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BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
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COMMISSIONERS
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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 POST-HEARING BRIEF

I. INTRODUCTION.

Unisource Electric ("UNSE" or "Company") is a public utility that provides electric distribution service to approximately 93,000 customers in Arizona.[1] The Company is requesting a rate increase of $8.5 Million over test year revenues. This amounts to a 5.5% increase. The Company intends to file another rate case within the next year or two. Staff believes that $8.5 Million being requested by the Company is inflated; and Staff is proposing instead a rate increase of $3.688 over test year revenues.

UNSE was formerly the Arizona electric distribution operations of Citizens Communications Company ("Citizens"), before it was purchased by UniSource Energy in 2003. In addition to purchasing the electric distribution assets of Citizens, it also purchased from Citizens its gas distribution assets.[2]

UNSE and UNS Gas are subsidiaries of UniSource Energy Services ("UES"). The stock of UES is held by UniSource Energy, a holding company, whose principal subsidiary is Tucson Electric Power Company ("TEP"), the second largest investor-owned generation and distribution utility in Arizona.[3] In 2006, UNSE accounted for about 12 percent of UniSource Energy's revenues and about 6 percent of its total assets.[4]

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[1] David Parcell Direct Test. (Ex. S-52) p. 12.
[2] *Id.*
[3] David Parcell Direct Test. (Ex. S-52) at p. 12.
[4] *Id.*

Company witness Grant testified that two key issues in the case account for approximately 80 percent of the difference between Staff's revenue requirement and the Company's revenue requirement, Construction Work in Progress ("CWIP") and cost of equity. [5]

This case, however, stands out for several other reasons as well. First, the Company currently obtains its power through a full requirements contract with Pinnacle West Capital Corporation ("PWCC").[6] Today, UNSE owns only nominal generation assets in Nogales that are used for must-run and voltage stability purposes.[7] UNSE must replace the power currently obtained from PWCC when it expires at the end of May, 2008. It hopes to replace that power through a combination of new wholesale power purchases, its own generation assets, or a combination of both.[8]

UES, an affiliate of UNES, has purchased assets to construct the Black Mountain Generating Station ("BMGS"), a 90 megawatt gas-fired power plant facility in the Kingman area.[9] UNSE would like to acquire BMGS and has asked for special treatment of the plant in this case. Staff opposes special treatment or inclusion of the plant in rate base at this time for a variety of reasons discussed in this brief.

The Company is also requesting extraordinary treatment of CWIP in this case, by asking that $10.8 Million of CWIP be included in rate base. Yet, as explained herein, the Company has not offered any compelling reasons for the extraordinary treatment in this case.

One of the reasons that the Company is requesting extraordinary treatment of CWIP and the BMGS, is due to customer growth. During the test period, Company witness Ferry testified that customer growth increased in Mohave County by 4.8 percent and in Santa Cruz County by 5.8 percent. However, most other utilities filing rate cases before the Commission have also claimed high growth rates to justify special rate base treatment of assets. The Commission has without exception denied those requests because the Company has not met its burden of proof to demonstrate compelling circumstances to justify such exceptional treatment.

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[5] Tr. at 956.
[6] Tr. at p. 15.
[7] *Id.*
[8] *Id.*
[9] Tr. at p. 15.

UNSE is requesting a cost of equity of 11.8%. Staff, on the other hand, relied upon three well-accepted methodologies in arriving at a range for cost of equity between 9.5% and 10.5%, with a mid-point of 10.0%. The Company's request for 11.8% flies in the face of recent electric utility statistics which show a decline in cost of equity for electric distribution companies over the last 5 years; with cost of equity figures much more in line with Staff's proposal in this case.

The Company has also proposed many significant revisions to its Purchase Power Fuel Adjustment Clause (PPFAC) in this case. Staff has used the recent changes made to APS' PSA as a helpful guideline in reviewing and recommending changes to the UNSE PPFAC.

The Company is proposing some significant changes to its rate design in this case as well. While Staff concurs with the philosophy behind those changes, Staff witness Radigan explains that a phased in approach such as he recommends with respect to certain of the changes including Time-of-Use (TOU) rates and merger of the Mohave and Santa Cruz rate structures would be more appropriate and send more rational pricing signals.

Finally, the Company is also requesting approval of additional financing which it plans to use to construct the BMGS. Staff supports the Company's request for financing under certain conditions.

Staff presented seven witnesses in this case. Mr. Alexander Igwe was the case lead and testified on the Company's financing application. Mr. Ralph Smith testified as to the Company's revenue requirement and proposed PPFAC. Mr. David C. Parcell testified on cost of capital. Mr. Frank Radigan testified on the Company's proposed rate design. Ms. Julie McNeely-Kirwan testified on the Company's DSM and CARES programs. Mr. Jerry Anderson testified on the DSM rate recovery mechanism and on various rule changes being proposed by UNSE. Finally, Mr. Prem Bahl sponsored the Staff's engineering report and assessment of "used and useful" plant in service.

Administrative Law Judge Teena Wolfe conducted hearings on the Company's application on September 10 through 14, 2007 and September 20 and 21, 2007 and October 2, 2007.

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II. REVENUE REQUIREMENT.

The Company proposes a revenue requirement or base rate increase of $8.5 Million.[10] Staff believes this is overstated and Staff Witness Ralph Smith recommends instead a base rate increase of $3.688 Million.[11] Mr. Smith is a Senior Regulatory Consultant with Larkin & Associates. Mr. Smith is a CPA, and has a law degree and a Master of Science in Taxation. His firm has sponsored expert witnesses in over 400 regulatory proceedings across the United States.[12]

A. Rate Base.

Staff is proposing an original cost rate base of $130,707,320.00 and a fair value rate base of $167,518,337.00.[13] The Company, on the other hand, is proposing an original cost rate base of $140,991,324.00 and a fair value rate base of $167,281,765.00.[14] Staff is proposing four adjustments to the Company's proposed rate base.[15] The primary difference between the Company's proposed rate base and Staff's proposed rate base relates to whether or not to include CWIP in rate base.

1. CWIP.

UNSE proposes to include $10.8 Million of CWIP in rate base.[16] As Staff witness Smith discusses in his testimony, the Commission's general practice is not to include CWIP in rate base, unless there are extraordinary circumstances such as financial distress.[17] The Company has not demonstrated that it is in financial distress or has experienced extraordinary circumstances that would justify inclusion of CWIP in rate base.[18]

The primary reason for the Company's proposal to include CWIP appears to be disagreement with the Commission's use of the historical test year.[19] Company witness Kentton Grant testified that inclusion of CWIP in rate base is one of the few available tools to mitigate the effects of

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[10] David Dukes Direct Test. (Ex. UNSE-23) at pp. 4 and 19.
[11] Tr. at 1196.
[12] Ralph Smith Direct Test. (Ex. S-56) at p. 1.
[13] Ralph Smith Surrebuttal Test. (Ex. S-58) at p. 6.
[14] *Id.*
[15] Tr. at p. 1198.
[16] *Id.* at p. 13.
[17] *Id.* at p. 14; See also Tr. at p. 1198.
[18] Tr. at p. 1199.
[19] Ralph Smith Direct Test. (Ex. S-56) at p. 13; See also Kentton Grant Direct Test. (Ex. UNSE-34) at p. 24.

regulatory lag.[20] He also stated that if the Company's request is denied, the authorized rate of return should be increased.[21]

Staff witness Smith explained why inclusion of CWIP is not appropriate except in exceptional circumstances in the following passage from his testimony:

> CWIP, as the title designates, is not plant that is completed and providing service to ratepayers during the test year. During the test year, it was not used or useful in providing electric service to the Company's customers. The ratemaking process is predicated on an examination of the operations of a utility to insure that the assets upon which ratepayers are required to provide the utility with a rate of return are prudently incurred and are both used and useful in providing services on a current basis. Facilities in the process of being built are not used or useful. The ratemaking process therefore excludes CWIP from rate base until such projects are completed and providing service to ratepayers in the context of a test year that is being used for determining the utility's revenue requirement.[22]

It is well recognized that inclusion of CWIP in rate base would also result in a mismatch in the ratemaking process.[23] To the extent that CWIP is to serve additional customers, it is considered revenue producing.[24] However, the revenues have been annualized to the end of the test year only and not beyond.[25] And, if the CWIP is expense reducing, those reductions have not been reflected beyond the test year.[26]So it is a mismatch to include CWIP since the post test year impacts have not been quantified and reflected as adjustments to operating income.[27]

The Company also argues that $8.7 million of the $10.8 million in CWIP was plant in service as of June 30, 2007. But as Mr. Smith notes, 2007 is a whole year outside of the end of the test year, therefore, its suffers from the same mismatch problem. [28]

The Company does receive a return representing its financing costs called Allowance for Funds Used During Construction ("AFUDC").[29] And, when the plant is placed into service, the AFUDC is capitalized and depreciated along with the plant.[30]

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[20] Ralph Smith Direct Test. (Ex. S-56 at p. 13; Kenton Grant Direct Test. (Ex. UNSE-34) at p. 24.
[21] *Id.*
[22] Ralph Smith Direct Test. (Ex. S-56) at p. 15.
[23] *Id.*
[24] Tr. at pp. 1198-1199
[25] Tr. at 1199.
[26] *Id.*
[27] *Id.*
[28] Tr. at p. 1223.
[29] Ralph Smith Direct Test. (Ex. S-56) at p. 16.

Further, Staff's cost of capital witness, David C. Parcell, disputed the Company's assertion that inclusion of CWIP in rate base is necessary for the Company to attract capital in the future. [31] Mr. Parcell explained that his research indicated that the rating agencies describe the operations of UNSE as low risk.[32] Mr. Parcell also explained that UNSE receives its financing based on the credit quality of UniSource Energy or UES, its holding company which is publicly traded.[33]

2. CWIP Adjustments for Plant in Service.

Staff witness Smith's review of the CWIP account, and Staff's field inspection revealed that there was a project in the CWIP account that was used and useful as of the end of the test year.[34] The project was Rhodes Homes (task 8009729), which involved a line extension with a cost of $442,255, inspected by Staff on June 6, 2007 and in service on May 26, 2006, which was prior to the end of the test year.[35] The project involved the installation of 21 kV overhead line to supply service to water pumps for a proposed housing project.[36] Customer advances related to this project totaled $360,117.00 and were already reflected by the Company in its proposed rate base.[37] Staff increased rate base by $442,255.00 in Adjustment B-2 to reflect that this project was in service by the end of the test year.

