	$ (2,000)	$ 13,477	$ (8,470)	$ 5,007

Notes and Source

Col. A: Amounts taken from the Company's response to STF 3.72

a: Staff adjustment for Regular Dues based on a disallowance percentage of 49.93% (see page 2)

	Staff Adjustment
Regular Dues	$ 10,000
Regular Dues disallowance percentage	49.93%
Staff adjustment to Regular Dues	$ 4,993
Less: Company adjustment	$ (2,000)
Remaining Staff adjustment to Regular Dues	$ 2,993

b: Allocation of TEP's portion of 2005 UARG in the amount of $24,071 booked in error. Corrected by Journal Entry 910.

TEP allocation of 2005 UARG	$ 24,071
Correcting JE910	$ (21,396)
UNS Electric allocation of 2005 UARG	$ 2,675

Page 17 of Mr. Dukes' rebuttal testimony agrees that the UARG dues should be removed.

Col D: Per letter from Edison Electric Institute included in Company's workpapers for its EEI adjustment, 100% of environmental related separately funded activities are classified as "non-deductible" expenses

FERC 930

Edison Electric Institute
Schedule of Expenses by NARUC Category
For Core Dues Activities
For the Year Ended December 31, 2005

NARUC Operating Expense Category	% of Dues	Recommended Disallowance
Legislative Advocacy	20.38%	20.38%
Legislative Policy Research	6.02%	
Regulatory Advocacy	16.49%	16.49%
Regulatory Policy Research	13.99%	
Advertising	1.67%	1.67%
Marketing	3.68%	3.68%
Utility Operations and Engineering	11.31%	
Finance, Legal, Planning and Customer Service	18.75%	
Public Relations	7.71%	7.71%
Total Expenses	100.00%	49.93%

Comments:

* The above percentages represent expenses associated with EEI's core dues activities, based on the operating expense categories established by NARUC. Core expenses are those expenses paid for by shareholder-owned electric utilities' dues.

* The legislative advocacy percent will differ slightly for IRS reporting requirements. For 2005, the lobbying % for IRS reporting is 19.4%.

* Administrative expenses are included in the percentages listed above. Approximately 11% of EEI's core dues expenses are administrative.

UNS Electric, Inc.
Other Membership and Industry Association Dues

Docket No. E-04204A-06-0783
Schedule C-13

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Arizona Utility Investors Association	$ 2,500	930
2	Alliance of Utility Shareholder Associations (AUSA)	$ 100	930
3	Golden Valley Chamber of Commerce	$ 70	930
4	Kingman Mohave Lions Club	$ 120	921/930
5	Kingman Rotary Club	$ 383	921/930
6	Kingman Route 66 Rotary Club	$ 508	921/930
7	Kingsmen	$ 125	930
8	Kiwanis Club of Havasu	$ 666	930
9	Mohave Museum of History & Arts	$ 200	930
10	Nogales-Santa Cruz Chamber of Commerce	$ 60	930
11	Arizona-Mexico Commission	$ 1,750	930.1
12	Total Membership Dues	$ 6,482	

		Total From Above	Adjustment
13	Total Amount Recorded in Account 921	$ 568	$ (568)
14	Total Amount Recorded in Account 930	$ 5,914	$ (5,914)
15	Total	$ 6,482	$ (6,482)

Notes and Source

Amounts taken from the Company's response to STF 3.72

L.11: Also see responses to data requests STF 3.55 and MM DR 2.27:
"The $1,750 for the Arizona-Mexico Commission should have been removed from expenses included in the revenue requirement. This invoice was overlooked in error and will be adjusted out of test year expense."

UNS Electric, Inc.
Interest Synchronization

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-14 (Revised)

Line No.	Description		Amount	Reference
1	Adjusted rate base	$	130,707,320	Schedule B
2	Weighted cost of debt		4.10%	Schedule D
3	Synchronized interest deduction	$	5,359,000	Line 1 x Line 2
4	Synchronized interest deduction per UNS Electric	$	5,819,157	Note A
5	Difference (decreased) increased interest deduction	$	(460,157)	Line 3 - Line 4
6	Combined federal and state income tax rates		38.598%	UNS Electric Sch. C-3
7	Increase (decrease) to income tax expense	$	177,611	

Notes and Source

A RUCO 1.10 2006 UNSE Lead-Lag Summary.xls
Also, UNS Electric filing, Schedule B-5, page 3 of 3, line 21

UNS Electric, Inc.
Depreciation Rates Correction

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-15

Line No.	Description	Amount	Reference
1	Adjustment to Depreciation & Amortization Expense	$ (63,105)	A

Notes and Source

A: Per Company's workpapers used to calculate its depreciation expense adjustment (except where noted)

FERC	Description	UNS Electric Proforma Adj. to Depreciation Expense	Staff Proforma Adj. to Depreciation Expense	Staff Adjustment	Additional Reference
403	Depreciation Expense	$ 122,500	$ 57,628	$ (64,872)	Pages 2 & 3
404	Amortization of Utility Plant	$ 323,410	$ 323,410	$ -	Page 3
406	Amortization of Utility Plant Acquisition Adjustment	$ 137,076	$ 138,843	$ 1,767	Page 4
	Total	$ 582,986	$ 519,881	$ (63,105)	

UNS Electric, Inc.
Depreciation & Amortization Expense - Supplemental Worksheet

Docket No. E-04204A-06-0783
Schedule C-15

Test Year Ended June 30, 2006

Depreciation Annualization Adjustment

Line No.	FERC Account	Description	Balance at 6/30/06	Adjustments	Adjusted Balance	Depreciation Rate	Annualized Depreciation	
		A. Rates Per Company Proforma Adjustment						
1	392	Transportation Equipment - Class 1	$ 366,331	$ 10,369	$ 376,700	12.75%	$ 48,029	
2	392	Transportation Equipment - Class 2	$ 1,151,599	$ 32,595	$ 1,184,194	16.99%	$ 201,195	
3	392	Transportation Equipment - Class 3	$ 1,185,238	$ 33,548	$ 1,218,786	20.21%	$ 246,317	
4	392	Transportation Equipment - Class 4	$ 5,641,612	$ 159,683	$ 5,801,295	13.47%	$ 781,434	
5	392	Transportation Equipment - Class 5	$ 1,995,626	$ 56,485	$ 2,052,111	12.55%	$ 257,540	
7		Total Annualized Transportation Equip.					$ 1,534,515	
		B. Rates Per Response to STF 11.8						
8	392	Transportation Equipment - Class 1	$ 366,331	$ 10,369	$ 376,700	11.48%	$ 43,245	
9	392	Transportation Equipment - Class 2	$ 1,151,599	$ 32,595	$ 1,184,194	15.29%	$ 181,063	
10	392	Transportation Equipment - Class 3	$ 1,185,238	$ 33,548	$ 1,218,786	18.69%	$ 227,791	
11	392	Transportation Equipment - Class 4	$ 5,641,612	$ 159,683	$ 5,801,295	11.97%	$ 694,415	
12	392	Transportation Equipment - Class 5	$ 1,995,626	$ 56,485	$ 2,052,111	11.29%	$ 231,683	
13		Total Annualized Transportation Equip.					$ 1,378,197	
		C. Staff Adjustment						
14		Staff Adjustment Before Capitalization					$ (156,318)	L13 - L7
15		O&M Portion of Vehicle Depreciation					41.5%	
16		Staff Adjustment to Depreciation Expense					$ (64,872)	L14 x L15

Notes and Source

Staff proforma adjustment for Depreciation & Amortization based on revised depreciation rates for FERC account 392 - Transportation Equipment, which reflected a 10% net salvage rate that was inadvertently omitted from the depreciation study as addressed in the responses to STF 3.39 and STF 11.8

UNS Electric, Inc.
Depreciation & Amortization Expense - Supplemental Worksheet

Test Year Ended June 30, 2006

Depreciation Annualization Adjustment

Line No.	Description	Account 403	Account 404	O&M Exp.	Total	
	UNS Electric Proforma Adjustment - Schedule 15.1, page 12					
1	Test Year Recorded	$ 14,308,205	$ 390,304	$ 332,503	$ 15,031,012	
2	Annualized Depreciation	$ 16,110,715	$ 713,714		$ 16,824,429	
3	Less: Depr on CWIP Removed	$ (449,816)			$ (449,816)	
4	Vehicle Depreciation Chgs CWIP	$ (1,534,515)		$ 636,824	$ (897,691)	
5	Adjusted Annualized Depreciation	$ 14,126,384	$ 713,714	$ 636,824	$ 15,476,922	
6	Adjustment Amount	$ (181,821)	$ 323,410	$ 304,321	$ 445,910	

	Staff Proforma Adjustment - Schedule 15.2, page 8	Account 403	Account 404	O&M Exp.	Total	
7	Test Year Recorded	$ 14,308,205	$ 390,304	$ 332,503	$ 15,031,012	
8	Annualized Depreciation	$ 15,954,397	$ 713,714		$ 16,668,111	
9	Less: Depr on CWIP Removed	$ (449,816)			$ (449,816)	
10	Vehicle Depreciation Chgs CWIP	$ (1,378,197)		571,952	$ (806,245)	
11	Adjusted Annualized Depreciation	$ 14,126,384	$ 713,714	$ 571,952	$ 15,412,050	
12	Adjustment Amount	$ (181,821)	$ 323,410	$ 239,449	$ 381,038	
13	Staff Adjustment				$ (64,872)	L12 - L6

UNS Electric, Inc.
Depreciation & Amortization Expense - Supplemental Worksheet

Docket No. E-04204A-06-0783
Schedule C-15

Test Year Ended June 30, 2006

Acquisition Discount Annualization Adjustment

Line No.	FERC Account	Description	Balance at 6/30/06	Adjustments	Adjusted Balance	Depreciation Rate	Annualized Depreciation	
		Rates Per Company Proforma Adjustment						
1	392	Transportation Equipment - Class 1	$ (51,192)	$ 39,563	$ (11,629)	12.75%	$ (1,483)	
2	392	Transportation Equipment - Class 2	$ (16,191)	$ 12,513	$ (3,678)	16.99%	$ (625)	
3	392	Transportation Equipment - Class 3	$ (92,982)	$ 71,860	$ (21,122)	20.21%	$ (4,269)	
4	392	Transportation Equipment - Class 4	$ (362,404)	$ 280,080	$ (82,324)	13.47%	$ (11,089)	
5	392	Transportation Equipment - Class 5	$ -	$ -	$ -	12.55%	$ -	
7		Total Annualized Amort-Acq Adj	$ (522,769)	$ 404,016	$ (118,753)		$ (17,466)	
		Rates Per Response to STF 11.8						
8	392	Transportation Equipment - Class 1	$ (51,192)	$ 39,563	$ (11,629)	11.48%	$ (1,335)	
9	392	Transportation Equipment - Class 2	$ (16,191)	$ 12,513	$ (3,678)	15.29%	$ (562)	
10	392	Transportation Equipment - Class 3	$ (92,982)	$ 71,860	$ (21,122)	18.69%	$ (3,948)	
11	392	Transportation Equipment - Class 4	$ (362,404)	$ 280,080	$ (82,324)	11.97%	$ (9,854)	
12	392	Transportation Equipment - Class 5	$ -	$ -	$ -	11.29%	$ -	
13		Total	$ (522,769)	$ 404,016	$ (118,753)		$ (15,699)	
14		Staff Adjustment					$ 1,767	L13 - L7

Proforma Adjustment to FERC Account 406

		Per Company Adj. Workpaper	Staff Adjusted	Staff Adjustment
15	Intangible Plant	$ (181,550)	$ (181,550)	
16	Other Production Plant	$ (136,670)	$ (136,670)	
17	Transmission Plant	$ (400,629)	$ (400,629)	
18	Distribution Plant	$ (2,824,706)	$ (2,824,706)	
19	General Plant	$ (238,101)	$ (236,334)	
		$ (3,781,656)	$ (3,779,889)	
20	Test Year Amount per Books	$ (3,918,732)	$ (3,918,732)	
21	Adjustment - FERC 406	$ 137,076	$ 138,843	$ 1,767

Notes and Source

Staff proforma adjustment for Acquisition Discount Annualization Adjustment based on revised depreciation rates for FERC account 392 - Transportation Equipment, which reflected a 10% net salvage rate that was inadvertently omitted from the depreciation study as addressed in the responses to STF 3.39 and STF 11.8

UNS Electric, Inc.
Emergency Bill Assistance Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-16

Line No.	Description	Account	Amount	Reference
1	Increase to Emergency Bill Assistance Expense		$ 20,000	A

Notes and Source

A Testimony of Staff witnesses Ralph C. Smith and Julie McNeely-Kirwan

UNS Electric Inc.
Southwest Energy Services (SES) Charges

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-17

Line No.	Description	Amount	Reference
1	Remove Mark-up Related to SES Charges	$ (10,906)	A

Notes and Source

A: Amount taken from UNS Electric's supplemental response to STF 15.1

Primarily FERC Account 902. See responses to data request STF 10.4 (direct billings) and STF 10.5 (indirect billings) for additional account details

UNS Electric Inc.
Bad Debt Expense

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	UNS Electric Adjustment to Bad Debt Expense per Filing	$ 222,556	A
2	UNS Electric Revised Adjustment to Bad Debt Expense	$ 66,947	B
3	Adjustment to Bad Debt Expense	$ (155,609)	L2 - L1

Notes and Source

A: UNS Electric filing, Schedule C-2, page 3, line 6
B: Rebuttal testimony of Company witness Dallas Dukes, pages 21 and 22 and workpaper UNSE(0783)10580

FERC Account 904

UNS Electric Inc.
Outside Services - Demand Side Management

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Remove Double Count from Outside Services Related to DSM	$ (17,055)	A

Notes and Source

A: Rebuttal testimony of Company witness Dallas Dukes, page 27

FERC Account 908

UNS Electric Inc.
Year-End Accruals

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-20

Line No.	Description	Amount	Reference
1	Correct Year-End Accrual to Remove Prior Period Expense	$ (6,256)	A

Notes and Source

A: Rebuttal testimony of Company witness Dallas Dukes at page 22 and Rebuttal Exhibit DJD-1, page 3.

FERC Account 926

UNS Electric, Inc.
Purchased Power and Fuel Adjustment Clause
Plan of Administration

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1. GENERAL DESCRIPTION

This document describes the plan for administering the Purchased Power and Fuel Adjustment Clause ("PPFAC") the Arizona Corporation Commission ("Commission") approved for UNS Electric, Inc. ("UNSE") in Decision No. XXXXX [DATE]. The PPFAC provides for the recovery of fuel and purchased power costs from the date of that decision forward.

The PPFAC described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs to set a rate that is then reconciled to actual costs experienced. This POA describes the application of the PPFAC.

2. DEFINITIONS

Applicable Interest – Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15. The interest rate is adjusted annually on the first business day of the calendar year.

Base Cost of Fuel and Purchased Power – An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost embedded in the base rates as approved by the Commission in UNSE's most recent rate case. The Base Cost of Fuel and Purchased Power revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at $X.XXXX per kWh effective on [DATE].

Forward Component –An amount expressed as a rate per kWh charge that is updated annually on June 1 of each year and effective with the first billing cycle in June. The Forward Component for the PPFAC Year will adjust for the difference between the forecasted fuel and purchased power costs expressed as a rate per kWh less the Base Cost of Fuel and Purchased Power generally expressed as a rate per kWh embedded in UNSE's base rates. The result of this calculation will equal the Forward Component, expressed as a rate per kWh.

Forward Component Tracking Account – An account that records on a monthly basis UNSE's over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue; plus Applicable Interest. The balance of this account as of the end of each PPFAC Year is, subject to periodic audit, reflected in the next True-Up Component calculation. UNSE files the balances and supporting details underlying this Account with the Commission on a monthly basis via a monthly reporting requirement.

Mark-to-Market Accounting – Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load – Native load includes customer load in the UNSE control area for which UNSE has a generation service obligation.

PPFAC – The Purchased Power and Fuel Adjustment Clause approved by the Commission in Decision No. XXXXX that tracks changes in the cost of obtaining power supplies based upon forward-looking estimates of fuel and purchased power costs that are eventually reconciled to actual costs experienced as described herein.

PPFAC Rate - The combination of two rate components, the Forward Component and True-Up Component.

PPFAC Year - A consecutive 12-month period beginning each June 1 and lasting through May 31 the following year. The PPFAC will initially be set to zero on the date the Commission issues a decision in this proceeding (Decision No. XXXXX). The first year of the PPFAC will begin on June 1, 2008 and end on May 31, 2009.

System Book Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by UNSE to serve both Native Load and off-system sales, less the costs associated with applicable special contracts and Mark-to-Market Accounting adjustments. Wheeling costs and broker's fee are included.

Off-System Wholesale Sales Revenue - The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the UNSE system, using UNSE-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale - The portion of load from Native Load wholesale customers that is served by UNSE.

True-Up Component - An amount expressed as a rate per kWh charge that is updated annually on June 1 of each year and effective with the first billing cycle in June. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PPFAC Year tracking account balances to be refunded/collected from customers in the coming year's PPFAC rate.

True-Up Component Tracking Account – An account that records on a monthly basis the account balance to be collected or refunded via the True-Up Component rate as compared to the actual True-Up Component revenues, plus Applicable Interest; the balance of which at the close of the preceding PPFAC Year is, subject to periodic audit, then reflected in the next True-Up Component calculation. UNSE files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of UNSE's electricity over transmission facilities owned by others.

3. PPFAC COMPONENTS

The PPFAC Rate will consist of two components designed to provide for the recovery of actual, prudently incurred fuel and purchased power costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PPFAC Year (each June 1 through May 31 period shall constitute a PPFAC Year) fuel and purchased power costs and those embedded in base rates.

2. The True-Up Component, which tracks the differences between the PPFAC Year's actual fuel and purchased power costs and those costs recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PPFAC Year.

The PPFAC Year begins on June 1 and ends the following May 31. The first full PPFAC Year in which the PPFAC rate shall apply will begin on June 1, 2008 and end on May 31, 2009. Succeeding PPFAC Years will begin on each June 1 thereafter.

For the period from when the Commission issued Decision No. XXXXX in this case – until June 1, 2008 – the Base Cost of Fuel and Purchased Power rate established in that decision will be in effect.

On or before December 31 of each year, UNSE will submit a PPFAC Rate filing, which shall include a proposed calculation of the components for the PPFAC Rate. This filing shall be accompanied by supporting information as Staff determines to be required. UNSE will supplement this filing with True-Up Component filing on or before April 1 in order to replace estimated balances with actual balances, as explained below.

A. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) the fuel and purchased power costs embedded in base rates and (2) the forecasted fuel and purchased power costs over a PPFAC Year that begins on June 1 and ends the following May 31. UNSE will submit, on or before December 31 of each year, a forecast for the upcoming PPFAC year (June 1 through May 31) of its fuel and purchase power costs. It will also submit a forecast of kWh sales for the same PPFAC year, and divide the forecasted costs by the forecasted sales to produce the cents per kWh unit rate required to collect those costs over those sales. The result of subtracting the Base Cost of Fuel and Purchased Power from this unit rate shall be the Forward Component.

UNSE shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record UNSE's over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue. This account will operate on a PPFAC Year basis (i.e. June 1 to the following May 31), and its balances will be used to administer this PPFAC's True-Up Component, which is described immediately below.

Should an unusual event occur causing a drastic change in forecasted fuel and energy prices – such as a hurricane or other calamity – UNSE has the discretion to apply for an adjustment to the forward component. Such an adjustment ~~would only last until May 31 and~~ would not be implemented unless approved by ~~Staff and upon notice to~~ the Commission.

B. True-Up Component Description

The True-Up Component in any current PPFAC Year is intended to refund or recover the balance accumulated in the Forward Component Tracking Account (described above) during the previous PPFAC year. Also, any remaining balance from the True-Up Component Tracking Account as of May 31 would roll over into the True-Up Component for the coming PPFAC year starting June 1. The sum of projected Forward Component Tracking Account and True-Up Component Tracking Account balances on May 31 is divided by the forecasted PPFAC year kWh sales to determine the True-Up Component for the coming PPFAC year.

UNSE shall maintain and report monthly the balances in a True-Up Component Tracking Account, which will reflect monthly collections or refunds under the True-Up Component and the amounts approved for use in calculating the True-Up Component.

Each annual UNSE filing on December 31 will include an accumulation of Forward Component Tracking Account balances and True-Up Component Tracking Account balances for the preceding June through November and an estimate of the balances for December through May (the remaining six months of the current PPFAC Year). The UNSE filing shall use these balances to calculate a preliminary True-Up Component for the coming PPFAC Year. On or before April 1, UNSE will submit a supplemental filing that recalculates the True-Up Component. This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the December 31 filing.

The December 31 filing's use of estimated balances for December through May (with supporting workpapers) is required to allow the PPFAC review process to begin in a way that will support its completion and a Commission decision, if necessary, before June 1. The April 1 updating will allow for the use of the most current balance information available before the PPFAC rate would go into effect. In addition to the April 1 update filing, UNSE monthly filings (for the months of November through April) of Forward Component Tracking Account balance information and True-Up Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected True-Up Component unit rate required for the next PPFAC Year.

The True-Up Component Tracking Account will measure the changes each month in the True-Up Component balance used to establish the current True-Up Component as a result of collections under the True-Up Component in effect. It will subtract each month's True-Up Component collections from the True-Up Component balance. The True-Up Component Account will also include Applicable Interest on any balances. UNSE shall file the amounts and supporting calculations and workpapers for this account each month.

4. CALCULATION OF THE PPFAC RATE

The PPFAC rate is the sum of the two components; i.e., Forward Component and True-Up Component. The PPFAC rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PPFAC rate by May 31, the proposed PPFAC rate (as amended by the updated April 1 filing) shall go into effect on June 1. The PPFAC rate shall be applicable to UNSE's retail electric rate schedules (except those specifically exempted) and is adjusted annually. The PPFAC Rate shall be applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge that is the same for all customer classes.

The PPFAC rate shall be reset on June 1 of each year, and shall be effective with the first June billing cycle unless suspended by the Commission. It is not prorated.

5. FILING AND PROCEDURAL DEADLINES

A. December 31 Filing

UNSE shall file the PPFAC rate with all Component calculations for the PPFAC year beginning on the next June 1, including all supporting data, with the Commission on or before December 31 of each year. That calculation shall use a forecast of kWh sales and of fuel and purchased power costs for the coming calendar year, with all inputs and assumptions being the most current available for the Forward Component. The filing will also include the True-Up Component calculation for the year beginning on the next June 1, with all supporting data. That calculation will use the same forecast of sales used for the Forward Component calculation.

B. April 1 Filing

UNSE will update the December 31 filing by April 1. This update will replace estimated Forward Component Tracking Account balances~~,~~ and the True-Up Component Tracking Account balances with actual balances and with more current estimates for those months (March, April and May) for which actual data are not available. Unless the Commission has otherwise acted on the UNSE calculation by June 1, the PPFAC rate that UNSE proposed will go into effect on June 1.

C. Additional Filings

UNSE will also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PPFAC.

D. Review Process

The Commission Staff and interested parties will have an opportunity to review the December 31 and April 1 forecast, balances, and supporting data on which the calculations of the two PPFAC components have been based. Any objections to the December 31 calculations must be filed within 45 days of the UNSE filing. Any objections to the April 1 calculations must be filed within 15 days of the UNSE filing~~ (i.e. by April 15.)~~.

E. Extraordinary Circumstances

Should an unusual event occur that causes a drastic change in forecasted fuel and energy prices – such as a hurricane or other calamity – UNSE will have the ~~authority~~ability to request an adjustment to the forward component reflecting such a change. ~~Staff must review and either approve, modify or deny UNSE's request within 30 days. This adjustment will only last until May 31, or the end of the current PPFAC Year.~~The Commission may provide for the change over such period as the Commission determines appropriate.

6. VERIFICATION AND AUDIT

The amounts charged through the PPFAC will be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded in the True-Up Component for the following year (i.e. starting the next June 1.)

7. CALCULATIONS

A. Schedule 1: PPFAC Rate Calculation

[Specifics to be determined after reviewing illustrative schedules.]
~~Enter the appropriate effective periods for the Current and Proposed PPFAC columns and then complete the following in each respective column:~~

~~1. On Line 1, enter the Forward Component from Schedule 2, Line 8.~~
~~2. On Line 2, enter the True-Up Component from Schedule 4, Line 5.~~
~~3. On Line 3, enter the sum of Lines 1 and 2 to calculate the total PPFAC Rate.~~
~~4. Calculate the Increase/(Decrease) in rates and % Change by respective lines:~~
~~Proposed Rates Less Current Rates equals Increase/(Decrease) with result divided by Current Rate to determine % of Increase/(Decrease).~~

~~Reflect notes as appropriate.~~

B. Schedule 2: PPFAC Forward Component Rate Calculation

[Specifics to be determined after reviewing illustrative schedules.]

~~Enter the appropriate effective periods for the Current and Proposed PPFAC columns and then complete the following in each respective column:~~

1. ~~On Line 1, enter the Projected Fuel and Purchased Power Costs for the coming year.~~
2. ~~On Line 2, enter 90% of the Projected Off System Sales Revenue (entered as a negative value) for the coming year.~~
3. ~~On Line 3, enter the PPFAC Adjustments to Fuel and Purchased Power Costs for the coming year.~~
4. ~~On Line 4, enter the sum of Lines 1 through 3 to arrive at the Net Fuel and Purchased Power Costs.~~
5. ~~On Line 5, enter the Projected Native Load Sales (MWh), including Wholesale Native Load Customers for the coming year.~~
6. ~~On Line 6, enter the derivation of the Net Fuel and Purchased Power Costs divided by the Projected Native Load Sales to arrive at the Projected Average Net Fuel Cost per kWh.~~
7. ~~On Line 7, enter the Authorized Base Cost of Fuel and Purchased Power Rate per kWh.~~
8. ~~On Line 8, enter the sum of Line 6 less Line 7 to arrive at the Forward Component rate per kWh; and then carry forward resultant value to Schedule 1, Line 1.~~

~~Reflect notes as appropriate.~~

C. Schedule 3: Forward Component Tracking Account

[Specifics to be determined after reviewing illustrative schedules.]

~~Enter the appropriate: effective dates for the PPFAC Forward Component currently being tracked; year for the column headed "Cycle Billing Month"; and Base Rate and Forward Component in columns h and i. On lines 1 through 12 under the Cycle Billing Month, January through December for each respective column complete the following:~~

1. ~~On Lines 1 to 12, enter the monthly PPFAC Retail Energy Sales (MWh) and the monthly Wholesale Native Load Energy Sales in columns a and b, respectively. The sum of columns a and b equals the Total Native Load Energy Sales in column c. Currently, Wholesale Native Load Energy Sales include Traditional Sales for Resale and any Supplemental Sales.~~
2. ~~On Lines 1 to 12, enter the monthly System Book Fuel and Purchased Power Costs and 90% of the monthly System Book Off System Sales Revenue in columns d and e, respectively:~~

   - ~~The sum of column d minus e equals the monthly Net Native Load Power Supply Costs in column f.~~

- ~~The off-system sales margin is embedded in the Net Native Load Power Supply Cost. The costs associated with the off-system sales are included in the System Book Fuel and Purchased Power Costs.~~
- ~~When the System Book Off-System Sales Revenue is subtracted from the System Book Fuel and Purchased Power Costs, the difference between the off-system sales costs and revenue ends up in the Net Native Load Power Supply Cost. That difference is the off-system sales margin.~~
- ~~A list of the items included in the PPFAC sales and costs described above will be included in the PPFAC reporting schedules filed with the Commission each month.~~

3. ~~On Lines 1 to 12, calculate the PPFAC Retail Power Supply Costs, column g by dividing the PPFAC Retail Energy Sales in column a by the Total Native Load Energy Sales in column e, then multiply the product by the Net Native Load Power Supply Costs in column f.~~
4. ~~On Lines 1 to 12, calculate the amount recovered via the Commission approved embedded base fuel and purchased power rate by multiplying the Retail Energy Sales in column a by the Commission approved Base Cost of Fuel and Purchased Power rate entered in the above column heading the result which is entered in column h.~~
5. ~~On Lines 1 to 12, calculate the amount recovered via the Forward Component rate by multiplying said rate by the Retail Energy Sales in column a, the result which is entered in column i.~~
6. ~~On lines 1 to 12, calculate the respective level of (Over)/Under Collection in column j by subtracting the Base Rate Power Supply Recovery and the Forward Component Recovery from the PPFAC Retail Power Supply Costs, columns g and h, respectively.~~

~~An interest rate, based on the one year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, is applied each month to the previous month's Tracking Account Balance. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the UNSE customer deposit rate.~~

~~The (Over)/Under Collection, the Interest and the prior month's Tracking Account Balance produce the current month's balance.~~

D. Schedule 4: PPFAC True-Up Component Rate Calculation

[Specifics to be determined after reviewing illustrative schedules.]

~~Enter the appropriate effective periods for the Current and Proposed PPFAC-2 columns and then complete the following in each respective column:~~

1. ~~On Line 1, enter the Forward Component Tracking Account Balance from Schedule 3, Line13, column i.~~
2. ~~On Line 2, enter the True-Up Component Tracking Account Balance from Schedule 5, Line 8.~~

~~3. On Line 3, enter the sum of Lines 1, and 2 to arrive at the Total (Refundable)/Collection Amount Balance.~~
~~4. On Line 4, enter the respective Projected Energy Sales (MWh).~~
~~5. On Line 5, enter the Applicable True-Up Component rate by dividing Line 3 by Line 4.~~

~~Reflect notes as appropriate.~~

E. Schedule 5: True-Up Component Tracking Account

[Specifics to be determined after reviewing illustrative schedules.]

~~Enter the appropriate: effective dates for the PPFAC Prior True-Up Component being tracked:~~

~~On Line 8, for May and Line 1 for June, enter the True-Up Component balance as of June 1, 20XX. On Line 2, (Prior period PPFAC True-Up Component Calculation From Schedule 4, Line 4) for June enter any true-up for the use of prior period estimates, (i.e. prior estimated March, April and May True-Up Component rate application revenues to subsequent actual data), the sum of Lines 1 and 2, to reflect the Adjusted True-Up Component Beginning Balance as of June 1, 20XX.~~

~~Each month, the Applicable True-Up Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable True-Up Component rate. The revenue is subtracted from the Adjusted Beginning Balance.~~

~~Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the PPFAC Year.~~

~~Reflect notes as appropriate.~~

8. COMPLIANCE REPORTS

UNSE shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PPFAC. A UNSE Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PPFAC Rate Calculation (Schedule 1); Forward Component and True-Up Component Calculations (Schedules 2 and 4); Annual Forward Component and,

True-Up Component Tracking Account Balances (Schedules 3 and 5). Additional information will provide other relative inputs and outputs such as:

a. Total power and fuel costs.
b. Customer sales in both MWh and thousands of dollars by customer class.
c. Number of customers by customer class.
d. A detailed listing of all items excluded from the PPFAC calculations.
e. A detailed listing of any adjustments to the adjustor reports.
f. Total off-system sales revenues.
g. System losses in MW and MWh.
h. Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from UNSE for questions.

UNSE shall also provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports must be provided confidentially.

A. Information for each generating unit will include the following items:
   1. Net generation, in MWh per month, and 12 months cumulatively.
   2. Average heat rate, both monthly and 12-month average.
   3. Equivalent forced-outage rate, both monthly and 12-month average.
   4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
   5. Total fuel costs per month.
   6. The fuel cost per kWh per month.

B. Information on power purchases will include the following items per seller (information on economy interchange purchases may be aggregated):
   1. The quantity purchased in MWh.
   2. The demand purchased in MW to the extent specified in the contract.
   3. The total cost for demand to the extent specified in the contract.
   4. The total cost of energy.

C. Information on off-system sales will include the following items:
   1. An itemization of off-system sales margins per buyer.
   2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:
   1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
   2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.

E. UNSE will also provide:

1. Monthly projections for the next 12-month period showing estimated (Over)/undercollected amounts.
2. A summary of unplanned outage costs by resource type.
3. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
4. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate protective agreement. UNSE will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PPFAC at any time~~within XX years of those costs being incurred~~. Any costs flowed through the PPFAC are subject to refund, if those costs are found to be imprudently incurred.

9. ALLOWABLE COSTS

A. Accounts

The allowable PPFAC costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PPFAC. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

B. Other Allowable Costs

~~In addition to the fuel and purchased power costs in the above mentioned FERC accounts, the following costs will also be recovered through the PPFAC:~~
~~•Energy procurement, scheduling and management fees allocated to UNSE from TEP.~~
~~•Credit costs necessary to support fuel and purchased power contracts~~
~~•Any and all federal and/or state carbon taxes applied to UNSE's generation or fuel and purchased power contracts~~
~~•Outside legal expenses incurred to litigate fuel and purchased power matters on behalf of UNSE's customers, such as pipeline and transmission rate cases and contract disputes~~
~~•Amortized interstate pipeline and electric transmission interconnection costs~~None without pre-approval from the Commission in an Order..

Attachment RCS-8
Copies of UNS Electric's Responses to Data Requests and Workpapers Referenced in the Surrebuttal Testimony and Schedules of Ralph C. Smith

Data Request/ Workpaper No.	Subject	Page No.
UNSE(0783)10597	Fleet Fuel Expense - Invoices July 2006-June 2007	2
STF 15.1	Southwest Energy Services (SES) charges	3-13
UNSE(0783)10580	Bad Debt Expense	14
STF 3.88	Filing Information Updates and Revisions	15
	Total Pages Including this Page	15

[1] The attachment noted in the response to STF-3.88 is not included.

UNS Electric, Inc.
Fleet Fuel Expense - Invoices
July 2006 - June 2007 – full 12 months

Back-up for invoices from 7/2006 - 7/2006 and 5/2007 - 6/2007
Refer to pages 7.10-7.70
The other months are from STF 11.24 page 7.1

Wright Express Invoices

Invoice Date	Gallons	Fuel Cost	Cost/Gallon
7/6/2006	12,475	$37,944.79	$3.04
8/6/2006	12,678	$38,244.38	$3.02
9/6/2006	11,681	$34,985.15	$3.00
10/9/2006	7,678	$21,262.37	$2.77
11/7/2006	8,163	$20,690.44	$2.53
12/6/2006	5,878	$15,380.32	$2.62
1/6/2007	5,432	$14,316.33	$2.64
2/7/2007	6,283	$16,187.27	$2.58
3/7/2007	5,808	$14,937.11	$2.57
4/6/2007	6,503	$18,338.70	$2.82
5/6/2007	6,144	$18,354.94	$2.99
6/6/2007	6,729	$21,638.24	$3.22
	95,454	$272,280.04 7.7b	$2.85
Kingman Gascard			
7/5/2006	2,644	$7,844.45	$2.97
7/20/2006	2,441	$7,241.97	$2.97
8/5/2006	2,542	$7,848.05	$3.09
8/20/2006	2,071	$6,306.43	$3.05
9/5/2006	1,237	$3,862.25	$3.12
9/20/2006	3,612	$10,177.01	$2.82
10/5/2006	5,306	$14,208.66	$2.68
10/20/2006	4,578	$11,687.15	$2.55
11/5/2006	4,730	$11,880.83	$2.51
11/20/2006	5,079	$13,089.11	$2.58
12/5/2006	4,055	$10,891.93	$2.69
12/20/2006	6,373	$17,250.81	$2.71
1/5/2007	4,364	$13,746.23	$3.15
1/20/2007	4,951	$10,489.23	$2.12
2/5/2007	5,361	$13,260.98	$2.47
2/20/2007	6,249	$16,235.41	$2.60
3/5/2007	3,387	$9,181.32	$2.71
3/20/2007	4,148	$11,538.48	$2.78
4/5/2007	5,187	$14,657.28	$2.83
4/27/2007	4,371	$13,036.70	$2.98
5/5/2007	3,745	$11,460.83	$3.06
5/20/2007	3,888	$11,736.74	$3.02
6/5/2007	3,926	$11,709.83	$2.98
6/20/2007	5,174	$15,590.35	$3.01
	99,420	$274,932.03 7.7c	$2.77
Parker Oil			
2/28/2007	1,103	$2,789.54	$2.53
3/16/2007	974	$2,521.62	$2.59
3/31/2007	555	$1,445.36	$2.60
4/1/2007	2,064	$6,030.15	$2.92
4/1/2007	(2,064)	($5,257.87)	$2.55
4/16/2007	835	$2,565.84	$3.07
4/30/2007	1,051	$3,250.72	$3.09
5/16/2007	1,192	$3,700.57	$3.10
5/31/2007	1,106	$3,448.00	$3.12
6/16/2007	909	$2,822.44	$3.10
6/30/2007	1,051	$3,247.25	$3.09
	8,777	$26,563.62 7.7d	$3.03
Texmo Oil Company			
8/29/2006	435	$1,349.79	$3.10
8/30/2006	705	$2,190.40	$3.11
8/31/2006	304	$987.07	$3.25
8/31/2006	275	$889.71	$3.24
9/6/2006	430	$1,364.23	$3.17
9/7/2006	420	$1,330.63	$3.17
9/11/2006	561	$1,672.00	$2.98
9/12/2006	185	$566.54	$3.06
9/13/2006	345	$1,084.39	$3.14
	3,660	$11,434.76 7.7e	$3.12
Total Fuel Cost	207,310	$585,210	$2.82

The table was derived by pulling oivoices from the vendors and summarizing

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S FIFTEENTH SET OF DATA REQUESTS DOCKET NO. E-04204A-06-0783 July 13, 2007

STF 15.1 Southwest Energy Services (SES) charges. Refer to the responses to STF 10.4, STF 10.5, and STF 10.6.

a. The response to STF 10.6 indicates that "SES charges a 10% mark-up on the base wages of the supplemental worker." For each of the amounts of SES charges listed on the responses to STF 10.4 and STF 10.5, please identify the amount of the SES 10% mark-up over base wages. If exact amounts are not available, please provide the Company's best estimates of the SES 10% mark-up charges and show how such estimates were derived.

b. Do the SES charges to UNS Electric listed in the responses to STF 10.4 and STF 10.5 include any incentive compensation in the benefits cost? If so, please identify the amount of incentive compensation included in the SES charges to UNS Electric listed in the responses to STF 10.4 and STF 10.5.

c. Please list the benefits cost, by type of benefit, that is included in the SES charges to UNS Electric.

d. Is the 10% SES mark-up over base wages specified in a written contract? If so, please provide the contract, and indicate specifically where in the contract the 10% markup is specified.

RESPONSE: UNS Electric is in the process of gathering information and will provide the response to this data request as soon as the compilation is complete.

SUPPLEMENTAL RESPONSE:

a. The supplemental workforce for UniSource Energy Services, Inc. consists of electric and gas meter readers and warehouse personnel in Santa Cruz County. The amounts of the mark-ups over base wages on the SES supplemental workforce are $10,906 for test-year ended June 30, 2006; $8,183 for 2005; and $11,228 for 2006. The mark-up represents 6.5% of the total billings.

b. There is no incentive compensation in the benefit costs.

c. The supplemental workforce benefits consist of one charge of $4.37 per supplemental employee per hour worked, paid to the International Brotherhood of Electrical Workers, for health, dental, vision, life, the Employee Assistance Program, and short-term and long-term disability.

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S FIFTEENTH SET OF DATA REQUESTS DOCKET NO. E-04204A-06-0783 July 13, 2007

d. Please see STF 15.1 (d), Bates Nos. UNSE(0783)10004 to UNSE(0783)10012 for the written contract. The 10% markup is specified on page 3 of STF 15.1 (d). Bates Nos. UNSE(0783)10004 to UNSE(0783)10012 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

RESPONDENT: Bob Dame

WITNESS: Tom Ferry and Edmond Beck

ATTACHMENT

RCS 8

PAGES 5-13

IS

CONFIDENTIAL

UNS ELECTRIC, INC.
BAD DEBT EXPENSE
FOR TEST YEAR ENDED JUNE 30, 2006

REVISED - USING ACTUAL NET EXPENSE AND 3-YR AVERAGE RATE NET WRITE-OFF RATE

Test Year Retail Revenues	$153,864,975
Add: Late Fees and Misc Service Revenues	$813,854
	$154,678,829
Rate Case Adjustments	
Weather Normalization	($410,061)
Customer Annualization	$3,249,883
Uncollectible Revenue Adjustment Base	$157,518,651
3 Year Average Retail Write Off Rate	0.26913% (2)
Pro Forma Bad Debt Expense	$423,929
Recorded Test Year Bad Debt Expense	$356,982
Adjustment Required	$66,947 (1)

As filed	$222,556
Revised	$66,947
Change	($155,609)

Bad Debt expense

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2004	49,957.38	46,639.19	51,624.27	43,622.79	52,662.03	61,180.47	0.00	0.00	0.00	0.00	55,638.28	65,080.91	426,405.32
2005	0.00	0.00	0.00	45,096.77	0.00	21,244.59	31,052.65	39,048.51	43,332.19	44,413.73	53,552.67	18,686.59	296,427.70
2006	2,805.43	17,400.13	4,560.44	33,928.82	24,143.96	44,056.62	70,388.16	38,884.82	86,727.44	44,414.86	115,341.32	12,478.82	495,130.82
3 Year Bad Debt Expense													$ 1,217,963.84

Unadjusted Retail Revenue

2004	10,723,244.04	10,168,520.56	10,465,221.12	9,796,018.69	11,810,791.39	13,716,963.29	15,746,413.61	16,568,862.89	12,694,013.87	10,760,258.41	9,916,804.52	11,319,748.60	143,686,860.99
2005	11,210,737.07	9,933,237.90	10,440,160.60	9,814,174.13	12,064,796.79	14,598,843.91	17,774,045.88	16,235,323.56	13,757,683.70	11,539,171.78	10,032,506.58	11,901,792.54	149,302,474.44
2006	11,590,696.45	10,498,373.82	11,854,661.17	10,181,712.70	13,592,197.41	15,720,663.68	18,908,795.79	17,713,429.98	14,065,878.60	11,922,917.60	10,232,895.68	12,369,910.71	158,652,133.59
3 Year Retail Revenue													292,989,335.43

% Actual Retail Net Write Off to Retail Revenue

2004	0.0046588	0.0045866	0.0049329	0.0044531	0.0044588	0.0044602	0.0000000	0.0000000	0.0000000	0.0000000	0.0056105	0.0057493	0.0029676
2005	0.0000000	0.0000000	0.0000000	0.0045951	0.0000000	0.0014552	0.0017471	0.0024052	0.0031497	0.0038490	0.0053379	0.0015701	0.0019854
2006	0.000242042	0.001657412	0.000384696	0.003332329	0.00177631	0.002802466	0.003722509	0.002195217	0.006165803	0.003725167	0.011271621	0.001008804	0.0031209
3 Year Average Retail Write Off Rate													(2) 0.0026913

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007

STF 3.88 Filing Information. As the Company discovers errors in its filing identify such errors and provide documentation to support any changes. Please update this response as additional information becomes available.

RESPONSE: As the Company discovers errors in its filing, it will identify such errors and provide documentation to support any changes.

To date, TEP would like to revise two numbers referenced in Mr. James Pignatelli's Direct Testimony:

1) Page 3, line 19, the cost of debt is shown as 8.08%. Schedule D, however, reflects the accurate cost of debt as 8.22%.

2) Page 4, Line 12, the accurate customer count at the end of the test year is 91,860, not 91,850.

Please see STF 3.88 (Pignatelli DT), Bates Nos. UNSE(0783)06750 to UNSE(0783)06754, on the enclosed CD for supporting documentation.

RESPONDENT: Legal Department

WITNESS: Kent Grant – Cost of Debt
Thomas Ferry – Customer Count

Attachment RCS-9
Overtime Payroll Calculations for UNS Gas and UNS Electric
Accompanying the Surrebuttal Testimony of Ralph C. Smith

Description	Pages	Page #	UNSG Reference
Contents	1	1	
Calculations for UNS Gas:			
Overtime Payroll Calculation - O&M Only	1	2	Sch C-9, page 1 of 2
Overtime Payroll Calculation - Total Payroll	1	3	Sch C-9, page 2 of 2
Calculations for UNS Electric:			
Overtime Payroll Calculation - O&M Only	1	4	
Overtime Payroll Calculation - Total Payroll	1	5	
UNSE Workpaper from its Payroll Adjustment	1	6	
Total pages including contents page	**6**		

UNS Gas, Inc.
Overtime Payroll Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-9
Page 1 of 2

Line No.	Description	Amount	Reference
1	UNS Gas Proposed Overtime Expense	$ 1,070,133	A
2	Staff Recommended Overtime Expense	$ 947,123	B
3	Adjustment to Overtime Expense	$ (123,010)	L2 - L1

Notes and Source

A: UNS Gas workpaper used to calculate its payroll adjustment

B: Amounts taken from UNS Gas workpapers used to calculate its payroll adjustment

		2004	2005	2 Year Average
4	Overtime Charged Directly to O&M - Classified	$ 450,802	$ 871,111	$ 660,957
5	Overtime Charged Directly to O&M - Unclassified	$ 330,584	$ 129,333	$ 229,959
6	Total Overtime Charged Directly to O&M	$ 781,386	$ 1,000,445	$ 890,915

7	Regular Annualized O&M Payroll	$ 5,472,931
8	Adjusted 2005 Regular O&M Wages per Books	$ 5,148,145
9	Increase to Regular O&M Payroll	1.06309
10	Two Year Average Overtime Charged to O&M	$ 890,915
11	Increase to Regular Payroll	1.06309
12	Staff Recommended Increase to Overtime	$ 947,123

UNS Gas, Inc.
Adjustment to Overtime Payroll Expense - Alternative Calculation

Docket No. G-04204A-06-0463
Schedule C-9
Page 2 of 2

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	UNS Gas Proposed Total Overtime	$ 1,402,549	A
2	Staff Normalized Total Overtime	$ 1,220,536	B
3	Difference	$ (182,013)	L2 - L1
4	O&M Percentage	0.7630	C
5	Alternative Adjustment to Overtime Expense	$ (138,876)	

Notes and Source

A: UNS Gas workpaper used to calculate its payroll adjustment

B: Amounts taken from UNS Gas workpapers used to calculate its payroll adjustment

		2004	2005	2 Year Average
6	Overtime Charged Directly to O&M - Classified	$ 450,802	$ 871,111	$ 660,957
7	Overtime Charged Directly to O&M - Unclassified	$ 330,584	$ 129,333	$ 229,959
8	Overtime Charged to Non-O&M Accounts	$ 211,113	$ 303,260	$ 257,187
9	Total Overtime Charged Directly to O&M	$ 992,499	$ 1,303,705	$ 1,148,102

10	Regular Annualized O&M Payroll	$ 8,868,400
11	Adjusted 2005 Regular O&M Wages per Books	$ 8,342,113
12	Increase to Regular O&M Payroll	1.06309
13	Two Year Average Overtime Charged to O&M	$ 1,148,102
14	Increase to Regular Payroll	1.06309
15	Staff Recommended Increase to Overtime	$ 1,220,536

C:

16	Normalized Overtime Charged to O&M per Company	$ 1,070,133
17	Total Normalized Overtime per Company	$ 1,402,549
18	Percentage of Overtime Charged to O&M	0.7630

UNS Electric, Inc.
Overtime Payroll Expense

Docket No. E-04204A-06-0783
UNSE Overtime Staff W/P
Page 1 of 3

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	UNS Electric Proposed Overtime Expense	$ 823,097	A
2	Staff Recommended Overtime Expense	$ 887,319	B
3	Adjustment to Overtime Expense	$ 64,222	L2 - L1

Notes and Source

A: UNS Electric workpaper used to calculate its payroll adjustment

B: Amounts taken from UNS Electric workpapers used to calculate its payroll adjustment

		2004	2005	2 Year Average
4	Overtime Charged Directly to O&M - Classified	$ 740,770	$ 893,703	$ 817,236
5	Overtime Charged Directly to O&M - Unclassified	$ 25,091	$ 24,645	$ 24,868
6	Total Overtime Charged Directly to O&M	$ 765,861	$ 918,347	$ 842,104

7	Regular Annualized O&M Payroll	$ 3,267,815	
8	Test Year Regular O&M Wages per Books	$ 3,101,296	
9	Increase to O&M Payroll	1.05369	L7 / L8
10	Two Year Average Overtime Charged to O&M	$ 842,104	
11	Increase to Regular Payroll	1.05369	
12	Staff Recommended Increase to Overtime	$ 887,319	L10 x L11

UNS Electric, Inc.
Adjustment to Overtime Payroll Expense - Alternative Calculation

Docket No. E-04204A-06-0783
UNSE Overtime Staff W/P
Page 2 of 3

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	UNS Electric Proposed Total Overtime	$ 1,785,904	A
2	Staff Normalized Total Overtime	$ 1,675,291	B
3	Difference	$ (110,613)	L2 - L1
4	O&M Percentage	0.4609	C
5	Alternative Adjustment to Overtime Expense	$ (50,981)	

Notes and Source

A: UNS Electric workpaper used to calculate its payroll adjustment
B: Amounts taken from UNS Electric workpapers used to calculate its payroll adjustment

		2004	2005	2 Year Average
6	Overtime Charged Directly to O&M - Classified	$ 740,770	$ 893,703	$ 817,236
7	Overtime Charged Directly to O&M - Unclassified	$ 25,091	$ 24,645	$ 24,868
8	Overtime Charged to Non-O&M Accounts	$ 687,071	$ 808,577	$ 747,824
9	Total Overtime	$ 1,452,931	$ 1,726,925	$ 1,589,928

10	Regular Annualized Payroll	$ 8,261,628	
11	Test Year Regular Wages per Books	$ 7,840,637	
12	Increase to Regular O&M Payroll	1.05369	L10 / L11
13	Two Year Average Overtime Payroll	$ 1,589,928	
14	Increase to Regular Payroll	1.05369	
15	Staff Recommended Increase to Overtime	$ 1,675,291	L13 x L14

C:

16	Normalized Overtime Charged to O&M per Company	$ 823,096	
17	Total Normalized Overtime per Company	$ 1,785,904	
18	Percentage of Overtime Charged to O&M	0.4609	L16 / L17

UNS Electric, Inc.
Normalization of Classified Overtime Expense
Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
UNSE Overtime Staff W/P
Page 3 of 3
UNSE witness Dukes' workpaper

	2004	2005	2-Yr Average
Overtime Charged Directly to O&M - Classified	740,769.94	893,702.86	817,236.40
Regular Wages Charged Directly to O&M - Classified	2,189,016.50	2,306,475.14	2,247,745.82
	33.84%	38.75%	36.36%

UNS Electric, Inc.
Normalization of Unclassified Overtime Expense
Test Year Ended June 30, 2006

	2004	2005	2-Yr Average
Overtime Charged Directly to O&M - Unclassified	25,090.86	24,644.60	24,867.73
Regular Wages Charged Directly to O&M - Unclassified	1,064,548.36	1,034,695.64	1,049,622.00
	2.36%	2.38%	2.37%

UNS Electric, Inc.
Normalization of Non-O&M Account Overtime Expense
Test Year Ended June 30, 2006

	2004	2005	2-Yr Average
Overtime Charged Directly to Non-O&M Accounts	687,070.52	808,577.16	747,823.84
Regular Wages Charged Directly to Non-O&M Accounts	3,600,100.47	4,158,892.95	3,879,496.71
	19.08%	19.44%	19.28%

Note: Overtime expense is being included in cost of service for the test year based on the average overtime rate for the 2-yr period ended December 31, 2004 - 2005 applied to regular Classified and Unclassified wages direct charged to O&M as well as to Non-O&M accounts. The Overtime adjustment is being distributed across FERC accounts based on Test Year Payroll by Function-Classified and Unclassified wage distribution.

