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IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC., FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN AND FOR RELATED APPROVALS.	**Docket No. E-01575A-08-0328**
IN THE MATTER OF THE APPLICATION OF SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC., FOR AN ORDER INSTITUTING A MORATORIUM ON THE NEW CONNECTIONS TO THE V-7 FEEDER LINE SERVING THE AREAS OF WHETSTONE, RAIN VALLEY, ELGIN, CANELO, SONOITA, AND PATAGONIA, ARIZONA.	**Docket No. E-01575A-09-0453**

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NOTICE OF FILING
MARSHALL MAGRUDER DIRECT TESTIMONY
IN SUPPORT OF INTERVENOR SUE DOWNING

16 MARCH 2010

This filing contains the Direct Testimony of Marshall Magruder in support of Intervenor Sue Downing who requested that I be a witness in these hearings, in particular, a §40-252 review that was petitioned by Sulphur Springs Valley Electric Cooperative (SSVEC). The Cooperative then petitioned the Commission on 14 January 2010 to amend Decision No. 71274. SSVEC then requested an "expedited procedural order regarding petition to amend Decision No. 71274".

This testimony provides evidence and proves that the "exigent reliability circumstances" do not exist based on the Feasibility Study order by Decision No. 71274. Further, the Cooperative may avoid loss of American Relief and Recovery money if its management delayed longer.

As will be shown, the misleading conclusions reached by the Cooperative have been repeated so many times in the numerous and extremely voluminous filings by SSVEC, that their counsel seems to believe he is not "stretching" the truth beyond the facts that have been shown to be true (and different) in the Feasibility Study. It's a sad day when this Cooperative has been so misleading that it now believes its own bathwater.

I was asked by Ms Downing to assist her in this area, and based on my background at the Santa Cruz County/City of Nogales Joint Energy Commissioner, to which I was appointed in January 2000 through September 2008 as its Vice-Chairman.

My attached testimony will speak for itself with a firm recommendation that the petition by the Cooperative be denied based on the fact there is no basis for its claims to not follow the existing procedure as, outlined by the Administrative Law Judge, as no emergency exists.

I certify this filing has been mailed or delivered to parties on the Service List this date.

Respectfully submitted on this 16th day of March 2010.

MARSHALL MAGRUDER

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DIRECT TESTIMONY

OF

MARSHALL MAGRUDER

AS A

WITNESS

FOR

SUE DOWNING ,

INTERVENOR

16 MARCH 2010

IN THE MATTERS

OF

THE APPLICATION[S] OF SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE, INC.,

FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN AND FOR RELATED APPROVALS.

AND

FOR AN ORDER INSTITUTING A MORATORIUM ON THE NEW CONNECTIONS TO THE V-7 FEEDER LINE SERVING THE AREAS OF WHETSTONE, RAIN VALLEY, ELGIN, CANELO, SONOITA, AND PATAGONIA, ARIZONA.

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<u>Exhibits</u>

DIRECT TESTIMONY
OF MARSHALL MAGRUDER

SECTION 1 - BACKGROUND AND INTRODUCTION

1.1 Introduction.

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

A. My name is Peyton Marshall Magruder, Jr. I am a customer of UNS Gas and UNS Electricity, two public service companies that serve Santa Cruz County. I was Vice-Chairman of the Santa Cruz County/City of Nogales Energy Commission, and active in community projects including the AARP tax aide program. In this position, the entire county was in my area of concern, including the Northeast Santa Cruz County communities of Patagonia, Sonoita, Elgin, and Canelo. I participated in the creation, development, and drafting of the *2004 Santa Cruz County Comprehensive Plan* that established Character Areas in our county. The Northeast Character area corresponds to these communities, which is very similar to the Northwest Character area in which I live. This plan sets the County's goals, objectives and polices.[1]

I recently was employed as a Senior Scientist and Information Systems Architect for Integrated Systems Improvement Services (ISIS), Inc. in Sierra Vista, Arizona, working with information warfare, systems architectures, electronic and communications intelligence systems, test plans, information assurance, future cryptologic systems management, and information technology services. I am Systems Engineer and Training Systems Consultant for Imagine CBT, Inc., at Raytheon Naval and Maritime Systems in San Diego, doing systems engineering work with US and Royal Navy involving aircraft carriers and amphibious warfare ship's command, control, communications, computers, intelligence, surveillance and reconnaissance systems, (C4ISR) and all levels of training systems.

Annually, between January and April 15, I am seasonally employed as a Senior Tax Advisor Level III, the 10th of 13 pay levels for tax preparers, at H&R Block, Inc, in Tucson, Arizona. I retired from Raytheon, previously, Hughes Aircraft Company, as a Senior Systems Engineer after nearly 18 years and as a Naval Officer for 25 years. Please see Exhibit A for additional work experience.

[1] *Santa Cruz County Comprehensive Plan*, adopted by the Board of Supervisors Resolution No. 2004-11, 29 June 2004.

As an instructor, I taught for the University of Phoenix MBA courses "Operations Management for Total Quality" and "Managing R&D and Innovation Processes" in Nogales, Arizona, where all the students were from Mexican maquilas, and also in Tucson, Arizona.

I am the Vice President of the Martin B-26 Marauder Historical Society of some 1,700 World War II veterans and serve as Fund Raising Chairman for a five-million dollar "Lasting Legacy" fund drive to endow the MHS International Archives and restore a B-26 Marauder aircraft at the Pima Air & Space Museum/Arizona Aerospace Foundation in Tucson.

I hold two Masters of Science (MS) degrees, one from the University of Southern California in Systems Management (MSSM) with specialties in Managing R&D and Human Factors and from U.S. Naval Postgraduate School, a MS in Physical Oceanography with emphasis on underwater acoustics. My BS is from the U.S. Naval Academy.

My address is P.O. Box 1267, Tubac, Arizona, 85646.

1.2 Involvement in these Proceedings.

Q. Why are you involved in these proceedings?

A. Both my professional background and involvement in local energy issues have led me to participate during these proceedings. Due to time limitations and cost, I decided not to intervene, as I have other ongoing cases with two testimonies due in the next few weeks.

Q. What is a Systems Engineer?

A. I have over 40 years of engineering experience with that last few decades as a Systems Engineer, with most titles a Senior Systems Engineer or Principle Systems Engineer. A systems engineer is one who conceptualizes a system based on understanding its needs, its functions, and its expected results through delivery, operations and maintenance and disposal.

As I learned in my first class in a Systems Management course, a "system" usually is somewhere between an atom and the universe, each made up of subsystems and each being a subsystem of a larger system.

A Systems Engineer looks at the big picture, including economic, environmental, functional, human factors, reliability, and cost issues when designing options or alternatives[2] and a methodology to assess and select the best alternative to accomplish the task. As Exhibit A

[2] The terms "option" and "alternative" are used interchangeably herein, without any significance between them.

shows, many diverse kinds and types of systems have shaped my background with a continuous array of unique experiences, everyone involving electricity in one form or another.

1.3 Prior Experience before the Corporation Commission.

Q. Have you previously testified before this Commission?

A. Yes, I have made appearances at Arizona Corporation Commission (ACC) Open and Special Meetings and as an intervening party in the following ACC Dockets:

a. Arizona Power Plant and Transmission Line Siting Case No. 111, a Joint TEP and Citizens Communications Company CEC Application for 345 kV Transmission Line from Sahuarita, Arizona, to Santa Anna, Sonora, Mexico;

b. Docket No. E-01032C-00-0951, a Purchase Power and Fuel Adjustment Clause (PPFAC) case for Citizens Communications Company;

c. Docket Nos. E-1033A-02-0914, E-01032C-02-0914 and G-01032C-02-0914, the UniSource-Citizens Acquisition of Citizens Communications Company Arizona electricity and natural gas utilities cases;

d. Docket No. E-04230-03- 933, the UniSource-Sahuaro Acquisition case;

e. Reopened and ongoing Docket No. E-01032A-99-0401, the Santa Cruz County service quality, analysis of transmission and proposed Plan of Action case;

f. Reopened Arizona Power Plant and Transmission Line Siting Case No. 111;

g. Docket Nos. G-04204A-06-0463, G-04204A-06-0013, and G-04204A-05-0831, the UNS Gas, Inc., UNS Gas Rate, UNS Gas PGA and Prudency cases;

h. Docket No. E-04204A-06-0783, for UNS Electric rate case;

i. Arizona Power Plant and Transmission Line Siting Case No. 144, TEP and UNS Electric CEC Application for a 115 kV to 138 kV Transmission Line Upgrade from Vail to Nogales;

j. Open Docket No. E-04204A-09-09-0589, a Formal Complaint filed against UNS Electric for failing to fund student loans, failing to complete 32 defective underground cable and utility pole replacement projects, and failing to provide notification during an outage for all customers on life support during an outage; and

k. Open Docket Nos. S/SW-01303A-08-0227, Arizona-American Water Company (AAWC) water and sewage water rate cases. These initial rate cases are continued in Docket No. S/SW-01303A-09-0343 where consolidation of rates for all of this company's divisions. Hearings will begin on 19 April 2010 in Phoenix. I am a strong supporter of Rate Consolidation with its resultant benefits for the company and ratepayers.

In view of the variety and diversity of these cases, I feel that being a witness to a first-time intervenor who has never appeared before the Commission would help her case, provide Ms Downing advise based on my knowledge and experiences from prior participations. This should aid her in making her arguments with additional technical emphasis.

I also have intervened or participated in Federal Energy Regulatory Commission (FERC), U.S. Department of Energy (DOE), U.S. Bureau of Land Management (BLM), and U.S. Forest Service proceedings.

Q. Have you filed documents in these matters?

A. I have made two prior filings in these matters, which are included in the Attachment as Exhibits MM-2 and MM-3.

1.4 Preparation of this Testimony.

Q. Have you received advise or help from others in preparing you Testimony?

A. All filings and testimonies are totally mine and were produced at my own expense. I have received no compensation from anyone involving this case.

1.5 The Primary Reference for this Testimony.

Q. What is the primary reference used for this Testimony?

A. The primary reference used herein is the "*Feasibility Study*" (FS) prepared by an independent third-party, Navigant Consulting, Inc., (NCI) that includes Alternatives that could mitigate the need for a proposed 69 kV line to a planned Sonoita substation.[3] The FS was ordered by the Corporation Commission in ACC Order No. 71274 of 8 September 2009 due to the veracity of prior SSVEC statements being questioned by the public. Section 4 herein will provide some of the misleading statements being made by SSVEC's Counsel, SSVEC's CEO, and other SSVEC management personnel. The FS stated:

[3] *Independent Feasibility Study of Electric Supply Alternatives,* prepared for Sulphur Springs Valley Electric Cooperative, Willcox, Arizona, by Navigant Consultant, Inc., www.nagigantconsulting.com dated December 2009, filled in ACC Docket No. E-01056A-08-0328 on 31 December 2009 in compliance with ACC Order No. 71274 of 8 September 2009, hereafter "Feasibility Study" or "FS".

> "All findings presented herein were prepared independently, without bias or prior knowledge of feeder performance issues or concerns raised by customers and other interested parties." [FS p. 1]

Also, an "independent engineering and consulting firm, TRC Solutions, was engaged by SSVEC to respond to information and data requests submitted by NCI." [FS p. 1, fn 2] Due to this position to collaborate with SSVEC, testimony by TRC is of a lower quality than any testimony from NCI. Therefore, only truly "independent" testimony should be considered in this case, that is, testimony by the "independent study contractor" and not as an "in-between" liaison organization.

A serious question remains, as to why SSVEC chose to have TRC testify in these hearings instead of those who performed the feasibility study and wrote the actual report. If TRC did either of these actions, then, in my opinion, the FS would not be truely "independent". It is noted that there are no negative implications here for the work involving the FS accomplished by NCI.

1.6 This Witness Testimony.

Q. Why did you feel a need to be a witness in these proceedings?

A. When I read the Cooperative's Application for a Re-hearing, and additional Cooperative-produced letters and filings, many issues of concern became apparent. These included the following issues of concern:

a. Misleading statements concerning the <u>reliability</u> of the V-7 feeder line for the affected communities;
b. Ability to meet peak and emergency <u>demands</u>;
c. Ability of renewable energy Alternatives to provide additional capacity; and
d. Correction of the Cooperative's exaggerated claims with facts from the Feasibility Study.

Q. Why do you feel that the Cooperative is spending so much effort on pushing for the 69 kV line?

A. It appears to me that the Cooperative is not interested in ANY Alternative other than a 69 kV line, and refuses to really try to solve the issues in the matter without constructing a 69 kV line.

This is unfortunate. The Cooperative's senior management has not been open-minded, transparent or even making an attempt to be truly honest in these proceedings when it comes to working through the challenges in resolving this question by any other solution that a 69 kV line.

It appears to me that this line is a precursor for the three on-going mining exploration sites in the Patagonia Mountains, in Santa Cruz County. By double-circuiting this 69-kV line and continuing it to Patagonia, the Cooperative would use the same arguments, "we have a request for power", to take this action for a mine. This is one unintended consequence that is in direct opposition to Resolutions passed unanimously by the Santa Cruz County's Board of Supervisors and the will of the people in these communities, which are very far from Willcox, Benson and Sierra Vista.

SECTION 2

SUMMARY OF RECOMMENDATIONS AND CONCLUSIONS FOR THE ISSUES IN THIS TESTIMONY

2.1 Summary of Issues 1 to 4 from in Sections 3 to 6.

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

A. Yes. Several issues of concern are in my testimonies as follows:

- **Issue 1 –** In reliability terms, the Health of the Present V-7 Feeder Service Area does NOT require emergency construction of a 69 kV subtransmission line in Section 3.
- **Issue 2 –** Methods to meet short-term peak and emergency demands are more reasonable, cost effective, and available in Section 4.
- **Issue 3 –** Benefits of Renewable Energy (RE), Distributed Energy (DE), and Demand Side Management (DSM) to improve performance in the service area in Section 5.
- **Issue 4 –** Correction of exaggerated Cooperative claims in Section 6.

2.2 Summary of Conclusions.

2.2.1 The Feasibility Study did NOT recommend that the 69 kV line be Constructed under EMERGENCY Conditions.

The Cooperative quoted the FS [p. 3] in its petition for these §40-252 hearings, that

> *"The results of NCI's investigations indicates SSVEC should take immediate action to address current performance issues and capacity limits, including carefully assessing the impact of customer requests for new or expanded service on V-7 feeder performance and capacity."* [FS p. 3, italics in original]

This often repeated quote does NOT use the words "69 kV line" but it does specify that action should be taken by SSVEC. As shown in the FS and below, the most costly action would be a 69 kV line, while others are more economical. There has been no acknowledgement by the Cooperative that it could resolve its V-7 feeder area problems by combinations of these less expensive Alternatives contained in the Feasibility Study and other sources.