Staff's field review also raised an issue concerning whether UNSE had received a customer advance for another construction project, Tubac Golf Resort. Staff confirmed that UNSE had received and accounted for a Customer Advance for this project and therefore withdrew its Adjustment B-3.

3. Cash Working Capital.

Cash working capital is the cash necessary for the Company's day-to-day operations.[38] If the Company must pay its expenses in aggregate before it receives cash from operations to do so,

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30 *Id.*
31 David Parcell Direct Test. (Ex. S-52) at p. 14.
32 *Id.*
33 *Id.*
34 Ralph Smith Direct Test. (Ex. S-56) at p. 18.
35 *Id.* at pps. 18-19.
36 *Id.* at 19.
37 Ralph Smith Direct Test. (Ex. S-56) at p. 19.
38 *Id.* at p. 21.

investors have to provide the cash working capital.[39] A positive cash working capital requirement exists in this case.[40]

On the other hand, if revenues from operations are received before payment of expenses are necessary, on average, then ratepayers supply the cash working capital the Company needs and a negative cash working capital allowance is used to reduce rate base.[41]

In this case the Company did a lead/lag study to calculate its cash working capital requirements.[42]

Staff witness Smith testified that his review of the Company's lead/lag study indicated that UNSE has a negative cash working capital requirement.[43] This means that "[o]n average, revenues from ratepayers are received prior to the time when the utility pays the associated expenditures."[44]

4. Accumulated Deferred Income Taxes.

This adjustment by Mr. Smith decreases rate base by $161,555.00.[45] It reflects the impact from the following: 1) removal of the ADIT related to the Supplemental Executive Retirement Plan ("SERP"), and 2) removal of the ADIT relating to stock-based compensation[46]

The adjustments to ADIT are necessary for consistency with Staff's adjustments to remove the expense for SERP and for stock-based compensation.

B. <u>Operating Income and Expense Adjustments.</u>

1. CWIP Depreciation and Property Taxes.

The Company's proposal to treat CWIP at the end of the test year as if it were plant in service resulted in the Company increasing depreciation and property tax expenses.[47] Due to Staff's adjustment removing CWIP from rate base, the Staff has also removed UNSE's related adjustments for depreciation and property tax expenses.[48] Staff's adjustment reduces the Company's proposed

[39] *Id.*
[40] *Id.*
[41] *Id.* at 21.
[42] *Id.*
[43] *Id.*
[44] *Id.* at 21.
[45] Ralph Smith Direct Test. (S-56) at p. 22.
[46] *Id.*
[47] Ralph Smith Direct Test. (S-56) at p. 18.
[48] *Id.*

expenses for depreciation by $449,816.00 and property taxes by $239,696.00, for a total reduction of $689,512.00.[49]

2. Depreciation and Property Taxes for Adjustments to CWIP for Plant in Service.

This Staff adjustment increases depreciation expense by $18,265.00 and property tax expense by $8,317.00.[50] The adjustment increases test year expenses for depreciation and property taxes related to the Rhodes Homes project (task 8009729) which the Company included in CWIP but which Staff found to be used and useful prior to the end of the test year.[51] The plant was found to be in service on May 26, 2006.[52]

3. CARES Discount.

Staff witness Julie McNeely-Kirwan is recommending that the existing discount rate structure for CARES be retained. Therefore, Staff made an adjustment to reduce the Company's revenue by $52,937.00 which reversed the Company's new proposal to calculate the CARES discount in the future.[53] In Staff's final accounting schedules, on Schedule C-4, revised 9/17/2007, the Staff adjustment to fleet fuel expense was revised to an adjustment of $41,909.00. This revision utilized the pro forma fleet fuel expense of $605,498.00 per UNSE witness Dukes' rejoinder testimony at page 2.

4. Fleet Fuel Expense.

Staff reduced UNSE's proposed increase in Fleet Fuel expense by $70,391.00.[54] Staff's adjustment allows for an increase to fuel expense of $3,270.00.[55] This is based on a cost of gasoline of $2.69 and is based upon UNSE's actual fuel costs.[56]

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[49] *Id.* at pp. 23-24.
[50] *Id.* at p. 24.
[51] *Id.*
[52] *Id* at p 24.
[53] *Id.*
[54] Ralph Smith Direct Test. (Ex. S-56) at p. 25.
[55] *Id.* at p. 24.
[56] *Id.* at pp. 24-25.

5. Postage Expense.

Staff increased the Company's proposed normalized postage expense of $341,321.00 by $17,503.00.[57] This adjustment reflects an increase to annualized postage expense to reflect the May 14, 2007 increase in the cost of a first class letter from 39 cents to 41 cents.[58]

6. Injuries and Damages Expense.

Staff made a normalizing adjustment to the Company's Injuries and Damages expense to reflect a three-year average through December, 2006.[59] Staff witness Smith testified that "[t]he tests year Injuries and Damages expense (Account 925) is so high in comparison with the other years because a number of the types of expenses which are recorded in this account appear to be abnormally high in the test year, and would thus require separate adjustment, if the balance in this account were not normalized…"[60]

Finally, Directors' and Officers' Liability ("D&O) expense, another Account 925 expense, has increased dramatically since 2004.[61] In 2004, D&O expense was $22,032.00 and in 2006 it was $130,330.00.[62] Witness Smith testified that the "substantially increased cost of such D&O insurance is a concern because the direct monetary benefits of D&O Insurance is not enjoyed by ratepayers."[63] Mr. Smith further testified that "[b]ecause shareholders benefit materially from this insurance, it may be appropriate to allocate the cost of D&O Insurance equally between shareholders and ratepayers.[64]

Overall, because of these concerns, Staff reduced test year expense for Account 925 by $159,063.00.[65] As noted in Staff's final accounting schedules, Staff modified its adjustment to agree with the revised normalized amount stated in UNSE witness Dukes' rejoinder testimony at page 4. (See Staff final accounting schedules, Revised Schedule C-6, revised 9/17/2007). As a result of this, Staff's revised adjustment reduced UNSE's test year expense by $98,161.00.

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[57] Ralph Smith Direct Test. (Ex. S-56) at p. 25.
[58] *Id.*
[59] *Id.*
[60] Ralph Smith Direct Test. (S-56) at p. 26.
[61] *Id.* at p. 27.
[62] *Id.*
[63] *Id.*
[64] *Id.* at p.27.
[65] *Id.* at p.26.

7. Incentive Compensation.

Staff adjusted the Company's expenses associated with various incentive compensation plans, including the Performance Enhancement Plan ("PEP"). Staff adjusted the amount of the expense related to the various incentive compensation programs of UNSE by 50%.[66] Incentive compensation programs benefit both shareholders and ratepayers. The removal of 50% of the expense related to such programs provides an equal sharing of the cost of such programs between shareholders and ratepayers, since the programs benefit both groups.[67]

The recommendations made by Staff in this case are the same as its recommendations in the recent UNS Gas case. UNSE participates in the same incentive compensation arrangement, the PEP, as its affiliate UNS Gas.[68] The Company's non-union employees participate in the UniSource Energy Corporation's PEP. [69] UniSource Energy Services ("UES") is a subsidiary of UniSource Energy Corporation and the parent company of UNSE.[70] The PEP determines eligibility for certain bonus levels by measuring performance in three areas: (1) financial performance; (2) operational cost containment; and (3) core business and customer service goals.[71] 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.[72] The first two of these areas are of primary benefit to shareholders.

Staff also removed 100% of the expense associated with the Supplemental Executive Retirement Plan (SERP).[73] This plan provides supplemental retirement benefits for select executives of UNSE.[74] SERPs typically provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts.[75]

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[66] Ralph Smith Direct Test (Ex. S-56) at p. 27.
[67] *Id.*
[68] Ralph Smith Direct Test. (Ex. S-56) at p. 28.
[69] *Id.* at p. 28.
[70] *Id.*
[71] Ralph Smith Direct Test. (Ex. S-56) at p. 28.
[72] *Id.*
[73] *Id.*
[74] Ralph Smith Direct Test (Ex. S-56) at p. 27.
[75] *Id.*

Staff's adjustments are consistent with the Commission's recent decision in the last Southwest Gas rate case. In the Southwest Gas case, the Commission adopted Staff's recommendation for an equal sharing of incentive compensation plan costs and RUCO's recommendation to remove SERP expense in its entirety. In the following passage from that Order, the Commission addressed the removal of SERP expense:

> 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.[76]

The Company has not presented any rationale or support for the Commission to treat its incentive compensation plans differently for ratemaking purposes than the Commission's treatment of similar plans in the last Southwest Gas rate case. Further, there was considerable evidence presented regarding the Company's base salaries to support Staff's disallowance.[77] As noted in Staff's final accounting schedules, the amount of Staff's adjustment was modified in response to UNSE witness Dukes' rejoinder testimony at page 7. Staff's final adjustment (on Schedule C-7, revised 9/17/2007) of Staff's final accounting schedules reduced expense by $104,357 for incentive compensation ($79,871 for PEP and $24,486 for other incentive compensation), and by $4,160 for related payroll taxes.

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[76] Decision No. 68487 at 19.
[77] See Confidential Exhibit S-1.

8. Rate Case Expense.

UNSE is requesting $600,000.00 for rate case expense, normalized over a three year period, for an annual allowance of $200,000.00 per year.[78] This is the same amount and treatment that its sister company UNS Gas requested in its recent rate case.

Staff believes this amount is inflated and instead proposes a rate case expense allowance of $88,333.00 per year, based on a total of $265,000 normalized over three years.[79] The amount requested by UNSE for rate case expense is 3.8 times as high as the amount of rate case expense allowed by the Commission in the Southwest Gas rate case. Yet, the issues were not significantly different or more difficult that the Southwest Gas case.

While the current case may be the first rate case for this utility operation under its current ownership, it is not 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.

Moreover, the current UNSE rate case is similar to and presents many of the same issues, disallowance of incentive compensation, revisions to the commodity cost recovery mechanism ("PGA" or "PPFAC") addressed by the Commission in the Southwest Gas case, Docket No. G-01551A-04-0876. Staff believes that the Southwest Gas case and the recent UNS Gas rate case provide a reasonable benchmark for what a reasonable allowance for rate case cost should be in the current UNSE rate case.

