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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

Notice and Filing of the

Supplemental Direct Testimony

with Comments

of

Marshall Magruder

12 July 2007

As provided by the Procedural Orders of 1 February 2007, 27 March 2007, and 25 June 2007, herein is the Supplemental Direct Testimony of Marshall Magruder, a Santa Cruz County UNS Electric, Inc. ratepayer.

The Direct Testimony concentrated on several issues including the Demand-Side Management (DSM) which is reviewed herein and a preliminary UNSE DSM Adjustor rate determined, along with other issues, from the Direct Testimony of 28 June 2007. As indicated in the Direct Testimony, responses to earlier data requests had delayed some issues. It was resubmitted on 29 and 30 June, with responses apparently now delayed until approximately 16 or 17 July 2997, which is after submittal of this Supplemental Direct Testimony.

I certify this filing has been mailed to all known and interested parties in the Service List.

Respectfully submitted on this 12th day of July 2007

MARSHALL MAGRUDER

By Marshall Magruder

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Arizona Corporation Commission
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SUPPLEMENTAL DIRECT TESTIMONY

OF

MARSHALL MAGRUDER

12 July 2007

In the matter of
the

APPLICATION
OF UNS ELECTRIC, INC.,
FOR THE 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.

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SUPPLEMENTAL DIRECT TESTIMONY OF MARSHALL MAGRUDER

PART I – INTRODUCTION

1.1 Introduction.

Q. Why are you filing this supplemental direct testimony?

On or before 28 June 2007, all intervening parties were required to file their Direct Testimony. The Procedural Orders planned a second Direct Testimony to be filed not later than 12 July 2007. Originally, the second testimony was directed to include rate design issues; however, on 25 July 2007, this was changed to include both Direct-Side Management adjustor and Environmental Portfolio Standard surcharge. My filing on 28 June 2007 indicated that my 12 July 2007 Supplemental Direct Testimony would include both UNS Electric costs and expenses to provide reliable electricity in the Santa Cruz service area and the CARES/CARES-M Program issues.

1.2 Summary of Issues and Recommendations.

Q. Can you summarize the issues from your Direct Testimonies?

A. There are several issues of concern that are in my testimonies. I have numbered them for convenience as follows:

Issue 1 – Demand-Side Management (DSM) Program.

Issue 2 – Administrative Issues

Issue 3 – Costs to Improve Electric Reliability in the Santa Cruz service area.

Issue 4 – CARES and CARES-M Tariffs

Issue 5 – Environmental Portfolio Standard (EPS) Surcharge and Renewable Energy Standard and Tariff (REST)

Q. What are your recommendations?

A. My recommendations vary for each issue.

Issue 1 Recommendations – There are different recommendations for each DSM Program.

- Education and Outreach DSM Program (EC/EE). My detailed Recommendations are detailed in my Direct Testimony in paragraph 3.2.f and in 3.2 herein with the cost changes summarized in Table 1 resulting in adding $273,205 to the 2008 Cost Budget for this program, whose title is recommended to be changed to "DSM Education and Training Program."
- Direct Load Control DSM Program (DR). My detailed Recommendations are in paragraph 3.3.f of my Direct Testimony and 3.3 here. In general, there are serious

structural flaws in this program that need resolution prior to consideration for implementation, which delays determination of a realistic 2008 program Cost Budget.

- Low-Income Weatherization DSM Program (EE). My detailed Recommendations are in paragraph 3.4.f of my Direct Testimony and 2008 Cost Budget changes herein delete $5,104 from the proposed budget.
- Residential HVAC Retrofit DSM Program (EE). My detailed Recommendations are in paragraph 3.5.f of my Direct Testimony and 2008 Cost Budget changes herein to delete $27,954 from the proposed budget.
- Shade Tree DSM Program (EC). My detailed Recommendations are in paragraph 3.6.f of my Direct Testimony which recommend removal of this program from the DSM portfolio, thus to delete all funds ($65,000) in the 2008 Cost Budget because overhead costs exceeded customer benefits.
- Commercial Facilities Efficiency DSM Program (EE). My detailed recommendations are in paragraph 3.7.f of my Direct Testimony and the 2008 Cost Budget which expands customer participation and adds $93,289 to the proposed budget.
- The 2008 proposed total DSM Budget recommended is $3.428.000; however, by reducing all programs to 25% while excluding LIW, the recommended cost of the 2008 DSM Program is $934,878 and an DSM Adjustor rates for all customer billing in 2008 is 0.00057966 per kWh as presented in paragraph 3.9 herein.

Issue 2 Recommendations. See Part IV of my Direct Testimony and Part IV herein as there are numerous Administrative recommendations which delete billing schedule changes, eliminate use of predatory loan and check cashing facilities as UNSE Billing Agents, revise the billing statement, and changes to the UNSE Rules and Regulations.

Issue 3 Recommendations. The detailed electricity reliability in Santa Cruz service area recommendations are presented paragraph 5.4 herein which recommend deletion of $15,561,520 from the UNSE rate base for failure to comply with ACC Orders, to require complete and continuous compliance with the City of Nogales and ACC Staff Settlement Agreements, to avoid include expenses performed by Citizens prior to acquisition to be credited to UNSE, to increase access using WAPA transmission lines with significant customer savings when compared to using TEP transmission lines, to be consistent with objective measures for operations, to comply with NERC/WECC reliability for substation data management, to commence realistic actions required for a second transmission line and not just rebuild a single line, and to cease deliberate and untrue "fear ,mongering" about how soon the "lights will go out" in Nogales.

Issue 4 Recommendations. The detailed CARES and CARES-M recommendations are in paragraphs 6.4 and 6.5, with a major concern that life-support equipment for non-CARES-M ratepayers without any backup support during an outage.

Issue 5 Recommendations. The detailed recommendations for transition from EPS to REST are in paragraph 7.4 which require using the sample tariff surcharges within the first billing cycle after approval of this docket, that UNSE submit a detailed plan on how it will get on track to meet all REST requirements by 1 January 2010 as its renewable generation capabilities account for only 0.00646% of its retail sales in 2006, when the EPS standard required 1.05%.

1.3 Recommendations for additional Issues.

Q. Are there additional issues

A. Yes. Other areas of concern, from the Magruder Motion to intervene that may be resolved before or during the testimonial hearings:

a. *Mandatory* Time of Use (TOU) tariffs for new residential and small commercial ratepayers, This should not be a mandatory program and the use of the highest 15 minute period for calculation of the "demand" (that is one-sixteenth of the peak period and one-fourth eighth of the off-peak period) is not reasonable, thus one hour is appropriate.

b. Proposed Purchase Power and Fuel Adjustment Clause (PPFAC) rate structure includes energy losses, which I have requested by not received a response from UNSE. The present 4.95% WAPA and 10.69% energy losses are paid by ratepayers in the PPFAC. The quantification of energy losses from test year results should be presented by UNSE.

c. New purchase power, generation and transmission agreements impacts on ratepayers which have been requested but not received as they are "confidential",

d. Prudency of its *present* DSM Program since the last rate case as there has been very little "bang" for the "bucks" invested in the present DSM Program,

e. Reliability concerns for the single Nogales substation located in the100-year flood plain,

f. Effectiveness of the ACC *Environmental Portfolio Standard* since the last rate case,

g. Implementation of the *Renewable Energy Standard and Tariff* for all rate categories,

h. Potential for any Citizens-UniSource transition of ownership costs to be absorbed by the customers beyond those in the Settlement Agreement, and

i. Potential for UNS Electricity, Inc. ratepayers to pay multiple or imprudent charges to UniSource Energy and its subsidiaries including increases in O&M and G&A.

Some issues have not been addressed at present due to discovery issues but will be included later in these proceedings.

PART II – ISSUES IN THE DIRECT TESTIMONIES

2.1 Summary of Issues

Q. Can you summarize the issues from your Direct Testimonies?

A. There are several issues of concern that are included in my testimonies. I have numbered them for convenience.

Issue 1 – Demand Side Management Programs, see Part III

Issue 2 - Administrative Issues (Billing Schedules, Predatory Loan/Check Cashing Facilities as Billing Agents, Revised Billing Statement, and R&R Publication) in Part IV

Issue 3 – Cost to Improve Electricity Reliability in Santa Cruz County in Part V

Issue 4 - CARES and CARES-M Tariffs in Part VI

Issue 5 – Environmental Portfolio Standard (EPS) Surcharge and Renewable Energy Standard and Tariff (REST) in Part VII

The first and second issues were in the initial Direct Testimony and supplemental testimony is provided herein. The remaining issues are initially being presented here.

2.2 Impact of these Issues on proposed UNS Electric rates or administrative procedures.

Q. Do any of these issues impact overall capital cost or changes in the proposal?

A. Yes. Each issue will have different changes and impacts, if the recommendations are approved. A brief summary of these changes include:

Issue 1 – DSM Programs. The recommended changes impact the scope and expenses proposed for each proposed DSM Program. Based on these changes, then the aggregated summation of the DSM Adjustor necessary for each program will impact the resultant rates for all UNS Electric ratepayers.

Issue 2 – Administrative Issues. The recommended changes impact areas that are not directly related to company's expenses but directly impact the customers.

Issue 3 – Cost to Improve Electricity Reliability in Santa Cruz County. The recommended changes will remove some capital expenses from the test year which impact rate base.

Issue 4 – CARES and CARES-M Tariffs. The recommended changes may have minor impacts on company expenses as additional administrative procedures are proposed.

Issue 5 – EPS and REST Surcharge/Adjustor. The recommended changes include deletion of the EPS Surcharge; implement an interim Renewable Energy Standard and Tariff (REST) and REST Bank until USNE obtains approval of a new REST Surcharge/ Adjustor in a separate case, and for failing to meet the existing EPS Goals.

PART III – ISSUE 1
DEMAND-SIDE MANAGEMENT PROGRAMS
SUPPLEMENTAL

3.1 UNS Electricity Demand-Side Management Programs.

On 13 June 2007, UniSource Energy Services (UES), for UNS Electricity, Inc., filed with the ACC Docket Control a letter[1] that is the basis for my Direct Testimony. Since filing, additional information has come to light which is now included here. In addition, a summary is provided in paragraph 3.8 where each program's DSM Adjustors are derived and a preliminary aggregated DSM Adjustor rate is determined for billing. All changes to any of these DSM programs must be follow through to determine the impact on cost and the resultant DSM Adjustor rate and impacts ratepayer's bills. The initial Direct Testimony used "XXX" for this process, now superseded here.

The Recommendations from my Direct Testimony concern each UNS Electricity DSM Program below that is reviewed and, if applicable, changes[2] discussed below:

a. Education and Outreach Program in 3.2 below
b. Direct Load Control Program in 3.3 below
c. Low-Income Weatherization Program in 3.4 below
d. Residential New Construction Program in 3.5 below
e. Residential HVAC Retrofit Program in 3.6 below
f. Shade Tree Program in 3.7 below
g. Commercial Facilities Efficiency Program in 3.8 below

Each program is independent of the others; however, the Education and Outreach Program is expanded to provide for <u>all</u> the external media exposures, training, and marketing support in all UNSE DSM Programs, as benefits from one program impact other DSM programs and to facilitate centralized DSM training management, courseware development, media campaigns, and to save costs by cross-functional activities by personnel working in this program.

The terms Energy Conservation (EC), Energy Efficiency (EE), and Demand Reduction (DR) remain as defined in the Direct Testimony (in 3.1.1).

In paragraphs 3.2 to 3.8 of the Direct Testimony, each DSM program is discussed in terms of proposed scope, references, requirements, verification, and recommended improvements. This supplemental Direct Testimony uses the same paragraph numbers.

---

[1] UNSE letter "Re: UNS Electric, Inc.'s Demand Side Management Program Portfolio Filing, E-04204A-07-_____", hereafter "UNSE DSM Plan (13 June 2007)", at 2.

[2] Changes are preceded by "(NEW)".

3.2 Education and Outreach DSM Program (EC with potential EE), or DSM Education and Training Program.[3]

There are no changes to the Direct Testimony.

The following are estimated cost for Direct Testimony Recommendations in para 3.2.f:

(1) Add active implementation tools – no changes.

Annual Cost Impact of Recommendation (1): Add $20,000 per year.

(2) Develop into an Energy Efficiency (EE) program' – no changes.

Annual Cost Impact of Recommendation (2): Add $5,000 per year to administratively handle rebates and awards plus rebates initially at $15,000 per year, thus Add $20,000 per year to Program Cost.

This EE program will have Environmental Benefits thus, 2008 to 2012 is estimates are required for 30,000 annual CFL light bulb change rebates (note, probably twice that number will occur due to publicity) in the program for 2008 to 2012:

GHG	Saved in Pounds	GHG	Saved in Pounds	Others	Saved or not generated
CO2	XXXX	SO2	XXX	Water	XXX gallons
NOx	XXX	Ozone	XXX	Mercury	XXX oz

(3) Create an Energy eNewsletter – no change.

Annual Cost Impact of Recommendation (3): Add $20,000 per year.

(4) Expand "Telephone Energy Assistance" – no change.

Annual Cost Impact of Recommendation (4): Add $10,000 per year.

(5) Include builder in the Commercial educational programs – no change.

Annual Cost Impact of Recommendation (5): Add $40,000 per year.

(6) Aggressively pursue achieving and surpassing performance measures.

(a) Feedback Calls from Call Center - No change, cost is included in Recommendation (2)

(b) Active Speaker Program – No change, no cost.

Annual Cost Impact of Recommendation (6b): Add $10,000 per year for travel

(c) Add more Academic Education - No change.

Annual Cost Impact of Recommendation (6c): Add $30,000 per year but REMOVE from DSM funding, as this should be a corporate "out reach program" and remove "Academic Education," estimated at $15,000 per year, thus result is Remove $15,000 in DSM Program, Add $45,000 to outreach, safety training program in corporate overhead expenses.

---

[3] UNSE DSM Plan (13Jun2007), Attachment 1 – Education and Outreach Program. A new Title "DSM Education and Training Program" has been recommended as a better title for this program.

(d) Increase in use of Energy Advisor – No change, no cost impact.

(e) Increase academic performance measure - No change, no cost, in Recommendation (6c)

(f) Add easy feedback performance measure – No change, no cost impact

(7) Use Energy Advisor to provide customer's TOU information – No change.

Annual Cost Impact of Recommendation (7) – none (should be included)

(8) Ensure Energy Advisor to show customer's account data – No change.

Annual Cost Impact of Recommendation (8) – none (should be included)

(9) English/Spanish language toggle on the Energy Advisor – No change.

Annual Cost Impact of Recommendation (9) – none (should be included)

(10) Change definitions for types of DSM Programs – No Change, but critical if this Program can qualify as an ACC-defined DSM Program.

Annual Cost Impact of Recommendation (10) – none

(11) (NEW) Change the title of this DSM Program to "DSM Education and Training Programs" to eliminate impacts of Recommendation (10) and reduce potential corporate "marketing" or adverting overhead image. Further, this becomes a "critical" DSM program because it will include and coordinate the Education and Training tasks for all other UNSE DSM programs.

(12) (NEW) Additional Costs from DLC DSM Program from para 3.3.

(13) (NEW) Additional Costs from LIW DSM Program (see para 3.4.

(14) (NEW) Additional Costs from Residential New Construction (ESH) Program from para 3.5

(15) (NEW) Additional Costs from Residential HVAC DSM Retrofit Program from para 3.6,

(16) (NEW) Additional Costs from Shade Tree Program from para 3.7.

(17) (NEW) Additional Costs from Commercial Facilities Efficiency DSM Program from 3.8.

(18) (NEW) Total Annual costs of this program, and then divide by the total of a weighted number of monthly customers, so this program's DSM Adjustor can be calculated.

Table 1. Recommended Program Cost Summary for DSM Training and Education Programs for Implementation in 2008.

Sub para above in ( )	Recommendations as numbered above	Additional Cost	Reduced Cost
1	Add Active Implementation tools	$20,000	0
2	Develop in an Energy Efficient Program	$20,000	0
3	Create an Energy eNewsletter	$20,000	0
4	Expand Telephone Energy Assistance	$10,000	0
5	Include Builders in Commercial Education	$40,000	0
6a	Add Feedback Calls when Call Center not busy	0	0
6b	Add Active Speak Program	$10,000	0
6c	Add more Academic Education (note 1)	$30,000	$45,000
6d	Increase use of Energy Advisor	0	0
6e	Increase academic performance measure (in 6c)	0	0
6f	Add easy Feedback Performance Measures	0	0
7	Use Energy Advisor to Provide Customer's TOU info	0	0

Table 1. Recommended Program Cost Summary for DSM Training and Education Programs for Implementation in 2008.

8	Ensure Energy Advisor can show Customer's Account	0	0
9	English/Spanish toggle on Energy Advisor	0	0
10	Change DSM Program Definitions	0	0
11	Change title to "DSM Education and Training Programs	0	0
12	Training & Education Costs for DLC DSM Program	$125,000	0
13	Training & Education Costs for the LIW DSM Program	$2,552	0
14	Training & Education Costs for Residential New Construction Home (ESH) DSM Program	$21,942	0
15	Training & Education Costs for Residential HVAC Retrofit Program	$12,000	0
16	Training & Education Costs for DLC Shade Tree Program	0	0
17	Training & Education Costs for Commercial Facilities DSM Program	$6,711	0
	Total Cost Changes for DSM Education & Training Program	$318,205	$45,000

Note. Additional academic training was recommended, but the three program included are Company outreach programs for safety and understanding, not directly related to DSM, thus recommend that they be removed from DSM funding and added to corporate overhead expenses.