Further, as to be shown, NCI was not required to investigate key involved in making decisions for the V-7 feeder area, in particular

> "**Resolution of voltage anomalies were beyond the scope of this effort**, but should be addressed if the V-7 feeder remains in its current configuration. (Voltage perturbations may continue to be a problem even if certain upgrades outlined herein are implemented.)" [FS p. 2, emphasis added]

Further, the Commission Staff's Closing Brief of 22 May 2009 in the Rate Case had no mention the Sonoita Reliability Project (SRP) or this 69 kV subtransmission line; thus, the SRP must not have been considered as a serious an issue at that time.

Further, the Administrative Law Judge (ALJ) in the rate case Recommended Opinion and Order (ROO) of 14 June 2009 included the following statement:

> "To the extent residents in the area and the Cooperative believe it would be helpful, the Commission can make Staff available to moderate discussions on how renewable generation can successfully be integrated into its system. It is not in the public interest, however, to order SSVEC to delay the planned upgrade."[4]

The above ROO did <u>NOT</u> mention the SRP in the Finding of Fact other than facts about a Public Haring held in Sierra Vista on 11 February 2009. There are <u>NO</u> Orders in this ALJ ROO that pertains to the SRP or the proposed 69 kV line. The word "immediate" and "emergency" pertaining to the SRP were <u>NOT</u> found in this ROO. Similarly, the Commission Staff did <u>NOT</u> use these words. These will be discussed in greater detail in Section 6 below. And even the Commission does <u>NOT</u> use the words "urgent", "immediate", "expedite", or "emergency" anywhere in the Order Decision and Order No. 71274. Only the Cooperative repeatedly uses these words in these matters.

The study constraints established by SSVEC were NOR completely realistic as will be discussed in Section 6. These "constraints" led NCI to prematurely exclude what appear to be viable Alternatives. For example, NCI was not required to provide dig deeper into the voltage anomalies it knew were present? [FS p. 2]

2.2.2. Summary of Conclusions for Issue 1 to Issue 4.

Q. Can you summarize your conclusions for Issues 1 to 4?

A. Yes.

<u>Issue 1 Conclusion</u> – There is no "reliability" or outage emergency and the Commission's original schedule for rehearing the SSVEC Rate Case should not be changed due to the Emergency Petition under A.R.S §40-252.

[4] ACC Docket No. E-10575A-08-0328, Letter from ACC Acting Executive Director of 14 July 2009 distributing ALJ Rodda recommendation in the form of an Opinion and Order, page 39 at 1-4.

Issue 2 Conclusion – The Feasibility Study provides adequate ways for the Cooperative to use to in order meet short-term peak and emergency demands more economically than with its proposed and more expensive 69 kV subtransmission line.

Issue 3 Conclusion – The Cooperative should vigorously pursue – Renewable Energy (RE), Distributed Energy (DE) and Demand Side Management (DSM) Alternatives based on this Feasibility Study.

Issue 4 Conclusion – The Cooperative should not exaggerate its claims with misleading statements, when so vastly different from the facts in the Feasibility Study.

2.3 Recommendation.

Q. What is your recommendation with respect to the A.R.S. §40-252?

A. The Commission has no basis to approve an emergency request to construction at 69 kV line based on facts contained in the Feasibility Study or prior Commission Staff Recommendations. The ongoing procedural process should not be interrupted or changed based on the facts in the Feasibility Study until the total set of issues can be resolved with full testimonial hearings as the Procedural Orders now schedule.

Therefore, the Recommended Opinion and Order (ROO) from these hearings to the Commission should NOT recommend approval of the A.R.S. §40-252 Petition because evidence presented shows that the "situation" has not changed since the issuance of ACC Order No. 71274 on 9 December 2009 and therefore, this Order should NOT be changed.

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SECTION 3 - ISSUE 1

THE PRESENT HEALTH OF THE V-7 FEEDER AREA BASED ON INFORMATION IN THE FEASIBILITY STUDY

Issue 1 – The Present Health of the V-7 Service Area does NOT require Emergency Authorization to Construct a 69 kV Subtransmission line.

3.1 Reliability of Service in the V-7 Service Area.

Q. What does the Feasibility Study say about the Reliability in the V-7 service area?

A. There are many statements in the Feasibility Study that have used multiple years of performance data that shows that this feeder line is presently operating in a satisfactory manner. The Feasibility Study states:

> "While outages rates are high, **NCI[5] does not view current feeder outage performance to be unusual for a line with the distance and exposure of the V-7 feeder**; among other factors, the remote territory requires crews to travel longer distances to restore service, which increases average customer outage duration." [Feasibility Study, p. 1, emphasis added]

It is acknowledged that this service area does have some performance issues, but none are insurmountable or so drastic that emergency actions are required as shown below:

a. Annual Outages are near average in V-7 Feeder Area in 3.1.1 below

b. Outage Statistical Indices compare to RUS and National Standards in 3.1.2 below.

c. Total Number of Outages has been decreasing in 3.2 below.

d. Causes of Outages will not change or be improved with a 69 kV line in 3.3 below.

e. Outages on the present line to Sonoita have been minimal in 3.4 below.

f. New substation will improve the reliability; not the 69 kV line, in 3.5 below.

3.1.1 Outages are in an Acceptable Range.

Q. What does the Feasibility say about outages?

A. The Feasibility Study looked at the years of outage data for the V-7 Service area. It states:

> "Figure 2 presents **annual customer outage hours, which over 10 years has averaged three hours per customer**. While high, the duration is not unusual for very long feeders; the value drops to 2.4 hours if 1999 is excluded (in 1999 several wind-related events interrupted all customers served by the feeder.)" [FS Fig. 2, p. 11, emphasis added]

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5 NCI is Navigant Consulting, Inc., the company that conducted the independent feasibility study and report.

As shown in Figure 12 below, the annual average outage per customer in the V-7 service area exceeded 5.0 hours twice in the ten years, the RUS Bulletin 161 standard for rural cooperatives. Further, the above quote also indicated that if several 1994 windstorms were omitted, then the average would have been 2.4 hours per customer per year. At 3.0 hours of outage per year, this means the average customer had electricity 99.966% of the time [= 1.0 - 3.0/356.25*24]. At 2.4 hours of outage per year the availability of electricity is 99.971%. It is noted that SSVEC, like most utilities, and the FS defines an outage of five minutes or more, as used in IEEE Std 1633-203, *IEEE Guide for Electric Power Distribution Reliability Indices.* Momentary outages also have IEEE indices that are not used by SSVEC.

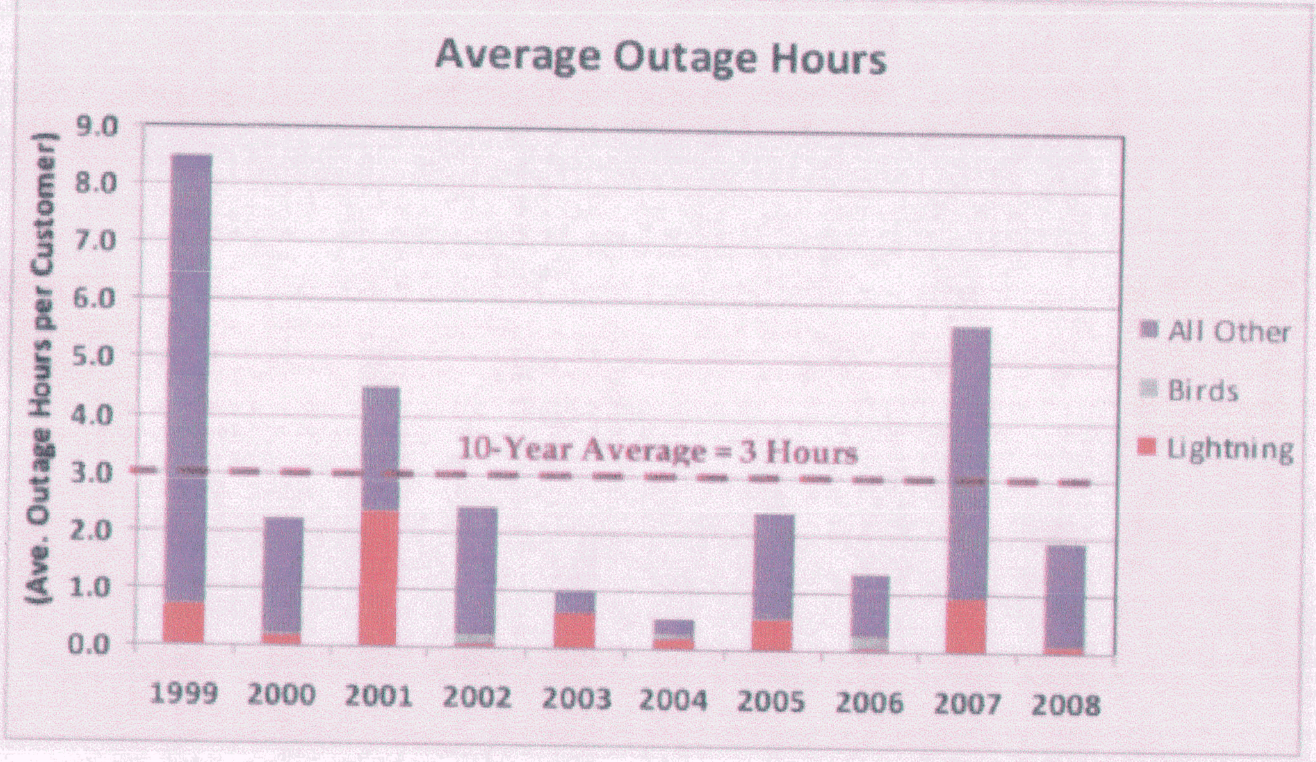

Figure 1. Average Outage Hours per Year Per Customer in the V-7 Service Area. [FS p. 11. Fig. 2]

3.1.2 Outage Statistical Indices Compare Favorably to RUS and National Standards

Q. Is 3.0 hours per customer a year of outage of a concern to the Rural Utility Service[6]?

A. Somewhat; however, SSVEC has several other feeders with higher outages than 3 hours per customer per year. What is important is that RUS Bulletin 161 considers **System Average**

[6] The Rural Utility Service or RUS is the present title of the Rural Electrification Administration (REA) in the U.S. Department of Agriculture (USDA).

Interruption Duration Index (SAIDI) of five hours (300 minutes) or more per customer as unacceptable, except under very unusual circumstances. These are "outages of concern". If the outages exceeded 5 hours per year per customer, then RUS requires an in-depth explanation by the Cooperative when it applies for RUS-discounted loans. These RUS loans fund electricity programs for rural and low-density communities. They make rural electric cooperatives cost-effective. It is very understandable that SSVEC does not want to exceed 5 hours of outage per customer per year. The ten-year average is well within this RUS requirement.

Q. How do the V-7 Reliability Indices Compare to National Utility Averages?

A. Table 1, from the FS, provided these standard distribution line reliability index values for the past ten years for this distribution feeder area.

Table 1: V-7 Reliability Indices

Year	SAIFI	SAIDI	CAIDI
1999	1.5	8.9	5.9
2000	0.9	2.2	2.6
2001	2.8	4.5	1.6
2002	1.5	2.3	1.5
2003	0.5	0.9	2.0
2004	0.3	0.5	1.8
2005	1.8	3.0	1.6
2006	0.3	1.1	3.9
2007	1.5	4.8	3.2
2008	1.3	1.6	1.3

Table 1 – Distribution Reliability Performance Indices for the V-7 Service Area.
[FS Table 1, p. 11][7]

The three different distribution reliability indices shown in Table 1 are from IEEE Std 1633-2003. This standard also includes a caveat that a minimum of five-years of data should be used as weather and other factors can cause significant annual changes in the indices:. These indices are defined below:

[7] . The IEEE standard uses minutes instead of hours for SAIDI and CAIDI, as shown in the FS and Table 1. They have been converted from hours to minutes in the following Tables 2 and 3. This standard also uses the term "interruptions" instead of the more familiar term, "outage".

- **SAIFI**, System Average Interruption Duration Index or the average number of interruptions experienced by customers per year.
- **SAIDI**, System Average Interruption Duration Index is the average number of interruption minutes experienced by customers per year.
- **CAIDI**, Customer Average Interruption Duration Index is the average duration of interruptions during the year.

The IEEE Standard 1366 provides the values of SAIFI, SAIDI, CAIDI, and MAIFI, based on measured utility data in the United States, by quartiles, as shown in Table 2 below:

Table 2 – Typical Reliability Index Values for US Utilities

Average	SAIFI (Outages)	SAIDI (Minutes)	CAIDI (Minutes)
Top or First Quartile (>75%)	0.90	54	55
Second Quartile (50-75%)	1.10	90	74
Average (50% - national average)	1.26	117	108
Third Quartile (25-50%)	1.45	138	108
Bottom or Fourth Quartile (<25%)	<1.45	<138	<108

Using the same process that the Corporation Commission has used for other utilities, it compares various distribution feeders during rate cases, the following Table 3 shows the Quartile from Table 2 that each of these three indices was measured in the past ten years.

Table 3 –Reliability Index Values for the V-7 Feeder Area

Average	SAIFI (Outages)	SAIDI (Minutes)	CAIDI (Minutes)
Top or First Quartile (>75%)	2006 (0.3) 2004 (0.3) 2003 (0.5) 2000 (0.9)	2004 (30) 2003 (54)	
Second Quartile (50-75%)	**2008 (1.3)**	**2008 (96)** 2006 (66)	**2008 (72)**
Average (50% - national average)	**1.45 outages**	**117 minutes**	**108 minutes**
Third Quartile (25-50%)		2002 (198) 2000 (132)	2005 (96) 2004 108) 2002 (90) 2001 (96)
Bottom or Fourth Quartile (<25%)	2007 (1.5) 2005 (1.8) 2002 (1.5) 2001 (2.8) 1999 (1.5)	2007 (288) 2005 (180) 2001 (270) 1999 (534)	2007 (192) 2006 (234) 2003 (120) 2000 (156) 1999 (354)

Some conclusions from this distribution reliability analysis in Tables 1, 2 and 3 for the V-7 service area:

- In the last year measured, 2008, all three indices were in the Second Quartile, that is, better than the average utility company, with 1.3 outages per customer (SAIFI), for average total outage duration of 96 minutes (SAIDI), and the average outage duration was 72 minutes (CAIDI).
- There were 0.3 outages per customer for the entire years of 2006 and 2004.
- The number of outages per customer in these ten years has, in general, been in the Top or Bottom quartile for 9 of the 10 years that shows a significant variability in outage durations.
- The RUS requirement for less than 5 hours of outage per customer (SAIDI) was exceeded in only one year, that was in 1999.
- The total annual durations of outages for a customer in the ten-year period varied from 30 minutes (in 2004) to nearly 9 hours (534 minutes) in 1999 when serious windstorms caused widespread outages that reduced repair crew availability throughout all of the SSVEC service areas. Many parts of the country have infrequent but long outages due to hurricanes, winter storms, earthquakes, flooding or windstorms. The IEEE Standard puts major events in a special category; however, most utilities do not use that process.
- The duration of outages (CAIDI), in all years but 2008, was worst than national average. The FS explains this because of the highly rural area, with less than 7 customers per distribution line mile, distance from nearest Cooperative repair facilities in Sierra Vista, terrain challenges, and long maintenance travel times and suggest having line crews pre-positioned in rural areas during predictable outages.