This schedule was included in UNS Electric's Payroll adjustment workpapers

ATTATCHMENT

RCS-10

IN ITS

ENTIRETY IS

CONFIDENTIAL

EXHIBIT
S-60
Admitted

Attachment RCS-11
Staff Revised Accounting Schedules
Accompanying the Testimony of Ralph C. Smith

Schedule	Description	Pages	Revised in RCS-6	Revised After RCS-6
	Revenue Requirement Summary Schedules			
A	Calculation of Revenue Deficiency (Sufficiency)	1	Revised	Revised
A-1	Gross Revenue Conversion Factor	1	Revised	Revised
B	Adjusted Rate Base	1	Revised	Revised
B.1	Summary of Adjustments to Rate Base	1	Revised	Revised
C	Adjusted Net Operating Income	1	Revised	Revised
C.1	Summary of Net Operating Income Adjustments	4	Revised	Revised
D	Capital Structure and Cost Rates	1	Revised	Revised
	Rate Base Adjustments			
B-1	Remove Construction Work in Progress	1		
B-2	Adjust CWIP for Plant in Service by End of Test Year	1		
B-3	Plant in Service Addition Subject to Reimbursement	1	Revised	
B-4	Cash Working Capital - Lead/Lag Study	1	Revised	Revised
B-5	Accumulated Deferred Income Taxes	1		
	Net Operating Income Adjustments			
C-1	Revenue Adjustment for CARES Discount	1		
C-2	Remove Depreciation & Property Taxes for CWIP	1		
C-3	Depreciation & Property Taxes for CWIP Found to be In-Service in the Test Year	1		
C-4	Fleet Fuel Expense	2	Revised	Revised [a]
C-5	Postage Expense	1		
C-6	Normalize Injuries and Damages Expense	1		Revised [b]
C-7	Incentive Compensation Expense	1		Revised [c]
C-8	Supplemental Executive Retirement Plant (SERP) Expense	1		
C-9	Stock Based Compensation Expense	1		
C-10	Property Tax Expense	1		
C-11	Rate Case Expense	1		
C-12	Edison Electric Institute Dues	2		
C-13	Other Membership and Industry Association Dues	1		
C-14	Interest Synchronization	1	Revised	Revised
C-15	Depreciation Rates Correction	4		
C-15.1	Depreciation Rates Correction - Details of Company's Pre-Correction Calculation		[RCS-2]	
C-15.2	Depreciation Rates Correction - Details of Calculation Using Corrected Rates		[RCS-2]	
C-16	Emergency Bill Assistance Expense	1		
C-17	Markup Above Cost in Charges from Affiliate, Southwest Energy Services	1	Added	
C-18	Bad Debt Expense	1	Added	
C-19	Remove Double Count from Outside Services-Demand Side Management	1	Added	
C-20	Correct Year-End Accrual Expense Amount for Out-of-Period Expense	1	Added	
	Total Pages, Including Content Listing	41		

[a]	Modified to utilize pro forma adjusted fleet fuel expense of $605,498 per UNSE witness Dukes' rejoinder testimony at page 2.
[b]	Revised to agree with the revised normalized amount stated in UNSE witness Dukes' rejoinder testimony at page 4
[c]	Modified in response to UNSE witness Dukes' rejoinder testimony at page 7.

[RCS-2] Depreciation Rates Correction Support was filed in Attachment RCS-2 with Mr. Smith's direct testimony.
That additional supporting detail has not changed, and is therefore not being re-filed with Mr. Smith's surrebuttal.

UNS Electric Inc.
Computation of Increase in Gross Revenue Requirement

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule A

Revised 9/17/2007

Line No.	Description	Reference	UNS Proposed Original Cost (A)	UNS Proposed Fair Value (B)	Staff Proposed Original Cost (C)	Staff Proposed Fair Value (D)
1	Adjusted Rate Base	Sch. B	$ 140,991,324	$ 177,802,341	$ 130,740,050	$ 167,551,067
2	Rate of Return	Sch. D	9.89%	7.84%	8.99%	7.02%
3	Operating Income Required		$ 13,946,320	$ 13,946,320	$ 11,749,701	$ 11,762,085
4	Net Operating Income Available	Sch. C	$ 8,742,011	$ 8,742,011	$ 9,505,982	$ 9,505,982
5	Operating Income Excess/Deficiency		$ 5,204,309	$ 5,204,309	$ 2,243,719	$ 2,256,103
6	Gross Revenue Conversion Factor	Sch. A-1	1.6346	1.6346	1.634626	1.634626
7	Overall Revenue Requirement		$ 8,507,097	$ 8,507,097	$ 3,667,642	$ 3,687,885

Notes and Source

Cols. A & B taken from UNS Electric, Inc. filing, Schedule A-1

UNS Electric, Inc.
Computation of Gross Revenue Conversion Factor

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule A-1

Revised 9/17/2007

Line No.	Description	Company Proposed (A)	Staff Proposed (B)
1	Gross Revenue	100.00%	100.00000%
2	Less: Uncollectible Revenue	0.36792%	0.36792%
3	Taxable Income as a Percent	99.63%	99.63208%
4	Less: Federal and State Income Taxes	38.46%	38.46%
5	Change in Net Operating Income	61.18%	61.17609%
6	Gross Revenue Conversion Factor	1.6346	1.634626

Notes and Source

Col.A: UNS Electric Inc. Filing, Schedule C-3
Col.B:

Components of Revenue Requirement Increase (Revised)

	Amount	Percent
Net Income	$ 2,243,720	61.18%
Federal and State Income Taxes	$ 1,410,428	38.46%
Uncollectibles	$ 13,494	0.37%
Total Revenue Increase	$ 3,667,642	100.00%

UNS Electric, Inc.
Original Cost and RCND Adjusted Rate Base

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B

Revised 9/17/2007

Line No.	Description	Original Cost As Adjusted by UNS (A)	Original Cost Staff Adjustments (B)	Original Cost As Adjusted by Staff (C)	RCND As Adjusted by UNS (D)	RCND Staff Adjustments (E)	RCND As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 390,513,651	$ (10,318,899)	$ 380,194,752	$ 612,326,062	$ (10,318,899)	$ 602,007,163
2	Less: Accumulated Depreciation	$ (159,524,693)	$ -	$ (159,524,693)	$ (257,585,628)	$ -	$ (257,585,628)
3	Net Utility Plant in Service	$ 230,988,958	$ (10,318,899)	$ 220,670,059	$ 354,740,434	$ (10,318,899)	$ 344,421,535
4	Citizens Acquisition Discount	$ (93,273,341)	$ -	$ (93,273,341)	$ (150,061,415)	$ -	$ (150,061,415)
5	Less: Accum. Amort. - Citizens Acq. Discount	$ (11,224,066)	$ -	$ (11,224,066)	$ (18,123,969)	$ -	$ (18,123,969)
6	Net Citizens Acquisition Discount	$ (82,049,275)	$ -	$ (82,049,275)	$ (131,937,446)	$ -	$ (131,937,446)
7	Total Net Utility Plant	$ 148,939,683	$ (10,318,899)	$ 138,620,784	$ 222,802,988	$ (10,318,899)	$ 212,484,089
8	Customer Advances for Construction	$ (8,692,444)	$ -	$ (8,692,444)	$ (9,559,141)	$ -	$ (9,559,141)
							$ -
9	Customer Deposits	$ (3,778,419)	$ -	$ (3,778,419)	$ (3,778,419)	$ -	$ (3,778,419)
							$ -
10	Accumulated Deferred Income Taxes	$ 1,154,833	$ (161,555)	$ 993,278	$ 1,780,258	$ (161,555)	$ 1,618,703
11	Total Deductions	$ (11,316,030)	$ (161,555)	$ (11,477,585)	$ (11,557,302)	$ (161,555)	$ (11,718,857)
12	Allowance for Working Capital	$ 3,367,671	$ 229,180	$ 3,596,851	$ 3,367,671	$ 229,180	$ 3,596,851
							$ -
13	Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -
							$ -
14	Regulatory Liabilities	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Rate Base	$ 140,991,324	$ (10,251,274)	$ 130,740,050	$ 214,613,357	$ (10,251,274)	$ 204,362,083

Notes and Source

Cols. A and D: UNS Electric Inc. filing, Schedule B

Fair Value Calculation (Per Company)

Original Cost	$ 140,991,324	
RCND	$ 214,613,357	
Total	$ 355,604,681	
Average (Fair Value)	$ 177,802,341	See Sch. A

Fair Value Calculation (Per Staff)

Original Cost	$ 130,740,050	
RCND	$ 204,362,083	
Total	$ 335,102,133	
Average (Fair Value)	$ 167,551,067	See Sch. A

UNS Electric, Inc.
Summary of Rate Base Adjustments

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B.1

Revised 9/17/2007

Line No.	Description	Staff Adjustments	CWIP	Rhode Homes Line Extensions	Customer Advances for Construction	Cash Working Capital	ADIT	N/A
			B-1	B-2	B-3 Revised	B-4 Revised	B-5	B-6
1	Gross Utility Plant in Service	$ (10,318,899)	$ (10,761,154)	$ 442,255				
2	Less: Accumulated Depreciation	$ -						
3	Net Utility Plant in Service	$ (10,318,899)	$ (10,761,154)	$ 442,255	$ -	$ -	$ -	$ -
4	Citizens Acquisition Discount	$ -						
5	Less: Accum. Amort. - Citizens Acq. Discount	$ -						
6	Net Citizens Acquisition Discount	$ -						
7	Total Net Utility Plant	$ (10,318,899)	$ (10,761,154)	$ 442,255	$ -	$ -	$ -	$ -
8	Customer Advances for Construction	$ -		$ -				
9	Customer Deposits	$ -						
10	Accumulated Deferred Income Taxes	$ (161,555)					$ (161,555)	
11	Total Deductions	$ (161,555)	$ -	$ -	$ -	$ -	$ (161,555)	$ -
12	Allowance for Working Capital	$ 229,180				$ 229,180		
13	Regulatory Assets	$ -						
14	Regulatory Liabilities	$ -						
15	Total Rate Base	$ (10,251,274)	$ (10,761,154)	$ 442,255	$ -	$ 229,180	$ (161,555)	$ -

UNS Electric, Inc.
Adjusted Net Operating Income

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C

Revised 9/17/2007

Line No.	Description	As Adjusted by UNS (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Electric Retail Revenues	$ 156,651,860	$ 52,937	$ 156,704,797
2	Sales for Resale	$ 246,016	$ -	$ 246,016
3	Other Operating Revenues	$ 1,589,014	$ -	$ 1,589,014
4	Total Operating Revenues	$ 158,486,890	$ 52,937	$ 158,539,827
	Operating Expenses			
5	Purchased Power	$ 106,224,185	$ -	$ 106,224,185
6	Other O&M Expenses	$ 26,423,248	$ (689,747)	$ 25,733,501
7	Depreciation & Amortization	$ 11,812,574	$ (494,656)	$ 11,317,918
8	Taxes Other Than Income Taxes	$ 3,447,533	$ (295,286)	$ 3,152,247
9	Income Taxes	$ 1,837,339	$ 768,655	$ 2,605,994
10	Total Operating Expenses	$ 149,744,879	$ (711,034)	$ 149,033,845
11	Net Operating Income	$ 8,742,011	$ 763,971	$ 9,505,982

Notes and Source

Col. A: UNS Electric, Inc. filing, Schedule C-1
Col. B: Staff Schedule C.1

UNS Electric, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2006

Line No.	Description	Stafff Adjustments	CARES Discount	Remove Depreciation & Property Taxes for CWIP	Depreciation & Property Taxes for CWIP Found in Service	Fleet Fuel Expense	Postage Expense
			C-1	C-2	C-3	C-4 Rev 9-17-07	C-5
	Operating Revenues						
1	Electric Retail Revenues	$ 52,937	$ 52,937				
2	Sales for Resale	$ -					
3	Other Operating Revenues	$ -					
4	Total Operating Revenues	$ 52,937	$ 52,937	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Purchased Power	$ -					
6	Other O&M Expenses	$ (689,747)				$ (41,909)	$ 17,503
7	Depreciation & Amortization	$ (494,656)		$ (449,816)	$ 18,265		
8	Taxes Other Than Income Taxes	$ (295,286)		$ (239,696)	$ 8,317		
9	PRE-TAX OPERATING EXPENSES	$ (1,479,689)	$ -	$ (689,512)	$ 26,582	$ (41,909)	$ 17,503
10	PRE-TAX OPERATING INCOME	$ 1,532,626	$ 52,937	$ 689,512	$ (26,582)	$ 41,909	$ (17,503)
11	Income Taxes	$ 768,655	$ 20,433	$ 266,138	$ (10,260)	$ 16,176	$ (6,756)
12	TOTAL OPERATING EXPENSES	$ (711,034)	$ 20,433	$ (423,374)	$ 16,322	$ (25,733)	$ 10,747
13	OPERATING INCOME	$ 749,658	$ 32,504	$ 423,374	$ (16,322)	$ 25,733	$ (10,747)

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per UNS Electric filing, Schedule C-3

[1] Adjustments C-17 thru C-20 were added in surrebuttal

UNS Electric, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2006

Line No.	Description	Injuries and Damages Expense	Incentive Compensation Expense	SERP Expense	Stock Based Compensation Expense	Property Tax Expense	Rate Case Expense
		C-6	C-7	C-8	C-9	C-10	C-11
		Rev 9-17-07	Rev 9-17-07				
	Operating Revenues						
1	Electric Retail Revenues						
2	Sales for Resale						
3	Other Operating Revenues						
4	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Purchased Power						
6	Other O&M Expenses	$ (98,161)	$ (104,357)	$ (83,506)	$ (82,873)		$ (111,667)
7	Depreciation & Amortization						
8	Taxes Other Than Income Taxes		$ (4,160)			$ (59,747)	
9	PRE-TAX OPERATING EXPENSES	$ (98,161)	$ (108,517)	$ (83,506)	$ (82,873)	$ (59,747)	$ (111,667)
10	PRE-TAX OPERATING INCOME	$ 98,161	$ 108,517	$ 83,506	$ 82,873	$ 59,747	$ 111,667
11	Income Taxes	$ 37,888	$ 41,885	$ 32,232	$ 31,987	$ 23,061	$ 43,101
12	TOTAL OPERATING EXPENSES	$ (60,273)	$ (66,632)	$ (51,274)	$ (50,886)	$ (36,686)	$ (68,566)
13	OPERATING INCOME	$ 60,273	$ 66,632	$ 51,274	$ 50,886	$ 36,686	$ 68,566

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per UNS Electric filing, Schedule C-3

[1] Adjustments C-17 thru C-20 were added in surrebuttal

UNS Electric, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C.1

Revised 9-17-2007

Line No.	Description	Edison Electric Institute Dues	Other Membership Dues	Interest Synchro-nization	Depreciation Rates Correction	Emergency Bill Assistance	SES Markup Above Cost
		C-12	C-13	C-14 Rev 9-17-07	C-15	C-16	C-17 Added [1]
	Operating Revenues						
1	Electric Retail Revenues						
2	Sales for Resale						
3	Other Operating Revenues						
4	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Purchased Power						
6	Other O&M Expenses	$ (8,470)	$ (6,482)			$ 20,000	$ (10,906)
7	Depreciation & Amortization				$ (63,105)		
8	Taxes Other Than Income Taxes						
9	PRE-TAX OPERATING EXPENSES	$ (8,470)	$ (6,482)	$ -	$ (63,105)	$ 20,000	$ (10,906)
10	PRE-TAX OPERATING INCOME	$ 8,470	$ 6,482	$ -	$ 63,105	$ (20,000)	$ 10,906
11	Income Taxes	$ 3,269	$ 2,502	$ 177,093	$ 24,357	$ (7,720)	$ 4,209
12	TOTAL OPERATING EXPENSES	$ (5,201)	$ (3,980)	$ 177,093	$ (38,748)	$ 12,280	$ (6,697)
13	OPERATING INCOME	$ 5,201	$ 3,980	$ (177,093)	$ 38,748	$ (12,280)	$ 6,697

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per UNS Electric filing, Schedule C-3

[1] Adjustments C-17 thru C-20 were added in surrebuttal

UNS Electric, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2006

Line No.	Description	Bad Debt Expense C-18 Added [1]	Outside Services-DSM C-19 Added [1]	Correct Year-End Accrual Expense C-20 Added [1]
	Operating Revenues			
1	Electric Retail Revenues			
2	Sales for Resale			
3	Other Operating Revenues			
4	Total Operating Revenues	$ -	$ -	$ -
	Operating Expenses			
5	Purchased Power			
6	Other O&M Expenses	$ (155,609)	$ (17,055)	$ (6,256)
7	Depreciation & Amortization			
8	Taxes Other Than Income Taxes			
9	PRE-TAX OPERATING EXPENSES	$ (155,609)	$ (17,055)	$ (6,256)
10	PRE-TAX OPERATING INCOME	$ 155,609	$ 17,055	$ 6,256
11	Income Taxes	$ 60,062	$ 6,583	$ 2,415
12	TOTAL OPERATING EXPENSES	$ (95,547)	$ (10,472)	$ (3,841)
13	OPERATING INCOME	$ 95,547	$ 10,472	$ 3,841

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per UNS Electric filing, Schedule C-3

[1] Adjustments C-17 thru C-20 were added in surrebuttal

UNS Electric, Inc.
Capital Structure & Cost Rates

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule D

Revised 9/17/2007

Line No.	Capital Source	Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
	UNS - Proposed				
1	Short-Term Debt	$ 5,000	3.97%	6.36%	0.25%
2	Long-Term Debt	$ 59,486	47.18%	8.22%	3.88%
3	Common Stock Equity	$ 61,587	48.85%	11.79%	5.76%
4	Total Capital	$ 126,073	100.00%		9.89%
	ACC Staff - Proposed				
5	Short-Term Debt	$ 5,000	3.96%	6.36%	0.25%
6	Long-Term Debt	$ 59,545	47.21%	8.16%	3.85%
7	Common Stock Equity	$ 61,587	48.83%	10.000%	4.88%
8	Total Capital	$ 126,132	100.00%		8.99%
9	Difference				-0.90%
10	Weighted Cost of Debt				4.10%
	ACC Staff - Proposed Cost of Capital for Fair Value Rate Base				
11	Short-Term Debt	$ 5,182,668	3.09%	6.36%	0.20%
12	Long-Term Debt	$ 61,720,390	36.84%	8.16%	3.01%
13	Common Stock Equity	$ 63,836,992	38.10%	10.000%	3.81%
	Capital financing OCRB	$ 130,740,051			
14	Appreciation above OCRB not recognized on utility's books	$ 36,811,017	21.98%	0% [a]	0.00%
15	Total capital supporting FVRB	$ 167,551,068	100.01%		7.02%

Notes and Source

Lines 11-15, Col.A:

Fair Value Rate Base	$ 167,551,067	Schedule A
Original Cost Rate Base	$ 130,740,050	Schedule A
Difference	$ 36,811,017	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

[a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

UNS Electric, Inc.
Remove Construction Work in Progress

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B-1

Line No.	Description	Amount	Reference
1	Remove Construction Work in Progress	$ (10,761,154)	A & B

Notes and Source

A: UNS Electric Filing, Schedule B-2, page 2, line 1
B: Testimony of Staff witness Ralph Smith

UNS Electric, Inc.
Adjust CWIP for Plant in Service by End of Test Year

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B-2

Line No.	Description	Plant Account	Amount	Reference
1	Adjustment to Plant in Service for Rhode Homes Line Extensions	365	$ 442,255	A
2	Adjustment to Customer Advances for Construction			A
3	Net Rate Base Adjustment		$ 442,255	

Notes and Source

A: Staff memorandum concerning its Preliminary Field Assessment of Used and Useful Review for UNS Electric as it relates to the Rhode Homes overhead line extensions

Line 2: Letter of Agreement dated March 2, 2006 indicates the customer will pay to the Company a total Customer Advance of $360,117
The Company's response to data request STF 15.4(f) and (g) indicate that, as of June 30, 2006, UNS Electric had received Customer Advances totaling $360,117 for this project, and no additional Customer Advances for this project have been received subsequent to June 30, 2006.

UNS Electric, Inc.
Plant in Service Addition Subject to Reimbursement

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B-3 (Revised)

Line No.	Description	Amount	Reference
1	Adjustment to Contributions in Aid of Construction	$ (236,874)	Notes A & B
	Decrease to Plant in Service	Withdrawn, subject to obtaining supporting documentation	

Notes and Source

A: Staff memorandum concerning its Preliminary Field Assessment of Used and Useful Review for UNS Electric as it relates to the Tubac Golf Resort Overhead to Underground Conversion

The Company's response to STF 15.4(d) states that: "this customer requested work was paid 100% by the customer as a Contribution in Aid of Construction."

B Adjustment withdrawn based on explanation in UNS Electric witness Karen Kissinger's rebuttal testimony at pages 4-5 subject to obtaining adequate supporting documentation, which was requested in data request STF 20.50

UNS Electric, Inc.
Cash Working Capital - Lead/Lag Study
For the Test Year Ending 6/30/06

Line No.	Description	FERC	Per UNS Electric Pro Forma Test Year Amount		Staff Adjustments	Staff Adjusted	Expense Lag Days		Net Lag Days (RevLag - Col. D)	Lead/Lag Factor (Col. E/365)	Cash Working Capital Required (Col. F X Col.C)
	(A)		(A)		(B)	(C)	(D)		(E)	(F)	(G)
	Operating Expenses:				Revised	Revised					Revised
	Non-Cash Expenses -										
1	Bad Debts Expense	904	$ 579,538	1a	(155,609)	423,929					$ -
2	Depreciation	403/404	15,594,232	1.2a	(494,656)	15,099,576					-
3	Amortization	406	(3,781,658)	1.2b	-	(3,781,658)					-
4	Deferred Income Taxes		494,521	1.3a		494,521					-
	Other Operating Expenses -										
5	Salaries and Wages (UNSE Direct Employees)	Multi	4,571,466	2.2a		4,571,466	23.33	D.	12.26	0.0336	153,601
6	Incentive Pay (UNSE Direct Employees)	Multi	98,247	3a	(79,871)	18,376	267.00	D.	(231.41)	(0.6340)	(11,650)
7	Purchased Power		106,021,950	1b		106,021,950	33.79	E.	1.80	0.0049	519,508
8	Transmission Other		7,009,878	1c		7,009,878	40.67	F.	(5.08)	(0.0139)	(97,437)
9	Meter Reading		730,556	1d		730,556	33.67	G.	1.92	0.0053	3,872
10	Customer Records & Collection Expenses (excluding alloc.)	903	2,982,604	1e-4b	-	2,982,604	34.94	H.	0.65	0.0018	5,369
11	Office Supplies and Expenses	921	535,854	1.1a		535,854	50.89	I.	(15.30)	(0.0419)	(22,452)
12	Injuries and Damages	925	512,417	1.1b	(98,161)	414,256	70.52	J.	(34.93)	(0.0957)	(39,644)
13	Pension & Benefits	926	1,172,133	1.1c	-	1,172,133	51.37	K	(15.78)	(0.0432)	(50,636)
14	Support Services (Direct Labor, Burdens, System Allocation)		5,631,155	4a	(190,865)	5,440,290	44.77	L.	(9.18)	(0.0252)	(137,095)
15	Property Taxes	408	3,096,371	1.3b	(291,126)	2,805,245	213.00	M.	(177.41)	(0.4861)	(1,363,630)
16	Payroll Taxes	408	348,088	1.3c	(4,160)	343,928	19.87	M.	15.72	0.0431	14,823
17	Current Income Taxes		1,342,818	1.3d		3,521,901	41.42	M.	(5.83)	(0.0160)	(56,350)
18	Interest on Customer Deposits	431	217,492	1.3e		217,492	182.50	Q.	(146.91)	(0.4025)	(87,541)
19	Other Operations and Maintenance	Multi	2,587,216	X	(165,241)	2,421,975	41.21	N.	(5.62)	(0.0154)	(37,298)
20	Total Operating Expenses		149,744,878		(1,479,689)	150,444,272					
	Other Cash Working Capital Elements:										
21	Interest on Long-Term Debt		5,819,157	8a	(458,815)	5,360,342	90.22	O.	(54.63)	(0.1497)	(802,443)
22	Revenue Taxes and Assessments	Calc	$ 13,983,561	P.	331,596	14,315,157	45.71	M.	(10.12)	(0.0277)	(396,530)
23	Total Cash Working Capital - Calculated										$ (2,405,533)
24	Total Cash Working Capital - Per UNS Electric Filing, Schedule B-5, page 3 of 3										(2,634,713)
25	Adjustment to Cash Working Capital										229,180

Notes and Source

UNS Electric filing, Schedule B-5, page 3 of 3
RUCO 1.10 2005 UNSE Lead-Lag Summary.xls
Revenue Lag, in days 35.59
Col.B: Staff workpapers for CWC calculation

Line 17, Col.C, Current income taxes:

26	Per UNS Electric, Current Income Taxes	$ 1,342,818	Col.A, line 17
27	Staff adjustments to Current Income Taxes	$ 768,655	Schedule C.1
28	Staff adjusted Current Income Taxes before Revenue Increase	$ 2,111,473	Schedule C
29	Income taxes for revenue increase	$ 1,410,428	Schedule A-1
30	Total current income taxes for CWC calculation	$ 3,521,901	

2,605,994	-	$ 2,111,473	=	$ 494,521
Total Income Taxes		Current Inc Taxes		Deferred Inc Taxes
Schedule C		Line 28		Col. A, Line 4

Line 22, Revenue Based Taxes

31	Revenue adjustments	$ 52,937	Schedule C
32	Staff recommended rate increase	$ 3,667,642	Schedule A, filtered through CWC macro
33	Revenue adjustments	$ 3,720,579	
34	Revenue based taxes	0.0891249	B-4 W/P 2
35	Adjustment to revenue based taxes	$ 331,596	

UNS Electric, Inc.
Cash Working Capital - Staff Adjustments to Expenses

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Workpapers for CWC Calculation

Revised 9/17/2007

Line No.	Description	Adjustment No.	O&M Expense Adjustment	Depreciation & Amortization	Incentive Comp	Injuries & Damages	Pensions & Benefits	Support Services - TEP	Property Taxes	Payroll Taxes	Other O&M	Bad Debt Expense
			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1	Revenue Adjustment for CARES Discount	C-1	$ -									
2	Remove Depreciation & Property Taxes for CWIP	C-2	$ (689,512)	$ (449,816)					$ (239,696)			
3	Depreciation & Property Taxes for CWIP Found to be In-Service in the Test Year	C-3	$ 26,582	$ 18,265					$ 8,317			
4	Fleet Fuel Expense	C-4	$ (41,909)								$ (41,909)	
5	Postage Expense	C-5	$ 17,503								$ 17,503	
6	Normalize Injuries and Damages Expense	C-6	$ (98,161)			$ (98,161)						
7	Incentive Compensation Expense	C-7	$ (108,517)		$ (79,871)			$ (24,486)		$ (4,160)		
8	Supplemental Executive Retirement Plant (SERP) Expense	C-8	$ (83,506)					$ (83,506)				
9	Stock Based Compensation Expense	C-9	$ (82,873)					$ (82,873)				
10	Property Tax Expense	C-10	$ (59,747)						$ (59,747)			
11	Rate Case Expense	C-11	$ (111,667)								$ (111,667)	
12	Edison Electric Institute Dues	C-12	$ (8,470)								$ (8,470)	
13	Other Membership and Industry Association Dues	C-13	$ (6,482)								$ (6,482)	
14	Interest Synchronization	C-14	$ -								$ -	
15	Depreciation Rates Correction	C-15	$ (63,105)	$ (63,105)								
16	Emergency Bill Assistance Expense	C-16	$ 20,000								$ 20,000	
17	Markup Above Cost in Charges from Affiliate, Southwest Energy Services	C-17	$ (10,906)								$ (10,906)	
18	Bad Debt Expense	C-18	$ (155,609)									$ (155,609)
19	Remove Double Count from Outside Services-Demand Side Management	C-19	$ (17,055)								$ (17,055)	
20	Correct Year-End Accrual Expense Amount for Out-of-Period Expense	C-20	$ (6,256)								$ (6,256)	
21	TOTAL		$ (1,479,689)	$ (494,656)	$ (79,871)	$ (98,161)	$ -	$ (190,865)	$ (291,126)	$ (4,160)	$ (165,241)	$ (155,609)
22	Total per Schedule C.1, line 9		$ (1,479,689)									
23	Difference, rounding		$ -							Crossfoot	$ (1,479,689)	
											$ -	
24	Current Income Taxes from Schedule C.1		$ 768,655									
25	Total operating expense adjustments (L17 + L19)		$ (711,034)									
26	Total operating expense adjustments from Sch C.1, L.11		$ (711,034)									
27	Difference, rounding		$ -									

This workpaper shows how the Staff adjustments to operating expenses from Schedule C.1 are posted for CWC purposes

UNS Electric, Inc.
Accumulated Deferred Income Taxes

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B-5

Line No.	Description	Account	Amount	Reference
1	SERP	190	$ (97,217)	A
2	Stock Based Compensation	190	$ (64,338)	A
3	Total Adjustment to ADIT		$ (161,555)	

Notes and Source

A: Staff has removed SERP and Restricted Stock from operating expenses and allocated incentive compensation expense 50/50 to shareholders and ratepayers. This adjustment coordinates the corresponding ADIT amounts with those recommendations.

	Account and Description	Per Books (1)	UNS Electric Adjustment (2)	UNS Electric Adjusted		Staff Adjustment
	Account 190					
4	SERP	$ 99,736	$ (2,519)	$ 97,217	a	$ (97,217)
5	Restricted Stock	$ 28,728	$ (1,970)	$ 26,758	b	$ (26,758)
6	Dividend Equivalents	$ 37,661	$ (1,844)	$ 35,817	c	$ (35,817)
7	Stock Options	$ -	$ 1,763	$ 1,763	d	$ (1,763)
8	Stock Based Compensation related ADIT	$ 66,389	$ (2,051)	$ 64,338		$ (64,338)

(1) Response to STF 3.60
(2) UNS Electric ADIT workpapers
a: UNS Electric workpaper "Pro Forma ADIT - Account 190" "SERP 12G"
b: UNS Electric workpaper "Pro Forma ADIT - Account 190" "Restricted Stock 12F"
c: UNS Electric workpaper "Pro Forma ADIT - Account 190" "Dividend Equivalents 12C"
d: UNS Electric workpaper "Pro Forma ADIT - Account 190" "Stock Options 12H"

UNS Electric, Inc.
Revenue Adjustment for CARES Discount

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Remove Company Revenue Adjustment for Company's Proposed Revisions to CARES Discounts	$ 52,937	A&B

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 1, line 1
B: Testimony of Staff witness Julie McNeely-Kirwan

UNS Electric, Inc.
Remove Depreciation & Property Taxes for CWIP

Docket No. E-04204A-06-0783
Schedule C-2

Test Year Ended June 30, 2006

Line No.	Description	Account	Amount	Reference
1	CWIP Related Depreciation Expense	403	$ (449,816)	A
2	CWIP Related Property Tax Expense	408	$ (239,696)	A
3	Total Adjustments		$ (689,512)	

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 4, lines 7 and 8

UNS Electric, Inc.
Depreciation & Property Taxes for CWIP Found to be In-Service in the Test Year

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-3

Line No.	Description	Account	Amount	Reference
1	Rhode Homes Related Depreciation Expense	403	$ 18,265	A
2	Rhode Homes Related Property Tax Expense	408	$ 8,317	B
3	Total Adjustments		$ 26,582	

A: Depreciation Rate taken from Attachment REW-2, Statement A, from Dr. White's testimony

		Plant Account	Amount	Depreciation Rate	Depreciation Expense
4	Rhode Homes Overhead Line Extensions (see Sch. B-2)	365	$ 442,255	4.13%	$ 18,265

B: **Calculation of Property Tax Expense**

5	Rhode Homes Overhead Line Extensions	$ 442,255	
6	Less: Accumulated Depreciation	$ (18,265)	
7	Subtotal	$ 423,990	
8	Assessment Ratio	23.5%	
9	Taxable Value	$ 99,638	
10	Mohave Property Tax Rate	8.3471%	per Company's Property Tax adjustment workpaper
11	Property Tax Expense	$ 8,317	

UNS Electric, Inc.
Fleet Fuel Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-4

Revised 9/17/2007

Line No.	Description	Amount	Reference
1	UNS Electric Adjustment to Fleet Fuel Expense	$ 73,661	A
2	Staff Recommended Pro Forma Adjustment to Fleet Fuel Expense	$ 31,752	B
3	Adjustment to Fleet Fuel Expense	$ (41,909)	L2 - L1

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 3, lines 5 and 6

B: Per Company's workpapers showing calculation of Fleet Fuel Expense adjustment (except where noted)

4	Average construction FTE from July 2005 to June 2006	109.2	
5	Average miles driven/contruction FTE (Total miles = 1,560,271)	14,293	
6	Construction FTE for July 2006	114.5	
7	Assumed 2006-2007 mileage	1,636,498	L5 x L6
8	Miles/gallon (1,560,271 / 204,180)	7.63	
9	Gallons purchased	214,497	L7 / L8
10	Weighted average price per gallon	$ 2.82	Note C
11	Pro forma fuel expenditures	$ 605,498	L9 x L10
12	Test year expenditures	$ 573,746	
13	Staff Recommended pro forma adjustment to Fleet Fuel Expense	$ 31,752	L11 - L12

C: **Amounts taken from the Company's response to STF 20.1**

	Gallons	Fuel Cost	Weighted Average Cost/Gal
Wright Express (July 2006 - June 2007)	95,454	$ 272,280	$ 2.85
Kingman Gascard (July 2006 - June 2007)	99,420	$ 274,932	$ 2.77
Parker Oil (February 2007 - June 2007)	8,777	$ 26,564	$ 3.03
Texmo Oil Company (August 2006 - September 2006)	3,660	$ 11,435	$ 3.12
Weighted Average	207,311	$ 585,210	$ 2.82

UNS Electric, Inc.
Adjustment to Fleet Fuel Expense (supplemental worksheet)
Allocation of Staff adjustment to FERC accounts

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-4
Page 2 of 2
Revised 9/17/2007

Co	Acct	Expense Type	FERC Account	DR	CR	Net Amount	% of Total	O&M Adjustment	Staff Adjustment
33	55000	403	546	$7,634.11		$7,634.11	0.85%	$1,829	($357)
33	55000	403	548	$1,198.26		$1,198.26	0.13%	$287	($56)
33	55000	403	549	$188.36		$188.36	0.02%	$45	($9)
33	55000	403	551	$9,428.90		$9,428.90	1.05%	$2,259	($441)
33	55000	403	553	$17,592.83		$17,592.83	1.96%	$4,214	($823)
33	55000	403	554	$9,332.50		$9,332.50	1.04%	$2,235	($437)
33	55000	403	557	$2,550.60		$2,550.60	0.28%	$611	($119)
33	55000	403	562	$3,237.60		$3,237.60	0.36%	$776	($152)
33	55000	403	563	$472.61		$472.61	0.05%	$113	($22)
33	55000	403	566	$2,075.77		$2,075.77	0.23%	$497	($97)
33	55000	403	570	$7,633.80		$7,633.80	0.85%	$1,829	($357)
33	55000	403	571	$395.23		$395.23	0.04%	$95	($18)
33	55000	403	580	$8,414.78		$8,414.78	0.94%	$2,016	($394)
33	55000	403	581	$54,108.09		$54,108.09	6.04%	$12,961	($2,532)
33	55000	403	582	$4,099.30		$4,099.30	0.46%	$982	($192)
33	55000	403	583	$33,150.21		$33,150.21	3.70%	$7,941	($1,551)
33	55000	403	584	$65,053.92		$65,053.92	7.26%	$15,583	($3,045)
33	55000	403	585	$165.43		$165.43	0.02%	$40	($8)
33	55000	403	586	$98,161.79		$98,161.79	10.96%	$23,513	($4,594)
33	55000	403	587	$1,717.22		$1,717.22	0.19%	$411	($80)
33	55000	403	588	$43,342.83		$43,342.83	4.84%	$10,382	($2,028)
33	55000	403	590	$9,421.61		$9,421.61	1.05%	$2,257	($441)
33	55000	403	592	$53,782.89		$53,782.89	6.01%	$12,883	($2,517)
33	55000	403	593	$93,650.75		$93,650.75	10.46%	$22,433	($4,383)
33	55000	403	594	$18,195.04		$18,195.04	2.03%	$4,358	($852)
33	55000	403	595	$8,141.32		$8,141.32	0.91%	$1,950	($381)
33	55000	403	596	$8,089.99		$8,089.99	0.90%	$1,938	($379)
33	55000	403	598	$171.22		$171.22	0.02%	$41	($8)
33	55000	403	901	$24,434.41		$24,434.41	2.73%	$5,853	($1,144)
33	55000	403	902	$13,012.92		$13,012.92	1.45%	$3,117	($609)
33	55000	403	903	$132,933.49		$132,933.49	14.85%	$31,842	($6,221)
33	55000	403	905	$1,969.74		$1,969.74	0.22%	$472	($92)
33	55000	403	908	$7,737.47		$7,737.47	0.86%	$1,853	($362)
33	55000	403	909	$7,376.08		$7,376.08	0.82%	$1,767	($345)
33	55000	403	910	$181.63		$181.63	0.02%	$44	($9)
33	55000	403	920	$0.00		$0.00	0.00%	$0	$0
33	55000	403	921	$111,418.51		$111,418.51	12.44%	$26,689	($5,215)
33	55000	403	925	$165.65		$165.65	0.02%	$40	($8)
33	55000	403	930	$34,835.19		$34,835.19	3.89%	$8,344	($1,631)
				$895,472.05	$0.00	$895,472.05		$214,500	($41,909)

Staff adjustment amount from page 1: $214,497 $ (41,909)

UNS Electric, Inc.
Postage Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-5

Line No.	Description	Amount	Reference
1	UNS Electric Annualized Postage Expense	$ 341,321	A
2	Recommended Staff Annualized Postage Expense	$ 358,824	B
3	Adjustment to Annualized Postage Expense	$ 17,503	L2 - L1

Notes and Source

A: Per Company workpaper used in calculating its Postage Expense adjustment

B:

4	UNS Electric Annualized Postage Expense	$ 341,321
5	Postage increase effective 5/14/07 (.41/.39)	1.05
6	Staff adjusted annualized Postage Expense	$ 358,824

UNS Electric, Inc.
Normalize Injuries and Damages Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-6

Revised 9/17/2007

Line No.	Description	Amount	Reference
1	UNS Electric Test Year Injuries and Damages Expense	$ 562,403	A
2	Staff Recommended Normalized Injuries and Damages Expense	$ 464,242	B
3	Adjustment to Injuries and Damages Expense	$ (98,161)	L2 - L1

Notes and Source

A: Amount taken from UNS Electric's response to STF 3.101

B: UNSE witness Dallas Dukes' rejoinder testimony, page 4

FERC Account 925

UNS Electric, Inc.
Incentive Compensation Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-7

Revised 9/17/2007

Line No.	Description	Amount	Reference
1	Staff Adjustment to UES's Performance Enhancement Plan (PEP)	$ (79,871)	A
2	Staff Adjustment to UES's Other Incentive Comp	$ (24,486)	B
3	Total Adjustment to Incentive Compensation Expense	$ (104,357)	
4	Adjustment to Taxes Other Than Income	$ (4,160)	A

Notes and Source

A: Per Company's workpapers showing calculation of Incentive Compensation adjustment (except where noted)

	Test Year Amount	Company Adjustment		Company Adjusted		Disallowance Percentage	Adjusted Amount
Performance Enhancement Plan (PEP)							
Non-union employees and managers	$ 62,326	$ 35,921	a	$ 98,247	b	50%	$ 49,124
Officers (per UNS Electric's response to STF 11.1)	$ 61,493	$ -		$ 61,493	b	50%	$ 30,747
Total PEP Expense	$ 123,819	$ 35,921		$ 159,740			$ 79,871
Taxes Other Than Income	$ 5,215	$ 3,105	a	$ 8,320		50%	$ 4,160

B: Per UNS Electric Inc.'s response to STF 3.83

Deferred Compensation Plan	$ 9,035	50%	$ 4,518
Officer's Long Term Incentive Plan	$ 39,935	50%	$ 19,968
	$ 48,970		$ 24,486

a: Amounts tie to UNS Electric's filing, Schedule C-2, page 2 of 5, lines 6 and 8
b: Amounts tie to UNS Electric's response to STF 11.1

UNS Electric, Inc.
Supplemental Executive Retirement Plant (SERP) Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-8

Line No.	Description	Amount	Reference
1	Remove Supplemental Executive Retirement Plan Expense	$ (83,506)	A

Notes and Source

A: Per the Company's response to STF 3.83

FERC 923

UNS Electric, Inc.
Stock Based Compensation Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-9

Line No.	Description	Amount	Reference
1	Remove Stock Based Compensation Expense	$ (82,873)	Note A

Notes and Source

A: Per Company's response to STF 10.11

Stock Option Expense	$	62,904
Performance Share Expense	$	19,969
Total	$	82,873

UNS Electric, Inc.
Property Tax Expense

Docket No. E-04204A-06-0783
Schedule C-10
Page 1 of 1

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	UNS Electric Proposed Decrease to Property Tax Expense	$ (130,301)	A
2	Staff Proposed Decrease to Property Tax Expense	$ (190,048)	B
3	Adjustment to Property Tax Expense	$ (59,747)	L2 - L1

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 5, line 8

B: Amounts taken from Company workpapers used to calculate its property tax expense adjustment

	Utility Plant in Service Taxes	Generation	Transmission	Distribution	General/ Intangible	Total
4	Total Net Plant in Service - Rate Base	$ 18,471,624	$ 15,073,774	$ 99,401,194	$ 16,474,253	$ 149,420,845
5	Less: Non-Taxable Licensed Transportation in Rate Base	$ -	$ -	$ -	$ (3,834,788)	$ (3,834,788)
6	Less: Land Cost & Rights of Way in Rate Base	$ (408,603)	$ (681,822)	$ (695,700)	$ (30,719)	$ (1,816,844)
7	Less: Environmental Property in Rate Base	$ -	$ -	$ (5,563,286)		$ (5,563,286)
8	Less: Non-Taxable WAPA Portion of N Havasu Sub			$ (4,674,822)		$ (4,674,822)
9	Less: CWIP in Rate Base	$ (777,167)	$ (1,234,041)	$ (7,840,042)	$ (951,066)	$ (10,802,316)
10	Less: Net Book Value of Generation	$ (17,285,854)				$ (17,285,854)
11	Plus: Full Cash Value of Generation	$ 7,943,440				$ 7,943,440
12	Plus: Land FCV per AZ Department of Revenue			$ 1,551,539		$ 1,551,539
13	Plus: Materials and Supplies in Rate Base			$ 5,650,559		$ 5,650,559
14	Plant in Service Full Cash Value	$ 7,943,440	$ 13,157,911	$ 87,829,442	$ 11,657,680	$ 120,588,473
15	Assessment Ratio	23.5%	23.5%	23.5%	23.5%	
16	Taxable Value	$ 1,866,708	$ 3,092,109	$ 20,639,919	$ 2,739,555	$ 28,338,291
17	Average Tax Rate	9.6858%	9.6858%	9.6858%	9.6858%	
18	Property Tax - Subtotal	$ 180,806	$ 299,495	$ 1,999,141	$ 265,348	$ 2,744,790
19	Environmental Property in Rate Base	$ -	$ -	$ 5,563,286	$ -	
20	Statutory Full Cash Value Adjustment	50%	50%	50%	50%	
21	Environmental Full Cash Value	$ -	$ -	$ 2,781,643	$ -	
22	Assessment Ratio	23.5%	23.5%	23.5%	23.5%	
23	Taxable Value	$ -	$ -	$ 653,686	$ -	
24	Average Tax Rate	9.6858%	9.6858%	9.6858%	9.6858%	
25	Property Tax - Subtotal	$ -	$ -	$ 63,315	$ -	$ 63,315
26	Total Property Taxes	$ 180,806	$ 299,495	$ 2,062,456	$ 265,348	$ 2,808,105
27	Less: Recorded Property Taxes Excluding Call Center	$ (101,364)	$ (395,121)	$ (2,266,077)	$ (222,391)	$ (2,984,953)
28	Property Tax Expense Adjustment (subtotal)	$ 79,442	$ (95,626)	$ (203,621)	$ 42,957	$ (176,848)
29	Less: Estimated Property Tax Related to PHFFU					$ (13,200) *
30	Property Tax Expense Adjustment					**$ (190,048)**

***Plant Held for Future Use**

	Transmission	Distribution	Total
Original Cost	$ 320,000	$ 120,000	$ 440,000
Estimated Property Tax Rate	3.0%	3.0%	
Estimated Property Tax Expense	$ 9,600	$ 3,600	$ 13,200

2008 Arizona Statutory Assessment Ratio 23.5%

FERC Account 408

UNS Electric, Inc.
Rate Case Expense

Docket No. E-04204A-06-0783
Schedule C-11

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	UNS Electric Rate Case Expense per Company Filing	$ 200,000	A
2	Staff Recommended Rate Case Expense	$ 88,333	B
3	Adjustment to Rate Case Expense	$ (111,667)	L2 - L1

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 3, line 6

B:	Staff Recommended Rate Case Expense	$ 265,000	Note 1
	Normalized Over Three Years	3	
	Staff Recommended Normalized Rate Case Expense	$ 88,333	

(1) Reflects an escalation of approximately 4% over the allowance recommended by Staff in the recent UNS Gas rate case

UNS Electric, Inc.
Edison Electric Institute Dues

Docket No. E-04204A-06-0783
Schedule C-12

Test Year Ended June 30, 2006

Line No.	Description	Test Year Amount (A)	Company Adjustment (B)	Company Adjusted Amount (C)	Staff Adjustment (D)	Staff Adjusted (E)
1	Regular Dues	$ 10,000	$ (2,000)	$ 8,000	$ (2,993) a	$ 5,007
2	2005 UARG	$ 24,071	$ -	$ 24,071	$ (2,675) b	$ -
3	2006 UARG	$ 2,802	$ -	$ 2,802	$ (2,802)	$ -
4	Total Test Year EEI Dues	$ 36,873	$ (2,000)	$ 34,873	$ (8,470)	$ 5,007
5	Journal Entry to Correct 2005 UARG per G/L	$ (21,396)	$ -	$ (21,396)	$ -	$ -
6	Adjusted Test Year EEI Dues	$ 15,477	$ (2,000)	$ 13,477	$ (8,470)	$ 5,007

Notes and Source

Col. A: Amounts taken from the Company's response to STF 3.72

a: Staff adjustment for Regular Dues based on a disallowance percentage of 49.93% (see page 2)

	Staff Adjustment
Regular Dues	$ 10,000
Regular Dues disallowance percentage	49.93%
Staff adjustment to Regular Dues	$ 4,993
Less: Company adjustment	$ (2,000)
Remaining Staff adjustment to Regular Dues	$ 2,993

b: Allocation of TEP's portion of 2005 UARG in the amount of $24,071 booked in error. Corrected by Journal Entry 910.

TEP allocation of 2005 UARG	$ 24,071
Correcting JE910	$ (21,396)
UNS Electric allocation of 2005 UARG	$ 2,675

Page 17 of Mr. Dukes' rebuttal testimony agrees that the UARG dues should be removed.

Col D: Per letter from Edison Electric Institute included in Company's workpapers for its EEI adjustment, 100% of environmental related separately funded activities are classified as "non-deductible" expenses

FERC 930

Edison Electric Institute
Schedule of Expenses by NARUC Category
For Core Dues Activities
For the Year Ended December 31, 2005

NARUC Operating Expense Category	% of Dues	Recommended Disallowance
Legislative Advocacy	20.38%	20.38%
Legislative Policy Research	6.02%	
Regulatory Advocacy	16.49%	16.49%
Regulatory Policy Research	13.99%	
Advertising	1.67%	1.67%
Marketing	3.68%	3.68%
Utility Operations and Engineering	11.31%	
Finance, Legal, Planning and Customer Service	18.75%	
Public Relations	7.71%	7.71%
Total Expenses	100.00%	49.93%

Comments:

* The above percentages represent expenses associated with EEI's core dues activities, based on the operating expense categories established by NARUC. Core expenses are those expenses paid for by shareholder-owned electric utilities' dues.

* The legislative advocacy percent will differ slightly for IRS reporting requirements. For 2005, the lobbying % for IRS reporting is 19.4%.

* Administrative expenses are included in the percentages listed above. Approximately 11% of EEI's core dues expenses are administrative.

UNS Electric, Inc.
Other Membership and Industry Association Dues

Docket No. E-04204A-06-0783
Schedule C-13

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Arizona Utility Investors Association	$ 2,500	930
2	Alliance of Utility Shareholder Associations (AUSA)	$ 100	930
3	Golden Valley Chamber of Commerce	$ 70	930
4	Kingman Mohave Lions Club	$ 120	921/930
5	Kingman Rotary Club	$ 383	921/930
6	Kingman Route 66 Rotary Club	$ 508	921/930
7	Kingsmen	$ 125	930
8	Kiwanis Club of Havasu	$ 666	930
9	Mohave Museum of History & Arts	$ 200	930
10	Nogales-Santa Cruz Chamber of Commerce	$ 60	930
11	Arizona-Mexico Commission	$ 1,750	930.1
12	Total Membership Dues	$ 6,482	

		Total From Above	Adjustment
13	Total Amount Recorded in Account 921	$ 568	$ (568)
14	Total Amount Recorded in Account 930	$ 5,914	$ (5,914)
15	Total	$ 6,482	$ (6,482)

Notes and Source

Amounts taken from the Company's response to STF 3.72

L.11: Also see responses to data requests STF 3.55 and MM DR 2.27:
"The $1,750 for the Arizona-Mexico Commission should have been removed from expenses included in the revenue requirement. This invoice was overlooked in error and will be adjusted out of test year expense."