The total Cost Change for this Program is to **Add $273,205** (318,205 – 45,000).

3.3 Direct Load Control (DLC) DSM Program (DR).[4]

There are no changes to the Direct Testimony.

There are no changes to the Direct Testimony Recommendations para 3.3.f, and if included this program, will require restructuring and new cost/benefits derived. Figure 1 shows information about the time of day and when the DLC control actions[5] might occur.

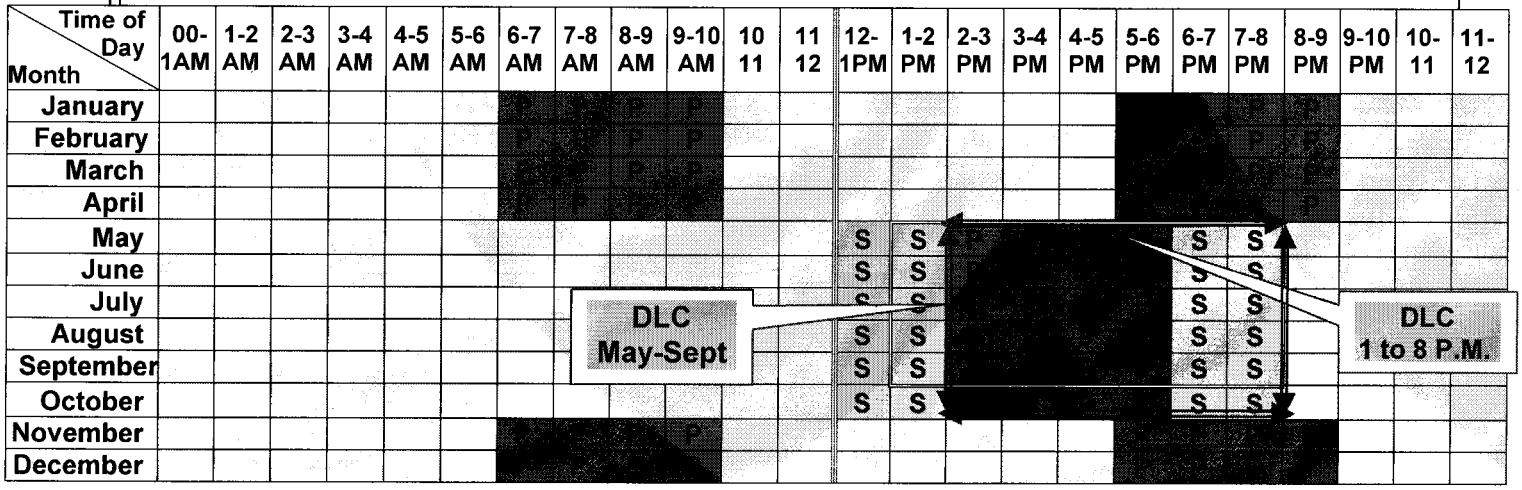

Figure 1. DLC Action Events and Time of Use (TOU). *This figure shows that DLC events will occur between May and September and from 1 PM to 8 PM in the Box with arrows. Peak Hours are shown with P (red), Shoulder with S (yellow), and Off-Peak (green) are blank.*

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[4] UNSE DSM Programs (13 June 2007), Attachment 2, "Direct Load Control (DLC) Programs"

[5] The months and hours that DLC actions might occur are from UNSE response to Data Request STF 13.32 of 18 June 2007.

Base on the proposed costs in the proposal (until new estimates are available, the training and education costs are estimated to be $125,000 for 2008 (from "Admin/marketing") and $75,000 annually in 2009 to 2012. This reduces the Program Cost to $1,843,000 in 2008.

3.4 Low-Income Weatherization (LIW) DSM Program (EE). [6]

There are no changes to the Direct Testimony.

The following are estimated cost for Direct Testimony Recommendations in para 3.4.f:

(1) Add Additional Environment Benefits in Reports – no change, no cost impact.

(2) Delete CARES Billing Assistance – no changes, reduce program cost.

Annual Cost Impact of Recommendation (1): Delete $2,552 per year.

(3) Recalculate customer benefits – no change, no cost now, will impact future results.

(4) Recalculate DSM Adjustor – see para. 3.9 below.

(5) Commission must decide if this DSM Program should recover Lost Net Revenue, and if so, how much – no change may have significant cost impact.

Based on a review of the Program Cost, Training costs shown are $2,552, which should be in the DSM Education and Training Program and deleted from the Program Cost which is now $99,896 [$105,000 - $2552 (training) - $2552 (Cares Billing)] for 2008.

3.5 Residential New Construction DSM Program a.k.a. Energy Smart Homes (ESH) (EE). [7]

There are no changes to the Direct Testimony.

The following are estimated cost for Direct Testimony Recommendations in para 3.5.f:

(1) Reduce recurrent costs – no changes, reduced cost impacts in 2009 to 2012.

(2) Increase participation annual goals – no changes, increased cost impacts in 2009 to 2012.

(3) Calculate DSM Adjustor – see below.

(4) (NEW) Commission must decide if this DSM Program should recover Lost Net Revenue, and if so, how much – no change is now assumed but could have significant cost impact.

Based on a review of the Program Cost, Training costs shown are $21,924 [36,540 (activity labor) – 10,962 (facilities audits) – 3,654 (facilities audits)], which should be in the DSM Education and Training Program, thus deleted from the Program Cost which is now $398,076 [$420,000 - $21,924 (training)] for 2008.

3.6 Residential HVAC Retrofit DSM Program (EE).[8]

There are no changes to the Direct Testimony.

---

[6] UNSE DSM Programs (13 June 2007), Attachment 3, "Low-Income Weatherization (LIW) Program"
[7] UNSE DSM Programs (13 June 2007), Attachment 4, "Residential New Construction Program"
[8] UNSE DSM Programs (13 June 2007), Attachment 5, "Residential HVAC Retrofit Program"

The following are estimated cost for Direct Testimony Recommendations in para 3.6.f:

(1) Remove subcontractor, internal marketing (to DSM Education and Training), - No change, reduce program cost by $47,952 [$35,952 (subcontractor) + $12,000 (DSM Ed/Training)] in 2008 and additional recurring expenses should be reduced in 2009 to 2012.

(2) 17 SEER and 18 SEER and heat pump incentives – no change, Add $10,000 for 17/18 and higher SEER ratings which were missing.

(3) Incentives increase as SEER ratings increase – no change, Add $10,000 for additional stepped-up SEER rating level.

(4) Commission must decide if this DSM Program should recover Lost Net Revenue, and if so, how much – no change but may have significant future cost impacts.

Based on a review of the Program Cost, Training costs shown are $12,000, which should be included in the DSM Education and Training Program, thus deleted from the Program Cost which is now $272,046 [$300,000 - $12,000 (training) - $35,954 (Subcontractor) +$10,000 (17/18 SEER, heat pump) + $10,000 (stepped SEER)] for the 2008 program costs.

3.7 Shade Tree DSM Program (EC).[9]

There are no changes to the Direct Testimony.

The following are estimated cost for Direct Testimony Recommendations in para 3.8.f:

(1) Delete Program – no change, save $65,000.

There DSM Adjustor is zero for this program.

3.8 Commercial Facilities Efficiency DSM Program (EE).[10]

There are no changes to the Direct Testimony.

The following are estimated cost for the Direct Cost Recommendations in para 3.7.f:

(1) Delete Program – no change, save $65,000.

There DSM Adjustor is zero for this program.

(1) Contractors as team players – no change, may have loan expenses but should be balanced by interest payment, net is zero.

(2) Proposal evaluations – no change, no cost.

(3) Commission must decide if this DSM Program should recover Lost Net Revenue, and if so, how much – no change may have significant cost impact.

(4) Add more equipment for rebates – no change, no cost impact as the rebates are fixed.

(5) (NEW) Moved training costs of $6,711 [$11,200 (labor) – $3,369 (Facilities Audits) - $1,120 (Facilities Audits)] to DSM Education and Training of builders and contractors.

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[9] UNSE DSM Programs (13 June 2007), Attachment 6, "Shade Tree Program"

[10] UNSE DSM Programs (13 June 2007), Attachment 7, "Commercial Facilities Efficiency Program"

(6) (NEW) Add 10 more participants per year – change program incentives, Add $100,000 without new administrative overhead by improved staff cost-containment efficiencies.

Based on a review of the Program Cost, Training costs shown are $6,711, which should be included in the DSM Education and Training Program, thus deleted from the Program Cost which is now $493,289 [$400,000 - $6,711 (training) + $100,000 (incentives)]

Q. Can you recommend a way to determine the DSM Adjustor?

A. Yes. Each program's DSM Adjustor factor equals the ratio of the Test Year total energy load in kWh[11] divided by the DSM Program Cost for the year. The sum of each DSM Program's DSM Adjustor factor equals the annual DSM Adjustor rate for ratepayers. All ratepayers will be assessed at the same DSM Adjustor rate for the year. Each year, this should be repeated, using the above process, and, after review and approval by the Commission, the next years DSM Adjustor rate implemented for all ratepayers. This process must be clear, verifiable, and transparent.

During each year, USNE will report the details to monitor each DSM Program, the derivation of the program's semi-annual cost, and for the end of the year, the Total DSM Program financial and performance results. If excess DSM revenue is collected from the effective DSM Adjustor, this excess is subtracted from the next year's cost for that DSM Program, before calculating the next year's DSM Adjustor factor.

During the semi-annual DSM program ACC Staff reviews, USNE should be required to report at least the semi-annual cost-to-date for each DSM program and if the cost minus revenue will positive or negative for each program. All excess DSM funds should be expended in the next year's DSM Adjustor process above. If USNE has overspent (negative excess), the ACC Staff should recommend how UNSE will compensate for overspending to the Commission during the Annual DSM Review for a decision.

Further, when any claims for lost revenue are made "the Commission shall determine whether a utility may be allowed to recover lost net revenue"[12] by the Commission during the Annual DSM Review. In addition, the utility will probably reduce its expenses based on the results of various DSM Programs. The reduction must be considered by the Commission during each Annual DSM Review. Any expense savings by the Company should be an important decision factor when the Commission determines the Annual DSM Adjustor rate.

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[11] The Test Year total energy was 1,606,376,387 kWh from UNSE Response to ACC Staff data request STF 13.14.

[12] ACC Staff's First Draft of Proposed DSM Rule, Exhibit 1, Draft Demand-Side Management Rules, R14-2-1709.B which states "The Commission shall determine whether a utility may be allowed to recover lost net revenue."

3.9 DSM Summary of DSM Costs and Recommended DSM Adjustor.

The proposed and recommended 2008 cost for each DSM program with the calculated DSM Adjustor factors for that DSM Program are in Table 2. It also shows the total cost for the USNE DSM Programs and recommended DSM Adjustor for each program.

Table 2. Cost of Proposed and Recommended Cost of UNSE DSM Programs with DSM Adjustor.

DSM Programs for 2008	Proposed		Recommended	
	Program Cost (100%)	DSM Adjustor[13]	Program Cost (100%)	DSM Adjustor
DSM Education and Training (Note 1)	$170,000	0.00010517	$318,205	0.00019809
Direct Load Control DSM Program	1,968,000	0.00122512	1,843,000	0.00114730
Low-Income Weatherization DSM Program	105,000	0.00006536	99,896	0.00006225
Residential New Construction DSM Program	420,000	0.00026146	398,076	0.00024781
Residential HVAC Retrofit DSM Program	300,000	0.00018676	272,046	0.00016935
Shade Tree Program	65,000	0.00004046	0	0.0
Commercial Faculties Efficiency DSM Program	400,000	0.00024901	493,289	0.00030708
Total	$3,428,000	0.00213334	$3,424,512	0.00213188

Note 1. The title of this program was changed, as recommended to ensure DSM funding for ALL Education & Training activites were included in this program.
Note 2. The Proposed and Recommended Program Costs are 100% but the Company has requested only 25% of costs plus 100% of the LIW program for the first year.

If the Proposed 2008 Program was implemented, the 2008 DSM Adjustor rate would be 0.00213334 so UNSE could recapture the total cost of $3,428,000 in the second column.

If the Recommended 2008 Program is implemented the 2008 DSM Adjustor rate would be 0.00213188 so to recapture the total cost of $3,424,512 in the fourth column.

UNSE has requested that the DSM Adjustor the first year program fund 25% of all DSM Programs except the LIW Program is funded at 100% to fund a study and that the DSM Program Adjustor start later.

Using this formula, the Proposed cost for the 2008 DSM Program is **$935,750** [(total/4 + 3xLIW/4)] (857,000+78,750). The Proposed DSM Adjustor rate is **0.00058236** (0.00053333+0.00004902),

The Recommended Cost of the 2008 DSM Program is **$934,878** (856,128 + 78,750). The Proposed Cost of the 2008 DSM Program was $950,000.

The Recommended DSM Adjustor rate for 2008 is **0.00057966** (0.00053297+0.00004669) per kWh. The proposed DSM Adjustor rate was 0.00059 per kWh.[14]

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[13] DSM Adjustor is calculated using same method in the UNSE Response to ACC Staff data request STF 13.14, by dividing cost by the test year adjusted kWh 1,606,376,397.

[14] Direct Testimony of James S. Pignatelli on behalf of UNS Electric, Inc., of 15 December 2006, hereafter "Pignatelli Direct Testimony" at 15.

Part IV – ISSUE 2
ADMINISTRATIVE ISSUES
SUPPLEMENTAL

Q. Are there any changes to this group of administrative Issues?

A. Yes, minor changes. The title has been shortened to Administrative Issues, with the former title now a subtitle. Also, there are several sub-issues, and for clarity, they are identified as follows:

a. Sub-Issue 2.1, Changes in "Connect" Fees

b. Sub-Issue 2.2, Billing Schedules

c. Sub-Issue 2.3, Predatory Loan/Check Cashing Facilities as Billing Agents

d. Sub-Issue 2.4, Revised Billing Statement

e. Sub-Issue 2.5, R&R Publication.

4.1 Supplemental Testimony Changes to these Administrative Issues.

There are no changes except as to my Direct Testimony Exhibit B. In Exhibit B, in addition to those in the Direct Testimony, and supplemental testimony are provided:

Sub-Issue 2.1 – Not at issue in this UNSE case

Sub-Issue 2.2 – Billing Schedule. Replace Exhibit B and Table B-2 on this issue with:

UNSE proposal to reduce the time between the Bill Due (when rendered, usually date mailed) and when the bill becomes "Past Due." Fifteen days after a bill becomes Past Due it is Delinquent, the penalty charge starts, and the Termination process begins. The Termination process for Delinquent bills requires 5 days notification by mail before Termination.

a. The Company's proposal is to change the interval from Bill Due to Delinquent from 15 days to 10 days.[15] A review of A.A.R., R14-2-210.C.1 states "All bills for utility services are due and payable no later than 15 days from the date of the bill. Any payment not received within this time-frame shall be considered delinquent and could incur a late payment charge." This change is a unique interpretation of the A.A.R.

b. The Company's proposal is to change the interval from when a Bill becomes Deliquent to the start of the Termination Process from 7 days to 5 days.

c. The Company issues a Suspension of Service Notice 15 days after the bill is rendered. The A.A.R. does not discuss a Suspension of Service Notice, only a Termination Letter.

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[15] Direct Testimony of Thomas J. Ferry on Behalf of UNS Electric, 15 December 2006, Exhibit TJF-1, relined page 82, Section 11.C.1, which states. All bills for electric service are due and payable no later than ten (10) days from the date the bill is rendered. Any payment not received within this time frame will be considered past due." [underlined were the changes, "fifteen (15)" and "shall" in original]

If they are the same, the proposed Timeline below for Termination becomes 20 days instead of 25 days, a 12 day reduction from the 37 days after billing to termination.

d. At the earliest, it is possible for a customer to have their service terminated 20 (or 25) days after the Bill is mailed, which can very between 25 and 35 days after prior bill. Within a ten day billing window, and a twenty day schedule, customer financial planning for monthly wage checks becomes very challenging for lower-income ratepayer.

THE PRESENT TIMELINE OF BILLING EVENTS:

Day -1 to 0	Meter is read, reported to the Company (between 25 and 35 days after prior reading)
Day 0	Billing Date, when the bill is rendered (considered when mailed), the Bill is Due
Day 15	(15 days after Due) Bill is Past Due
Day 25	(10 days after Past Due) Bill is Delinquent, Payment Penalty starts
Day 30	Late Penalty (1.5%/month) starts for all account balances 30 days after postmark of account bills
Day 32	(7 days after Delinquent) Termination Process begins
Day 37	(5 days after Termination letter is mailed, Earliest Termination

THE PROPOSED TIMELINE OF BILLING EVENTS:

Day -1 to 0	Meter is read, reported to the Company (between 25 and 35 days after prior reading)
Day 0	Billing Date, when the bill is rendered (considered when mailed), the Bill is Due
Day 10	(10 days after Due) Bill is Past Due
Day 15	(15 days after Due) Bill is Delinquent, Payment Penalty starts and is payable on a monthly basis, Suspension of Notice letter is sent
Day 20	(5 days after Delinquent) Termination Process starts
Day 25	(5 days after Termination Letter mailed), Earliest Termination

It should be noted in Table 3 the A.A.R. is generally inconsistent with respect to utility billing dates as summarized below. A typical credit card timeline is added for a comparison.

Table 3. Comparison between Present and Proposed Billing Schedules.