3.1.3 Other Measurements of Outages Available for the V-7 Service Area.

Q. Can you compare the V-7 feeder area with other SSVEC distribution areas?

A. Yes. Upon request, the Commission Staff provided 12-months of data for different months in 2008 and 2009. This data was presented to the Cooperative on 13 July 2009 in Figure 2 below.

Figure 2 shows at least three other feeder lines with higher hours of outage, and two other feeder lines with higher number of customer-hours of outage. This data show 0.06 hours or 36 minutes of outage per customer during this data set for 12 months.

2008 V-7 AND OTHER FEEDERS (CONNECTIVITY) OUTAGE DATA

Feeder Line	Hours Off	Number of Customers	Customer Hours OFF	Hours OFF/ customer
V-7 Sonoita/Patagonia	179.98	3057	3839.91	0.06
R-3 Ramsey	64.16	1006	2988.66	0.06
K-2 Chri	259.75	1828	4299.75	0.13
O-5 Mescal	392.22	2639	4657.97	0.15
J-3 Kansas Settlement	197.05	1202	3409.05	0.16

1. Three feeder lines have higher outages than V-7, with twice the outage hours per customer.
2. Only 1 V-7 outage was due to "overload" impacting 1 customer.

Analysis prepared by Jeanne Horsmann and Gail Getzwiller, Sonoita.
Ref: SSVEC 2008 Feeder Outage Data (without November)

Figure 2 – 2008 V-7 and Other SSVEC Feeders Outage Data.[8]

Q. Did the Commission Staff in the Rate Case review reliability?

A. Yes, the Commission Staff does this in all rate cases and found that the average Co-op customer had <u>2.09 hours of outage per year</u> between 2004 and 2007. The Co-op's average hours of outage per year varied between a low 1.10 hours in 2005 and 3.52 hours in 2007.[9] Based on these data, the <u>best</u> SAIDI was in 2005 for the entire Co-op's service area was in the Second Quartile. In terms of SAIDI (average outages per year per customer during 2004 to 2007), the Cooperative was in the Third Quartile, and its worst year (2007) it was in the Bottom Quartile according to Table 2 above.

The Commission Staff also agreed with the FS reliability, that the

> "**<u>SSVEC outage ratio is well below the Rural Utilities Service ("RUS") guidelines of 5 outage hours per consumer per year</u>**."[10] [emphasis added]

Again, it is noted that the V-7 Feeder area averaged 3.0 hours of outage per year per customer (SAIDI) which is slightly above that of the overall average for the entire Cooperative.

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8 From a Briefing that I provided to SSVEC staff on 13 July 2009, slide 10. [Slide notes are omitted]

9 ACC Docket No. E-0157A-*08-0328*, "Direct Testimony of Prem K. Bahl" on 17 February 2009, p. 15 at 9 to 12.

10 *Ibid.*

3.2 Total Number of Outages in the V-7 Service Area.

Q. What has been the trend been in total number of outages in the V-7 Area?

A. As shown in Figure 3 below, in the past ten-years, the number of outages has shown a moderat decline. This trend, according to the FS, is due to the continually increasing the number of utility poles with lightning arrestors and an aggressive utility pole replacement program that has produced these improvements. Replacement poles between Sonoita and Mustang Corner scheduled for last July did not happen; however, new poles are in from Sonoita to Patagonia.

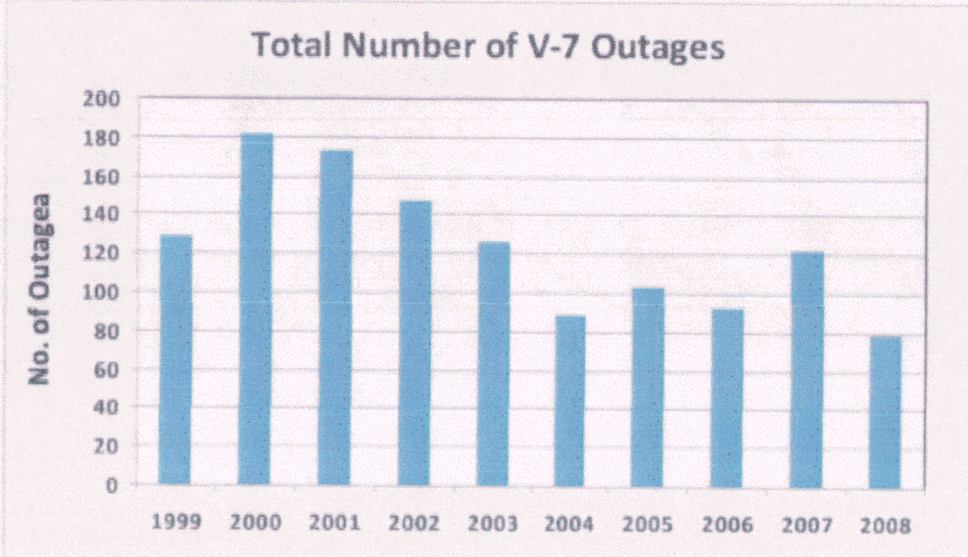

Figure 3 – Total Number of V-7 Service Area Outages. **[FS p. 12, Fig. 3]**

The FS states:

> "Figure 3 presents the annual outages on the V-7 feeder over the last 10 years. Although the number of outages is higher than most compact feeders with fewer feeder miles, **<u>the number does not appear inordinately high given the very rural area served and significant outage exposure</u>**." [FS, Fig. 3, p. 12, emphasis added]

3.3 Causes of Outages in the V-7 Service Area.

Q. What are the causes of outages in this area?

A. Using industry standards, the Cooperative uses a "cause code" whenever there is an outage. Figure 4 shows these with the highest outages causes first. The FS states:

> "Figure 4 presents composite 10-year outages by cause code for the V-7 feeder. The <u>primary causes of outages have been weather</u> (lightning, wind) <u>and animals</u> (birds, other animals). Other <u>dominant outage causes</u> include <u>unknown</u> and <u>other</u>, <u>many of which could be weather or animal-related</u>, but otherwise not observed by field personnel or the person reporting the outage." [FS p. 12, emphasis added]

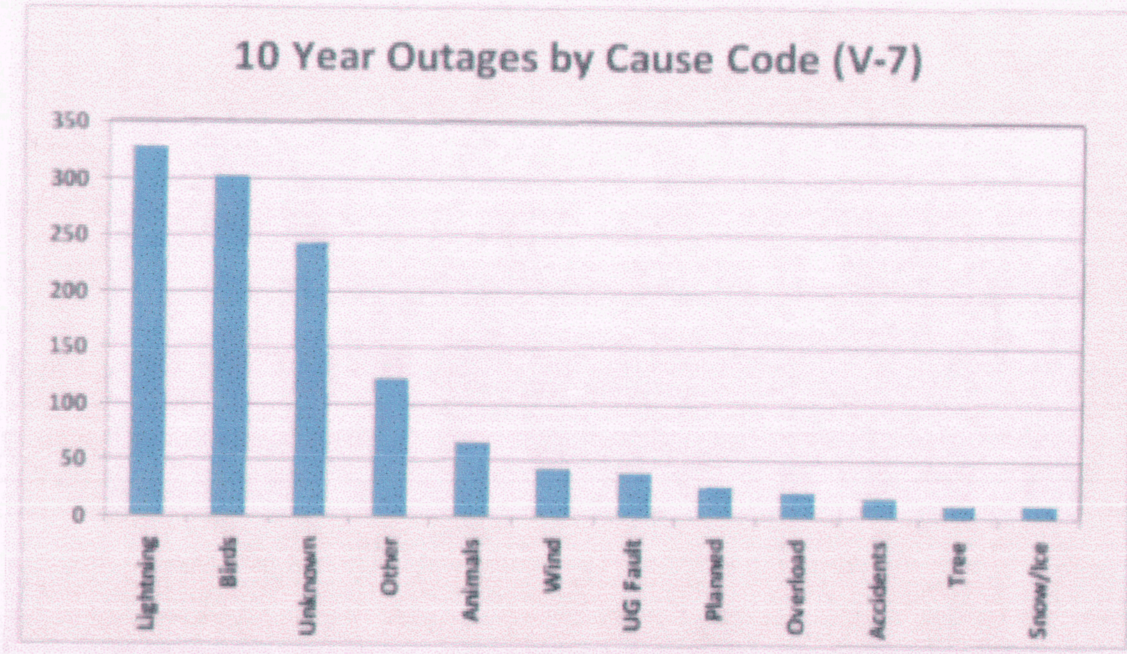

Figure 4 – Ten-Year Outages by Cause Code in the Service Area. **[FS Fig 4, p. 13]**

Lightning is the most common reported cause of an outage, followed by birds, "unknown", "other", animals, wind, underground fault, planned, overhead, accidents, tree, and snow/ice. As the utility adds more and more lightning arrestors, as recently done on the Patagonia line, this impacted the declining trend in Figure 3 for the past decade. The "other" and "unknown" codes are a fairly significant cause for about 365 outages in the ten-years.

The 350 miles of existing utility poles represented by Figure 4 will remain in the V-7 area. The additional 23 miles of the proposed 69 kV line will not make any changes to the results in Figures 3 and 4 above. In fact, any additional outages on the 69 kV line will need to be included whenever that line fails, to increase the potential total number of outages per customer per year or SAIDI. The substation, which is independent of the 69 kV line, improves outage reliability.

Figure 2, also includes causes of outages with "all Other" dominating for every year but 2001 when lightning-caused and number of outages averaged about 2.5 hours per customer that year. The proposed 69 kV line would also not have reduced those outages.

3.3.1 Equipment Caused Outages are Dominated by Pole Transformer Fuse Failures.

Q. What was the dominant equipment causes of these outages in the V-7 area?

A. Figure 5 shows <u>Transformer fuses</u> caused over 750 outages in the past ten years.

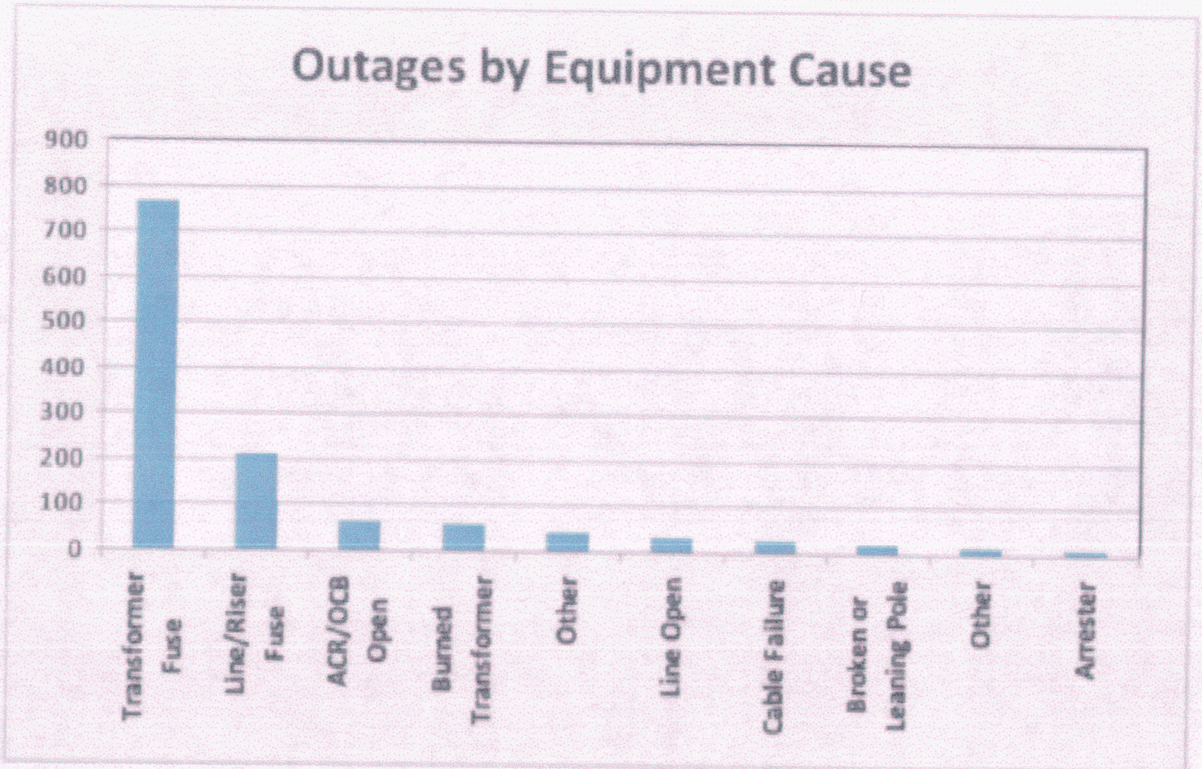

Figure 5 – Transformer Fuse Failures Dominate Equipment Caused Outages. **[FS p. 14, Figure 6]**

The failures of pole transformers was considered unique by NCI which that

> "…<u>indicate **most outages are due to transformer or pole riser fuses, many** of which **serve one or a few homes**</u>. (The very large lot sizes limit the number of secondary services that can be served by a single transformer: if the distance between line transformer and service entrance is over 300 feet, it may create unacceptable voltage drop.)" [FS p. 13, emphasis added]

This anomaly was assessed by NCI's statement and explained in the footnote as follows:

> "The large majority of outages were caused when line or transformer fuses opened [about 775 of about 1100 in 10 years]. Interestingly, the large **<u>number of transformer fuse operations is an unexpected finding</u>**, as most animal and lightning-related outages occur on the primary line; whereas transformer fuses typically open when a fault occurs on the secondary side of the transformer." [FS p. 14, emphasis added]

And in Footnote 8, explained as follows:

> "SSVEC's standard for line transformer arrestor placement is adjacent to the fuse cutout. **<u>Industry research suggest the preferred placement for arresters is directly on the transformer to reduce voltage potential rise on the transformer loads</u>**." [FS p. 14.emphasis added]