UNS Electric, Inc.
Interest Synchronization

Docket No. E-04204A-06-0783
Schedule C-14 (Revised)

Test Year Ended June 30, 2006

Line No.	Description		Amount	Reference
1	Adjusted rate base	$	130,740,050	Schedule B
2	Weighted cost of debt		4.10%	Schedule D
3	Synchronized interest deduction	$	5,360,342	Line 1 x Line 2
4	Synchronized interest deduction per UNS Electric	$	5,819,157	Note A
5	Difference (decreased) increased interest deduction	$	(458,815)	Line 3 - Line 4
6	Combined federal and state income tax rates		38.598%	UNS Electric Sch. C-3
7	Increase (decrease) to income tax expense	$	177,093	

Notes and Source

A RUCO 1.10 2006 UNSE Lead-Lag Summary.xls
Also, UNS Electric filing, Schedule B-5, page 3 of 3, line 21

UNS Electric, Inc.
Depreciation Rates Correction

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-15

Line No.	Description	Amount	Reference
1	Adjustment to Depreciation & Amortization Expense	$ (63,105)	A

Notes and Source

A: Per Company's workpapers used to calculate its depreciation expense adjustment (except where noted)

FERC	Description	UNS Electric Proforma Adj. to Depreciation Expense	Staff Proforma Adj. to Depreciation Expense	Staff Adjustment	Additional Reference
403	Depreciation Expense	$ 122,500	$ 57,628	$ (64,872)	Pages 2 & 3
404	Amortization of Utility Plant	$ 323,410	$ 323,410	$ -	Page 3
406	Amortization of Utility Plant Acquisition Adjustment	$ 137,076	$ 138,843	$ 1,767	Page 4
	Total	$ 582,986	$ 519,881	$ (63,105)	

UNS Electric, Inc.
Depreciation & Amortization Expense - Supplemental Worksheet

Test Year Ended June 30, 2006

Depreciation Annualization Adjustment

Line No.	FERC Account	Description	Balance at 6/30/06	Adjustments	Adjusted Balance	Depreciation Rate	Annualized Depreciation	
		A. Rates Per Company Proforma Adjustment						
1	392	Transportation Equipment - Class 1	$ 366,331	$ 10,369	$ 376,700	12.75%	$ 48,029	
2	392	Transportation Equipment - Class 2	$ 1,151,599	$ 32,595	$ 1,184,194	16.99%	$ 201,195	
3	392	Transportation Equipment - Class 3	$ 1,185,238	$ 33,548	$ 1,218,786	20.21%	$ 246,317	
4	392	Transportation Equipment - Class 4	$ 5,641,612	$ 159,683	$ 5,801,295	13.47%	$ 781,434	
5	392	Transportation Equipment - Class 5	$ 1,995,626	$ 56,485	$ 2,052,111	12.55%	$ 257,540	
7		Total Annualized Transportation Equip.					$ 1,534,515	
		B. Rates Per Response to STF 11.8						
8	392	Transportation Equipment - Class 1	$ 366,331	$ 10,369	$ 376,700	11.48%	$ 43,245	
9	392	Transportation Equipment - Class 2	$ 1,151,599	$ 32,595	$ 1,184,194	15.29%	$ 181,063	
10	392	Transportation Equipment - Class 3	$ 1,185,238	$ 33,548	$ 1,218,786	18.69%	$ 227,791	
11	392	Transportation Equipment - Class 4	$ 5,641,612	$ 159,683	$ 5,801,295	11.97%	$ 694,415	
12	392	Transportation Equipment - Class 5	$ 1,995,626	$ 56,485	$ 2,052,111	11.29%	$ 231,683	
13		Total Annualized Transportation Equip.					$ 1,378,197	
		C. Staff Adjustment						
14		Staff Adjustment Before Capitalization					$ (156,318)	L13 - L7
15		O&M Portion of Vehicle Depreciation					41.5%	
16		Staff Adjustment to Depreciation Expense					$ (64,872)	L14 x L15

Notes and Source

Staff proforma adjustment for Depreciation & Amortization based on revised depreciation rates for FERC account 392 - Transportation Equipment, which reflected a 10% net salvage rate that was inadvertently omitted from the depreciation study as addressed in the responses to STF 3.39 and STF 11.8

UNS Electric, Inc.
Depreciation & Amortization Expense - Supplemental Worksheet

Docket No. E-04204A-06-0783
Schedule C-15

Test Year Ended June 30, 2006

Depreciation Annualization Adjustment

Line No.	Description	Account 403	Account 404	O&M Exp.	Total
	UNS Electric Proforma Adjustment - Schedule 15.1, page 12				
1	Test Year Recorded	$ 14,308,205	$ 390,304	$ 332,503	$ 15,031,012
2	Annualized Depreciation	$ 16,110,715	$ 713,714		$ 16,824,429
3	Less: Depr on CWIP Removed	$ (449,816)			$ (449,816)
4	Vehicle Depreciation Chgs CWIP	$ (1,534,515)		$ 636,824	$ (897,691)
5	Adjusted Annualized Depreciation	$ 14,126,384	$ 713,714	$ 636,824	$ 15,476,922
6	Adjustment Amount	$ (181,821)	$ 323,410	$ 304,321	$ 445,910

	Staff Proforma Adjustment - Schedule 15.2, page 8	Account 403	Account 404	O&M Exp.	Total	
7	Test Year Recorded	$ 14,308,205	$ 390,304	$ 332,503	$ 15,031,012	
8	Annualized Depreciation	$ 15,954,397	$ 713,714		$ 16,668,111	
9	Less: Depr on CWIP Removed	$ (449,816)			$ (449,816)	
10	Vehicle Depreciation Chgs CWIP	$ (1,378,197)		571,952	$ (806,245)	
11	Adjusted Annualized Depreciation	$ 14,126,384	$ 713,714	$ 571,952	$ 15,412,050	
12	Adjustment Amount	$ (181,821)	$ 323,410	$ 239,449	$ 381,038	
13	Staff Adjustment				$ (64,872)	L12 - L6

UNS Electric, Inc.
Depreciation & Amortization Expense - Supplemental Worksheet

Test Year Ended June 30, 2006

Acquisition Discount Annualization Adjustment

Line No.	FERC Account	Description	Balance at 6/30/06	Adjustments	Adjusted Balance	Depreciation Rate	Annualized Depreciation	
		Rates Per Company Proforma Adjustment						
1	392	Transportation Equipment - Class 1	$ (51,192)	$ 39,563	$ (11,629)	12.75%	$ (1,483)	
2	392	Transportation Equipment - Class 2	$ (16,191)	$ 12,513	$ (3,678)	16.99%	$ (625)	
3	392	Transportation Equipment - Class 3	$ (92,982)	$ 71,860	$ (21,122)	20.21%	$ (4,269)	
4	392	Transportation Equipment - Class 4	$ (362,404)	$ 280,080	$ (82,324)	13.47%	$ (11,089)	
5	392	Transportation Equipment - Class 5	$ -	$ -	$ -	12.55%	$ -	
7		Total Annualized Amort-Acq Adj	$ (522,769)	$ 404,016	$ (118,753)		$ (17,466)	
		Rates Per Response to STF 11.8						
8	392	Transportation Equipment - Class 1	$ (51,192)	$ 39,563	$ (11,629)	11.48%	$ (1,335)	
9	392	Transportation Equipment - Class 2	$ (16,191)	$ 12,513	$ (3,678)	15.29%	$ (562)	
10	392	Transportation Equipment - Class 3	$ (92,982)	$ 71,860	$ (21,122)	18.69%	$ (3,948)	
11	392	Transportation Equipment - Class 4	$ (362,404)	$ 280,080	$ (82,324)	11.97%	$ (9,854)	
12	392	Transportation Equipment - Class 5	$ -	$ -	$ -	11.29%	$ -	
13		Total	$ (522,769)	$ 404,016	$ (118,753)		$ (15,699)	
14		Staff Adjustment					$ 1,767	L13 - L7

Proforma Adjustment to FERC Account 406

		Per Company Adj. Workpaper	Staff Adjusted	Staff Adjustment
15	Intangible Plant	$ (181,550)	$ (181,550)	
16	Other Production Plant	$ (136,670)	$ (136,670)	
17	Transmission Plant	$ (400,629)	$ (400,629)	
18	Distribution Plant	$ (2,824,706)	$ (2,824,706)	
19	General Plant	$ (238,101)	$ (236,334)	
		$ (3,781,656)	$ (3,779,889)	
20	Test Year Amount per Books	$ (3,918,732)	$ (3,918,732)	
21	Adjustment - FERC 406	$ 137,076	$ 138,843	$ 1,767

Notes and Source

Staff proforma adjustment for Acquisition Discount Annualization Adjustment based on revised depreciation rates for FERC account 392 - Transportation Equipment, which reflected a 10% net salvage rate that was inadvertently omitted from the depreciation study as addressed in the responses to STF 3.39 and STF 11.8

UNS Electric, Inc.
Emergency Bill Assistance Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-16

Line No.	Description	Account	Amount	Reference
1	Increase to Emergency Bill Assistance Expense		$ 20,000	A

Notes and Source

A Testimony of Staff witnesses Ralph C. Smith and Julie McNeely-Kirwan

UNS Electric Inc.
Southwest Energy Services (SES) Charges

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-17

Line No.	Description	Amount	Reference
1	Remove Mark-up Related to SES Charges	$ (10,906)	A

Notes and Source

A: Amount taken from UNS Electric's supplemental response to STF 15.1

Primarily FERC Account 902. See responses to data request STF 10.4 (direct billings) and STF 10.5 (indirect billings) for additional account details

UNS Electric Inc.
Bad Debt Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-18

Line No.	Description	Amount	Reference
1	UNS Electric Adjustment to Bad Debt Expense per Filing	$ 222,556	A
2	UNS Electric Revised Adjustment to Bad Debt Expense	$ 66,947	B
3	Adjustment to Bad Debt Expense	$ (155,609)	L2 - L1

Notes and Source

A: UNS Electric filing, Schedule C-2, page 3, line 6
B: Rebuttal testimony of Company witness Dallas Dukes, pages 21 and 22 and workpaper UNSE(0783)10580

FERC Account 904

UNS Electric Inc.
Outside Services - Demand Side Management

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-19

Line No.	Description	Amount	Reference
1	Remove Double Count from Outside Services Related to DSM	$ (17,055)	A

Notes and Source

A: Rebuttal testimony of Company witness Dallas Dukes, page 27

FERC Account 908

UNS Electric Inc.
Year-End Accruals

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-20

Line No.	Description	Amount	Reference
1	Correct Year-End Accrual to Remove Prior Period Expense	$ (6,256)	A

Notes and Source

A: Rebuttal testimony of Company witness Dallas Dukes at page 22 and Rebuttal Exhibit DJD-1, page 3.

FERC Account 926

ALL-STATE LEGAL®
EXHIBIT
S-61
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

DIRECT

TESTIMONY

OF

FRANK W. RADIGAN

ON BEHALF OF

THE ARIZONA CORPORATION COMMISSION,

UTILITIES DIVISION STAFF

JULY 12, 2007

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783

Class Cost of Service Study ("CCOSS") -- The allocation of purchased power is the single largest factor driving the results. To properly allocate this cost, one needs to either entirely exclude all purchased power costs from the cost of service study or thoroughly analyze individual cost components that make up purchased power so as to understand if they are demand related or customer related. Yet, the Company has provided no proof that its allocation method is consistent with the costs incurred. Until this is done, I recommend that the results of the CCOSS not be used for revenue allocation purposes and that any revenue increase be allocated on an equal percentage basis.

Time of Use ("TOU") Rates – Mandatory TOU rates for customers should not be implemented given that most usage for most customers is so small that it would not justify the added expense.

TOU Time Periods – In general the time periods selected by the Company are reasonable and coincide with those in the marketplace and other neighboring utilities.

TOU TIME PERIOD RATE DIFFERENTIALS - While I recognize that these differentials may change with adjustments to the PPFAC mechanism, they were reasonably developed and give the proper price signals to customers to switch usage to the off-peak period.

INCLINING BLOCK RATE STRUCTURE - While I agree with this recommendation in principle to give customers some price signal that the more they use the more it costs to serve, the introduction of the inclining block rates at this time was impractical given the small recommended rate increase and increases in the customer charge.

MERGER OF MOHAVE AND SANTA CRUZ RATES - Given that the current absolute dollar differential in the customer's bill is small, that costs for the Company as a whole are increasing and the small overall rate increase being recommended, I recommend that a complete elimination of the differential not be made at this time. Rather, the customer charge for both counties should be increased and the remaining revenue requirement be recovered from increasing the energy charge of the Mohave County customers.

RESETTING THE PPFAC TO ZERO - Per the problems outlined by Staff Witness Smith and noted in the CCOSS section of my testimony, it is premature to make this change at this time. The rates have been designed, however, to separately show the power supply costs that are currently included in base rates.

CUSTOMER CHARGES – Balancing rate impacts and the cost to serve as indicated by the CCOSS, the customer charge for the Residential Service Class should be increased from $6.50 per month to $7.50 per month, an increase of $1.00 per month, or 15.4 percent. For the Small General Service Class, I recommend that the customer charge increase from $10 per month to $12 per month, an increase of $2.00 per month or 18.3 percent. For the Large General Service Class and the Interruptible Service Class, I recommend that the customer charge be set at $15.50 per month for both the TOU and non-TOU rates. Each of these

charges is somewhat below the indicated cost to serve and also limits the rate impacts to customers. For the Large Power Service Class, the CCOSS indicates that the customer component is $2,140 per month but the Company is proposing to keep the customer charge for service at less than 69 kV at $365 per month and for service above 69 kV decreasing the charge from $800 per month to $400 per month. While neither of these proposals comports with the CCOSS, I recommend that they be approved to avoid unnecessary bill increases.

MISCELLANEOUS SERVICE FEES – Staff supports adopting the Miscellaneous Service Fees proposed by UNS Electric. While the Company's cost data for Reconnection or Connection of Service after Normal Business Hours and After Hours of Service Establishment/Re-establishment (includes weekends and holidays) shows $126.66 as opposed to the $75 proposed by the Company, the Company's proposal to raise these fees from the current level of $60 to the proposed level of $75 reflects a gradual approach to implementing rate changes, which is supported by Staff. The other Miscellaneous Service Fees proposed by the Company are supported by the cost data and should be adopted.

DEMAND CHARGES FOR LARGE GENERAL AND LARGE POWER SERVICE - The CCOSS does not break down cost of service data for the LPS >69 kV or <69 kV nor rate differential between TOU and Non-TOU for LGS. In discovery, I asked the Company to provide the cost basis for its proposal and any associated workpapers or cost studies used to support it. None were given. Given the lack of justification on the Company's part, I recommend no realignment of the demand charge differentials at this time.

INCREASING THRESHOLD FOR LARGE GENERAL SERVICE - The Company's proposal for increasing the threshold for large general service to 7,500 kWh is reasonable and should be adopted. A small general service customer that uses 10,000 kWh per month currently pays approximately $940 per month while under the Large General Service Class it would pay approximately $1,200 per month or 28% higher. Given that there is no change in the physical service being provided to the customer, there is no justification for the increased costs to the large general service rate customer under the current threshold. The Company's proposal should be adopted.

CARES DISCOUNT - Staff Witness Julie McNeely-Kirwan has recommended that the Company's proposal to revise the structure of the CARES discount be rejected and the current CARES discount structure be retained. I have reflected these recommendations in the CARES rate design.

BLACK MOUNTAIN GENERATING STATION – The Company's proposal to increase the average base delivery charge to customers by approximately 0.6 cents per kWh and to make a corresponding decrease of 0.6 cents per kWh to the base power supply rate on June 1, 2008 or the date of commercial operation of Black Mountain Generating Station ("BMGS") described on page 3 of UNS Electric witness Larson's testimony appears to be rate gimmickry and should not be adopted.

INTRODUCTION

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

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services regarding the electric utility industry and specializing in the fields of rates, planning and utility economics. My office address is 120 Washington Avenue, Albany, New York 12210.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Chemical Engineering from Clarkson College of Technology in Potsdam, New York (now Clarkson University) in 1981. I received a Certificate in Regulatory Economics from the State University of New York at Albany in 1990. From 1981 through February 1997, I served on the Staff of the New York State Department of Public Service ("DPS") in the Rates and System Planning sections of the Power Division. My responsibilities included resource planning and the analysis of rates, depreciation rates and tariffs of electric, gas, water and steam utilities in the State and encompassed rate design and performing embedded and marginal cost of service studies as well as depreciation studies.

Before leaving the DPS, I was responsible for directing all engineering staff during major rate proceedings including those relating to integrated resource planning and environmental impact studies. In February 1997, I left the DPS and joined a firm called Louis Berger & Associates as a Senior Energy Consultant. In December 1998, I formed my own Company. In my 25 years of experience, I have testified as an expert witness in utility rate proceedings on more than 50 occasions before various utility regulatory bodies, including this Commission, the Nevada Public Utility Commission, the New York State Department of Taxation and Finance, the Connecticut Department of Utility Control, the

Rhode Island Public Utilities Commission, the Michigan Public Service Commission and the Federal Energy Regulatory Commission.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment FWR-1 provides details concerning my experience and qualifications.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachment FWR-2 shows the recommended rate design and Attachment FWR-3 shows Staff's bill impact analysis, showing the impact of Staff's recommended rates over a variety of representative usage levels for customers in each customer class. Attachment FWR-4 shows Staff's proof of revenue.

Q. What is the scope of your testimony in this case?

A. I will address the class cost of service study, revenue allocation and the proposed rate design.

Q. Have you reviewed the rate design proposals submitted by the Company in this case?

A. Yes. I reviewed Company witness, Mr. D. Bentley Erdwurm's testimony. Mr. Erdwurm is sponsoring a number of rate design changes. I also reviewed the testimony of Company witness Kevin P. Larson concerning rate changes related to the Black Mountain Generating Station ("BMGS").

CLASS COST OF SERVICE STUDY

Q. What is the purpose of a Class Cost of Service Study ("CCOSS")?

A. The purpose of a CCOSS or embedded cost of service study ("ECOS") is to assign the historic costs incurred by the utility to each of the service classifications of the utility in order to determine the relative profitability of each of the service classifications to the overall average. By doing this, it allows the analyst to re-allocate revenue responsibility amongst classes so that each of the service classifications are providing their fair share of costs and one service classification is not subsidizing other service classifications. Any re-allocation of revenue responsibility must be tempered by customer impact concerns.

Q. Have you reviewed the CCOSS model and inputs presented by the Company in this proceeding?

A. Yes, the model accurately assigns costs by the assumed allocation factors and summarizes them by function. Schedule G-6, page 3 of 4, shows the results of the classification and allocation for each of the service classifications and the utility as a whole using the claimed rate of return by service classification. Use of the claimed rate of return for each service classification assumes that rates are re-set so that each service classification is providing exactly the same profitability to the utility without regard to customer bill impacts. This is a useful tool to design cost based rates by cost causality (i.e. customer charge, demand charge, etc.).

Q. Please Summarize the Results of the Company's Study.

A. As shown on Schedule G-6, page 3 of 4, the Company's overall revenue requirement of $166,993,986 is comprised of $37,567,388 of demand-related costs, $16,394,769 of customer-related costs and $113,031,829 of energy-related costs. The energy-related costs which make up 68% of UNS's total costs to serve come from just two accounts: Account

555 – Purchased Power and Account 565 – Transmission of Electricity by Others. While these two accounts are classified by the Company as energy-related, they were allocated based on the average and peaks method.

Q. Please describe the Average and Peaks Method.

A. The Average and Peaks Method is made up of two components: an average demand component (with a percentage weight of the system load factor) and a peak demand component (with a percentage weight of one minus the system load factor). While there are many theories and methods to allocate production-related plant, the average and peaks method tries to recognize that the system must have both adequate capacity to satisfy demand at the time of the peak and that utilities try to satisfy the energy supply over the course of the year with the most economical supply available. Thus, it is argued that the average and peaks method recognizes that classes of customers should receive some allocation of costs reflecting contribution to peak and an average demand component to recognize that different types of capacity - baseload, intermediate and peaking capacity – are installed depending on energy use and the duration of load. Since baseload capacity generally has a relatively high capital cost, but a relatively low running (incremental O&M and fuel) cost, the average total cost per kWh, which is the sum of capital cost and running cost, from baseload capacity falls as the utilization of the baseload capacity increases.

Q. Given that UNS has so little of its own generation what is the Company's reason for continuing to use the Average and Peaks Method?

A. As explained in the direct testimony of Company witness Erdwurm, UNS believes that the Average and Peaks Methodology is appropriate because power suppliers typically will demand a higher average price to serve a load with high peaks and a low load factor. The

Average and Peaks approach appropriately allocates more cost to customer groups with relatively high coincident peak demand and relatively low system load factor, as opposed to an energy only allocation approach. He explains that an energy-only allocation would lower the assigned cost to a low load factor class, and would result in a perverse price signal that a class' load factor - and therefore a system's load factor - has no bearing on the price demanded by a purchased power supplier.

Q. Do you agree?

A. The theory that Mr. Erdwurm proffers is not correct under today's deregulated wholesale market place. As noted by Company Witness DeConcini, the Company is currently a full requirements customer of Pinnacle West Capital Corporation that runs through May 31, 2008. That contract does in fact provide for all energy and ancillary services to serve the Company's load at a fixed price per MWh. (DeConcini, pages 2 and 3). Thus, an argument could be made that since the Company incurs purchased power costs on a volumetric basis they should be allocated that way as well. At the same time it must be recognized that the contract is set to expire next year so some look should be given to future procurement. The Company states that it has developed a detailed Procurement Plan to ensure that it has the necessary resources and contracts to reliably serve its load after the expiration of that contract. The Company states that the plan provides for a mix of market power purchases, resource acquisitions and contracts to provide the necessary capacity, energy and reserves to meet its load requirements. (DeConcini, pages 3 and 4). In Exhibit MJD-2, the Company illustrates how its supply portfolio will change over time as its existing contract expires. As shown on that exhibit, the supply portfolio changes from year to year with current resources heavily base load now and relying more on peaking resources out in the future.

Q. Please explain how the use of the Average and Peaks Method Impacts the Revenue Allocation and rate design in this case.

A. I will use the Residential Service Classification to illustrate how the allocation of the purchased power costs can impact the cost responsibility as indicated by the Cost of Service Study. Under the Company' proposed Average and Peaks Method, the Residential Service Classification is allocated approximately $58 million of the $106 million in costs for Account 555 Purchased Power. The Large Power Service Class receives a $9.8 million allocation. The result of this allocation method shows that the Residential Class is deficient -- a -3.7 percent rate of return compared to the overall average of 6.2 percent -- and the Large Power Service is providing a return well above the average -- a 34.4 percent return compared to the overall average of 6.2 percent.

If an energy allocation was used, however, the Residential Service Classification would receive an allocation of $53 million and the Large Power Service would receive an allocation of $13.1 million. The change in the allocation is large enough to drive the indicated rate of return for the Residential Service Classification from a negative to a positive and for the Large Power Service from a large positive to a small negative. Account 555 is not the only account that is allocated on the Average and Peaks Method. As noted previously, Account 565 is as well but also all production related plant and transmission related plant.

I am not advocating that all of the purchased power costs be allocated on an energy basis. I am pointing out that this one assumption on how to allocate the largest costs of the utility drives the results of the whole cost of service study. To properly take the results of this into account, therefore, one needs to either entirely exclude all generation costs from the cost of service study or thoroughly analyze individual cost components that make up

purchased power so as to understand if they are demand-related or customer-related. Given that the Average and Peaks assumption drives so many of the other allocation factors, the first option cannot be easily done. The second option is essentially what Staff Witness Smith is advocating that a new mechanism for the PPFAC be studied and implemented for the Company. Until such time that the new mechanism is in place, I recommend that the results of the CCOSS not be used for revenue allocation purposes and that any revenue increase is allocated on an equal percentage basis.

Q. Does this recommendation have any impacts on rate design?

A. Yes, as shown on Schedule H-2, page 2 of 2, the Company is proposing to allocate the base power supply amongst service classifications per the results of its cost of service study. Together with Company Witness Erdwurm's recommendation that all purchased power costs be recovered in base rates (Erdwurm, page 21), the assumptions in the cost of service study have a direct impact on the rate design per service classification. Given my recommendation that the results of the cost of service study not be used to reallocate revenues amongst classes, I am also recommending that the results of the cost of service study not influence the design of rates. This is in agreement with Staff Witness Smith's recommendation that the roll-in of the PPFAC not be done without further study. How this recommendation impacts the results of the individual rates for each service classification will be discussed in the rate design section of my testimony.

RATE DESIGN

Q. How is the Rate Design Section of your testimony organized?

A. Given the number of proposed rate design changes and the fact that some of them impact several service classifications, I will first comment on the proposed changes and then follow with a discussion of the Staff's recommended rates bill impacts for each service

classification. The base power supply costs for each rate class were unbundled from the delivery service charge except for the Lighting Class. It is impractical to unbundle power supply from an un-metered service classification. The rates and bill impacts are shown on Attachments FWR-2 and FWR-3 respectively. The Staff Proof of Revenue is shown on Attachment FWR-4.

A. Time of Use Rates

Q. Please address the issue of time of use rates ("TOU Rates").

A. The Company is proposing to include TOU rates to provide a stronger price signal to customers to shift load out of the critical peak period. Reducing peak means that less power will be needed when it is most costly. Consequently, less power will have to be purchased from the spot market during peak times. This will result in savings for the Company and its customers. TOU customers who "shave" the peak and "fill in" the off-peak valleys reduce the average price that they pay for electricity. (Erdwurm, page 17).

The Company's proposal is to require TOU rates for all new residential, small general service, and large general service (4000 kW) customers and all new and existing Large Power Service customers.

Q. Do you agree with the Company's proposal?

A. No. While it is true that TOU rates can provide price signals to customers to shift load, not all customers can or will want to do that. In order to make economic sense, a customer should only shift power to off-peak periods when the price differential is large enough to pay for the cost of the new meter. In general, customers with large energy use have the best opportunity to move enough power to off-peak periods to save money and also pay for the new meter. For example, for a meter with a cost of $200 and a carrying

charge of 15 percent, the incremental annual cost of a new meter is approximately $30 per year. Using the Summer On-Peak/Off-Peak differentials proposed by the Company (Exhibit DBE-1) for the residential service classification, a customer would have to move over 2,200 kWh of energy during the summer months from on-peak to off-peak. This equates to a shift of almost 400 kWh per month. However, the billing data provided by the Company shows that 30 percent of all bills are for less than 400 kWh in total. In fact, almost 92 percent of all bills are for usage of less than 2,000 kWh per month (Schedule H-5, page 1 of 7). Since most bills are for relatively small amounts of energy, it is very doubtful that the customers could move enough energy from the on-peak period to the off-peak period to justify the meter expense. That said, these are the types of customers who would most likely benefit from a TOU rate design. While only 8 percent of bills are for usage above 2,000, this small amount of bills accounts for over 25 percent of all sales to the Residential Service Classification. These customers are the ones most likely to be able to shift a large amount of usage and a vigorous customer education program should be initiated to get these customers to volunteer to move to TOU rates.

The Small General Service Classification is similar to the Residential Customers. Using the $200 meter example from above, based on the Company's proposed on-peak/off-peak price differential, a customer would have to shift over 2,100 kWh during the summer period to pay for the meter. This equates to a shift in monthly energy use of just over 350 kWh per month. For this service classification, almost 39 percent of all bills are under 400 kWh per month and 84 percent of all bills are for usage under 2,000 kWh per month (Schedule H-5, page 3 of 7). The 16 percent of the bills that are above 2,000 kWh per month account for 49 percent of all usage from the service classification. Again, if this small amount of customers could be tapped, there might be a great potential for shifting usage.

B. Time of Use Periods

Q. Please comment on the Company's proposed determination of TOU periods.

A. The Company is proposing that the Summer Period (May-October) peak be from 2 p.m. to 6 p.m. with a shoulder period on either side of the peak period (Noon to 2 p.m. and 6 p.m. to 8 p.m.), resulting in a total of four hours in the shoulder. Consequently, sixteen hours of each summer day are not peak under UNS's proposal. For the Winter Period (November-April), the Company is proposing a morning peak (6 a.m. to 10 a.m.) and an evening peak (5 p.m. to 9 p.m.), for a total of eight hours per day of winter on-peak. There is no shoulder in the winter. Consequently, sixteen hours of each winter day are also not peak. The Company states that large numbers of off-peak hours offer convenient opportunities for customers to shift usage out of peak and shoulder periods (Erdwurm, page 19).

The Company's proposal is reasonable. The proposed summer peak/shoulder period is sometimes referred to as the super-peak and consists of the hours when energy costs are at their highest. Having a shoulder period within that time frame is an additional benefit because it still encourages customers to move usage away from the Company's peak demand which generally occurs around 4 p.m. As such, even if customers can't move usage to the off-peak period they still might be able to shift usage to the shoulder period which would be a benefit for transmission and capacity planning.

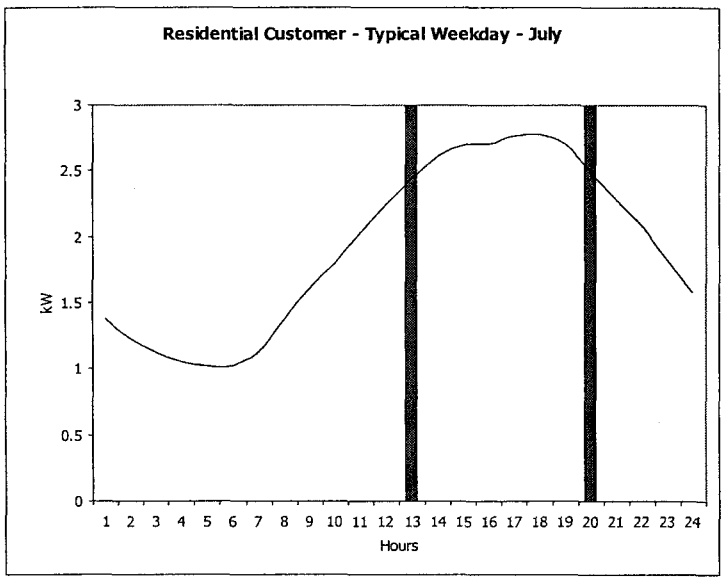
Q. Have you reviewed the TOU time periods of other Arizona utilities?

A. Yes. I examined the TOU rate periods for Arizona Public Service ("APS") and the Salt River Project ("SRP"). APS has two residential TOU options. Schedule ECT-1R has a peak period of 9 a.m. - 9 p.m. Schedule ECT-2 has a peak of 12 noon to 7 p.m. SRP has a peak period of 1 p.m. to 8 p.m. UNS is proposing a shoulder and peak period - Shoulder

is 12 noon to 2 p.m. and 6 p.m. to 8 p.m. and a peak of 2 p.m. to 6 p.m. Thus, the total shoulder and peak period proposed where ratepayers are given a higher price signals is from 12 noon to 8 p.m.

While the total time periods are similar to those being used by other Arizona utilities, the UNS proposal is superior because it introduces a shoulder period that gives customers even more flexibility to move load from the peak period (usually 4 p.m. or 5 p.m. for UNS) to the off-peak period or a shoulder period which both saves them money in the short run and broadens the peak for long-term capacity purchases. To illustrate the difficulty that customers might have in shifting load out of the longer on-peak period, below is the usage for a typical UNS customer during July. The vertical bars indicate the beginning and end of the peak period for SRP. As can be seen most of the usage occurs in that seven-hour period, with the peak occurring at 6 p.m. This is intuitive since that's when most people get home. It may be difficult, or troublesome, for most people to shift usage out of the peak period in order to take advantage of lower cost power. For example, since many people with small children find it difficult to change dinner time and some don't want to hear the dishwasher running during prime time, they refrain from taking advantage of lower prices and shifting usage. The introduction of a shoulder period, however, gives more flexibility and can still garner great benefits. For example, as shown on the graph, the typical UNS residential customer uses 2.8 kW between 5 p.m. and 6 p.m. But between 12 p.m. and 1 p.m., the typical usage is 2.4 kW or 14 percent less than the peak period. There is still a large amount of difference and if all of the roughly 77,000 residential customers shifted just half the difference (e.g. through pre-cooling the house before they came home), it would result in a peak usage reduction of almost 15 MW or 3.7 percent of UNS' peak load. Similarly, if these same customers could shift this usage to the 7 p.m. to 8 p.m. time frame when the typical usage is 2.5 kW, the same shifting of half

the difference (e.g. running the dishwasher at the time) the shifted usage would result in a shift from peak usage of 12 MW or 2.8 percent of peak. While I don't expect that every residential customer will volunteer for TOU rates and UNS will see these results, the examples do indicate that the addition of shoulder periods do provide the opportunity to realize real benefits from them being there.



C. Time of Use Rate Differentials

Q. Please comment on the Company's proposed time differentiated rate differentials.

A. While I recognize that these differentials may change with adjustments to the Company's PPFAC mechanism, they were reasonably developed and give the proper price signals to customers to switch usage to the off-peak period.

D. Inclining Block Rate Structure

Q. Please discuss the Company's proposal for an inclining block rate structure for the residential and small general service customers.

A. The Company is proposing the introduction of an inverted (or inclining) block structure aimed at encouraging conservation. Residential and small general service customers would now be able to purchase their first 400 kWh per month at a one-cent per kWh discount relative to the second block of consumption (over 400 kWh per month). The Company states that this rate structure would reward customers who are able to conserve for their efforts to conserve electricity. (Erdwurm, page 19).

I agree with this recommendation in principle to give customers some price signal to reflect that the more they use, the more it costs to serve. However, the introduction of the inclining block rates at this time was impractical given the relatively small recommended rate increase and the increases in the customer charge. For instance, for the Small General Service class almost all of the recommended rate increase was recovered through the increase in the customer charge. To implement an inclining block rate structure, in addition to the increases in customer charges, would have resulted in a wide variety of rate impacts, with some customers receiving decreases and some customers receiving increases, that could lead to unnecessary customer confusion. Thus, while implementing inclining block rates in the current case does not appear to be desirable for the practical considerations described above, I would recommend that an inclining block rate design be re-evaluated in the context of the Company's next rate case.

E. Elimination of Separate Rates for Mohave and Santa Cruz

Q. Please discuss the Company's proposal to eliminate separate rates for Mohave and Santa Cruz Counties.

A. As noted in the testimony of Company Witness Erdwurm, rates that differ across a service area are sometimes the result of a prior merger of utility systems. Separate rate structures initially may help avoid "rate shock" associated with an immediate movement to system-wide rates. Mr. Erdwurm suggests that these separate rates should be transitional, not permanent. (Erdwurm, page 20).

While Mr. Erdwurm is correct that the rates should be transitional since the Company is now operating and supplying service as a single entity, "rate shock" should never be ignored but tempered against the goal of uniform rates. In this case, there exists a differential in the energy charge of approximately 0.44 cents per kWh in the energy rates for the Residential and Small General Service Classifications with Mohave County being the less expensive. For a customer using 400 kWh per month in Santa Cruz County, the bill is $45.52 and for a customer in Mohave County the month bill is $43.76. For a customer using 1,000 kWh per month, the monthly bill for a customer in Santa Cruz County is $104.05 per month and $99.65 per month in Mohave County. Given that the current absolute dollar differential in the customer's bill is small, that costs for the Company as a whole are increasing and the relatively small overall rate increase being recommended, it is my position that a complete elimination of the differential not be made at this time. Rather, after increasing the customer charge applicable to customers in both counties as described above in order to give the price signal to customers that costs are increasing, my proposed rate design then left energy rates for Santa Cruz customers at their current levels and recovered the remaining rate increase from the energy charge of the Mohave County customers. This recommendation avoids decreasing the per-kWh

charge to Santa Cruz customers and also accomplishes the objective of decreasing the current Santa Cruz-Mohave rate differential significantly for the Residential Service Class to $0.003 per kWh and for the Small General Service Class to $0.043 per kWh. These remaining Santa Cruz-Mohave rate differentials could then presumably be eliminated altogether in the Company's next rate case.

F. Resetting the PPFAC to Zero

Q. Please comment on the Company's proposal to reset the PPFAC to zero, increase base rates for power supply, and separate the rates for the delivery and power supply components.

A. Per the problems outlined by Staff Witness Smith and noted in the CCOSS section of my testimony, it is premature to make this change at this time. The current PPFAC structure reflects costs under the Company's current power supply contract. As such, no change is necessary until a new power supply arrangement is known. Since the current power supply contract will not expire until May 31, 2008 that time is not now. In addition Staff Witness Smith's recommendation that the roll-in of the PPFAC not be done without further study of how the PPFAC mechanism should work heightens my concern that the Company's proposal is premature. The rates have been re-designed to separately show the power supply costs that are currently in base rates.

G. Customer Charges

Q. Please comment on the company's proposed customer charge increases.

A. Per Company witness Erdwurm, the Company is asking to set customer charges at cost-based levels indicated in the CCOSS. The Company states this will help avoid the subsidization of low use customers by high use customers. While the Company understands that conservation of energy is an important policy goal, this must also be

balanced with the ratemaking principle that those who cause costs should pay a reasonable share of those costs. The Company states that it seeks to strike this balance through its inverted block rate design and its proposed customer charges. The Company states that its proposed changes to the customer charges result in increases of no more than $2.00 per month. (Erdwurm, page 22).

While the CCOSS presented by the Company does justify the increase in the customer charge proposed for most service classifications, it should also be noted that a large portion of the costs allocated to the customer component is for line transformers. The 1992 NARUC Electric Utility Cost Allocation Manual recognizes that there are various ways to allocate the distribution costs between a demand component and a customer component and it believes that the most accurate method is the use of the minimum intercept method. Under this method, a regression calculation is performed to determine the amount of equipment necessary to just supply service to a customer that uses no power. The zero intercept gives the percent breakdown of costs that should be classified as customer costs. This method would not assign all line transformer costs to the customer component and would tend to reduce the amounts calculated by the Company. That said, the minimum intercept method also applies to other equipment such as poles and services. Under the Company's method, poles are not a customer component and if included would tend to increase the costs calculated by the Company. These effects might offset each other, but it is not known. I recommend that the Company be directed to use both methods in its next cost of service study so as to determine the difference. In the meantime, I recommend using the customer component calculations as presented by the Company.

In designing rates, one must always recognize that setting cost based rates must be tempered against large increase to individual customers. When a utility gets a modest rate increase of say 3 percent and a customer sees a rate increase of 10-15 percent in the customer's own bill, it causes confusion and sometimes resentment at both the utility and the regulatory body. In my experience, when one limits increase or decrease to individual service classification and segments of those customers, customer acceptance of changes increases.

H. Demand Charges for Large General Service and Large Power Service

Q. Please discuss the Company's proposed demand charges for Large General Service and Large Power Service.

A. As testified to by Company Witness Erdwurm, the current demand charge for Large Power Service ("LPS") for service at less than 69 kV is $24.75 / kW-mo. For LPS at service greater than or equal to 69 kV, the demand charge is $16.10 / kW-mo. For Large General Service the current demand charge is $9.50 / kW-mo. According to Mr. Erdwurm, the differentials between these charges are currently overstated, based on costs (Erdwurm, page 23).

The CCOSS does not breakdown cost of service data for the LPS >69 kV or <69 kV. In discovery, I asked the Company to provide the cost basis for its proposal and any associated workpapers or cost studies used to support it. None were given. In addition, the Company's proposal on demand charges appears to be influenced on its proposal to roll all PPFAC costs into base rates. For example, the current energy charges for LPS less than 69 kV total $0.0418 per kWh as compared to the proposed new power supply component proposed of $.0527 per kWh. Since the overall energy charge is increasing by almost 25% it only makes sense that the demand charge would decrease. In fact, the

Company proposed that the demand charge for LPS less than 69 kV be decreased from $24.75 per kW/month to $21.53 per kW/month. Given the lack of justification on the Company's part, I recommend no realignment of the demand charge differentials at this time.

I. CARES Discount

Q. Please discuss the Company's proposal for the CARES discount.

A This program allows qualified low income customers to receive discounts. Specifically, the current program provides declining percentage discounts for participating customers, with a flat $8.00 discount for usage over certain thresholds (1,000 kWh for CARES customers and 2,000 kWh for Medical CARES customers). The Direct testimony of Staff Witness Julie McNeely-Kirwan recommends that the Company's proposal to change the structure of the CARES discount be rejected and the current discount structure be retained. Retaining the current discount method results in an immediate loss of revenue to the Company on the Staff recommended revenue requirement. The lost revenue is less than $11,000 and is recovered through the rates of all other customer classes. Recovery of CARES lost revenue is reflected in Staff's Proof of Revenue.

J. Threshold for Large General Service

Q. Please comment on the Company's proposal to increase the threshold that causes Small General Service customers to be moved to Large General Service.

A. As explained by Company Witness Erdwurm, Small General Service customers are automatically switched to Large General Service if their usage exceeds 5,000 kWh per month for two consecutive months. When this is done, these customers often end up paying substantially more under the LGS rate, even though the costs to serve them do not rise significantly. Changing the threshold to 7,500 kWh per month will help avoid these

automatic switches. Mr. Erdwurm states that customers have expressed concern to the Company about the current threshold, and the Company agrees and recommends the threshold increase (Erdwurm, page 23).

The Company's proposal is reasonable. A small general service customer that uses 10,000 kWh per month currently pays approximately $940 per month while under the Large General Service Class it would pay approximately $1,200 per month or 28% higher. Given that there is no change in the physical service being provided to the customer, there is no justification for the increased costs. The Company's proposal should be adopted.

K. Synchronization of Billing Determinants

Q. Did you encounter any issues with the actual design of the rates?

A. Only one that involved the synchronization of billing determinants between the revenue requirement determination and the rate design. The company made two adjustments to the test year revenues that affected billing determinants; one for customer count and one for weather normalization. These adjustments impact not only the revenue requirement but also the billing determinants to design rates. I reviewed the Company's calculations and they appear reasonable. However, when I priced out the present rates at the billing determinants provided by the Company, they did not exactly match the target revenue requirement. Some classes were too high, and some classes were too low. On a Company-wide basis, the present rates would provide revenues of $157.8 million compared to the target level of $156.7 million. While this is a small difference, 3/4 of one percent, and can be caused by a number of reasons given all the assumptions that go into the calculation, it is important to design rates that will actually produce the intended revenue increase. Otherwise the Company will over-collect or under-collect its revenue requirement. A simple mechanism to ensure that this does not happen is to restate the test

year billing determinants so that they agree with the test year revenue target. I did this and then proceeded to design rates to correspond with the Staff recommended revenue requirement.

L. Recommended Rate Design and Related Customer Bill Impacts

Q. Please discuss your recommended rate design and the related customer bill impacts.

A. In the case of the Residential Service Class, I recommend increasing the customer charge from $6.50 per month to $7.50 per month, an increase of $1.00 per month, or a 15.4 percent increase. The CCOSS indicated a monthly customer cost of $12.63 but I wanted to limit the increase to mitigate rate impacts. The energy rate for Santa Cruz County was left unchanged and the portion of the revenue requirement not recovered through the increase in the customer charge was recovered in the energy rate for Mohave County. The bill impacts resulting from this design are shown on page 1 of Attachment FWR-3. For a customer in Mohave County, the minimum bill will increase by $1.00 per month, 15.4 percent, and 2.5 percent for a customer using 1,000 kWh per month. Page 1 of Attachment FWR-3 also shows the bill impacts for customers in Santa Cruz County. The minimum bill will increase by $1.00 per month, 15.4 percent, and 1.0 percent for a customer using 1,000 kWh per month.

Q. Does your recommended rate design reduce the rate differentials between Mohave and Santa Cruz?

A. Yes. The recommended rate design reduces, but does not eliminate, the current rate differentials between Mohave and Santa Cruz. The difference in total electric bills for customers in Mohave and Santa Cruz Counties having the same monthly usage are decreasing significantly under this rate design. As an example, a residential customer in Santa Cruz County using 1,000 kWh per month would have a monthly bill of $105.05 at

proposed rates. A residential customer in Mohave County using 1,000 kWh per month would have a monthly bill of $102.19. The differential in bills under proposed rates is $2.86. This compares to the current rate differential of $4.40 per month (Santa Cruz of $104.05 less Mohave of $99.65).

Q. Please explain Staff's proposed rate design for Residential CARES customers.

A. The rate design for the CARES discount remains unchanged; customers continue to receive declining percentage discounts off their bills, with a flat $8.00 discount for usage over certain thresholds. On page 2 of Attachment FWR-3, the bill impacts show that for a customer in Mohave County the minimum bill will increase by $0.70 per month, or 15.4 percent, and $2.01, or 2.8 percent, for a CARES customer using 800 kWh per month. Also, on page 2 of Attachment FWR-3 are the bill impacts for CARES customers in Santa Cruz County. As shown, the minimum bill will increase by $0.70 per month, or 15.4 percent, and $0.90, 1.2 percent, for a CARES customer using 800 kWh per month.

Q. Please explain your proposed rate design for Small General Service customers.

A. For the Small General Service Class, I recommend increasing the customer charge from $10.00 per month to $12.00 per month, an increase of $2.00 per month, or a 20 percent increase. The CCOSS indicated a monthly customer cost of $17.74, but I wanted to limit the customer charge increase to mitigate rate impacts. The energy rate for Santa Cruz County was left unchanged and the portion of the revenue requirement not recovered through the increase in the customer charge was recovered in the energy rate for Mohave County. The bill impacts resulting from this design are shown on page 3 of Attachment FWR-3 and show that for a customer in Mohave County the minimum bill will increase by $2.00 per month, 20 percent, and $3.02, 2.9 percent, for an average customer using 1,000 kWh per month. Also shown on page 3 of Attachment FWR-3 are the bill impacts for

customers in Santa Cruz County. As shown, the minimum bill will increase by $2.00 per month, 20 percent, and $2.00, 1.4 percent, for an average customer using 1,000 kWh per month.

The difference in total bills for customers in Mohave and Santa Cruz Counties decreases under this rate design. For the customer using 1,000 kWh per month, the differential in bills under current rates is $43.80 per month – Santa Cruz being higher. The recommended rate design reduces the bill differential to just under $42.77 per month. I believe a gradual approach to reducing the billing differentials, and avoiding rate decreases is preferable to the Company's proposal. Under the proposed rate design, customers in each county still receive an increase which signals to them that the cost of providing electric service is increasing. For customers in Mohave County, the rates overall are increasing by 2.9 percent and for customers in Santa Cruz County the rates overall are increasing by 1.5 percent.

Q. Please explain your proposed rate design for Large General Service customers.

A. For the Large General Service Class, I recommend that the customer charge be set at $15.50 per month for both the non-TOU and TOU rates. For a non-TOU customer, the customer charge increases by $5.40 per month from its current level of $10.10 per month. For a TOU customer, the customer charge increases by $0.50 per month from its current level of $15.00 per month. Each of these charges is somewhat below the indicated cost to serve of $74.61 per month. I elected not to raise the customer charge to the level indicated by the CCOSS but rather collect the revenue requirement in the demand charge. This rate design continues to give the utility steady cash flow but also encourages customers to conserve energy. The energy charge is eliminated with the base power supply cost being unbundled.

The bill impacts shown on Page 4 of Attachment FWR-3 are acceptable with the smallest users, 5,000 kWh per month, in the non-TOU rate class receiving a 3.5 percent rate increase and the largest users, 500,000 kWh per month, receiving a 2.5 percent increase. For the TOU rate class, the smallest users, 5,000 kWh per month, receive a 2.5 percent rate increase and the largest users, 500,000 kWh per month, receive a 2.5 percent increase.

Q. Please explain your proposed rate design for Large Power Service customers.

A. As noted previously, for Large Power Service the CCOSS indicates that the customer component is $2,140 per month (Schedule G-6, page 3 of 4, line 19, column 5). Although the Company's CCOSS shows a customer charge of $2,140 per month for this rate class, the Company is proposing to keep the customer charge for service at less than 69 kW at $365 per month and decreasing the charge from $800 per month to $400 per month for service above 69 kV. To avoid undue bill impacts, I recommend that the Company's proposal be allowed at this time but the customer charge levels should be reviewed for adequacy in the next rate case The Company provided no justification for changing the differential by voltage level in the demand charge for this class; I retained it. In order to unbundle power supply the existing energy charge of $0.236 per kWh was reduced to zero. The revenue requirement not recovered through the increase in the customer charge is recovered in the demand charge.

This rate design decreases the demand charge for customers taking service at less than 69 kV from $24.75 per kW to $10.51, a 58 percent decrease. For a customer taking service at 69 kV and above, the demand charge decreases from $16.10 per kW to $1.86 per kW, an 89 percent decrease. Since the power supply is being stated separately, the cumulative energy charges increase. For all customers in the class the total energy charge (energy

rates, base power supply and PPFAC) increases from $0.04185 per kWh to $0.07019 per kWh, a 68 percent increase.

On balance, however, the bill impacts shown on page 5 of Attachment FWR-3 are acceptable with the smallest users, 300,000 kWh per month, in the <69 kV rate class receiving a 0.5 percent rate increase and the largest users, 2,500,000 kWh per month, receiving a 0.5 percent increase. For customers taking service at >69 kV and above, the smallest users, 300,000 kWh per month, in the non-TOU rate class receiving a 3.1 percent rate increase and the largest users, 500,000 kWh per month, receiving a 3.2 percent increase. The customers taking service at >69 kV and above get a slightly higher rate increase as they have a higher load factor (more energy intensive).

Q. Please explain your proposed rate design for Interruptible customers.

A. I recommend that the customer charge be set at $15.50 per month up from its current level of $10.10 per month. The current customer charge is the same as the non-TOU Large General Service Class. The recommended customer charge is also the same as being recommended for the Large General Service class. The recommended customer charge is well below the indicated cost to serve of $46.00 per month. I elected not to raise the customer charge to the level indicated by the CCOSS but rather collect the revenue requirement in the demand charge. This rate design continues to give the utility steady cash flow but also encourages customers to conserve energy. The energy charge is eliminated and replaced with the base power supply charge. The resultant demand charge increases from its current level of $2.50 per kW to $3.40 per kW.