9. Edison Electric Institute Dues.

Staff witness Ralph Smith reduced test year expense by $8, 470.00 which reflects 49.93 percent of EEI core dues and 100 percent of EEI UARG dues.[80] Mr. Smith reduced the expense levels recorded by the Company because EEI core dues related to the following activities should be excluded and were not:

- Legislative Advocacy
- Regulatory Advocacy

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[78] Ralph Smith Direct Test. (Ex. S-56) p. 33.
[79] *Id.* at p. 34.
[80] Ralph Smith Direct Test. (S-56) p. 34.

- Advertising
- Marketing
- Public Relations[81]

The NARUC categorization of EEI dues expenses utilized by Mr. Smith is intended to help state commissions by weeding out potential costs that may not be undertaken for the benefit of ratepayers.[82] For instance, the Arkansas Public Service Commission in Docket No. 06-101-U, an Entergy Arkansas, Inc., rate case (Order No. 10 dated 6/15/07) utilized the NARUC categorizations to disallow 49.93 percent of EEI core dues.

Further, Mr. Smith recommends disallowance of $5,477.00 of UARG dues from the cost of service.[83] UARG is the EEI Utility Air Regulatory Group which is also referred to as a separately funded activity for the environment. This group advocates the electric utility industry's views before legislative, regulatory and judicial bodies which positions may not be consistent with ratepayer interests.[84] Accordingly, they should be disallowed.

10. Other Membership Dues.

Mr. Smith also disallowed $6,482.00 in other discretionary membership and industry association dues which were not related to the safe and reliable provision of electric utility service.[85] This includes $1,750.00 for the Arizona-Mexico Commission which the Company concedes was included in error.[86]

Mr. Smith also recommended that in future rate filings, the Company should include a cost-benefit analysis which reflects all of the benefits it believes it received over the prior period from any trade organization for which it seeks recovery of dues.[87]

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[81] *Id.* at p. 35.
[82] Ralph Smith Direct Test. (S-56) p. 35.
[83] *Id.* at p. 36.
[84] *Id.* at p. 36.
[85] *Id.* at 37.
[86] *Id.*
[87] Ralph Smith Direct Test. (Ex. S-56) at p. 38.

11. Interest Synchronization.

This adjustment increases income tax expense by $177,093.00 as shown on Staff revised Schedule C-14 and decreases the Company's operating income by a similar amount.[88]

12. Depreciation Rates.

Staff witness Smith agrees with the depreciation rate study conducted by Dr. White for the Company with one correction for transportation equipment.[89] The Company's data response to Staff 3.39 stated as follows:

> Foster Associates inadvertently failed to include a 10 percent net salvage rate for UNS Electric transportation equipment. The impact of this oversight would e a further reduction in 2006 annualized accruals of $143,297.00. It is the opinion of Foster Associates that the magnitude of the additional depreciation reduction does not warrant a refilling of the depreciation study.[90]

Staff witness Smith made an adjustment that reduced the Company's proposed annualized depreciation expense by $64,872.00 and also adjusted the utility plant acquisition adjustment account by $1767.00, for an overall net reduction to operating expense of 63,105.00. [91] UNS Electric agreed that this correction was necessary.

Mr. Smith also recommends 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.[92] This will allow depreciation expense related to the inclusion estimated future cost of removal in depreciation to be tracked and accounted for by plant account.[93]

13. Emergency Bill Assistance Expense.

Staff increased test year expense to $20,000.00 to provide for the increase requested by the Company for emergency bill assistance. [94] UNSE included this amount in its request for increased funding for its low-income weatherization program.[95]

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[88] *Id.*
[89] Ralph Smith Direct Test. (Ex. S-56) at p. 39.
[90] *Id.*
[91] *Id.* at p. 39.
[92] *Id* at p. 68.
[93] *Id.*
[94] Ralph Smith Direct Test. (Ex. S 56) at p. 41.
[95] *Id.*

The Company had requested that the low-income weatherization program be included in the Demand Side management ("DSM") programs. [96] However, as discussed in the testimony of Staff witness McNeely-Kirwan, bill assistance should not be a part of the Company's DSM program. Further this particular expense should not be included in the separate DSM surcharge rate. [97]

14. Mark-up Above Cost for Charges From Affiliate, Southwest Energy Services.

Southwest Energy Services ("SES") is an affiliated company of UNSE and supplies additional work force assistance to UNSE and its other affiliates.[98] In response to Staff data requests, it was revealed that SES began performing meter reads for UNSE beginning in February, 2005.[99] In the Company's data response, the Company stated that when SES provides supplemental work force services to UNSE, TEP of other affiliates, SES charges a 10% mark-up on the base wages of the workers.[100] In addition, SES charges the cost of the employer's taxes, workers' compensation and benefits.[101] Test year expense should be reduced by $10,906 to remove the affiliated mark-up above cost.

15. Other Uncontested Adjustments

Staff's final accounting schedules (and Mr. Smith's surrebuttal testimony) addressed three adjustments which Staff believes are uncontested by UNSE. These adjustments are reflected in Staff's final accounting schedules in Adjustments C-18 (bad debt expense), C-19 (removes double count from outside services Demand Side Management, and C-20 (corrects year-end accrual expense for an out-of-period expense).

B. <u>Cost of Capital</u>.

Staff witness David C. Parcell, President and Senior Economist of Technical Associates, Richmond, Virginia, presented Staff's position on cost of capital. [102] Mr. Parcell holds a B.A. and M.A. degree in economics from Virginia Polytechnic Institute and State University and a M.B.A.

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[96] *Id.*
[97] *Id.* at 41.
[98] Ralph Smith Direct Test. (Ex. S-56) at p. 42.
[99] *Id.*
[100] *Id.*
[101] *Id.* at p. 42.
[102] David Parcell Direct Test. (Ex. S-52) at p. 1.

from Virginia Commonwealth University. He has provided cost of capital testimony in public utility ratemaking proceedings dating back to 1972. He has filed testimony and or testified in approximately 400 utility proceedings before 40 regulatory agencies in the United States and Canada.

1. Capital Structure.

UNSE has used its capital structure as of June 30, 2007 for purposes of this proceeding.[103] Staff witness Parcell proposed use of the actual test period capital structure of UNSE as of June 30, 2006.[104]

Mr. Parcell explained in his Direct Testimony that determining an appropriate capital structure is important because one needs to ensure that the capital structure is "appropriate relative to its level of business risk and relative to other utilities."[105] The common equity ratio receives the most attention for the following three reasons: 1) it commands the highest cost rate; 2) it generates associated income tax liabilities; and, 3) it causes the most controversy since its cost cannot be precisely determined.[106]

UNSE is a subsidiary of UES, which is a subsidiary of UniSource Energy.[107] UNSE was created when Unisource purchased the electric distribution assets of Citizens Communications.[108] Thus UNSE's capital structure did not exist until 2003.[109] Since 2003, UNSE's common equity ratio has been steadily increasing. In 2003, the common equity ratio of the company (including short-term debt) was 37.6%. By contrast, in 2006, the Company's common equity ratio was 45.0% (including short-term debt).[110] UniSource Energy's common equity ratio has also increased over this same period from 28.8% in 2002 (including short-term debt) to 34.9 % in 2006 (including short-term debt).[111]

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[103] *Id.* at p.2.
[104] *Id.*
[105] *Id.* at p. 15.
[106] David Parcell Direct Test. (Ex. S-52) at p. 15.
[107] *Id.* at 16.
[108] *Id.*
[109] *Id.*
[110] David C. Parcell Direct Test. (Ex. S-52) at 16.
[111] *Id.*

Mr. Parcell also studied the common equity ratios of the two groups of electric utilities reported by AUS Utility Reports: electric and combination gas and electric companies. The common equity ratios of those two groups which were 38% and 36% respectively (inclusive of short-term debt) in 2002 had increased to 45% and 44% respectively (inclusive of short-term debt) in 2006.[112]

The Company's June 30, 2007, capital structure contains a 48.85% common equity ratio.[113] Mr. Parcell's proposed capital structure based upon the end of the test year is 48.83%.[114] Thus, the capital structures proposed by the Company and Mr. Parcell are only marginally different. In fact the difference in the capital structure between them amounts to only three (3) basis points of the total cost of capital.[115]

2. Cost of Capital.

With respect to cost of capital, the primary difference between Staff and the Company is basically cost of equity.[116] Mr. Parcell has computed an overall cost of capital for UNSE of 8.74 to 9.23 percent, with a midpoint of 8.99%.[117] The Company proposed an overall cost of capital of 9.89%.[118]

a. Cost of Debt.

Mr. Parcell used a cost of long-term debt of 8.16%; and a cost of short-term debt of 6.36%.[119] These were the rates as of June 30, 2006.[120] The Company is proposing a cost of long-term debt of 8.22%.[121]

Mr. Parcell testified that the cost of debt is determined primarily by interest payments, issue prices and related expenses.[122]

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[112] *Id.* at 17.
[113] *Id.*
[114] Id. ; DCP-1, Schedule 13.
[115] Tr. at-. 1125.
[116] Tr. at 1126.
[117] *Id.*
[118] Tr. at 957.
[119] David Parcell Direct Test. (Ex. S-52) at p. 18.
[120] *Id.*
[121] Tr. at p. 974.
[122] David Parcell Direct Test. (Ex. S-52) at p. 18.

b. Cost of Equity.

The major difference between the Company's overall cost of capital and Staff's overall cost of capital has to do with the computation of the Company's cost of equity.[123] UNSE is requesting an 11.8 percent cost of equity. Staff witness Parcell is proposing a cost of equity for the Company within a range of 9.5% to 10.5% [124]

Mr. Parcell used three different methodologies to estimate the Company's cost of equity.[125] Since UNSE is not publicly traded, it is not possible to apply cost of equity models directly to it.[126] While its parent UniSource Energy is publicly traded, the results of a direct analysis applied to this Company would be of limited value because of its diversified nature.[127] Consequently, Mr. Parcell used a group of comparison or proxy companies to determine UNSE's cost of equity.[128]

The three primary methods for determining cost of equity are the Discounted Flow Model ("DCF"), the Comparable Earnings Method ("CE") and the Capital Asset Pricing Model ("CAPM").