3.3.2 Number of Customers Impacted by Outages in the V-7 Service Area.

Q. How many customers were impacted by these outages?

A. As shown in Figure 6, most of these outages involved a small number of customers.

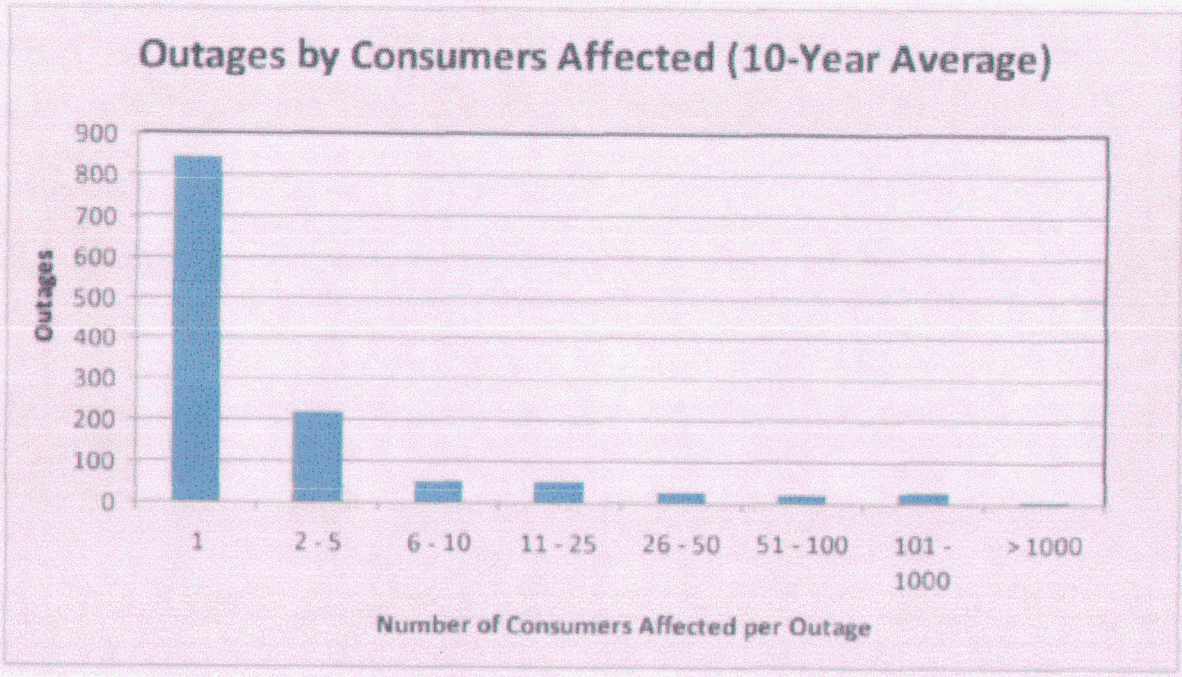

Figure 6 – Number of Customers Affected by Outages. **[FS p. 13, Fig. 5]**

About 850 of the approximately 1100 outages in the past ten years impacted only ONE customer, almost 78%. According to NCI, **<u>over 90% of the outages impacted less than 3 customers</u>**. This shows that transformers to service lines, with 1 to 3 customers per service line, appear to be where the vast number of outages occurs. The 69 kV line will not resolve the transformer fuse reliability issues that average of 75 outages per year.

3.3 3 Weather Impacts on Outages.

Q. What impacts do lightning, wind, rain and storms have on the reliability?

A. Lightning dominates weather-caused outages, which peak during the summer monsoon months, as shown in Figure 7. Also, diurnal outages occur more frequently in early morning hours between 9AM and 1 PM and again between 6-7 PM in Figure 8. The early morning outages can be explained as occurring from an unnoted outage that occurred during the hours between midnight and 7 AM when most people are asleep and are unaware that an outage has occurred. The early evening peak appears due to afternoon thunder and wind storms.

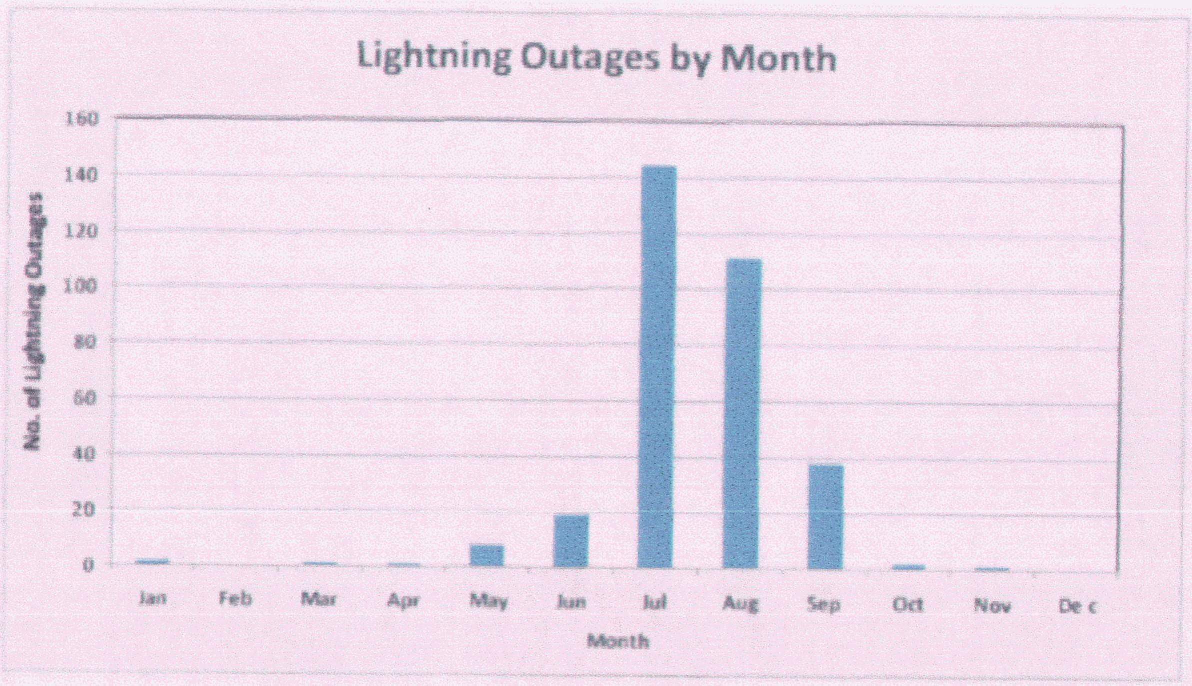

Figure 7 – Lighting Outages by Month. **[FS p. 15, Fig. 7]**

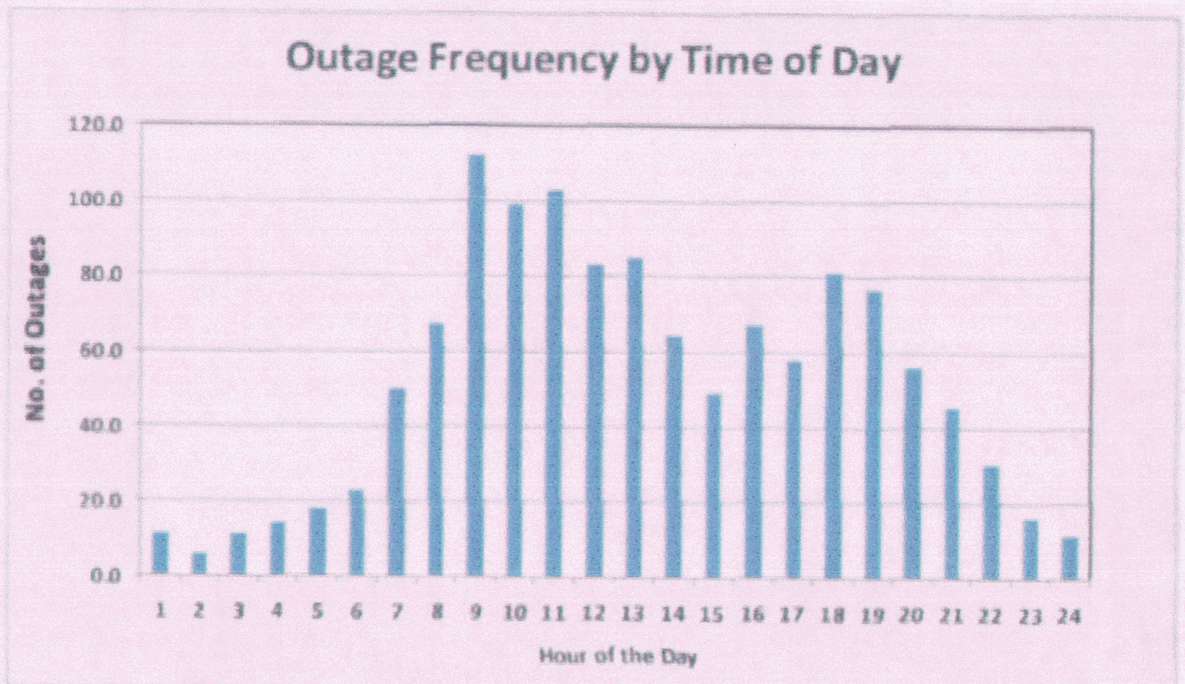

Figure 8 – Outage Frequency by Time of Day. **[FS p. 15, Fig. 8]**

3.4 Outages on the line Between Mustang Corner transformer to Sonoita.

Q. Are there outages on the existing 24.9 kV line from Mustang Corner to Sonoita?

A. The FS states that <u>only limited outages have occurred</u> on this line between the SR-90/SR-83 junction and Sonoita (vicinity of SR-83 south of the "Sonoita Crossroads"):

> "The low number of full feeder outages and effective use of reclosing circuit breakers along many sections of the V-7 feeder has limited the average outage hours per customer to about three hours. "Notably, **<u>full feeder outages that interrupt all customers served by the V-7 feeder has been very low</u>** – less than one per year over the last five years." [FS p. 1-2, emphasis added]

and

> "…**<u>very few outages interrupted all customers served by V-7</u>** … Figure 5 indicates the **<u>majority of outages only interrupted a single customer</u>**; **<u>over 90 percent of the outages interrupted three or fewer customers</u>**." [FS p. 13, emphasis added]

The excellent responses by SSVEC's line crews with easy access from SR-82, SR-83 and Elgin Road and improved line design have reduced line outages on this approximately 24 mile 24.9 kV line segment. NCI did not state or imply that this line segment was of serious concern.

3.5 Reliability Improvements with a new Sonoita Distribution Substation.

Q. What does the Feasibility Study say about improving reliability with the new Sonoita Substation?

A. Construction of the new distribution substation will improve reliability. The FS states:

> "New supply alternatives which reduce line exposure by **<u>creating new feeder segments would improve reliability by 15 to 30 percent</u>** <u>beyond current levels</u>." [FS Pp. 2 and 14, emphasis added]

Q. What additional authority does the Cooperative need to construct the Sonoita Distribution Substation?

A. None. The Santa Cruz County Board of Adjustment approved this substation in May of 2009. The Cooperative to not commenced construction of this distribution hub for the communities with a feeder line for Patagonia, Elgin, Canelo and Sonoita. The fifth feeder line will be for renewable energy generated from a 750 kW solar array adjacent to the substation.

All of these actions can be accomplished without additional regulatory actions, other than submission of routine building permits. The ongoing 69 kV line disputes are independent of the substation, thus it should be under construction at this time. There are no reasons for delay in construction of the Sonoita substation, as Santa Cruz County grants these building permits.[11]

[11] Discussions with the Santa Cruz County Planning Director indicated the building permits had not been received.

3.6 Conclusions for Issue 1.

Q. What are the conclusions from the Feasibility Study concerning reliability?

A. NCI states that

> "NCI <u>concludes that</u> **<u>feeder and substation facilities are generally in good condition and appropriately maintained</u>**. Our findings regarding **<u>the need for capacity support generally is independent of feeder and substation equipment needs.</u>**" [FS p. 17, emphasis added]

Q. What are your conclusions concerning reliability?

A. Based on the evidence by NCI in the FS, the Commission Staff, and other independent analysis, there does NOT presently exist a significant reliability problem in the V-7 service area. Resolution of these known problems are not so urgent to require emergency action, but do suggest that serious action to be taken by the Cooperative improve the Distribution Line Reliability Indices to reach the Top and Second Quartiles in the V-7 Feeder <u>and</u> all other lower performing feeder areas in the Cooperative's service area.

The performance of Cooperative by continuous incremental upgrades and plannning and its effective maintaining and operating personnel for this distribution system is why the reliability, in this challenging rural environment, is steadily improving. Other than construction of the distribution substation to make a 15% to 30% improvement in reliability, in my opinion, the Cooperative is on the right track with respect to reliability, in particular, in reducing the number, frequency and durations of outages. This has no direct relationship with a 69 kV line.

3.7 Recommendations for Issue 1.

It is recommended that curing the known reliability problems in the V-7 Feeder Area are <u>not</u> dependent of the construction of a 69 kV subtransmission line; however, the construction of the approved Sonoita distribution substation should not be delayed.[12]

Therefore, no conditions exist that involve reliability in terms of the standard indices that are urgent or require emergency authorization to construct a 69 kV subtransmission line.

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[12] In view of the importance of the Sonoita Substation for reliability improvements, the distribution portion could be constructed without an interconnection (but space reserved) while the 69 kV line issue is being resolved. A Phase I for the distribution station and its five feeders could to be followed by a possible Phase II for the 69 kV connection and transformer equipment, if that is the final action of the Commission. This two Phase approach has been suggested to the Cooperative several times since May of 2009.

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SECTION 4 - ISSUE 2

MEETING THE ELECTRICITY DEMANDS WITHOUT A 69 KV LINE BASED ON INFORMATION IN THE FEASIBILITY STUDY

Issue 2 – The electricity short-term peak and emergency demands in the V-7 Feeder Area can be met by methods in the Feasibility Study other than the 69 kV line.

4.1 Distribution Line Capacity Capabilities in the V-7 Service Area.

Q. What are the capacity limitations for the V-7 service area?

A. The FS indicates that the V-7 maximum capacity is limited by the Mustang Corner substation transformer capacity with a rating of 7.0 MW [FS p. 37] and with a nameplate rating of 7.0 MVA when the power factor is 1.0 [FS p. 30]. The FS goes on and states:

> "... utilities often adjust the rating of substation transformers based on ambient conditions and load patterns, and reasonable reduction of equipment life.[13] Because the V-7 feeder and the Huachuca substation are winter peaking, **the capacity of the transformer typically is higher than nameplate due to ambient cooling**. This is in contrast to substation peak in the summer, in which case maximum transformer loading is closer to nameplate.
>
> "NCI did not independently calculate the weather-adjusted transformer rating, but notes that other utilities will apply rating above nameplate for devices experiencing short-duration cold weather loading.[14] Notably, the 2008 V-7 summer peak was about 5800 kW [5.8 MW], about 16 percent lower than the most recent winter peak of 6903 kW. Hence, **an additional 1000 kW [1 MW] of substation transformer capacity would be available at Huachuca** [at Mustang Corners] **substation if the winter rating is increased by at least 16 percent above the nameplate rating**." [FS p. 31, emphasis added]

During a recent discussions with the Cooperative, an additional capacity limitation of 2.333 MW per phase was also indicated, or equal to one-third of the 7.0 MW equally allocated to each of the three distribution line phases: A, B, and C.