The bill impacts shown on page 6 of Attachment FWR-3 are acceptable with the small users, 10,000 kWh per month, receiving a 2.7 percent rate increase and the large users, 150,000 kWh per month, receiving a 2.1 percent increase.

Q. Please explain your proposed rate design for the Lighting Service Class.

A. No cost information was provided that would indicate that the current cost structure needs to be changed. The Company included a new customer charge of $1.84 per month but gave no justification for it, so I recommend it be rejected. To meet revenue requirement all rates were increased by the class average increase of 2.4 percent. As noted previously the rates for this class cannot have a separate base power supply charge as their usage is un-metered. A comparison of present and proposed rates is shown on page 7 of Attachment FWR-3.

MISCELLANEOUS SERVICE FEES

Q. Please discuss the Miscellaneous Service Fees proposed by UNS Electric and your recommendations for such fees.

A. Staff supports adopting the Miscellaneous Service Fees proposed by UNS Electric. The Miscellaneous Service Fees proposed by UNS Electric, as summarized in the following table, appear to be reasonable. The proposed fees are supported by the Company's cost data with the exception of the Reconnection or Connection of Service after Normal Business Hours and After Hours of Service Establishment/Re-establishment (includes weekends and holidays). The Company's cost data, which was provided in response to RUCO 1.10, for Reconnection or Connection of Service after Normal Business Hours and After Hours of Service Establishment/Re-establishment (includes weekends and holidays) shows a cost of $126.66 as opposed to the $75 rate proposed by the Company. However, cost of service information is not the only basis for establishing rates. The Company's

proposal to raise these fees from the current level of $60 to the proposed level of $75 reflects a gradual approach to implementing rate changes, which is supported by Staff. The proposed $75 after-hours charge reflects a 25 percent increase over the current charge of $60. Additionally, the proposed after-hours charge of $75 is 150 percent higher than the charge for comparable service performed during regular business hours. The other Miscellaneous Service Fees proposed by the Company are supported by the cost data and should also be adopted as proposed by UNS Electric and Staff:

	STATEMENT OF ADDITIONAL CHARGES	Test Year Fees	Test Year Revenues	Units	Company Proposed Fees	Increased Revenue	Staff Proposed Fees	Increased Revenue	Difference
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
A.	Establishment/Re-establishment of Service	$20.00	$497,235	24,862	$30.00	$248,617	$30.00	$ 248,617	$ -
B.	Reconnection or Connection of Service During Normal Business Hours per Section I	$20.00	$43,800	2,190	$30.00	$21,900	$30.00	$ 21,900	$ -
C.	Reconnection or Connection of Service After Normal Business Hours per Section I	$60.00	$25,568	426	$75.00	$6,392	$75.00	$ 6,392	$ -
D.	After Hours of Service Establishment/Re-establishment (includes weekends and holidays)	$60.00	$32,820	547	$75.00	$8,205	$75.00	$ 8,205	$ -
E.	Meter Reread per Section III	$15.00	$930	62	$20.00	$310	$20.00	$ 310	$ -
	TOTAL ADJUSTMENT TO SERVICE REVENUES					$285,424		$285,424	$0

Source: RUCO 1.10, Income - Service Fees

C&D: Although the Company's cost of service evaluation shows a cost of $126.66 for after hours reconnection and service establishment, the Company and Staff proposed increases to these rate elements reflect a gradual approach to increasing the rates.

BLACK MOUNTAIN GENERATING STATION

Q. Please discuss the Company's proposed rate change relating to Black Mountain Generating Station.

A. The Company proposes to implement a reclassification of rates effective June 1, 2008, or at a later date based on commercial operation, associated with a post test year adjustment to rate base for the BMGS. This proposal is presented in the Direct Testimony of Kevin P. Larson. As a practical matter, this change will have no initial impact on what the customer pays; an average increase in the delivery charge of 0.6 cents/kWh is offset by a decrease in the power supply charge of 0.6 cents/kWh. No change in rate design would be

necessary since the Company is proposing simply to move a portion of the base power supply charge to the base delivery charge on a volumetric basis (per kWh).

Q. Does this conclude your direct testimony?

A. Yes, it does.

Attachment FWR-1

Qualifications of
FRANK W. RADIGAN

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EDUCATION

B.S., Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

SUMMARY OF PROFESSIONAL EXPERIENCE

1998–Present **Principal, Hudson River Energy Group, Albany, NY** -- Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues. Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements. Perform depreciation studies, conservation studies and proposes feasible conservation programs.

1997–1998 **Manager Energy Planning, Louis Berger & Associates, Albany, NY** – Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply.

1981–1997 **Senior Valuation Engineer, New York State Public Service Commission, Albany, NY** – Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

FIELDS OF SPECIALIZATION

Hudson River Energy Group

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies. Wholesale power system modeling with GE-MAPS.

PROJECT HIGHLIGHTS

Wholesale Commodity Markets

Transmission Expansion Planning – Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool – the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

Locational Based Pricing – Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

Merchant Plant Analysis – Confidential client – Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract. 2002

Market Price Forecasting – El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract. 2002

Market Price Analysis – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

Gas Aggregation – Village of Illion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

Gas Procurement – Albany County, New York – Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply. 2000

HQ Prudence Review – Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation. 1998

Wholesale Power Supply – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

Analysis of Load Pockets and Market Power – Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

Study of IPP Contracts and Impacts in New York Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity; determined level of non-optimal reserves for each utility. 1995

Power Purchase Contract Policies and Procedures – Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD); forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

Integrated Resource Planning - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

Intrastate Wheeling Commission Transmission Analysis and Assessment – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

Rate Setting

Economic Development Rate – Massena Electric Department – For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Study – Pascoag Utility District – Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers. 2003

Rate Study - Kennebunk Power and Light Department – Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

Rate Case Cost of Service Study – Village of Arcade, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Philadelphia, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Case Cost of Service Study – Fillmore Gas Company – For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Rowlands Hollow Water Works – For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Standby Rates – Independent Power Producers of New York – Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs; participated in settlement negotiations for new rates. 2002

Economic Development Rates – Pascoag Utility District – Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality. 2002

Municipalization Study – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served; performed valuation of the plant currently owned by Central Maine Power. 2001

Water Rate Study – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement. 2001

Pole Attachment Rates – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

ISO Service Tariff -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO Service Tariffs. 2000

Pole Attachment Rates – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers. 1999

OATT Rates – On behalf of four municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates; represent utilities before ISO New England committees on transmission rate setting issues. 1998-2004

Consolidated Edison Restructuring – Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by $700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation; established customer education programs on restructuring; established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

Cost-of-service Review and Rate Unbundling – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

Vintage Year Salvage and Study - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates. 1985

Environmental Issues

Energy Conservation Study – Pascoag Utility District – Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002

Clean Air Act Lawsuit – New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002.

Environmental Impact Study and Simulation Modeling Analysis – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

Renewable Resources – Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

Environmental and Economic Impacts Study – Directed study of pool-wide power plant dispatch with environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders. 1994

Clean Air Impact Study – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reduction control facilities were elected to comply with 1990 Clean Air Act Amendments; installed components on units in metropolitan NY region. 1994

Environmental Externalities and Socioeconomic Impacts Study – Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes: explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

EXPERT WITNESS TESTIMONY

Case 05-S-1376 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of he method of allocating costs between the utility's steam system and its electric system. 2006

Docket No. 06-48-000 – Braintree Electric Light Department – On behalf of the municipal utility presented an cost of service study used to calculate the annual revenue requirement for a generating station that was deemed to be required for reliability purposes.

Case 05-E-1222 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed average service lives, forecast net salvage figures, and proposal to switch from whole life to remaining life method. 2006

Docket No. 05-10004 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed electric depreciation rates and expense levels. 2006

Docket No. 05-10006 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed gas depreciation rates and expense levels. 2006

Docket No. ER06-17-000 – ISO New England, Inc. – On behalf of a group of municipal utilities in Massachusetts prepared an affidavit on the reasonableness of proposed changes to the Regional Network Service transmission revenue requirements rate setting formula. 2005

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study. 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service. 2004

Docket No. 04-3011 – Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Docket No. ER03-563-030 -- Devon Power, LLC, *et al.* – On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England.

Docket No. 03-10002 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 – Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant. 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners – Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No. 2930 – Narragansett Electric – Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No. 03-07-01 – Connecticut Light and Power Company – Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No. ER03-1274-000 – Boston Edison Company – Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels. 2003

Case 210293 – Corning Incorporated – Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 – Nucor Steel Auburn, Inc. – Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 – Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers. 2003

Case 00-M-0504 – New York State Electric and Gas Corporation – Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates. 2002

Docket No. TX96-4-001 – On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 – Consolidated Edison: Electric Rate Restructuring – On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 – Petition of New York State Electric & Gas – Multi-Year Electric Price Protection Plan – Addressed reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 – Joint Petition of Co-Owners of Nine Mile Nuclear Station – Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG. 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of ISO's proposed $4.75/kW/month Installed Capability Deficiency Charge. June 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed Installed $0.17/kW/month Capability Deficiency Charge. January 2001

Docket No. 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates. 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates

proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et. al. – New England Power Pool: OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District: Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment. 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of $400 million. Directed team in review of resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer. Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison: Gas Rates – Testified on reasonableness of utility's proposed depreciation rates. 1994

Case 93-S-0997 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system. 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate plan proposed by the utility. 1994

Case 94-E-0098 – Niagara Mohawk: Electric Rates – Reviewed utility's management of its portfolio of power purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates. 1994

Case 93-E-0807 – Consolidated Edison: Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison: Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric: Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric: Electric Rates – Review of utility's historic and forecast O&M expenditure levels, forecast and rate treatment of profits from wholesale power, and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast; forecast and rate treatment of profits from sales of wholesale power; estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric: Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers. 1984

PRESENTATIONS

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers.

IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future: Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities.

MEMBERSHIPS/ASSOCIATIONS

Member American Public Power Association, Northeast Public Power Association and New York State ISO.

UNS Electric, Inc.
Comparison of Present and Staff Proposed Rates
Test Year Ended June 30, 2006

	Present Rate	Proposed Rate	Increase $	Increase %
Residential Service Delivery Charges - Mohave County				
Customer Charge	$6.50	$7.50	$1.00	15.4%
Energy Charge, first 400 kWhs	$0.074900	$0.024497	-$0.0504	-67.3%
Energy Charge, all additional kWhs	$0.074900	$0.024497	-$0.0504	-67.3%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Residential Service Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Residential Service Delivery Charges - Santa Cruz County				
Customer Charge	$6.50	$7.50	$1.00	15.4%
Energy Charge, first 400 kWhs	$0.079300	$0.027360	-$0.0519	-65.5%
Energy Charge, all additional kWhs	$0.079300	$0.027360	-$0.0519	-65.5%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Residential Service Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Residential Time of Use Rates, all kWhs				
(These rates would include all Delivery charges above and replace The Base Power Supply charge)				
Summer on-peak		$0.066130		
Summer Shoulder		$0.055750		
Summer off-peak		$0.051130		
Winter on-peak		$0.054820		
Winter off-peak		$0.039820		
Small General Service Delivery Charges - Mohave County				
Customer Charge	$10.00	$12.00	$2.00	20.0%
Energy Charge, first 400 kWhs	$0.074500	$0.023585	-$0.0509	-68.3%
Energy Charge, all additional kWhs	$0.074500	$0.023585	-$0.0509	-68.3%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Small General Service Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Small General Service Delivery Charges - Santa Cruz County				
Customer Charge	$10.00	$12.00	$2.00	20.0%
Energy Charge, first 400 kWhs	$0.118300	$0.066360	-$0.0519	-43.9%
Energy Charge, all additional kWhs	$0.118300	$0.066360	-$0.0519	-43.9%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Small General Service Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Small General Service Time of Use Rates, all kWhs				
(These rates would include all Delivery charges above and replace The Base Power Supply charge)				
Summer on-peak		$0.066550		
Summer Shoulder		$0.055860		
Summer off-peak		$0.051550		
Winter on-peak		$0.055650		
Winter off-peak		$0.040650		

UNS Electric, Inc.
Comparison of Present and Staff Proposed Rates
Test Year Ended June 30, 2006

	Present Rate	Proposed Rate	Increase $	Increase %
Large General Service Delivery Charges				
Customer Charge	$10.10	$15.50	$5.40	53.5%
Demand Charge, per kW	$9.50	$10.71	$1.21	12.7%
Energy Charge (kWhs)	$0.053300	$0.000000	-$0.05	-100.0%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Large General Service Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Large General Service TOU Delivery Charges				
Customer Charge	$15.00	$15.50	$0.50	3.3%
Demand Charge, per kW	$9.50	$10.71	$1.21	12.7%
Energy Charge (kWhs)	$0.053300	$0.000000	-$0.0533	-100.0%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Large General Service (TOU) Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Large General Service Time of Use Rates, all kWhs				
(These rates would include all Delivery charges above and replace The Base Power Supply charge)				
Summer on-peak		$0.067710		
Summer Shoulder		$0.056330		
Summer off-peak		$0.052710		
Winter on-peak		$0.055950		
Winter off-peak		$0.040950		
Large Power Service (<69KV) Delivery Charges				
Customer Charge	$365.00	$365.00	$0.00	0.0%
Demand Charge, per kW	$24.75	$10.51	-$14.24	-57.5%
Energy Charge (kWhs)	$0.023600	$0.000000	-$0.0236	-100.0%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Large Power Service (<69KV) Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Large Power Service (>69KV) Delivery Charges				
Customer Charge	$800.00	$800.00	$0.00	0.0%
Demand Charge, per kW	$16.10	$1.86	-$14.24	-88.5%
Energy Charge (kWhs)	$0.023600	$0.000000	-$0.0236	-100.0%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Large Power Service (>69KV) Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Large Power Service Time of Use Rates, all kWhs				
(These rates would include all Delivery charges above and replace The Base Power Supply charge)				
Summer on-peak		$0.068850		
Summer Shoulder		$0.056860		
Summer off-peak		$0.053850		
Winter on-peak		$0.056850		
Winter off-peak		$0.041850		

UNS Electric, Inc.
Comparison of Present and Staff Proposed Rates
Test Year Ended June 30, 2006

	Present Rate	Proposed Rate	Increase $	Increase %
Interruptible Power Service Delivery Charges				
Customer Charge	$10.10	$15.50	$5.40	53.5%
Demand Charge, per kW	$2.50	$3.40	$0.90	36.0%
Energy Charge (kWhs)	$0.053300	$0.000000	-$0.0533	-100.0%
PPFAC Charge	$0.018250	$0.018250	$0.0000	0.0%
Interruptible Power Service Base Power Supply Charge, all kWhs		$0.051940	$0.0519	N/A
Interruptible Power Service Time of Use Rates, all kWhs				
(These rates would include all Delivery charges above and replace The Base Power Supply charge)				
Summer on-peak		$0.068310		
Summer Shoulder		$0.056140		
Summer off-peak		$0.053310		
Winter on-peak		$0.055860		
Winter off-peak		$0.040860		
Lighting Dusk to Dawn Delivery Charges				
Existing Wood Pole - Overhead	$0.00	$0.00	$0.00	0.0%
New 30' Wood Pole (Class 6) - Overhead	$4.02	$4.12	$0.10	2.4%
New 30' Metal or Fiberglass - Overhead	$8.05	$8.25	$0.20	2.4%
Existing Wood Pole - Underground	$2.01	$2.06	$0.05	2.4%
New 30' Wood Pole (Class 6) - Underground	$6.04	$6.19	$0.15	2.4%
New 30' Metal or Fiberglass - Underground	$10.06	$10.30	$0.24	2.4%
Wattage, per Watt	$0.053040	$0.054331	$0.001291	2.4%

Utilites Division Staff Recommendation for UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006

Residential Service Delivery Charges - Mohave County	Present	Proposed
Customer Charge	$6.50	$7.50
Energy Charge, first 400 kWhs	$0.07490	$0.02450
Energy Charge, all additional kWhs	$0.07490	$0.02450
PPFAC Charge	$0.01825	$0.01825
Residential Service Base Power Supply Charge, all kWhs		$0.05194

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	$6.50	$7.50	$1.00	15.4%
50	$11.16	$12.23	$1.08	9.7%
100	$15.82	$16.97	$1.15	7.3%
200	$25.13	$26.44	$1.31	5.2%
400	$43.76	$45.37	$1.61	3.7%
500	$53.08	$54.84	$1.77	3.3%
800	$81.02	$83.25	$2.23	2.8%
1,000	$99.65	$102.19	$2.54	2.5%
2,000	$192.80	$196.87	$4.07	2.1%
2,500	$239.38	$244.22	$4.84	2.0%
5,000	$472.25	$480.94	$8.69	1.8%
10,000	$938.00	$954.37	$16.37	1.7%
Average Increase For Subclass				2.6%
Average Increase For Service Classification				2.4%
Overall Average Increase				2.4%

Residential Service Delivery Charges - Santa Cruz County	Present	Proposed
Customer Charge	$6.50	$7.50
Energy Charge, first 400 kWhs	$0.079300	$0.027360
Energy Charge, all additional kWhs	$0.079300	$0.027360
PPFAC Charge	$0.018250	$0.018250
Residential Service Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	$6.50	$7.50	$1.00	15.4%
50	$11.38	$12.38	$1.00	8.8%
100	$16.26	$17.26	$1.00	6.2%
200	$26.01	$27.01	$1.00	3.8%
400	$45.52	$46.52	$1.00	2.2%
500	$55.28	$56.28	$1.00	1.8%
800	$84.54	$85.54	$1.00	1.2%
1,000	$104.05	$105.05	$1.00	1.0%
2,000	$201.60	$202.60	$1.00	0.5%
2,500	$250.38	$251.38	$1.00	0.4%
5,000	$494.25	$495.25	$1.00	0.2%
10,000	$982.00	$983.00	$1.00	0.1%
Average Increase For Subclass				1.3%
Average Increase For Service Classification	$2.20	$1.43		2.4%
Overall Average Increase				2.4%

Residential Service Cares - Delivery Charges Mohave County	Present	Proposed
Customer Charge	$6.50	$7.50
Energy Charge, first 400 kWhs	$0.074900	$0.024497
Energy Charge, all additional kWhs	$0.074900	$0.024497
PPFAC Charge	$0.018250	$0.018250
Discount	Varies	Varies
Residential Service Cares Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Present Discount	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	30%	$4.55	$5.25	$0.70	15.4%
50	30%	$7.81	$8.56	$0.75	9.7%
100	30%	$11.07	$11.88	$0.81	7.3%
200	30%	$17.59	$18.51	$0.92	5.2%
500	20%	$42.46	$43.87	$1.41	3.3%
600	20%	$49.91	$51.45	$1.54	3.1%
800	10%	$72.92	$74.92	$2.01	2.8%
1,000	10%	$89.69	$91.97	$2.28	2.5%
2,000	$8.00	$184.80	$188.87	$4.07	2.2%
2,500	$8.00	$231.38	$236.22	$4.84	2.1%
5,000	$8.00	$464.25	$472.94	$8.69	1.9%
10,000	$8.00	$930.00	$946.37	$16.37	1.8%
Average Increase For Subclass					2.6%
Average Increase For Service Classification					2.4%
Overall Average Increase					2.4%

Residential Service Cares - Delivery Charges Santa Cruz County	Present	Proposed
Customer Charge	$6.50	$7.50
Energy Charge, first 400 kWhs	$0.079300	$0.02736
Energy Charge, all additional kWhs	$0.079300	$0.02736
PPFAC Charge	$0.018250	$0.018250
Discount	Varies	Varies
Residential Service Cares Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Present Discount	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	30%	$4.55	$5.25	$0.70	15.4%
50	30%	$7.96	$8.66	$0.70	8.8%
100	30%	$11.38	$12.08	$0.70	6.2%
200	30%	$18.21	$18.91	$0.70	3.8%
400	20%	$36.42	$37.22	$0.80	2.2%
500	20%	$44.22	$45.02	$0.80	1.8%
800	10%	$76.09	$76.99	$0.90	1.2%
1,000	10%	$93.65	$94.55	$0.90	1.0%
2,000	$8.00	$193.60	$202.60	$9.00	4.6%
2,500	$8.00	$242.38	$251.38	$9.00	3.7%
5,000	$8.00	$486.25	$495.25	$9.00	1.9%
10,000	$8.00	$974.00	$983.00	$9.00	0.9%
Average Increase For Subclass					1.3%
Average Increase For Service Classification					2.4%
Overall Average Increase					2.4%

Small General Service Delivery Charges - Mohave County	Present	Proposed
Customer Charge	$10.00	$12.00
Energy Charge, first 400 kWhs	$0.074500	$0.023585
Energy Charge, all additional kWhs	$0.074500	$0.023585
PPFAC Charge	$0.018250	$0.018250
Small General Service Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	$10.00	$12.00	$2.00	20.0%
50	$14.64	$16.69	$2.05	14.0%
100	$19.28	$21.38	$2.10	10.9%
250	$33.19	$35.44	$2.26	6.8%
500	$56.38	$58.89	$2.51	4.5%
1,000	$102.75	$105.78	$3.02	2.9%
2,000	$195.50	$199.55	$4.05	2.1%
3,500	$334.63	$340.21	$5.59	1.7%
5,000	$473.75	$480.88	$7.12	1.5%
10,000	$937.50	$949.75	$12.25	1.3%
30,000	$2,792.50	$2,825.25	$32.75	1.2%
50,000	$4,647.50	$4,700.75	$53.25	1.1%
Average Increase For Subclass				2.9%
Average Increase For Service Classification				2.4%
Overall Average Increase				2.4%

Small General Service Delivery Charges Santa Cruz County	Present	Proposed
Customer Charge	$10.00	$12.00
Energy Charge, first 400 kWhs	$0.118300	$0.066360
Energy Charge, all additional kWhs	$0.118300	$0.066360
PPFAC Charge	$0.018250	$0.018250
Small General Service Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
0	$10.00	$12.00	$2.00	20.0%
50	$16.83	$18.83	$2.00	11.9%
100	$23.66	$25.66	$2.00	8.5%
250	$44.14	$46.14	$2.00	4.5%
500	$78.28	$80.28	$2.00	2.6%
1,000	$146.55	$148.55	$2.00	1.4%
2,000	$283.10	$285.10	$2.00	0.7%
3,500	$487.93	$489.93	$2.00	0.4%
5,000	$692.75	$694.75	$2.00	0.3%
10,000	$1,375.50	$1,377.50	$2.00	0.1%
30,000	$4,106.50	$4,108.50	$2.00	0.0%
50,000	$6,837.50	$6,839.50	$2.00	0.0%
Average Increase For Subclass				1.5%
Average Increase For Service Classification				2.4%
Overall Average Increase				2.4%

Large General Service Delivery Charges	Present	Proposed
Customer Charge	$10.10	$15.50
Demand Charge, per kW	$9.50	$10.71
Energy Charge, per kWh	$0.053300	$0.000000
PPFAC Charge	$0.018250	$0.018250
Large General Service Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Demand	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5,000	16	$519.86	$537.82	$17.96	3.5%
10,000	32	$1,029.62	$1,060.14	$30.52	3.0%
25,000	80	$2,558.90	$2,627.10	$68.21	2.7%
50,000	160	$5,107.70	$5,238.71	$131.01	2.6%
100,000	320	$10,205.29	$10,461.92	$256.62	2.5%
200,000	640	$20,400.49	$20,908.34	$507.85	2.5%
300,000	960	$30,595.68	$31,354.76	$759.07	2.5%
400,000	1,280	$40,790.88	$41,801.18	$1,010.30	2.5%
500,000	1,600	$50,986.07	$52,247.60	$1,261.52	2.5%
600,000	1,920	$61,181.27	$62,694.02	$1,512.75	2.5%
Average Increase For Subclass					2.4%
Average Increase For Service Classification					2.4%
Overall Average Increase					2.4%

Large General Service TOU Delivery Charges	Present	Proposed
Customer Charge	$15.00	$15.50
Demand Charge, per kW	$9.50	$10.71
Energy Charge, per kWh	$0.053300	$0.000000
PPFAC Charge	$0.018250	$0.018250
Large General Service (TOU) Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Demand	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
5,000	16	$524.76	$537.82	$13.06	2.5%
10,000	32	$1,034.52	$1,060.14	$25.62	2.5%
25,000	80	$2,563.80	$2,627.10	$63.31	2.5%
50,000	160	$5,112.60	$5,238.71	$126.11	2.5%
100,000	320	$10,210.19	$10,461.92	$251.72	2.5%
200,000	640	$20,405.39	$20,908.34	$502.95	2.5%
300,000	960	$30,600.58	$31,354.76	$754.17	2.5%
400,000	1,280	$40,795.78	$41,801.18	$1,005.40	2.5%
500,000	1,600	$50,990.97	$52,247.60	$1,256.62	2.5%
600,000	1,920	$61,186.17	$62,694.02	$1,507.85	2.5%
Average Increase For Subclass					3.0%
Average Increase For Service Classification					2.4%
Overall Average Increase					2.4%

Large Power Service (<69KV) Delivery Charges	Present	Proposed
Customer Charge	$365.00	$365.00
Demand Charge, per kW	$24.75	$10.51
Energy Charge, per kWh	$0.023600	$0.000000
PPFAC Charge	$0.018250	$0.018250
Large Power Service (<69KV) Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Demand	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
300,000	587	$27,447	$27,590	$143	0.5%
450,000	880	$40,988	$41,202	$214	0.5%
650,000	1,272	$59,042	$59,351	$309	0.5%
850,000	1,663	$77,096	$77,501	$405	0.5%
950,000	1,859	$86,124	$86,576	$452	0.5%
1,500,000	2,935	$135,773	$136,488	$714	0.5%
1,750,000	3,424	$158,342	$159,175	$833	0.5%
2,000,000	3,913	$180,910	$181,862	$952	0.5%
2,500,000	4,891	$226,046	$227,236	$1,190	0.5%
Average Increase For Subclass					0.5%
Average Increase For Service Classification					2.4%
Overall Average Increase					2.4%

Large Power Service (>69KV) Delivery Charges	Present	Proposed
Customer Charge	$800.00	$800.00
Demand Charge, per kW	$16.10	$1.86
Energy Charge, per kWh	$0.023600	$0.000000
PPFAC Charge	$0.018250	$0.018250
Large Power Service (>69KV) Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Demand	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
300,000	549	$22,199.60	$22,877.70	$678	3.1%
450,000	824	$32,899.40	$33,916.55	$1,017	3.1%
650,000	1,190	$47,165.80	$48,635.02	$1,469	3.1%
850,000	1,557	$61,432.20	$63,353.48	$1,921	3.1%
950,000	1,740	$68,565.40	$70,712.72	$2,147	3.1%
1,500,000	2,747	$107,797.99	$111,188.50	$3,391	3.1%
1,750,000	3,205	$125,630.99	$129,586.58	$3,956	3.1%
2,000,000	3,662	$143,463.99	$147,984.66	$4,521	3.2%
2,500,000	4,578	$179,129.99	$184,780.83	$5,651	3.2%
Average Increase For Subclass					3.1%
Average Increase For Service Classification					2.4%
Overall Average Increase					2.4%

Interruptible Power Service Delivery Charges	Present	Proposed
Customer Charge	$10.10	$15.50
Demand Charge, per kW	$2.50	$3.40
Energy Charge, per kWh	$0.053300	$0.000000
PPFAC Charge	$0.018250	$0.018250
Interruptible Power Service Base Power Supply Charge, all kWhs		$0.051940

Average Sales per Month	Demand	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase $	Proposed Increase %
10,000	34	$809.61	$831.65	$22.04	2.7%
15,000	50	$1,209.36	$1,239.72	$30.36	2.5%
20,000	67	$1,609.11	$1,647.79	$38.68	2.4%
30,000	101	$2,408.62	$2,463.94	$55.33	2.3%
50,000	168	$4,007.63	$4,096.24	$88.61	2.2%
75,000	252	$6,006.39	$6,136.60	$130.21	2.2%
100,000	336	$8,005.15	$8,176.97	$171.82	2.1%
125,000	420	$10,003.92	$10,217.34	$213.42	2.1%
150,000	504	$12,002.68	$12,257.71	$255.03	2.1%

Average Increase For Service Classification	2.4%
Overall Average Increase	2.4%

Lighting Dusk to Dawn Delivery Charges	*Present*	*Proposed*	Proposed Increase $	Proposed Increase %
	Overhead Service			
Existing Wood Pole	$0.00	$0.00	$0.00	0.0%
New 30' Wood Pole (Class 6)	$4.02	$4.12	$0.10	2.4%
New 30' Metal or Fiberglass	$8.05	$8.25	$0.20	2.4%
	Underground Service			
Existing Wood Pole	$2.01	$2.06	$0.05	2.4%
New 30' Wood Pole (Class 6)	$6.04	$6.19	$0.15	2.4%
New 30' Metal or Fiberglass	$10.06	$10.30	$0.24	2.4%
Per Watt	$0.053040	$0.054331	$0.0013	2.4%
Base Power Supply, all kWhs		$0.000000		
100 Watts - Overhead				
Existing Wood Pole	$5.30	$5.43	$0.13	2.4%
New 30' Wood Pole (Class 6)	$9.32	$9.55	$0.23	2.4%
New 30' Metal or Fiberglass	$13.35	$13.68	$0.32	2.4%
100 Watts - Underground				
Existing Wood Pole	$7.31	$7.49	$0.18	2.4%
New 30' Wood Pole (Class 6)	$11.34	$11.62	$0.28	2.4%
New 30' Metal or Fiberglass	$15.36	$15.74	$0.37	2.4%
200 Watts - Overhead				
Existing Wood Pole	$10.61	$10.87	$0.26	2.4%
New 30' Wood Pole (Class 6)	$14.63	$14.98	$0.36	2.4%
New 30' Metal or Fiberglass	$18.66	$19.11	$0.45	2.4%
200 Watts - Underground				
Existing Wood Pole	$12.62	$12.93	$0.31	2.4%
New 30' Wood Pole (Class 6)	$16.65	$17.05	$0.41	2.4%
New 30' Metal or Fiberglass	$20.67	$21.17	$0.50	2.4%
400 Watts - Overhead				
Existing Wood Pole	$21.22	$21.73	$0.52	2.4%
New 30' Wood Pole (Class 6)	$25.24	$25.85	$0.61	2.4%
New 30' Metal or Fiberglass	$29.27	$29.98	$0.71	2.4%
400 Watts - Underground				
Existing Wood Pole	$23.23	$23.79	$0.57	2.4%
New 30' Wood Pole (Class 6)	$27.26	$27.92	$0.66	2.4%
New 30' Metal or Fiberglass	$31.28	$32.04	$0.76	2.4%

UNS ELECTRIC, INC.
SCHEDULE H SUPPORT - RATES

Line No.	A Class of Service	B Actual Booked BD	C Adjustments to Booked BD	D Adjusted Booked BD TOTAL	Adjusted Booked BD By Area	Existing Rate	Present Adjusted Revenue	Target	Adjusted Billing Determinents	Adjusted Test Year Revenues	F Proposed TY Revenue Increase	Proposed Revenue	I New Rates	J New Revenues	K % Increase
	Residential Service														
1	**Santa Cruz**												7.50	$1,244,031	
2	Customer Charge	905,171	23,917	929,088	167,236	6.50	$1,087,033		165,871	$1,078,160			0.02736	$1,305,337	
3	Energy Charge 1st 400 kWhs	311,809,221	8,872,957	320,682,177	48,102,327	0.07930	$3,814,515		47,709,693	$3,783,379			0.027360	$1,958,006	
4	Energy Charge, all additional kWhs	467,713,831	13,309,435	481,023,266	72,153,490	0.07930	$5,721,772		71,564,539	$5,675,068					
	Delivery Revenue						$10,623,319			$10,536,607					
5	Total Sales	779,523,051	22,182,392	801,705,444	120,255,817								0.051940	$6,195,104	
6	Base Power Supply Charge, all kWhs												0.018250	$2,176,755	
7	PPFAC, all kWhs			801,705,444	120,255,817	0.01825	$2,194,669		119,274,232	$2,176,755					
8	TOTAL RESIDENTAL - SANTA CRUZ						$12,817,988			$12,713,361	$309,346	$13,022,708		$12,879,232	1.3%
9															
10	**Mohave**														
11	Customer Charge	905,171	23,917	929,088	761,852	6.50	$4,952,039		755,634	$4,911,618			7.50	$5,667,252	
12	Energy Charge 1st 400 kWhs	311,809,221	8,872,957	320,682,177	272,579,851	0.07490	$20,416,231		270,354,926	$20,249,584			0.0244970	$6,622,885	
1	Energy Charge, all additional kWhs	467,713,831	13,309,435	481,023,266	408,869,776	0.07490	$30,624,346		405,532,389	$30,374,376			0.024497	$9,934,327	
3	Delivery Revenue	$78,397,054	2,186,829	$80,583,883			$55,992,616			$55,535,578				$22,224,463	
4	Total Sales	779,523,051	22,182,392		681,449,627								0.051940	$35,105,587	
5	Base Power Supply Charge, all kWhs												0.018250	$12,334,943	
	PPFAC, all kWhs			801,705,444		0.01825	$12,436,456		675,887,315	$12,334,943					
7	TOTAL RESIDENTAL - MOHAVE						$68,429,072			$67,870,522	$1,651,450	$69,521,972		$69,664,994	2.6%
8															
9	TOTAL RESIDENTAL SERVICE REVENUE				801,705,444		$81,247,060	$80,583,883		$80,583,883	$1,960,796	$82,544,679		$82,544,226	2.4%
	Small General Service														
11	**Santa Cruz**														
	Customer Charge	87,649	2,265	89,914	23,674	10.00	$236,740		23,671	$236,711			12.00	$284,054	
	Energy Charge 1st 400 kWhs	35,729,532	682,482	36,412,014	8,738,883	0.11830	$1,033,810		8,737,827	$1,033,685			0.06636	$579,842	
13	Energy Charge, all additional kWhs	53,594,298	1,023,723	54,618,021	13,108,325	0.11830	$1,550,715		13,106,741	$1,550,527			0.06636	$869,763	
15	Total Sales	89,323,830	1,706,205	91,030,034	21,847,208				21,844,568						
14	Delivery Revenue	$10,106,565	$191,274	$10,297,839	$3,285,813										
16	Base Power Supply Charge, all kWhs												0.051940	$1,134,607	
17	PPFAC, all kWhs			91,030,034	21,847,208	0.01825	$398,712		21,844,568	$398,663			0.018250	$398,663	
19	Total Santa Cruz			$10,297,839	$3,285,813		$3,219,976			$3,219,587	$78,340	$3,297,927		$3,266,929	1.5%
20															
22	**Mohave County**			13,108,325											
24	Customer Charge	87,649	2,265	89,914	66,240	10.00	$662,400		66,232	$662,320			12.00	$794,784	
	Energy Charge 1st 400 kWhs	35,729,532	682,482	36,412,014	27,673,130	0.07450	$2,061,648		27,669,786	$2,061,399			0.02359	$652,592	
13	Energy Charge, all additional kWhs	53,594,298	1,023,723	54,618,021	41,509,696	0.07450	$3,092,472		41,504,679	$3,092,099			0.02359	$978,888	
14	Total Sales	89,323,830	1,706,205		69,182,826				69,174,464						
15	Delivery Revenue	$10,106,565	191,274	$10,297,839	$7,012,026										
	Base Power Supply Charge, all kWhs												0.051940	$3,592,922	
18	PPFAC, all kWhs			91,030,034	69,182,826	0.01825	$1,262,587		69,174,464	$1,262,434			0.018250	$1,262,434	
	Total Mohave			$10,297,839	$7,012,026		$7,079,107			$7,078,251	$172,231	$7,250,482		$7,281,619	2.9%
20															
21	**TOTAL SMALL GENERAL SERVICE REVENUE**				**$10,297,839**		**$10,299,083**	$10,297,839		**$10,297,839**	**$250,571**	**$10,548,409**		**10,548,549**	2.4%
22															

	A	B	C	D							F		I	J	K
Line No.	Class of Service	Actual Booked BD	Adjustments to Booked BD	Adjusted Booked BD TOTAL	Adjusted Booked BD By Area	Existing Rate	Present Adjusted Revenue	Target	Adjusted Billing Determinents	Adjusted Test Year Revenues	Proposed TY Revenue Increase	Proposed Revenue	New Rates	New Revenues	% Increase
23	**LARGE GENERAL SERVICE**														
24	**Delivery Charges**														
	Customer Charge	24,021	280	24,301		10.10	$245,440		24,050	$242,901			15.50	$372,769	
	Demand Charge, per kW	1,410,360	16,520	1,426,880		9.50	$13,555,357		1,412,119	$13,415,134			10.71	$15,123,798	
25	Energy Charge (kWhs)	488,503,189	2,743,092	491,246,281		0.0533	$26,183,427		486,164,590	$25,912,573			0.00000	$0	-49.70%
26															
27	Revenue	$48,221,859	250,518	$48,472,376											
28															
29	**LARGE GENERAL SERVICE (TOU)**														
	Delivery Charges														
30	Customer Charge	154	(34)	120		15.00	$1,800		119	$1,781			15.50	$1,841	
31	Demand Charge, per kW	14,246	(3,162)	11,084		9.50	$105,299		10,969	$104,209			10.71	$117,482	
32	Energy Charge (kWhs)	3,691,460	(787,745)	2,903,715		0.0533	$154,768		2,873,678	$153,167			0.00000	$0	-44.88%
33															
34	Revenue	$358,864	-76,527	$282,337											
35	**Base Power Supply Charge, all kWhs**												0.051940	$25,400,648	
36	**PPFAC, all kWhs**			494,149,996		0.01825	$9,018,237		489,038,268	$8,924,948			0.018250	$8,924,948	
37	TOTAL LARGE GENERAL SERVICE REVENUE			$48,754,713			$49,264,328	$48,754,713		$48,754,713	$1,186,317	$49,941,031		$49,941,486	2.4%
38															
39	**LARGE POWER SERVICE (<69KV)**														
40	**Delivery Charges**														
41	Customer Charge	69	6	75		365.00	$27,375		75	$27,290			1000.00	$74,768	
42	Demand Charge, per kW	74,564	6,484	81,047		24.75	$2,005,921		80,797	$1,999,726			10.34	$835,603	
43	Energy Charge (kWhs)	39,094,759	2,287,280	41,382,039	69%	0.02360	$976,616		41,254,230	$973,600			0.000000	$0	-55.69%
44															
45	Revenue	$3,782,246	210,575	$3,992,821											
46															
47	**LARGE POWER SERVICE (>69KV)**														
	Delivery Charges														
48	Customer Charge	64	5	69		800.00	$55,200		69	$55,030			1000.00	$68,787	
49	Demand Charge, per kW	267,616	20,908	288,524	2,290	16.10	$4,645,228		287,632	$4,630,881			1.69	$486,674	
50	Energy Charge (kWhs)	157,105,746	138,971	157,244,717	2,180,556	0.0236	$3,710,975		156,759,064	$3,699,514			0.00000	$0	-69.62%
51															
52	Revenue	$10,990,900	16,063	$11,006,963											
53	Total kWhs	196,200,505	2,426,251	198,626,756											
54	**Base Power Supply Charge, all kWhs**												0.051940	$10,284,810	
	PPFAC, all kWhs			198,626,756		$0.01825	$3,624,938		198,013,294	$3,613,743			0.018250	$3,613,743	
55															
56	TOTAL LARGE POWER SERVICE REVENUE			$14,999,784			$15,046,254	$14,999,784		$14,999,784	$364,980	$15,364,764		$15,364,385	2.4%
57															
58	**INTERRUPTIBLE POWER SERVICE**														
59	**Delivery Charges**														
60	Customer Charge	235	0	235		10.10	$2,374		236	$2,379			15.50	$3,651	
61	Demand Charge, per kW	63,585	0	63,585		2.50	$158,964		63,732	$159,330			3.40	$216,689	
62	Energy Charge (kWhs)	17,598,914	0	17,598,914		0.0533	$938,022		17,639,506	$940,186			0.000000	$0	
63															
64	Revenue	$1,423,816	0	$1,423,816											
65	**Base Power Supply Charge, all kWhs**												0.051940	$916,196	
66	**PPFAC, all kWhs**			17,598,914		$0.01825	$321,180		17,639,506	$321,921			0.018250	$321,921	
67	TOTAL INTERRUPTIBLE POWER SERVICE REVENUE			$1,423,816			$1,420,539	$1,423,816		$1,423,816	$34,645	$1,458,461		$1,458,457	2.4%
68															
69	**LIGHTING DUSK TO DAWN**														
70	Existing Wood Pole - Overhead	38,757	520	39,277		0.00	$0								
71	New 30' Wood Pole (Class 6) - Overhead	8,111	109	8,220		4.02	$33,043		8,846	$35,563			4.12	$36,428	
72	New 30' Metal or Fiberglass - Overhead	2,353	32	2,385		8.05	$19,196		2,566	$20,660			8.25	$21,162	
73	Existing Wood Pole - Underground	677	9	686		2.01	$1,379		738	$1,484			2.06	$1,520	
74	New 30' Wood Pole (Class 6) - Underground	342	5	347		6.04	$2,094		373	$2,253			6.19	$2,308	
75	New 30' Metal or Fiberglass - Underground	7,545	101	7,646		10.06	$76,923		8,230	$82,789			10.30	$84,804	

	A	B	C	D							F		I	J	K
Line No.	Class of Service	Actual Booked BD	Adjustments to Booked BD	Adjusted Booked BD TOTAL	Adjusted Booked BD By Area	Existing Rate	Present Adjusted Revenue	Target	Adjusted Billing Determinents	Adjusted Test Year Revenues	Proposed TY Revenue Increase	Proposed Revenue	New Rates	New Revenues	% Increase
76	Wattage, per Watt	7,762,533		7,866,778		0.053040	$417,254		8,466,756	$449,077			0.05433	$460,004	
77	Revenue	583,672	8,153	$591,825											
78		3,219,530	45,722	3,265,253											
79	Total Number of Units	57,784													
80	**Base Power Supply Charge, customer charge**			58,560		1.84									
81															
82	TOTAL LIGHTING DUSK TO DAWN REVENUE			$591,825			$549,887	$591,825		$591,825	$14,401	$606,226		$606,226	2.4%
83															
84															
85															
86	Customers	1,075,147	27,215	1,102,362											
87	kWhs	1,578,060,479	28,315,918	1,606,376,397											
88	Total Revenue	#REF!	#REF!	#REF!			$157,827,151			$156,651,860	$3,811,710	$160,463,570		$160,463,329	
89	Base Power Supply Revenue Requirement														
90	Total Delivery Revenue Requirement														
91	Total Delivery Revenue Requirement Increase										$3,811,710	$160,463,570			
92	Percent Increase										2.42%				
93	TOTAL UNS ELECTRIC REVENUE REQUIREMENT														

EXHIBIT
ALL-STATE LEGAL®
S-62
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF	)DOCKET NO. E-04204A-06-0783
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	)

SURREBUTAL

TESTIMONY

OF

FRANK W. RADIGAN

ON BEHALF OF

THE ARIZONA CORPORATION COMMISSION,

UTILITIES DIVISION STAFF

AUGUST 24, 2007

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783

CUSTOMER CHARGES – Based on a revised cost of service study, the Company has revised its proposed customer charges and now proposes a charge of $7.70 per month for the Residential Class and $12.00 per month for the Small General Service Class. These charges are in line with those that I proposed in my original testimony. Accordingly, the customer charge for the Residential Service Class should be increased from $6.50 per month to $7.50 per month and the charge for the Small General Service Class should be increased from $10 per month to $12 per month.

PURCHASED POWER ALLOCATION - The Company has still not provided any evidence that shows that purchased power should be allocated on other than a cent per kWh basis.

INCLINING BLOCK RATE STRUCTURE – Given the relatively small recommended rate increase and increases in the customer charge that Staff is recommending, I do not believe the current case presents the best situation for introducing an inclining block rate structure. The Company has not provided any new evidence to show that it is imperative or necessary at this time to introduce an inclining block rate structure. Absent such a showing, I urge rejection of the Company's proposal.

MANDATORY TIME OF USE ("TOU") RATES – The Company continues to argue for Mandatory TOU rates for new customers but has failed to provide any cost justification for it. Instead, it argues that it will be beneficial in the long term. While this may be true, it must still be cost justified and until such time that the Company provides evidence showing that it is, its position should be rejected.

DEMAND CHARGES FOR LARGE GENERAL AND LARGE POWER SERVICE - The Company continues to argue to lower the demand charges for large commercial customers taking service at less than 69 kV but does not have any cost data to support the proposal. Absent the showing of cost of service data that the demand charge should be lowered, the Company's position should be rejected.

MERGER OF MOHAVE AND SANTA CRUZ RATES - In my original testimony, I recommended a more tempered elimination of the rate differential between Mohave and Santa Cruz Counties. The Company's Rebuttal Testimony provides no new evidence that convinces me that I should alter my position.

INTRODUCTION

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

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services regarding the electric utility industry and specializing in the fields of rates, planning and utility economics. My office address is 120 Washington Avenue, Albany, New York 12210.

Q. Are you the same Frank Radigan that previously filed testimony in this proceeding?

A. Yes. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. What is the scope of your Surrebuttal Testimony?

A. I will address certain issues raised by Company Witness D. Bentley Erdwurm in his Rebuttal Testimony dated August 14, 2007. Specifically, I address his recommendations on 1) the revised customer charges, 2) the allocation of purchased power, 3) the implementation of an inclining block rate structure, 4) the implementation of mandatory time of use rates, 5) his justification for decreasing the differential in the demand charges for large general service customers, and 6) his proposal to merge the rates of Mohave County and Santa Cruz County customers.

A. Customer Charges

Q. Please comment on the company's proposed customer charge increases.

A. In Mr. Erdwurm's Rebuttal Testimony, he provides results of the cost of service study that eliminate line transformers from the calculation of the customer charge (Erdwurm Rebuttal Testimony, pages 2-6). The new study results in what Mr. Erdwurm calls a "bare bones" customers charge and he now recommends a $7.70 per month charge for the

Residential Class and a $12.00 per month charge for the Small General Service Class. These charges are in line with those that I proposed in my original testimony - a customer charge for the Residential Service Class of $7.50 per month and a customer charge for the Small General Service Class of $12 per month and should be approved.

B. Power Purchase Allocation

Q. Please discuss the Company's objection to the Power Purchase Allocation.

A. Company Witness Erdwurm continues to opine for an allocation of purchased power costs on an Average and Peaks Method (Erdwurm Rebuttal, pages 6-9). The Average and Peaks Method is made up of two components: an average demand component (with a percentage weight of the system load factor) and a peak demand component (with a percentage weight of one minus the system load factor). Mr. Erdwurm urges this method and rejects the energy allocation that I recommended in my original testimony. Mr. Erdwurm states that the Average and Peaks Method recognizes the importance of demand and energy when determining the costs to serve customers (Erdwurm Rebuttal, page 8). Mr. Erdwurm uses purchased power costs of Tucson Electric Power ("TEP") to develop a split of costs which he then applies to the purchased power contract that the Company has with Pinnacle West Capital Corporation (Erdwurm Rebuttal, pages 6-7).

The contract with Pinnacle West Corporation is the Company's power supply contract. It has no provision for demand charges or any segregation of charges by time of day, month or season. It is merely an energy charge. However much Mr. Erdwurm tries to reverse engineer this energy charge into demand and energy components, the simple fact remains that the purchased power charge is purely volumetric. The Company has provided no credible evidence to show that the Average and Peaks Method should be used in this case.

C. Inclining Block Rate Structure

Q. Please discuss the Company's proposal for an inclining block rate structure for the Residential and Small General Service Rate Classes.

A. The Company continues to urge acceptance of an inclining block rate structure (Erdwurm Rebuttal, pages 9-11). Casting aside my concerns about rate impacts, Mr. Erdwurm states that if conservation is an important goal to the Commission, then my argument of balancing conversation goals with bill impacts is against policy.

My arguments in my initial testimony properly balanced the goals on increasing energy conservation with other rate design changes being made. The reasoning is quite simple. I recommended against consolidation given the combination of the level of rate increase being recommended, the fact that power supply is being unbundled from delivery charges, the amount of the rate increase being recovered in the customer charge and the fact that I was recommending that the Santa Cruz and Mohave rates not be consolidated at this time. To do so would result in some customers getting rate decrease and others getting large rate increase. As most of the other elements of the rate design were determined to be more important than the introduction of inclining block rates at this time, I see no quantitative evidence in Mr. Erdwurm's testimony that cause me to change my mind in this regard.

D. Time of Use Rates

Q. Please address the issue of mandatory Time of Use Rates ("TOU Rates").

A. The Company continues to propose mandatory TOU rates even though he admits that my reservation about implementing a mandatory TOU rate should consider cost-benefit analyses (Erdwurm, page 12). Mr. Erdwurm takes this position because he states he is looking at the problem from a long term perspective. He states that even though a cost differential exists today between TOU and non-TOU meters, this differential should

eventually disappear. He states that some cross subsidization exists already so this factor should not be an impenetrable barrier to implementing TOU rates.

The Company admits that it provided no cost justification for its proposal in its original case and does not provide any in its rebuttal testimony. Thus, in both the short and long term, there is simply no evidence that mandatory TOU meters are costs effective.

E. Demand Charges for Large General Service and Large Power Service

Q. Please discuss the Company's proposed demand charges for Large General Service and Large Power Service.

A. In his Rebuttal Testimony Company witness Erdwurm states that the differential in demand charge for services over 69 kW and under 69 kV is too high. Mr. Erdwurm admits that he has no study to determine a more exact differential but he notes that the differential for similar service at Arizona Public Service Company is almost half of the one that exists here. Mr. Erdwurm recognizes that though he was unable to provide results from a specific study, he asks that Staff reconsider its position based on the information given about Arizona Public Service (Erdwurm Rebuttal, page 14).

Eliminating a large differential for similar service is a noble goal but using the cost figures for another utility whose rate structure is not being examined in this case is not proper justification. UNS transmits power at 115 kV and 69 kV. On the UNS system there is a variety of 69 kV substations transforming power down to a variety of different voltages. Without a study, one cannot determine which of these lower voltages the majority of large commercial customers are taking power from or what the cost differential might be. For example, a large commercial customer could take service from a 13.8 kV line and should pay for not only the transformation of power but for the distribution of power across many

miles of distribution lines. Without a study, it is impossible to tell how much equipment on the other side of the step down transformer is being used by the large commercial customers. Rather than guess what the differential should be, a UNS specific cost of service study should be developed and the issue be raised in the next rate proceeding.