The DCF Model is based upon the "dividend discount model" and determines the value or price of a security by calculating the discounted present value of all future cash flows.[129] Results under the DCF Model were calculated by Mr. Parcell assuming that dividends are expected to grow at a constant rate.[130] The DCF Equation recognizes that the return expected by investors is comprised of dividend yield (current income) and expected growth in dividends (future income). [131]

In determining return, Mr. Parcell combined the current dividend yield for each group of proxy utility stocks with several indicators of expected dividend growth.[132] The dividend growth rate component of the model is usually the most controversial piece of the equation.[133] Mr. Parcell considered the following five indicators of growth in his DCF analysis:

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[123] Tr. at p. 1126.
[124] Tr. at p. 1126.
[125] David Parcell Direct Test. (Ex. S-52) at p. 18.
[126] *Id.*
[127] *Id.*
[128] David Parcell Direct Test. (Ex. S-52) at pp. 18-19.
[129] David Parcell Direct Test. (Ex. S-52) at p. 19.
[130] *Id.* at pp. 19-20.
[131] *Id.* at p. 20.
[132] *Id.*
[133] *Id.* at p. 21.

1. 2002-2006 (5-year average) earnings retention, or fundamental growth (per Value Line);
2. 5-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS)(per Value Line);
3. 2007, 2008 and 2010-2012 projections of EPS, D PS, and BVPS (per Value Line); and,
4. 2004-2006 to 2010-2012 projections of EPS, DPS, and BVPS (per Value Line); and,
5. 5-year projections of EPS growth as reported in First Call (per Yahoo Finance).[134]

The DCF results in Schedule 7 of Mr. Parcell's Direct Testimony indicate average DCF cost rates of approximately 8.5%. Mr. Parcell's analysis yielded a range of 9.5% to 10.5% percent for the proxy group.[135] The Company's DCF analysis (9.7% to 10.5%) does not vary significantly from Staff's DCF analysis (9.5% to 10.5%).

Mr. Parcell then used the CAPM model which is a version of the risk premium method.[136] The CAPM describes the relationship between a security's investment risk and its market rate of return.[137] Mr. Parcell used the same group of proxy companies when calculating the cost of equity using CAPM.[138]

The first variable in the equation is the risk-free rate.[139] The risk-free rate is generally recognized by use of U.S. Treasury securities. Mr. Parcell used the three month average yield (March-May 2007) for 20-year U.S. Treasury bonds which produced an average yield of 4.91 percent.[140] The next variable in the CAPM equation is beta, which is a measure of the relative volatility or risk of a stock in relation to the overall market.[141] To calculate the risk premium (the investor expected premium of common stock over the risk-free rate) Mr. Parcell used the S&P 500

[134] *Id.* at p. 21.
[135] *Id.* at 23.
[136] David Parcell Direct Test. (Ex. S-52) at p. 23.
[137] *Id.*
[138] *Id.* at p. 24.
[139] *Id.*
[140] *Id.*
[141] David Parcell Direct Test. (Ex. S-52) at p. 24.

and 20 year U.S. Treasury Bonds.[142] This yielded a risk premium of about 5.9%.[143] The CAPM calculations indicated a cost of about 10% to 10.5% for the two groups of comparable utilities.[144]

The Company CAPM results are much different than Staff's, because the Company relied only upon 1926-2005 arithmetic average differences between large company stocks (S&P 500) and long-term Treasury bonds.[145] As Mr. Parcell testified it is preferable to have multiple sources of risk premium measures.[146] Further, Company witness Grant's 7.1 risk premium used only arithmetic returns and ignores geometric (compound) returns in deriving the risk premium, which is again inappropriate.[147] Investors have access to both types of returns and use both when they make their investment decisions.[148] Mr. Parcell also points out that Value Line, one of the reports relied by UNSE, show historic on a geometric rate basis, not on an arithmetic rate basis.[149]

Finally, with respect to his CAPM analyses, Mr. Grant focuses on the top end of the range in developing his recommendation with respect to cost of equity. He chose 11.2%, the top end of his CAPM range, which represents the result for a single company.[150] Had he instead focused on the mid-points of his DCF and CAPM analyses, his recommendation would have been within a range (10.1% to 10.8%) very similar to Mr. Parcell's (9.5% to 10.5%).[151]

The CE method is based upon the "corresponding risk" standard of the United States Supreme Court's decisions in the *Bluefield*[152] and *Hope*[153] cases. The CE method is "designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises."[154] Under Mr. Parcell's CE analysis is based upon market data (through the use of market-to-book ratios) and thus is a market test.[155] He considered the equity returns of the proxy groups of utilities for the

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142 *Id.* at p. 25.
143 *Id.* at p. 25.
144 *Id.* at p. 26.
145 David C. Parcell Direct Test. (Ex. S-52) at p. 32.
146 *Id.*
147 *Id.*
148 David C. Parcell Direct Test. (Ex. S-52) at p. 32.
149 *Id.* at p 33.
150 David C. Parcell Direct Test. (S-52) at p. 35.
151 *Id.*
152 *Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923).
153 *Federal Power Comm'n v. Hope Natural Gas Co.*, 230 U.S. 591 (1942).
154 David Parcell Direct Test. (Ex. S-52) at p. 26.
155 *Id.* at p. 27.

period 1992-2006, or the last 15 years.[156] Mr. Parcell explained that he used this period because the CE analysis requires the use of a long period of time to determine trends in earnings over at least a full business cycle.[157] Mr. Parcell discussed his results in the following passage from his Direct Testimony:

> These results indicate that historic returns of 9.0-10.6 percent have been adequate to produce market-to-book ratios of 148-154 percent for the groups of proxy utilities. Furthermore, projected returns on equity for 2007, 2008, and 2010-2012 are within a range of 9.5 percent to 10.7 percent for the utility groups. These relate to 2006 market-to-book ratios of 151 percent or higher.[158]

Overall, Mr. Parcell testified that his CE analysis indicated a cost of equity for the proxy utilities of no more than 10%.[159] He stated that recent returns of 9.0%-10.6% have resulted in market-to-book ratios of 148 and greater.[160] Prospective returns of 9.5% to 10.7% have resulted in market-to-book ratios of over 151%. Thus, an earned return of 10% should result in a market-to-book ratio of at least 100%.[161]

A summary of Mr. Parcell's results under the three methods is:

Discounted Cash Flow	9.5-10.5% (10.0% mid-point)
Capital Asset Pricing Model	10.0-10.5% (10.25% mid-point)
Comparable Earnings	10%

Thus, his cost of equity for UNSE is a range from 9.5% to 10.5% with a mid-point of 10.0%.[162] This results in an overall total cost of capital of a range from 8.74% to 9.23% with a mid-point of 8.99 percent.[163]

UNSE witness Grant made a 60 basis point adjustment for UNSE. Thus he compounded his overstated cost of equity for UNSE by adding sixty basis points to his 9.7% to 11.2% range to reflect

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[156] *Id.*
[157] *Id.*
[158] David Parcell Direct Test. (Ex. S-52) at p. 28.
[159] *Id.* at p. 29.
[160] *Id.* at p. 29.
[161] *Id.*
[162] David Parcell Direct Test. (Ex. S-52) at p. 30.
[163] *Id.*

UNSE's operations which he states are decidedly riskier than the proxy group.[164] The adjustment was made because he has erroneously assumed that UNSE is a non-investment grade company.[165]

He also cited size as one reason for adjustment but this is not a legitimate reason since UNSE does not raise its own equity capital and its debt is guaranteed by UES.[166] It is not the size of UNSE that investors evaluate, rather it the size of the publicly-traded entity, UES.[167]

Staff's proposed cost of equity is also much more consistent with trends in authorized returns on equity for electric utilities as reported by Regulatory Research Associates in recent years:

2000	11.43%
2001	11.09%
2002	11.16%
2003	10.99%
2004	10.75%
2005	10.54%
2006	10.36%[168]

c. *Chaparral City Water Company* Decision.

UNSE proposed in Schedule A-1, that the total cost of capital for the Company be applied to the "fair value" of the Company's rate base. This is apparently in response to the recent Arizona Court of Appeals decision in *Chaparral City Water Company*.[169]

UNSE's proposal to simply apply the same cost of capital analysis as is applied to original cost rate base is inappropriate and would result in overstatement of the Company's current cost of capital. The Court in *Chaparral City* recognized this when it stated: 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."[170]

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[164] *Id.* at p. 35.
[165] *Id.*
[166] *Id.*
[167] *Id.*
[168] David C. Parcell Direct Test. (Ex. S-52) at p. 34.
[169] *Chaparral City Water Company v. Arizona Corporation Commission*, 1CH-CC-05-0002 (2007).
[170] *Id.*

The Commission currently has a proceeding open to address the Chaparral City Water Company decision. That proceeding is still underway.

The Company argues 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."[171]

The Company's argument that Staff through its methodology is backing into a rate of return is meritless. As Mr. Smith pointed out, the cost of capital applicable to the amount of FVRB that is in excess of the Original Cost Rate Base 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 (debt or equity) that is reported on the utility's financial statements. [172] Moreover, the application of Staff's adjusted weighted cost of capital to the FVRB results in revenue increase of $3.668 million. Thus, in this case, the application produces a slightly higher revenue requirement than does the application of the unadjusted rate of return to Original Cost Rate Base. [173]

Further, Mr. Smith pointed out at the hearing that Unisource responded to Staff data requests that information concerning reconstruction cost new, reconstruction cost new depreciated, Handy-Whitman Index information, Marshall Index information, Bureau of Labor Statistics information was given little or no weight by UniSource in deciding how much to pay for the electric utility. The arms-length transaction that occurred demonstrates that the RCND was not a good estimate of the fair value of this utility as of the date of the acquisition.[174] Mr. Smith further testified:

> The price paid in an arms-length transaction would represent the fair value of the utility as of the date of the acquisition. The price paid was substantially below the original cost depreciated book value. Because the acquisition occurred fairly recently in August of 2003, this suggests that using RCN and RCND information to establish the fair value of the utility rate base in the current rate case could potentially result in a

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[171] Kentton C. Grant Rebuttal Test. (Ex. UNSE-35) at p. 3.
[172] Ralph C. Smith Surrebuttal Test. (Ex. S-58) at p. 5.
[173] *Id.* at pps. 5-6.
[174] Tr. at pp. 1197-1198.

> substantial overstatement of the fair value rate basing of the Commission's traditional methods for determining fair value rate base.[175]

d. Financing Application.