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[13] IEEE, an industry group that develops guidelines and standards for electrical equipment, has published guidelines that enable electric utilities to determine the increase in transformer rating as a function of a device pre-loading, ambient temperature and expected increase in loss of equipment life. **Our experience indicates winter-peaking utilities often increase transformer rating by 25 percent (or higher) for devices in good condition.** In contrast, transformers known to have operational or design constraints often are limited to the nameplate capacity ratings. [FS Footnote 17, p. 31, emphasis added]

[14] The determination of acceptable transformer loading is utility and location-specific. The value typically is based on a combination of several factors including average ambient temperature, transformer pre-loading, transformer design, condition, performance history (including number of high current through-faults), and acceptable loss of life. [FS Footnote 18, p. 31]

Q. What would be the impact of using weather-adjusted transformer ratings?

A. The maximum capacity for the existing 24.9 kV line would be increased from 7.0 MW to at least 8.0 MW, based on the information provided by NCI. If the rating was increased by 25%, as indicated in FS footnote 17, then the transformer would have a winter peak capacity of 8.75 MW. This is significant, because it increases the A, B, and C Phase ratings between 333 kW to 583 kW to a weather-adjusted winter rating to between 2.666 MW and 2.916 MW per phase.

Q. Has the V-7 Transformer been known to exceed its weather-related capacity?

A. No. No data presented in the FS show any winter peaking that exceeds 7.0 MW other than in one instance as a result of a substation breaker locking out and causing an interruption of service in December 2009, but this was below the trip setting of the phase conductors [FS p. 20, fn 10]. Even under these conditions that may have happened over a very short time period, the transformer was not damaged. The trip settings for the phase conductors are not in the FS.

The impact of using or considering weather-related capacities for the 69:24.9 kV transformer at the Mustang Corner substation significantly changes the "urgency" of upgrading the transmission capabilities to the new Sonoita distribution substation.

Q. How can additional capacity be provided for the V-7 service area?

A. Yes. This is discussed in some detail in Section 5 below.

4.2 The Impact of Line Loss or Energy Loss on the Capacity of the V-7 system.

Q. What are the line or energy losses on the existing system?

A. All electricity systems require energy to transmit electricity through conducting wires. In utility-scale systems, due to the I^2R law, as voltage increases on the wire, less energy per Watt transmitted is required. Using the existing V-7 system, NCI calculated the energy required to transmit electricity to customers in the V-7 area. The FS states:

> "…any increase in load can significantly increase line losses, particularly on longer lines. Such as in the case with the V-7 feeder, where **losses at peak are approximately 30 percent of total feeder demand.** Significantly, **incremental losses approach 50 percent** - that is, for each additional one kilowatt (kW) of load added to the feeder, on average, approximately1.5 kW must be delivered from the [Mustang Corner] Huachuca substation at peak." [FS p. 23, emphasis added]

The FS provided model data that show a substantial portion of the total electricity demand is consumed in losses. [FS p. 23] These losses are nothing more than **wasted energy** used to transmit electricity to the V-7 customers. These losses are not unexpected or unusual because as the length of the line causes losses to be much higher than with shorter feeders, that result when the Sonoita substation is built. Table 4 shows the Peak Losses in kilowatts (kW).

Table 4 – Peak Losses (kW) and Percent for Actual Peak Loads. [FS p. 24, Table 3]

Year	Peak Load (kW)	Peak Losses (kW)	Total Load (kW)	Percent Losses
2000	4511	715	5226	16%
2001	4856	854	5710	18%
2002	4919	881	5800	18%
2003	4440	689	5129	16%
2004	4668	777	5445	17%
2005	4787	824	5611	17%
2006	5464	1124	6588	21%
2007	5652	1248	6900	22%
2008	5655	1248	6903	22%
2009	5406	1124	6530	21%

The percent of total load being lost has increased from around 16-18% to 21-22% between 2000 and 2009, as the total loads have increased from 5,236 kW (5.236 MW) to 6,530 kW (6.530 MW). These corresponding actual line losses, when at peak demands, which increased from 715 kW (0.715 MW) in 2000 to 1,124 kW (1.124 MW) in 2009 on the existing 24.9 kV line. Customers all pay for these line losses.

This Table also shows that the total peak loads for 2007 and 2008 were nearly identical at 6.9 MW (6900 kW) and <u>in 2009 the **peak load decreased to 6,530 kW (6.53 MW) or 5.4%**</u>. This is another indication that <u>**total load growth has been decreasing**</u>, along with the DOE Energy Information Administration (EIA) national electric load decreases for the past three years, averaging about 2 to 3% per year nationally.

These line losses were estimated to cost the Cooperative and its ratepayers over 3,000,000 kilowatt-hours, kWh (3,000 MWh) in the V-7 Feeder Area. This is equivalent to about $230,000 in 2009. [FS p. 24, Table 4]

This extra power required to transmit exists on all feeder lines and increases the infrastructure requirements for Cooperative, by compounding all of the line losses millions of dollars all at ratepayer expense. It must be noted that infrastructure is developed to meet peak load conditions, thus just in this one feeder area, over 20% additional infrastructure is necessary, up the line to the generation source, is required.

One way to reduce line losses is to reduce the length of the line. Local generation in the form of renewable energy or distributed generation can be designed to reduce line losses. This will be discussed in the next section.

4.3 Service Load Demands in the V-7 Area.

Q. What is the peak demand or load on the V-7 distribution system?

A. Various customer classes use the V-7 feeder shown in Table 5. There are a total of 2,355 customers in this service area, of which 1,675 or 71.6% have residential rate codes. There are some 642 or 26.8% general service (small business customers), 13 or 0.6% residential (SunWatts) customers, 8 large power customers, 4 irrigation customers (agriculture), 1 residential Time of Use (TOU) and 6 TOU (Total kWh) customers plus some others on miscellaneous rates. There is 1 customer with a pre-meter construction rate, thus <u>only ONE customer in this entire feeder area was under construction when this data were obtained</u>.

Table 5 – Number of Customers by Rate Codes. [FS p. 26, Table 5]

Rate Code	Rate Description
GS DEMAND 1-PHASE	67
GS DEMAND 3-PHASE	31
GS NON-DEMAND 1-PHASE	536
GS NON-DMD 3-PHASE	8
IRR CONTROL AW	2
IRR LOAD FACTOR DMD	1
IRR SEASONAL	1
LARGE POWER	8
LINE EXTENSION	3
PRE-METER CONST MIN	1
RESIDENTIAL	1675
RESIDENTIAL SUNWATTS	13
RESIDENTIAL TOU ON-PEAK	1
SET-UP RATE	2
TOU TOTAL KWH	6
TOTAL	**2355**

4.3.1 Peak Loads and Demands can be reduced with Shorter Lines.

Q. What is the impact of the feeder and load total demands compared to capacity?

A. The FS provided the substation load profile in Figure 9 shows the substation transformer nameplate 7.0 MW rating with load demands the number of hours in the year 2008. Customer actual Loads for 2008 are in Red, below the Total Load curve, with the Total Load in Black above. The difference between these two curves is the Line Loss. It is noted that when the total customer demand or load is below approximately 3.0 MW (3000 kW), that the line losses decrease, about 50% of the time. Conversely, when the customer demands are higher, such as above 4.0 MW (4000 kW), the line losses cause the Red (customer load) curve to separate from the black (total load) curve. In other words, Line Losses increases as Customer Loads increase.

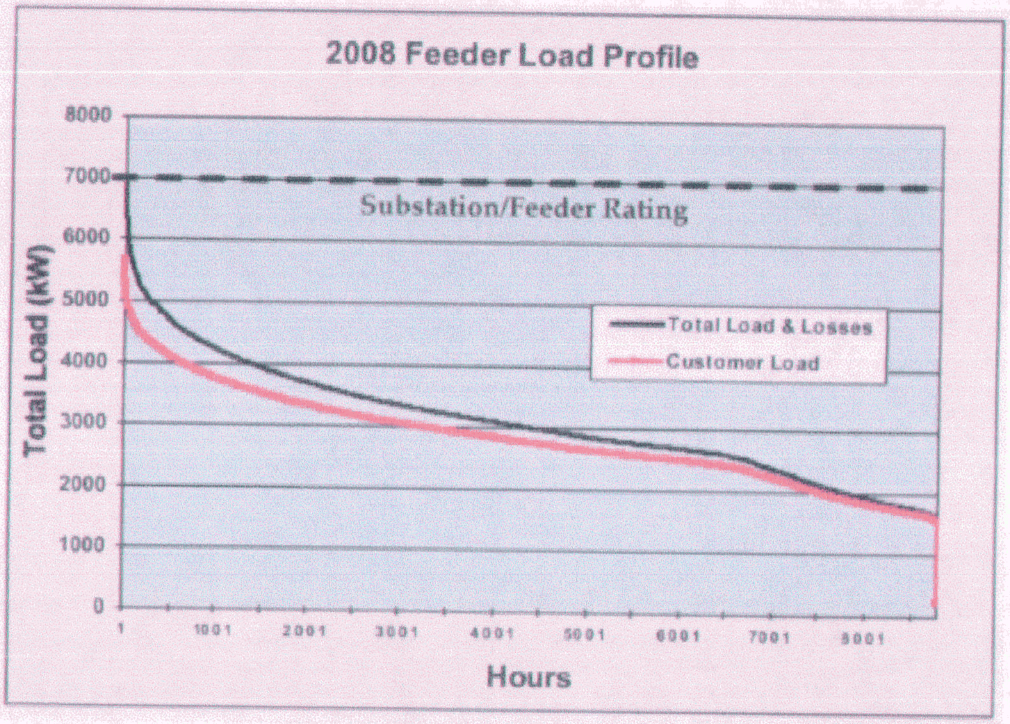

Figure 9 – The V-7 Feeder Load Profile for 2008. [FS p. 27, Fig. 13][15]

This figure shows that less than about 1,000 hours does the Total Load in the V-7 feeder area exceed 4.0 MW (4000 kW) and less than 500 hours exceeding 4.5 MW or less than 100 hours exceeding 5.0 MW. It is important to note that Line Losses become more significant at higher customer loads. If weather-adjusted transformer capacity data were used, then at 8.0 MW (8000 kW) there would be no capacity issues in the V-7 service area.

4.3.2 Peak Loads and Demands vary as according to the Time of Day.

Q. What are the impacts of Time of Day on Peak Loads?

[15] In Figure 9, the top curve is labeled "Total Load & Losses". This is an error. It should be labeled as "Total Load" and the differenced between these two curves labeled as "Line Losses".

A. Based on the 20 highest peak load days in the past three years, Figure 10 shows the diurnal peak loads. Of the 16 dates shown on the right of the figure (the remaining 4 dates are not known, thus are not considered).

All of these <u>peak load days occurred between 26 December and 11 February</u>, in a short period of some 6 weeks. With one exception, every (or 95%) of the peak periods occurred during the <u>winter morning hours</u>.

There also is a secondary but a lower peak in the early afternoon that occurred about 5% of the time. On 27 December 2007, the peak that day was an early evening peak. In general, 95% of early evening secondary peak demands were between 10 to 30% or more lower than the morning winter peak.

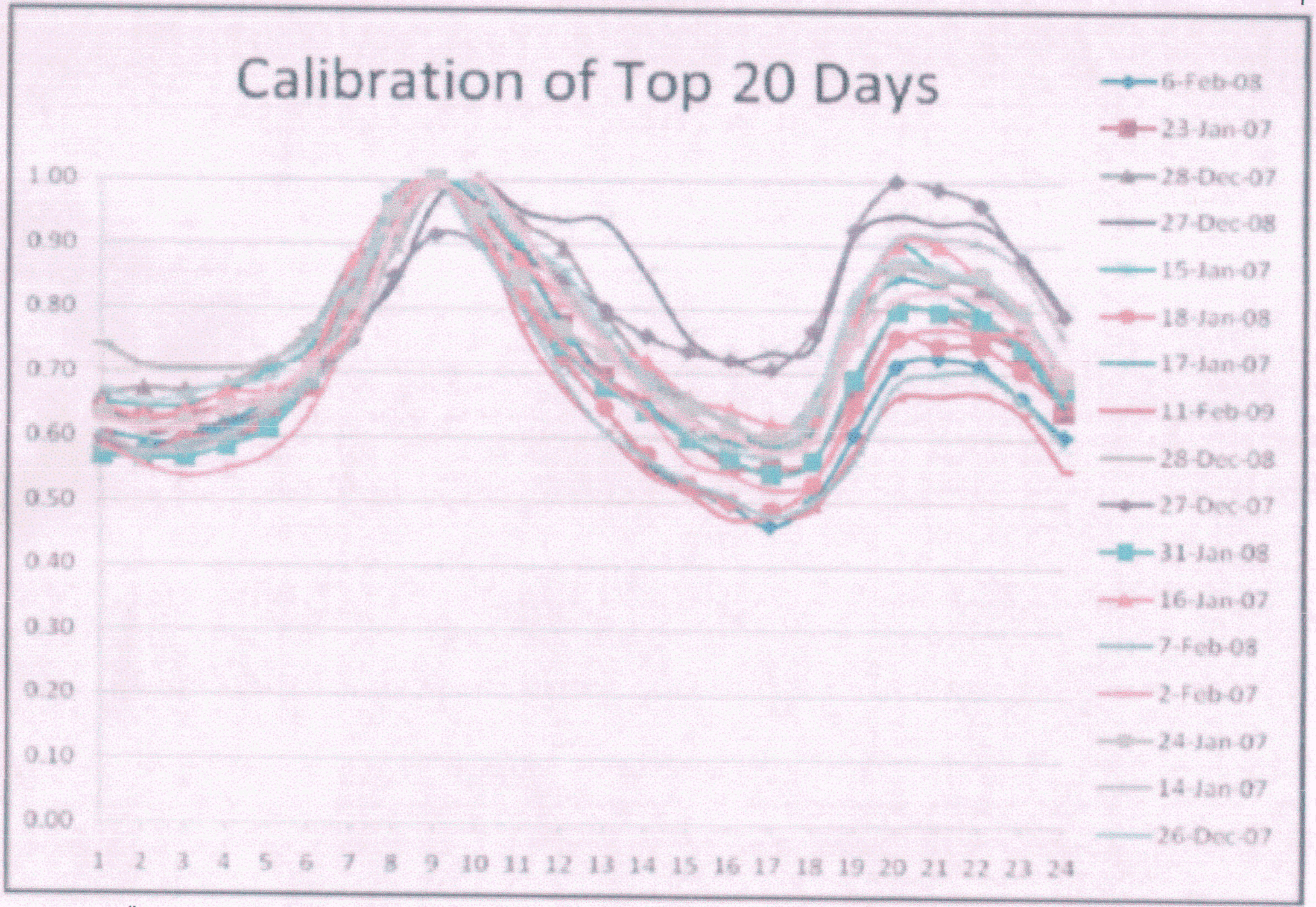

***Figure 10 – The Hourly Peak Load Profile for the 20 Highest Peak Days in the Last 3 Years.* [FS p. 27, Fig. 14]**

The FS noted that

> "…there is **high degree of comparability among the peak day load curves**. This consistency likely is due to recurring heating load during colder winter days - all 20 days of highest peak load occurred during winter months. **Predictable load patterns enable system planners to design programs to reduce daily peaks; e.g., targeted load reduction programs**. Further, **the duration of the peak hours on days with the highest demand is relatively short, as load quickly tapers off after sharp early morning peaks**." [FS p. 27, emphasis added]

These comments are very important as Demand Side Management (DSM) programs can be developed to reduce these consistent short-term peak loads, as discussed below in Issue 3.