Utility	Billing Due	Past Due or Delinquent	Termination (days after Past Due)
Electricity	0	+15 days	+5 days after letter
Natural Gas	0	+10 days	+5 days after letter
Water	0	+15 days	+10 days after letter
Telephone	0	+15 days	+7 days after Past
Sewage	0	10 for Past Due	+15 to Start Term. + 5 days after letter
Credit Card	Purchased up to 31 days before	+20 days	Between 21 and 51 days after purchase

It is recommended that:

(1) That Past Due dates conform to the A.A.R., using 15 days after Billing date.

(2) That all proposed billing schedule changes be denied.

Sub-Issue 2.3 - Predatory Loan/Check Cashing Facilities as Billing Agents.

See Exhibit B, which provides the basis, discussion and recommendations to the proposed changes in billing statements. UNSE refers ratepayers to these facilities hired as UNSE billing agents to pay in person by cash "at multiple 'ACE Cash Express Stores' located throughout the UNS Electric service territory."[16] It is not appropriate to use possible predatory loan/check cashing facilities as UNSE billing agents for lower income ratepayers to pay their bills in "cash" since most do not have a bank account and also have to pay a "check-cashing" commission to "cash" their paycheck in order to pay their bill in cash.

No changes in testimony or recommendations from that in Exhibit B are necessary. Two new Enclosures to Exhibit B are in this Supplemental Testimony.

Enclosure B-3 provides the present UNSE Payment Agents for making cash-only bill payments. The UES website lists 12 ACE Cash Express and one QA Quick Cash facilities.[17]

Enclosure B-4 provides how one could pay their bill online with a bank withdrawal or with a credit or debit card with a third-party administration fee of $3.95 per payment.

The Recommendations in Exhibit B remain unchanged: (1) Do not allow payday loan organizations as payment agents and (2) Do not require any fees for online bill payments.[18]

Sub-Issue 2.4 – Revised Billing Statement. See Exhibit B for detailed recommendations to changes proposed to the billing statement sent monthly to UNSE ratepayers. No changes in testimony or recommendations from that in Exhibit B are necessary. There were fourteen recommendations to revise a new billing statement format presented in the UNS Gas Rate Case as found in Exhibit B. Since the billing statements for UNSG and UNSE are very similar, these same detailed recommendations apply. These details will be presented for the record as a Magruder Exhibit during oral testimony.

Sub-Issue 2.5 – R&R Publication. See Exhibit B and recommendations to publish the ACC-approved UNSE Rules and Recommendations (R&R). No changes in testimony or recommendations from that in Exhibit B are necessary. Table B-3 reflects the UNSE R&R Section Titles.

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[16] Direct Testimony of Thomas J. Ferry on Behalf of UNS Electric, Inc., of 15 December 2007, hereafter as "Ferry Direct Testimony" at 8.

[17] See www.uesaz.com/Customersvc/PaymentOptions/Agents.asp (verified 9 July 2007)

[18] See https://secure3.i-doxs.net/unisource/OneTime_Add_UniElec.asp?Ac (assessed via UNSE website, verified 9 July 2007)

Part V – ISSUE 3

Costs to Improve Electricity Reliability in the Santa Cruz Service Area

5.1 Reliability Issues in the Santa Cruz Service Area.

Q. Why are Reliability Issues in Santa Cruz Service Area important in this rate case?

A. As a long-term issue, expenses to rectify reliability issues impact the Company's costs and thus will impact rates. This issue is long and needs to be introduced in the context of original problems, ACC reviews and Orders, and compliance.

Q. What are the recent ownership changes of the electric companies in Santa Cruz area?

A. In the 1990's Citizens Utilities Company was renamed Citizens Communications Company Arizona Electric Division (AED)[19] in Santa Cruz service area (and also the Mohave service area). Citizens held the CC&Ns for service in the Santa Cruz River Valley area of Santa Cruz County, from the Pima County line to the Mexican border. Citizens purchased the Nogales Electric Company, who had provided local electricity service in the 1890s, about 1950. Citizens installed the first transmission line between Nogales and Tucson about 1952.

Unfortunately, Citizens initial service was less than desired. Only by a technical error[20] an election for the City of Nogales to municipalize Citizens was overturned during 1953-55.

To the east is Sulfur Valley Springs Rural Cooperative and to the west is TRICO, another rural cooperative. Citizens obtained two DOE Presidential permits to supports a Santa Cruz, small village in Mexico, and to provide an emergency transmission line connection between the two countries which has never been completed nor used.

On 11 August 2003, the purchase of Citizens by UniSource, Inc. was completed and the new public service company, UNS Electric, Inc. combined the organization for the Mohave and Santa Cruz service areas. The Purchase Agreement required Citizens to deliver to UniSource various agreements needed by the Buyer.[21]

Q. How did reliability become such a problem in this area?

A. In 1998 and 1999, there were a series of frequent and long electrical outages in the Santa Cruz service area. These outages were so severe that the City of Nogales filed a Formal

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[19] Hereafter, Citizens.

[20] The technical error was misspelling "Citizens" as "Citizen's" on the bonds required for the City's purchase, which eventually adjudicated to negate the vote to municipalize. Another municipalization attempt occurred failed in the September 2003 election.

[21] Asset Purchase Agreement by and between Citizens Communications Company, as Seller, and UniSource Energy Corporation, as Buyer (hereafter, UniSource-Citizens Purchase Agreement), of 29 December 2002, section 3.5 (Deliveries by Seller) at pages 24-25 net al, found in ACC Docket No. E-01032C-00-0751, et al, which resulted in ACC Decision 66028.

Complaint with the Commission, Nogales cancelled its franchise agreement with Citizens, and demanded actions be taken to improve reliability. After a series of ACC hearings, the City of Nogales and Citizens signed a Settlement Agreement[22] which includes demands on Citizens:

a. To direct payments of $15.00 to all customers in Santa Cruz County (completed)
b. To provide a neutral claims resolution procedure for all customers. (completed)
c. To fund low income relief. (completed)
d. To fund several Santa Cruz County economic-development efforts. (remains open)
e. To fund annual four-year, interest free, scholarship/loans for Santa Cruz County high school graduates that will be forgiven, if the student returns to live and work in the County for two years. (remains open)
f. To improve future electric service and community relations, Citizens and the City will:
   (1) Create a Citizens Advisory Council, (initially resolved but now is open)
   (2) Collaborate to determine the order in which circuits are energized in the event of future transmission-related outages. (presumed closed)
   (3) Develop a mutually acceptable Service Upgrade Plan for submission to the Commission. (remains open)
   (4) Negotiate a mutually acceptable 25-year franchise for Citizens. (completed)

The City also dismissed the Complaint with prejudice. [underlined in original]

In addition to the Citizens-Nogales Agreement, Citizens lost a civil law suit for $2.5 million, most of which $1.9 million was rebated to all its customers during this time period.[23]

Q. Why is this City of Nogales-Citizens Settlement Agreement still important?

A. Because it formed the foundation to improve reliability and quality of service in this area. It established actions required by Citizens, and its successor, UNS Electric. But before we go to other ACC Orders and Agreements, let us look at compliance with the terms of this agreement. As indicated above, some of these Citizens agreements remain open eight years later.

Q. Why would action required by an ACC Order for Citizens pertain to UNS Electric?

A. When UNS Electric, Inc. acquired Citizens, all Citizens obligations should have automatically been novated directly to UNSE.[24] Incomplete actions required by ACC Order Nos. 61793, 62011, and others are on going or not completed. The remaining actions are discussed next.

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[22] The "Citizens-City of Nogales Settlement Agreement" was approved in ACC Decision No. 61793 of 29 June 1999 for Docket No. E-01032B-98-0621 without change which also "ordered that Citizens Utilities Company shall provide a planned service date and required a cost benefit analysis for the system components of a second transmission line be included in its Plan of Action" at page 4, at 11 to 14.

[23] *Chilcote versus Citizens Utilities.*

Q. What "Santa Cruz Economic Development" efforts remained?

A. In addition to provision of "seed" money, Citizens was to work with the Citizens Advisory Council and an Economic Development Roundtable to "develop new-business incentive-rate tarries intended to attack new business to Santa Cruz County" and to "evaluate appropriate changes to existing commercial and industrial tariffs" and to file resulting changes with the ACC for approval.

This has NOT been accomplished, as the existing business electric rates discouraged bussiness. This was a major objection I had in my filings in the Purchase Power and Fuel Adjustment Clause case in Docket No. E-01032C-00-0751. Further, Mohave County Economic Development personnel also objected to these high business and commercial tariffs during those hearings.[25]

Q. What is the status of the annual "Funding Four-Year Scholarship/Loans"?

A. A review of the annual scholarships sections in recent *Nogales International* newspapers have not listed any scholarships from UniSource, UES or UNS Electric, Inc. This Settlement Agreement, in Article 9, stated "Each year, the program will select..."[26] which is clear this is an annual scholarship program. This has NOT been continued, may not ever have started. I have an open data requests on this to UNSE, which has not responded as of this submission.

Q. What has been done with the "Create a Citizens Advisory Council" obligation?

A. This was initially established to "discuss electric and gas service issues, upcoming Commission filings and other topics of mutual interest such as electric deregulation and demand-side management."[27] The last meeting of the CAC was in September 2000, just after TEP and Citizens agreed to work together on the 345 kV transmission project. This has NOT been continued, "Public participation" was unilaterally stopped, without Commission approval and unilaterally by the utility."[28] In response to a Magruder Data Request "UNSE Electric has not

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[24] UniSource-Citizens Purchase Agreement, *op cit.*

[25] Docket No. E-01032C-00-0751, In the Matter of the Application of the Arizona Electric Division of Citizens Communications Company to Change the Current Purchased Power and Fuel Adjustment Clause Rate, to Establish a new Purchased Power and Fuel Adjustment Clause Bank, and to Request Approval Guidelines for the Recovery and Costs Incurred in Connection with Energy Risk Management Initiatives, the "Marshall Magruder Brief," of 15 May 2003, page 3 at 27 to 30, page 7 at 9 to 13, et al. It should be noted, the above docket was merged with two other docket Nos. G-01032A-00-0598 and E-01933A-02-0914.

[26] City of Nogales-Citizens Settlement Agreement, p. 7, Article 9, Educational Support.

[27] *Ibid.* p. 4, Article 3, Citizens Advisory Council.

[28] Citizens in a Docket No E-01032B-98-0621 filing "Settlement Agreement Between the City of Nogales, Arizona, and Citizens Utilities Company" of 12 February 1999, stated "The CAC will meet regularly (as agreed by its members) to discuss electric and gas service issues, upcoming Commission filings and other topics of mutual interest such as electric deregulation and demand-side management. The CAC will also assist Citizens by evaluating alternatives for long-term electric reliability in Santa Cruz County, such as a

held any public meetings regarding the [this] filing."[29] A press release "sent to Santa Cruz County Manager and Nogales City Manager" and one billing stuffer are inadequate for informing the ratepayers about the significant changes in this application.[30] Even though some meetings where held in Mohave County, the Time of Use (TOU) provision was only mentioned "generally as an incentive to shift load off of UNS Electric' peak load times." The Purchase Power and Fuel Adjuster [sic, Adjustment] Clause was not discussed."[31]

Q. What about "Determine the Order of Circuits after Transmission Outages"?

A. This task was established to promote collaboration by Citizens with the City to determine the initial order for circuits to be re-energized due to an outage of WAPA or 115 kV transmission lines. The local turbines would be used. This appears to have been accomplished by changes in tie lines so that all emergency circuits were energized first. This task stated "in collaboration with the CAC, Citizens will evaluate whether to keep generation in spinning reserve during inclement weather."[32] As there have been no CAC meetings since September 2000, unilaterally, UES requested and obtained ACC approval in 2004-05 not to have spinning reserve (turbines in standby) during storms.[33] Any collaboration with the CAC on the issue of having the local turbines in "standby" or spinning reserves <u>was not complied as agreed</u>.

Q. What about "Develop a Mutually Acceptable Service Upgrade Plan"?

A. This task was for Citizens to file a Service Upgrade Plan for comments by both the City and the Residential Utility Consumers Office (RUCO) including Citizens funding RUCO for this task. This plan was filed and incorporated into the ACC Staff Settlement Agreement months before ACC Decision No. 62011 on 2 November 1999 was decided when the Commission approved the Citizens Plan of Action agreements with the ACC Staff. <u>No collaboration with RUCO occurred</u> in the development of this plan.

Q. What about a "Mutually Acceptable Franchise Agreement"?

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second transmission line, and <u>recommend a preferred alternative</u> to Citizens and the Commission" at page 3, paragraph 3. The actions indicated by the last sentence were <u>never</u> accomplished by the CAC.

29 UNSE response to Magruder data request MM DR 1.8a.

30 UNSE response to Magruder data request MM DR 1.8b.

31 UNSE response to Magruder data request MM DR 1.8c.

32 Nogales-Citizens Settlement Agreement, p. 4, Article 4, Back-up Generation.

33 See ACC Order No. 67151 of 3 August 2004 that waived the $30,000 penalty for failing to have a second transmission line in service by 31 December 2003.

A. This was not accomplished by Citizens but added as a Condition to the UniSource Acquisition of Citizens Settlement Agreement.[34] A Franchise Agreement was approved in the general election in September 2004.[35]

Q. You mentioned an ACC Staff- Citizens Settlement Agreement, what is this about?

A. This ACC Staff-Settlement Agreement is in the Citizens "Supplement to Santa Cruz Electric Division Transmission Alternatives and Plan of Action"[36] which was filed to comply with ACC Order No. 61383.[37] UNSE's witness Mr. Beck Direct Testimony stated:

> "Prior to UNS Electric's acquisition of the system from Citizens, there were significant concerns about the reliability of electric service in Santa Cruz County. As a result of these concerns and a Commission proceeding, Staff and Citizens filed a Settlement Agreement in August 1999 the committed Citizens to a Plan of Action. The Settlement Agreement was subsequently approved by the Commission in Decision No. 62011 (November 2, 1999). Under the Plan of Action, Citizens had:
>
> - Added a new system (sync-check relay) to synchronize Citizens generation units at Valencia Power Plant with Western Area Power Administration's ("WAPA") transmission system;
> - Installed a new 115kV switching station at Nogales Tap Station to convert the interconnection between Citizens and WAPA from a simple tap to a three breaker ring bus;
> - Replaced selected structures and components on the existing 115kV line;
> - Pursued a second transmission source into the service area."[38]

This Supplement Agreement listed and required many reliability improvements that impact all elements of the Santa Cruz electrical system. The Settlement Agreement also required a second transmission line and other improvements, not dependent on the Second Transmission Line, and schedules and Gantt chart showing completion by the end of 2003.[39]

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[34] In ACC Docket Nos. E-01032C-00-0751, G-01032A-00-0598, E-01933A-02-0914, E-01032C-02-0914 and G-01032A-02-0914, the resultant joint ACC Staff-Citizens Settlement Agreement (hereafter Staff-Citizens SA), at pages 7 to 8, paragraphs 8 and 9, required that all franchise agreements be provided to the Commission within 365 days of closing, which occurred on 11 February 2003. Thus, based on the following footnote, this franchise was approved more that 365 days later.

[35] On 2 November 2003, the 55.6% of City of Nogales voters approved the UNSE franchise and 57.19% voted to approve the UNSG franchise. These are not large majorities.

[36] Direct Testimony by Edmond A. Beck on Behalf of UNS Electric, Inc., of 15 December 2006, hereafter "Beck Direct Testimony", at 4,

[37] This "supplement" is also in TEP and UES filing in Docket No. E-01032A-99-0401, "Notice of Filing Response to Commission Questions and Updated Outage Response Plan for Santa Cruz County" filed on 9 February 2004, in the first exhibit (sic), filed by Citizens under Docket No. E-01032A-98-0611, et al, "Supplement to Santa Cruz Electric Division Transmission Alternatives and Plan of Action," filed on 7 May 1999. In addition, on 15 April 1999, Citizens filed the "Transmission Alternatives and Plan of Action" (written by Citizen's consultants, Power Engineers and Dames & Moore) to which the "supplement" amplified.

[38] Beck Direct Testimony at 4 and 5.

[39] This filing with for the Citizens "Supplemental Plan" does not have numbered pages. The Adobe PDF version, filed in TEP's 9 February 2004 in Docket No. E-01032A-99-0401 is paginated by the PDF program. These pages numbers are used for reference purposes as "Citizens Supplemental Plan, PDF page X".

The Settlement Agreement has many ACC-approved commitments by Citizens, now assumed by its successor, UNSE. A Citizens "Plan of Action" dated April 15, 1999 and updated on 7 May 1999 and 13 July 1999 addressed service quality issues in ACC Decisions No. 61383 and 61793.[40] These

a. Require Citizens to construct a second transmission line.[41]

b. State Citizens "will endeavor to place the second transmission line in service by four years after the date of a Commission Order approving this Settlement Agreement."[42] That date was November 2, 2003.

c. State "If an Environmental Impact Statement is not needed, Citizens [UNS Electricity] will endeavor to achieve an in-service date of 39 months after the date of a Commission Order approving this Settlement Agreement."[43] That is an in-service date of February 2, 2003 and would itself have been subject to the Delay Penalties.

d. Require USNE to "fulfill Citizens' obligations for the second transmission line as a condition of the Commission's approval of the sale."[44]

e. Order Citizens (USNE)

> "to proceed with planning, permitting, and constructing a second transmission line to serve its Santa Cruz Electric Division Customers, subject to the siting process and schedule that Citizens filed on July 13th, 1999. Presently the preferred alternative is the Bicknell-Valencia route, but the parties recognize that completion of transmission studies and environmental approvals may identify another route as the route to be constructed."[45] [Note: Bicknell-Valencia did not require an EIS.]

f. The Settlement Agreement has a "Delay Penalties" clause which reads:

"4. Delay Penalties.

a. If the second transmission line is not placed in service by December 31, 2003, then Citizens will owe a penalty of $30,000 per month for each full month of delay after December 31, 2003. This penalty represents liquidated damages for Citizens' failure to fulfil its obligations under this Agreement and will be for the benefit of Citizens' Arizona electric customers. Citizens will compute and owe the penalty no later than 30 days after the transmission line's actual in-service date. If the transmission line is not in service by December 31, 2003, then on January 31, 2005, Citizens will compute and owe the accrued penalty for the previous year. Citizens' obligation will then continue in a like manner on each January 31, thereafter, until the transmission line is actually in service. In the year the transmission line is actually placed in service, Citizens will then compute and owe the penalty no later than 30 days after the transmission line's actual in-service date.