F. Elimination of Separate Rates for Mohave and Santa Cruz

Q. Please discuss the Company's proposal to eliminate separate rates for Mohave and Santa Cruz Counties.

A. In Rebuttal Testimony Company witness Erdwurm urges combining the rates for Santa Cruz and Mohave at this time. Mr. Erdwurm characterizes my reluctance to fully meld the rates for the two Counties as being hypersensitive to rate changes (Erdwurm Rebuttal, page 15).

Mr. Erdwurm is incorrect in his assertion that I want to continue the status quo. In my original testimony I proposed that the customer charges for both counties be increased but not the energy charges. To do so would cause a rate decrease for some Santa Cruz customers. I didn't want this to happen since rates for the utility as a whole were increasing and I thought that was an improper price signal. Instead, I suggested that the differential be eliminated over two rate cases. Mr. Erdwurm has presented no factual evidence to change my mind.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

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BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

DIRECT

TESTIMONY

OF

JERRY D. ANDERSON

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 12, 2007

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DEMAND SIDE MANAGEMENT PROGRAMS SUMMARY JDA-1

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783

On December 15, 2006, UNS Electric, Inc. ("UNS Electric" or "the Company") filed an application with the Arizona Corporation Commission ("ACC" or "Commission") for a 5.5 percent increase in its base rates throughout its service territory in the State of Arizona. UNS Electric serves 91,850 customers in its service territory in Mohave County in northwestern Arizona and in Santa Cruz County in southern Arizona.

Included in UNS Electric's application is a request to add new Demand-Side Management ("DSM") programs and to enhance existing DSM programs for residential and commercial customers. Details of the Company's proposed DSM activities were filed in its "Demand Side Management Portfolio Plan 2008 – 2012" in Docket No. E-04204A-07-0365 on June 13, 2007. Recommendations regarding the Company's proposed DSM programs will be made in that proceeding; however, funding for those programs is better dealt with in the context of a rate case and is the subject of this testimony.

In addition, Staff has made recommendations in this testimony regarding changes in the funding for Renewables programs at UNS Electric. Staff's recommendations in this regard are to better position the Company to be responsive to future changes in renewables programs, particularly the coming change from the Environmental Portfolio Standard to the Renewable Energy Standard and Tariff rules.

Having examined relevant portions of UNS Electric's rate case filing and its DSM Portfolio Plan filing, Staff recommends the following:

1. Staff recommends that the LIW program be moved into UNS Electric's DSM portfolio plan as a DSM program and that it be funded as a DSM program.

2. Staff recommends that the Emergency Bill Assistance component of the LIW program not be included as part of that program if LIW is re-categorized as DSM, and that Emergency Bill Assistance not be funded with DSM funds.

3. Staff recommends that UNS Electric's TOU pricing plans not be considered as DSM, and that these activities not be funded with DSM funds.

4. Staff recommends that UNS Electric discontinue recovery of its DSM costs from base rates, and that it be allowed to recover its prudently incurred costs in connection with Commission-approved DSM activities through a separate DSM adjustment mechanism, and that such a mechanism should be established in this proceeding.

5. Staff recommends that Commission-approved DSM costs should be assessed to all UNS Electric customers as a clearly labeled single line item per kWh charge on customer bills.

6. Staff recommends DSM related expenses should be recorded in the DSM Adjustor account by DSM program and other major categories of DSM expenses with each major category further disaggregated by type of expense.

7. Staff recommends that UNS Electric's DSM adjustor rate be reset annually on June 1 of each year beginning June 1, 2009; and that the per kWh rate be based upon currently projected DSM costs for that year, adjusted by the previous year's over- or under-collection, divided by projected retail sales (kWh) for that same year.

8. Staff recommends UNS Electric submit to the Commission in Docket Control its DSM expenses, prudently incurred during the previous calendar year in connection with Commission-approved DSM programs and activities, and its actual DSM cost recovery collected in the previous year, annually by April 1 of each year.

9. Staff recommends that UNS Electric submit, with its previous year DSM costs and DSM recovery, a proposed calculation of the new DSM adjustor rate for the current year, annually by April 1 of each year.

10. Staff recommends that UNS Electric's proposed new DSM adjustor rate shall become effective on June 1 of each year beginning June 1, 2009, if no action is taken by the Commission to modify or reject it.

11. Staff recommends that from the effective date of an Order in this rate case until June 1, 2009, the initial DSM adjustor rate should be based upon 25 percent of currently estimated Portfolio Plan first year (2008) program costs for all programs except the LIW program for which 100 percent of the estimated 2008 program costs should be included. These costs should be divided by adjusted Test Year kWh retail sales as reported on Schedule H-2, page 1, line 9.

12. Staff recommends that the EFPS tariff become permanent.

13. Staff recommends that the EFPS surcharge tariff become an adjustor mechanism.

14. Staff recommends the amount of the renewables charge continue to be billed as a separate line item on UNS customer's bills.

INTRODUCTION

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

A. My name is Jerry D. Anderson. I am a Public Utilities Analyst V employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I provide recommendations to the Commission on electric and gas rate filings, purchased power and fuel adjustment matters, Demand-Side Management ("DSM") programs, and other energy-related matters as assigned.

Q. Please describe your educational background and professional experience.

A. I graduated from Western Kentucky University, Bowling Green, Kentucky, receiving a Bachelor of Science degree with double majors in Economics and Business Management. My course of studies included classes in micro-economic price theory, macro-economic theory and business cycles, accounting, management, and data processing. I earned an MBA degree from Xavier University, Cincinnati, Ohio, with an area of concentration in multinational business.

After working as a computer programmer for a major oil and refining company, I applied my computer skills to rate research, load research, and load forecasting as a member of the Cincinnati Gas & Electric Company's (later Cinergy/Duke Energy) Rate & Economic Research Department for 15 years. I was promoted to a succession of more responsible positions there and ultimately was named Economist in charge of all electric sales and load forecasting activities. In this position I was responsible for constructing econometric

models of the regional economy for the purpose of forecasting electric system peak demands and sales by class of service for a three-state service territory. Since that time, I have served as a consultant and branch manager of two consulting firms providing services to such clients as the State of Arizona and the Los Alamos National Laboratories, Los Alamos, New Mexico. More recently, I have held positions in the government sector and in 2005 was employed by the ACC as a Public Utilities Analyst.

I have participated in various classes on general regulatory and utility issues, including the University of Wisconsin's "Gas Rate Fundamentals" class, New Mexico State University's "Basics" class, and Michigan State University's "Camp NARUC" program. I am a member of the National Association for Business Economics and have testified before the Arizona Corporation Commission.

Q. What is the scope of your testimony in this case?

A. In this case, I will address a funding or cost recovery mechanism for DSM at UNS Electric, Inc. ("UNS Electric" or the "Company"). I will also suggest a funding change for Renewables programs at UNS Electric.

Time of Use rates ("TOU"), although included by UNS Electric in this filing as a DSM program, will be addressed in this case by Staff witness, Frank Radigan, as a rate matter and, therefore, costs related to that program will not be included in the DSM funding mechanism. UNS Electric proposed that its Low Income Weatherization Program ("LIW") be removed from base rates to become one of its residential DSM programs. Staff witness, Ms. Julie McNeely-Kirwin, addressed UNS Electric's proposed bill assistance component of the LIW in her Direct Testimony.

Since UNS Electric has filed details of its "Demand Side Management Portfolio Plan 2008 – 2012" ("Portfolio Plan") for Commission approval outside of this rate case (Docket No. E-04204A-07-0365), my focus on DSM at this time will be to make general comments on UNS Electric's DSM activities. I have examined UNS Electric's Portfolio Plan filing to make observations on the scope of the DSM activities contemplated by the Company in order to make appropriate recommendations in this proceeding for DSM cost recovery, but will not address the individual DSM programs in this proceeding. I will make recommendations also regarding cost recovery aspects of renewables programs at UNS Electric, but will not address the individual renewables programs.

Q. Have you reviewed relevant portions of UNS Electric's filing in Docket No. E-04204A-06-0783 submitted by the Company in this case?

A. Yes, I have. I have also examined the Company's DSM Portfolio Plan filed in Docket No. E-04204A-07-0365, but Staff has not completed analysis of the Portfolio Plan or the DSM programs in that portfolio and will make no specific recommendations regarding the Portfolio Plan in this proceeding.

CURRENT DEMAND SIDE MANAGEMENT COST RECOVERY

Current DSM Programs and Funding

Q. What DSM Programs does UNS Electric currently conduct?

A. According to its Semi-Annual Report on Demand Side Management Programs ("semi-annual reports"), UNS Electric currently conducts the following DSM programs:

1. Residential Energy Survey Program
2. Commercial Energy Survey Program
3. Residential New Construction
4. Academic Education

UNS Electric also conducts a Low Income Weatherization ("LIW") program not currently considered DSM, but it is proposing to include LIW as a DSM program.

Q. How are current UNS Electric DSM programs funded?

A. Decision No. 59951, January 3, 1997, allowed $175,000 annually from base rates to fund on-going DSM programs.

Q. Was the LIW program included in that $175,000 DSM funding?

A. No. Decision No. 59951 allowed an additional $70,000 annually from base rates to fund the LIW program which was no longer categorized as DSM as a result of that same rate case.

Q. How much has UNS Electric been spending on DSM activities in recent years?

A. The following is a summary of DSM expenditures reported by UNS Electric in its semi-annual reports. These amounts do not include expenditures on the LIW program.

UNS Electric, Inc. Demand Side Management Costs * 2004 – 2006 (actual)		
2004 - January – June	$20,379	
July – December	$142,715	$163,094
2005 - January – June	$72,098	
July – December	$122,121	$194,219
2006 - January – June	$53,013	
July – December	$101,294	$154,307
* Does not include the LIW Program		

PROPOSED DEMAND SIDE MANAGEMENT COST RECOVERY

Proposed DSM Programs and Funding

Q. What DSM Programs were proposed by UNS Electric in this proceeding?

A. UNS Electric proposed the following DSM programs:

1. TOU Pricing Plans
2. Direct Load Control ("DLC") Program
   a) Air conditioner cycling
   b) Programmable thermostat control
3. Energy Smart Homes Program
4. Shade Tree Program
5. Low Income Weatherization (included as DSM)

Staff also determined that the Company intends to continue or enhance its Residential Energy Survey program, Academic Education program, and Commercial Energy Survey program as components of an Education and Outreach Program.

Q. UNS Electric has proposed moving the LIW program into DSM. Does Staff concur with this proposal?

A. Yes. Staff recommends that the LIW program be moved into UNS Electric's DSM portfolio plan as a DSM program and that it be funded as a DSM program. As a DSM program, however, LIW will need to be proven to be cost-effective or to be modified to become cost-effective like any other DSM program.

Q. Are the DSM Programs proposed in UNS Electric's Portfolio Plan the same as those proposed in the instant proceeding?

A. No. It appears that UNS Electric made significant changes to its DSM plans after the time it made this rate case filing. UNS Electric subsequently filed its DSM Portfolio Plan and related programs in Docket No. E-04204A-07-0365 on June 13, 2007.

Q. Mr. Anderson, what changes to UNS Electric's DSM plans outlined in this rate case filing have come to your attention?

A. In its Portfolio Plan filing, UNS Electric proposed the following three additional DSM programs:

1. Residential HVAC Retrofit Program
2. Education and Outreach Program
3. Commercial Facilities Efficiency Program

The Education and Outreach Program is a new DSM program for UNS Electric which includes five components, three of which have evolved from and are similar to the 1) Residential Energy Survey, the 2) Commercial Energy Survey, and the 3) Academic Education existing DSM programs.

Q. Did you notice any other changes between the DSM plans filed in this case and the more recently filed Portfolio Plan?

A. Yes. The DLC program filed in the Portfolio Plan no longer includes a component to directly cycle air conditioners. It proposes only the Programmable Thermostat Control component of the DLC program which would cycle air conditioners through the thermostat.

UNS Electric also removed $20,000 annually for Emergency Bill Assistance from its estimate of costs for the LIW program. Staff does not consider Emergency Bill Assistance as DSM and, therefore, agrees that Emergency Bill Assistance should not be included with the LIW program if that program is categorized as a DSM program. Staff has indicated that the Emergency Bill Assistance should be included in UNS Electric's Warm Spirits program and that the $20,000 for that component be funded through base rates (see Direct Testimony of Staff witness Julie McNeely-Kirwin, p. 11, line 20 through p. 12, line 21). Staff recommends that the Emergency Bill Assistance component of the LIW program not be included as part of that program if LIW is re-categorized as DSM, and that Emergency Bill Assistance not be funded with DSM funds.

Q. Are UNS Electric's Time of Use ("TOU") pricing plans included in the Portfolio Plan?

A. No. They are not. The TOU pricing plans were included by UNS Electric as DSM in this rate case filing, but they are not included as DSM in the Company Portfolio Plan filing. TOU education, however, was included as a component of the Education and Outreach Program in the Company's Portfolio Plan. Staff recommends that UNS Electric's TOU pricing plans not be considered as DSM, and that these activities not be funded with DSM funds. TOU education will be evaluated by Staff outside this rate case as a component of the Education and Outreach DSM Program when UNS Electric's Portfolio Plan filing is addressed.

Q. Mr. Anderson, would you summarize your understanding of what DSM programs UNS Electric is currently proposing to undertake, subject to Commission approval?

A. Yes. My understanding is that UNS Electric's current DSM plans are to engage in those programs included in its Portfolio Plan filed with the Commission on June 13, 2007 in Docket No. E-04204A-07-0365.

Q. Would you summarize the DSM programs included in that Portfolio Plan?

A. Yes. The following DSM programs are included:

1. Education and Outreach Program
    a) Residential Education
    b) Academic Education
    c) Commercial Education
    d) Time of Use Education
2. Direct Load Control Program
    a) Programmable thermostat control
3. Low Income Weatherization Program
4. Residential New Construction Program
5. Residential HVAC Retrofit Program
6. Shade Tree Program
7. Commercial Facilities Efficiency Program

Q. How much does UNS Electric estimate it will spend on these DSM activities in the next five years?

A. According to UNS Electric's estimated budget information filed in its Portfolio Plan, the following DSM expenditures are anticipated over the period 2008 through 2012. These

planned expenditures are estimates only and are contingent upon Commission approval of UNS Electric's DSM programs for which it has made application.

UNS Electric, Inc. Demand Side Management Costs 2008 – 2012 (estimated)					
	2008	2009	2010	2011	2012
Education and Outreach	$170,000	$130,000	$133,900	$137,917	$142,055
Direct Load Control	$1,968,000	$1,288,389	$1,370,300	$1,453,372	$1,537,637
Low Income Weatherization *	$105,000	$108,150	$111,395	$114,736	$118,178
Residential New Construction	$420,000	$432,600	$445,578	$458,945	$472,714
HVAC Retrofit	$300,000	$309,000	$318,000	$327,818	$337,653
Shade Tree Program	$65,000	$66,050	$67,132	$68,246	$69,393
Com. Facilities Efficiency	$400,000	$412,000	$424,360	$437,091	$450,204
TOTAL	$3,428,000	$2,746,189	$2,870,665	$2,998,125	$3,127,834

* LIW cost estimates do not include $20,000 each year for Emergency Bill Assistance

DSM Cost Recovery Considerations

Q. Do the DSM Programs proposed by UNS Electric in its Portfolio Plan comprise the DSM activities for which you are recommending a cost recovery mechanism in this rate case?

A. Generally, yes. While the Portfolio Plan programs are our most current understanding of what UNS Electric is proposing, it is not known at this time which of these DSM programs the Commission will approve or disapprove or when this will occur. In the final analysis, programs could be disapproved, new programs could be added, and proposed programs could be modified either in scope or in concept. Staff's objective is to propose a

funding mechanism that would be responsive to those DSM programs and activities that the Commission may ultimately approve for UNS Electric outside of this docket.

Q. How is UNS Electric proposing to recover the costs of its DSM programs following disposition of this rate case?

A. UNS Electric is proposing to exclude DSM costs from base rates and to implement a single line-item per kWh charge on all customers' bills to collect the amount estimated to be spent on DSM during a given year. The per kWh charge is proposed to be calculated simply by dividing annual estimated DSM costs for the next year by the annual estimated kWh sales for that same year. The Company is proposing to adjust the subsequent year's DSM charge to account for any mismatch in a given year's spending and cost recovery.

In responses to Staff Data Requests 13.14 and 13.15, UNS Electric has outlined a modified methodology to calculate the DSM Adjustor rate during the initial period to recognize that this period will be characterized as a "ramp-up" period during which DSM activities will be ramping up to become fully operational. The Company is proposing to include 100 percent of the LIW costs and 25 percent of the costs for the other DSM programs in the calculation of this initial adjustor rate. UNS Electric believes the LIW program can immediately use the additional new funding without significant ramp-up time as the proposed program is little changed. The Company proposes to calculate the initial DSM charge by dividing these costs, reflecting ramp-up DSM activities, by the kWh recorded in the test year.

Q. Is the DSM cost recovery mechanism UNS Electric is proposing a "DSM Adjustor?"

A. Yes, it is. Although UNS Electric has not used that terminology, the mechanism the Company proposes is a DSM adjustor mechanism.

Q. Is it fair to conclude that Staff is in general agreement with UNS Electric regarding the need to establish a DSM adjustor cost recovery mechanism for the Company in this proceeding?

A. Yes. Staff recommends that UNS Electric discontinue recovery of its DSM costs from base rates, and that it be allowed to recover its prudently incurred costs in connection with Commission-approved DSM activities through a separate DSM adjustment mechanism, and that such a mechanism should be established in this proceeding.

Q. What alternatives for recovery of Commission-approved DSM costs did Staff consider?

A. Alternative methods considered by Staff for recovering the cost of DSM program activities at UNS Electric include the following: (1) recovery through base rates with no deferral accounting; (2) recovery through a deferral account; (3) recovery by amortization or capitalization of costs over time; and (4) recovery through a combination method.

Q. Should UNS Electric recover its Commission-approved DSM costs through base rates with no deferral accounting?

A. No. This method, while providing timely recovery, lacks the flexibility to adjust as new programs are added or current programs are expanded between rate cases. This method is what is currently in place for UNS Electric DSM cost recovery, but is not appropriate as we are looking toward rapid, yet uncertain, expansion of DSM activities at UNS Electric. One weakness of this methodology is when actual incurred costs are less than the base rate amount, it can result in ratepayers paying for DSM costs that have not yet been expended by the utility without any true-up.

Q. Should UNS Electric recover its Commission-approved DSM costs through a deferral account?

A. No. Although this method has been used at UNS Electric (Citizens) in the past, it is not considered an appropriate methodology at the present time. UNS Electric is planning to significantly expand its DSM activities and to increase the dollars expended on those activities commensurately. Staff believes those expenditures should be recovered in a more timely manner than this method allows. A deferral account typically does not allow recovery until the next rate case.

Q. Should UNS Electric recover its Commission-approved DSM costs through recovery by amortization or capitalization of costs over time?

A. No. This method treats DSM expenditures much the same as an investment in new plant or equipment where the investment is recovered in rates over time. It has the advantage of lessening the impact of DSM costs by spreading the costs over a period of time which may more closely mirror the time period over which the DSM benefits are realized. In the case of UNS Electric, however, such a methodology is not appropriate at this time when programs are still small or just beginning. It could become appropriate later when DSM programs may be significantly expanded, and costs for the programs could become more burdensome to ratepayers.

Q. Should UNS Electric recover its Commission-approved DSM costs through a combination method?

A. No. The Commission has used a combination DSM funding method for another utility in the past; however, Staff does not believe such a method is appropriate for UNS Electric at this time because of the uncertain levels and timelines for proposed DSM activities. A combination method could, for example, allocate a fixed amount of Commission-approved

costs to be recovered annually in base rates, and any approved costs over that amount could be recovered through a DSM adjustor mechanism. This method can exhibit some of the same characteristics of the base rate method and can also be confusing and less than transparent to customers.

Proposed DSM Cost Recovery

Q. What costs should UNS be able to recover through Staff's recommended DSM adjustor mechanism?

A. UNS Electric should be allowed to recover all prudently incurred DSM program and related costs incurred by the Company in connection with Commission-approved DSM programs and activities. Commission approval of budgets for DSM programs and activities will be established initially when the Commission acts on UNS Electric's Portfolio Plan filing. Changes to approved budget levels could be subsequently approved by the Commission in response to Company application(s) for DSM program changes or through independent action of the Commission.

Allowable costs for Commission-approved programs could include, for example; costs for rebates or other incentives including rebate processing, customer training and technical assistance, customer education, program planning and administration, program implementation, program marketing and communications, measurement and evaluation activities, and properly allocated portions of baseline study expenses if and when such a study is approved by the Commission. Actual incurred costs should be itemized in the Company's DSM semi-annual reports, and would be reviewed by Staff.

Q. How should DSM costs be charged to UNS Electric customers?

A. Staff recommends that Commission-approved DSM costs should be assessed to all UNS Electric customers as a clearly labeled single line item per kWh charge on customer bills. The per kWh charge would be a result of the DSM adjustor mechanism calculation and would be re-calculated annually. Staff believes the individual DSM line-item charge would provide maximum transparency to UNS Electric customers.

Q. How should DSM-related expenses be recorded in the DSM Adjustor account?

A. Staff recommends DSM related expenses should be recorded in the DSM Adjustor account by DSM program and other major categories of DSM expenses with each major category further disaggregated by type of expense. Within each DSM program or major category sub-account, the further disaggregation by type of expense would separately record rebates and incentives, marketing, direct program implementation, administrative costs, etc.

Q. How should the per kWh DSM adjustor rate be reset each year?

A. Staff recommends that UNS Electric's DSM adjustor rate be reset annually on June 1 of each year beginning June 1, 2009; and that the per kWh rate be based upon currently projected DSM costs for that year, adjusted by the previous year's over- or under-collection, divided by projected retail sales (kWh) for that same year. Staff further recommends UNS Electric submit to the Commission in Docket Control its DSM expenses, prudently incurred during the previous calendar year in connection with Commission-approved DSM programs and activities, and its actual DSM cost recovery collected in the previous year, annually by April 1 of each year. The disaggregated costs placed in each DSM Adjustor sub-account for the previous year should be summed to a total DSM cost and compared with documented DSM cost recovery that same year to

determine the over- or under-collection adjustment needed to modify projected DSM costs for the current year adjustor rate calculation. Staff further recommends that UNS Electric submit, with its previous year DSM costs and DSM recovery, a proposed calculation of the new DSM adjustor rate for the current year. Staff also recommends that UNS Electric's proposed new DSM adjustor rate shall become effective on June 1 if no action is taken by the Commission to modify or reject it. If Staff has concerns with the DSM expenses submitted, the DSM revenues collected, or the proposed DSM adjustor rate calculation, Staff will work with the Company to resolve such discrepancies prior to the June 1 effective date. If necessary, Staff would present a proposal to the Commission for a decision.

Q. Why are you recommending that an adjustor rate from this calculation procedure not become effective until June 1, 2009?

A. Under a scenario where Commission approval is granted for the proposed Portfolio Plan DSM activities in 2007, 2008 would be the first full year of spending under the new portfolio of DSM programs at UNS Electric. Under such a scenario, it is likely that most programs would still be ramping-up during 2008 and early 2009, but the new programs should be in effect during that period. The DSM adjustor rate to become effective June 1, 2009, would be the first adjustor rate based upon actual operation (during calendar year 2008) of the DSM programs proposed in the Portfolio Plan.

Q. If the DSM adjustor rate calculated using the proposed procedure does not become effective until June 1, 2009, what DSM Adjustor rate should be used immediately upon the conclusion of this rate case and until June 1, 2009?

A. Staff recommends that from the effective date of an Order in this rate case until June 1, 2009, the initial DSM adjustor rate should be based upon 25 percent of currently estimated

Portfolio Plan first year (2008) program costs for all programs except the LIW program for which 100 percent of the estimated 2008 program costs should be included. These costs should be divided by adjusted Test Year kWh retail sales as reported on Schedule H-2, page 1, line 9 (1,606,376,397 kWh). The following table summarizes the estimated DSM costs to be included in the calculation; recognizing that these numbers could change based upon Commission approval, disapproval, or revisions to the contemplated programs:

UNS Electric, Inc.
Demand Side Management Costs
To be Included in 2009 DSM Adjustor Calculation
(estimated)

	2008 Estimate	Percentage	Included Costs
Education and Outreach	$170,000	25%	$42,500
Direct Load Control	$1,968,000	25%	$492,000
Low Income Weatherization	$105,000	100%	$105,000
Residential New Construction	$420,000	25%	$105,000
HVAC Retrofit	$300,000	25%	$75,000
Shade Tree Program	$65,000	25%	$16,250
Commercial Facilities Efficiency	$400,000	25%	$100,000
	$3,428,000		$935,750

Q. Under this calculation, what would be the level of the initial DSM adjustor rate?

A. The initial DSM adjustor rate would be $935,750 divided by 1,606,376,397 kWh or $0.000583 per kWh. For a residential customer using 866 kWh per month (2006 average usage), this would result in a charge on each monthly bill of $0.50 or about $6.00 per year.

Q. Is this calculation in agreement with what was proposed by UNS Electric in response to STF 13.14?

A. Yes, the calculation is in agreement with UNS Electric's response to STF 13.14.

COST RECOVERY FOR RENEWABLES PROGRAMS

Changes in Renewables Requirements

Q. Why are you introducing the issue of cost recovery for renewables programs in your testimony?

A. Staff is concerned that changes and mandates regarding renewable energy initiatives may require UNS Electric to expand or alter its renewables programs and associated spending in the near future. Staff is interested in ensuring that a funding mechanism flexible enough to adapt to changes which may occur in the future is in place at UNS Electric.

Q. What types of changes are occurring in renewables energy standards and requirements in Arizona?

A. UNS Electric was required to meet the Environmental Portfolio Standard ("EPS") embodied in A.A.C. R14-2-1618 and approved by the Commission in 2001. The EPS required load-serving entities to derive a portion of the retail energy they sell from solar resources or environmental friendly renewable electricity technologies. The portfolio percentage increases annually. It was 1.00 percent in 2005 and became 1.05 percent in 2006 with at least 60 percent from solar resources. The requirement is 1.1 percent for 2007.

Q. Are the EPS rules still in effect?

A. Yes, but the Commission adopted the Renewable Energy Standard and Tariff ("REST") rules on November 14, 2006, in Decision No. 69127. The REST rules are intended to replace the current EPS rules.

Q. What is the status of the REST rules?

A. The Commission submitted its adopted rules to the Office of the Arizona Attorney General for certification. It received that certification on June 15, 2007. The REST rules are expected to become effective 60 days after being received by the Secretary of State to whom they were sent after certification, or on August 14, 2007

Q. Does UNS Electric rely upon renewables programs to meet a portion of its load requirements?

A. Yes. UNS Electric has been engaged in various renewables programs in an attempt to meet its obligations under the EPS. After the REST rules become effective, Staff expects UNS Electric to comply with them.

Current Renewables Cost Recovery

Q. How does UNS Electric currently recover its renewables costs?

A. UNS Electric currently recovers its renewable costs in an EPS surcharge. The Environmentally Friendly Portfolio Surcharge ("EFPS") tariff outlines EPS surcharge amounts assessed monthly to every metered and non-metered retail electric service. The surcharge in the EFPS tariff is currently set at $0.000875 per kWh with monthly caps per service of $0.35 for residential customers, $13.00 for non-residential customers, and $39.00 for non-residential customers with demands of 3,000 kW or more.

Q. How many dollars have been collected by UNS Electric for renewables?

A. During the test year, $538,502 was collected through the EFPS surcharge. Additional funding in the amount of $5,296 was collected during the test year through the Green Watts program which is a voluntary supplemental source of funds for renewables.

Proposed Renewables Cost Recovery

Q. Should renewables programs at UNS Electric continue to be funded through the EFPS tariff?

A. Yes. However, Decision No. 63360 had approved the EFPS on an interim basis, on February 8, 2001, pending true-up in a rate review proceeding in which fair value findings are determined by the Commission. Since the current proceeding would constitute such a rate review proceeding, Staff recommends that the EFPS tariff become permanent. In order to provide more flexibility, however, Staff recommends that the EFPS surcharge tariff become an adjustor mechanism. The initial amount of this adjustor rate would be the same as contained in the current EFPS tariff, including caps. An adjustment mechanism would allow for future funding changes.

The REST rules require each utility to file a tariff within 60 days of the effective date of the REST rules. The REST rules provide for a utility that has an adjustor mechanism to file a request to reset its adjustor rates in lieu of the tariff. Such approved adjustor rates would replace the EFPS surcharge rates in this adjustor mechanism.

Q. How would the adjustor mechanism work?

A. The Company would be able to file an Application for Commission approval to change the renewables adjustor rate and caps. Each Application would be reviewed by Staff, and

Staff recommendations would be made to the Commission. The Commission would approve, disapprove, or modify the Company's application.

Q. If approved, how would the renewables charge under the adjustor mechanism be assessed to customers?

A. The renewables surcharge amount is currently billed as a separate line item on UNS customers' bills. Under the adjustor mechanism, Staff recommends the amount of the renewables charge continue to be billed as a separate line item on UNS customer's bills. The renewables charge line item would be separate and distinct from the DSM charge line item which would also appear on customers' bills.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. Staff recommendations are as follows:

1. Staff recommends that the LIW program be moved into UNS Electric's DSM portfolio plan as a DSM program and that it be funded as a DSM program.
2. Staff recommends that the Emergency Bill Assistance component of the LIW program not be included as part of that program if LIW is re-categorized as DSM, and that Emergency Bill Assistance not be funded with DSM funds.
3. Staff recommends that UNS Electric's TOU pricing plans not be considered as DSM, and that these activities not be funded with DSM funds.
4. Staff recommends that UNS Electric discontinue recovery of its DSM costs from base rates, and that it be allowed to recover its prudently incurred costs in connection with Commission-approved DSM activities through a separate DSM adjustment mechanism, and that such a mechanism should be established in this proceeding.

5. Staff recommends that Commission-approved DSM costs should be assessed to all UNS Electric customers as a clearly labeled single line item per kWh charge on customer bills.
6. Staff recommends DSM related expenses should be recorded in the DSM Adjustor account by DSM program and other major categories of DSM expenses with each major category further disaggregated by type of expense.
7. Staff recommends that UNS Electric's DSM adjustor rate be reset annually on June 1 of each year beginning June 1, 2009; and that the per kWh rate be based upon currently projected DSM costs for that year, adjusted by the previous year's over- or under-collection, divided by projected retail sales (kWh) for that same year.
8. Staff recommends UNS Electric submit to the Commission in Docket Control its DSM expenses, prudently incurred during the previous calendar year in connection with Commission-approved DSM programs and activities, and its actual DSM cost recovery collected in the previous year, annually by April 1 of each year.
9. Staff recommends that UNS Electric submit, with its previous year DSM costs and DSM recovery, a proposed calculation of the new DSM adjustor rate for the current year, annually by April 1 of each year.
10. Staff recommends that UNS Electric's proposed new DSM adjustor rate shall become effective on June 1 of each year beginning June 1, 2009, if no action is taken by the Commission to modify or reject it.
11. Staff recommends that from the effective date of an Order in this rate case until June 1, 2009, the initial DSM adjustor rate should be based upon 25 percent of currently estimated Portfolio Plan first year (2008) program costs for all programs except the LIW program for which 100 percent of the estimated 2008 program costs should be included. These costs should be divided by adjusted Test Year kWh retail sales as reported on Schedule H-2, page 1, line 9.

12. Staff recommends that the EFPS tariff become permanent.

13. Staff recommends that the EFPS surcharge tariff become an adjustor mechanism.

14. Staff recommends the amount of the renewables charge continue to be billed as a separate line item on UNS customer's bills.

Q. Does this conclude your direct testimony?

A. Yes, it does.

DEMAND-SIDE MANAGEMENT PROGRAMS SUMMARY

UNS Electric, Inc. Demand Side Management Programs (Summary)		
Current per Semi-Annual Report	**Proposed in Rate Case**	**Proposed in Portfolio Plan**
		Education and Outreach
Residential Energy Survey	**Residential Energy Survey**	Residential Education
Academic Education	**Academic Education**	Academic Education
Commercial Energy Survey	**Commercial Energy Survey**	Commercial Education
		TOU Education
	Direct Load Control	**Direct Load Control**
	Programmable Thermostat Control	Programmable Thermostat Control
	Air Conditioner Cycling	
	Low Income Weatherization	**Low Income Weatherization**
Energy Smart Homes	**Energy Smart Homes**	**Residential New Construction**
		Residential HVAC Retrofit
	Shade Tree	**Shade Tree**
		Commercial Efficiency
	Time-of-Use Pricing Plan	

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BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

DIRECT

TESTIMONY

OF

BING E.YOUNG

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 28, 2007

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ATTACHMENT

RESUME 1

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783

In reviewing UNS' proposed Rules and Regulations, Staff recommends that UNS be required to re-file its line extension tariff within 30 days that eliminates the free footage allowance for new construction.

Staff additionally recommends that the Commission take no action in this proceeding with regard to hook-up fees, but defers to the generic proceeding.

Lastly, Staff recommends that UNS be required to file a bill estimation tariff containing specific methodologies for calculating estimates for various situations as described in my testimony, and that this tariff be filed with the Commission within 30 days of a final opinion and order.

I. INTRODUCTION AND STATEMENT OF WITNESS QUALIFICATION

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

A. My name is Bing E. Young. I am a Public Utility Analyst IV employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utility Analyst.

A. In my capacity as a Public Utility Analyst, I provide analysis and recommendations to the Commission on a range of issues related to the electric and telecommunications industries.

Q. Please describe your educational background and professional experience.

A. I have a Juris Doctorate (Law) degree from the University of Idaho and a Bachelor of Science degree in Geography from Brigham Young University. I was admitted to the Idaho State Bar in 1986, the Nevada State Bar in 1987, and the Utah State Bar in 2000. My professional work experience is summarized in my attached resume, Attachment 1.

Q. Are you presently licensed to practice law in Arizona?

A. No. I am not licensed to practice law in Arizona. I am, however, a member in good standing of the State Bar of Nevada and the Utah State Bar, though inactive in both states.

Q. What is the purpose of your testimony?

A. My primary focus in this case is to address certain changes to rules and regulations proposed by UNS, including line extensions; hookup fees; and bill estimation procedures.

II. RULES, REGULATIONS, AND LINE EXTENSION POLICIES

Q. Has UNS proposed any modifications to its Rules, Regulations, and Line Extension Policies?

A. Yes. UNS has proposed numerous modifications to its Rules and Regulations. UNS' existing rules are largely those that it inherited when UniSource Energy, the parent company of Tucson Electric Power Company ("TEP"), purchased Citizens Electric's Arizona assets and associated service territories. A large number of these changes are intended to make the UNS Rules and Regulations roughly analogous to those of TEP.

Q. Does Staff support the various modifications?

A. Staff supports or has no objection to many of the modifications. The ones Staff is concerned with are noted below.

Q. What modifications to the Rules and Regulations is Staff addressing?

A Staff is particularly concerned with the proposed changes UNS seeks to make to its line extension tariff and bill estimation procedures.

III. UNS' PROPOSED LINE EXTENSION TARIFF

Q. What modifications does UNS seek to make to its line extension tariff?

A. UNS seeks to modify its existing policy to allow for one span of overhead service conductor for each customer. UNS would also increase the total free overhead extension distance from 400 feet to 500 feet, including the service drop, for all customers. The goal of changing this tariff to allow a 500 feet free allowance is evidently to make the free allowance the same as that which TEP presently offers under its line extension tariff.

Q. Has UNS Electric performed any analysis to justify increasing the free footage allowance from 400 feet to 500 feet?

A. No. In responding to Staff data requests, it appears UNS' proposal is based solely on UNS Electric's desire to have consistent line extension policies with TEP.

Additionally, in response to a Staff data request asking UNS to calculate or estimate the revenue that would have been collected had there been no free line extension tariff in place and each customer required to advance or contribute the actual costs of extending distribution facilities, UNS states that it does not keep statistics of such information that would allow for a retroactive determination of how much could have been collected. UNS indicates that during the test year, 4,980 work orders were closed in both of its service territories, and each one would have to be examined individually to determine the revenue that would have been collected by the Company had there been no free line extension tariff in place.

Q. Has UNS Electric considered eliminating the free footage allowance altogether?

A. No. In response to a Staff data request, UNS indicates that it did not consider eliminating the free footage allowance.

Q. Does Staff support UNS Electric's proposed increase in free distribution line allowance as proposed?

A. No. UNS' witness Mr. Thomas J. Ferry states that phenomenal growth is occurring in both of UNS' service territories. During the test period, he states that customer growth increased in the Mohave County service territory by 4.8 percent and in Santa Cruz County service territory by 5.8 percent. In the past ten years, Mohave County's customer growth increased 58.5 percent, while Santa Cruz County's customer growth was 71.8 percent.

By comparison, UNS witness James S. Pignatelli states that the annual growth rate for TEP is approximately 2.5 percent, while the national average is 1.5 percent. By any measure, the growth rates for both Mohave and Santa Cruz service territories are significant.

This growth rate seems unlikely to slow anytime soon. Mr. Ferry indicates that growth is expected to continue at between five (5) to seven (7) percent annually for the foreseeable future. As soon as the Hoover Dam bypass bridge is complete, parts of Mohave County will be close enough to Las Vegas, Nevada (also one of the fastest growing areas of the country) to be bedroom communities for the Las Vegas metropolitan area. Mr. Ferry further indicates that several residential developers have announced plans to build communities of tens of thousands of homes, primarily in northern Mohave County.

Likewise, in Santa Cruz County, which contains the border port cities of Nogales, Arizona, and Nogales, Mexico, continued high growth is expected, with new developments in the Tubac and Rio Rico areas north of Nogales. "Fast Lane" commercial shipping crossings at the Mexican border have increased demand for additional warehousing facilities in the Nogales area, as Nogales has evolved into one of the major ports of entry between Mexico and the United States in the post North American Free Trade Agreement ("NAFTA") world.

Mr. Ferry states that UNS Electric has invested some $74 million in capital improvements since it took over the Citizens' system in 2003. This is a great deal of capital invested in a three-year period for a system with only 91,650 customers between the two service territories. While some of this capital has likely been necessary to improve or replace existing facilities, Staff believes a large part of this investment has been required in order

to pay for the significant growth in new generation, transmission and distribution facilities.

Under these circumstances, there will be great financial pressure placed on UNS Electric to meet its increasing demand, which also will likely translate to significant upward pressure on the rates it must charge. Staff believes that UNS should use the means it has to offset its costs attributable to this growth. Staff believes that such a policy to eliminate the free footage allowance would significantly improve UNS Electric's ability to recover its distribution costs associated with this growth.

Rather than increasing a free footage allowance for new customers, Staff believes that eliminating the free footage allowance altogether by requiring new customers to at least pay the costs of the distribution lines and facilities they impose on the system will ameliorate, in part, the upward pressure on rates that such growth imposes on the system.

Staff notes that the free footage allowance was recently eliminated by the Commission for Arizona Public Service Company ("APS"), an electric utility facing similar growth rates in Arizona. Staff recommends that UNS Electric be required to submit a revised line extension tariff in Section 9 of its Rules and Regulations, eliminating all free footage allowances and setting forth the methodology by which it will bill developers and new customers for construction of new distribution facilities which are required to serve these new loads. This revision should be filed within 30 days of the issuance of the Commission's final opinion and order.

There may be individual circumstances in which elimination of all free footage allowances may impose extraordinarily harsh consequences on customers. In such cases, UNS or a

potential customer could be permitted to apply to the Commission, on a case-by-case basis, for a waiver or partial waiver of this new policy.

IV. HOOK-UP FEES

Q. Please explain why Staff is addressing the issue of hook-up fees.

A. On March 28, 2006, Commissioner Mundell issued a letter in the recent APS rate case docket (Docket No. E-01345A-05-0816) requesting that the parties provide an analysis of the efficacy of using hook-up fees to help fund APS' capital expenditures so that existing customers are not continually subject to rate increases to pay for growth. Since that time a generic docket has been opened (Docket No. E 00000K-07-0052) to consider whether hook-up fees for new electric (and natural gas) customers is appropriate.

Q. Has UNS Electric done any analysis to consider whether the adoption of hook-up fees or charging a contribution in aid of construction is appropriate?

A. No. UNS indicates in response to data requests that it is participating actively in the Commission's generic docket regarding hook-up fees, but until then it is "abiding" by existing Commission regulations to use economic viability as the key determinant to extend facilities. UNS states that the actual costs of extending service lines varies considerably, but, on average, the free allowance of a single span of service and one span of distribution line for each new customer is fair and easy for customers to understand.

Q. Has Staff researched the adoption of hook-up fees for utilities in other jurisdictions?

A. Yes. Staff surveyed Commissions in other states and found that where they existed, hook-up fees were more commonly adopted for water and wastewater utilities. However, at least one jurisdiction responding to Staff's survey (Maine) adopted a policy where all new

customers pay 100 percent of the distribution and transmission costs of the electric utility to serve that specific customer.

Q. Do any of Arizona's electric utilities currently have hook-up fees in place?

A. Yes. Staff is aware of two electric utilities in Arizona that utilize hook-up fees. Dixie Escalante Rural Electric Association which serves a small portion of the northeastern part of Arizona has a Commission-approved impact fee that imposes a $750 per residential hook-up for installed capacity of over 20 kW plus a $20 connect fee and $60 per kW based on the maximum installed capacity for Commercial, Irrigation, and General Service plus a $20 connect fee.

In addition, Wellton-Mohawk Irrigation and Drainage District ("Wellton"), which provides electric service to a small portion of the southwestern part of Arizona, recently adopted a $750 hook-up fee for new residential facilities plus a $29 connect fee. Wellton has indicated that hook-up fees for non-residential facilities are considered on a case-by-case basis.

Q. Is Staff recommending the adoption of hook-up fees for UNS at this time?

A. No. Though Staff may eventually explore the question of hook-up fees with UNS, at this time Staff recommends that questions related to hook-up fees be deferred to the generic docket.

V. BILL ESTIMATION

Q. Section 11, proposed paragraph 2 (pg. 79) of UNS' proposed Rules and Regulations contains certain provisions related to bill estimation. Does Staff believe that this Section adequately describes the manner in which UNS will estimate a customer's usage related to energy, demand, and time of use?

A. No. The provisions in UNS' Rules and Regulations do not address specific estimation methodologies. Staff believes that it is important to provide such information to the Commission and UNS' customers, as it will limit confusion about the manner in which UNS estimates its customer's usage.

Q. What does Staff recommend with regard to UNS' bill estimation procedures?

A. Staff recommends that UNS be required to submit through Docket Control a separate tariff describing its estimation methodologies for Commission approval within thirty days of a decision in this matter. The tariff should address energy, demand, and time-of-use estimations for situations including but not limited to the following:

a) An energy estimate with at least one year of history. Same customer at same premise or new customer with at least one year of premise history.

b) An energy estimate with less than twelve months history. Same customer at same premise.

c) An energy estimate with less than twelve months history. New customer with premise history.

d) An energy estimate. No history.

e) And energy estimate with at least one year of history. Same customer at the same premise or new customer with one year of premise history.

f) An energy estimate with less than twelve months history. Same customer at same premise.

g) A demand estimate with less than twelve months history. New customer with premise history.

h) A demand estimate with no history.

i) A time-of-use ("TOU") estimate with at least one year of history. Same customer at same premise or new customer with at least one year of premise history.

j) A TOU estimate with less than twelve months history. Same customer at same premise.

k) A TOU estimate with less than twelve months history. New customer with premise history.

l) A TOU estimate. No history. New customer at new premise.

VI. SUMMARY OF RECOMMENDATIONS

Q. Please provide a summary of your recommendations.

A. They are as follows:

1. Staff recommends that UNS be required to re-file its line extension tariff within 30 days that eliminates the free footage allowance for new construction.

2. Staff additionally recommends that the Commission take no action in this proceeding with regard to hook-up fees, but defers to the generic proceeding.

3. Staff recommends that UNS be required to file a bill estimation tariff containing specific methodologies for calculating estimates for various situations as described in my testimony, and that this tariff be filed with the Commission within 30 days of a final opinion and order.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BING EDWARD YOUNG

EDUCATION

J.D. Law, University of Idaho (1986)
B.S. (Geography), Brigham Young University (1983)
Post-Graduate Work, University of Nevada-Reno (1995)

ADDITIONAL TRAINING

Musical Production Studies, Musicians Institute, Hollywood, California (1999)
National Institute of Trial Advocacy, Two Week Litigation Seminar, New Orleans (2003)

PROFESSIONAL ASSOCIATIONS

Member of the Nevada and Utah State Bar Associations

EMPLOYMENT HISTORY

2006-2007

Arizona Corporation Commission, Phoenix, AZ, Public Utilities Analyst IV

2006

United States Census Bureau, Austin, Texas, Worked with US Census Bureau on special project being conducted in Austin, Texas.

2005

Consulting Work for University of South Carolina, Interviewed dozens of Hispanic individuals in the New Orleans area who were victims of Hurricane Katrina as part of a project sponsored by the University of South Carolina, "Latinos in the Aftermath of Hurricane Katrina".

Private Musician and Piano Bar Entertainer, New Orleans, Louisiana, Worked as private performing musician in New Orleans.

2003-2006

Royal Caribbean International, Celebrity Cruise Lines, Miami, Florida. Various contracts as piano bar entertainer aboard Royal Caribbean and Celebrity cruise ships, including CENTURY, ADVENTURE OF THE SEAS, NAVIGATOR OF THE SEAS and GRANDEUR OF THE SEAS.

2002-2003

Private Law Practice, Salt Lake City, Utah, private practice focusing on immigration law, wills and estates, personal injury, domestic relations and business law.

2001

Office of the Attorney General, State of Nevada, Bureau of Consumer Protection, worked with the Nevada Attorney General Consumer Advocate's office assisting with several matters related to electrical deregulation for the State of Nevada and legislation related thereto.

2000-2001

Consulting Attorney, Nevada Public Utilities Commission, consulting attorney for the staff of the Nevada Public Service Commission handling telephone, water, gas and electric related cases.

1996-1999

Public Service Commission of Nevada, Public Utilities Commission of Nevada, attorney for the staff of the Public Service Commission of Nevada (in Las Vegas) and later as general counsel for its successor agency, the Public Utilities Commission of Nevada (in Carson City) handling numerous public utility and transportation-related filings, as well as internal legal matters such as employment discrimination lawsuits.

1995

Nevada Public Service Commission, Part-time work for the Staff of the Nevada Public Service Commission working on cases related to small telephone and water companies while attending graduate school.

1988-1994

Nevada Power Company, worked for Nevada Power Company, Nevada's largest electric utility, in Las Vegas in positions including Assistant Staff Counsel, Staff Counsel and Associate General Counsel with responsibilities including regulatory filings and hearings, especially in the areas of environmental permitting for new power plants, transmission and distribution lines, and general and energy rate cases filed before the Commission. Also served as Manager of Resource Procurement and Administration, administering contracts with non-company wholesale energy providers and creating an RFP ("request for proposals") for contracts with potential non-utility providers of energy.

Miscellaneous

Law Clerk for District Judge Carl Christensen in Las Vegas, Nevada (1987-1988)
Law Clerk for District Judge Dan Meehl in Twin Falls, Idaho (1986-1987)
Intern, Idaho State Supreme Court, Justice Robert Huntley (Summer 1985)
Intern, United States Senate Energy and Natural Resources Committee,
James McClure (R-ID) Chairman, Washington, D.C. (Summer 1984)

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BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

SURREBUTTAL TESTIMONY

OF

BING E.YOUNG

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 24, 2007

TABLE OF CONTENTS

Page

I. Introduction and Statement of Witness Qualification 1

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-904204A-06-0783

This Surrebuttal Testimony addresses issues raised in the Rebuttal Testimony of Mr. Thomas G. Ferry relating to Staff's proposed elimination of free footage allowances for new construction. The Surrebuttal Testimony continues to support elimination of the free footage allowance.

I. INTRODUCTION AND STATEMENT OF WITNESS QUALIFICATION

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

A. My name is Bing E. Young. I am a Public Utility Analyst IV employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed Direct Testimony addressing UNS Electric's Rules and Regulations and Line Extension policies.

Q. What is the subject matter of this Surebuttal Testimony?

A. My Surrebuttal Testimony will address the line extension tariffs and Staff's proposed elimination of the free footage allowance which was discussed in the Rebuttal Testimony of Mr. Thomas J. Ferry.

Q. Could you please discuss Mr. Ferry's Rebuttal Testimony related to the line extension tariffs?

A. Yes. In his Rebuttal Testimony, Mr. Ferry states that I was incorrect in my statement that the Company was proposing an increase in the free footage allowance. Specifically, Mr. Ferry testifies that:

> Subsection 6.2.a of the Rules and Regulations was changed to allow only one span of wire from existing facilities to the customer's point of service. The Company suggested reduction in the service line extension policy which currently allows 150 feet of service wire and one carryover pole. This change would recognize that each customer will have a service drop; but if an individual desires

> to locate their point of service further from the lines than one span, they should pay for the longer line. In Subsection 9.D. of the Rules and Regulations the Company proposed combining the current distribution line footage allowance of 400 foot (sic) with a service allowance of 100 feet for the total of 500 foot per customer; the combined total being 50 foot and one carryover pole less than what is currently allowed.

Mr. Ferry appears to testify that while UNS has given 100 feet more of free allowance to customers on one hand (as part of Section 9 of the Proposed Line Extension Rules), UNS has at the same time proposed taking away other allowances that are currently given to customers (as part of Section 6 of the Proposed Service Lines and Establishment Rules), since under the proposed rule, there is "50 foot and one carryover pole less" than what customers are currently allowed.

Staff does not know whether UNS believes that the 100 feet of extra allowance to customers "nets out" the things that have been taken away. In his Direct Testimony, Mr. Ferry did not indicate that new customers were to lose anything along with the increase in free footage allowance as part of the revised tariffs. In reviewing Section 6.2.a of the new rules, there is nothing obvious in the red-lined version to indicate that this rule constitutes a significant policy change, and one which would balance out the increase in free footage allowance. To the extent that there is some sort of proposed offset to the proposed extra 100 feet of free allowance proposed, this was clearly not spelled out in Mr. Ferry's Direct Testimony, nor is it obvious by a reading of the rule.

Q. Does Mr. Ferry's explanation of UNS's proposed Section 6.2.a of its Rules and Regulations (related to carryover poles and service drops) change Staff's recommendation related to the issue of the line extension tariffs?

A. No. Even if it were true (which Staff does not necessarily concede) that UNS' proposed revisions in Section 6 of the Proposed Service Lines and Establishments essentially nets out or balances out the changes UNS proposes for the increase in free footage allowance in Section 9, this is essentially a moot point, given Staff's position.