4.4. Forecasts for Peak Demands Need Realistic Information.

Q. Does the Feasibility Study provide realistic peak demand forecasts?

A. Not exactly. In particular, there has been almost no building in Santa Cruz County or in the V-7 area in the past two years. Shown in Table 5 above, there was only one pre-construction "temporary" electrical connection. Older forecasts, such as the 2006 Arizona DES data used in the FS are suspect, due to a major decline in building permits. This is an area where NCI may have used old data.

The Cooperative believes that hundreds of homes are being planned for three housing developments in the Patagonia area. Conversations with the Santa Cruz County Planning Director indicate NONE of these three developments are active, at least two are bankrupt, and NONE have any active building at this time. In general, only about a dozen or so homes are being constructed this year in the V-7 service area.

Further, all new developments in Santa Cruz County are having a requirement that at least ten percent of the homes be EnergyStar™ certified that will reduce future residential electrical loads.

The FS found the estimated annual feeder peak loads to be as shown in Figure 11 below.

The data in Figure 11 has three forecasts; however, based on present growth, the "low" case appears even higher for the next few years. Further, historical growth rates can NOT continue unabated in the V-7 feeder area because of the lack of water resources. The *2004 Santa Cruz County Comprehensive Plan* limits the population growth in the part of the county in the Santa Cruz Active Management Area (SCAMA) to 31,000 more people due to requirements SCAMA must remain sustaining. This plan also implements a special *Sonoita Cross-Roads Compressive Plan* that is more restrictive than the county's Plan. In 2009 Town of Patagonia

General Plan requires that community to be sustaining in its resources and emphases renewable energy development.

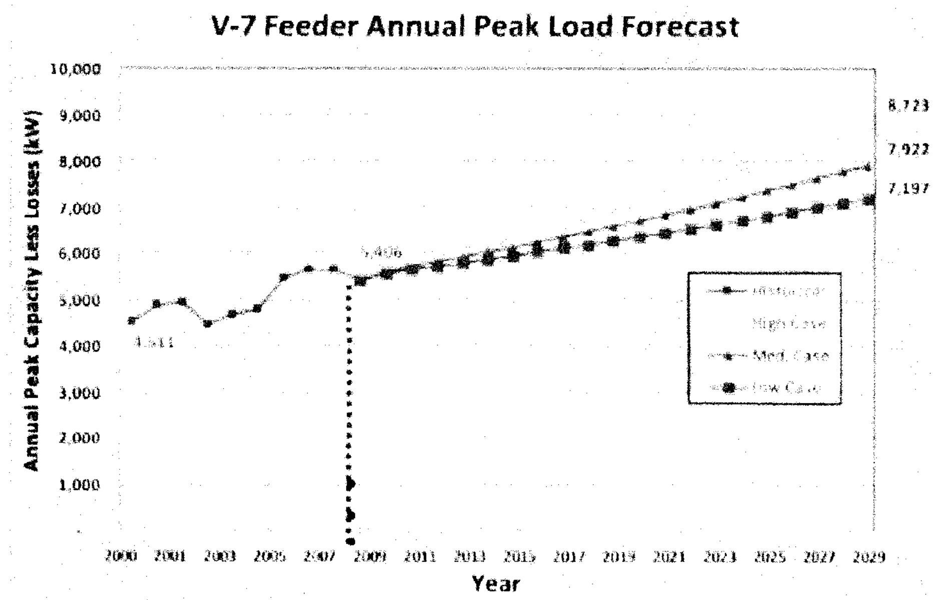

***Figure 11 – V-7 Feeder Annual Peak Load Forecasts based on 2006 Population Forecasts.* [FS p. 29, Fig. 16]**

In summery, all large future building projects will have to prove they meet the goals, objectives and policies in these management plans. Thus, long-term future growth in the Northeast Character Area of Santa Cruz County will be limited.

Q. What are the future load requirements for the V-7 Feeder area?

A. The FS states that

> The load forecast indicates about 2500 kW of new load will added to V-7 over the next 20 years *prior* to losses, an increase of about 40 percent. As noted, incremental line losses at peak are approximately 50 percent. Accordingly, supply alternatives that reduce total feeder load also reduce the percent losses on the V-7 feeder. <u>Supply options that create a new source in Sonoita or other central locations of the feeder will cause losses to decline significantly due to the reduced loading on the primary section of line between the Huachuca substation and V-7 load centers</u>. If total losses are brought down to more reasonable levels of 10 to 15 percent at peak, total capacity deficits will be about 1500kW in 10 years and 3500kW in 20 years. [FS Pp. 31-32, underline and bold emphasis added, italics in original]

Therefore, the FS supports adding new supply sources in Sonoita or other central locations in the feeder area, to reduce line losses. Further, NCI has stated that losses could be reduced to 10 to 15 % of peak instead of the 40 or higher levels of line loss, and then there will be a capacity deficiency, without any new supply sources as follows:

a. <u>In **2019**, an additional **1.5 MW** (1500 kW) of capacity will be needed.</u>

b. <u>In **2029**, an additional **3.5** MW (3500 kW) of capacity will be needed.</u>

4.5 Voltage Changes on the V-7 Feeder under various Load Conditions.

Q. What did the FS say about Feeder Voltage issues?

A. NCI modeled the voltage profiles for two long extension of the V-7 feeder, to Canelo and to Patagonia, at peak loads. Both required significant regulation to maintain voltages, and the model results "predicted that <u>they are within acceptable limits</u>" [FS Pp. 17-19]

Q. Are there voltage variations between the Phases?

A. Yes. A long single-phase (B-Phase) line serves Canelo and areas south of the Babacomari Land Grant. The B-Phase is the only phase that has exceeded 2.333 MW in the past three years, other than one hour when the A-Phase was greater than 2.333 MW.

Some possible solutions, not included in the FS, could include adding a second-phase line partway along this long one-phase feeder to off-load the B-Phase, or to use other methods to reduce the B-Phase loads. Action is necessary to reduce voltage imbalances.

Q. Can Feeder Protection Issues be Resolved?

A. Yes. On long feeder lines, line-end voltage outages produce fault currents at the Mustang Corner substation that approach levels to trip the phase lines. This is common for long circuits with attendant problems for reclosers, fuse protection, power quality degradation, and additional impedance problems. The FS then states:

> "One of the <u>advantages of new supply options (substation) located centrally along the existing V-7 feeder is the corresponding increase in available fault current</u>. The higher fault current allows protective devices to operate faster, thereby <u>improving power quality and protection coordination</u>. Protection coordination also is facilitated by the fewer number of protection zones, achieved by <u>creating several independent feeders</u>, each with independent substation feeder breakers - <u>four were proposed for the new</u> 69/24.9kV <u>Sonoita Substation, with one spare for future use or to connect DG</u>." [FS p. 19, emphasis added]

This statement supports the Sonoita substation and its four distribution feeder lines and one distributed generation feeder line; however, a new 69 kV line has no benefits.

Q. What Power Quality issues are discussed in the Feasibility Study?

A. The voltage dips caused by recloser or fuse operations impact sections of line farthest from Mustang Corner. The FS states:

> "<u>Absent a new supply source that will strengthen voltages in outlying areas, voltage dips and perturbations are likely to continue, and worsen as loads increase.</u> As noted in other sections, high line losses under high load conditions exacerbate voltage drop." [FS p. 21, emphasis added]

Therefore, the addition of new supply sources, such as renewable energy or distributed generation, will improve Power Quality.

Q. Are there harmonic and resonance performance issues?

A. Yes there is a potential for these issues but have "not been confirmed or independently verified" [FS p. 21] If these are present, mechanical and thermal stresses may impact magnetic devices such as motors, transformers or relay coils. Further, telephone interference, causing harmonic Electromagnetic fields (EMF) or even faulty meter readings. Mitigation is usually done by additional feeder sectionalizing or removing system capacitance or adding filters. [FS p. 22]

The FS suggest for mitigation of harmonic distortion to

> "…there may be several options available for mitigation. Two of these methods could include <u>either feeder separation</u>, such as the 69kV Sonoita Substation - <u>four feeder option or by implementing filters along the V-7 feeder.</u> Most likely if the filters were needed, they would be shunt filters designed to mitigate harmonic frequencies observed on secondary voltages for the V-7 feeder." [FS p. 22]

Q. Have actions taken by SSVEC been effective to reduce these problems?

A. Yes. The Cooperative has installed additional reclosers and protective equipment that have successfully limited full feeder lockouts, which improves reliability; however, momentary interruptions are caused to all customers on the V-7 feeder. [FS p.20] Again, the new substation will limit this on only those customers on one of the four feeder lines from that substation.

4.6 Conclusions for Issue 2

Q. What are the conclusions from the FS concerning capacity?

A. The FS contains the following:

"<u>SSVEC should take immediate steps to ensure sufficient capacity is available to serve existing and new customers in the short and long-term.</u> SSVEC should carefully review the impact any new load will have on feeder loading and performance to ensure voltage and loading standards are not exceeded or violated. An exception would be load that is proven to peak at times other than the current peak – these typically occur on cold winter mornings with a secondary peak during early evening hours." [FS p. 31, emphasis added]

It is noted that "how" SSVEC should proceed is not included in this statement. Further, it states that sufficient capacity is available to serve existing and "new" customers.

Q. What are your conclusions concerning capacity?

A. Based on information in the Feasibility Study:

1. SSVEC should calculate the weather-adjusted capacity capabilities of the transformer presently serving the V-7 feeder area for winter and summer peak conditions.
2. New capacity limits need to be used to determine line loading peaks, in particular for Phases A, B and C.
3. Phase B loads should be redistributed as soon as possible to Phases A and C, which are significantly less loaded.
4. Reduction of line losses should be determined by the use of local distributed generation and renewable energy generation systems.
5. The Sonoita distribution substation with its feeders and 750 kW solar generation source should be constructed as soon as possible.
6. Additional capacity enhancements are also included in the next section.

4.7 Recommendation for Issue 2.

It is recommended that new weather-adjusted capacity limits for the transformer and lines be calculated and implemented as recommended in the Feasibility Study, Phase loading should be adjusted to reduce overloading of Phase B and to equalize loading on all three phase lines, local generation should be used to reduce line losses, and that the Sonoita substation with its four feeders and the 750 kW solar plant constructed as soon as possible.

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SECTION 5 - ISSUE 3

MEETING THE PERFORMANCE REQUIREMENTS WITH ACTIONS BASED ON INFORMATION FROM THE FEASIBILITY STUDY

Issue 3 – The Renewable Energy, Distributed Generation, Demand Side Management, and Distribution System Actions from the Feasibility Study can Achieve the Performance Requirements for the V-7 Service Area

5.1 Renewable Energy Supply Alternatives.

Q. What Renewable Energy Supply Alternatives were considered in the FS?

A. In summary, five different renewable energy (RE) Alternatives were considered:

R1 – Solar Photovoltaic (PV),

R2 – Concentrated Solar Power (CSP),

R3 – Wind Generation,

R4 – Energy Storage, and

R5 – Distributed Generation (discussed in 5.2 below)

5.1.1 Solar Photovoltaic Energy Supply (R1)

Q. What did the FS say about use of Photovoltaic Energy Supply Alternatives?

A. Southern Arizona has very high solar insolation levels that make PS a suitable option. The winter morning and early evening peaks, as shown in Figure 10 above. A PV system in this area has an output profile as shown in Figure 12. There are several demand curves, with the top curve in Green th average of the Top 20-day peak demand curves shown in Figure 10. This curve shows the morning peak about 8 AM and secondary evening peak at 8 PM.

The second curve from the top in Olive is the result when a 3 MW Fixed PV system's output is combined with the Top 20-day peak demand curve. This Fixed PV supply source lowers the morning Peak Demand from 6.5 MW to about 6.0 MW based on an average 3 MW Fixed PV output curve (the lowest curve) in Red based on data for 8 years from 1998 to 2005.

The third curve from the top in Aqua represents a 3 MW rotating axis-tracking PV system's output when combined with the Top-20 peak demand curve. This further reduces the morning peak to about 5.75 MW, for a total reduction of 750 kW, based on its output curve.