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40 ACC Staff-Citizens Settlement Agreement, 1/17-18.
41 *Ibid.*, 1-15-16.
42 *Ibid.*, 1-27-29.
43 *Ibid.*, 29/2 to 2/1-2.
44 *Ibid.*, 3/5-8.
45 *Ibid.*, 1/20-25.

b. No later than each date in the preceding paragraph by which Citizens is to compute and owe a penalty, Citizens will file with the Commission its proposal as to which of Citizens' electric customers will receive the benefit of the penalty amount and how the benefit will be distributed (e.g., bill credit, credit to PPFAC bank balance, refund, or other methodology). The Commission will then determine by Order the appropriate recipients and distribution methodology.

c. If Citizens believes that circumstances beyond its reasonable control (such as unavoidable delay in obtaining a Certificate of Environmental Compatibility, court injunction, or other good cause) are responsible for the delay, Citizens may apply – no later than December 31, 2003 – with the Commission to delay the December 31, 2003, date or to waive the penalty. If Citizens makes such a filing, Staff and any other, interested party may file a response either supporting, not objecting to, or objecting to Citizens' application. The Commission will then determine the appropriate relief, if any."[46]

Q. What did this Staff-Citizens Agreement say about a second transmission line?

A. It had seven requirements for the second transmission line that include:

a. Proposed Deadline for Implementation. The earliest deadline indicated was February 2002; however, an in-service date of 2003 was indicated.[47]

b. Cost-Benefit Analysis. A detailed Cost-Benefit Analysis was filed by Citizens. The Supplement has preliminary cost estimates for the four potential interconnections and routes in Table 4.

Table 4 – *Transmission Alternatives Considered by Citizens and Cost Estimates.*
This Citizens assessment provided four 115 kV alternatives for the Second Transmission Line to the Nogales Valencia Substation.

Interconnection With	From Substation	To Substation	Initial Cost Estimates	Cost in Supplement[48]
AEPCO	Bicknell	Valencia	$10.6 million	$ 21.0 million
AEPCO	Sierra Vista	Valencia	$11.6 million	$ 20.9 million
AEPCO	Pantano	Valencia	$14.0 million	$ 23.0 million
TEP	Vail	Valencia	$16.25 million	$ 27.0 million

c. Alternatives. The four 115 kV transmission line routes above were identified, with the Bicknell being the preferred with respect to system performance and cost and "this

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46 *Ibid.*, 4/3 to 5/4. The ACC Staff Direct Testimony of 20 August 1999 stated "The [ACC Staff-Citizens] Agreement also establishes a framework for delay penalties applicable for Citizens failure to perform in accordance with their proposed schedule." Page 2, lines 3 and 4.

47 In Citizens Supplemental Plan, PDF pages 24, 25, and 36 to 39. On PDF page 39, the Citizens Data Response to Staff's First Set of Data Requests, 28 January 1999, Date Request No. RF-2, the ACC Staff asked how the year 2003 was selected; the earliest possible in-service date and what could prevent Citizens from installing this line prior to 2003. In ACC Staff Supplemental Testimony of 16 July 1999, the "Staff is concerned about schedule creep ... this seems to indicate that Citizens has just recently become serious about planning for and constructing a second transmission line, despite the report of September 1971 [which indicated the reliability need]. Staff believes the delay in starting the process and filling the associated reports has been excessive and unreasonable." At page 8 lines 7 to 14.

48 These costs were referenced in the Joint TEP-Citizens CEC Application for a 345 kV line as the maximum Citizens would be required to pay under all scenarios' for a second transmission line to meet the ACC-mandate in ACC Order No. 62011. TEP managed the construction and would absorb all other costs.

interconnection is the best technically, is the lowest capital cost, and the route generally crosses terrain that has other linear developments, such as natural gas pipe line and interstate highway".[49]

d. Power Flow Studies. Preliminary power flow studies completed by AEPCO supported the Bicknell alternative. Further, the "second 115 kV line would need to operate in parallel with WAPA's transmission system."[50] TEP did not conduct any power flow studies for its proposed "Vail" interconnection.[51]

e. Environmental. Of these four alternatives, the Bicknell and Vail alternatives presented fewer environmental permitting problems; however, a TEP Vail alternative would transverse more highly-developed areas. The other two alternatives would follow AZ Highway 82 is far more environmentally sensitive.[52]

f. Transmission Service Costs. The

> "addition of a second transmission line interconnected to a system other than WAPA will require an interconnection agreement and potentially, a transmission service contract with the transmission owner. Any transmission service costs are expected to be in addition to those presently incurred for use of the WAPA's system."[53]

Thus, any system, other than WAPA's, has higher rates for the Santa Cruz customers.

g. Selection of the Preferred Plan. Citizens with Power Engineers and Dames & Moore, consulting firms, developed the work plan; environmental characteristics for each alternative; outlined the required steps; and projected a permitting, design and construction schedules for the second transmission line. This plan was for "planning with local, state, and federal agencies to develop the information necessary for applying for a Certificate of Environmental Compatibility" with the Line Siting Committee the Transmission Alternatives and Plan of Action Report.[54]

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[49] In Citizens Supplemental Plan, PDF page 25.

[50] *Ibid.* PDF pages 29 and 37. This point is very important. Almost all power consumed by Citizens is "firm" delivery, which means the supplier MUST always provide this power. In general, when the same suppler provides transmission in "parallel" for two of its interconnections, the user will only have to pay for electricity that is consumed and transmission charges for what is transmitted, one pays for power once. If a second, independent (a different) provider transmits power, the "second" power supplier must also be paid, even if NO power is consumed, one pays for power twice. Thus, one supplier is less costly for ratepayers when compared to two suppliers. WAPA is the transmission supplier for both Citizens and AEPCO but is not for TEP. Thus, as early as January 1999, this principle was known and understood by Citizens in its own report.

[51] In Citizens Supplemental, PDF page 37, "TEP has not completed power flow cases for any potential interconnection."

[52] *Ibid.* PDF page 30.

[53] *Ibid.*

[54] *Ibid.* This report was filed with the Commission on 15 April 1999.

Q. And what are the other (non-second transmission line) reliability Improvements in the Citizens Plan?

A. Yes, these involved many projects for above ground pole replacements, below ground cable replacements, power supply improvements, and several substation improvements including Nogales Tap, SCADA and communications improvements. The Citizens plan extended from 1999 through 2003, with completion of a second transmission line and reliability improvements by the end of 2003. All were important. Each project directly impacted customer's reliability.

Q. Were all of these ACC-approved reliability improvements implemented as planned?

A. Let us look at each because, as some of these items remain to be completed and others were completed by Citizens or UNS Electric. Some are visible, such as utility pole and underground cable replacements.

Q. What is the status of the above ground pole replacements compared to the plan?

A. The Citizens plan presented a ground pole replacement plan for each year, from 1999 through 2003 to replace 3,060 poles that "have reached the end of their life cycle."[55] Twenty different pole replacement projects were approved at a total expenditure of $9,155,000 with $4,320,000 to be spent in 1999 and $1,265,000 in 2000. In 2001, 2002, and 2003 the expenditures for pole replacements was level at $1,275,000 each year. A "progress to date" in 15 April 1999,[56] shows that 634 poles had been replaced for the estimated 616 as of this report. Table 5 below shows the plan for replacing these above ground poles.[57] The early results of this program were impressive; however, when it was known Citizens was "for sale" it appears this work effort was reduced or stopped.

The important unanswered question in this UNSE Rate case is how many of the 3,080 above-ground utility poles approved by the Commission in the Citizens-ACC Staff Agreement have been actually replaced? UNSE should have finished these twenty projects by the end of 2003 as shown in Table 5; however, this has not been verified as completed work.

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55 *Ibid.* PDF page 52.

56 I tried to obtain an update with data requests this docket but was refused so far. In an earlier ACC Docket No E-01032A-99-0401 without success as I was told to pursue this issue in the "next rate case." Please see Magruder Testimony of 8 July 2005 in that docket, Appendix E.2, pages 135 to 136 for the utility pole replacement programs. I know these areas and by observation, many "old" poles remain and the new poles are obvious, many being metal ones replaced by Citizens are a real improvement and should improve distribution reliability.

57 In Citizens Supplemental Plan, PDF pages 26, 41, 43, 45, and 52.

Table 5 – Above Ground Pole Replacement Plan. Twenty different ground pole replacement projects were to be accomplished by 31 December 2003 at a cost of $9.155 million.

Proj. ID	Pole Replacement Project	Total No of Poles	1999 Est. No.	Poles to date	1999 ($)	2000 ($)	2001 ($)	2002 ($)	2003 ($)
1	Nogales Wash area	75	75	26	300,000	0	0	0	0
2	Nogales West north area	75	15	28	90,000	30,000	30,000	30,000	30,000
3	Reconductor Mariposa Industrial Park	75	1	1	90,000	75,000	0	0	0
4	Downtown Southeast	300	60	74	360,000	120,000	120,000	120,000	120,000
5	Downtown Northwest	300	60	115	360,000	120,000	120,000	120,000	120,000
6	Downtown Southwest	500	100	91	474,000	200,000	200,000	200,000	200,000
7	Downtown Northeast	300	60	20	360,000	120,000	120,000	120,000	120,000
8	Beatus Estates	150	0	0	180,000	60,000	60,000	60,000	60,000
9	Valle Verde	150	30	106	180,000	60,000	60,000	60,000	60,000
10	Chula Vista	50	2	0	60,000	20,000	20,000	20,000	20,000
11	Activate Circuit 6242	100	0	0	180,000	60,000	60,000	60,000	60,000
12	Circuit 6241	50	10	0	60,000	20,000	20,000	20,000	20,000
13	Meadow Hills North	75	15	0	90,000	30,000	30,000	30,000	30,000
14	Meadow Hills South	75	15	0	90,000	30,000	30,000	30,000	30,000
15	Transmission Line	20	2	0	320,000	0	0	0	0
16	Highway 82	250	60	148	275,000	120,000	120,000	120,000	120,000
17	Old Tucson Road	10	10	9	25,000	0	0	0	0
18	Rio Rico Highway Crossing	0	0	0	126,000	0	0	0	0
19	Rio Rico Industrial Park	25	1	16	100,000	0	0	0	0
20	Flux Canyon area	500	100	0	600,000	200,000	200,000	200,000	200,000
	Totals	3,080	616	634	$4,320,000	$1,265,000	$1,190,000	$1,190,000	$1,190,000

Magruder Data Request 3.12 of 29 June 2007 to UNSE requested the detailed completion status of ACC Order No. 62011 and others that implemented Citizens reliability improvement projects. This DR has not been answered by the filing date for this testimony.

However, a review of the UNSE response to STF DR 3.118 (and STF DR 2.1) shows the following are potential correlations of these projects to work accomplished, data for most projects was not located in STF DR 2.1:

Project 5 (Downtown Northwest), a "distribution syst Repl Nog" project expenses was $6,262,41 and completed on 2 May 2006 and "Line Repl < $10,000 replacement of old service pole with new service pole @ 544 N. Potrero Ave" expense was $5,847.90, completed on 14 Nov. 2004, with a budget of $320,000 in 1999 and $120,000 annually for 2000 through 2003. Total expenses of $12,110.31 for two jobs in 2004 and 2006 are minor to have made any impact on Project 5. They appear unassociated a pole replacement plan.

Project 9 (Valle Verde), "distribution Syst Repl Nog" project expenses was $1,529.12 and $465.43, completed on 12 April 2006 and 1 June 2006, with a budget of $180,000 in 1999 and $60,000 annually from 2000 to 2003. Project 9 specified 150 utility poles would be replaced. In 1999, 106 were replaced. This appears as an isolated pole replacement project.

Project 15, (Transmission line), an "115kV Line Replacement" project expenses of $117,768.43 was completed on 31 July 2003. This was a Citizens expense, not UNSE, based on a completion date before acquisition. A "2003-115kV line transmission" completed on 30 Nov 2003 for $6,223.21. The project budget was $320,000 in 1999 only. Two of 20 NOG poles were replaced in 1999 but 18 poles remained uncompleted in 1999. These expenses should be UNSE's. Project 15, with less than 18 poles to replace, in 1999, may have expended $123,991.64 of the $320,000 the 1999 budget on two projects completed in 2003, one by Citizens and another by UNSE. The money and tasks do not appear to match.

Project 16 (Highway 82), a "Line Repl ADOT-HWY 82 Project, Overhead Line Relocation" project expenses was $5.074.46, and completed on 31 July 2003, as Citizens expense, not USNE, based on completion before 11 August 2003. A "Distribution Syst Repl Nog, ADOT SR-82, Kino Springs" project expenses was $4,420.52, completed on 23 January 2005. Project 16 budget was $275,000 in 1999 and $120,000 annually from 2000 through 2003 with 250 utility OH poles to be replaced. In 1999, 148 had already been replaced. Thus, Citizens completed $5,074.46 of work in 2003 when $120,000 was scheduled. UNSE completed $4,420.52 two years after this project should have been completed.

Project 17 (Old Tucson Road), three jobs for "Distribution Syst Repl Nog" at 130, 144, and 190 Old Tucson Road were competed on 1 June 2005. One job for a "Distribution System Bettr. Nog" at 80 Old Tucson Road was completed 9 June 2006, with total Project 17 costs of $60,993.56 (25,325.60 + 26,749.55 + 7,711.93 + 1,206.48), with a budget of $25,000. Project 17 is scheduled only in 1999 and finished in 1999 with 9 of the 10 poles already replaced by then. No credit recommended for UNSE.

Project 20 (Flux Canyon area), for "distribution system Bettr. Nog, Flux Canyon Road, Patagonia" project costs were $11,415.03 and $933.15, completed on 20 Feb 2005 and 1 June 2005, with a budget at $200,000 per year from 2000 through 2003.

It appears that "poles, fixtures and towers" capital expenses[58] for both the Mohave (approximately four times larger than Santa Cruz) and the Santa Cruz Divisions as follows:

Year	Planned in Santa Cruz County	Total Actual in Both Counties
1999	$4,320,000	$11,336,691
2000	$1,265,000	$211,055
2001	$1,190,000	$3,113,175
2002	$1,190,000	$2,515,741
2003	$1,190,000	$1,216,447

[58] Direct Testimony of Ronald E. White on Behalf of UNS Electric, Inc., of 15 December 2006, Exhibit REW-2, Depreciation Rate Review of 24 November 2006, Schedule B, Account 364.00, Poles, Fixtures, and Towers, at 31. The Budget (Table 5) exceeded the actual expenditures 2 of 5 years for only 20% of the company.

SUMMARY for Pole Replacements.

1. The data do NOT support completing ANY Pole Replacement Projects 1 through 20.
2. UNSE records claim Citizens expenses before the acquisition.

Q. Were all the underground cables replaced as required by the ACC-approved plan?

A. The Commission approved an underground cable replacement plan from 1999 through 2003. Citizens stated the cable to be replaced had known reliability problems due to being directly buried cable (improperly installed) and the old cable was defective with high failure rates.[59]

Twelve projects are shown in Table 6 to replace 161,388 total feet (over 35 miles) of underground cable between 1999 and 2003. The budget in 1999 was $1,310,104 and annually $1,275,104 for 2001, 2002, and 2003 for a total cost of $6,406,520 to replace defective cables and to improve customer reliability.

The underground cable replacement plan required that Rio Rico and Tubac have the highest priority. A 1999 "progress to date" showed only 25,741 actual feet of cable replaced in 1999 of the scheduled 32,753 feet. Some of the first cable replacements, in the "Ft. to date" column, significantly over-ran the planed number of feet when compared to actual number of feet replaced.

Table 6 – Underground Cable Replacement Plan. *The 1999 estimates and "to date" actual installations do not meet the planned number of replacements.*

Proj. ID	Underground Cable Replacement Project	Total Feet	1999 Est. Ft.	Ft. to date	1999 ($)	2000 ($)	2001 ($)	2002 ($)	2003 ($)
1	Mariposa Manor	7,677	1,535	0	61,416	61,416	61,416	61,416	61,416
2	Monte Carlo	12,040	2,408	2,454	96,320	96,320	96,320	96,320	96,320
3	Rio Rico Urban 3	28,160	5,632	14,157	225,280	225,280	225,280	225,280	225,280
4	Preston Trailer Park	3,633	727	0	29,064	29,064	29,064	29,064	20,064
5	Tubac Country Club	6,900	1,380	0	55,200	55,200	55,200	55,200	55,200
6	Tubac Valley County Club	4,300	860	7,290	34,400	34,400	34,400	34,400	34,400
7	Palo Parado	15,530	2,706	0	108,240	108,240	108,240	108,240	108,240
8	Empty Saddle Estates	8,180	1,636	0	65,440	65,440	65,440	65,440	65,440
9	Mt. Hopkins	52,800	11,435	0	457,000	422,400	422,400	422,400	422,400
10	Meadow Hills	15,840	3,168	0	126,720	126,720	126, 720	126, 720	126, 720
11	Canyon Del Oro/Vista Del Cielo	4,500	900	1,840	36,000	36,000	36,000	36,000	36,000
12	Rio Rico Resort	1,828	366	0	14,624	14,624	14,624	14,624	14,624
	Totals	161,388	32,753	25,741	$1,310, 104	$1,275, 104	$1,275, 104	$1,275, 104	$1,275, 104

However, a review of the UNSE response to STF DR 3.118 (and STF DR 2.1) shows the following are potential correlations of these projects to work accomplished, data for most projects was not located in STF DR 2.1:

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[59] Citizens Supplemental Plan, PDF pages 26, 42, 43, 45, 52 and 53.