This case also included a request by the Company for authority to issue up to $40 Million in new debt securities consisting of either long-term 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 favorable market conditions exist.[176] The Company is seeking authority to obtain $80 Million in total (including the $40 Million in new debt securities) of new financing authority in order to finance the $60 to $65 Million purchase price for BMGS. The Company intends to receive the additional $40 Million through an infusion of additional equity from UniSource Energy Corporation ("UniSource") and seeks Commission authority of this infusion to maintain a balanced capital structure.[177] UNSE is also seeking Commission authority to enter into indentures or security agreements which grant liens on some or all of its properties to provide security with the financing transactions.[178]

The Staff witness addressing the Company's financing application was Mr. Alexander Igwe. Mr. Igwe has a B.S. degree in Accounting from the University of Benin, Nigeria and a Master of Information Systems Management degree from Keller Graduate School of Management of Devry University. He is a C.P.A. and a member of the American Institute of Certified Public Accountants. Mr. Igwe recommended:

> "1) that the Commission approve UNS request to incur up to $40 million in new debt financing and to receive up to $40 million in new equity infusion, for the sole purpose of acquiring BMGS;
>
> 2) that the Commission authorize UNS to issue up to $40 million in debt financing as recommended in (1) above, in long-term debt, and in short-term to intermediate-term debt;
>
> 3) that the Commission authorize UNS to refinance any short-term and intermediate-term debt, issued under this docket, to long-term debt, without further Commission authorization;

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[175] Tr. at p. 1198.
[176] Application (Ex. UNSE-1) p. 5 and p. 8.
[177] *Id.* at p. 9
[178] *Id.* at p 7.

4) that the Commission authorize UNS to issue guarantees and grant liens on some or all of its assets, including BMGS, and any other properties acquired subsequent to this transaction, to secure its obligation under the proposed debt issuance and to secure other obligations at the time such liens are granted;

5) that the Commission authorize UNS to engage in any transactions and to execute or cause to be executed any documents so as to effectuate the authorizations requested with this application.

6) that UNS file a report with Docket Control demonstrating that it had a DSC and a TIER equal to or greater than 1.0, at the time of new debt issuance, within 60 days from the close of each transaction under this docket.

7) that UNS file a report with Docket Control, within 60 days from the close of each financing package, describing the transaction and demonstrating that the terms are consistent with those generally available to comparable entities."[179]

UNSE accepted all of Mr. Igwe's recommendations.[180] As to the impact upon Mr. Parcell's capital structure recommendation in this case, Mr. Igwe testified that grant of the Company's financing application would have no material impact.[181] He also testified that the exact impact of UNS' proposed financing on its capital structure cannot be determined at this time because of its need for flexibility in determining the appropriate mix of debt and equity at the time the various transactions occur.[182]

In addition, because of the Company's request for flexibility, and factors such as the exact debt amount, composition of proposed debt, interest rates and durations are vague at this time, Staff could not calculate the traditional financial indicators such as the DSC ratio and TIER. Instead Staff witness Igwe recommended that UNSE be required to demonstrate that it meets a minimum DSC and a TIER, equal to or greater than 1.0, at the time of each debt issuance.[183]

III. BLACK MOUNTAIN GENERATING UNIT (BMGS).

In his pre-filed testimony, UNSE Vice President Michael DeConcini discussed UNSE's power requirements. UNSE has a current base demand of 200-250 MW, with a peak demand of 450 MW. Presently, UNSE obtains 100% of its power through a full requirements Power Supply

[179] Alexander Igwe Direct Test. (Ex. S-54) at p. 7.
[180] Tr. at 1251.
[181] Alexander Igwe Direct Test. (Ex. S-54) p. 4.
[182] *Id.*
[183] *Id.* at p. 6.

Agreement ("PSA") with Pinnacle West Capital Corporation ("PWCC").[184] The contract with PWCC expires at the end of May, 2008.[185] As Kevin Larson, Vice President of UniSource Energy Services testified, "[W]e essentially are going to lose all of our resources on the 1st of June 2008."[186] Currently, UNSE is negotiating with alternative vendors to replace the power no longer being provided under the PSA with PWCC.

One component of UNSE's strategy to remedy its situation is the Black Mountain Generating Station ("BMGS"). BMGS is a proposed 90 Mw peaking facility slated for construction in Mohave County, near Kingman, Arizona. If and when it is placed in service, the facility would provide approximately 20 to 25% of UNSE's peak demand.[187] The site for the project has been selected and two turbines have been purchased, but actual construction has not yet begun.

Currently, "all of the development and the buildout is being done by UniSource Energy Development Company" ("UED").[188] "UED has purchased the turbines and then has entered into a turnkey contract."[189] 1) The cost of the turbines themselves was approximately $17 million,[190] and the total projected cost of the MBGS is currently projected to be at least $60 to $65 million.[191] To date, all costs have been incurred by UED. To date, UNSE has contributed nothing to the cost of BMGS.[192] Because construction has not yet begun, no UNSE customers are yet receiving any benefit from the proposed plant.

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[184] Michael DeConcini Direct Test. (Ex. UNSE-14) p. 1.
[185] *Id.*
[186] Tr. at 175.
[187] Tr. at 198.
[188] Tr. at p. 163.
[189] *Id.*
[190] Tr. at p. 164.
[191] Tr. at p. 89.
[192] Tr. at p. 89.

The expenses related to the BMGS have been carried as Construction Work In Progress ("CWIP"). UNSE has proposed to have the BMGS put into rate base at this time. However, to allow UNSE to begin earning a return on the BMGS at this time would be inappropriate for many reasons.

A. <u>The BMGS is Not Owned by UNSE</u>.

In order for an asset to be placed into rate base, the asset must be owned by the utility requesting rate recognition. BMGS does not currently belong to UNSE. It is the property of UED. When commissioner Mayes asked UNSE witness Pignatelli why UNSE was unable to secure financing for the project, Pignatelli responded "It is owned by another company." He went on to add that for financing purposes "[T]hese companies are stand-alone and should be treated as stand-alone."[193] This same statement is just as valid for rate-making purposes. UNSE has no basis for requesting that an asset of UED be placed into the rate base of UNSE. More directly, there is no authority which would allow UNSE to earn a return from its ratepayers on an asset belonging to UED.

Unless and until BMGS is transferred to UNSE, there is no basis for placing the asset into the UNSE rate base.

B. <u>CWIP Should Not be Included in Rate Base</u>.

Even if BMGS were the property of UNSE, the costs associated with the CWIP should not be included in rate base.

1. BMGS is not yet used and useful.

One of the fundamental considerations in deciding whether or not an expense can be placed into rate base is whether or not the item is used and useful. Utilities can not earn a return on an asset that is not being used to serve current customers. Even if the Commission were to overlook the fact

[193] Tr. at p. 85.

that BMGS belongs to UED, or if the Commission were to consider BMGS an asset of UNSE, the fact remains that BMGS is currently nothing more than an idea.

As of the date of hearing, construction had not yet begun. UNSE witness Larson was questioned about the date BMGS could be placed into service.

> Q: Now you want to get this asset into rate base and start earning a return on it right away, but it's not actually going to be operational at the close of this proceeding; correct?
>
> A: We expect it to be operational … May 1.[194]

And as Larson had previously testified:

> Q: So the earliest that it will be used and useful will be in May of 2008 or when the completion report is done; correct?
>
> A: Yes.[195]

Until the asset is placed into service of UNSE customers, UNSE is not entitled to earn a return on the asset.

2. Final Cost of BMGS is Not Known and Measurable.

Before a utility can expect to earn a return on an asset, that asset must have a known value. The total cost of the BMGS project, however, can not be measured with any certainty. The company has provided testimony that the project will cost $60 to $65 million, but the only amount that is in any way certain is the cost of the turnkey contract, at $46 million. The remaining costs are mere estimates of such expenses as:

> The additional costs of permitting, making site improvements, obtaining water supply, connecting to a nearby gas pipeline, making substation improvements, providing project supervision and paying interest on borrowed funds during construction…[196]

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[194] Tr. at p. 206.
[195] Tr. at p. 177.
[196] Kevin Larson Direct Test. (Ex. UNSE-8) p. 4.

And as Mr. Larson admits, "Because these additional costs are not known with certainty, the Company's proposed adjustment to rate base reflects the minimum cost estimate of $60 million."[197]

UNSE readily admits that it can only estimate an additional $14 to $19 million for the "additional costs" associated with BMGS, and these $14 to $19 million dollars only reflect the *minimum* costs that UNSE expects.

The only figure that UNSE can provide with any certainty is the $46 million associated directly with the construction costs. Beyond those, there are expenses estimated within a $5 million window, at a minimum. This is hardly a figure that can be said to be "known and measurable" for ratemaking treatment. The Commission should wait until UNSE actually owns the BMGS and knows not only the final construction cost but how much UNSE actually paid for the laundry list of provisional expenses.

As a final consideration, if these contingent costs do end up making the BMGS more expensive than currently planned, UNSE may never acquire the asset at all, and even if it does so, the Commission may disallow much of the expenses when it considers the prudence of the transaction. All of these considerations indicate that placing BMGS into rate base now would be premature.

3. BMGS is Not Being Built by UNSE.

As already stated, BMGS is currently being developed and built by UED. The turnkey contract for construction was negotiated and executed by UED officials. Upon completion, the BMGS project will be owned by UED. According to UNSE, there is a plan in place by which the parent company of UNSE and UED will transfer ownership of the BMGS to UNSE upon completion, but even so, there exists much uncertainty.

As UNSE witness Larson testified:

> Q: [I]s there a contract, a formal written agreement between these two companies for the transfer of the facility?

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[197] *Id.*

A: I don't believe there is at this time, no.[198]

Larson testified that upon completion of the BMGS, the facility would be transferred to UNSE "at cost."[199] But in the absence of a written agreement, there are still questions to be answered about the transaction. For example, UNSE may have the option to buy the plant at cost, but is UNSE *required* to buy? If there have been cost overruns, is UNSE required to pay the final price, including the overruns, or will they be passed on to UED or the ultimate parent company? If UNSE buys the BMGS despite cost overruns, how much will UNSE be willing to pay and how much will UNSE seek to put into rate base?

Absent a written agreement, there is no way to answer these questions. Without answers to these questions, placing the BMGS project into rate base is extremely premature.

4. Project is Still in the Planning Stage.

As of the date of hearing, UED has purchased two turbines and selected a site for the BMGS project. No actual construction had yet begun. As shown previously, the only cost figures known with certainty are those directly associated with the construction contract itself. A list of ancillary expenses was also provided by UNSE which cited additional expenditures which could total as much as $19 million more. Because the project is still in such an early stage, there is simply no way to know with any reasonable certainty just how much the final bill for BMGS will be. Until that figure is known, UNSE can not be certain it will even purchase the BMGS. And until that purchase is actually consummated and the final cost figure to UNSE is known, UNSE can not expect the Commission to allow UNSE to earn a return on the project.