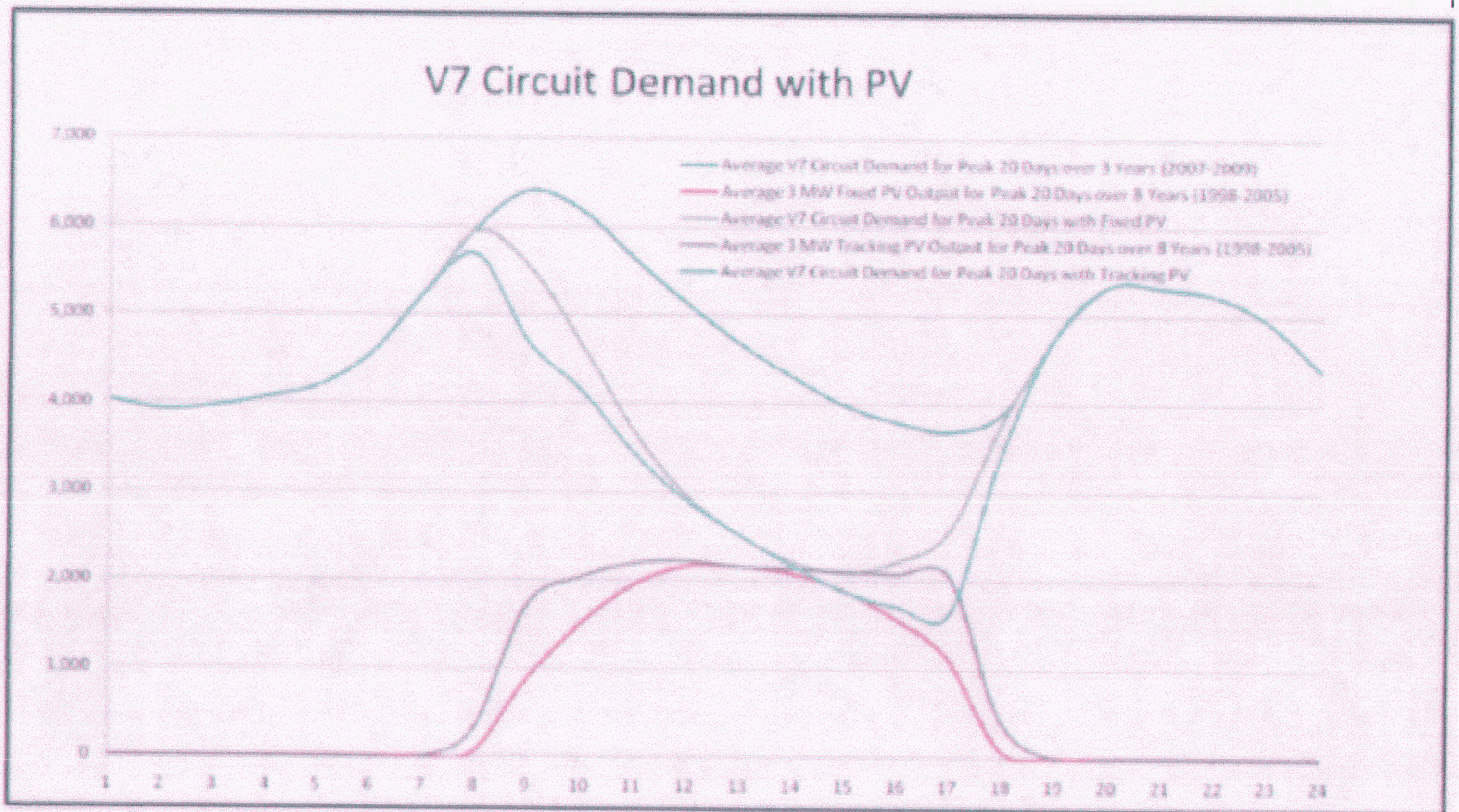


Figure 12 – V-7 Feeder Demand Changes with Fixed and Tracking 3 MW PV Systems. [RS p. 43, Fig. 23]

These changes due to the benefits of Fixed versus Tracking PV systems was not further developed in the FS. The other benefits of a 3 MW PV generation system in the V-7 area were also not discussed. In fact, the FS stated:

> "Eligible PV systems include rooftop and central system arrays. Because most residential rooftop systems can only accommodate fixed axis systems, **central systems are likely the only feasible alternative** (such systems could be customer or utility-owned). [FS p. 43]

This simple discussion on PV systems missed the "fixed" benefits in Figure 12. In addition, well over $1,500,000 in building permits has been issues in Santa Cruz County in the V-7 area for solar PV and solar heating systems in the past nine months. The residents in the V-7 area are very aware of the benefits of reducing total demand and are paying their money for these systems. Unfortunately, the Cooperative has failed to provide the promised rebates. This may result in bankruptcy proceedings for several local solar installers. These new PV systems are not reflected in the number of customers with residential or commercial solar rates in Table 5.

Q. Why did the FS reject Photovoltaic Systems as a Supply Source?

A. The FS states

> "**Both rooftop-mounted and ground-based PV is insufficient to defer capacity due to the limited amount of firm capacity coincident with the early morning peaks**. At minimum, five to six MWs would be needed to provide sufficient offsets under favorable conditions. However, the intermittent nature of PV does not match other supply options from a firm capacity standpoint. Further, the amount of PV operating at full output may exceed actual feeder loads, thereby violating screening criterion." [FS p. 57, emphasis added]

These are very weak reasons to totally reject solar PV systems. As the trainable PV system was not further developed in the FS, this conclusion missed that opportunity. PV systems can be combined with several storage methods by generating electricity during the day for use during evening hours.

Q. What is the screening criteria being used to reject alternatives?

A. The 'screening criteria' found on pages 54 and 55 is too restrictive to be practical. For example, the 'screening criteria' used above to reject PV systems states

> "All DG and renewable energy solutions should be able to meet capacity and performance requirements without exceeding feeder loads as measured at the Huachuca substation. Generally, this means the total rated *output* of these options should not exceed load at any hour of the days. It excludes options where output production can be adjusted via local or remote controls." [FS p. 55, italics in original, other emphasis added]

The bold part of this criterion seems to not permit any power output to the Mustang Corner (Huachuca) substation.

Let me explain. The 24.9 kV line has a capacity of at least 7 MW. If there is 5 or 6 MW of PV generated power, then several of these MW would be used in the V-7 feeder area to satisfy local load demands. Just as with netmetering, any excess, up to 7 MW greater than local demands, should be able to go back through the Huachuca substation and on to its transmission lines for use by other members of the Cooperative, as electricity can flow both ways on these lines. Obviously, this criterion has not been satisfactorily developed to handle these distributed generation benefits to the Cooperative. Other "screening" criterion are also defective, as will be discussed later in 5.8 below.

I disagree with this "screening" criterion, as written.

5.1.2 Concentrated Solar Power (CSP) Energy Supply (R2)

Q. What did the FS say about use of Concentrated Solar Power (CSP) Supply Alternatives?

A. Four basic CSP technologies were discussed (parabolic trough, power tower, solar dish and linear/Fresnel lens). The FS states:

> "The Parabolic Trough is the most advanced CSP technology and the only one with commercial deployment. It is technically viable, and field performance has been proven. However, <u>trough systems require extremely flat land (less than one percent slope)</u>. It is difficult to maintain this over a large area. Typical land requirements are five to ten acres per MW." [FS p. 44, emphasis added]

The other three technologies, based on the "screening criteria", were discussed as not been commercially available.

Q. Why did the FS reject CSP (2) as a Supply Source?

A. The FS states

> "The absence of suitable flat sites for parabolic trough CSP and the high cost of these devices (coupled with high cost of remote and multiple interconnections) exclude CSP from further consideration. Further, most CSP is large - greater than 10MW - and would not be suitable for a distribution feeder. Other promising CSP technology that less slope dependent may be viable once they have achieved commercial status; however, all other technologies are still at the pilot or demonstration phase." [FS p. 57]

5.1.3 Wind Generation Energy Supply (R3).

Q. What did the FS say about use of Wind Generation Supply Alternatives?

A. Wind generation has expanded rapidly in the past few years. The FS states:

> "...the average wind profile for southern Arizona generally is on the lower end of the wind power classification scale, with ratings of mostly 1 and 2. Most of the V-7 feeder is located in a Class 1 area, which is defined as having poor wind resource potential. There may be pockets where local wind profiles may be higher grade, but likely insufficient to provide significant wind potential. Further, most wind projects are assigned minimal or no firm capacity credits due to the highly intermittent nature of wind - a brief drop-off in wind speed can cause unit shutdown or reduced output, with resultant loss of feeder capacity. Accordingly, <u>NCI did not further analyze the capability of wind to reduce V-7 feeder loadings to meet current and future capacity requirements</u>." [FS Pp. 48-49, emphasis added]

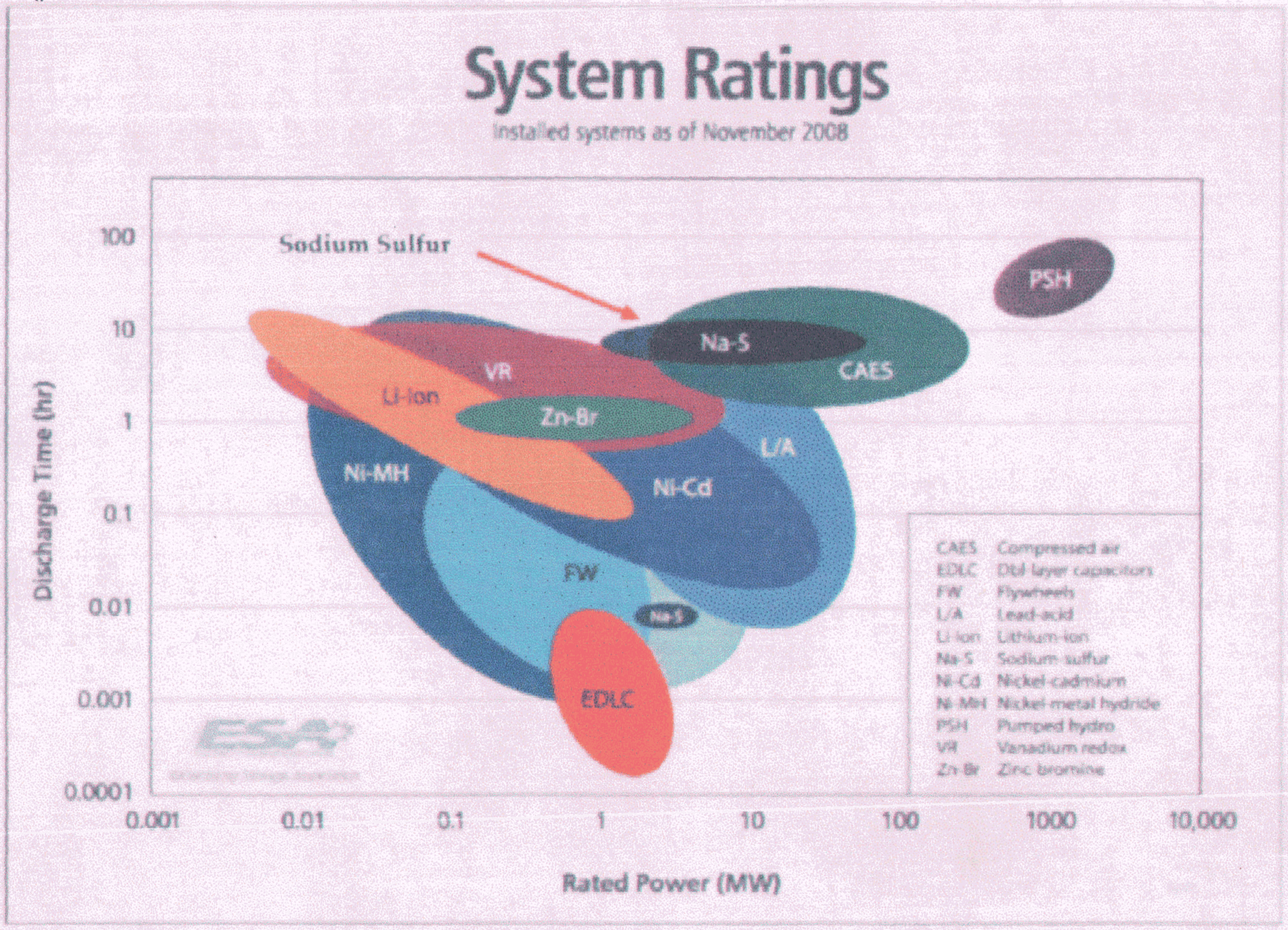
5.1.4 Energy Storage as Energy Supply (R4).

Q. What did the FS say about use of Energy Storage Alternatives?

A. The FS states:

> "**Electric energy storage systems have the potential to reduce feeder peak load by charging and storing electric energy during off-peak hours when load are low; and then discharging the device during high load, on-peak hours.** Although various forms of battery storage systems have been commercially available for many years, energy storage systems of sufficient size, capability and cost for electric utility applications have only recently started to appear on utility grids; and *many of these have been pilot or demonstration projects.*" [FS p. 48, italics emphasis in original, other emphasis added]

Many different energy storage devices were assessed in the FS, as shown in Figure 13.



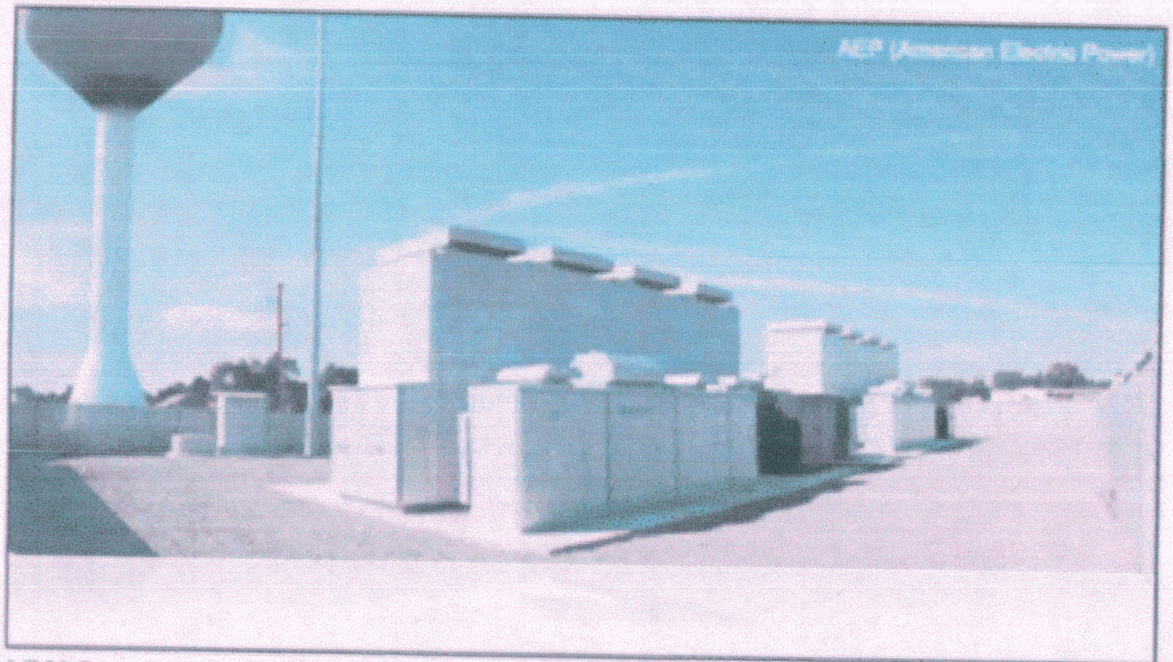
Source: Energy Storage Association Web Site

Figure 13 – Energy Storage Device Attributes in terms of Rated Power and Discharge Time. [FS p. 49, Fig. 29]

The FS evaluated the systems in Figure 13 and states:

> Of the technologies considered, <u>sodium sulfur appears best suited for meeting V-7 capacity needs,</u> as the storage capacity and discharge hours conform to feeder *peak* load intervals. Sodium sulfur batteries have been used domestically to support or defer distribution upgrades at a cost of about $3000/kW. American Electric Power (AEP) is among the leaders in the US. in applying NaS to T&D systems. <u>Utilities in Japan have successfully applied NaS systems for several years, with over 50 installations</u>. [FS p. 49, italics in original, other emphasis added]

A typical substation application is shown in Figure 14 below.