Staff agrees with Mr. Ferry's statement that "growth should pay for growth." Certainly one of the easiest and cleanest means by which we can assure that growth help pays for growth is to require developers and new customers to pay the *actual* costs that UNS must incur to extend its distribution system in order to provide service.

Given the astronomical growth rates of five to seven percent being experienced in both of UNS' service territories, it is difficult to imagine that Staff's proposed policy change of eliminating free footage allowances will have any "far-reaching, negative impact(s) on development in (UNS') service territories, " as Mr. Ferry has testified.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

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EXHIBIT
S-66
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

DIRECT

TESTIMONY

OF

JULIE MCNEELY-KIRWAN

PUBLIC UTILITIES ANALYST II

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 28, 2007

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783

On December 15, 2006, UNS Electric, Inc. ("UNS") filed an application with the Arizona Corporation Commission ("Commission") for an increase in its rates throughout the State of Arizona. In addition, UNS proposes to change the existing Customer Assistance Residential Energy Support ("CARES") and Customer Assistance Residential Energy Support Medical programs from volumetric discounts to a flat discount of $8.00.

1. Staff recommends that UNS Electric work with the Arizona Health Care Cost Containment System ("AHCCCS") to ensure that AHCCCS participants eligible for Medical CARES discounts are made aware of the UNS Electric program.

2. Staff recommends that the current discount structures be retained for the CARES and CARES Medical classes.

3. Staff recommends that an adjustment to test year data be made in order to reflect Staff's recommendations regarding Residential rates.

4. Staff recommends a $400 limit per year, per household, for the UNS Electric Warm Spirits emergency bill assistance program, to conform with the UNS Gas program and to allow more households in crisis to benefit from this funding.

5. Staff also recommends that UNS Electric set the following additional eligibility requirements, in conformance with the UNS Gas program: (i) a household income of 150 percent, or less, of the Federal Poverty Guidelines; (ii) a UNS Electric utility customer; (iii) a delinquent or unpaid UNS Electric utility bill; and (iv) no Warm Spirits emergency bill assistance received in the previous 12 months. (UNS Gas, Gary A. Smith, p. 12)

6. Staff recommends that community action agencies administering the emergency bill assistance funding have flexibility in determining how much to provide to each household, up to the $400 limit.

7. Staff also recommends that, if the Warm Spirits program is approved, UNS Electric work to create awareness of the emergency bill assistance available under the program, so that eligible customers will know of this resource before they are facing disconnection for non payment, as discussed in the next section.

8. Staff recommends that the $20,000 proposed for the emergency bill assistance component of the Low-income Weatherization program be added, instead, to the Warm Spirits program. Staff also recommends that the $20,000 be funded through base rates, rather than through the DSM adjustor.

9. Staff recommends that non-CARES Residential customers experiencing difficulty paying utility bills be informed of the CARES program and of the Medical CARES and low-income weatherization programs, if those would be appropriate. Staff also recommends that non-CARES Residential customers be made aware of the Warm Spirits program, if that program is approved by the Commission.

10. Staff recommends that CARES customers experiencing difficulty paying utility bills be informed of the Warm Spirits emergency bill assistance program, if that program is approved, and of the Medical CARES and low-income weatherization programs, if those are appropriate.

11. Staff recommends that UNS Electric provide additional information concerning the above disconnections, and regarding any procedures the Company has in place to ensure that the provisions of R14-2-211 are complied with. Staff also recommends that Medical CARES customers having difficulty paying their utility bills be made aware of the low-income weatherization program, and of the Warm Spirits program, if that program is approved by the Commission.

INTRODUCTION

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

A. My name is Julie McNeely-Kirwan. I am a Public Utilities Analyst II employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst II.

A. In my capacity as a Public Utilities Analyst II, I review monthly filings of purchased gas adjustors. My duties include reviewing annual utility affiliated interest reports for compliance and evaluating demand-side management programs submitted for approval to the Commission. My duties have also included preparing written testimony in the UNS Gas rate case, as well testifying during the UNS Gas rate case hearing.

Q. Please describe your educational background and professional experience.

A. In 1979, I graduated magna cum laude from Arizona State University, receiving a Bachelor of Arts degree in History. In 1987, I received a Master's Degree in Political Science from the University of Wisconsin, Madison. I have been employed by the Commission since September of 2006.

Q. What is the subject matter of this testimony?

A. This testimony will present Staff's analysis and evaluation of UNS Electric, Inc.'s ("UNS Electric") existing low-income assistance programs and the proposed changes to those programs. This testimony will also include discussion and analysis of the Company's proposal to add an emergency bill assistance component to its Low-income Weatherization ("LIW") program, as well as its proposal to create a Warm Spirits program for UNS Electric.

LOW-INCOME ASSISTANCE PROGRAMS

CARES and Medical CARES

Q. What low-income assistance programs does UNS currently provide for its customers?

A. UNS provides the Customer Assistance Residential Energy Support ("CARES") program and Medical Customer Assistance Residential Energy Support ("Medical CARES") program. (Thomas J. Ferry, p. 9-10)

Q. Please describe the eligibility requirements for the current CARES program.

A. To be eligible for the UNS Electric CARES program a household's gross income must be at, or below, 150 percent of the Federal Poverty Guidelines. The FPG guidelines establish poverty levels for households based on the number of individuals in each household. For 2007, the annual FPG level for a household with four persons is $20,650; 150 percent of $20,650 is $30,975 annually, or $2,581 per month. (Thomas J. Ferry; p. 9; 2007 Health and Human Services Poverty Guidelines)

Q. Please describe the application process for the CARES program.

A. Low-income customers must submit an application to qualify for the CARES program to UNS Electric. Originally, the Department of Economic Security processed applications, and enrollment took up to 45 days. Due to program modifications authorized by the Commission in 2004, applications are processed in-house and low-income customers can now be enrolled in CARES in less than 20 days. In addition, customers are no longer required to recertify themselves on an annual basis. Instead, UNS Electric recertifies a sample group of participants every two years and when a customer changes residence. (Thomas J. Ferry, p. 9; Decision No. 67434)

Q. How many UNS Electric customers participate in the CARES program and how has participation changed over time?

A. Average participation for the six months ending December 2006 was 5,985, or 7.56 percent of Residential customers. Average participation for the six months ending December 2004 was 5,157, or 7.18 percent of Residential customers. (UNS Electric, Inc. CARES Discount Program semi-annual reports.) Over two years this represents an increase of 16 percent in the number of participants, although participation as a percentage of Residential customers has remained relatively steady.

Q. Please describe the discounts currently offered under the CARES program.

A. The CARES program provides declining tiered percentage discounts. The discount is 30 percent for bills with usage from 0 to 300 kWh, 20 percent for bills with usage of 301 to 600 kWh and 10 percent for bills with usage of 601-1,000 kWh. CARES customers using over 1,000 kWh receive a flat $8.00 discount. (Thomas J. Ferry, pp. 9-10; Schedule H-4)

The total level of usage determines the discount applied to all kWh used. For example, to receive a 30 percent discount a CARES customer must use 300 kWh or less in a month. If a CARES customer uses 301 kWh, the amount of the discount decreases to 20 percent for all 301 kWh used.

Q. Please describe the eligibility requirements and application process for the current Medical CARES.

A. Customers must submit an application to UNS Electric, along with verification from a physician that they are dependent on medical life-support equipment. This physician-verification is required in addition to the CARES eligibility standard that household

income be at, or below, 150 percent of the Federal Poverty Guidelines. (Thomas J. Ferry, pp. 9-10; Schedule H-4; Tariff No.: C.A.R.E.S. – M, Effective December 3, 2004)

The types of medical support equipment that qualify as essential under the Medical CARES program include the following: (i) Ventilator; (ii) Oxygen Concentrator; (iii) Peritoneal Dialysis Cycler; (iv) Hemo Dialysis Equipment; (v) Feeding Pump; (vi) Infusion Pump; (vii) Suction Machine; (ix) Small Volume Nebulizer; and (x) Oximeter. (Tariff No.: C.A.R.E.S. – M, Effective December 3, 2004)

Q. How many UNS Electric customers participate in the Medical CARES program?

A. UNS Electric states that, as of March 2007, there were 178 Medical CARES participants. With 80,327 Residential customers reported as of March 2007, Medical CARES customers represent 0.22 percent of Residential customers. (Response to STF 5.7; March 2007 UNS Electric Bank Balance Report FA-3.)

Staff recommends that UNS Electric work with the Arizona Health Care Cost Containment System ("AHCCCS") to ensure that AHCCCS participants eligible for Medical CARES discounts are made aware of the UNS Electric program.

Q. Does the current Medical CARES program offer discounts different from those offered under the standard CARES program? If so, please describe the discounts currently offered under the Medical CARES program.

A. Yes, under the current Medical CARES program the tiered percentage discounts are tied to usage ranges that are twice those offered under the standard CARES program. The Medical CARES program provides monthly discounts of 30 percent for bills with usage from 0-600 kWh (0-300 kWh under standard CARES), 20 percent for bills with usage

from 601-1,200 kWh (301-600 kWh under standard CARES), 10 percent for bills with usage from 1,201-2,000 kWh (601-1,000 kWh under standard CARES). There is a flat $8.00 discount for usage over 2,000 kWh. (Under standard CARES the flat $8.00 discount applies after 1,000 kWh.) (Thomas J. Ferry, p 9-10; www.uesaz.com)

As with the standard CARES program, the total level of usage by a Medical CARES customers determines the discount applied to the entire bill. For example, while a Medical CARES customer using 1,200 kWh would receive a 20 percent discount for all 1,200 kWh, a Medical CARES customer using 1,201 kWh would receive a 10 percent discount for all 1,201 kWh.

Q. Does the discount proposed by UNS Electric provide different discounts to CARES and Medical CARES customers?

A. No. In his testimony, Mr. Ferry indicates that UNS Electric proposes to eliminate the volumetric discount for both CARES and Medical CARES and to apply a "universal" discount of $8.00 (or less than $8.00 for bills under that amount).

Q. Should Medical CARES customers receive discounts different from those provided to standard CARES customers?

A. Yes. While Medical CARES and standard CARES customers are both low-income, Medical CARES are also: (i) dependent upon medical equipment; and (ii) have average usage rates higher than those for either standard CARES or non-CARES Residential customers.

Q. How many kWh do CARES, Medical CARES and non-CARES Residential customers use on average?

A. The averages from the test year are as follows:

- On an annual basis, the average CARES customer uses 744 kWh per month, ranging from a low of 520 kWh to a high of 1,009 kWh.
- On an annual basis, the average Medical CARES customer uses 1,113 kWh per month, ranging from a low of 780 kWh to a high of 2,498 kWh per month.
- On an annual basis, the average non-CARES Residential customer uses 869 kWh per month, ranging from a low of 592 kWh to a high of 1,281 per month.

(Response to STF 5.6)

Q. Why is kWh usage by CARES Medical customers higher than for other CARES or non-CARES Residential customers?

A. UNS Electric states that it has done no studies regarding the differing usage rates for CARES, Medical CARES and non-CARES Residential customers. (Response to STF 12-4.) Decision No. 67434 states that the Medical CARES program provides bill discounts for UNS Electric customers "at higher consumption levels when the customer requires the use of medical equipment for sustaining life and a physician verifies the situation."

Q. What percentage of CARES and Medical CARES bills qualify for percentage discounts, based on usage under 1,000 kWh for CARES customers, and 2,000 kWh for Medical CARES customers?

A. The bill frequency provided by UNS Electric does not break out Medical CARES customers (under 200 participants). For the combined CARES/Medical CARES class, 83.83 percent of customer bills were for 1,000 kWh, or less. (Schedule H-5, pp. 1-2) The

small number of Medical CARES customers would be eligible for percentage discounts up to 2,000 kWh.

Q. Does UNS propose to change the CARES program discount?

A. Yes. Under the UNS Electric proposal, the declining tiered percentage discounts would be eliminated. As stated elsewhere in this testimony, UNS proposes a flat monthly CARES discount of $8.00 on all bills that total $8.00 or more. CARES customers with bills totaling less than $8.00 would receive lower discounts; those discounts would equal the amount of the bills. (UNS states that fewer than 2.51 percent of CARES bills total less than $8.00.) (Bentley Erdwurm, p.24; UNS Response to STF 5.5; Schedule H-5, p. 2 of 7)

Q. Do the proposed CARES and Medical CARES discounts promote conservation as well as the current discounts?

A. No. A flat discount applied to all bills, regardless of usage, does not provide the same incentive to conserve as the current declining tiered percentage discount. The current discount provides the highest percentage discount for the lowest usage rates, and provides progressively lower discounts for progressively higher usage rates. Under a flat discount, customers would receive the same discount, without regard to their energy consumption. (The one exception to the flat rate is that customers with kWh charges amounting to less than $8.00 would receive discounts equal to those lower amounts.)

Q. What would be the impact on customer bills of the discount changes proposed by UNS Electric?

The below tables provide bill impacts, based on current UNS Electric rates, for CARES and Medical CARES customers with average usage; the tables cover both Mohave and Santa Cruz County.

CARES Bills at Average Levels of Usage (Mohave County)

Averages	Usage	With Current Discount	With UNS Proposed Discount	Increase/ Decrease	Percentage Change
Lowest Monthly	520	$43.95	$46.94	$2.99	6.80%
Highest Monthly	1,009	$92.49	$92.49	$0.00	0.00%
Annual	744	$68.20	$67.80	($0.40)	($0.59%)

CARES Bills at Average Levels of Usage (Santa Cruz County)

Averages	Usage	With Current Discount	With UNS Proposed Discount	Increase/ Decrease	Percentage Change
Lowest Monthly	520	$45.78	$49.23	$3.45	8.00%
Highest Monthly	1,009	$96.93	$96.93	$0.00	0.00%
Annual	744	$71.17	$71.08	($0.09)	($0.13%)

Medical CARES Bills at Average Levels of Usage (Mohave County)

Averages	Usage	With Current Discount	With UNS Proposed Discount	Increase/ Decrease	Percentage Change
Lowest Monthly	738	$60.20	$60.74	$0.54	0.90%
Highest Monthly	2,498	$231.19	$231.198	$0.00	0.00%
Annual	1,113	$88.14	$95.68	$7.54	8.55%

Medical CARES Bills at Average Levels of Usage (Santa Cruz County)

Averages	Usage	With Current Discount	With UNS Proposed Discount	Increase/ Decrease	Percentage Change
Lowest Monthly	738	$62.79	$70.49	$7.70	12.26%
Highest Monthly	2,498	$242.18	$242.18	$0.00	0.00%
Annual	1,113	$92.06	$107.07	$15.01	16.30%

A different rate structure for Residential customers would shift the impact of UNS Electric's proposed discount changes. For example, under the Residential rate changes proposed by

UNS Electric, the largest impacts would be to Medical CARES customers with usage from 400 kWh to 1,000 kWh. Under the UNS Electric proposed rates these increases would range from 12.13 percent to 27.94 percent for customers in both Mohave and Santa Cruz County. (Response to STF 12-5)

Q. Why is the impact of UNS Electric's proposed changes different for Santa Cruz County than for Mohave County customers?

A. Under existing rates there is a per-kWh energy charge of $0.0749 for all Mohave County Residential customers and a per-kWh energy charge of $0.0793 for all Santa Cruz County Residential customers. Under the rate proposal put forward by UNS Electric, Residential customers in both counties would be covered by the same rates, which also affect CARES/Medical CARES customers.

Q. Does Staff recommend the proposed changes to the CARES and Medical CARES discounts?

A. No. The proposed changes to the CARES and Medical CARES discounts would eliminate the incentive to conserve provided by the existing discount structure, and would generally have a larger negative impact on CARES Medical customers with low-average, or average, usage, and on CARES customers with low-average usage.

Staff recommends that the current discount structures be retained for the CARES and CARES Medical classes.

Q. Would an adjustment to test year data be required with respect to the CARES discount proposed by UNS Electric?

A. Yes. The CARES Expense noted on Schedule-2, -$52,937, Page 1 of 5, reflects UNS Electric's proposed changes to the CARES and Medical CARES programs.[1] (Dallas J. Dukes, p. 7; Response to STF 5.1) This amount should be removed and replaced with an amount calculated using the discounts recommended by Staff. Staff will recommend that final amount to be used for the adjustment once Staff makes its recommendations regarding Residential rates.

Staff recommends that an adjustment to test year data be made in order to reflect Staff's recommendations regarding Residential rates.

Warm Spirits

Q. Please describe the Warm Spirits program, as proposed by UNS Electric.

A. The proposed UNS Electric Warm Spirits program is modeled on the existing UNS Gas Warm Spirits program. The UNS Electric program would provide emergency bill assistance to low-income customers in crisis. The proceeds would be distributed by community action agencies. Under the UNS Electric proposal, the community action agencies would determine which customers would receive assistance and how much.

Q. Does Staff have any recommendations concerning the proposed Warm Spirits program?

A. Yes. Staff recommends a $400 limit per year, per household, for the UNS Electric Warm Spirits emergency bill assistance program, to conform with the UNS Gas program and to allow more households in crisis to benefit from this funding. Staff also recommends that

[1] Test year CARES discount = $532,009 - $584,937 (normalized CARES bills = 73,118 x $8.00 flat discount = $584,937) = ($52,937).

UNS Electric set the following additional eligibility requirements, in conformance with the UNS Gas program: (i) a household income of 150 percent, or less, of the Federal Poverty Guidelines; (ii) a UNS Electric utility customer; (iii) a delinquent or unpaid UNS Electric utility bill; and (iv) no Warm Spirits emergency bill assistance received in the previous 12 months. (UNS Gas, Gary A. Smith, p. 12.) The above requirements would be in addition to the requirements for establishing that a customer is in crisis, including loss of reduction of income, unexpected expenses and a danger to the health or safety of the household (Thomas J. Ferry, P. 19)

Staff recommends that community action agencies administering the emergency bill assistance funding have flexibility in determining how much to provide to each household, up to the $400 limit.

Staff also recommends that, if the Warm Spirits program is approved, UNS Electric work to create awareness of the emergency bill assistance available under the program, so that eligible customers will know of this resource before they are facing disconnection for non payment, as discussed in the next section.

Q. What is the proposed funding for the Warm Spirits program?

A. UNS Electric has proposed that its Warm Spirits program be funded through donations from ratepayers, and matched, up to $25,000, by shareholder donations. (Thomas J. Ferry, p. 11.)

Staff recommends that the $20,000 proposed for the emergency bill assistance component of the Low-income Weatherization program be added, instead, to the Warm Spirits

program. (Thomas J. Ferry, p 19) Staff also recommends that the $20,000 be funded through base rates, rather than through the DSM adjustor, as proposed by UNS Electric.

Q. Please explain why Staff is proposing to move the emergency bill assistance funding into the Warm Spirits program, and why Staff recommends that this funding not be included in the DSM adjustor.

A. UNS Electric has proposed that the Low-income Weatherization ("LIW") program be included as part of its DSM portfolio. Emergency bill assistance, although a benefit for customers in crisis situations, is a low-income assistance program and should not be included in the DSM portfolio. There are several negative consequences to including emergency bill assistance within a DSM portfolio:

(i) UNS has proposed a separate DSM charge. If emergency bill assistance is funded through a separate DSM adjustor it may not be clear to ratepayers that they are also paying for a non-DSM program through the DSM charge;

(ii) funding a non-DSM program through a DSM adjustor reduces clarity regarding the total funding level for actual DSM programs; and

(iii) inclusion of non-DSM program components within the DSM portfolio could reduce clarity regarding the objectives of DSM.

DISCONNECTIONS

Q. How many non-CARES Residential customers were disconnected during the test year?

A. UNS Electric reports 1,171 disconnections for nonpayment of non-CARES Residential customers from July 2005 through June 2006. UNS Electric reported an average of 69,492 non-CARES Residential customers for this same period. (Responses to STF 5.6 and 5.11)

Staff recommends that non-CARES Residential customers experiencing difficulty paying utility bills be informed of the CARES program and of the Medical CARES and low-income weatherization programs, if those would be appropriate. Staff also recommends that non-CARES Residential customers be made aware of the Warm Spirits program, if that program is approved by the Commission.

Q. How many CARES customers were disconnected for non-payment during the test year?

A. UNS Electric reports 117 disconnections for nonpayment of CARES customers from July 2005 through June 2006. Average CARES participation for that period was 5,792. (Responses to STF 5.6 and 5.11.)

Staff recommends that CARES customers experiencing difficulty paying utility bills be informed of the Warm Spirits emergency bill assistance program, if that program is approved, and of the Medical CARES and low-income weatherization programs, if those are appropriate.

Q. Have there been any recent disconnections for nonpayment of Medical CARES participants?

A. During the period from July 2005 through June 2006, UNS Electric reports six disconnections of Medical CARES customers for nonpayment. The average number of Medical CARES participants during this period was 147. There were an additional two such disconnections in the nine months ending March 2007). (Responses to STF 5.6 and 5.11.)

Staff is very concerned about these disconnections of Medical CARES participants and has asked UNS Electric for more information about them.

Q. Are there Arizona Administrative Code rules regulating disconnections of customers with medical issues?

A. Yes. R14-2-211.A.5 states that residential service shall not be terminated "where the customer has an inability to pay and:

"a. The customer can establish through medical documentation that . . .termination would be especially dangerous to the health of a customer or a permanent resident residing on the customer's premises, or

"b. Life supporting equipment used in the home that is dependent on utility service for operation of such apparatus."

Staff recommends that UNS Electric provide additional information concerning the above disconnections, and regarding any procedures the Company has in place to ensure that the provisions of R14-2-211.A.5 are complied with. Staff also recommends that Medical CARES customers having difficulty paying their utility bills be made aware of the low-income weatherization program, and of the Warm Spirits program, if that program is approved by the Commission.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. Staff recommends that UNS Electric work with the Arizona Health Care Cost Containment System ("AHCCCS") to ensure that AHCCCS participants eligible for Medical CARES discounts are made aware of the UNS Electric program.

2. Staff recommends that the current discount structures be retained for the CARES and CARES Medical classes.

3. Staff recommends that an adjustment to test year data be made in order to reflect Staff's recommendations regarding Residential rates.

4. Staff recommends a $400 limit per year, per household, for the UNS Electric Warm Spirits emergency bill assistance program, to conform with the UNS Gas program and to allow more households in crisis to benefit from this funding.

5. Staff also recommends that UNS Electric set the following additional eligibility requirements, in conformance with the UNS Gas program: (i) a household income of 150 percent, or less, of the Federal Poverty Guidelines; (ii) a UNS Electric utility customer; (iii) a delinquent or unpaid UNS Electric utility bill; and (iv) no Warm Spirits emergency bill assistance received in the previous 12 months. (UNS Gas, Gary A. Smith, p. 12)

6. Staff recommends that community action agencies administering the emergency bill assistance funding have flexibility in determining how much to provide to each household, up to the $400 limit.

7. Staff also recommends that, if the Warm Spirits program is approved, UNS Electric work to create awareness of the emergency bill assistance available under the program, so that eligible customers will know of this resource before they are facing disconnection for non payment, as discussed in the next section.

8. Staff recommends that the $20,000 proposed for the emergency bill assistance component of the Low-income Weatherization program be added, instead, to the Warm Spirits program. Staff also recommends that the $20,000 be funded through base rates, rather than through the DSM adjustor.

9. Staff recommends that non-CARES Residential customers experiencing difficulty paying utility bills be informed of the CARES program and of the Medical CARES and low-income weatherization programs, if those would be appropriate. Staff also recommends that non-CARES Residential customers be made aware of the Warm Spirits program, if that program is approved by the Commission.

10. Staff recommends that CARES customers experiencing difficulty paying utility bills be informed of the Warm Spirits emergency bill assistance program, if that program is approved, and of the Medical CARES and low-income weatherization programs, if those are appropriate.

11. Staff recommends that UNS Electric provide additional information concerning the above disconnections, and regarding any procedures the Company has in place to ensure that the provisions of R14-2-211 are complied with. Staff also recommends that Medical CARES customers having difficulty paying their utility bills be made aware of the low-income weatherization program, and of the Warm Spirits program, if that program is approved by the Commission.

1 **Q. Does this conclude your direct testimony?**

2 A. Yes, it does.

EXHIBIT
S-67
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

SURREBUTTAL

TESTIMONY

OF

JULIE MCNEELY-KIRWAN

PUBLIC UTILITIES ANALYST II

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 24, 2007

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INTRODUCTION 1

CARES DISCOUNT 1

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-743

This Surrebuttal Testimony addresses issues raised by UNS Electric, Inc., in its Rebuttal Testimony, including the CARES discount, the Medical CARES discount and Medical CARES disconnections.

1. Staff recommends that the current discount structures for CARES and Medical CARES be retained.

2. If the current discount structure is retained, Staff recommends that the language of the website, and other UNS Electric marketing materials, be clarified to more clearly describe the discounts available under the CARES and Medical CARES programs.

3. Staff recommends that Medical CARES participation be reported separately in UNS Electric's CARES semi-annual reports.

4. Staff also recommends that any disconnections of Medical CARES customers for non-payment be reported in the CARES semi-annual reports, and that the Company should include explanations for why the reported disconnections do not violate the provisions of Arizona Administrative Code R14-2-211.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Julie McNeely-Kirwan. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed Direct Testimony addressing UNS Electric's CARES and Medical CARES programs and discounts. My testimony also discussed concerns regarding disconnections of Medical CARES customers.

Q. What is the subject matter of this Surrebuttal Testimony?

A. This Surrebuttal Testimony will address the CARES program discounts, including the new Medical CARES discount proposed by UNS Electric in its rebuttal testimony. My testimony will also discuss clarifying disconnect procedures to ensure that Medical CARES customers dependent upon medical equipment are not disconnected, in accordance with the provisions of Arizona Administrative Code R14-2-211.

CARES DISCOUNT

Q. Do you agree with testimony by UNS Electric that the current CARES and Medical CARES discount structures should be replaced with flat discounts?

A. No. The current CARES and Medical CARES discount structures provide incentives to conserve that are not available under the proposed flat rate discounts.

Q. Would the increased Medical CARES discount proposed by UNS Electric address all of Staff's concerns regarding the proposed discount changes for CARES and Medical CARES customers?

A. No. While increasing the flat rate discount for Medical CARES customers (from $8.00 to $10.00) would lessen bill impacts on Medical CARES customers, increases for Medical CARES customers with average usage would remain disproportionate. The new discount structure would also lessen incentives to conserve. Staff recommends that the current discount structures for CARES and Medical CARES be retained.

Q. Do you agree with the testimony of D. Bentley Erdwurm, on page 16 of his Rebuttal Testimony, that the current CARES discount requires CARES customers to "use more energy in order to receive a needed discount"?

A. No. Under the declining tiered structure currently provided by UNS Electric, all CARES customers receive discounts with built-in incentives to conserve. Customers using the least amount of energy receive the highest percentage discounts (30%) on their entire bills, while customers using more energy receive progressively lower percentage discounts (20%, 10% or a flat $8.00 discount). CARES customers using 1,001 kWh, or more, would have $8.00 taken off the bill, and would receive a discount of less than one percent.

Q. Is it Staff's understanding that RUCO supports the Company's proposed changes to the CARES discount?

A. Yes. Ms. Diaz Cortez, of RUCO, states on page 5 of her Additional Direct Testimony that RUCO supports the Company's proposed changes to the CARES discounts. Ms. Diaz Cortez also states that under the current rate structure "only the largest users receive the maximum benefits from the CARES discount."

Q. Does Staff concur with RUCO's testimony in this matter?

A. No. The actual dollar discount on a CARES or Medical CARES bill varies depending on the level of usage and the discount applicable to that level of usage. Generally, discounts under the current structure range between $6.00 and $12.00 on a regular CARES bill. Regardless of the discount, the total bill always increases as usage increases. Customers with the higher usage levels receive both lower percentage discounts and higher bills than customers with lower usage.

Q. Does Staff have any recommendations concerning the marketing of the CARES discount program?

A. Yes. If the current discount structure is retained, Staff recommends that the language of the website, and other UNS Electric marketing materials, be clarified to more clearly describe the discounts available under the CARES and Medical CARES programs. It should be clearly indicated that the level of discount *for the entire bill* is determined by where the total monthly usage falls in relation to specific cutoffs: 300, 600 or 1,000 kWh for regular CARES customers, or 600, 1,200 or 2,000 kWh for Medical CARES customers. (For example, a regular CARES bill showing total usage of 300 kWh would be discounted, in its entirety, at 30%, while a regular CARES bill showing total usage of 301 kWh would be discounted, also in its entirety, at 20%.)

Q. Does Staff have any recommendation concerning CARES reporting and disconnections of Medical CARES customers?

A. Yes. Staff recommends that Medical CARES participation be reported separately in UNS Electric's CARES semi-annual reports. Separate reporting will indicate whether efforts to expand Medical CARES participation are succeeding. Staff also recommends that any disconnections of Medical CARES customers for non-payment be reported in the CARES

semi-annual reports, and that the Company should include explanations for why the reported disconnections do not violate the provisions of Arizona Administrative Code R14-2-211.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

EXHIBIT
S-68
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

RECEIVED

2007 SEP 28 P 4: 53

AZ CORP COMMISSION
DOCKET CONTROL

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR APPROVAL OF 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.	DOCKET NO. E-04204A-06-0783 **STAFF'S NOTICE OF FILING PROPOSED PPFAC CAP LANGUAGE**

Staff of the Arizona Corporation Commission ("Staff") hereby files its proposal with respect to a PPFAC cap which the Staff recommends to address the potential rate shock issues raised by the Company's Exhibit A-43 in the above-referenced matter.

RESPECTFULLY SUBMITTED this 28th day of September 2007.

Maureen A. Scott, Senior Staff Counsel
Kevin O. Torrey, Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

Original and thirteen (13) copies of the foregoing filed this 28th day of September 2007 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85003

. . .

Copies of the foregoing e-mailed and/or mailed this 28th day of September 2007 to:

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Phoenix, Arizona 85004-2202

Karyn Christensen

UNS Electric PPFAC provisions to prevent a rate shock situation from occurring

Exhibit UNSE 43 illustrates how UNS Electric projects that its purchased power and fuel cost for the period June 2008 through May 2009 is projected to vary, depending upon the price level of natural gas. That exhibit shows the Company's estimated total rates, including the PPFAC forward component rates, at natural gas prices of $6.00, $7.50 and $9.00 per MMBtu, respectively. It shows the Company's forecast of a PPFAC forward component of 0.48 cents/kWh at $6.00/MMBtu natural gas prices, and 1.73 cents and 2.98 cents at $7.50 and $9.00 natural gas prices. The total percentage increases from present rates (including UNS Electric's proposed base rate increase) range from 8.8% at $6.00 natural gas, and were projected by the Company to be 21.5% and 34.2% at $7.50 and $9.00 natural gas prices, respectively.

Staff believes this information raises concerns about the potential for customer rate shock, especially if natural gas prices move significantly higher than the $7.50/MMBtu that UNS Electric used as the basis for its bill impact estimates in Exhibit UNSE 44. Because natural gas prices can be very volatile, no one currently knows with accuracy what natural gas prices, and, by reference, what UNS Electric's power costs will be, for the period June 2008 through May 2009 when the first PPFAC forward component would be in effect.

After receiving the information contained in Exhibits UNSE 43 and 44, Staff therefore wanted to highlight for the Commission the potential PPFAC rate shock issue, and to offer a recommendation for addressing such a situation, should it occur.

Staff recommends that the Commission impose an annual cap to address the potential of PPFAC rate shock given new information presented by UNSE. The PSA that the Commission approved for APS contains an annual cap of 4 mills which limits the amount by which the new annual rate can change from the current annual rate.[1] That level of annual cap would not be appropriate for UNSE because UNSE does not own any base load generation power costs and its power costs are subject to a higher degree of volatility than are APS'. During cross examination by Staff and under Commission questioning, UNSE witness DeConcini suggested that, if a cap were to be imposed on the UNSE PPFAC, it would need to reflect a wider range than the 4 mill cap contained in the APS PSA. Mr. DeConcini suggested that one way of determining a cap for the UNSE PPFAC would be to examine the volatility of the PPFAC rates under a range of natural gas prices. That type of analysis, including information on customer bill impacts, is essentially what UNSE provided in Exhibits UNSE 43 and 44.[2] Using the information provided in Exhibits UNSE 43 and 44, an annual cap for UNSE's PPFAC could be developed that would be tailored to UNSE's unique circumstances and exposure to power

[1] APS' 4 mill cap, as it came out of the most recent rate case decision, is a limit on the amount of change that can occur from the current annual rate to the new annual rate. The annual rate is the sum of the Forward, Historical, and Transition components.

[2] UNS Electric also provided additional bill impacts in Exhibit UNSE 45, assuming "solid fuel resources," i.e., a coal plant; however, Staff views that scenario as speculative, and accordingly, does not accord it any weight in evaluating what an annual cap on the UNSE PPFAC could be.

cost price volatility. For example, if the Commission wanted to use UNSE's "base forecast" of power costs (which are based on natural gas at $7.50 per MMBtu), an annual PPFAC cap could be developed using such information. Based on the information shown in Exhibit UNSE 43, for example, if an annual cap were set at 1.73 cents per kWh for the PPFAC forward component, the total rate increase under UNSE's projection would be limited to approximately the 21.5% shown on that exhibit.[3] If the cap for the UNSE PPFAC were established in this manner, the 1.73 cents per kWh would be a "hard cap" that could not be exceeded.[4] (This would differ from APS' cap which is a limit on change.)

In summary, the Staff recommends an annual PPFAC cap as discussed herein to prevent the potential for rate shock in this case.[5]

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[3] The 21.5% increase assumes that UNSE's full base rate increase request and its requested ratemaking treatment of Black Mountain Generating Station (BMGS) would be approved. If the Commission approves something less than UNSE's full base rate request, the total increase would be lower. With respect to the impact of BMGS, UNSE witness Grant testified under cross examination by Staff that the rate impacts shown on Ex. UNSE 43 would be similar with and without the Company's requested ratemaking treatment for BMGS.

[4] In this illustrative example, based on Ex UNSE 43, the 1.73 cents/kWh cap would apply to the PPFAC forward component only and could be viewed as a "hard cap" on the forward component. If the 1.73 cent PPFAC forward component produced an under-collection of cost, the under collection would be addressed in the PPFAC true-up component for the next period. If gas prices and power costs increase substantially in UNSE's PPFAC filing for the forward component beyond what they are expected to be currently (i.e., beyond the 1.73 cents per kWh shown on Ex UNSE 43), the application of this cap on the PPFAC forward component would essentially result in a deferral of cost recovery in order to avoid a rate shock situation.

[5] Staff's initial PPFAC recommendation did not include a cap. However, , after seeing the potential for a rate shock situation in UNSE's projections in Exhibit UNSE 43 that assumed higher gas and power prices, Staff now supports the implementation of a PPFAC cap for UNSE.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
JEFF HATCH-MILLER- CHAIRMAN
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

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

UNS Electric, Inc. ("UNS Electric" or "Company"), pursuant to A.R.S. §§ 40-250, 40-251 and 40-301, and A.A.C. R14-2-103, hereby files this Application requesting the following:

1. Approval of an increase in its base rates of $8,507,097, or approximately 5.5%, over test year revenues, and to set UNS Electric's fair value rate base at $177,802,341. UNS Electric further requests approval of UNS Electric's proposed rate design with new rates becoming effective January 1, 2008;
2. Approval of a modification of its Purchased Power and Fuel Adjustment Clause ("PPFAC") to be effective June 1, 2008;
3. Approval of a revenue neutral post-test year adjustment to rate base effective June 1, 2008 in connection with UNS Electric's proposed acquisition of a new 90 MW peaking facility in Mohave County; and
4. Approval of financing authority necessary for UNS Electric to acquire the 90 MW generating facility within its Mohave County service area.

EXHIBIT
UNSE-1
Admitted

In support of this Application, UNS Electric respectfully states as follows:

OVERVIEW

A. Summary of Application.

UNS Electric's current rates and charges do not produce a reasonable return on the fair value of its property devoted to public service and are therefore not just and reasonable. Therefore, the Company is requesting an increase in its base rates of $8,507,097, or approximately 5.5%, over test year revenues, and to set UNS Electric's fair value rate base at $177,802,341. This increase reflects an overall rate of return and weighted average cost of capital of 9.89%. This overall rate of return is based on an 11.8% cost of common equity capital, an 8.22% cost of long-term debt and a 6.36% cost of short-term debt, with a capital structure consisting of 48.85% common equity, 47.18% long-term debt and 3.97% short-term debt, which was UNS Electric's actual capital structure as of June 30, 2006. The requested rate of return on fair value rate base is 7.84%. The rate increase sought is required to enable the Company to earn a fair rate of return on the fair value of its assets devoted to public service, which return will recover the Company's capital costs necessarily and prudently incurred in rendering utility service to customers. The requested increase is necessary for UNS Electric to operate as a financially strong utility that can ensure UNS Electric customers continued reliable service, on demand, and at reasonable prices into the future.

Moreover, as set forth in more detail in the accompanying testimony, UNS Electric is requesting that the Commission approve: (i) the Company's proposed rate design, including mandatory Time of Use ("TOU") rates for new residential and small commercial customers and for all customers with over 1000 kilowatts in demand; (ii) new or enhanced Demand-Side Management ("DSM") programs and a charge to cover the cost of the DSM programs; and (iii) changes to the Company's Rules and Regulations.

Finally, UNS Electric presently obtains all of its power under a full requirements Power Supply Agreement with Pinnacle West Capital Corporation ("PWCC PSA"). The PWCC PSA will expire on May 31, 2008. The Company is in the process of procuring a new power portfolio

to replace the PWCC PSA, including power supply contracts and Company-owned generating facilities. The new power portfolio gives rise to financial issues that UNS Electric believes should be addressed in this docket in order to allow the Company to obtain a new power supply in the most prudent manner possible. Therefore, UNS Electric is requesting to: (i) modify its PPFAC effective June 1, 2008 to adequately address the costs of new power supplies; (ii) make a post-test year adjustment to rate base in connection with its proposed purchase of the Black Mountain Generating Station ("BMGS"); (iii) issue up to $40 million in additional debt securities and receive up to $40 million in additional equity contributions directly related to purchasing BMGS.

B. Purchased Power and Fuel Adjustment Clause.

The Company is requesting several significant changes to its PPFAC. Given the volatile nature of the natural gas and purchase power markets, the current PPFAC must be modified to deal with this new volatility. For instance, UNS Electric is proposing that the PPFAC have an automatic adjustment mechanism; it does not have such a mechanism currently. The Company is proposing to: (i) clarify the costs that can be included in the PPFAC; (ii) use a 12-month rolling average cost of purchase power and fuel (and including a period to "phase-in" this rolling average); and (iii) recognize carrying costs on PPFAC bank balances at an interest rate equal to the cost of short-term borrowing for UNS Electric.

Specifically, UNS Electric believes that the following costs should be included in the PPFAC mechanism: (i) all generation fuel used in steam generation including natural gas, fuel oil and coal, as well as fuel transportation and coal rail expenses; (ii) generation fuel used in combustion turbine generation including natural gas and fuel oil; (iii) purchased power costs for both energy and demand charges; and (iv) transmission-related expenses. Credit costs, because they are a real cost of doing business in the wholesale markets for both fuel and purchased power, also should be recovered through the PPFAC.

UNS Electric proposes that the PPFAC rate automatically adjust on a monthly basis. This will provide a certain level of price smoothing to UNS Electric customers and mitigate extreme

price changes that may be only short-term in nature. UNS Electric proposes a mechanism similar to what is in effect for both UNS Gas, Inc. and Southwest Gas Corporation. Further, UNS Electric proposes that the PPFAC rate be phased-in based on the last six months starting July 1, 2008, and adding an additional month into the average until a 12-month average is being used. For instance, the PPFAC rate would be based on the last six months in July, 2008 (January through June 2008); for August, 2008, the PPFAC rate would be based on the last seven months (January through July 2008).

C. Black Mountain Generating Station.

UNS Electric is requesting approval of a post-test year adjustment to rate base in connection with UNS Electric's proposed acquisition of a new 90 MW peaking facility in Mohave County, known as the Black Mountain Generating Station ("BMGS"). This facility is being developed by an affiliate of UNS Electric – UniSource Energy Development Company ("UEDC"). The total cost for UNS Electric to acquire BMGS will be at least $60 million (and potentially up to $65 million). BMGS is an important element of the Company's power portfolio that will replace the PWCC PSA and ownership of BMGS provides operational, reliability and financial benefits to UNS Electric and its customers.

In order to acquire BMGS, the Company must be reasonably able to assure: (i) repayment to its lenders; (ii) maintenance of the minimum financial ratios contained in UNS Electric's credit agreements; and (iii) an opportunity to earn a reasonable return on invested equity capital. The $60 million acquisition cost is known and measurable. Therefore, to meet these objectives, UNS Electric requests a post-test year adjustment to rate base of $60 million, effective June 1, 2008, the date when commercial operation will commence. UNS Electric will not seek treatment of any acquisition cost above $60 million until it files a subsequent rate application.

UNS Electric also seeks to reclassify rates effective June 1, 2008. The rate base adjustment and related rate reclassification initially will be revenue neutral. The effect of a $60 million post-test year adjustment will be to add $10 million to the Company's non-fuel revenue requirement, and to increase the base delivery charge by approximately 0.6 cents per kWh. But

the Company also proposes to decrease the base power supply rate by 0.6 cents per kWh when the post-test year adjustment is made.

As set forth in the accompanying testimony, the proposed recognition will provide both operational and financial benefits to UNS Electric and to its ratepayers. The Company's proposal provides the best means to ensure access to capital necessary for the purchase of BMGS. Ownership of BMGS by UNS Electric results in long-term benefits through the effects of book depreciation and deferred income taxes on rate base. The operational benefits include the flexibility of have full and unfettered dispatch rights; full control over operations and maintenance to ensure high standards of reliability; firm availability of a facility to meet UNS Electric's peak capacity and reserve needs; and reductions in transmission costs while improving system reliability. Given the operational and financial benefits, the Company believes that the Commission should approve the requested rate base treatment of BMGS as being just and reasonable and in the public interest.

D. Financing Authority.

In connection with the proposed acquisition of BMGS, UNS Electric is requesting authority to issue up to $40 million of new debt securities, and to receive up to $40 million of additional equity contributions from UNS Electric's parent company, over and above any contributions that could otherwise be made under Commission rules and orders. This combination of debt and equity will be used to finance the acquisition of BMGS. Because UNS Electric will need some flexibility to determine the appropriate mix of debt and equity capital to use, the Company is requesting a total of $80 million of new financing authority in order to finance the $60 to $65 million purchase price for BMGS. Granting the requested financing authority will allow the Company to maintain a reasonably balanced capital structure and to have the flexibility to determine the appropriate percentage of debt capital to use, depending on the cost of debt and other factors at the time of the final decision.

1. **Debt Securities.**

With regards to the debt securities, UNS Electric is seeking authority to issue up to $40 million in debt securities in addition to any indebtedness arising out of transactions described in its Application for Financing Order (Docket No. E-0424A-06-0493) filed July 28, 2006, and currently pending before the Commission. These new debt securities will either be in the form of new long-term debt, or new short-term or intermediate-term debt that UNS Electric would intend to refinance with long-term debt at a later date.

a. Long-Term Debt.

If the debt is long-term debt, the terms will depend upon market conditions that exist at the time of issuance and on investors' or lenders' assessment of UNS Electric's creditworthiness. The Company expects this long-term debt would have a maturity of five to thirty years at a fixed rate of interest. The principal would then likely be due in a single payment at maturity, although the possibility exists of some required principal amortization or more than one maturity date. The debt may be issued either in the public markets or in a private placement. This debt may also be issued in connection with a refinancing of short-term or intermediate-term debt as described below. The debt may be unsecured, secured by the assets being purchased with the financing, or secured on the same basis as other secured borrowings at UNS Electric.

b. Short-Term or Immediate-Term Debt.

It may be more advantageous for UNS Electric, however, to issue short-term or immediate-term debt (debt with a maturity not to exceed five years) depending on the market conditions at the time the Company needs to issue the new debt. UNS Electric would intend, and is seeking authorization allowing it, to refinance this debt with long-term debt when market conditions are more favorable.

The terms of this short-term or intermediate-term debt will depend on market conditions at the time of issuance. The terms will also be dependent on lenders' assessment of UNS Electric's creditworthiness. The Company expects that it would issue short-term or intermediate-term debt with a maturity of one-month to five-years. The interest payable on this debt would

likely be at a variable rate, but it could be fixed depending on market conditions. The principal would also likely be due in on bullet payment at maturity, although some required principal amortization is possible. This debt may be unsecured, secured by the assets being purchased with the financing, or secured on the same basis as other secured borrowings at UNS Electric.

c. Security.

UNS Electric is seeking Commission authority to enter into indentures or security agreements which grant liens on some or all of its properties to provide security in connection with the financing transactions described herein.

UNS Electric's obligations under its Credit Agreement and its Senior Notes are unsecured. In the Credit Agreement and the Note Purchase and Guaranty Agreement for the Senior Notes, UNS Electric covenants that it will not allow any lien to exist securing indebtedness for borrowed money on any of its properties (unless it makes provisions to equally and ratably secure the obligations covered by such agreements with the other indebtedness secured thereby). Depending on the market conditions existing at the time of the issuance of the new debt for which UNS Electric is requesting authority, or the subsequent refinancing of UNS Electric's short-term or intermediate-term debt authorized hereby, it may be necessary or desirable for UNS Electric to issue secured debt to complete the financing.

The lien of such secured debt could attach to some or all of UNS Electric's properties, including the properties acquired with the proceeds of such financing and property acquired after the date the initial lien is granted. In connection therewith, UNS Electric may enter into indentures or security agreements granting liens and providing for the issuance of secured debt. If, at the time that such a lien were granted to secure the new indebtedness, UNS Electric continued to be bound by covenants which required existing indebtedness to be equally and ratably secured, UNS Electric would need to make arrangements to cause the existing indebtedness to be equally and ratable secured. Those arrangements could include the issuance of mortgage bonds for the benefit of holders of existing indebtedness to collateralize the existing indebtedness. So, in addition to seeking Commission authority to incur liens to secure the

obligations of UNS Electric under the new debt described herein, UNS Electric is also seeking the authority for such liens to secure any other of its obligations which will need to be secured in connection with the granting of such liens. To the extent that the Commission deems that UNS Electric must receive authorization to enter into any of these indentures or security agreements or other agreements and transaction documents in connection therewith, UNS Electric requests that such authority be granted in the order approving this Application.

2. Additional Equity Contributions.

UNS Electric is also requesting the authority to receive up to $40 million of additional equity contributions from UniSource Energy Corporation ("UniSource"). The additional equity amount would be over and above any contributions that could otherwise be made under Commission rules and orders. This equity contribution would be for the purpose of the Company's purchase of BMGS. This authority will also allow the Company to maintain a balanced capital structure.

UNS Electric believes that allowing it the authority to issue up to $40 million in debt and to receive up to $40 million in additional equity to finance the purchase of the BMGS is consistent with sound financial practices and its duty as a public service corporation, is prudent and is in the public interest. Further, by granting UNS Electric's financing request in addition to its requested rate treatment for BMGS, UNS Electric's ability to provide reliable electric service will be enhanced.

Therefore, in connection with its request for financing approvals, UNS Electric seeks a Commission Order:

(1) Approving its financing request within this rate application;

(2) Authorizing the Company to issue up to $40 million in either long-term debt and/or short- to intermediate-term debt and allowing the Company to refinance any short- or intermediate-term debt into long-term debt when the Company believes market conditions are favorable to do so;

(3) Authorizing the Company to receive an additional amount of equity, up to $40 million, in connection with the purchase of BMGS to allow the Company to maintain a balanced capital structure;

(4) Authorizing UNS Electric to grant a lien on some or all of its properties, including the properties acquired with the proceeds of this financing, and properties acquired after the date of the grant of the lien, to secure its obligations under the debt for which authorization is sought and to secure any other obligations of UNS Electric existing at the time such lien is granted which need to be secured if such lien is granted;

(5) Authorizing UNS Electric to engage in transactions and to execute or cause to be executed any documents or modifications to existing transaction documents necessary to effectuate the authorizations requested from UNS Electric in connection with the financing of the BMGS purchase;

(6) Authorizing the execution, delivery and performance by UNS Electric of all contracts, agreements, and other instruments incidental to any or all of the foregoing or otherwise deemed by UNS Electric to be necessary, desirable, or appropriate in connection with this financing request; and

(7) Ordering that any Order or Orders be deemed effective upon issuance.

APPLICATION

I.

The Company is a corporation duly organized, existing and in good standing under the laws of the State of Arizona. Its principal place of business is 2498 Airway Avenue, Kingman, Arizona 86409.

II.

The Company is a public service corporation principally engaged in the transmission and distribution of electricity for sale in Arizona pursuant to Certificates of Convenience and Necessity issued by the Commission.

III.

All communications and correspondence concerning this Application, as well as communications and pleadings with respect thereto filed by other parties, should be served upon the following:

Raymond S. Heyman, Esq.
Michelle Livengood, Esq.
UniSource Energy Corporation
One South Church, Suite 200
Tucson, Arizona 85701

and

Michael W. Patten, Esq.
Roshka, DeWulf & Patten, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

IV.

This Commission has jurisdiction to conduct public hearings to determine the fair value of the property of a public service corporation, to fix a just and reasonable rate of return thereon, and thereafter, to approve rate schedules designed to develop such return. Further, the Commission has jurisdiction to establish the practices and procedures to govern the conduct of such hearing, including, but not limited to, such matters as notice, intervention, filing, service, exhibits, discovery and other prehearing and hearing matters.

V.

Accompanying this Application are the standard filing requirements and rate design schedules described in A.A.C. R14-2-103 and the direct testimony and related exhibits of the following witnesses:

- James S. Pignatelli
- Thomas J. Ferry
- Kentton C. Grant
- Kevin P. Larson

- Karen G. Kissinger
- Dr. Ronald E. White
- Dallas J. Dukes
- Michael J. DeConcini
- Edmund A. Beck
- D. Bentley Erdwurm

VI.