Project 2 (Monte Carlo) "replace URD primary wire @ 455 Baffert Dr.," cost $10,180.84, completed 13 June 2004. Project 2 annual 5-year budget is $96,320 per year to replace 12,040 feet. This job appears a single dwelling. It may have been in the project plan.

Project 5 or 6, (Tubac County Club/Tubac Valley County Club), Over Head to Underground expense of $236,873.96, completed 16 October 2005. Projects 5 and 6 budget was $317,320 (145,320+172,000). Since 1999, the Golf Resort has significantly expanded with over 200 new homes and nine holes on the golf course. This was under construction in 2005; one 13.2kV feeder cable was placed underground in the new golf course area. This is not the same as the 1999 Citizens' Projects 5 or 6, since hundreds of older homes have had underground cable for over two decades and appear as the intended recipients of the replaced underground cable.

Project 7 (Palo Parado), "Remove and replace 1000 ft single phase URD primary wire@west boundary of Palo Pardo Sub" job cost was $16,924.15 and "Line Repl>$10,000 (Nog) Replace 1000 feet of URD single primary conductor, conduit and TXF @ Palo Prado Subdivision" job cost was $4,156.57, both completed on 31 July 2003. Project 7 is for a total of 15,530 feet of underground replacement cable with an annual budget of $108,240. Due to completion date by Citizens, no credit of $21,080.72 should be claimed as UNSE expenses.

Project 9 (Mt. Hopkins), a "Kantor Substation Mt. Hopkins underground replacement project" job cost $155,440.94, completed on 31 July 2003. Project 9 budget, from Table 3, is over $2.18 million. This was a Citizens expense, not UNSE, based on the completion date.

SUMMARY for Cable Replacements.

1. The data do NOT support completing ANY Cable Replacement Projects 1 through 12.
2. UNSE records claim Citizens expense as they were before the acquisition.

Recommendation. From the above ground pole and underground cable replacements, the following expenses were Citizens since they were completed prior to UNSE acquisition on 11 August 2003. These are NOT UNSE expenses and should be deleted from the rate basis for UNSE:

a. Utility Pole Replacements

Project 15	$117,768.43	
Project 16	$ 5,074.46	
	Subtotal	$122,842.89

b. Underground Cable Replacements

Project 7	$ 4,156.57	
Project 9	$155,440.94	
	Subtotal	$159,597.51

c. For both of these pole and cable replacement projects, UNSE rate base should be decreased by **$282,440.41**. These projects were completed by Citizens prior to acquisition.

d. Based on the above jobs, NO Projects from either Plan appear completed.

e. In my opinion, the ratepayers were "short-changed" by both Citizens and UNSE on essential projects to improve reliability in the Santa Cruz service area.

As UNSE has refused to respond to data requests associated with these two projects, I feel it necessary, that until UNSE can produce records that show that

(1) At least 3,060 above ground poles were replaced as planned since 1999 and

(2) At least $9,155,000 was spent on the pole replacement plan since 1999, and

(3) At least 161,388 feet of defective underground cable has been replaced and

(4) At least $6,406,520 was spend on replacing defective underground cables, then I **recommend** the following actions for failure to comply with ACC Orders:

- **DELETE $9,155,000 from UNSE Rate base** for failure to replace defective OH poles and
- **DELETE $6,406,520 from UNSE Rate base** for failure to replace defective UG cables,

Q. What are the Power Demands for Santa Cruz service area?

A. The following Table 7 shows the actual Peak Demand for each year since 1993 and "forecasts" from organizations that have managed the Santa Cruz service area. Each band of ten MWs is the same color, so one can see how accurate the "forecasts" to actual peak for that year. Data for the past two years, 2005 and 2006, based the testimony in these proceedings have not been consistent, as discussed in the "notes" record the data sources of the data. Two forecasts are in these proceedings, one for a 3% annual growth rate and another for a 6% annual growth rate. During the 1990 to 2000 decade, census data have the annual growth was 1.7%.[60] The latest Arizona Department of Economic Security (ADES) official population predictions show a growth rate of 2.74% in 2007, 2.47% in 2010, 1.17% in 2015, and 1.06% in 2020 and continually decreasing through 2055 at 0.71%.[61] Since 90% of the county lives in this service area, it appears the 5% forecast maybe to high and the 3% growth forecast is still higher than expected, if electrical growth equals to population growth. The referenced Magruder Testimony explains and accounts for limiting load factors, such as the 100-year Assured Water Supply (AWS) requirements for the Santa Cruz Active Management Area require continual water resource sustainment. The County Comprehensive Management Plan shows that maximum population limit is estimated at 71,000,[62] with ADES showing 46,545 in 2007.

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[60] Magruder Testimony in ACC Docket No. E-01032A-00-0401, pages 181 to 184 for additional Santa Cruz service area growth details.

[61] "Santa Cruz County Population Projections 2005-2055, ADES, Research Administration, Population Statistics Unit, approved by ADES Director on 31 March 2006, found on County and ADES websites.

[62] *2004 Santa Cruz County Comprehensive Plan*, revised 2005, page 65.

Table 7. Actual and Forecast Annual Peak Demand for the Santa Cruz Area. The actual observed values, in the second column, show the actual annual peak demand in MW, with forecasts that are "higher" than forecast in **red** and "lower" than forecast in **blue**. Each 10 MWhr is shaded in a different background color. Newer forecasts are to the left and older to the left. Above the line between 2006 and 2007 indicates "history" which future demand predictions are below.

REAL WORLD Data		FORECAST PEAK DEMAND for the Santa Cruz Service Area												
Year	ACTUAL Peak Demand	UNSE Rate Case (3% gr)	UNSE Rate Case (5% gr)	UNS Electric and SEC	Very Slow Scenario	TEP/ UNS Electric	UNS Electric	TEP Hot Forecast	TEP High Forecast	TEP Normal-ized	RAC 2 Hot	RAC 2 Normal	Citizens C/B Analysis	Citizens Briefing
		Mar 2007	Mar 2007	Dec 2006	Oct 2005	July 2005	June 2004	Feb/Apr 2004	Feb/Apr 2004	Feb 2004	2000	2000	1999	1998?
1993	40.0													
1994	43.7													
1995	41.6													
1996	41.9													
1997	42.5													
1998	45.3													
1999	50.36												46.7	50.5
2000	52.60											50.2A	48.0	52.6
2001	50.54										60.0	55.0	49.9	55.7
2002	57.99										62.0	58.0	51.6	56.9
2003	57.64							59.1		57.5	65.0	60.0	52.4	58.2
2004	60.768						61.4	61.4	64.4	59.7	67.0	62.0	54.5	59.5
2005*	69.408 or 69.6			69.5			63.6	63.2	63.6	66.8	61.9	69.0	64.0	60.7
2006*	71.7 or 73.152			71.1	72.7		65.3	64.9	65.8	69.0	64.0	72.0	66.0	
2007				74.0	74.1	63.6	66.7	66.5	67.9	71.3	66.1	74.0	68.0	
2008		76.1	76.1	76.5	76.5	65.3	68.1	68.0	70.1	73.5	68.2	76.0	70.5	
2009		78.4	79.9	79.1	77.0	66.7	69.4	69.5	72.2	75.8	70.3	78.0	73.0	
2010		80.7	83.9	81.7	78.5	68.1	70.8	71.0	74.5	78.2	72.5	80.0	74.0	
2011		83.2	88.1	84.3	79.9	69.4	72.2	72.5	76.8	80.6	74.7			
2012		85.7	92.5	86.9	81.5	70.8	73.6	74.0	79.2	83.1	77.0			
2013		88.2	97.1	90		72.2	74.9	75.4	81.6	85.7	79.4			
2014		90.9	102.0	92		73.6	76.1	76.7	84.1	88.3	81.8			
2015		93.6	107.1	95		74.9	77.3	78.8	86.7	91.0	84.3			
2016		96.4	112.4	98		76.1	78.5	79.3						
2017		99.3	118.1	101		77.3	79.7	80.6						
2018		102.3	124.0	103		78.5	80.9	81.9						
2019				105		79.7	82.0	83.3						
2020				107		80.9	83.3	84.6						

Historical Peak Demand Data

Historical Forecast Peak Demand Data

Table 7. Actual and Forecast Annual Peak Demand for the Santa Cruz Area. The actual observed values, in the second column, show the actual annual peak demand in MW, with forecasts that are "higher" than forecast in **red** and "lower" than forecast in **blue**. Each 10 MWhr is shaded in a different background color. Newer forecasts are to the left and older to the left. Above the line between 2006 and 2007 indicates "history" which future demand predictions are below.

REAL WORLD Data		FORECAST PEAK DEMAND for the Santa Cruz Service Area												
Year	ACTUAL Peak Demand	UNSE Rate Case (3% gr)	UNSE Rate Case (5% gr)	UNS Electric and SEC	Very Slow Scenario	TEP/ UNS Electric	UNS Electric	TEP Hot Forecast	TEP High Forecast	TEP Normal-ized	RAC 2 Hot	RAC 2 Normal	Citizens C/B Analysis	Citizens Briefing
		Mar 2007	Mar 2007	Dec 2006	Oct 2005	July 2005	June 2004	Feb/Apr 2004	Feb/Apr 2004	Feb 2004	2000	2000	1999	1998?
2021				109		82.0		86.3						
2022						83.3		88.0						
2023								89.8						
2024								91.6						
2025								93.4						
2026								95.3						
2027								97.2						
2028								99.1						
2029								101.1						
2030								103.1						
2031								105.2						
2032								107.3						
2033								109.4						
2034								111.6						
2035								113.9						
2036								116.1						
2037								118.5						
2038								120.8						
2039								123.2						
2040								125.7						

Historical Peak Demand Data

Forecast Peak Demand Data

Forecast Data Sources and notes (reading from left to right columns)

***Actual Peak Demand (1993 to 2006)** – In the UNSE Rate Case, ACC Docket E-04204A-06-0783, the peak loads for 2006 and 2005 were given as 71.7 MW and 69.6MW, in UNSE response to ACC Staff data request STF 1.1. In USNE response to MM DR 1.15 the peak load for 2006 was provided by UNSE to be 73.152 MW was provided as the 2006 peak load. In this UNSE response to MM DR 1.15, the peak load demands for 2003 through 2006 were provided which included a 2003 peak at 54.144 MW that occurred after 11 Aug 2003, under UNSE, while the actual 2003 peak occurred under Citizens at 57.64 MW earlier that summer. Additional peak data were in TEP's response to MM Data Request 221.c in ACC Docket E-01032A-99-0401.

UNSE Rate Case (3% gr, 5% gr((Mar 2007) – In UNSE's response to MM Data Request 1.15 (Excel spread sheet) in ACC Docket E-04204A-06-0783 for years 2008 through 2018 using a 3% and 5% growth rates.

UNS Electric and SEC (Dec. 2006) – For 2005 to 2012, from Testimony of Ed Beck in UNS Electric Rate case ACC Docket E-04204A-06-0783 and from 2013 to 2021 from the UniSource SEC Form 25 submitted in Dec 2006 and Exhibit MJD-1 to Michael DeConcini in the above UNS Electric Rate case. The SEC filing also included the earlier years, rounded off to an even MWhr as Weather Normalized Peak Demand Forecast.

UNSE "Very Slow" Scenario (Oct 2005) – From UNSE Annual Peak Load Forecast, emails in March 2006, from MM Data Request 1.9.g in ACC Docket E-04204A-06-0783.

TEP/UNS (July 2005) – From Beck Testimony of 8 July 2005, Exhibit 3 (Annual Peak Load Forecast for Santa Cruz County)

UNS Electric (June 2004) – From UES "Long-term Transmission Plans for Santa Cruz County UNS Electric System," June 2004. For years 2021 and later, the forecast is extrapolated based on a 2% growth factor.

TEP Hot, High, and Normalized Forecast (Feb/April 2004) – From Exhibit 4 (February 2004) where TEP forecast is for the average year (also in the RMR report for 2005, 2008, 2012) and the "high" for years that are hotter than normal.[63] This also has been published as "Nogales Retail Peak Forecast – April 2004:" with the years 2004 to 2020 designated as the "UniSource Forecast (MW)" and the years 2021 to 2040 as "Extrapolated Forecast (2% growth factor (MW)

UniSource Energy Services – Loads & Resources Peak (weather normalized) Demand Forecast (used by UniSource for the competition for a new Purchase Power Agreement for Santa Cruz County (February 2004)

RAC2 Hot, Normal (2000), Testimony of Rasel Craven, Citizens Director of Engineer, May 1, 2001, Docket No. L-00000C/F-01-0111, Line Siting Case No. 111, as Exhibit RAC-2, which indicated on June 30, 2000, a record of 50.2 MW was reached (marked by A) above. Values for 2001 to 2003 are from testimony, from 2004 to 2010 from Exhibit 4 (February 2004) as footnoted above. The "normal" and "hot" were for years which were average or higher than average. The R.W. BECK & Co. determined the RAC-2 forecasts in early 2000.

Citizens' Cost-Benefit Analyses (1999) of Transmission-Line Alternatives, ACC Docket E-01032A-98-0611 in Exhibit F of July 13, 1999 at Nogales Tap for "normal weather."

Citizens Briefing (1988) given to the Joint Santa Cruz County/City of Nogales Energy Commission in February 2001; however, content appeared to be dated about 1988.

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[63] See Exhibit 4 from the TEP and UES "Response to Commission Questions and Updated Response Plan for Santa Cruz County" of 9 February 2004, in ACC Docket No. E-01032A-99-0401.

During the 1990 to 2000 decade, census data have the annual growth was 1.7%.[64] The latest Arizona Department of Economic Security (ADES) official population predictions show a growth rate of 2.74% in 2007, 2.47% in 2010, 1.17% in 2015, and 1.06% in 2020 and continually decreasing through 2055 at 0.71%.[65] Since 90% of the county lives in this service area, it appears the 5% forecast maybe to high and the 3% growth forecast is still higher than expected, if electrical growth equals to population growth. The referenced Magruder Testimony explains and accounts for limiting load factors, including the 100-year Assured Water Supply (AWS) requirements for the Santa Cruz Active Management Area require continual water resource sustainment. The County Comprehensive Management Plan shows that maximum population limit is estimated at 71,000,[66] with ADES showing 46,545 in 2007.

Based on this data and an analysis local situational factors it was determined that "between 2040 and 2050, the maximum peak electrical load is estimated to be between 115.8 MW and 137.3 MW" for this service area.[67]

Q. What are the local generation capabilities to meet these loads?

A. There are many conflicts within the UNSE Testimony as to the local generation capabilities at the Valencia Substation in Nogales, Arizona, the only generation capability in this service area.[68] There are three combustion generators at the Valencia substation. Each is rated for site peak "nameplate rating" of 17.65 MW with a maximum site peak rating of 19.15 MW. I will use a nominal 16 MW is used throughout this Testimony.[69] Further, during the last rate case test year in 1998, power generated by each turbine was tested greater than 16 MW.

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[64] Magruder Testimony in ACC Docket No. E-01032A-99-0401, pages 181 to 184 for additional Santa Cruz service area growth details.

[65] "Santa Cruz County Population Projections 2005-2055, ADES, Research Administration, Population Statistics Unit, approved by ADES Director on 31 March 2006, found on County and ADES websites.

[66] *2004 Santa Cruz County Comprehensive Plan*, revised 2005, page 65.

[67] Magruder Testimony in ACC Docket No. E-01032A-99-0401, pages 181 to 185. Using a possible long-term improvement in efficiency (Demand-Side Management), distributed generation resources based on the ACC's Renewable Energy Standard and Tariff (REST), and other EC and EE results, a reasonable upper limits of the peak electricity demand for the UNSE service area" could be between "99 and 109 MW." at 184.

[68] Direct Testimony by Edmond A. Beck on Behalf of UNS Electric, Inc., of 15 December 2006, hereafter "Beck Direct Testimony", at 6, three turbines have a "combined output of approximately 47 [48] MW" at 6; "an emergency UNS Electric 46 kV line that ties TEP's system and can provide approximately 10 [22] MW of electricity" at 9; "the combination of the four generators in Nogales and the 46 kV line may not be sufficient to restore the customer's entire load" at 9. See DeConcini Direct Testimony, "UNS Electric also owns 65 MW of generation capacity within Santa Cruz County load area that is used for reliability must run circumstances" at 1; "approximately 65 MW of generation ... generation consists of three 15 MW simple cycle combustion turbines and a new 20 MW simple cycle combustion turbine" at 3; Schedule D, FERC Form 1, 2005/2Q, "Total Installed Cap (Max Gen Name Plate Ratings-MW) 54.00" and "Net Peak Demand on Plant – MW (60 minutes) 59" at page 402.

[69] This information was in TEP's response in ACC Docket No. E-01032A-99-0401 to Magruder data request MM-329.a, "Design Data," for turbine no. 214354. Since all are the same model, and for consistency with other information, the nominal value of 18 MW per turbine have been used in this Testimony.