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[198] Tr. at p. 193.

[199] Tr. at pp. 192-193; See also, Kevin Larson Rebuttal Test. (Ex. UNSE-9) at 12.

5. UNSE May Never Own BMGS.

At hearing, UNSE witness Kevin Larson testified that there existed the possibility that UNSE may *never* own BMGS, depending largely on how the Commission chose to treat the facility for ratemaking purposes.

> Q: I asked you if you were telling me that the company would have trouble remaining financially viable if this asset were not included in rate base in this rate proceeding.
> A: '... I guess depending upon how this proceeding – how Black Mountain is ultimately treated will determine whether or not we transfer it into UNS Electric.' [200]
>
> Q: And so if Black Mountain is not put into the rate base of UNS Electric in this proceeding, that Black Mountain facility will possibly never be transferred to UNS Electric; is that correct?
> A: There could be a scenario like that, yes.[201]
>
> Q: So in other words, you're not actually going to transfer the asset to UNS Electric until it looks financially viable for UNS Electric?
> A: I think it would be a mistake on the part of management to transfer an asset into UNS Electric if it's going to put it in a very difficult financial condition.[202]

As UNSE testified, there is no formal written agreement to purchase the finalized BMGS project. In the absence of such an agreement, there is no guarantee that UNSE will ever own BMGS. The primary consideration, then, in determining if the transfer of BMGS to UNSE takes place at all is the financial condition that UNSE will be placed in as a result. If the project goes as planned and there are no cost overruns with construction, then UNSE would likely accept the asset upon which it was already making a return.

However, should cost overruns occur, and the parties could not agree on equitable terms for the transfer, UNSE is clearly not *obligated* to purchase BMGS in any way. For example, if the project were to end up costing $80 million, UNSE may find that it could satisfy its power needs more cheaply on the open market, making the BMGS an imprudent investment. Knowing it would not

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[200] Tr. at pp. 211-212.
[201] Tr. at p. 213.

receive rate base reimbursement for an imprudent investment, UNSE may have no choice but to forego the purchase. If BMGS were already placed into rate base, however, UNSE ratepayers would be providing a return to UNSE on an investment UNSE *never even made*.

The obvious way to avoid this is to forego putting the BMGS into rate base until the company can meet the minimum requirement for rate treatment and show that it has at least acquired the asset.

6. Operational and Maintenance Costs are Uncertain.

In the event UNSE does purchase BMGS, the final costs associated with the BMGS are quite uncertain. Until construction is completed and the plant actually becomes operational, UNSE has no way to know how much the plant will cost to operate and to maintain. Operation and Maintenance ("O & M") fees can be quite significant, depending upon a long list of factors, including the physical size of the plant and the cost of fuel to run the plant. Because none of these figures can be stated with certainty, there is simply no way to determine what the impact upon the company's revenues will be. It is possible that BMGS will enable UNSE to produce 90 MW of power that is cheaper than that available on the market. But it is also possible that unforeseen circumstances will render the cost only equal to the market cost, in which case the company would have been more prudent to have simply purchased the power instead of acquiring an asset which produces increased overhead for the same power.

Coupled with the other unknown potential costs, the uncertainty regarding the cost to UNSE of O & M expenses makes the final cost of the BMGS even less certain and makes the option to include the facility in rate base much less viable.

C. The Commission Has Not Made a Determination of Prudence.

As a general ratemaking principal, before any utility may earn a return on an investment, the Commission must make a determination that the expense was prudently incurred. But as UNSE

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[202] *Id.*

acknowledges, their proposal to include BMGS in rate base in the current case would prevent the Commission from doing so.

> Q: Well, let's take the potential situation that the Commission were to approve it. The company were to file its report in May 2008, and the Commission were to determine at that time that the project was not prudent. The costs under the company's proposal would already be in rate base at that time; correct?
>
> A: Yes.[203]

In the case of the BMGS, there are many factors which the Commission will need to consider in determining whether or not the investment in BMGS was prudent.

First, the cost of the plant itself will dictate the extent of the benefit, if any, to ratepayers of constructing the resource. If the plant is too expensive, then it may be a great many years before the asset begins to show a benefit to ratepayers and the Commission may decide that UNSE was imprudent in its decision. If that were to happen, the Commission would normally simply disallow recovery of the asset in rate base.

In the instant matter, however, UNSE's suggested course of action takes that discretion from the Commission. If the Commission were to take such action, and BMGS were later found to have been prudent, then there would be no issue. However, in the event that unforeseen circumstances lead the Commission to decide the BMGS was imprudently acquired, the Commission would then have to take action not only to remove the asset from rate base, but to reverse the harm to ratepayers that had already occurred in allowing a return on the investment. At that time, it may prove difficult to determine exactly the extent of reimbursement to which UNSE's ratepayers would be entitled. And even if the assessment were made, it is likely that many ratepayers who had contributed to UNSE's ill-gotten gains would no longer be UNSE customers. There may also be customers who did

[203] Tr. p. 169.

not contribute to the return but who would be customers at the time the rates were adjusted to compensate. These customers would receive a benefit to which they were not entitled.

UNSE has suggested that BMGS be included in rate base now, while "the prudence of construction costs can be addressed in the company's next rate case."[204] UNSE seems to acknowledge that prudence review is essential while avoiding it at all costs.

The only scenario by which there can be certainty as to the prudence of the decision is to subject the asset to a prudence review *before* placing it into rate base. UNSE is correct that a determination of BMGS's prudence should be determined in UNSE's *next* rate case. But in the mean time BMGS should not be placed into rate base in *this* rate case.

IV. RATE DESIGN.

Frank Radigan presented Staff's testimony on the Company's proposed revenue allocation and rate design.[205] Mr. Radigan is a principal with the Hudson River Energy Group which is an energy consulting firm. He has 25 years of experience and has testified as an expert witness in utility rate proceedings on more than 50 occasions before various regulatory bodies.

Staff and the Company are in substantial agreement on the following issues:

1) customer charges for the residential and small Residential or Small General Service classes;[206] 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. Mr. Radigan had proposed that the Residential Class customer charge increase from $6.50 to $7.50 per month and that the Small General Service Class should be increased from $10.00 to $12.00 per month.[207]

2) the level of miscellaneous service fees;[208]

3) the increased threshold at which a customer would be placed on a large general service;[209]

[204] Kevin Larson Rebuttal Test. (Ex. UNSE-9) p. 9.
[205] See Frank Radigan Direct and Surrebuttal Test. (Ex. S-61 and Ex. S-62).
[206] Tr at p. 1255.
[207] Frank Radigan Surrebuttal Test. (Ex. S-62) Exec. Summary.
[208] *Id.*

4) the rate differentials in the time-of-use periods for the time-of-use classes;[210]

On the other hand, Staff and the Company are not in agreement on the following issues:

1) whether time-of-use rates should be mandatory;[211]

2) full merger of the rates between Mohave and Santa Cruz County over the next two rate cases;[212]

3) implementation of inclining block rates over the next two rates cases;[213]

4) differential in the demand charge for large service customers;[214]

5) purchased power allocation between service classes.[215]

Staff's positions on the issues in dispute are discussed next.

A. <u>Time of Use (TOU) Rates Should Not be Mandatory</u>.

The Company proposes 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.[216] Staff opposes mandatory TOU rates, but supports their use on a voluntary basis. Staff witness Radigan based his conclusion on the Company's billing data.[217] He testified that for a meter with a cost of $200 and a carrying cost of 15%, the incremental annual cost of a new meter would be approximately $30.00.[218]

Using the Summer On-Peak/Off-Peak differentials proposed by the Company, a residential customer would have move over 2,200kWh of energy during the summer months from on-peak to off-peak or 400 kWH per month to break even or benefit.[219] But the billing data shows 30 percent of

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209 *Id.*
210 Tr. at p. 1256.
211 Tr. at p. 1255-1256.
212 Tr. at 1256.
213 *Id.*
214 *Id.*
215 Tr. at 1256.
216 D. Bentley Erdwurm Direct Test. (Ex. UNSE-17) at pp. 16-17.
217 Frank Radigan Direct Test. (Ex. S-61) at p. 9.
218 *Id.*
219 *Id.*

bills are for less than 400 kWh in total.[220] Ninety-two percent of all bills are for usage of less than 2,000 kWh per month.[221]

Mr. Radigan stated that "[s]ince 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. [222]

But Staff witness Radigan recognized that some customers would benefit from TOU rates. Those 8% of residential customers with over 2,000 kWh per month account for over 25 percent of all UNSE's sales to the Residential Service Classification.[223] These customers could benefit from TOU rates and thus Mr. Radigan recommended a vigorous customer education program to incent these customers to move to TOU rates.[224]

The Small General Service Classification is similar to the Residential Customer Classification. Based upon the meter cost discussed above, a customer would have to shift over 2,100 kWh during the summer period to pay for the meter, or 340 kWh per month.[225] For the Small General Service Classification, 39% of bills are over 340 kWh per month, and 84% are under 2,000 kWh per month.[226] So, there is likely to be little benefit for these customers. But for the 16% of bills above 2,000 kWh per month which account for 49 percent of all usage for this service classification, there is a great potential benefit.[227]

B. <u>Merger of Mohave and Santa Cruz Rates At This Time</u>.

The Company also proposes to eliminate the separate rate structures for Mohave and Santa Cruz counties in this case.[228] Staff witness Radigan has proposed to accomplish the complete merger of these rates over two rate cases for the following reasons.

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[220] Frank Radigan Direct Test. (Ex. S-61), p. 9.
[221] *Id.*at pp. 8-9.
[222] *Id.*
[223] Frank Radigan Direct Test. (Ex. S-61). P. 9.
[224] *Id.*
[225] *Id.*
[226] *Id.*
[227] Frank Radigan Direct Test. (Ex. S-61) p. 9.
[228] *Id.* at p. 14.

First, under the separate rate structures now in existence, the absolute dollar differential in the customer's bill is small.[229] Merger of the two separate rate structures at this time, would send the wrong price signal to some customers since it would end up in Santa Cruz customer's experiencing a decrease in rates (a lower per kWh rate) at a time when the Company's costs are rising.[230]

Second, it would seem to make more sense to increase the customer charge applicable to both counties, and then leave Santa Cruz customers at their current levels and recover the remaining rate increase from the energy charge of the Mohave County customers. [231] The remaining Santa Cruz differentials could be eliminated altogether in the Company's next rate case.