UNS Electric respectfully requests that this Commission set a date for a hearing on this Application such that new rates for the Company will become effective on January 1, 2008. At the hearing conducted pursuant to this rate request, UNS Electric will establish, among other things, that:

(1) its current rates and charges do not permit the Company to earn a fair return on the fair value of its assets devoted to public service and are therefore no longer just and reasonable;

(2) the requested increase is the minimum amount necessary to allow the Company an opportunity to earn a fair return on the fair value of its assets devoted to public service, for preservation of the Company's financial integrity and for the attraction of new capital investment on reasonable terms;

(3) the Company requires additional permanent base revenue of at least $8,507,097 million based on annualized test period sales in order to continue to provide adequate and reliable gas service to its customers as required by law;

(4) the proposed rate design, including mandatory TOU rates for all new residential and small commercial customers and for all customers with over 1 megawatt in demand should be approved;

(5) the separate DSM charge proposed by UNS Electric to fund new and expanded DSM programs should be approved;

(6) the proposed modifications to UNS Electric's tariffs (specifically, its Rules and Regulations);

(7) the existing PPFAC for the Company should be revised so that proper and timely price signals are provided to the customers and so UNS Electric timely recovers the cost of fuel and purchased power;

(8) the recognition of the BMGS by making a post-test year adjustment to rate base and reclassifying rates effective June 1, 2008, should be approved in order to facilitate the acquisition of the facility; and

(9) the Company should be authorized to issue up to $40 million of new debt securities, and to receive up to $40 million of additional equity contributions from UNS Electric's parent company for the proposed acquisition of BMGS.

VII.

In addition to setting a hearing date, UNS Electric asks that the Commission issue a procedural order setting forth the prescribed notice for the Application, establishing procedures for intervention, and providing for appropriate discovery. UNS Electric further requests that the Company should be authorized to serve all discovery requests, answers and objections electronically. Hard copy service would remain available to parties upon request or where the confidential nature of the information makes the use of electronic service impractical.

WHEREFORE, UNS Electric respectfully requests that the Commission:

(1) issue a procedural order establishing a date for hearing evidence concerning the Application and prescribing the time and form of notice to UNS Electric customers and establishing procedures for intervention and discovery as described above;

(2) issue a final order granting the Company the permanent rate increase sought herein;

(3) issue a final order approving the new or modified rate and service schedules included with the Company's Application with an effective date no later than January 1, 2008;

(4) issue a final order approving UNS Electric's revised Rules and Regulations, which were submitted with this Application and related testimony;

(5) issue a final order approving UNS Electric's proposed DSM charge to fund DSM programs;

(6) issue a final order authorizing UNS Electric's depreciation rates and classifications;

(7) issue a final order approving the requested modifications to the PPFAC effective as of June 1, 2008;

(8) issue a final order approving UNS Electric's proposed rate base adjustment and rate reclassification with respect to the proposed acquisition of Black Mountain Generating Station, effective June 1, 2008;

(9) issue a final order granting approval for UNS Electric to issue up to $40 million of new debt securities, and to receive up to $40 million of additional equity contributions from UNS Electric's parent company, in order to finance UNS Electric's proposed acquisition of the Black Mountain Generating Station. Specifically, the Company requests that the Commission:

(a) approve its financing request within this rate application;

(b) authorize the Company to issue up to $40 million in either long-term debt and/or short- to intermediate-term debt and allow the Company to refinance any short- or intermediate-term debt into long-term debt when the Company believes market conditions are favorable to do so;

(c) authorize the Company to receive an additional amount of equity, up to $40 million, in connection with the purchase of BMGS to allow the Company to maintain a balanced capital structure;

(d) authorize the Company to grant a lien on some or all of its properties, including the properties acquired with the proceeds of this financing, and properties acquired after the date of the grant of the lien, to secure its obligations under the debt for which authorization is sought and to secure any other obligations of UNS Electric existing at the time such lien is granted which need to be secured if such lien is granted;

(e) authorize UNS Electric to engage in transactions and to execute or cause to be executed any documents or modifications to existing transaction documents necessary to effectuate the authorizations requested from UNS Electric in connection with the financing of the BMGS purchase;

(f) authorize the execution, delivery and performance by UNS Electric of all contracts, agreements, and other instruments incidental to any or all of the foregoing or otherwise deemed by UNS Electric to be necessary, desirable, or appropriate in connection with this financing request; and

(g) provide that any Order or Orders be deemed effective upon issuance.

(10) grant the Company such additional relief as the Commission deems just and proper.

RESPECTFULLY SUBMITTED this 15th day of December 2006.

UNS Electric, Inc.

By _____
Michael W. Patten
ROSHKA DEWULF & PATTEN, PLC.
One Arizona Center
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Phoenix, Arizona 85004

and

Raymond S. Heyman
Michelle Livengood
UniSource Energy Services
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Tucson, Arizona 85702

Attorneys for UNS Electric, Inc.

Original and thirteen copies of the foregoing filed this 15th day of December 2006, with:

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

Copy of the foregoing hand-delivered this 15th day of December 2006, to:

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

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

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

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

Commissioner Barry Wong
Arizona Corporation Commission
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Ernest Johnson, Esq.
Director, Utilities Division
Arizona Corporation Commission
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Phoenix, Arizona 85007

By Mary Ippolito

EXHIBIT
UNSE-2
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

At the request of Commission Staff, UNS Electric, Inc., through undersigned counsel, hereby files copies of clean and redlined versions of the Phase 1 and Phase 2 tariffs as a Supplement to the Application filed on December 15, 2006.

RESPECTFULLY SUBMITTED this 11th day of January 2007.

UNS Electric, Inc.

By _____

Michael W. Patten
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One Arizona Center
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Phoenix, Arizona 85004

and

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Michelle Livengood
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Tucson, Arizona 85702

Attorneys for UNS Electric, Inc.

UNSE-2

Original and thirteen copies of the foregoing filed this 11th day of January 2007, with:

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

Copy of the foregoing hand-delivered this 11th day of January 2007, to:

Chairman Jeff Hatch-Miller
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By Mary Ippolito

Phase 1

CLEAN

VERSION

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan C.A.R.E.S.
Customer Assistance Residential Energy Support

AVAILABILITY

This C.A.R.E.S. pricing plan is available in all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

This C.A.R.E.S. pricing plan is available to those residential customers presently taking service under the Company's residential service pricing plan whose gross annual income is not more than one hundred fifty percent (150%) of the federal poverty level guideline effective at the time qualification and annual certification is sought. Residential customers who desire to qualify for such pricing plan must initially make application to the Company for qualification and must provide verification to the Company that the customer's household gross income does not exceed one hundred fifty percent (150%) of the federal poverty level. Subsequent to the initial certification, the residential customer who seeks to retain eligibility for the C.A.R.E.S. pricing plan must provide a personal certification that the household gross income of the residential dwelling unit involved does not exceed one hundred fifty percent (150%) of the federal poverty level. Eligibility information provided by the customer on the application form is subject to verification by the Company. Samples of the existing CARES participants will be re-certified every two years prior to January 1 and when a customer changes residence.

RATE

The monthly bill shall be in accordance with the RES-01 pricing plan except that a discount of $8.00 per month shall be applied. The minimum bill shall be the customer charge under Pricing Plan RES-01 as applicable.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan RES-01
Residential Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

Service is provided at one point of delivery measured through one meter and is restricted to private single family dwellings or individually metered apartments.

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:

Delivery Charges:

Minimum Customer Charge per month @	$8.00
First 400 kWhs per month @	$0.012617
All additional kWhs per month @	$0.022617
Base Power Supply Charge, all kWhs per month @	$0.077178

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan RES-01
Residential Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

Service is provided at one point of delivery measured through one meter and is restricted to private single family dwellings or individually metered apartments.

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:

Delivery Charges:

Minimum Customer Charge per month @	$8.000
Unbundled Customer Charge	
Customer Other	$3.691
Metering	$1.504
Meter Reading	$0.449
Billing and Collection	$2.356
First 400 kWhs per month @	$0.012617
Unbundled $/kWh Charge	
Transmission	$0.003633
Sub-transmission	$0.004032
Delivery	$0.004599
Production not in Power Supply (1)	$0.000353
All additional kWhs per month @	$0.022617
Unbundled $/kWh Charge	
Transmission	$0.003633
Sub-transmission	$0.004032
Delivery	$0.014599
Production not in Power Supply (1)	$0.000353
Base Power Supply Charge, all kWhs per month @	$0.077178

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

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.

AVAILABILITY

In all territory served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To all Customers establishing service on or after the effective date of this Pricing Plan, to all Customers who relocate thus establishing service at a new premise on or after the effective date of this Pricing Plan, and to all customers requiring a meter change-out on or after the effective date of this Pricing Plan. Available as an optional rate to Customers served under the Company's Pricing Plan RS, Residential Service (Frozen). Service is provided at one point of delivery measured through one meter and is restricted to private single family dwellings or individually metered apartments.

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:

Minimum Customer Charge per month @	$8.00
Delivery - Energy Charge 1st 400 kWh/month per kWh @	$0.012618
Delivery - Energy Charge additional kWh/month per kWh @	$0.022618

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific RS-TOU PPFAC minus RS PPFAC (from the frozen non-time differentiated rate)" are:

Differentials

Summer On-Peak:	+ $0.01419 (i.e., add $0.01419 to the non-time differentiated RS PPFAC)
Summer Shoulder:	+ $0.00381 (i.e., add $0.00381 to the non-time differentiated RS PPFAC)
Summer Off-Peak:	- $0.00081 (i.e., subtract $0.00081 to the non-time differentiated RS PPFAC)
Winter On-Peak:	+ $0.00288 (i.e., add $0.00288 to the non-time differentiated RS PPFAC)
Winter Off-Peak:	- $0.01212 (i.e., subtract $0.01212 to the non-time differentiated RS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan RS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan RS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01419 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan RS.)

RESIDENTIAL SERVICE – TIME-OF-USE (continued)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan SGS-10
Small General Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer for any purpose where service is provided at one point of delivery and measured through one meter and 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.

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:

Delivery Charges:

Minimum Customer Charge per month @	$12.00
First 400 kWhs per month @	$0.027772
All additional kWhs per month @	$0.037772
Base Power Supply Charge, all kWhs per month @	$0.074947

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan SGS-10
Small General Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer for any purpose where service is provided at one point of delivery and measured through one meter and where the monthly usage is not more than 5,000 kWh in any two (2) consecutive months. Customers who use more than 5,000 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.

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:

Delivery Charges:

Minimum Customer Charge per month @	$12.00
Unbundled Customer Charge	
Customer Other	$4.495
Metering	$2.441
Meter Reading	$0.814
Billing and Collection	$4.250
First 400 kWhs per month @	$0.027772
Unbundled $/kWh Charge	
Transmission	$0.002756
Sub-transmission	$0.003270
Delivery	$0.021404
Production not in Power Supply (1)	$0.000342

All additional kWhs per month @	$0.037772
Unbundled $/kWh Charge	
Transmission	$0.002756
Sub-transmission	$0.003270
Delivery	$0.031404
Production not in Power Supply (1)	$0.000342
Base Power Supply Charge, all kWhs per month @	$0.074947

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

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

AVAILABILITY

In all territory served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To all Customers establishing service on or after the effective date of this Pricing Plan, to all Customers who relocate thus establishing service at a new premise on or after the effective date of this Pricing Plan, and to all customers requiring a meter change-out on or after the effective date of this Pricing Plan. Available as an optional rate to Customers served under the Company's Pricing Plan SGS, Small General Service Service (Frozen). To any customer for any purpose where service is provided at one point of delivery and measured through one meter and 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 – Time-of-Use 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.

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:

Minimum Customer Charge per month @	$12.00
Delivery - Energy Charge 1st 400 kWh/month per kWh @	$0.027772
Delivery - Energy Charge additional kWh/month per kWh @	$0.037772

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific SGS-TOU PPFAC minus SGS PPFAC (from the frozen non-time differentiated rate)" are:

SMALL GENERAL SERVICE – TIME-OF-USE (continued)

Differentials

Summer On-Peak:	+ $0.01461 (i.e., add $0.01461 to the non-time differentiated SGS PPFAC)
Summer Shoulder:	+ $0.00392 (i.e., add $0.00392 to the non-time differentiated SGS PPFAC)
Summer Off-Peak:	- $0.00039 (i.e., subtract $0.00039 to the non-time differentiated SGS PPFAC)
Winter On-Peak:	+ $0.00371 (i.e., add $0.00371 to the non-time differentiated SGS PPFAC)
Winter Off-Peak:	- $0.01129 (i.e., subtract $0.01129 to the non-time differentiated SGS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan SGS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan SGS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01461 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan SGS.)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

TAX CLAUSE

To the charges computed under the above pricing plan, 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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

SMALL GENERAL SERVICE – TIME-OF-USE (continued)

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

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

Standard offer sales service to any customer for any purpose where such service is supplied at one point of delivery and measured through one meter and the maximum monthly demand is less than 1,000 kW.

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:

Delivery Charges:

Minimum Customer Charge per month @	$11.10
If optional time-of-use service is elected, Minimum Customer Charge per month @	$16.00
Billing Demand Charge per kW @	$10.50
Energy Charge per kWh @	$0.007497
Base Power Supply Charge, all kWhs per month @	$0.066362

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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

LARGE GENERAL SERVICE (continued)

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.

DETERMINATION OF BILLING DEMAND

Normal service: If the time-of-use option is not chosen, the monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month.

Time-of-Use: If time-of-use service is chosen, 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 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.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

LARGE GENERAL SERVICE (continued)

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LGS
Large General Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

Standard offer sales service to any customer for any purpose where such service is supplied at one point of delivery and measured through one meter and the maximum monthly demand is less than 1,000 kW.

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:

Delivery Charges:

Minimum Customer Charge per month @	$11.100
Unbundled Customer Charge	
Customer Other	$8.338
Metering	$0.754
Meter Reading	$0.325
Billing and Collection	$1.683
If optional time-of-use service is elected,	
Minimum Customer Charge per month @	$16.000
Unbundled Customer Charge	
Customer Other	$12.020
Metering	$1.087
Meter Reading	$0.468
Billing and Collection	$2.425
Billing Demand Charge per kW @	$10.500
Unbundled $/kWh Charge is entirely a Delivery Charge	

Energy Charge per kWh @	$0.007497
Unbundled $/kWh Charge	
Transmission	$0.001167
Sub-transmission	$0.001834
Delivery	$0.004190
Production not in Power Supply (1)	$0.000306
Base Power Supply Charge, all kWhs per month @	$0.066362

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

Normal service: If the time-of-use option is not chosen, the monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month.

Time-of-Use: If time-of-use service is chosen, 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 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.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

Standard offer sales service to any customer for any purpose where such service is supplied at one point of delivery and measured through one meter and the maximum monthly demand is less than 1,000 kW.

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.

RATE

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

Minimum Customer Charge per month @	$11.10
Delivery - Billing Demand Charge per kW-mo @	$10.50
Delivery Energy Charge per kWh @	$0.007497

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific LGS-TOU PPFAC minus LGS PPFAC (from the terminated non-time differentiated rate)" are:

LARGE GENERAL SERVICE – TIME-OF-USE (continued)

Differentials

Summer On-Peak:	+ $0.01577 (i.e., add $0. 01577 to the non-time differentiated LGS PPFAC)
Summer Shoulder:	+ $0.00439 (i.e., add $0. 00439 to the non-time differentiated LGS PPFAC)
Summer Off-Peak:	+ $0.00077 (i.e., add $0.00077 to the non-time differentiated LGS PPFAC)
Winter On-Peak:	+ $0.00401 (i.e., add $0.00401 to the non-time differentiated LGS PPFAC)
Winter Off-Peak:	- $0.01099 (i.e., subtract $0.01099 to the non-time differentiated LGS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan LGS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan LGS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01577 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan LGS.)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

Normal service: If the time-of-use option is not chosen, the monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month.

Time-of-Use: If time-of-use service is chosen, 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 or 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.

LARGE GENERAL SERVICE – TIME-OF-USE (continued)

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LPS
Large Power Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer for any purpose where the service is supplied at one point of delivery and measured through one meter when the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE

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

For service at less than 69,000 volts (Distribution Service):

Delivery Charges:

Minimum Customer Charge per month @	$365.00
Billing Demand Charge per kW @	$21.53
Energy Charge per kWh @	N/A

Base Power Supply Charge, all kWhs per month @ $0.052704

For service at 69,000 volts or higher (Transmission Service):

Delivery Charges:

Minimum Customer Charge per month @	$400.00
Billing Demand Charge per kW @	$12.53
Energy Charge per kWh @	N/A

Base Power Supply Charge, all kWhs per month @ $0.052704

LARGE POWER SERVICE (continued)

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Maximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge

Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

LARGE POWER SERVICE (continued)

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

LARGE POWER SERVICE (continued)

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

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.

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer for any purpose where the service is supplied at one point of delivery and measured through one meter when the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE

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

For service at less than 69,000 volts (Distribution Service):

Delivery Charges:

Minimum Customer Charge per month @	$365.000
Unbundled Customer Charge	
Customer Other	$208.686
Metering	$0.709
Meter Reading	$25.303
Billing and Collection	$130.302
Billing Demand Charge per kW @	$21.530
Unbundled $/kW Charge	
Transmission	$0.110
Sub-transmission	$0.441
Delivery	$20.854
Production not in Power Supply (1)	$0.125
Energy Charge per kWh @	N/A
Base Power Supply Charge, all kWhs per month @	$0.052704

For service at 69,000 volts or higher (Transmission Service):

Delivery Charges:

Minimum Customer Charge per month @	$400.000
Unbundled Customer Charge	
Customer Other	$228.696
Metering	$0.777
Meter Reading	$27.730
Billing and Collection	$142.797
Billing Demand Charge per kW @	$12.530
Unbundled $/kW Charge	
Transmission	$0.118
Sub-transmission	$0.472
Delivery	$11.806
Production not in Power Supply (1)	$0.134
Energy Charge per kWh @	N/A
Base Power Supply Charge, all kWhs per month @	$0.052704

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Maximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

LARGE POWER SERVICE continued

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

LARGE POWER SERVICE continued

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

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.

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer for any purpose where the service is supplied at one point of delivery and measured through one meter when the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE

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

For service at less than 69,000 volts (Distribution Service):

Minimum Customer Charge per month @	$365.00
Delivery - Billing Demand Charge per kW @	$21.53

For service at 69,000 volts or higher (Transmission Service):

Minimum Customer Charge per month @	$400.00
Delivery - Billing Demand Charge per kW @	$12.53

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

LARGE POWER SERVICE - TOU (continued)

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific LPS-TOU PPFAC minus LPS PPFAC (from the terminated non-time differentiated rate)" are:

Differentials

Summer On-Peak:	+ $0.01691 (i.e., add $0. 01691 to the non-time differentiated LPS PPFAC)
Summer Shoulder:	+ $0.00492 (i.e., add $0. 00492 to the non-time differentiated LPS PPFAC)
Summer Off-Peak:	+ $0.00191 (i.e., add $0.00191 to the non-time differentiated LPS PPFAC)
Winter On-Peak:	+ $0.00491 (i.e., add $0.00401 to the non-time differentiated LPS PPFAC)
Winter Off-Peak:	- $0.01009 (i.e., subtract $0.01009 to the non-time differentiated LPS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan LPS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) isobtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan LPS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01691 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan LPS.)

A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Maximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge

Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

LARGE POWER SERVICE - TOU (continued)

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

LARGE POWER SERVICE - TOU (continued)

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

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.

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer with a minimum demand of 50 kW for any purpose where such service is supplied at one point of delivery and measured through one meter and is interruptible within fifteen (15) minutes of verbal notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE

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

Delivery Charges:

Minimum Customer Charge per month @	$11.10
Billing Demand Charge per kW @	$3.50
Energy Charge per kWh @	$0.018268
Base Power Supply Charge, all kWhs per month @	$0.054911

Penalty for failure to interrupt:

In the event that the Customer fails to interrupt its load when requested to do so by the Company, the customer shall pay an additional charge as follows:

Billing Demand Charge per kW @	$10.00

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm pricing plan for a period of at least twelve (12) months.

INTERRUPTIBLE POWER SERVICE (continued)

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

The Company reserves the right to curtail service to the customer at any time and for such period of time that, in the sole judgment of the Company, the operation of the system requires curtailment by the customer.

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. Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

INTERRUPTIBLE POWER SERVICE (continued)

The Company will endeavor to provide the customer with as much advance notice as possible of the required interruptions or curtailments. However, the customer shall interrupt or curtail service within fifteen (15) minutes, if so requested.

The Company reserves the right to have automatic equipment installed for immediate interruption of the customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption or curtailment of service under this pricing plan.

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

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan IPS
Interruptible Power Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer with a minimum demand of 50 kW for any purpose where such service is supplied at one point of delivery and measured through one meter and is interruptible within fifteen (15) minutes of verbal notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE

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

Delivery Charges:

Minimum Customer Charge per month @	$11.100
Unbundled Customer Charge	
Customer Other	$6.708
Metering	$1.118
Meter Reading	$0.531
Billing and Collection	$2.743
Billing Demand Charge per kW @	$3.500
Unbundled $/kWh Charge is entirely a Delivery Charge	
Energy Charge per kWh @	$0.018268
Unbundled $/kWh Charge	
Transmission	$0.000615
Sub-transmission	$0.001225
Delivery	$0.016175
Production not in Power Supply (1)	$0.000253
Base Power Supply Charge, all kWhs per month @	$0.054911

Penalty for failure to interrupt:

In the event that the Customer fails to interrupt its load when requested to do so by the Company, the customer shall pay an additional charge as follows:

Billing Demand Charge per kW @ $10.00
Unbundled $/kWh Charge is entirely a Delivery Charge

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm pricing plan for a period of at least twelve (12) months.

INTERRUPTIBLE POWER SERVICE (continued)

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

The Company reserves the right to curtail service to the customer at any time and for such period of time that, in the sole judgment of the Company, the operation of the system requires curtailment by the customer.

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. Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

The Company will endeavor to provide the customer with as much advance notice as possible of the required interruptions or curtailments. However, the customer shall interrupt or curtail service within fifteen (15) minutes, if so requested.

The Company reserves the right to have automatic equipment installed for immediate interruption of the customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption or curtailment of service under this pricing plan.

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

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.

AVAILABILITY

In all territories served by the Company in Santa Cruz and Mohave Counties at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer with a minimum demand of 50 kW for any purpose where such service is supplied at one point of delivery and measured through one meter and is interruptible within fifteen (15) minutes of verbal notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE

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

Minimum Customer Charge per month @	$11.10
Delivery - Billing Demand Charge per kW @	$3.50
Delivery - Energy Charge per kWh @	$0.018268

Penalty for failure to interrupt:

In the event that the Customer fails to interrupt its load when requested to do so by the Company, the customer shall pay an additional charge as follows:

Delivery - Billing Demand Charge per kW @	$10.00

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm pricing plan for a period of at least twelve (12) months.

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC

INTERRUPTIBLE POWER SERVICE – TIME-OF-USE (continued)

adjustments applicable to each time-of-use period shall be set such that the differences "time period specific IPS-TOU PPFAC minus IPS PPFAC (from the terminated non-time differentiated rate)" are:

Differentials

Summer On-Peak:	+ $0.01637 (i.e., add $0. 01637 to the non-time differentiated IPS PPFAC)
Summer Shoulder:	+ $0.00420 (i.e., add $0. 00420 to the non-time differentiated IPS PPFAC)
Summer Off-Peak:	+ $0.00137 (i.e., add $0.00137 to the non-time differentiated IPS PPFAC)
Winter On-Peak:	+ $0.00392 (i.e., add $0.00401 to the non-time differentiated IPS PPFAC)
Winter Off-Peak:	- $0.01108 (i.e., subtract $0.01108 to the non-time differentiated IPS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan IPS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan IPS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01637 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan IPS.)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

INTERRUPTIBLE POWER SERVICE – TIME-OF-USE (continued)

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

The Company reserves the right to curtail service to the customer at any time and for such period of time that, in the sole judgment of the Company, the operation of the system requires curtailment by the customer.

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. Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

The Company will endeavor to provide the customer with as much advance notice as possible of the required interruptions or curtailments. However, the customer shall interrupt or curtail service within fifteen (15) minutes, if so requested.

The Company reserves the right to have automatic equipment installed for immediate interruption of the customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption or curtailment of service under this pricing plan.

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

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LTG
Dusk-To-Dawn Lighting Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any Customer, including public agencies, for the lighting of streets, alleys, thoroughfares, public parks, playgrounds, or other public or private property where such lighting is controlled by a photocell and a contract for service is entered into with the Company.

CHARACTER OF SERVICE

Service is supplied on Company-owned fixtures and poles which are maintained by the Company. The poles, fixtures, and lamps available are the standard items stocked by the Company, and service is rendered at standard available voltages.

MONTHLY BILL

The monthly bill shall be the sum of the following charges and adjustments for each light:

Service Charge (per month):	Overhead Service	Underground Service
Existing Wood Pole	$0.00	$2.25
New 30' Wood Pole (Class 6)	$4.50	$6.76
New 30' Metal or Fiberglass	$9.02	$11.27

Lighting Charge:
Based on the rated wattage value of each lamp installed per month: $0.062281 per watt

Base Power Supply Charge per month @ $1.84

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated, purchased, or transmitted above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

CONTRACT PERIOD

All dusk-to-dawn lighting installations for public agencies will require an agreement for service.

All dusk-to-dawn lighting installations for other than public agencies will require a contract for service as follows:

Five (5) years initial term for installations on existing facilities, and

Five (5) years initial term, or longer at the Company's option, for installations requiring new and/or an extension of facilities.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

Overhead extensions beyond one hundred fifty (150) feet and underground extensions beyond one hundred (100) feet will require specific agreements providing adequate revenue or arrangements for construction financing.

The Customer is not authorized to make connections to the lighting circuit or make attachments or alterations to the Company-owned pole.

Should a Customer request a relocation of a dusk-to-dawn lighting installation, the costs of such relocation must be borne by the customer.

The Customer is expected to notify the Company when lamp outages occur.

The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

The Company may require a refundable advance for the installation of new construction for facilities.

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

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LTG
Dusk-To-Dawn Lighting Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any Customer, including public agencies, for the lighting of streets, alleys, thoroughfares, public parks, playgrounds, or other public or private property where such lighting is controlled by a photocell and a contract for service is entered into with the Company.

CHARACTER OF SERVICE

Service is supplied on Company-owned fixtures and poles which are maintained by the Company. The poles, fixtures, and lamps available are the standard items stocked by the Company, and service is rendered at standard available voltages.

MONTHLY BILL

The monthly bill shall be the sum of the following charges and adjustments for each light:

Service Charge (per month):	Overhead Service	Underground Service
Existing Wood Pole	$0.000	$2.251 (All billing and collections)
New 30' Wood Pole (Class 6)	$4.502 Billing & coll: $3.000 Delivery: $1.502	$6.765 Billing and coll: $3.000 Delivery: $3.765
New 30' Metal or Fiberglass	$9.016 Billing & coll: $3.000 Delivery: $6.016	$11.267 Billing and coll: $3.000 Delivery: $8.267

Lighting Charge:
Based on the rated wattage value of each lamp installed per month: $0.062281 per watt
Prod. Not incl. in Power Supply: $0.000150
Delivery: $0.062131

Base Power Supply Charge per month @ $1.840

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated, purchased, or transmitted above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

CONTRACT PERIOD

All dusk-to-dawn lighting installations for public agencies will require an agreement for service.

All dusk-to-dawn lighting installations for other than public agencies will require a contract for service as follows:

Five (5) years initial term for installations on existing facilities, and

Five (5) years initial term, or longer at the Company's option, for installations requiring new and/or an extension of facilities.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

Overhead extensions beyond one hundred fifty (150) feet and underground extensions beyond one hundred (100) feet will require specific agreements providing adequate revenue or arrangements for construction financing.

The Customer is not authorized to make connections to the lighting circuit or make attachments or alterations to the Company-owned pole.

Should a Customer request a relocation of a dusk-to-dawn lighting installation, the costs of such relocation must be borne by the customer.

The Customer is expected to notify the Company when lamp outages occur.

The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

The Company may require a refundable advance for the installation of new construction for facilities.

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

REDLINED

VERSION

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan C.A.R.E.S.
Customer Assistance Residential Energy Support

AVAILABILITY

This C.A.R.E.S. pricing plan is available in all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

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APPLICABILITY

This C.A.R.E.S. pricing plan is available to those residential customers presently taking service under the Company's residential service pricing plan whose gross annual income is not more than one hundred fifty percent (150%) of the federal poverty level guideline effective at the time qualification and annual certification is sought. Residential customers who desire to qualify for such pricing plan must initially make application to the Company for qualification and must provide verification to the Company that the customer's household gross income does not exceed one hundred fifty percent (150%) of the federal poverty level. Subsequent to the initial certification, the residential customer who seeks to retain eligibility for the C.A.R.E.S. pricing plan must provide a personal certification that the household gross income of the residential dwelling unit involved does not exceed one hundred fifty percent (150%) of the federal poverty level. Eligibility information provided by the customer on the application form is subject to verification by the Company. Samples of the existing CARES participants will be re-certified every two years prior to January 1 and when a customer changes residence.

RATE

The monthly bill shall be in accordance with the RES-01 pricing plan except that a discount of $8.00 per month shall be applied. The minimum bill shall be the customer charge under Pricing Plan RES-01 as applicable.

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¶
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For Bills with¶
Usage of: ... [1]

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Filed By:	Dennis R. Nelson	Tariff No.:	C.A.R.E.S.
Title:	Senior Vice President and Chief Operating Officer	Effective:	PENDING
District:	Entire Electric Service Area	Page No.:	1 of 1

For all qualified C.A.R.E.S. residential customers, the monthly bill shall be computed in accordance with the Company's currently approved residential pricing plan except:

For Bills with Usage of:	The Total Bill (Before Taxes & Regulatory Assessment) will be Discounted by:
0 – 300 kWh	30%
301 – 600 kWh	20%
601 – 1,000 kWh	10%
1,001 + kWh	$8.00

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan RES-01
Residential Service

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AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

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APPLICABILITY

Service is provided at one point of delivery measured through one meter and is restricted to private single family dwellings or individually metered apartments.

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:

Delivery Charges:

Minimum Customer Charge per month @	$8.00
First 400 kWhs per month @	$0.012617
All additional kWhs per month @	$0.022617
Base Power Supply Charge, all kWhs per month @	$0.077178

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Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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TERMS AND CONDITIONS

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

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.

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UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan RES-01
Residential Service

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AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

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APPLICABILITY

Service is provided at one point of delivery measured through one meter and is restricted to private single family dwellings or individually metered apartments.

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:

Delivery Charges:

Minimum Customer Charge per month @	$8.000
Unbundled Customer Charge	
Customer Other	$3.691
Metering	$1.504
Meter Reading	$0.449
Billing and Collection	$2.356
First 400 kWhs per month @	$0.012617
Unbundled $/kWh Charge	
Transmission	$0.003633
Sub-transmission	$0.004032
Delivery	$0.004599
Production not in Power Supply (1)	$0.000353
All additional kWhs per month @	$0.022617
Unbundled $/kWh Charge	
Transmission	$0.003633
Sub-transmission	$0.004032
Delivery	$0.014599
Production not in Power Supply (1)	$0.000353
Base Power Supply Charge, all kWhs per month @	$0.077178

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All additional kWhs per month @ $0.022618
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Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

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.

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UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan RS-TOU
Residential Service – Time-of-Use

AVAILABILITY

In all territory served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To all Customers establishing service on or after the effective date of this Pricing Plan, to all Customers who relocate thus establishing service at a new premise on or after the effective date of this Pricing Plan, and to all customers requiring a meter change-out on or after the effective date of this Pricing Plan. Available as an optional rate to Customers served under the Company's Pricing Plan RS, Residential Service (Frozen). Service is provided at one point of delivery measured through one meter and is restricted to private single family dwellings or individually metered apartments.

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:

Minimum Customer Charge per month @	$8.00
Delivery - Energy Charge 1st 400 kWh/month per kWh @	$0.012618
Delivery - Energy Charge additional kWh/month per kWh @	$0.022618

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific RS-TOU PPFAC minus RS PPFAC (from the frozen non-time differentiated rate)" are:

Differentials

Summer On-Peak:	+ $0.01419 (i.e., add $0.01419 to the non-time differentiated RS PPFAC)
Summer Shoulder:	+ $0.00381 (i.e., add $0.00381 to the non-time differentiated RS PPFAC)
Summer Off-Peak:	- $0.00081 (i.e., subtract $0.00081 to the non-time differentiated RS PPFAC)
Winter On-Peak:	+ $0.00288 (i.e., add $0.00288 to the non-time differentiated RS PPFAC)
Winter Off-Peak:	- $0.01212 (i.e., subtract $0.01212 to the non-time differentiated RS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan RS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan RS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01419 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan RS.)

RESIDENTIAL SERVICE – TIME-OF-USE (continued)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan SGS-10
Small General Service

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AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

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APPLICABILITY

To any customer for any purpose where service is provided at one point of delivery and measured through one meter and 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.

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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:

Delivery Charges:

Minimum Customer Charge per month @	$12.00
First 400 kWhs per month @	$0.027772
All additional kWhs per month @	$0.037772
Base Power Supply Charge, all kWhs per month @	$0.074947

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Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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TAX CLAUSE

To the charges computed under the above pricing plan, 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.

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RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

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UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan SGS-10
Small General Service

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AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

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APPLICABILITY

To any customer for any purpose where service is provided at one point of delivery and measured through one meter and where the monthly usage is not more than 5,000 kWh in any two (2) consecutive months. Customers who use more than 5,000 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.

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:

Delivery Charges:

Minimum Customer Charge per month @	$12.00
Unbundled Customer Charge	
Customer Other	$4.495
Metering	$2.441
Meter Reading	$0.814
Billing and Collection	$4.250
First 400 kWhs per month @	$0.027772
Unbundled $/kWh Charge	
Transmission	$0.002756
Sub-transmission	$0.003270
Delivery	$0.021404
Production not in Power Supply (1)	$0.000342

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All additional kWhs per month @	$0.037772
Unbundled $/kWh Charge	
Transmission	$0.002756
Sub-transmission	$0.003270
Delivery	$0.031404
Production not in Power Supply (1)	$0.000342
Base Power Supply Charge, all kWhs per month @	$0.074947

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Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

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AVAILABILITY

In all territory served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To all Customers establishing service on or after the effective date of this Pricing Plan, to all Customers who relocate thus establishing service at a new premise on or after the effective date of this Pricing Plan, and to all customers requiring a meter change-out on or after the effective date of this Pricing Plan. Available as an optional rate to Customers served under the Company's Pricing Plan SGS, Small General Service Service (Frozen). To any customer for any purpose where service is provided at one point of delivery and measured through one meter and 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 – Time-of-Use 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.

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:

Minimum Customer Charge per month @	$12.00
Delivery - Energy Charge 1st 400 kWh/month per kWh @	$0.027772
Delivery - Energy Charge additional kWh/month per kWh @	$0.037772

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific SGS-TOU PPFAC minus SGS PPFAC (from the frozen non-time differentiated rate)" are:

SMALL GENERAL SERVICE – TIME-OF-USE (continued)

Differentials

Summer On-Peak:	+ $0.01461 (i.e., add $0.01461 to the non-time differentiated SGS PPFAC)
Summer Shoulder:	+ $0.00392 (i.e., add $0.00392 to the non-time differentiated SGS PPFAC)
Summer Off-Peak:	- $0.00039 (i.e., subtract $0.00039 to the non-time differentiated SGS PPFAC)
Winter On-Peak:	+ $0.00371 (i.e., add $0.00371 to the non-time differentiated SGS PPFAC)
Winter Off-Peak:	- $0.01129 (i.e., subtract $0.01129 to the non-time differentiated SGS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan SGS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan SGS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01461 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan SGS.)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

TAX CLAUSE

To the charges computed under the above pricing plan, 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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

SMALL GENERAL SERVICE – TIME-OF-USE (continued)

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

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LGS
Large General Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

Deleted: in Santa Cruz and Mohave Counties

APPLICABILITY

Standard offer sales service to any customer for any purpose where such service is supplied at one point of delivery and measured through one meter and the maximum monthly demand is less than 1,000 kW.

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:

Delivery Charges:

Minimum Customer Charge per month @	$11.10	Deleted: 0
If optional time-of-use service is elected, Minimum Customer Charge per month @	$16.00	Deleted: 5
Billing Demand Charge per kW @	$10.50	Deleted: 9
Energy Charge per kWh @	$0.007497	Deleted: 533
Base Power Supply Charge, all kWhs per month @	$0.066362	

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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TAX CLAUSE

To the charges computed under the above pricing plan, 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

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

LARGE GENERAL SERVICE (continued)

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.

DETERMINATION OF BILLING DEMAND

Normal service: If the time-of-use option is not chosen, the monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month.

Time-of-Use: If time-of-use service is chosen, 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 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.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

LARGE GENERAL SERVICE (continued)

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.

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LGS
Large General Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

Deleted: in Santa Cruz and Mohave Counties

APPLICABILITY

Standard offer sales service to any customer for any purpose where such service is supplied at one point of delivery and measured through one meter and the maximum monthly demand is less than 1,000 kW.

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:

Delivery Charges:

Minimum Customer Charge per month @	$11.100
Unbundled Customer Charge	
Customer Other	$8.338
Metering	$0.754
Meter Reading	$0.325
Billing and Collection	$1.683
If optional time-of-use service is elected,	
Minimum Customer Charge per month @	$16.000
Unbundled Customer Charge	
Customer Other	$12.020
Metering	$1.087
Meter Reading	$0.468
Billing and Collection	$2.425
Billing Demand Charge per kW @	$10.500

Unbundled $/kWh Charge is entirely a Delivery Charge

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Inserted: . . . Customer Other . . . . $3.691¶ . . . Metering . . . . . $1.504¶ . . . Meter Reading . . . . $0.449¶ . . . Billing and Collection . . . $2.356¶
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Deleted: August 11, 2003
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Energy Charge per kWh @	$0.007497
Unbundled $/kWh Charge	
Transmission	$0.001167
Sub-transmission	$0.001834
Delivery	$0.004190
Production not in Power Supply (1)	$0.000306
Base Power Supply Charge, all kWhs per month @	$0.066362

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

Normal service: If the time-of-use option is not chosen, the monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month.

Time-of-Use: If time-of-use service is chosen, 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 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.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

Deleted: August 11, 2003
Deleted: Mohave and Santa Cruz Counties, Arizona

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

Standard offer sales service to any customer for any purpose where such service is supplied at one point of delivery and measured through one meter and the maximum monthly demand is less than 1,000 kW.

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.

RATE

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

Minimum Customer Charge per month @	$11.10
Delivery - Billing Demand Charge per kW-mo @	$10.50
Delivery Energy Charge per kWh @	$0.007497

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific LGS-TOU PPFAC minus LGS PPFAC (from the terminated non-time differentiated rate)" are:

LARGE GENERAL SERVICE – TIME-OF-USE (continued)

Differentials

Summer On-Peak:	+ $0.01577 (i.e., add $0. 01577 to the non-time differentiated LGS PPFAC)
Summer Shoulder:	+ $0.00439 (i.e., add $0. 00439 to the non-time differentiated LGS PPFAC)
Summer Off-Peak:	+ $0.00077 (i.e., add $0.00077 to the non-time differentiated LGS PPFAC)
Winter On-Peak:	+ $0.00401 (i.e., add $0.00401 to the non-time differentiated LGS PPFAC)
Winter Off-Peak:	- $0.01099 (i.e., subtract $0.01099 to the non-time differentiated LGS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan LGS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan LGS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01577 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan LGS.)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

Normal service: If the time-of-use option is not chosen, the monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month.

Time-of-Use: If time-of-use service is chosen, 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 or 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.

LARGE GENERAL SERVICE – TIME-OF-USE (continued)

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LPS
Large Power Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

Deleted: n Santa Cruz and Mohave Counties

APPLICABILITY

To any customer for any purpose where the service is supplied at one point of delivery and measured through one meter when the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE

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

For service at less than 69,000 volts (Distribution Service):

Delivery Charges:

Minimum Customer Charge per month @	$365.00
Billing Demand Charge per kW @	$21.53
Energy Charge per kWh @	N/A

Base Power Supply Charge, all kWhs per month @ $0.052704

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For service at 69,000 volts or higher (Transmission Service):

Delivery Charges:

Minimum Customer Charge per month @	$400.00
Billing Demand Charge per kW @	$12.53
Energy Charge per kWh @	N/A

Base Power Supply Charge, all kWhs per month @ $0.052704

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LARGE POWER SERVICE (continued)

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

Deleted: energy charge

A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Maximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge

Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

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LARGE POWER SERVICE (continued)

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

LARGE POWER SERVICE (continued)

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

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.

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LPS
Large Power Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer for any purpose where the service is supplied at one point of delivery and measured through one meter when the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE

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

For service at less than 69,000 volts (Distribution Service):

Delivery Charges:

Minimum Customer Charge per month @	$365.000
Unbundled Customer Charge	
Customer Other	$208.686
Metering	$0.709
Meter Reading	$25.303
Billing and Collection	$130.302
Billing Demand Charge per kW @	$21.530
Unbundled $/kW Charge	
Transmission	$0.110
Sub-transmission	$0.441
Delivery	$20.854
Production not in Power Supply (1)	$0.125
Energy Charge per kWh @	N/A
Base Power Supply Charge, all kWhs per month @	$0.052704

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For service at 69,000 volts or higher (Transmission Service):

Delivery Charges:

Minimum Customer Charge per month @	$400.000
Unbundled Customer Charge	
Customer Other	$228.696
Metering	$0.777
Meter Reading	$27.730
Billing and Collection	$142.797
Billing Demand Charge per kW @	$12.530
Unbundled $/kW Charge	
Transmission	$0.118
Sub-transmission	$0.472
Delivery	$11.806
Production not in Power Supply (1)	$0.134
Energy Charge per kWh @	N/A
Base Power Supply Charge, all kWhs per month @	$0.052704

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Ma ximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

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LARGE POWER SERVICE continued

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

Deleted: August 11, 2003

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LARGE POWER SERVICE continued

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

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.

Deleted: August 11, 2003

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Mohave and Santa Cruz Counties, Arizona

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer for any purpose where the service is supplied at one point of delivery and measured through one meter when the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE

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

For service at less than 69,000 volts (Distribution Service):

Minimum Customer Charge per month @	$365.00
Delivery - Billing Demand Charge per kW @	$21.53

For service at 69,000 volts or higher (Transmission Service):

Minimum Customer Charge per month @	$400.00
Delivery - Billing Demand Charge per kW @	$12.53

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

LARGE POWER SERVICE - TOU (continued)

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific LPS-TOU PPFAC minus LPS PPFAC (from the terminated non-time differentiated rate)" are:

Differentials

Summer On-Peak:	+ $0.01691 (i.e., add $0. 01691 to the non-time differentiated LPS PPFAC)
Summer Shoulder:	+ $0.00492 (i.e., add $0. 00492 to the non-time differentiated LPS PPFAC)
Summer Off-Peak:	+ $0.00191 (i.e., add $0.00191 to the non-time differentiated LPS PPFAC)
Winter On-Peak:	+ $0.00491 (i.e., add $0.00401 to the non-time differentiated LPS PPFAC)
Winter Off-Peak:	- $0.01009 (i.e., subtract $0.01009 to the non-time differentiated LPS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan LPS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) isobtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan LPS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01691 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan LPS.)

A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Maximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge

Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

LARGE POWER SERVICE - TOU (continued)

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

LARGE POWER SERVICE - TOU (continued)

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan IPS
Interruptible Power Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

Deleted: in Santa Cruz and Mohave Counties

APPLICABILITY

To any customer with a minimum demand of 50 kW for any purpose where such service is supplied at one point of delivery and measured through one meter and is interruptible within fifteen (15) minutes of verbal notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE

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

Delivery Charges:

Minimum Customer Charge per month @	$11.10	Deleted: 0
Billing Demand Charge per kW @	$3.50	Deleted: 2
Energy Charge per kWh @	$0.018268	Deleted: 533
Base Power Supply Charge, all kWhs per month @	$0.054911	

Penalty for failure to interrupt:

In the event that the Customer fails to interrupt its load when requested to do so by the Company, the customer shall pay an additional charge as follows:

Billing Demand Charge per kW @ $10.00

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm pricing plan for a period of at least twelve (12) months.

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

INTERRUPTIBLE POWER SERVICE (continued)

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

Deleted: energy charge

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

The Company reserves the right to curtail service to the customer at any time and for such period of time that, in the sole judgment of the Company, the operation of the system requires curtailment by the customer.

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. Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

Deleted: August 11, 2003

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INTERRUPTIBLE POWER SERVICE (continued)

The Company will endeavor to provide the customer with as much advance notice as possible of the required interruptions or curtailments. However, the customer shall interrupt or curtail service within fifteen (15) minutes, if so requested.

The Company reserves the right to have automatic equipment installed for immediate interruption of the customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption or curtailment of service under this pricing plan.

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

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.

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan IPS
Interruptible Power Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

Deleted: in Santa Cruz and Mohave Counties

APPLICABILITY

To any customer with a minimum demand of 50 kW for any purpose where such service is supplied at one point of delivery and measured through one meter and is interruptible within fifteen (15) minutes of verbal notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE

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

Delivery Charges:

Minimum Customer Charge per month @	$11.100
Unbundled Customer Charge	
Customer Other	$6.708
Metering	$1.118
Meter Reading	$0.531
Billing and Collection	$2.743
Billing Demand Charge per kW @	$3.500
Unbundled $/kWh Charge is entirely a Delivery Charge	
Energy Charge per kWh @	$0.018268
Unbundled $/kWh Charge	
Transmission	$0.000615
Sub-transmission	$0.001225
Delivery	$0.016175
Production not in Power Supply (1)	$0.000253
Base Power Supply Charge, all kWhs per month @	$0.054911

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Penalty for failure to interrupt:

In the event that the Customer fails to interrupt its load when requested to do so by the Company, the customer shall pay an additional charge as follows:

Billing Demand Charge per kW @ $10.00
Unbundled $/kWh Charge is entirely a Delivery Charge

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm pricing plan for a period of at least twelve (12) months.

INTERRUPTIBLE POWER SERVICE (continued)

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

Deleted: energy charge

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

TERMS AND CONDITIONS

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

The Company reserves the right to curtail service to the customer at any time and for such period of time that, in the sole judgment of the Company, the operation of the system requires curtailment by the customer.

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. Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

The Company will endeavor to provide the customer with as much advance notice as possible of the required interruptions or curtailments. However, the customer shall interrupt or curtail service within fifteen (15) minutes, if so requested.

The Company reserves the right to have automatic equipment installed for immediate interruption of the customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption or curtailment of service under this pricing plan.

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

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.

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

AVAILABILITY

In all territories served by the Company in Santa Cruz and Mohave Counties at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer with a minimum demand of 50 kW for any purpose where such service is supplied at one point of delivery and measured through one meter and is interruptible within fifteen (15) minutes of verbal notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE

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

Minimum Customer Charge per month @	$11.10
Delivery - Billing Demand Charge per kW @	$3.50
Delivery - Energy Charge per kWh @	$0.018268

Penalty for failure to interrupt:

In the event that the Customer fails to interrupt its load when requested to do so by the Company, the customer shall pay an additional charge as follows:

Delivery - Billing Demand Charge per kW @	$10.00

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm pricing plan for a period of at least twelve (12) months.

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC

INTERRUPTIBLE POWER SERVICE – TIME-OF-USE (continued)

adjustments applicable to each time-of-use period shall be set such that the differences "time period specific IPS-TOU PPFAC minus IPS PPFAC (from the terminated non-time differentiated rate)" are:

Differentials

Summer On-Peak:	+ $0.01637 (i.e., add $0. 01637 to the non-time differentiated IPS PPFAC)
Summer Shoulder:	+ $0.00420 (i.e., add $0. 00420 to the non-time differentiated IPS PPFAC)
Summer Off-Peak:	+ $0.00137 (i.e., add $0.00137 to the non-time differentiated IPS PPFAC)
Winter On-Peak:	+ $0.00392 (i.e., add $0.00401 to the non-time differentiated IPS PPFAC)
Winter Off-Peak:	- $0.01108 (i.e., subtract $0.01108 to the non-time differentiated IPS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan IPS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan IPS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01637 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan IPS.)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

INTERRUPTIBLE POWER SERVICE – TIME-OF-USE (continued)

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

The Company reserves the right to curtail service to the customer at any time and for such period of time that, in the sole judgment of the Company, the operation of the system requires curtailment by the customer.

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. Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

The Company will endeavor to provide the customer with as much advance notice as possible of the required interruptions or curtailments. However, the customer shall interrupt or curtail service within fifteen (15) minutes, if so requested.

The Company reserves the right to have automatic equipment installed for immediate interruption of the customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption or curtailment of service under this pricing plan.

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

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LTG
Dusk-To-Dawn Lighting Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

Deleted: in Santa Cruz and Mohave Counties

APPLICABILITY

To any Customer, including public agencies, for the lighting of streets, alleys, thoroughfares, public parks, playgrounds, or other public or private property where such lighting is controlled by a photocell and a contract for service is entered into with the Company.

CHARACTER OF SERVICE

Service is supplied on Company-owned fixtures and poles which are maintained by the Company. The poles, fixtures, and lamps available are the standard items stocked by the Company, and service is rendered at standard available voltages.

MONTHLY BILL

The monthly bill shall be the sum of the following charges and adjustments for each light:

Service Charge (per month):	Overhead Service	Underground Service
Existing Wood Pole	$0.00	$2.25
New 30' Wood Pole (Class 6)	$4.50	$6.76
New 30' Metal or Fiberglass	$9.02	$11.27

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Lighting Charge:
Based on the rated wattage value of each lamp installed per month: $0.062281 per watt

Base Power Supply Charge per month @ $1.84

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated, purchased, or transmitted above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

Deleted: August 11, 2003

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CONTRACT PERIOD

All dusk-to-dawn lighting installations for public agencies will require an agreement for service.

All dusk-to-dawn lighting installations for other than public agencies will require a contract for service as follows:

Five (5) years initial term for installations on existing facilities, and

Five (5) years initial term, or longer at the Company's option, for installations requiring new and/or an extension of facilities.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

Overhead extensions beyond one hundred fifty (150) feet and underground extensions beyond one hundred (100) feet will require specific agreements providing adequate revenue or arrangements for construction financing.

The Customer is not authorized to make connections to the lighting circuit or make attachments or alterations to the Company-owned pole.

Should a Customer request a relocation of a dusk-to-dawn lighting installation, the costs of such relocation must be borne by the customer.

The Customer is expected to notify the Company when lamp outages occur.

The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

The Company may require a refundable advance for the installation of new construction for facilities.

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

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UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LTG
Dusk-To-Dawn Lighting Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any Customer, including public agencies, for the lighting of streets, alleys, thoroughfares, public parks, playgrounds, or other public or private property where such lighting is controlled by a photocell and a contract for service is entered into with the Company.