A new General Electric LM-2500 turbine was operational on 31 May 2006. It has a nominal 20 MW capability; even through its normal rating is 22.1 MW.[70]

The nameplate total normal peak for three turbines is 52.95 MW (3 x 17.65) while the maximum peak is 57.45 MW (3 x 19.15 MW). Thus, a nominal value for these three turbines of 48 MW (16 x 3) is rather conservative. Experience has shown that turbines operating at a maximum power at 108% (19.15/17.65) in this case, are a common practice.[71]

Summary of local generation capabilities are as follows:

Nominal Load	**68.0 MW** (48+20)[72]
Nameplate Load:	**75.12 MW** (52.95+22.1)
Maximum Peak Load:	**84.99 MW** [57.45+(1.1x22.1)]

These turbines are excellent "peaker" turbines, for a short duration peak load that might occur during the summer. One turbine will be necessary to meet such a peak load. As indicated in Mr. Beck's Direct Testimony, the Western Area Power Administration (WAPA) line between the APS Saguaro Power Station, has constrained Full Transmission point-to-point service to 65.8 MW from 1 January 2007 through 28 February 2008.[73] The WAPA transmission charge is $0.0078/kW-month.[74]

Q. If you are limited by WAPA to only 65.8 MW, what alternatives exist to meet peak loads?

A. There are several alternatives.

One is work with WAPA to obtain higher capacity. As presented by TEP's Mr. Ed Beck at the ACC 2007 Summer Preparedness, UNSE is working with WAPA for a solution. In Mohave service area, by changing from point-to-point service to network service, the

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70 General Electric "LM2500 Aeroderivative Gas Turbines, which also states "Full Power in ten minutes" which improves reaction time during an outage or if needed to meet a peak load greater than is being received on the 115 kV transmission line is found at the below web site http://gepower.com/prod_serv/products/aero_turbines/lm2500... (reviewed 11 June 2007) My experience is that LM2500's, from a cold start, are fully operational in much less than ten minutes. One can actually "turn the key" on the bridge of a warship and be underway five or so minutes. It takes that long to bring in the lines if alongside a pier and up to 30 knots in less than ten minutes at 107% of rated power. The US Navy has been using LM2500s since the early 1970s.

71 The US Navy uses the General Electric LM2500 turbines on all cruisers, destroyers and frigates, where operations as high as 110% of rated power are frequently for short periods of time, if extra power is needed. These turbines are in many electric power plants. Jet aircraft turbines frequently "go buster" when exceeding normal power. This Testimony has not used this capability that inherently exists with these turbines.

72 The UNSE response to ACC Staff data request STF 1.1 is incorrect, each older turbine is rated at 16 MW and not 14 MW or greater and the LM2500 is not a 19 MW turbine. The numbers above are correct. This kind of error, using 61 MW vice 68 MW is important as the local load also is increasing a few MW per year, every MW is important, and such "round-offs" are despicable. In addition, UNSE response to Magruder data request MM DR 1.9a stated "UNS Electric's only generation facility is the 70 MW (nameplate) four-unit Valencia..."

73 DOE WAPA, Desert Southwest Regional Office Contract No. 87-BCA-10140, Amendment 3, Exhibit A, Revision 19, page 3.

74 *Ibid.*, Exhibit B.PPK, page 1, para 3.

resultant additional capacity made the constraint problem go away.[75] Mr. Beck is negotiating with WAPA now to make this same change for the Santa Cruz service area. Also, changing from point-to-point service has a lower transmission charge, which will be an important benefit, as this charge is directly passed through to the ratepayers,

A second is to use one of the "peaker" turbines in Nogales to generate the additional power above 65.8 MW required by the local load. Mr. Beck's Direct Testimony provided the percent of time and MW demand for these peaker needs. Table 8 below expands this alternative.

Table 8. Peaker Turbine Operations in Nogales. *Using UNSE Additional Generation and MWhs per Year, a Very Conservative Cost can be estimated. Actual cost should be less than One-Third that shown.*

Year	Load Exceeds 65 MW[76]	Hours per year	Additional Generation Required[77]	MWh per Year (note 1)	Annual Cost @ $150/MWh (note 2)
2006	1.7%	148.9	4.7 MW	700	$104,975
2007	2.2%	192.7	7.0 MW	1,349	$202,335
2008	2.9%	254.0	9.5 MW	2,413	$361,950
2009	3.4%	297.8	12.1 MW	3,603	$540,507
2010	4.1%	359.2	14.7 MW	5,280	$792,036
2011	5.5%	481.8	17.3 MW	8,335	$1,250,271
2012	6.3%	551.9	19.9 MW	19,983	$1,647,422
7-year Totals		2286.3	2286.3 MW	41,663	$4,899,490

Note 1. This assumed that the Additional Generation was required for all the hours per year, which is not reasonable; however, the result will be higher than reality.
Note 2. On the average, a LM2500 turbine generates electricity for less than $150/MWh. In 2000, actual results for the older combustion turbines was about $158/MWh.

Table 8 is too conservative, as the Additional Generation is the "peak" generation necessary when only 65.8 MW is all that is available on the WAPA lines. Still conservative, the total MWh is the area under a daily "load – time" curve. In general, this is about two-thirds the peak, thus the annual costs are reduced by at least 1/3rd so for 7 years, then $1,633,163 (4,899,490/3) is the cost for peaker operation.[78] The TEP proposed single-circuit 138-kV second transmission line cost is over $100 million, thus peaker costs are important but such cost are not the critical project driver. The real mission driver is a second transmission line for redundancy, to provide a backup line, necessary to improve transmission reliability (discussed later). This example shows that additional power is needed to the Santa Cruz service area, preferably from external lower-priced generated power.

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75 Beck Direct Testimony at 16.
76 *Ibid.*, at 10.
77 *Ibid.*, at 11.
78 *Ibid.*, at 10, where Mr. Beck said "The load forecasts show that Santa Cruz County has a very short duration peak."

Q. How much power can the existing 115 kV transmission line carry?

A. We need to first determine the physical characteristics of this line. Table 9, shows these characteristics for each segment. Based on Table 7 above, this line has adequate capacity through at least the year 2040. There are two possible bottlenecks; one would be when over backup WAPA line rated at 120 MW between Del Bac substation and the Nogales Tap. The other is the last 4.8 mile segment north of the Valencia substation in Nogales. Based on the four substations in this service area, less than 50% of the total loads will be required for Valencia, thus this 68 MW segment is adequate until the total demand exceeds 136 MW or higher.

Table 9. *Existing 115 kV Transmission Lines Capacity Ratings in the Santa Cruz Grid.* "Thermal" ratings determine the maximum physical capacity or load carrying capabilities for transmission lines.[79]

Line Status	Line Section (Location)	Length in miles	Conduct or Type	Structure Type	Thermal Ampacity Rating (amperes)	Thermal Rating at 115 kV (MVA)
WAPA-owned Lines (before Citizens 115 kV)	Del Bac (WAPA) to Nogales Tap (Tucson)	---	---	---	603*	**120 MW**
	Adams (WAPA) to Nogales Tap (Tucson)	---	---	---	803**	**160 MW**
Existing 115 kV transmission line	Nogales Tap (Tucson) to Amado (Kantor substation)	27.7	559.5 AAAC	Steel Monopole	663**	**132 MW**
	Amado (Kantor) to North Rio Rico (Canez substation)	13.5	559.5 AAAC	H-Frame	663**	**132 MW**
	North Rio Rico (Canez) to South Rio Rico (Sonoita substation)	3.3	559.5 AAAC	H-Frame	663**	**132 MW**
	South Rio Rico (Sonoita) to the Conductor Change	3.6	559.5 AAAC	H-Frame	663**	**132 MW**
	1Conductor Change to Nogales (Valencia substation)	4.8	4/0 ACSR	H-Frame	340***	**68 MW**
Proposed 115 kV line from Gateway	115 kV Gateway Substation to Nogales (Valencia substation)	3.5	559.5 AAAC	Steel Monopole	663**	**132 MW**

* Thermal ampacity ratings for Del Bac and Adams substations to Nogales Tap at the Nogales Switchyard in Tucson were obtained from the WSCC database.

** The thermal ampacity rating for the 559.5 AAAC conductor reference is the *Southwire Handbook*, (*Citizens Santa Cruz 2002 Plan of Action).*

*** The thermal ampacity rating for the 4/0 ACSR conductor is from the Westinghouse Transmission and Distribution Reference Book.

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[79] *Citizens Communications Company Arizona Electric Division – Santa Cruz District Transmission System Action Plan*, June 2002, filed at ACC Docket Control July 1, 2002, hereafter "Plan of Action." This plan was developed by Power Engineers, Inc., a respected power analysis company for Citizens. Power Engineers and Dames & Moore prepared the "Santa Cruz Electric Division Transmission Alternatives and Plan of Action" in April 1999 (with two supplemental filings in the TEP/UNS Updated Outage Response Plan, February 9, 2004) the "plan of action" in the title of ACC Docket No. E-01032A-00-0401. The Citizens' environmentalist used the *Plan of Action* in 1999 for Line Siting Case 111 for the Citizens' 115 kV transmission line part of the TEP proposed 345 kV transmission line hearings. Thus, outside technical and environmental assistance consultant's experiences were consistent to augment Citizens staff from 1999 through 2002. pages 8 and 9. This Study uses MVA (apparent power) and MW (active power) interchangeably when discussing this table, thus the right column shows MW for each line segment.

Other factors, such as the present WAPA 65.8 MW constraint for power sources to the UNSE transmission system, substation upgrades involving higher-power rated reactive capacitors, voltage regulators, and other equipment. Power Engineering ran a series of power loading cases using the existing 115 kV line, and was able to have a safe load carry capability up to 95 MW while meeting NERC/WECC reliability criteria.[80]

Q. If the existing 115 kV transmission line is adequate, why is a second transmission line needed?

A. The short answer is simple, REDUNDANCY. When a second, independent line (or for the matter anything) can provide a parallel path, then a failure of a component does not have to result in an outage because a second, redundant line is present. Using Reliability Engineering, I showed how this works based on over ten years of data, from 1994 through 2004 in the Santa Cruz service area, using actual failure and outage data.[81]

The basis results of this analysis are summarized as follows:

a. Total Outage per Customer per year. The total number of minutes of outage per customer per year, over this 10-year time frame, was 201.4 minutes of outage.

b. Total Storm Outages per Customer per year. Nearly 106 minutes of outage per customer were during storms that occur significantly less than 5% of the time.

c. Total Other Outages per Customer per year. All Other outages were 88 minutes per customer.[82]

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[80] *Ibid.,* Due to the distance from the generation sources for the Santa Cruz load, line voltage changes when demand suddenly changes, usually dropping. The WECC planning level criteria has established that a ± 5% voltage must be maintained with respect to the specified voltage, thus the 115 kV can vary from 109.25 to 120.75 kV and still be considered to be within normal limits. These cases, looked at this voltage, and when outside of these limits, shown in red, are such cases (see this summarized in Docket No. E-01032A-00-0401, Magruder Testimony of 8 July 2005, pages 38 and 39). The primary way to reduce these voltage drops is to install capacitors that can "hold" the voltage until the supply source adjusts for this change. The amount of these capacitors is expressed in millions of volt-ampere-reactance (MVAR). These "cases" were to assess various MVAR options so the utility would purchase and install what is necessary to be compliant with WECC planning criteria. It is noted that under none of these cases was the 115 kV transmission line stressed, only at 70% of its normal thermal capacity was observed at a 95 MW Santa Cruz load. A second, recurrent problem observed was that the Valencia 115:13.2 kV transformers were overloaded. This is because they need more circuits or higher capacity transformers. The primary requirement for the 13.2 kV capabilities for the Gateway substation are to off-load the Valencia transformers which will then increase the capacity for the 115 kV transmission line. The Gateway substation, with additional 115:13.2 kV transformers and circuits are an essential capability which is necessary to off-load Valencia.

[81] ACC Docket No. E-01032A-99-0401, Magruder Testimony of 8 July 2005, Appendix B, "Electric Reliability Data in the Santa Cruz Service Area, 1994-2004," pages 109 to 116, and Appendix C, "Reliability Engineering Analysis, pages 117 to 130.

[82] The sum of Storm plus Other is 204 minutes, while the Total is 201. This table were taken directly from the Citizens monthly reports to the ACC; however, this difference of less than 1.5% is perceived to be cumulative round-off error. The individual column sums will be used and the "total" only when discussing in the "aggregate" for the whole system. Magruder Testimony, Table C-3, page 111 for analysis.

d. Total Supplier Outages per Customer per year. "Supplier" outages were all before a switch was installed in 2000 at the Nogales Tap. No outages have occurred since. The 17.8 minutes attributed to Supplier outages should be almost zero in the future.

e. Total Transmission Outages per Customer per year. The total "transmission" outages were 62.8 minutes, of which nearly 42 minutes were during storms, or 66.6%.

f. Total Distribution Outages per Customer per year. Total "distribution" outages were 107.1 minutes, considered excessive. Nearly 63 minutes or 59.6% were during storms.

The analysis used Citizens data provided monthly to the ACC and before implementation of the IEEE Standard 1366, which has been used since 2004 by UNSE in this service area. During this decade, there were 4 supplier outages, 20 transmission outages, 4,297 distribution outages and 41 scheduled (by Citizens) outages.

Using Reliability Engineering methodologies, table 10 was derived, which looked at each subsystem (supply or generation, transmission, distribution)'s outages and those scheduled, to determine the percent of the time that subsystem was operational and available. When one multiplies the number of hours in a year times (1.0 minus Availability %), then you can determine the percent a subsystem in not operational or available.

Table 10. ***Santa Cruz System and Subsystem Availability by Outage Type.***[83]

Kind of Outage	Availability (storm)	Availability (other)	Total Availability
Supply	99.99973181%	99.99688451%	99.99653412%
Transmission	99.99204024%	99.99469123%	99.98673424%
Distribution	99.98672316%	99.99194378%	99.98333611%
Scheduled	Not Applicable	99.99983762%	99.99983762%
		Total Availability	99.96644492%

When one considers "redundancy" but installing a second, independent and identical component, then we can determine the impact on operations, and for Transmission, this is very logical and is easy to understand. The following is from the Magruder Testimony.

"**D.3 Impact of the Second Transmission Line between the Nogales Tap and Nogales**. When a second, redundant transmission line is installed, the overall transmission reliability will be significantly improved. Using mathematic rules for the addition for probabilities, were the "sum of the individual probabilities minus their product" yields the combined probabilities for two independent events we determine the Availability or probability of success (not having a failure) for Transmission-Total, from Table D-2 [now Table 10], is 99.986734241%.

"Assume the Availability of a second transmission line is both independent and equivalent to that from existing 115 kV line between 1994 and 2003, or 99.986734241%. We can determine the resulting probability of success (Availability) for having one of these two transmission lines always

[83] This is Table D-3, Santa Cruz System Availability (A) by Outage Type in ACC Docket No. E-01032A-99-0401, page 118.

available by adding this number and then subtracting their product, given by (all "A" values given as decimals) then,

A (transmission-1 of 2 lines) = A (Transmission-Total) + A (Transmission -Total) – [A x A]
A (transmission-1 of 2 lines) = (0.99986734241+ 0.99986734241) – (0.99986734241x 0.99986734241)
A (transmission-1 of 2 lines) = 1.999973456482 – 0.999973468658
A (transmission-1 of 2 lines) = 0.99999998782 or 99.999998782%

"Thus, 99.999998782% of the time, one of these two switches [or lines] will always be available, or conversely, 1.0 – this number is the amount of time neither of these two switches [or lines] will be available, or 0.000001218% of the time. Using 33,557,600 seconds per 365.25 days per year (x 24x60x60), we see that 0.409 seconds per year, both transmission lines (the existing and the second, redundant, independent) will NOT be available. Since there was a total MTBF[84] for transmission line outages of 4,381 hours (from Table D-1), then an outage due to one of these two transmission lines NOT being available, based on these assumptions is shown below.

"One transmission outage every 4,381 hours (MTBF), but there are only 0.409 seconds per year that neither of these two transmission lines are available, so for one of these failures to occur during this interval, we see the

"Computed MTBF with a redundant transmission line =
MTBF (two lines fail) = (4,381 hours/failure 60 min x 60 sec) / (0.409 sec/year)
MTBF (two lines fail) = 38,561,369 years per failure
Thus, once every 38 million years, a failure will occur by both of these transmission lines at the same time. Note, this calculation assumed the following:

a. That the second transmission line was redundant and independent of the first line.
b. That the second transmission line had the same outages (MTBF) as the existing 115 kV line had during the 1994 to 2003 time frame.

"It is important to note that the MTBF for both the existing and the second transmission line failure is NOT dependent upon voltage, size or location, just that a second, redundant, and independent transmission line is installed. Further, these data are conservative as some of the prior root causes of failure have been mitigated, thus the existing 115 kV transmission line would, today, have a higher MTBF and lower MTTR than it had during the 1994 to 2003 period."[85]

Q. What else has improved the reliability in Santa Crux Service Area?

A. The Citizens Plan included and accomplished the following prior to the sale to UNS Electric:

a. Generator synchronization equipment to automatically close and re-establish the WAPA tie.
b. At the Nogales Tap, the system synchronization equipment was installed.
c. A new three-ring bus breaker was installed to reduce interruptions.
d. At the Valencia substation, the 115 kV breakers and controls, voltage regulation equipment, protective relay and control work was completed.
e. At the Sonoita substation, voltage regulation, controls and building were completed, 115 kV sectionalization equipment was installed.
f. At the Kantor substation sectionalization equipment installed.