Mr. Radigan's proposed rate design still significantly reduces the rate differentials between the two counties.[232] However, both sets of customers would receive a small increase to rates; for customers in Mohave County, the increase would be approximately 2.9% and for customers in Santa Cruz County the rates would increase overall by 1.5%. [233]

C. <u>**Inclining Block Rates.**</u>

The Company is also proposing to introduce an inclining block rate structure in this case to encourage conservation.[234] While Mr. Radigan supports the use of inclining block rate structures in general, in this case it is impractical given the relatively small recommended rate increase and increases in the customer charge.[235] This would result in additional increase in the customer charge, and would have widely divergent impacts on the customer base of the Company.[236] Some customers would receive decreases and others would receive increases leading to unnecessary confusion. Mr. Radigan recommends for this reason that an inclining block rate structure be reevaluated in the Company's next rate case.[237]

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[229] *Id.*
[230] Frank Radigan Direct Test. (Ex. S-61) p. 14-15.
[231] *Id.* at 14.
[232] *Id.* at p. 20.
[233] *Id.* at p. 22.
[234] Frank Radigan Direct Test. (Ex. S-61) at p. 13.
[235] *Id.*
[236] *Id.*
[237] Frank Radigan Direct Test. (Ex. S-61) at p. 13.

D. Differential in Demand Charge for Large Service Customers.

The Company proposed to lower the demand charges for large commercial customers taking service at less than 69 kV but it has not offered, nor does it have, any cost data to support its proposal.[238]

The Company admits that it has no cost study data to support its proposal in this case. Instead it relies upon what was approved the APS case.[239] But APS' costs are not relevant or comparable to UNSE's costs. Mr. Radigan testified that UNS transmits power at 115 kV and 69 kV and that:

> "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 13.9 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."[240]

E. Purchased Power Allocation

The Company proposes to allocate purchased power using the Average and Peaks Method which is made of two components: an average demand component and a peak demand component.[241] Company witness Erdwurm uses the purchased power costs of TEP to develop a split of costs which he then applies to the PWCC purchased power contract which expires in 2008.[242] But as discussed by Mr. Radigan, this is like to fit a square peg into a round hole. Mr. Radigan explained in the following passage from his surrebuttal testimony:

> "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

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[238] *Id.*
[239] *Id.*
[240] Id. at p. 5.
[241] *Id.* at p. 2
[242] *Id.*

volumetric. The Company ahs provided no credible evidence to show that the Average and Peaks Method should be used in this case." [243]

V. PURCHASED POWER FUEL ADJUSTMENT CLAUSE (PPFAC).

In its Application, the Company proposed several major changes to its PPFAC.[244] UNSE proposed that its PPFAC have an automatic adjustment mechanism on a going forward basis.[245] Staff and the Company agree that the revised or new PPFAC for UNSE should become effective June 1, 2008.[246] The Company also proposed that the Commission do the following: 1) clarify the costs that can be included in the PPFAC; 2) use a 12-month rolling average cost of purchase power and fuel; 3) recognize carrying costs on PPFAC bank balances at an interest rate equal to the cost of the Company's short-term borrowing. [247]

UNSE also proposed that the following costs be subject to recovery in its PPFAC: 1) all generation fuel used in steam generation including natural gas, fuel oil and coal, and fuel transportation and coal rail expenses; 2) generation fuel used in combustion turbine generation including natural gas and fuel oil; 3) purchased power costs for both energy and demand charges; 4) transmission related expenses; and 5) credit costs for both fuel and purchased power.[248]

UNSE finally proposed that the PPFAC rate automatically adjust on a monthly basis.[249]

The Company's proposed changes to its PPFAC were addressed by Staff witness Ralph Smith. Mr. Smith testified that despite difference between APS and UNSE, the extensive evaluation of APS' PSA and related Staff recommendations in the last APS rate case, can provide helpful guidance for any changes to UNSE's PPFAC in this case.[250]

The Current UNSE PPFAC rate was set in Commission Decision No. 66028 dated July 3, 2003, which approved the acquisition of Citizen's electric distribution assets. The current PPFAC rate is \$0.01825/kWh and reflects the fixed energy price under the PWCC PSA.[251] The PPFAC

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[243] *Id.*
[244] Application (Ex. UNSE-1) at p. 3.
[245] *Id.*
[246] Tr. at 1201.
[247] *Id.*
[248] Application (Ex. UNSE-1) at p. 3.
[249] *Id.*
[250] Ralph Smith Direct Test. (Ex. S-56) at pp. 70-71.
[251] *Id.* at p. 72.

provides an adjustment mechanism which allows UNSE to pass through purchased power and fuel cost increases and/or savings relative to a base power supply rate through a surcharge or credit.[252] The Company's current base power supply rate is $0.05194/kWh established in Decision No. 59951 dated January 3, 1997.

Mr. Smith described the functioning of the current PPFAC in the following passage from his direct testimony:

> The current PPFAC functions in the following manner. The Company's actual fuel and purchased power costs (excluding demand charges) are charged to a PPFAC Bank Balance. The sum of the base power supply rate plus any PPFAC rate are multiplied by energy consumption. The product of that multiplication, indicating the Company's recovery of fuel and purchased power costs, is subtracted from the PPFAC bank balance. When the PPFAC bank balance reaches a predetermined threshold, UNS Electric must make a filing with the Commission to propose a method to recover or return the bank balance. The current PPFAC cannot be changed without Commission approval.[253]

Staff witness Smith presented testimony in this case which agreed that some changes to the Company's PPFAC were warranted. In fact, Mr. Smith presented a copy of a red-lined version of the APS Plan of Administration, revised for use for UNSE, which is presented in Attachment RCS-7 to Mr. Smith's surrebuttal testimony

Witness Smith took exception to a number of the Company's proposals. First, the Company was and is still including inappropriate costs in its PPFAC most notably expenses for credit support.[254] Second, the Company was sponsoring changes to its PPFAC which would make it more self-effectuating and less subject to regulatory approvals and oversight.[255] In addition, the Company proposes to include the costs from FERC accounts 501, 547, 555 and 565 in its PPFAC. However, for 2002 through 2006, the Company did not record any fuel expenses to these accounts.[256] UNSE

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[252] *Id.*
[253] *Id.* at p. 72.
[254] *Id.*
[255] Ralph Smith Direct Test. (Ex. S-56) p. 72.
[256] *Id.* at p. 74.

has typically recorded its purchased power costs to FERC Account 555.[257] Nonetheless, all of these accounts were essentially the same accounts that the APS PSA Plan of Administration covered.[258]

Other changes proposed by Mr. Smith to the Company's proposed PPFAC included: 1) allowance of prudent direct costs of contracts it uses for hedging system fuel and purchased power under its PPFAC, 2) inclusion of purchased energy expenses; however exclusion of capacity costs.[259] A normalized level of purchased capacity costs are typically recovered in the utility's base rates. [260] Such dissimilar treatment as allowing purchased capacity costs to be recovered in the PPFAC while the Company's own generation or transmission capacity costs are included in base rates is neither appropriate or desirable.[261]

The Company and Staff have been able to come to agreement on most aspects of the Company's PPFAC. The Company ultimately accepted many of Witness Smith's revisions to its PPFAC. The Company agrees with the revisions presented in Attachment RCS-7 with the exception of one area.[262]

The Company still wants to include the costs of credit support associated with fuel and purchased power procurement and hedging in its PPFAC.[263] Witness Smith testified that this is neither reasonable or appropriate nor is it common industry practice that such costs would be recorded in these FERC accounts and recovered through a PPFAC mechanism.[264]

Finally, due to late-filed information by the Company regarding prospective gas prices, Staff is also recommending a cap on the PPFAC in order to prevent rate shock.

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[257] *Id.*
[258] *Id.*
[259] Ralph Smith Direct Test. (Ex. S-56) at p. 75.
[260] *Id.*
[261] *Id.* at p. 76.
[262] Tr. at p. 1202.
[263] *Id.* at p. 78.
[264] Ralph C. Smith Direct Test. (S-56) at p. 78.

VI. DEMAND SIDE MANAGEMENT PROGRAMS AND EPS/REST ADJUSTOR

A. Demand Side Management

Staff's position on Demand Side Management and the EPS/REST Adjustor was presented by Ms. Julie McNeely-Kirwan and Mr. Jerry Anderson. Ms. McNeely-Kirwan graduated magna cum laude from Arizona State University and holds a Master's Degree from the University of Wisconsin. Mr. Anderson has double majors in Economics and Business Management. He also has an MBA degree from Xavier University in Cincinnati, Ohio.

Within the context of this rate case, UNSE has proposed to add new programs to its existing portfolio. Staff has proposed many recommendations regarding cost recovery of the programs, but consideration of the programs themselves is being undertaken in a separate docket E-04204A-07-0365. Within the context of this rate case, Staff has made recommendations regarding only the method by which the programs are funded.

Currently, UNSE funds four separate Demand-Side Management programs, aimed at decreasing customer demand. These programs are funded from base rates, in the amount of $175,000 annually, as ordered by the Commission in Decision No. 59951, January 3, 1997.

Because it is not known at this time which of UNSE's proposed programs ultimately be approved by the Commission, Staff's objective is to provide a funding mechanism that would be responsive to those DSM programs and activities that the Commission may ultimately approve for UNSE outside of this docket.

B. Low Income Weatherization Program

UNSE currently operates a Low Income Weatherization ("LIW") program, costing $70,000. In Decision No. 59951, the Commission removed the program from the UNSE DSM portfolio, but continued to finance the program separately from base rates. Staff has recommended that the LIW program be returned to the DSM portfolio. UNSE has concurred in Staff's position.

Staff made no recommendation regarding the viability of the program itself, and insists that the program be proven cost-effective, just as any other DSM program.

a. Emergency Bill Assistance.

UNSE had included $20,000 annually in its LIW program for Emergency Bill Assistance ("EBA"). Staff does not consider the EBA program to be DSM, and removed it.

However, Staff does believe the EBA program should be included as part of UNSE's Warm Spirits program, and that Warm Spirits should continue to be funded through base rates and shareholder contributions. EBA should not be funded through DSM funds.