CHARACTER OF SERVICE

Service is supplied on Company-owned fixtures and poles which are maintained by the Company. The poles, fixtures, and lamps available are the standard items stocked by the Company, and service is rendered at standard available voltages.

MONTHLY BILL

The monthly bill shall be the sum of the following charges and adjustments for each light:

Service Charge (per month):	Overhead Service	Underground Service
Existing Wood Pole	$0.000	$2.251 (All billing and collections)
New 30' Wood Pole (Class 6)	$4.502 Billing & coll: $3.000 Delivery: $1.502	$6.765 Billing and coll: $3.000 Delivery: $3.765
New 30' Metal or Fiberglass	$9.016 Billing & coll: $3.000 Delivery: $6.016	$11.267 Billing and coll: $3.000 Delivery: $8.267

Lighting Charge:
Based on the rated wattage value of each lamp installed per month: $0.062281 per watt
Prod. Not incl. in Power Supply: $0.000150
Delivery: $0.062131

Base Power Supply Charge per month @ $1.840

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated, purchased, or transmitted above or below the base cost per kWh sold.

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TAX CLAUSE

To the charges computed under the above pricing plan, 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.

CONTRACT PERIOD

All dusk-to-dawn lighting installations for public agencies will require an agreement for service.

All dusk-to-dawn lighting installations for other than public agencies will require a contract for service as follows:

Five (5) years initial term for installations on existing facilities, and

Five (5) years initial term, or longer at the Company's option, for installations requiring new and/or an extension of facilities.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

Overhead extensions beyond one hundred fifty (150) feet and underground extensions beyond one hundred (100) feet will require specific agreements providing adequate revenue or arrangements for construction financing.

The Customer is not authorized to make connections to the lighting circuit or make attachments or alterations to the Company-owned pole.

Should a Customer request a relocation of a dusk-to-dawn lighting installation, the costs of such relocation must be borne by the customer.

The Customer is expected to notify the Company when lamp outages occur.

The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

The Company may require a refundable advance for the installation of new construction for facilities.

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

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

Phase 2

CLEAN

VERSION

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan RES-01
Residential Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

Service is provided at one point of delivery measured through one meter and is restricted to private single family dwellings or individually metered apartments.

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:

Delivery Charges:

Minimum Customer Charge per month @	$8.00
First 400 kWhs per month @	$0.019695
All additional kWhs per month @	$0.029695
Base Power Supply Charge, all kWhs per month @	$0.070350

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan RES-01
Residential Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

Service is provided at one point of delivery measured through one meter and is restricted to private single family dwellings or individually metered apartments.

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:

Delivery Charges:

Minimum Customer Charge per month @	$8.000
Unbundled Customer Charge	
Customer Other	$3.691
Metering	$1.504
Meter Reading	$0.449
Billing and Collection	$2.356
First 400 kWhs per month @	$0.019695
Unbundled $/kWh Charge	
Transmission	$0.003633
Sub-transmission	$0.004031
Delivery	$0.011678
Production not in Power Supply (1)	$0.000353
All additional kWhs per month @	$0.029695
Unbundled $/kWh Charge	
Transmission	$0.003633
Sub-transmission	$0.004032
Delivery	$0.021677
Production not in Power Supply (1)	$0.000353

Base Power Supply Charge, all kWhs per month @ $0.070350

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

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.

AVAILABILITY

In all territory served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To all Customers establishing service on or after the effective date of this Pricing Plan, to all Customers who relocate thus establishing service at a new premise on or after the effective date of this Pricing Plan, and to all customers requiring a meter change-out on or after the effective date of this Pricing Plan. Available as an optional rate to Customers served under the Company's Pricing Plan RS, Residential Service (Frozen). Service is provided at one point of delivery measured through one meter and is restricted to private single family dwellings or individually metered apartments.

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:

Minimum Customer Charge per month @	$8.00
Delivery - Energy Charge 1st 400 kWh/month per kWh @	$0.012618
Delivery - Energy Charge additional kWh/month per kWh @	$0.022618

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific RS-TOU PPFAC minus RS PPFAC (from the frozen non-time differentiated rate)" are:

Differentials	
Summer On-Peak:	+ $0.01419 (i.e., add $0.01419 to the non-time differentiated RS PPFAC)
Summer Shoulder:	+ $0.00381 (i.e., add $0.00381 to the non-time differentiated RS PPFAC)
Summer Off-Peak:	- $0.00081 (i.e., subtract $0.00081 to the non-time differentiated RS PPFAC)
Winter On-Peak:	+ $0.00288 (i.e., add $0.00288 to the non-time differentiated RS PPFAC)
Winter Off-Peak:	- $0.01212 (i.e., subtract $0.01212 to the non-time differentiated RS PPFAC)

RESIDENTIAL SERVICE – TIME-OF-USE (continued)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan RS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan RS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01419 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan RS.)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan SGS-10
Small General Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer for any purpose where service is provided at one point of delivery and measured through one meter and 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.

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:

Delivery Charges:

Minimum Customer Charge per month @	$12.00
First 400 kWhs per month @	$0.034088
All additional kWhs per month @	$0.044088
Base Power Supply Charge, all kWhs per month @	$0.068316

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan SGS-10
Small General Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer for any purpose where service is provided at one point of delivery and measured through one meter and where the monthly usage is not more than 5,000 kWh in any two (2) consecutive months. Customers who use more than 5,000 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.

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:

Delivery Charges:

Minimum Customer Charge per month @	$12.000
Unbundled Customer Charge	
Customer Other	$4.495
Metering	$2.441
Meter Reading	$0.814
Billing and Collection	$4.250
First 400 kWhs per month @	$0.034088
Unbundled $/kWh Charge	
Transmission	$0.002756
Sub-transmission	$0.003270
Delivery	$0.027720
Production not in Power Supply (1)	$0.000342
All additional kWhs per month @	$0.044088
Unbundled $/kWh Charge	
Transmission	$0.002756
Sub-transmission	$0.003270

Delivery	$0.037720
Production not in Power Supply (1)	$0.000342
Base Power Supply Charge, all kWhs per month @	$0.068316

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

AVAILABILITY

In all territory served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To all Customers establishing service on or after the effective date of this Pricing Plan, to all Customers who relocate thus establishing service at a new premise on or after the effective date of this Pricing Plan, and to all customers requiring a meter change-out on or after the effective date of this Pricing Plan. Available as an optional rate to Customers served under the Company's Pricing Plan SGS, Small General Service Service (Frozen). To any customer for any purpose where service is provided at one point of delivery and measured through one meter and 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 – Time-of-Use 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.

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:

Minimum Customer Charge per month @	$12.00
Delivery - Energy Charge 1st 400 kWh/month per kWh @	$0.027772
Delivery - Energy Charge additional kWh/month per kWh @	$0.037772

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific SGS-TOU PPFAC minus SGS PPFAC (from the frozen non-time differentiated rate)" are:

SMALL GENERAL SERVICE – TIME-OF-USE (continued)

Differentials

Summer On-Peak:	+ $0.01461 (i.e., add $0.01461 to the non-time differentiated SGS PPFAC)
Summer Shoulder:	+ $0.00392 (i.e., add $0.00392 to the non-time differentiated SGS PPFAC)
Summer Off-Peak:	- $0.00039 (i.e., subtract $0.00039 to the non-time differentiated SGS PPFAC)
Winter On-Peak:	+ $0.00371 (i.e., add $0.00371 to the non-time differentiated SGS PPFAC)
Winter Off-Peak:	- $0.01129 (i.e., subtract $0.01129 to the non-time differentiated SGS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan SGS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan SGS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01461 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan SGS.)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

TAX CLAUSE

To the charges computed under the above pricing plan, 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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

SMALL GENERAL SERVICE – TIME-OF-USE (continued)

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

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

Standard offer sales service to any customer for any purpose where such service is supplied at one point of delivery and measured through one meter and the maximum monthly demand is less than 1,000 kW.

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:

Delivery Charges:

Minimum Customer Charge per month @	$11.10
If optional time-of-use service is elected, Minimum Customer Charge per month @	$16.00
Billing Demand Charge per kW @	$10.50
Energy Charge per kWh @	$0.013143
Base Power Supply Charge, all kWhs per month @	$0.060491

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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

LARGE GENERAL SERVICE (continued)

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.

DETERMINATION OF BILLING DEMAND

Normal service: If the time-of-use option is not chosen, the monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month.

Time-of-Use: If time-of-use service is chosen, 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 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.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

LARGE GENERAL SERVICE (continued)

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LGS
Large General Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

Standard offer sales service to any customer for any purpose where such service is supplied at one point of delivery and measured through one meter and the maximum monthly demand is less than 1,000 kW.

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:

Delivery Charges:

Minimum Customer Charge per month @	$11.100
Unbundled Customer Charge	
Customer Other	$8.338
Metering	$0.754
Meter Reading	$0.325
Billing and Collection	$1.683
If optional time-of-use service is elected,	
Minimum Customer Charge per month @	$16.000
Unbundled Customer Charge	
Customer Other	$12.020
Metering	$1.087
Meter Reading	$0.468
Billing and Collection	$2.425
Billing Demand Charge per kW @	$10.500
Unbundled $/kWh Charge is entirely a Delivery Charge	

Energy Charge per kWh @	$0.013143
Unbundled $/kWh Charge	
Transmission	$0.001167
Sub-transmission	$0.001834
Delivery	$0.009836
Production not in Power Supply (1)	$0.000306
Base Power Supply Charge, all kWhs per month @	$0.060491

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

Normal service: If the time-of-use option is not chosen, the monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month.

Time-of-Use: If time-of-use service is chosen, 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 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.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

UNS Electric, Inc.
Pricing Plan LGS-TOU
Large General Service Time-of-Use

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

Standard offer sales service to any customer for any purpose where such service is supplied at one point of delivery and measured through one meter and the maximum monthly demand is less than 1,000 kW.

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.

RATE

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

Minimum Customer Charge per month @	$11.10
Delivery - Billing Demand Charge per kW-mo @	$10.50
Delivery Energy Charge per kWh @	$0.007497

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific LGS-TOU PPFAC minus LGS PPFAC (from the terminated non-time differentiated rate)" are:

LARGE GENERAL SERVICE – TIME-OF-USE (continued)

Differentials

Summer On-Peak:	+ $0.01577 (i.e., add $0. 01577 to the non-time differentiated LGS PPFAC)
Summer Shoulder:	+ $0.00439 (i.e., add $0. 00439 to the non-time differentiated LGS PPFAC)
Summer Off-Peak:	+ $0.00077 (i.e., add $0.00077 to the non-time differentiated LGS PPFAC)
Winter On-Peak:	+ $0.00401 (i.e., add $0.00401 to the non-time differentiated LGS PPFAC)
Winter Off-Peak:	- $0.01099 (i.e., subtract $0.01099 to the non-time differentiated LGS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan LGS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan LGS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01577 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan LGS.)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

Normal service: If the time-of-use option is not chosen, the monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month.

Time-of-Use: If time-of-use service is chosen, 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 or 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.

LARGE GENERAL SERVICE – TIME-OF-USE (continued)

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer for any purpose where the service is supplied at one point of delivery and measured through one meter when the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE

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

For service at less than 69,000 volts (Distribution Service):

Delivery Charges:

Minimum Customer Charge per month @	$365.00
Billing Demand Charge per kW @	$24.00
Energy Charge per kWh @	N/A
Base Power Supply Charge, all kWhs per month @	$0.048041

For service at 69,000 volts or higher (Transmission Service):

Delivery Charges:

Minimum Customer Charge per month @	$380.00
Billing Demand Charge per kW @	$15.00
Energy Charge per kWh @	N/A
Base Power Supply Charge, all kWhs per month @	$0.048041

LARGE POWER SERVICE (continued)

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Maximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge

Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

LARGE POWER SERVICE (continued)

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

LARGE POWER SERVICE (continued)

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

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.

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer for any purpose where the service is supplied at one point of delivery and measured through one meter when the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE

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

For service at less than 69,000 volts (Distribution Service):

Delivery Charges:

Minimum Customer Charge per month @	$365.000
Unbundled Customer Charge	
Customer Other	$208.686
Metering	$0.709
Meter Reading	$25.303
Billing and Collection	$130.302
Billing Demand Charge per kW @	$24.000
Unbundled $/kW Charge	
Transmission	$0.110
Sub-transmission	$0.441
Delivery	$23.324
Production not in Power Supply (1)	$0.125
Energy Charge per kWh @	N/A
Base Power Supply Charge, all kWhs per month @	$0.048041

For service at 69,000 volts or higher (Transmission Service):

Delivery Charges:

Minimum Customer Charge per month @	$380.00
Unbundled Customer Charge	
Customer Other	$217.262
Metering	$0.7380
Meter Reading	$26.3430
Billing and Collection	$135.657
Billing Demand Charge per kW @	$15.000
Unbundled $/kW Charge	
Transmission	$0.118
Sub-transmission	$0.472
Delivery	$14.276
Production not in Power Supply (1)	$0.134
Energy Charge per kWh @	N/A
Base Power Supply Charge, all kWhs per month @	$0.048041

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Maximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge

Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

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.

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer for any purpose where the service is supplied at one point of delivery and measured through one meter when the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE

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

For service at less than 69,000 volts (Distribution Service):

Minimum Customer Charge per month @	$365.00
Delivery - Billing Demand Charge per kW @	$21.53

For service at 69,000 volts or higher (Transmission Service):

Minimum Customer Charge per month @	$400.00
Delivery - Billing Demand Charge per kW @	$12.53

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

LARGE POWER SERVICE - TOU (continued)

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific LPS-TOU PPFAC minus LPS PPFAC (from the terminated non-time differentiated rate)" are:

Differentials

Summer On-Peak:	+ $0.01691 (i.e., add $0. 01691 to the non-time differentiated LPS PPFAC)
Summer Shoulder:	+ $0.00492 (i.e., add $0. 00492 to the non-time differentiated LPS PPFAC)
Summer Off-Peak:	+ $0.00191 (i.e., add $0.00191 to the non-time differentiated LPS PPFAC)
Winter On-Peak:	+ $0.00491 (i.e., add $0.00401 to the non-time differentiated LPS PPFAC)
Winter Off-Peak:	- $0.01009 (i.e., subtract $0.01009 to the non-time differentiated LPS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan LPS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan LPS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01691 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan LPS.)

A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Maximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge

Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

LARGE POWER SERVICE - TOU (continued)

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

LARGE POWER SERVICE - TOU (continued)

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

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.

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer with a minimum demand of 50 kW for any purpose where such service is supplied at one point of delivery and measured through one meter and is interruptible within fifteen (15) minutes of verbal notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE

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

Delivery Charges:

Minimum Customer Charge per month @	$11.10
Billing Demand Charge per kW @	$3.50
Energy Charge per kWh @	$0.022967
Base Power Supply Charge, all kWhs per month @	$0.050053

Penalty for failure to interrupt:

In the event that the Customer fails to interrupt its load when requested to do so by the Company, the customer shall pay an additional charge as follows:

Billing Demand Charge per kW @	$10.00

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm pricing plan for a period of at least twelve (12) months.

INTERRUPTIBLE POWER SERVICE (continued)

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

The Company reserves the right to curtail service to the customer at any time and for such period of time that, in the sole judgment of the Company, the operation of the system requires curtailment by the customer.

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. Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

INTERRUPTIBLE POWER SERVICE (continued)

The Company will endeavor to provide the customer with as much advance notice as possible of the required interruptions or curtailments. However, the customer shall interrupt or curtail service within fifteen (15) minutes, if so requested.

The Company reserves the right to have automatic equipment installed for immediate interruption of the customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption or curtailment of service under this pricing plan.

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

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan IPS
Interruptible Power Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer with a minimum demand of 50 kW for any purpose where such service is supplied at one point of delivery and measured through one meter and is interruptible within fifteen (15) minutes of verbal notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE

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

Delivery Charges:

Minimum Customer Charge per month @	$11.100
Unbundled Customer Charge	
Customer Other	$6.708
Metering	$1.118
Meter Reading	$0.531
Billing and Collection	$2.743
Billing Demand Charge per kW @	$3.500
Unbundled $/kWh Charge is entirely a Delivery Charge	
Energy Charge per kWh @	$0.022967
Unbundled $/kWh Charge	
Transmission	$0.000615
Sub-transmission	$0.001225
Delivery	$0.020873
Production not in Power Supply (1)	$0.000253
Base Power Supply Charge, all kWhs per month @	$0.050053

Penalty for failure to interrupt:

In the event that the Customer fails to interrupt its load when requested to do so by the Company, the customer shall pay an additional charge as follows:

Billing Demand Charge per kW @ $10.00
Unbundled $/kWh Charge is entirely a Delivery Charge

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm pricing plan for a period of at least twelve (12) months.

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

The Company reserves the right to curtail service to the customer at any time and for such period of time that, in the sole judgment of the Company, the operation of the system requires curtailment by the customer.

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. Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

The Company will endeavor to provide the customer with as much advance notice as possible of the required interruptions or curtailments. However, the customer shall interrupt or curtail service within fifteen (15) minutes, if so requested.

The Company reserves the right to have automatic equipment installed for immediate interruption of the customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption or curtailment of service under this pricing plan.

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

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.

AVAILABILITY

In all territories served by the Company in Santa Cruz and Mohave Counties at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer with a minimum demand of 50 kW for any purpose where such service is supplied at one point of delivery and measured through one meter and is interruptible within fifteen (15) minutes of verbal notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE

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

Minimum Customer Charge per month @	$11.10
Delivery - Billing Demand Charge per kW @	$3.50
Delivery - Energy Charge per kWh @	$0.018268

Penalty for failure to interrupt:

In the event that the Customer fails to interrupt its load when requested to do so by the Company, the customer shall pay an additional charge as follows:

Delivery - Billing Demand Charge per kW @ $10.00

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm pricing plan for a period of at least twelve (12) months.

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC

INTERRUPTIBLE POWER SERVICE – TIME-OF-USE (continued)

adjustments applicable to each time-of-use period shall be set such that the differences "time period specific IPS-TOU PPFAC minus IPS PPFAC (from the terminated non-time differentiated rate)" are:

Differentials

Summer On-Peak:	+ $0.01637 (i.e., add $0. 01637 to the non-time differentiated IPS PPFAC)
Summer Shoulder:	+ $0.00420 (i.e., add $0. 00420 to the non-time differentiated IPS PPFAC)
Summer Off-Peak:	+ $0.00137 (i.e., add $0.00137 to the non-time differentiated IPS PPFAC)
Winter On-Peak:	+ $0.00392 (i.e., add $0.00401 to the non-time differentiated IPS PPFAC)
Winter Off-Peak:	- $0.01108 (i.e., subtract $0.01108 to the non-time differentiated IPS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan IPS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan IPS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01637 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan IPS.)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

INTERRUPTIBLE POWER SERVICE – TIME-OF-USE (continued)

TERMS AND CONDITIONS

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

The Company reserves the right to curtail service to the customer at any time and for such period of time that, in the sole judgment of the Company, the operation of the system requires curtailment by the customer.

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. Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

The Company will endeavor to provide the customer with as much advance notice as possible of the required interruptions or curtailments. However, the customer shall interrupt or curtail service within fifteen (15) minutes, if so requested.

The Company reserves the right to have automatic equipment installed for immediate interruption of the customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption or curtailment of service under this pricing plan.

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

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.

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any Customer, including public agencies, for the lighting of streets, alleys, thoroughfares, public parks, playgrounds, or other public or private property where such lighting is controlled by a photocell and a contract for service is entered into with the Company.

CHARACTER OF SERVICE

Service is supplied on Company-owned fixtures and poles which are maintained by the Company. The poles, fixtures, and lamps available are the standard items stocked by the Company, and service is rendered at standard available voltages.

MONTHLY BILL

The monthly bill shall be the sum of the following charges and adjustments for each light:

Service Charge (per month):	Overhead Service	Underground Service
Existing Wood Pole	$0.00	$2.25
New 30' Wood Pole (Class 6)	$4.50	$6.76
New 30' Metal or Fiberglass	$9.02	$11.27

Lighting Charge:
Based on the rated wattage value of each lamp installed per month: $0.061502 per watt

Base Power Supply Charge per month @ $1.67

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated, purchased, or transmitted above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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

DUSK-TO-DAWN LIGHTING SERVICE (continued)

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.

CONTRACT PERIOD

All dusk-to-dawn lighting installations for public agencies will require an agreement for service.

All dusk-to-dawn lighting installations for other than public agencies will require a contract for service as follows:

Five (5) years initial term for installations on existing facilities, and

Five (5) years initial term, or longer at the Company's option, for installations requiring new and/or an extension of facilities.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

Overhead extensions beyond one hundred fifty (150) feet and underground extensions beyond one hundred (100) feet will require specific agreements providing adequate revenue or arrangements for construction financing.

The Customer is not authorized to make connections to the lighting circuit or make attachments or alterations to the Company-owned pole.

Should a Customer request a relocation of a dusk-to-dawn lighting installation, the costs of such relocation must be borne by the customer.

The Customer is expected to notify the Company when lamp outages occur.

The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

The Company may require a refundable advance for the installation of new construction for facilities.

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

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LTG
Dusk-To-Dawn Lighting Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any Customer, including public agencies, for the lighting of streets, alleys, thoroughfares, public parks, playgrounds, or other public or private property where such lighting is controlled by a photocell and a contract for service is entered into with the Company.

CHARACTER OF SERVICE

Service is supplied on Company-owned fixtures and poles which are maintained by the Company. The poles, fixtures, and lamps available are the standard items stocked by the Company, and service is rendered at standard available voltages.

MONTHLY BILL

The monthly bill shall be the sum of the following charges and adjustments for each light:

Service Charge (per month):	Overhead Service	Underground Service
Existing Wood Pole	$0.000	$2.251 (All billing and collections)
New 30' Wood Pole (Class 6)	$4.502 Billing & coll: $3.000 Delivery: $1.502	$6.765 Billing and coll: $3.000 Delivery: $3.765
New 30' Metal or Fiberglass	$9.016 Billing & coll: $3.000 Delivery: $6.016	$11.267 Billing and coll: $3.000 Delivery: $8.267

Lighting Charge:
Based on the rated wattage value of each lamp installed per month: $0.061502 per watt
Prod. Not incl. in Power Supply: $0.000150
Delivery: $0.061352

Base Power Supply Charge per month @ $1.670

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated, purchased, or transmitted above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

CONTRACT PERIOD

All dusk-to-dawn lighting installations for public agencies will require an agreement for service.

All dusk-to-dawn lighting installations for other than public agencies will require a contract for service as follows:

Five (5) years initial term for installations on existing facilities, and

Five (5) years initial term, or longer at the Company's option, for installations requiring new and/or an extension of facilities.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

Overhead extensions beyond one hundred fifty (150) feet and underground extensions beyond one hundred (100) feet will require specific agreements providing adequate revenue or arrangements for construction financing.

The Customer is not authorized to make connections to the lighting circuit or make attachments or alterations to the Company-owned pole.

Should a Customer request a relocation of a dusk-to-dawn lighting installation, the costs of such relocation must be borne by the customer.

The Customer is expected to notify the Company when lamp outages occur.

The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

The Company may require a refundable advance for the installation of new construction for facilities.

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

REDLINED

VERSION

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan RES-01
Residential Service

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AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

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APPLICABILITY

Service is provided at one point of delivery measured through one meter and is restricted to private single family dwellings or individually metered apartments.

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:

Delivery Charges:

Minimum Customer Charge per month @	$8.00
First 400 kWhs per month @	$0.019695
All additional kWhs per month @	$0.029695
Base Power Supply Charge, all kWhs per month @	$0.070350

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Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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TERMS AND CONDITIONS

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

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.

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UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan RES-01
Residential Service

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AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

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APPLICABILITY

Service is provided at one point of delivery measured through one meter and is restricted to private single family dwellings or individually metered apartments.

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:

Delivery Charges:

Minimum Customer Charge per month @	$8.000
Unbundled Customer Charge	
Customer Other	$3.691
Metering	$1.504
Meter Reading	$0.449
Billing and Collection	$2.356
First 400 kWhs per month @	$0.019695
Unbundled $/kWh Charge	
Transmission	$0.003633
Sub-transmission	$0.004031
Delivery	$0.011678
Production not in Power Supply (1)	$0.000353
All additional kWhs per month @	$0.029695
Unbundled $/kWh Charge	
Transmission	$0.003633
Sub-transmission	$0.004032
Delivery	$0.021677
Production not in Power Supply (1)	$0.000353

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Base Power Supply Charge, all kWhs per month @ $0.070350

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Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

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.

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Unbundled $/kWh Charge

Transmission	$3.691
Sub-transmission	$1.504
Delivery	$0.449
Production not in Power Supply (1)	$2.356

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Unbundled $/kWh Charge

Transmission	$3.691
Sub-transmission	$1.504
Delivery	$0.449
Production not in Power Supply (1)	$2.356

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Unbundled $/kWh Charge

Transmission	$3.691
Sub-transmission	$1.504
Delivery	$0.449
Production not in Power Supply (1)	$2.356

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan RS-TOU
Residential Service – Time-of-Use

AVAILABILITY

In all territory served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To all Customers establishing service on or after the effective date of this Pricing Plan, to all Customers who relocate thus establishing service at a new premise on or after the effective date of this Pricing Plan, and to all customers requiring a meter change-out on or after the effective date of this Pricing Plan. Available as an optional rate to Customers served under the Company's Pricing Plan RS, Residential Service (Frozen). Service is provided at one point of delivery measured through one meter and is restricted to private single family dwellings or individually metered apartments.

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:

Minimum Customer Charge per month @	$8.00
Delivery - Energy Charge 1st 400 kWh/month per kWh @	$0.012618
Delivery - Energy Charge additional kWh/month per kWh @	$0.022618

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific RS-TOU PPFAC minus RS PPFAC (from the frozen non-time differentiated rate)" are:

Differentials	
Summer On-Peak:	+ $0.01419 (i.e., add $0.01419 to the non-time differentiated RS PPFAC)
Summer Shoulder:	+ $0.00381 (i.e., add $0.00381 to the non-time differentiated RS PPFAC)
Summer Off-Peak:	- $0.00081 (i.e., subtract $0.00081 to the non-time differentiated RS PPFAC)
Winter On-Peak:	+ $0.00288 (i.e., add $0.00288 to the non-time differentiated RS PPFAC)
Winter Off-Peak:	- $0.01212 (i.e., subtract $0.01212 to the non-time differentiated RS PPFAC)

RESIDENTIAL SERVICE – TIME-OF-USE (continued)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan RS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan RS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01419 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan RS.)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan SGS-10
Small General Service

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AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

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APPLICABILITY

To any customer for any purpose where service is provided at one point of delivery and measured through one meter and 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.

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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:

Delivery Charges:

Minimum Customer Charge per month @	$12.00
First 400 kWhs per month @	$0.034088
All additional kWhs per month @	$0.044088
Base Power Supply Charge, all kWhs per month @	$0.068316

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Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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TAX CLAUSE

To the charges computed under the above pricing plan, 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.

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RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

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UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan SGS-10
Small General Service

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AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

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APPLICABILITY

To any customer for any purpose where service is provided at one point of delivery and measured through one meter and where the monthly usage is not more than 5,000 kWh in any two (2) consecutive months. Customers who use more than 5,000 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.

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:

Delivery Charges:

Minimum Customer Charge per month @	$12.000
Unbundled Customer Charge	
Customer Other	$4.495
Metering	$2.441
Meter Reading	$0.814
Billing and Collection	$4.250
First 400 kWhs per month @	$0.034088
Unbundled $/kWh Charge	
Transmission	$0.002756
Sub-transmission	$0.003270
Delivery	$0.027720
Production not in Power Supply (1)	$0.000342
All additional kWhs per month @	$0.044088
Unbundled $/kWh Charge	
Transmission	$0.002756
Sub-transmission	$0.003270

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. . . Metering . . . . . $1.504¶
. . . Meter Reading . . . . $0.449¶
. . . Billing and Collection . . . $2.356¶
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. . . Customer Other . . . . $3.691¶
. . . Metering . . . . . $1.504¶
. . . Meter Reading . . . . $0.449¶
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. . . Delivery . . . . . $0.004599 ¶
. . . Production not in Power Supply (1) . . $0.000353
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. . . Transmission . . . . $0.003633 ¶
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Delivery	$0.037720
Production not in Power Supply (1)	$0.000342
Base Power Supply Charge, all kWhs per month @	$0.068316

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. . . Transmission . . . . $0.003633 ¶
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Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

TAX CLAUSE

To the charges computed under the above pricing plan, 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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

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AVAILABILITY

In all territory served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To all Customers establishing service on or after the effective date of this Pricing Plan, to all Customers who relocate thus establishing service at a new premise on or after the effective date of this Pricing Plan, and to all customers requiring a meter change-out on or after the effective date of this Pricing Plan. Available as an optional rate to Customers served under the Company's Pricing Plan SGS, Small General Service Service (Frozen). To any customer for any purpose where service is provided at one point of delivery and measured through one meter and 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 – Time-of-Use 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.

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:

Minimum Customer Charge per month @	$12.00
Delivery - Energy Charge 1st 400 kWh/month per kWh @	$0.027772
Delivery - Energy Charge additional kWh/month per kWh @	$0.037772

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific SGS-TOU PPFAC minus SGS PPFAC (from the frozen non-time differentiated rate)" are:

SMALL GENERAL SERVICE – TIME-OF-USE (continued)

Differentials

Summer On-Peak:	+ $0.01461 (i.e., add $0.01461 to the non-time differentiated SGS PPFAC)
Summer Shoulder:	+ $0.00392 (i.e., add $0.00392 to the non-time differentiated SGS PPFAC)
Summer Off-Peak:	- $0.00039 (i.e., subtract $0.00039 to the non-time differentiated SGS PPFAC)
Winter On-Peak:	+ $0.00371 (i.e., add $0.00371 to the non-time differentiated SGS PPFAC)
Winter Off-Peak:	- $0.01129 (i.e., subtract $0.01129 to the non-time differentiated SGS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan SGS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan SGS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01461 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan SGS.)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

TAX CLAUSE

To the charges computed under the above pricing plan, 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

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

SMALL GENERAL SERVICE – TIME-OF-USE (continued)

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

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LGS
Large General Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

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APPLICABILITY

Standard offer sales service to any customer for any purpose where such service is supplied at one point of delivery and measured through one meter and the maximum monthly demand is less than 1,000 kW.

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:

Delivery Charges:

Minimum Customer Charge per month @	$11.10	Deleted: 0
If optional time-of-use service is elected, Minimum Customer Charge per month @	$16.00	Deleted: 5
Billing Demand Charge per kW @	$10.50	Deleted: 9
Energy Charge per kWh @	$0.013143	Deleted: 5331314 Deleted: 3
Base Power Supply Charge, all kWhs per month @	$0.060491	

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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TAX CLAUSE

To the charges computed under the above pricing plan, 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

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LARGE GENERAL SERVICE (continued)

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.

DETERMINATION OF BILLING DEMAND

Normal service: If the time-of-use option is not chosen, the monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month.

Time-of-Use: If time-of-use service is chosen, 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 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.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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LARGE GENERAL SERVICE (continued)

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.

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UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LGS
Large General Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

Standard offer sales service to any customer for any purpose where such service is supplied at one point of delivery and measured through one meter and the maximum monthly demand is less than 1,000 kW.

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:

Delivery Charges:

Minimum Customer Charge per month @	$11.100
Unbundled Customer Charge	
Customer Other	$8.338
Metering	$0.754
Meter Reading	$0.325
Billing and Collection	$1.683

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If optional time-of-use service is elected,

Minimum Customer Charge per month @	$16.000
Unbundled Customer Charge	
Customer Other	$12.020
Metering	$1.087
Meter Reading	$0.468
Billing and Collection	$2.425

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Billing Demand Charge per kW @ $10.500

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Unbundled $/kWh Charge is entirely a Delivery Charge

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Energy Charge per kWh @	$0.013143
Unbundled $/kWh Charge	
Transmission	$0.001167
Sub-transmission	$0.001834
Delivery	$0.009836
Production not in Power Supply (1)	$0.000306
Base Power Supply Charge, all kWhs per month @	$0.060491

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

Normal service: If the time-of-use option is not chosen, the monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month.

Time-of-Use: If time-of-use service is chosen, 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 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.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

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During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

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AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

Standard offer sales service to any customer for any purpose where such service is supplied at one point of delivery and measured through one meter and the maximum monthly demand is less than 1,000 kW.

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.

RATE

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

Minimum Customer Charge per month @	$11.10
Delivery - Billing Demand Charge per kW-mo @	$10.50
Delivery Energy Charge per kWh @	$0.007497

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific LGS-TOU PPFAC minus LGS PPFAC (from the terminated non-time differentiated rate)" are:

LARGE GENERAL SERVICE – TIME-OF-USE (continued)

Differentials

Summer On-Peak:	+ $0.01577 (i.e., add $0. 01577 to the non-time differentiated LGS PPFAC)
Summer Shoulder:	+ $0.00439 (i.e., add $0. 00439 to the non-time differentiated LGS PPFAC)
Summer Off-Peak:	+ $0.00077 (i.e., add $0.00077 to the non-time differentiated LGS PPFAC)
Winter On-Peak:	+ $0.00401 (i.e., add $0.00401 to the non-time differentiated LGS PPFAC)
Winter Off-Peak:	- $0.01099 (i.e., subtract $0.01099 to the non-time differentiated LGS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan LGS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan LGS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01577 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan LGS.)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

Normal service: If the time-of-use option is not chosen, the monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month.

Time-of-Use: If time-of-use service is chosen, 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 or 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.

LARGE GENERAL SERVICE – TIME-OF-USE (continued)

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LPS
Large Power Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

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APPLICABILITY

To any customer for any purpose where the service is supplied at one point of delivery and measured through one meter when the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE

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

For service at less than 69,000 volts (Distribution Service):

Delivery Charges:

Minimum Customer Charge per month @	$365.00
Billing Demand Charge per kW @	$24.00
Energy Charge per kWh @	N/A
Base Power Supply Charge, all kWhs per month @	$0.048041

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For service at 69,000 volts or higher (Transmission Service):

Delivery Charges:

Minimum Customer Charge per month @	$380.00
Billing Demand Charge per kW @	$15.00
Energy Charge per kWh @	N/A
Base Power Supply Charge, all kWhs per month @	$0.048041

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LARGE POWER SERVICE (continued)

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Maximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge

Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

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LARGE POWER SERVICE (continued)

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

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LARGE POWER SERVICE (continued)

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

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.

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UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LPS
Large Power Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer for any purpose where the service is supplied at one point of delivery and measured through one meter when the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE

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

For service at less than 69,000 volts (Distribution Service):

Delivery Charges:

Minimum Customer Charge per month @	$365.000
Unbundled Customer Charge	
Customer Other	$208.686
Metering	$0.709
Meter Reading	$25.303
Billing and Collection	$130.302
Billing Demand Charge per kW @	$24.000
Unbundled $/kW Charge	
Transmission	$0.110
Sub-transmission	$0.441
Delivery	$23.324
Production not in Power Supply (1)	$0.125
Energy Charge per kWh @	N/A
Base Power Supply Charge, all kWhs per month @	$0.048041

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Deleted: Unbundled Customer Charge¶
. . . Customer Other . . . . $3.691¶
. . . Metering . . . . . $1.504¶
. . . Meter Reading . . . . $0.449¶
. . . Billing and Collection . . . $2.356¶

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Inserted: Unbundled Customer Charge¶
. . . Customer Other . . . . $3.691¶
. . . Metering . . . . . $1.504¶
. . . Meter Reading . . . . $0.449¶
. . . Billing and Collection . . . $2.356¶

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. . . Transmission . . . . $0.003633 ¶
. . . Sub-transmission . . . . $0.004032 ¶
. . . Delivery . . . . . $0.004599 ¶
. . . Production not in Power Supply
(1) . . $0.000353

Inserted: Unbundled $/kW Charge¶
. . . Transmission . . . . $0.003633 ¶
. . . Sub-transmission . . . . $0.004032 ¶
. . . Delivery . . . . . $0.004599 ¶
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UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LPS
Large Power Service

For service at 69,000 volts or higher (Transmission Service):

Delivery Charges:

Minimum Customer Charge per month @	$380.00
Unbundled Customer Charge	
Customer Other	$217.262
Metering	$0.7380
Meter Reading	$26.3430
Billing and Collection	$135.657
Billing Demand Charge per kW @	$15.000
Unbundled $/kW Charge	
Transmission	$0.118
Sub-transmission	$0.472
Delivery	$14.276
Production not in Power Supply (1)	$0.134
Energy Charge per kWh @	N/A
Base Power Supply Charge, all kWhs per month @	$0.048041

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Maximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge

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. . . Customer Other . . . . $3.691¶
. . . Metering . . . . . $1.504¶
. . . Meter Reading . . . . $0.449¶
. . . Billing and Collection . . . $2.356
Inserted: Unbundled Customer Charge¶
. . . Customer Other . . . . $3.691¶
. . . Metering . . . . . $1.504¶
. . . Meter Reading . . . . $0.449¶
. . . Billing and Collection . . . $2.356¶
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Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

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RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

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.

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Unbundled $/kW Charge

Transmission	$0.003633
Sub-transmission	$0.004032
Delivery	$0.004599
Production not in Power Supply (1)	$0.000353

Page 2: [2] Inserted **wendy erdwurm** **1/9/2007 4:38 AM**

Unbundled $/kW Charge

Transmission	$0.003633
Sub-transmission	$0.004032
Delivery	$0.004599
Production not in Power Supply (1)	$0.000353

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LARGE POWER SERVICE (continued)

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Mohave and Santa Cruz Counties, Arizona

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer for any purpose where the service is supplied at one point of delivery and measured through one meter when the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE

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

For service at less than 69,000 volts (Distribution Service):

Minimum Customer Charge per month @	$365.00
Delivery - Billing Demand Charge per kW @	$21.53

For service at 69,000 volts or higher (Transmission Service):

Minimum Customer Charge per month @	$400.00
Delivery - Billing Demand Charge per kW @	$12.53

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

LARGE POWER SERVICE - TOU (continued)

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC adjustments applicable to each time-of-use period shall be set such that the differences "time period specific LPS-TOU PPFAC minus LPS PPFAC (from the terminated non-time differentiated rate)" are:

Differentials

Summer On-Peak:	+ $0.01691 (i.e., add $0. 01691 to the non-time differentiated LPS PPFAC)
Summer Shoulder:	+ $0.00492 (i.e., add $0. 00492 to the non-time differentiated LPS PPFAC)
Summer Off-Peak:	+ $0.00191 (i.e., add $0.00191 to the non-time differentiated LPS PPFAC)
Winter On-Peak:	+ $0.00491 (i.e., add $0.00401 to the non-time differentiated LPS PPFAC)
Winter Off-Peak:	- $0.01009 (i.e., subtract $0.01009 to the non-time differentiated LPS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan LPS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan LPS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01691 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan LPS.)

A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Maximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge

Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

LARGE POWER SERVICE - TOU (continued)

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

LARGE POWER SERVICE - TOU (continued)

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan IPS
Interruptible Power Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

Deleted: in Santa Cruz and Mohave Counties

APPLICABILITY

To any customer with a minimum demand of 50 kW for any purpose where such service is supplied at one point of delivery and measured through one meter and is interruptible within fifteen (15) minutes of verbal notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE

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

Delivery Charges:

Minimum Customer Charge per month @	$11.10	Deleted: 0
Billing Demand Charge per kW @	$3.50	Deleted: 2
Energy Charge per kWh @	$0.022967	Deleted: 533
Base Power Supply Charge, all kWhs per month @	$0.050053	

Penalty for failure to interrupt:

In the event that the Customer fails to interrupt its load when requested to do so by the Company, the customer shall pay an additional charge as follows:

Billing Demand Charge per kW @ $10.00

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm pricing plan for a period of at least twelve (12) months.

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

INTERRUPTIBLE POWER SERVICE (continued)

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

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TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

The Company reserves the right to curtail service to the customer at any time and for such period of time that, in the sole judgment of the Company, the operation of the system requires curtailment by the customer.

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. Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

INTERRUPTIBLE POWER SERVICE (continued)

The Company will endeavor to provide the customer with as much advance notice as possible of the required interruptions or curtailments. However, the customer shall interrupt or curtail service within fifteen (15) minutes, if so requested.

The Company reserves the right to have automatic equipment installed for immediate interruption of the customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption or curtailment of service under this pricing plan.

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

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.

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan IPS
Interruptible Power Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

Deleted: in Santa Cruz and Mohave Counties

APPLICABILITY

To any customer with a minimum demand of 50 kW for any purpose where such service is supplied at one point of delivery and measured through one meter and is interruptible within fifteen (15) minutes of verbal notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE

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

Delivery Charges:

Minimum Customer Charge per month @	$11.100
Unbundled Customer Charge	
Customer Other	$6.708
Metering	$1.118
Meter Reading	$0.531
Billing and Collection	$2.743
Billing Demand Charge per kW @	$3.500
Unbundled $/kWh Charge is entirely a Delivery Charge	
Energy Charge per kWh @	$0.022967
Unbundled $/kWh Charge	
Transmission	$0.000615
Sub-transmission	$0.001225
Delivery	$0.020873
Production not in Power Supply (1)	$0.000253
Base Power Supply Charge, all kWhs per month @	$0.050053

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. . . Customer Other . . . . $3.691¶
. . . Metering . . . . . $1.504¶
. . . Meter Reading . . . . $0.449¶
. . . Billing and Collection . . . $2.356¶

Inserted: . . . Unbundled Customer Charge¶
. . . Customer Other . . . . $3.691¶
. . . Metering . . . . . $1.504¶
. . . Meter Reading . . . . $0.449¶
. . . Billing and Collection . . . $2.356¶

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. . . Transmission . . . . $0.003633 ¶
. . . Sub-transmission . . . . $0.004032 ¶
. . . Delivery . . . . . $0.004599 ¶
. . . Production not in Power Supply
(1) . . $0.000353

Inserted: . Unbundled $/kWh Charge¶
. . . Transmission . . . . $0.003633 ¶
. . . Sub-transmission . . . . $0.004032 ¶
. . . Delivery . . . . . $0.004599 ¶
. . . Production not in Power Supply
(1) . . $0.000353 ¶

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Penalty for failure to interrupt:

In the event that the Customer fails to interrupt its load when requested to do so by the Company, the customer shall pay an additional charge as follows:

Billing Demand Charge per kW @ $10.00
Unbundled $/kWh Charge is entirely a Delivery Charge

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm pricing plan for a period of at least twelve (12) months.

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.

Deleted: energy charge

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

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

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

The Company reserves the right to curtail service to the customer at any time and for such period of time that, in the sole judgment of the Company, the operation of the system requires curtailment by the customer.

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. Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

The Company will endeavor to provide the customer with as much advance notice as possible of the required interruptions or curtailments. However, the customer shall interrupt or curtail service within fifteen (15) minutes, if so requested.

The Company reserves the right to have automatic equipment installed for immediate interruption of the customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption or curtailment of service under this pricing plan.

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

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.

Deleted: August 11, 2003

Deleted: Mohave and Santa Cruz Counties, Arizona

AVAILABILITY

In all territories served by the Company in Santa Cruz and Mohave Counties at all points where the adjacent facilities of the Company are adequate and suitable.

APPLICABILITY

To any customer with a minimum demand of 50 kW for any purpose where such service is supplied at one point of delivery and measured through one meter and is interruptible within fifteen (15) minutes of verbal notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE

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

Minimum Customer Charge per month @	$11.10
Delivery - Billing Demand Charge per kW @	$3.50
Delivery - Energy Charge per kWh @	$0.018268

Penalty for failure to interrupt:

In the event that the Customer fails to interrupt its load when requested to do so by the Company, the customer shall pay an additional charge as follows:

Delivery - Billing Demand Charge per kW @	$10.00

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm pricing plan for a period of at least twelve (12) months.

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold. The per kWh PPFAC

INTERRUPTIBLE POWER SERVICE – TIME-OF-USE (continued)

adjustments applicable to each time-of-use period shall be set such that the differences "time period specific IPS-TOU PPFAC minus IPS PPFAC (from the terminated non-time differentiated rate)" are:

Differentials

Summer On-Peak:	+ $0.01637 (i.e., add $0. 01637 to the non-time differentiated IPS PPFAC)
Summer Shoulder:	+ $0.00420 (i.e., add $0. 00420 to the non-time differentiated IPS PPFAC)
Summer Off-Peak:	+ $0.00137 (i.e., add $0.00137 to the non-time differentiated IPS PPFAC)
Winter On-Peak:	+ $0.00392 (i.e., add $0.00401 to the non-time differentiated IPS PPFAC)
Winter Off-Peak:	- $0.01108 (i.e., subtract $0.01108 to the non-time differentiated IPS PPFAC)

(All unbundled components for this Pricing Plan match those shown in Pricing Plan IPS, with the exception that the Base Power Supply Charge for time-differentiated energy use (e.g., for summer on-peak energy) is obtained by adding these Differentials to the non-time-differentiated Base Power Supply Charge in Pricing Plan IPS. By way of example, Base Power Supply Charge for summer on-peak energy are calculated by adding $0.01637 to the non-time-differentiated Base Power Supply Charge in the Pricing Plan IPS.)

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

TAX CLAUSE

To the charges computed under the above pricing plan, 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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

INTERRUPTIBLE POWER SERVICE – TIME-OF-USE (continued)

TERMS AND CONDITIONS

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

The Company reserves the right to curtail service to the customer at any time and for such period of time that, in the sole judgment of the Company, the operation of the system requires curtailment by the customer.

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. Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

The Company will endeavor to provide the customer with as much advance notice as possible of the required interruptions or curtailments. However, the customer shall interrupt or curtail service within fifteen (15) minutes, if so requested.

The Company reserves the right to have automatic equipment installed for immediate interruption of the customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption or curtailment of service under this pricing plan.

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

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.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LTG
Dusk-To-Dawn Lighting Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

Deleted: in Santa Cruz and Mohave Counties

APPLICABILITY

To any Customer, including public agencies, for the lighting of streets, alleys, thoroughfares, public parks, playgrounds, or other public or private property where such lighting is controlled by a photocell and a contract for service is entered into with the Company.

CHARACTER OF SERVICE

Service is supplied on Company-owned fixtures and poles which are maintained by the Company. The poles, fixtures, and lamps available are the standard items stocked by the Company, and service is rendered at standard available voltages.

MONTHLY BILL

The monthly bill shall be the sum of the following charges and adjustments for each light:

Service Charge (per month):	Overhead Service	Underground Service
Existing Wood Pole	$0.00	$2.25
New 30' Wood Pole (Class 6)	$4.50	$6.76
New 30' Metal or Fiberglass	$9.02	$11.27

Lighting Charge:
Based on the rated wattage value of each lamp installed per month: $0.061502 per watt

Base Power Supply Charge per month @ $1.67

Purchased Power Fuel Adjuster Clause ("PPFAC"): The energy charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated, purchased, or transmitted above or below the base cost per kWh sold.

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TAX CLAUSE

To the charges computed under the above pricing plan, 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

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DUSK-TO-DAWN LIGHTING SERVICE (continued)

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.

CONTRACT PERIOD

All dusk-to-dawn lighting installations for public agencies will require an agreement for service.

All dusk-to-dawn lighting installations for other than public agencies will require a contract for service as follows:

Five (5) years initial term for installations on existing facilities, and

Five (5) years initial term, or longer at the Company's option, for installations requiring new and/or an extension of facilities.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

Overhead extensions beyond one hundred fifty (150) feet and underground extensions beyond one hundred (100) feet will require specific agreements providing adequate revenue or arrangements for construction financing.

The Customer is not authorized to make connections to the lighting circuit or make attachments or alterations to the Company-owned pole.

Should a Customer request a relocation of a dusk-to-dawn lighting installation, the costs of such relocation must be borne by the customer.

The Customer is expected to notify the Company when lamp outages occur.

The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

The Company may require a refundable advance for the installation of new construction for facilities.

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

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UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LTG
Dusk-To-Dawn Lighting Service

AVAILABILITY

In all territories served by the Company at all points where the adjacent facilities of the Company are adequate and suitable.

Deleted: in Santa Cruz and Mohave Counties

APPLICABILITY

To any Customer, including public agencies, for the lighting of streets, alleys, thoroughfares, public parks, playgrounds, or other public or private property where such lighting is controlled by a photocell and a contract for service is entered into with the Company.

CHARACTER OF SERVICE

Service is supplied on Company-owned fixtures and poles which are maintained by the Company. The poles, fixtures, and lamps available are the standard items stocked by the Company, and service is rendered at standard available voltages.

MONTHLY BILL

The monthly bill shall be the sum of the following charges and adjustments for each light:

Service Charge (per month):	Overhead Service	Underground Service
Existing Wood Pole	$0.000	$2.251 (All billing and collections)
New 30' Wood Pole (Class 6)	$4.502 Billing & coll: $3.000 Delivery: $1.502	$6.765 Billing and coll: $3.000 Delivery: $3.765
New 30' Metal or Fiberglass	$9.016 Billing & coll: $3.000 Delivery: $6.016	$11.267 Billing and coll: $3.000 Delivery: $8.267

Lighting Charge:
Based on the rated wattage value of each lamp installed per month: $0.061502 per watt
Prod. Not incl. in Power Supply: $0.000150
Delivery: $0.061352

Base Power Supply Charge per month @ $1.670

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated, purchased, or transmitted above or below the base cost per kWh sold.

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TAX CLAUSE

To the charges computed under the above pricing plan, 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.

CONTRACT PERIOD

All dusk-to-dawn lighting installations for public agencies will require an agreement for service.

All dusk-to-dawn lighting installations for other than public agencies will require a contract for service as follows:

Five (5) years initial term for installations on existing facilities, and

Five (5) years initial term, or longer at the Company's option, for installations requiring new and/or an extension of facilities.

RULES AND REGULATIONS

This rate is subject to the General Rules and Regulations of the Company on file with the Arizona Corporation Commission which are made a part hereof.

TERMS AND CONDITIONS

Overhead extensions beyond one hundred fifty (150) feet and underground extensions beyond one hundred (100) feet will require specific agreements providing adequate revenue or arrangements for construction financing.

The Customer is not authorized to make connections to the lighting circuit or make attachments or alterations to the Company-owned pole.

Should a Customer request a relocation of a dusk-to-dawn lighting installation, the costs of such relocation must be borne by the customer.

The Customer is expected to notify the Company when lamp outages occur.

The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

The Company may require a refundable advance for the installation of new construction for facilities.

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

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