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[84] This is Mean Time Between Failure (or outage) or MTBF = Hours Operational / number of failures.
[85] See Magruder Testimony in ACC Docket No. E-01032A-99-0401, pages 120 to 121.

g. General Electric inspected, tested and calibrated the generation protection and control systems, voltage regulator was replaced, DC power system used to black start the turbines was upgraded with redundant batteries and low voltage warning alarms, and some protective relay improvements made.

h. The SCADA system was improved with an operator station at the Valencia generation station (now moved to Tucson), and remote outage monitoring system completed (but then replaced by TEP's system).

ALL these improved reliability in this service area.

Q. What reliability issues remain in this Service Area?

A. Based on the analysis in the Magruder Testimony of July 2005, distribution outages were the most significant type of outage with higher outage rates during storms.

Table 11. ***Average Hours of Outages per Customer.*** *Storms caused most outages and Distribution subsystem outages were caused the customer's longest outage times.*[86]

Year	Major Storms			All Other Outages				
	Supplier	Trans	Dist	Supplier	Trans	Dist	Sched	Total
1994	0.000	0.000	0.622	0.116	0.000	0.976	0.000	1.714
1995	0.000	0.000	0.098	0.000	0.000	0.968	0.000	1.066
1996	0.235	0.000	0.684	0.000	0.035	0.067	0.000	1.336
1997	0.000	0.000	2.393	0.000	0.000	1.117	0.000	3.509
1998	0.000	2.838	2.199	2.614	4.617	0.583	0.000	12.850
1999	0.000	0.166	0.808	0.000	0.000	0.715	0.048	1.737
2000	0.000	1.404	1.259	0.000	0.000	0.572	0.004	3.238
2001	0.000	0.828	1.426	0.000	0.000	0.416	0.052	2.722
2002	0.000	0.000	0.288	0.000	0.000	1.136	0.032	1.456
2003	0.000	1.737	0.654	0.000	0.000	0.531	0.006	2.928
2004	0.000	0.000	NA	0.000	0.000	NA	NA	NA
Totals	**0.235**	**6.973**	**10.431**	**2.730**	**4.652**	**7.081**	**0.142**	**32.556**
Average per year in hours	**0.024**	**0.697**	**1.043**	**0.273**	**0.465**	**0.709**	**0.014**	**3.356**
Average per year in minutes	**1.4**	**41.8**	**62.6**	**16.4**	**28.0**	**42.5**	**0.9**	**201.4**

When UNSE purchased Citizens, the monthly reporting format to the ACC Staff changed, thus continuing to use the above "total system" reliability approach lacked the necessary distribution data. It should be noted that all the "unreliable" years are included in Table 11. The system reliability improvements become obvious when the outage trends decrease starting in 2000 when the Action Plan was showing progress. At 201.4 minutes per year, the average customer outage duration compares favorably with the Rural Utilities Service

[86] This is Table C-3, Average Hours of Outages per Customer, in Magruder Testimony in ACC Docket No. E-01032A-99-0401, page 111.

Bulletin 161-5 standard for total customer outages in rural areas not to exceed 300 minutes per year.[87]

The Commission started using several indices in IEEE Std 1366™-2003[88] in 2004 and UNSE started maintaining data required to compute these distribution reliability indices. Table 12 shows the definitions of common IEEE Std 1366 indices.

Table 12. Definitions of Key Distribution Reliability Indices. *These are used to report distribution reliability data to the ACC Staff by utilities in Arizona.*

Index	Definition
Average Service Availability Index (ASAI)	This index represents the fraction of time (often in percentage) that a customer has received power during the defined reporting period. Mathematically, this is given by the following equation: $$\textbf{ASAI} = \frac{\Sigma\ \textbf{Customer Hours Service Availability}}{\textbf{Customers Hours Service Demands}}$$
Customer Average Interruption Frequency Index (CAIFI)	This index gives the average frequency of sustained interruptions for those customers experiencing sustained interruptions. The customer is counted once regardless of the number of times interrupted for this calculation. Mathematically, this is given by the following equation: $$\textbf{CAIFI} = \frac{\Sigma\ \textbf{Total Customers Interrupted}}{\textbf{Total Number of Customers Interrupted}}$$
Momentary Average Interruption Frequency Index (MAIFI)	This index indicates the average frequency of momentary interruptions. Mathematically, this is given by the following equation: $$\textbf{MAIFI} = \frac{\Sigma\ \textbf{Total Number of Customer Momentary Interruptions}}{\textbf{Total Number of Customers Served}}$$
System Average Interruption Duration Index (SAIDI)	This index indicates the total duration for the average customer during a predefined period of time. It is commonly measured in customer minutes or customer hours of interruption. Mathematically, this is given by the following equation: $$\textbf{SAIDI} = \frac{\Sigma\ \textbf{Customers Interrupted Durations}}{\textbf{Total Number of Customers Served}}$$
System Average Interruption Frequency Index (SAIFI)	This index indicates how often the average customer experiences a Sustained Interruption over a predefined period of time. Mathematically, this is given by the following equation: $$\textbf{SAIFI} = \frac{\Sigma\ \textbf{Total Number of Customers Interrupted}}{\textbf{Total Number of Customers Served}}$$

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[87] Direct Testimony of Steve Taylor Electric Utility Engineer, Utilities Division, Arizona Corporation Commission of 28 June 2007, hereafter "Taylor Direct Testimony", Exhibit ST-1, "Staff's Assessment of Quality of Service, Used and Useful, Construction Work in Progress Capital Assets, Black Mountain Generation Station" of 28 June 2007, hereafter "Taylor Staff Report", at 2.

[88] *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366™-2003, hereafter "IEEE Std 1366" of 14 May 2004.

Earlier in this testimony I used the term "Availability" which is the same as Average Service Availability Index (ASAI) shown in Table 10, for the distribution subsystem is 99.9867% during storms, 99.9919% during other times with a total Availability or ASAI of 99.9833% when the two are combined using probability addition mathematics. In Table 11, the average of 201.4 minutes of outage per customer per year is the same as System Average Interruption Duration Index (SAIDI). As shown in Table 10, SAIDI, or the bottom line, is computed for each component of the Santa Cruz system during storms and during other conditions. This is the ten year average with individual (in hours) SAIDI.

Most of the data are available to compute Customer Average Interruption Frequency Index (CAIFI); however, pre-2004 data are inadequate for Momentary Average Interruption Frequency Index (MAIFI) and System Average Interruption Frequency Index (SAIFI).

In the UNSE Response to Data Request STF 1.1 of 12 March 2007, UNS Electric distribution SAIDI was reported as 68.4 minutes in 2004, 89.3 minutes in 2005, and 153.1 minutes in 2006. Table 10 shows a ten-year average of 62.6 minutes in storms and 42.5 minutes during other times for a total SAIDI of 105.1 minutes of distribution outage per customer per year. The years of 2004 and 2005 were better while 2006 was considerably worse. Only two years (1997 and 1998)[89] were total distribution outage durations longer than 2006 and conversely eight of the ten years were better than 2006. In 2005 there was a Category C outage at the Kantor substation on 27 May 2005. A detailed analysis of this major day incident is in my testimony in ACC Docket No. E-01032A-99-0401.[90]

5.2 Improvements Initiated by UNSE in the Santa Cruz Service Area.

See Mr. Beck's Direct Testimony.

5.3 Conclusions.

Some reliability improvements have been made in the Santa Cruz service area but the failure to install a second transmission line is a disgraceful act in view of the direction from the Commission, especially from TEP's senior executives, by relying on a proposed 345 kV line that will not ever be constructed. The reasons are beyond the scope of these hearings and several alternatives have been proposed but TEP has not listened nor wanted to listen to logical, beneficial, and less costly options. TEP seems determined to want the most expensive

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[89] The duration of distribution outages in 1997 was 210.6 minutes [(2.393 + 1.117) x 60] and 1998 was 166.9 minutes [(2.199+0.583)x60]

[90] Magruder Testimony of 8 July 2005, ACC Docket No. E-01032A-00-0401, D.4.2 Results During an Actual Outage in May 2005, pages 123 and 124. The root cause of this accident was the failure to remove reverse power relays for the Valencia turbines which was reported to Citizens by General Electric on 21 April 1999 (in footnote 89), which extended the outage several hours, and prevented restoration of power within the advertised 10 to 15 minute window by using the new 48 kV line and remote TEP generator controls.

options so their "rate base" is higher, thus more revenue for the Company. TEP has utterly failed to honor the Project Development Agreement in the CEC Application.

5.4 Recommendations.

There are several important recommendations to be considered.

1. Decrease the rate base by $15,561,520 for failure to comply with an ACC Order No. 62011 (see above) and ensure compliance with all actions in the ACC Staff-Citizens Settlement Agreement and
2. Complete and continue to take ALL actions required by the City of Nogales-Citizens Settlement Agreement.
3. Ensure that the UNSE rate base does not include expenses incurred prior to the acquisition, such as the $122,842.89 for utility pole replacements and $159,597.51 for underground cable replacements presented above.
4. Obtain more access on the WAPA lines, with considerably lower wheeling costs, than using TEP facilities.
5. Be consistent with objective data for load capacities when presenting operational data.
6. Compute reliability indices at the substation level, as required by NERC/WECC reliability criteria.
7. Delete considerations of a 345 kV line and get started with a second parallel transmission line for each substation, either 115/138 double-circuit or a backup 46/59 kW double-circuit.
8. AND to cease "fear mongering" by saying the "lights are going out" in Nogales in 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011, 2012, and later until firm clear alternatives have been objectively considered.

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Part VI – ISSUE 4

CARES and CARES-M Tariffs

6.1 Concerns about CARES and CARES-M Programs.

These are two important programs for lower income ratepayers, Customer Assistance Residential Energy Support (C.A.R.E.S., hereafter CARES) and Medical CARES or CARES-M.

The CARES-M program restricted to those who have live-saving electrical equipment needs. Unfortunately, the Company does not know the types of such equipment its customers have, if such equipment has back-up batteries, or how long such equipment might continue operations during a power outage. Also, "The Company does not typically contact outside agencies during a power outage regarding CARES customers" was the response to a data request which requested "how does UNSE coordinate with local authorities, such as local fire and/or police departments during an electrical outage."[91]

In Santa Cruz County the local fire departments, sheriff and police have lists of known residences that have electrical life-support equipment. During emergencies, these agencies attempt to contact these residences. There are reasonable and critical safety issues involved here that need immediate action by USNE to establish and maintain coordination, procedures and policies required for the safety of its customers. For example, in response to "please provide a copy of any 'check sheets' and company policies that are located at the 'Call Center' that are used for CARES-M customers" was "please clarify what is meant by 'check sheets'."[92]

All of this begs another critical issue.

- What are UNSE's concerns for those with electrical life-support equipment that are NOT CARES-M customers?
- Does UNSE have any moral, ethical, and safety responses for these people? [this data request has not been responded by UNSE]

6.2 CARES Participation.

Table 13 shows 1,859 CARES participants in Santa Cruz and 4,130 CARES participants in the Mohave service areas. CARES eligibility is 150% of the Federal Poverty Level (FPL). As shown, Poverty (<100% FPL) varies between 13.9% to 24.5% and Working Poor (100 to 200% FPL) between 24.5% and 29.8% in each county. The 150% FPL population is not known,

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91 UNSE response to Magruder data request MM DRs 1.4c, 1.4d, 1.4e, and 1.4i.

92 UNSE response to Magruder data request MM DR 1.4j. If USNE does not know what a "check sheet" kind of response procedure involved, then its "Call Center" management personnel need basic training in effective contingency response processes. From other data, check sheets are required to be used by UNSE linemen for many contingencies.

however, splitting the difference between Working Poor and Poor is a very conservative number for the number of CARES-eligible customer who are NOT in the CARES rate program. The estimated number of CARES-eligible ratepayers NOT in this program are about 3,400 in Santa Cruz and about 9,900 in Mohave service areas. In the Santa Cruz area, about 65% of those eligible for CARES are NOT in the program with similar impacts in Mohave.

Table 13. Number of CARES Customers in Each County. *The number of Customers Eligible for CARES and the number on Potential CARES Participants.*

County / Poverty Status / Factors	Santa Cruz County		Mohave County	
	Poor (< 100% Federal Poverty Level)	**Working Poor** (100 to 200% federal poverty level)	**Poor** (< 100% Federal Poverty Level)	**Working Poor** (100 to 200% federal poverty level)
Total UNSE Customers in County	19,650		72,200	
Poverty Percent of the County	24.5%	29.8%	13.9%	24.9%
Number of Poor and Working Poor	4,814	5,699	10,035	17,977
Number of CARES participants[93]	1,859		4,130	
Percent of CARES eligible and participating in CARES	38.6%	32.7%	41.1%	22.9%
Number who are NOT participating in CARES	2,955	3,840	5,905	13,847
Half difference between 100% and 200% poverty level nonparticipants	**~3,397** CARES eligible and not in CARES program		**~9,876** CARES eligible and not in CARES program	
2007 CARES Qualifying Income at 150% Federal Poverty Level	Qualified for CARES is $2,581[94] a month or $30,975 a year (family of 4)			

6.3 CARES-M Participation.

As of March 2007, there are a total of 178 participants in the CARES-M program.[95] Between August 2003 and the end of 2006, the number of CARES-M participants in Mohave increased from 58 to 170 (193%) and in Santa Cruz from 1 to 10 (900%).[96] There has been a steady increase in CARES-M participants. Since there are unique CARES-M benefits with lower rates and avoidance of cut-off, it is important that this program be properly managed. As with the CARES program, all additional costs for these two programs are borne by the other ratepayers.

Q. What might cause this rapid rise in CARES-M participation?

A. The requirements to participate are that one has meet the income level, require life-support equipment, and, if requested, "submit a signed statement from the attending physician that the customer is medically-life support dependent and the type of essential medical equipment used

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93 UNSE response to ACC Staff data request STF 3.2 Erdwurm UNS_ECustomerAdjustments.xls. spread sheet for June 2006, end of test year.

94 UNSE response to Magruder data request MM DR 1.4f, CARES Application, Bates number UNSE(0783)0352) shows $2,500 a week for a family of four.

95 UNSE response to ACC Staff data request STF 5.7.

96 UNSE response to Magruder data request 1.4a.

at the residence."[97] A review of the application does not indicate the "type of essential medical equipment used" is required.[98]

6.4 Recommendations to Improve the CARES Program.

I concur with the proposed change in the CARES tariff.

In my opinion, I recommend that this program needs to be reviewed by a qualified, outside team with goals and objectives to (1) continue streamlining the application process, (2) increase background data verification to ensure ratepayer funds are used for those truly meeting the income levels, (3) do a media analysis for effectiveness (using data collection box numbers, etc.) and shift funds to higher performing media, and (4) that CARES participation rates be required to increase 10% a year until 75% of those eligible for CARES are included as CARES ratepayer, with targets of 35% on 1 January 2008; 45% on 1 January 2009, 55% on 1 January 2010, 65% on 1 January 2011, and 75% on 1 January 2012..

6.5 Recommendations to Improve the CARES-M Program.

I concur with the proposed change in the CARES-M tariff.

This program has some fundamental flaws which need management attention, as presently constructed, appears to have liability risk for the Company. This is a good program, which is just limping along without attention. Include CARES-M in with the program survey above for CARES.

It is recommended that the following actions be accomplished:

(1) All CARES-M Applications must be verified and validated at least annually to include equipment needs in terms of type of equipment, equipment manufacture and model number, frequency of equipment use and duration every 24 hours embedded battery back capability and estimated duration of operation on battery (if any), portability of this equipment, and a signed statement from the attending physician that states

> "This patient _____ of mine is required to use _____ equipment for life support and if this equipment is not operable for greater than _____ (hrs/minutes), this patient will be in an unsafe condition.
> I understand that if this patient is not required to use this equipment for life support, I will nullify any prior statements with UNS Electric, Inc.
> If there changes in this statement I will also notify by phone or facsimile directly to the Company."

(2) A list of all CARES-M patients will be maintained at the Call Center, along with a "check sheet" of actions required to ensure the safety of all CARES-M and other non-CARES

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[97] UNSE response to Magruder data request MM DR 1.4h.
[98] UNSE response to Magruder data request MM DR 1.4f, CARES Application.

ratepayers on life-support equipment. This life-support check list will include for the patient's phone number and the local first responder's phone number. All ratepayers on life-support equipment (including non-CARES-M) will have their residences or locations mapped for rapid customer locational access. At least annually, UNSE will develop, host, conduct, and provide realistic training and feedback and lessons learned in a CARES-M ratepayer oriented drill or exercise. Results will be included in the appropriate reports to the Commission. Drills and exercises will be created by UNSE in collaboration with first responders and implemented throughout a county. The Call Center and County Emergency Management offices should be treated as key implementers for local life-support necessary for the safety of all customers requiring electricity-driven life-support equipment.

(3) UNSE will aggressively seek, identify, classify, and manage life-support information with its CARES-M databases for customers who are NOT in the CARES programs.

(4) All participants will have their records checked and physician statements renewed.

(5) Each County Emergency Management or Control Division will be provided with current ratepayers on electrical life-support equipment containing essential information in (2) above. The County will be requested to ensure communications and emergency response teams can meet the life-support requirements for these customers.

(6) UNSE will employ or obtain services of a medical life-support equipment specialist. This person shall be used to verify all CARES-M and other customers on life-support equipment. If and when a situation is deemed to be potentially fraudulent, additional expert advisor(s) or specialists should be readily available to assist UNSE in a supporting role.