B. <u>Time Of Use Rates</u>.

UNSE has proposed that Time Of Use ("TOU") pricing be considered as an option to reduce demand during peak hours. The TOU rates have been evaluated by Staff witness Frank Radigan. Staff believes that TOU pricing plans are not considered part of DSM and that TOU pricing plans not be funded using DSM monies.

C. <u>Funding of DSM Programs</u>.

UNSE has proposed to exclude costs from base rates and to implement a single line-item per kWh charge on all customers' bills in order to collect the necessary funds. In essence, this line-item charge constitutes a "DSM adjustor mechanism". Staff supports the removal of DSM program costs from base rates and the use of this adjustor mechanism to recover UNSE's prudently-incurred costs related to DSM. UNSE has concurred.

a. Alternative Approaches.

Staff has reviewed several alternatives to the adjustor mechanism, including 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. After weighing these alternatives, Staff concluded that an adjustor mechanism is preferable.

1. Recovery Through Base Rates with Deferral Account.

Staff believes this method would provide timely recovery, but would lack the flexibility to adjust as new programs were added or current programs were expanded. A specific weakness is that when actual incurred costs are less than the base rate amount, ratepayers could be paying for DSM costs not yet expended. UNSE concurs in Staff's analysis.

2. Recovery Through Deferral Account.

Staff believes that a deferral account does not allow a timely recovery of DSM costs and would not appropriate for that reason. UNSE concurs.

3. Amortization or capitalization.

While this program has the advantage of lessening the impact of recovery over time, it is not appropriate where programs are small or just beginning. UNSE concurs with Staff's analysis.

4. Combination Method.

While this method has been used with other utilities in the past, it is inappropriate in a case such as this in which there are uncertain levels and timelines for the DSM activities. The program could actually be confusing and less than transparent to customers. UNSE does not dispute Staff's analysis.

D. DSM Cost Recovery.

Staff recommends that UNSE be allowed to recovery all prudently-incurred DSM expenses in conjunction with Commission-approved DSM programs and activities. These costs should include 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 studies are approved by the Commission.

Actual incurred costs should be itemized in the Company's semi-annual DSM reports, and should be reviewed by Staff. Staff recommends DSM related expenses be recorded in the DSM adjustor account by DSM program and other major categories of expense. Within each DSM program or major sub-account, the further disaggregation by type of expense would separately record rebates and incentives, marketing, direct program implementation, and administrative costs. UNSE has not objected.

Staff recommends that UNSE's DSM adjustor rate be reset annually on June1 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 for that same year. Staff further recommends that UNSE submit to Docket Control its prudently-incurred DSM expenses from the previous calendar year in connection with Commission-approved DSM programs and activities, and that UNSE submit 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 over- or under-collection adjustment needed to modify projected DSM costs for the current year adjustor rate calculation. Staff further recommends that UNSE 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 UNSE'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.

Staff is recommending that the adjustor rate not be reset until June 1, 2009 because that date would be the first adjustor rate based upon actual operation of the DSM programs proposed in UNSE's Portfolio Plan.

Staff proposes that the initial adjustor rate be based upon 25 percent of currently estimated Portfolio Plan first year 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.

UNSE has concurred with Staff proposal as suggested above.

E. EPS/REST Adjustor.

UNSE is required to meet the Environmental Portfolio Standard ("EPS") set forth in A.A.C. R14-2-1618. Staff witness Jerry Anderson described the EPS requirements in the following passage from his Direct Testimony:

> 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.[265]

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.[266]

UNSE currently recovers its renewable costs in an EPS surcharge. The Environmentally Friendly Portfolio Surcharge ("EFPS") tariff contains the following surcharges: $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.[267]

Decision No. 63360 had approved the EFPS on an interim basis on February 8, 2001, pending true-up in a rate case in which fair value findings would be made by the Commission.[268] Staff witness Anderson recommendation was that the EFPS surcharge become an adjustor mechanism. The initial rate would be the same as the current EFPS tariff including caps, with an allowance for

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[265] Jerry D. Anderson Direct Test. (Ex. S-63) at p. 17.
[266] *Id.* at p. 18.
[267] *Id.*
[268] See Decision 63360, Citizens Communications Company (EFPS Surcharge) February 8, 2001.

future funding changes.[269] The change to an adjustor mechanism would accommodate the REST rules requirement that a utility have an adjustor mechanism in place under which the utility can request to reset those rates at certain times.[270]

Witness Anderson testified that the adjustor would work through an application filed by the Company to change the renewables adjustor rate and caps. Staff would review each application and make recommendations to the Commission for approval.[271]

VII. RULE CHANGES.

UNSE proposed numerous changes to its rules and regulations. The Company's reasons for doing so were addressed in the testimony of UNSE witness Ferry. The Company's existing rules and regulations were "inherited" from Citizens Electric when it sold its assets to UniSource Energy. The Company stated that many of the changes it is proposing are intended to make UNSE's rules and regulations more consistent with those of TEP.[272] Staff supports or has no objection to the majority of changes.[273]

Staff is concerned with the changes UNSE is proposing to make to its line extension tariff and its bill estimation procedures.[274]

A. <u>Line Extension Charges.</u>

With respect to its line extension tariff, the Company is proposing to increase the total free overhead extension distance from 400 feet to 500 feet, including the service drop.[275] The goal appears to be to make the free allowance the same as TEP offers under its current tariff.[276]

In response to Staff data requests, UNSE indicated that during the test year, if closed approximately 4, 980 work orders in both of its service territories.[277] The Company also responded

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[269] Jerry D. Anderson Direct Test. (Ex. S-63) at p. 19.
[270] *Id.*
[271] *Id.* at pp. 19-20.
[272] Bing E. Young Direct Test. (Ex. S-64) at p. 2.
[273] *Id.* at p. 2.
[274] *Id.*
[275] *Id.*
[276] Bing E. Young Direct Test. (Ex. S-64), p. 2.
[277] *Id.*

that each work order would have to be individually examined in order to determine the forgone revenue associated with the free allowance.[278]

At the same time the Company is proposing to increase the free footage allowance for new customers, it cites to increased growth in both service areas.[279] Staff believes that in this circumstance, and as a result proposed, that the Company eliminate the free footage allowance for new customers, rather than expand it.[280] Staff witness Young testified in support of Staff's proposal in the following passage from his direct testimony:

> 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.[281]

The Commission took similar action in eliminating the free footage allowance in the recent Arizona Public Service Company rate case.[282]

Finally, ALJ Wolfe asked the parties to address whether elimination of the free line extension allowance comported with the requirements of the Arizona Administrative Code. A.A.C. R14-2-207(C) states in part as follows:

> 1. A maximum footage or equipment allowance to be provided by the utility at no charge. The maximum footage or equipment allowance may be differentiated by customer class.
>
> 2. An economic feasibility analysis for those extensions which exceed the maximum footage or equipment allowance. Such economic feasibility analysis shall consider the incremental revenues and costs associated with the line extension. In those instances where the requested line extension does not meet the economic feasibility criteria established by the utility, the utility may required the customer to provide funds to the utility, which will make the line extension economically feasible. The methodology employed by the utility in determining economic feasibility shall be applied uniformly and consistently to each applicant requiring a line extension.

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[278] *Id.*
[279] Bing E. Young Direct Test. (Ex. S-64) pp. 4-5
[280] *Id.* at p. 5.
[281] *Id.*
[282] See, APS Rate Case (Docket No. E-01345A-05-0816), Decision No. 69663, dated 6/28/07.

Staff does not believe that these provisions of the Arizona Administrative Code mandate that a company provide a free footage allowance. Rather, where the rules mandate that the Company's policies on free footage allowances be specifically set forth in its line extension tariff, even if that footage allowance is zero, as Staff is recommending in this case. In regard to (C)(2) of the rules, if the free footage is zero, then all extensions would be economically feasible from the utility's perspective. In any event, even if these rules are interpreted to require a free footage allowance, the Commission can always waive that requirement of the rules as it has done in at least one other recent case.

At the request of Commissioner Mayes to examine the efficacy of hook-up fees in this case, the Company proposed at the hearing to introduce a $250 hook-up fee in this case.[283] The Commission has also opened a generic docket (Docket No. E-00000K-07-0052) to examine the efficacy of hook-up fees for new electric and natural gas customers in the future. Staff witness Young testified that Staff is aware of at least two electric utilities in Arizona that utilize hook-up fees: Dixie Escalante Rural Electric Association and Wellton-Mohawk Irrigation and Drainage District.[284] Staff continues to believe that the issue of hook-up fees for electric utilities should be addressed in the generic docket.

B. <u>Bill Estimation Methodologies</u>.

Currently, the Company's tariff does not describe its estimation methodologies.[285] Staff belies that the Company should be required to submit a separate tariff setting forth its estimation methodologies for Commission approval within 30 days of a decision in this docket.[286] Staff witness Young addressed the specific parameters that the Company's tariff should include at pages 8-9 of his direct testimony.[287]

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[283] Tr. at pp. 960-961.
[284] Bing E. Young Direct Test. (Ex. S-64) p. 7.
[285] *Id.*
[286] *Id.* at p. 8.
[287] *Id.* at pp. 8-9.

C. **Bill Due Dates.**

One of the changes proposed by UNSE to its tariff was to move up the due date on bills by 5 days. This would mean a significant change to customer bills. Currently customer bills are due 15 days after issuance. The Company's proposed change would mean that customer bills would henceforth be due 10 days after issuance. Staff opposes UNSE's proposal in this regard.

UNSE modeled its proposed billing terms to match the UNS Gas billing terms.[288] The Commission's rules, however, differ for electric and gas companies on this point. For electric companies, the rules provide: "All bills for utility services are due and payable no later than 15 days from the date of the bill."[289] UNSE should comply with Commission rules on this point.

VIII. CONCLUSION.

The Commission should approve increased revenues for the Company in the amount of $3.688 Million. The Commission should deny UNSE's requests for extraordinary treatment of CWIP and the BMGS in this case. The Company has not met its burden of proof in this case to justify the special treatment it is requesting. The Commission should approve the changes to the Company's PPFAC proposed by Staff. The Staff's changes are modeled after the new Plan of Administration adopted in the APS rate case, with appropriate adjustments where necessary to recognize the unique circumstances of the Company.

RESPECTFULLY SUBMITTED this 5th day of November 2007.

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[288] Thomas Ferry Direct Test. (Ex. UNSE-20) at p. 24.
[289] See R14-2-210(C)(1).

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