(7) Because non-CARES ratepayers on life-support equipment have not been officially included in any UNSE such programs, it is recommended that a letter from top management be sent to all UNSE and UNSG customers informing all of the expansion of medical life-support and the CARES-M ratepayers, details about the program, and an application.

Part VII – ISSUE 5

Environmental Portfolio Standard (EPS) and Renewable Energy Standard and Tariff (REST) Surcharges

Q. Does UNSE have a Renewable Energy Program?

A. Barely, about 0.6% of what it is required to generate a year, which is also small, only 1.1% of its total retail sales. Again, this is 0.6% of 1.1%, which was 0.00646% of the total sales in 2006, the best year-to-date!

7.1 Reason for the EPS Surcharge.

Every ratepayer is presently required to pay a surcharge to fund renewable energy projects. The residential ratepayer has a monthly $0.35 surcharge on their bills. UNSE is required to use those funds as rebates for solar-electric, grid-connected systems or to purchase "green" power from appropriate sources.

Table 14 shows the required percent of the total power demand that is required by the Energy Portfolio Standard (EPS) as mandated by ACC Decision No. 67178. Actual data are shown before 2007. From this table it is obvious that the UNSE renewable energy program is a dismal failure. UNSE generated less than 0.6% (0.00646/1.05) of the required renewable power established for 2006. During the Test Year, the expenses incurred by UNSE to manage this program exceeded $33,330 for payroll ($27,880), marketing ($902), training and travel ($1,458), outside services and contracting ($2,923) and materials and supplies ($167). This program does NOT have ANY management attention at UNSE, but the public is demanding renewable energy, especially in Arizona, to sustain our national security, quality of life, and provide a healthy environment for the future. Obviously, UNSE's management does not share these goals, nor is UNSE or any UniSource entity ISO 14400 certified for Environmental Management, that forward-looking utilities have found very beneficial and cost effective.

Table 14. Actual Renewable Energy Generated to Date. *A total of 256 MWh of solar generate power has been generated since 1997. In 2006, the best year to date, only 0.00646% of the total UNSE load requirements, well below the 1.05% mandated by EPS, and was 16,818 MWh short.*[99]

Year	UNSE/Citizens Total Retail sales (MWh)	EPS Percent Renewable Electricity	Needed to meet EPS Standard (MWh)	Solar Generated (MW)	Actual Percent Renewable	Annual Renewable Deficit (MWh)
Column	(1)	(2)	(3)=(1)x(2)	(4)	(4)/(1)x100 (%)	(4)-(3)
>2001	NA	NA	NA	57.0	unknown	NA
2001	1,275,036	0.2 %	2,550	19.0	0.00149 %	-2,531

[99] This table used the UNSE response to ACC Staff data request 13.40, which included UNSE Test Year Annual Report on Environmental Portfolio Standard Programs, and UNSE response to ACC Staff data request 3.137, "Deferred Environmental Portfolio Surcharge Revenue Activity", Aug 2003 through Dec. 2006

Table 14. Actual Renewable Energy Generated to Date. *A total of 256 MWh of solar generate power has been generated since 1997. In 2006, the best year to date, only 0.00646% of the total UNSE load requirements, well below the 1.05% mandated by EPS, and was 16,818 MWh short.*[99]

Year	UNSE/Citizens Total Retail sales (MWh)	EPS Percent Renewable Electricity	Needed to meet EPS Standard (MWh)	Solar Generated (MW)	Actual Percent Renewable	Annual Renewable Deficit (MWh)
2002	1,136,581	0.4 %	4,546	19.4	0.00171%	-4,526
2003	1,392,466	0.6 %	8,355	13.3	0.00096%	-8,342
2004	1,462,633	0.8 %	11,701	10.0	0.00068%	-11,691
2005	1,631,947	1.0 %	15,210	26.7	0.00164%	-15,187
2006	**1,711,420**	**1.05%**	**16,919**	**110.6**	**0.00646%**	**-16,818**
subtotal	8,610,083	NA	59,281	256.0	NA	-59,095
2007e	1,659,763	1.10%	18,257			
2008e	1,709,555	1.10%	18,805			
2009e	1,760,842	1.10%	19,369			
2010e	1,813,667	1.10%	19,950			
2011e	1,868,077	1.10%	20,549			
2012e	1,924,120	1.10%	21,164			

Q. Where has all the EPS Surcharge money gone?

A. To the EPS Bank.

7.2 The UNSE EPS Bank.

Based on income from all customers paying the EPS surcharge, UNSE has been receiving $38,000 and $50,000 every month to support renewable energy programs. Most of these funds have gone into an EPS Bank which grows a few hundred thousand dollars a year, with a balance of $1,834,786 at the end of the test year on 30 June 2006.

Q. Has UNSE purchased any Renewable Energy?

A. Yes. Almost $1 million in "other" renewable energy. It has purchased Landfill Gas from TEP several times, in fact, during the Test Year UNSE purchased 6,000 MWh of Landfill gas and with this purchase will "carry a surplus of 1,981 MWh of 'other' credits into the second half of 2006."[100]

Date	**Amount**
December 2003	$200,000,00
January 2005	$131,502.17
December 2005	$159,000.00
September 2006	$290,255.92
December 2006	$173,250.00
Total	$954,008.09 for landfill gas from TEP[101]

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[100] UNSE response to ACC Staff data request 13.40, Test Year EPS Report at 6.

[101] UNSE response to ACC Staff data request 3.137, "Deferred Environmental Portfolio Surcharge Revenue Activity"

Q. What has UNSE done in solar electric energy?

A. Some. In 1997, Citizens installed four solar-electric systems, with two at Lake Havasu City and two at Kingman, using DOE funds, which provided about half of the pre-2002 solar-electric energy. Each site has an output of approximately 4 kW, similar to the demands for a home. Both are grid-connected, without batteries. A total of 52 solar panels are involved, enough for two or so average homes. WOW! That is impressive and done so long ago. Citizens must have been a real leader back then. These systems used to generate 19 or so MWh per year but some components failed in 2003 and 2004 which reduced the total solar output in Table 14.

Q. Has UNSE had other systems producing solar energy?

A. As shown in Table 14, in 2004 the solar generated electricity leaped from 10 MWh to 26.7 in 2005 and to 110.6 MWh in 2006. During the Test Year, in Kingman, UNSE actually purchased 25.25 MW and in Lake Havasu City another 29.32 MW for a total of 54.58 MW. No solar electricity has been generated in Santa Cruz service area.

Q. How will be the future of ESP be transitioned to the new ACC Environmental Standard?

A. In November 2006, the Commission adopted a new environment standard, called Renewable Energy Standard and Tariff (REST) in ACC Decision No. 69127. Appendix A of this Decision contains the "rules" to implement REST.

7.3 Renewable Energy Standard and Tariff (REST) and UNSE.

Table 15 shows the REST requirements for 2006 to 2024 and beyond. This standard uses "credits" to account for renewable energy. In general, one REST credit equates to one MWh. The first year a utility is under the standard, the percentage of required renewable energy. This table uses the long-term UNSE generated requirements[102] in the second column, and estimates (e) for later years. The third column is the percentage of retail electricity sold that needs REST credits. The fourth column is the number of REST credits required for that year. The REST rules specify that some of the REST credits must be used for distributed generated electricity, using the percentages shown in the fifth column, while the sixth column are the annual REST distributed generation required. REST also required that residential REST credits must be at least half of the distributed generated energy, which is shown in the last column.

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[102] DeConcini Direct Testimony, Exhibit MJD-1, page 2.

Table 15. Some of the REST Requirements for UNSE.

Year	UNSE/Citizens Total Retail sales (MWh) Estimate	REST Percent Renewable Energy (%)[103]	Credits to meet REST (~MWhr)	Percent Distributed Generation (~MWh)[104]	Distributed Generated (~MWh)	Residential Generated (~MWh)[105]
Column	(1)	(2)	(3)=(1)x(2)	(4)	(5)=(3)x(4)	(6)=0.5x(5)
2006	1,631,000	1.25%	20,380	5%	1,119	555
2007	1,690,000	1.50%	25,350	10%	2,535	1,267
2008	1,790,000	1.75%	31,325	15%	4,699	2,345
2009	1,921,000	2.00%	38,420	20%	7,684	3,842
2010	2,022,000	2.50%	50,550	25%	11,333	5,566
2011	2,127,000	3.00%	63,810	30%	19,120	9,560
2012	2,234,000	3.50%	78,190	30%	23,457	11,728
2013	2.342,000	4.0%	93,680	30%	28,104	14,052
2014	2,449,000	4.5%	110,205	30%	33,061	16,530
2015	2,545,000	5.0%	127,250	30%	38,175	19,087
2016	2,629,000	6.0%	157,740	30%	47,220	23,610
2017	2,706,000	7.0%	189,420	30%	56,826	28,413
2018	2,760,000	8.0%	220,800	30%	66,240	33,120
2019	2,815,000	9.0%	253,350	30%	76,005	38,002
2020	2,872,000	10.0%	287,200	30%	86,160	43,080
2021	2,929,000	11.0%	322,190	30%	96,657	48,323
2022	No data	12.0%	380,000e	30%	1,140,000e	57,000e
2023	No data	13.0%	445,000e	30%	1,335,000e	66,750e
2024	No data	14.0%	510,000e	30%	1,530,000e	76,500e
2024+	No data	15.0%	560,000e	30%	1,680,000e	84,000e

7.4 Recommendations to Convert ESP Surcharge to a REST Surcharge/Adjustor.

Based on the present performance of UNSE in obtaining, using, and adding renewable energy generation equipment to its portfolio, UNSE will have to "catch-up" as the 260 MWs generated in 2006 falls far short of 20,380 MWh of REST credits required.

The following are **recommendations**

(1) That UNSE invigorate its "Green Watts" program, which was upgraded and expanded by ACC on 21 December 2006.

(2) That UNSE present an implementation plan to the Commission prior to 1 January 2008 showing how UNSE will be on track with the requirements of REST by 1 January 2010.

(3) That UNSE commence implementation of sample tariff REST surcharge, within the first billing cycle 30-days after Commission approval of this docket.

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[103] ACC Decision No. 69127, Appendix A, R14-2-1804.B, page 11.
[104] *Ibid.*, R14-2-1804.F, page 13.
[105]

Exhibit B

Enclosure B-3, UNSE Payment Agents

Customer Service
- Account Manager
- Account Services
- Billing & Payment Options
  - Payment Options
  - Courtesy Payment Box Location
  - Cash Payment Agent
  - UES e-bill
  - Pricing plans
  - Budget Billing
  - SNAP
  - GreenWatts
  - Warm Spirit
  - Bill Inserts

Customer Service

Payment Agents

- ACE Cash Express Locations
- Additional Cash Only Locations

- Cash only -

- You will be provided with a receipt after cash payment has been made.
- Please verify the accuracy of your account number on your receipt before leaving.
- Please take your bill stub with you. This will help make sure your payment is processed accurately.
- A $1.00 fee will apply at selected locations (see below).

ACE Cash Express Locations

Bullhead City

1812 Highway 95, Ste 20, Bullhead City, AZ 86442
(928) 763-8865
($1.00 fee will apply)

Store Hours: Monday through Thursday 8:30 a.m. to 6:30 p.m.; Friday 8:30 a.m. to 7:00 p.m.; Saturday 9 a.m. to 5 p.m.; Closed Sunday

Camp Verde

522 Finnie Flats Road, #F, Camp Verde, AZ 86322
(928) 567-0676

Store Hours: Monday through Friday 9:00 a.m. to 6:00 p.m.; Saturday 9:00 a.m. to 3:00 p.m.; Closed Sunday

Chino Valley

1578 N. US-89 Suite A, Chino Valley, AZ 86323
(928) 636-5545

Store Hours: Monday through Thursday 8:00 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Cottonwood

989 S. Main, Ste B, Cottonwood, AZ 86326
(928) 639-1000

Store Hours: Monday through Friday 8:30 a.m. to 6:30 p.m.; Saturday 10:00 a.m. to 5:00 p.m.; Closed Sunday

Golden Valley

52 S. Hope #A1, Golden Valley, AZ 86431
(928) 565-5055
($1 fee will apply)

Store Hours: Monday through Thursday 10 a.m. to 6:00 p.m.; Friday 10 a.m. to 7 p.m.; Saturday 10:00 a.m. to 2:00 p.m.; Closed Sunday

Kingman

3787 Stockton Hill Road, Kingman, AZ 86401
(928) 692-7110
2785 Northern Ave, Kingman, AZ 86401

Account Manager
E-mail:
Password:
LOGIN
New user?
Learn more | Enroll
Forgot your password?
Tell a friend

What's New
A NEW WEB SITE
A NEW ACCOUNT NUMBER
A NEW LOOK FOR YOUR BILL

UES e-bill
UES e-bill
RECEIVE • VIEW • PAY
SIGN UP TO RECEIVE, VIEW AND PAY YOUR UES BILL ONLINE.
LEARN MORE >>

Energy Advisor
ENERGY ADVISOR
ANALYZE YOUR HOME OR BUSINESS ENERGY USE. LEARN WHERE YOU CAN SAVE MONEY!
LEARN MORE >>

Safety
STAY AWAY AND STAY ALIVE. STAY AWAY FROM DOWNED POWER LINES.
LEARN MORE >>

(928) 757-7575
($1 fee will apply)

Store Hours: Monday through Thursday 8:00 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Lake Havasu City

20 N. Acoma Blvd, Lake Havasu City, AZ 86403
(928) 854-4447

Store Hours: Monday through Thursday 8:00 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Nogales

1965 N. Grand Ave., Nogales, AZ 85621
(520) 761-3999

Store Hours: Monday through Saturday 9:00 a.m. to 9:00 p.m.; Sunday 10:00 a.m. to 6:00 p.m.

570 W. Mariposa, Nogales, AZ 85621
(520) 377-2013
($1 fee will apply)

Store Hours: Monday through Saturday 9:00 a.m. to 6:00 p.m.; Sunday 9:00 a.m. to 4:00 p.m.

43 N. Morley Ave, Nogales, AZ 85621
(520) 287-7400
($1 fee will apply)

Store Hours: Monday through Saturday 10:00 a.m. to 6:00 p.m.; Sunday 10:00 a.m. to 4:00 p.m.

Prescott

621 Miller Valley Road, Prescott, AZ 86301
(928) 777-0039

Store Hours: Monday through Thursday 8:00 a.m to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Prescott Valley

8101 E. Hwy. 69, Ste A, Prescott Valley, AZ 86314
(928) 759-9939

Store Hours: Monday through Thursday 9:00 a.m. to 6:30 p.m.; Friday 9:00 a.m. to 7:00 p.m.; Saturday 9:30 a.m. 5:00 p.m.; Closed Sunday

Additional Cash Only Locations

Flagstaff

OA Quick Cash
3470 E. Route 66, Suite 101, Flagstaff AZ 86004
(928) 526-5626
Store Hours: Monday through Friday 9:00 a.m. to 5:30 p.m.; Saturday 10:00 a.m. to 2:00 p.m.; Closed Sunday

Winslow

Winslow Document Express
118 B E. Second St., Winslow AZ
(928) 289-3290
Store Hours: Monday through Friday 9:00 a.m. to 5:00 p.m.; Closed Saturday and Sunday

Show Low

Audio Advantage/Radio Shack
4431 S. White Mountain Rd., Suite 1, Show Low AZ 85901
(928) 532-0462
Store Hours: Monday through Saturday 9:00 a.m. to 6:00 p.m.; Closed Sunday

Sedona

Weber IGA Food & Drug
100 Verde Valley School, Sedona AZ 86351
(928) 284-1144
Store Hours: Monday through Saturday 6:00 a.m. to 10:00 p.m.;
Sunday 6:00 a.m. to 9:00 P.M.

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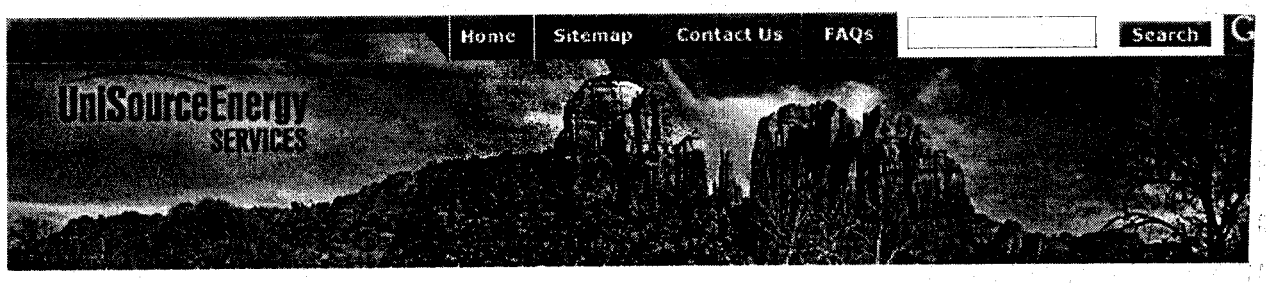
07/09/2007 12:18 AM

Exhibit B

Enclosure B-4, Credit and Debit Card, and Bank Withdrawal Application



This payment service is provided by a third party payment processor for electric customers of UniSource Energy Services. The payment processor will add a convenience fee of $3.95 for every $250 to the total amount of the payment. You will be given an opportunity to accept or decline the payment after the total amount is calculated.

Order Information:

Payment Date: 7/9/2007

UES Account Number (Electric): (Example: 7831092)

Please enter your account number as shown on your bill

Enter Payment Amount: $

Customer Information:

Customer Name:

E-mail Address:

Pay From:

○ **Debit Card** ○ **Bank Account** ○ **Credit Card**

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