Source: *NGK Insulators, Ltd*, Reference Substation Installation (AEP)

Figure 14 – Sodium-Sulfur (NaS) Energy Storage System (2 MW) **[FS p. 48, Fig. 30]**

The charge and discharge profiles for energy storage systems are managed by automated control and communications equipment based on demand thresholds and device attributes. Figure 15 shows a typical charge/discharge profile for the 20 days with highest peak demands over the past 3 years in the V-7 service area.

The Aqua curve is the average Top 20-day peak demands curve shown previously. The Lower or Red curve at the bottom of Figure 15 is a NaS energy storage system with 40% losses. The middle or Olive curve, shows that the morning peak has been smoothed out and the maximum load is about 5.5 MW compared to 6.5 MW in the Top 20-day peak curve. This energy storage system has reduced the peak about 1.0 MW by efficiently smoothing out demand.

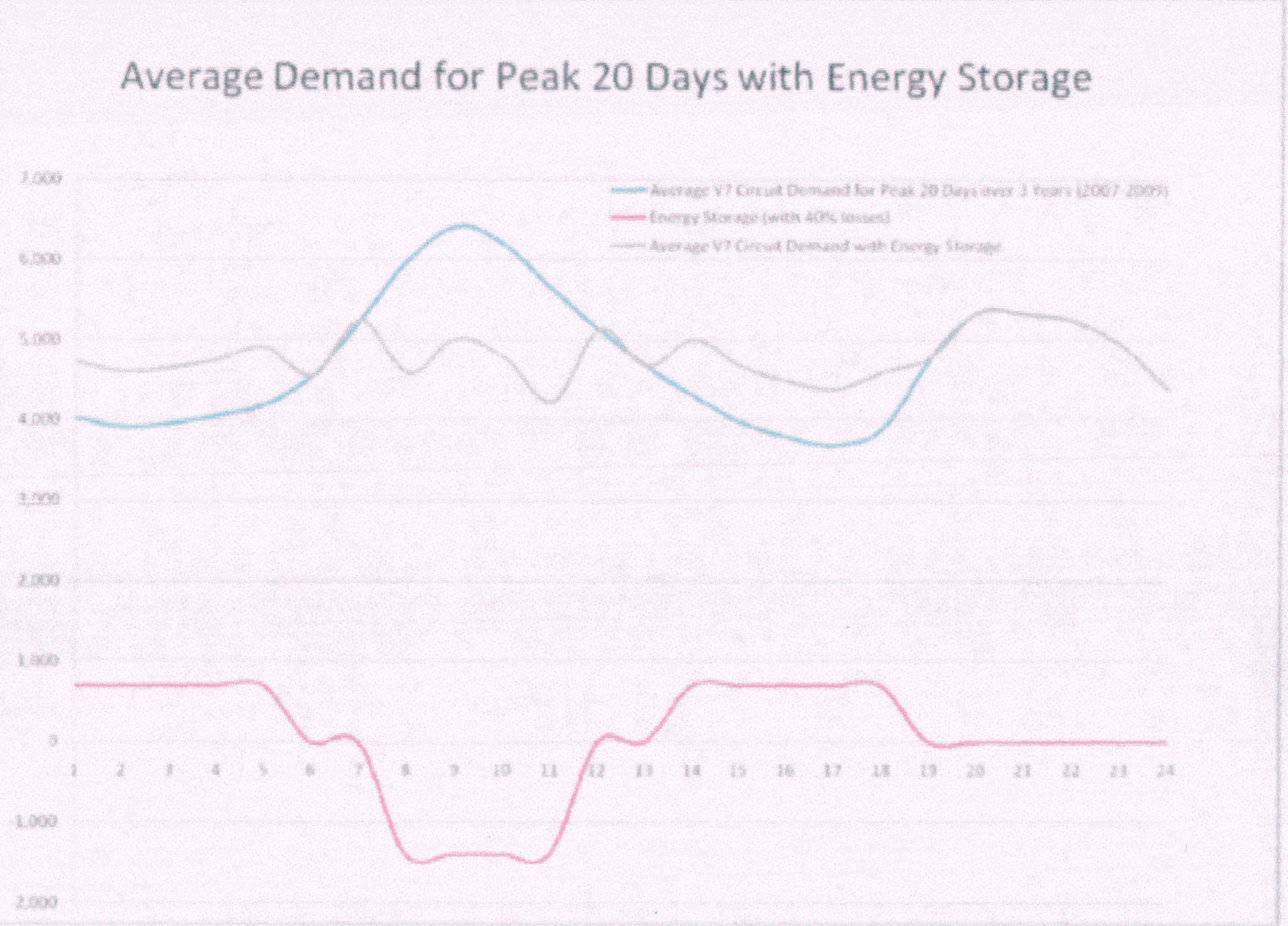


***Figure 15 – Average Demands for the Top 20-days Peaks with Energy Storage.* [FS p. 50, Fig. 31]**

Q. Why did the FS reject Energy Storage (R4)?

A. The FS states:

> "The limited number of installations beyond the demonstration or pilot phase, and the few suppliers of sodium sulfur energy storage systems preclude this option as a commercially available, mature technology." [FS p. 57, emphasis added]

This rejection is seriously question, in particular, because the FS also states:

> "Notably, NaS battery availability currently is limited due to a high order backlog (up to one year or longer)." [FS p. 49, emphasis added]

With over 50 utilities using this system and a sizable backlog are strong indicators this system is well beyond the "demonstration or pilot phase". This rejection should be reconsidered.

5.2 Distributed Generation (R5) Energy Supply Alternatives.

Q. What did the FS say about use of Distributed Generation (R5)?

A. The FS states

> "Distributed generation connected to the V-7 feeder would <u>reduce effective loads during those hours in which it operates</u>. The number of operating hours would be limited to the highest load hours or when it might be needed to meet feeder peak demands or stabilize voltages. Operation in a stand-alone, islanded mode is not considered, although SSVEC could consider the merits of stand-alone operation in the event of a loss of source supply from the Huachuca substation." [FS p. 51, emphasis added]

The DG could be trailer or ground mounted "diesel units burning low-sulfur distillate oil or natural gas depending on the availability of local gas supply." A 1.5 MW (1500 kV) to 2.5 MW (2500 kV) unit could be used to supply the existing 24.9 kV distribution lines. The Sonoita substation site was considered the "preferred location." [FS p. 51]

NCI might not have been aware that the El Paso Natural Gas transmission line goes through Patagonia, where there are many gas distribution meters from UNS Gas, including going past the Cooperative's office (about 1.5 acres of land) in Patagonia. This EPNG line continues northeast passing less than 1 mile or less past the Sonoita SRs-82/83 Cross-Roads.

Due to many complications with diesels, natural gas turbine technology, not considered by NCI, could be more advantageous in this area, either in Patagonia or at the Sonoita substation. There are many large natural gas generator sets in Santa Cruz County, many operated by water utility companies. In Tubac, there is a 500 kW gas turbine in the Tubac Barrio's water company.

Q. What will be the impact of DG outputs on the V-7 Feeder system?

A. The FS states that DG output <u>reduces the effective loading which then reduces the substation transformer loading, improves feeder voltages and reduces line losses</u>. If the distributed generator is located in Sonoita, as shown in Table 6 below, the DG impacts on the feeder from zero, in 500 kW increments to 2,000 kW (2 MW) are show the following when at a 5656 MW peak load plus DG:

- System Losses decrease so that at 2,000 kW, the DG actually is 2,746 kW, regaining 746 kW more than actually generated due to less line losses.
- Line losses decrease from 29.8% to 16.6%.
- All three Phase Voltage Drops are decreased.

Thus, the 746 MW are reduced from Mustang Corner by a net unit 2.0 MW rating or about 35%.

Table 6 – Distributed Generation Feeder Impacts for 500 to 2000 kW Generation. [FS p. 59, Table 9]

Sonoita: DG Voltage drop and Losses at Peak (5656 MW) + DG							
	System Losses	Highest Voltage Drop				Losses	Load + Losses – DG
DG (KW)	Regained	Phase A (V)	Phase B (V)	Phase C (V)	Net Losses (kW)	(% of Total Load)	(kW)
0	---	113	115	119	1683	29.8	7339
500	227	114	115	119	1456	25.7	6612
1000	437	116	115	119	1246	22	5902
1500	602	116	115	120	1081	19.1	5237
2000	746	117	115	119	937	16.6	4593

Q. What is the long-term performance with Distributed Generation (R5) and the 69 kV transmission line?

A. Up to 2 MW of DG will be sufficient to maintain voltages with acceptable levels; however, in the long-term another 2 MW will be needed. Table 7 shows the results of both 2MW and 4MW of DG and the 69 kV line.

Table 7 – DG and 69 kV Line Alternatives Performance in 2029. **[FS p. 60, Fig. 33]**

2029 Peak Forecasted Loads Voltage Drop and Loss Comparison 2MW & 4MW DG and 69 kV Option							
		Highest Voltage Drop				Losses	
2029 Forecasted Load (Low, Base, High) kW	DG (KW)	Phase A (V)	Phase B (V)	Phase C (V)	Net Losses (kW)	(% of Total Load)	Load + Losses – DG (kW)
DG & Energy Storage							
7197	2000	112	113	118	1543	21	6740
	4000	115	113	118	927	13	4124
7922	2000	107	112	117	1907	24	7829
	4000	115	112	118	1142	14	5064
8723	2000	103	110	117	2165	25	8888
	4000	113	111	118	1456	17	6179
69-kV Option							
7197	---	116	113	118	691	10	7888
7922	---	115	112	117	732	9	8654
8723	---	114	111	117	780	9	9503

It should be noted that both DG and the 69 kV line would have problems that need correction in the future. The FS states:

> "Results presented above [in Table 7] also indicate <u>Phase A and B voltages are below acceptable levels in year 2029, and these would need to be resolved for whichever solution is selected</u>." [FS p. 60, emphasis added]

Q. What is an estimated cost for Distributed Generation?

A. The FS has cost estimates for two DG options: diesel or natural gas fueled in Table 8.

***Table 8 – Cost Estimates for 2 x 500 kW Diesel and Natural Gas Distributed Generators.* [FS page 52, Table 7]**

Unit Type	Cost (2009 $Million)				
	2-500 kW Units ($000)	Site Costs ($000)	Interconnection ($000)	Total Cost ($000)	Total Cost ($/kW)
Diesel	$400	$100	$100	$600	$600
Natural Gas	$500	$100*	$100	$700	$700

* Includes cost of fencing, screening, enclosures, and oil retention facilities

5.3 Demand Side Management (DSM) Energy Supply Alternatives.

Q. What demand Side Management Alternatives were considered in the FS?

A. In summary, the FS considered five demand side management (DSM) Alternatives:

DS1 – Targeted DSM,

DS2 – Electric Storage Handling,

DS3 – Incentive Rate Alternative,

DR4 – Space Heating/Fuel Switching, and

DR5 – Combination of the above DS1 through DS5.

DSM includes energy efficiency (EE), demand reduction (DR) and direct load control (DLC) and other measures to reduce the load in order to avoid construction of new facilities required t meet capacity requirements.

There is an instance where Florida Power and Light used DLC to control air conditioners, pool pumps, and other high energy consumption equipments where is saved 3,000 MW of new generation and associated transmission and distribution (T&D) infrastructure costs of $3 billion for a cost of about $800 million. The one challenge with DSM programs is that they need "hands-on management" to be effective.

5.3.1 Targeted DSM Energy Supply (DS1).

Q. What did the FS say about use of Targeted DSM Supply Alternatives?

A. The FS total discussion concerning Targeted DSM as follows:

> "An energy efficiency and distributed resource program targeted to customers located on the V-7 feeder has the potential to defer capacity upgrades if the level of firm demand reduction is coincident with the feeder peak load intervals, is sustainable over time and customers are willing to participate in the program. Customer participation typically is a function of the level of incentives provided versus the inconvenience of Participation or disinterest. Our experience with similar programs indicates customer willingness to participate is perhaps the greatest challenge. The level of participation declines as the perceived cost or value of the program is diminished, or where customers are inconvenienced by program measures." [FS p. 40, emphasis added]

Q. Why did the FS reject Targeted DSM Supply Alternatives?

A. The FS states:

> "While aggressive DSM may be cost-effective and provide benefits independent of area capacity needs, even large increases above current programs levels is insufficient to materially defer the date for additional feeder and station capacity. Because the additional amount of DSM that could be achieved is uncertain, at best, it is not advisable to defer new capacity for the one of few years the need date could be extended." [FS p. 56, emphasis added]

This rejection of Targeted DSM is unfortunate because there are so many ways to motivate customers to make behavioral changes to reduce demands, or to use new equipment necessary to ensure energy efficiencies, or to establish effective DLC or DR programs, with appropriate incentives. The lack of even wanting to "try DSM" is more than discouraging; especially since no specific DSM programs were even discussed in Alternative DS1.

5.3.2 Storage Electric Heating Energy Supply (DS2).

Q. What did the FS say about use of Storage Electric Heating Supply Alternatives?

A. The FS provided a good description of this program that is targeted at reducing the demand from electric heating. The FS states:

> "Utilities for several years have marketed electric storage heating devices to reduce peak demand and energy consumption during the highest cost hours. The operating mode of these devices is straightforward. Electric storage heaters contain high-density bricks or ceramics that thermally store electric heat produced during off-peak, low-cost hours. A time of use meter or timer sends a signal to the storage heating devices to ensure devices do not charge during the

peak cost hours. The thermal stored energy is discharged during high cost [peak] hours via use of small internal fans that circulate and heat ambient air through small opening in the bricks to vents located on the front of the heating enclosure. Customers achieve savings by charging the heaters only during low cost [off-peak] hours." [FS p. 40]

This Alternative would be very useful for Cooperative customers who are not in the UNS Gas service area. The FS continues with

> "The amount of existing electric heating load can be estimated by comparing daily load profiles for peak winter days to non-heating days - the difference is likely due to electric heating load, with some additional peak loading created by lighting small motor and pumping load. Figure [16] illustrates this differential, which indicates <u>incremental loads of about 3 MW on peak load days</u>. <u>A portion of this load likely is eligible for conversion to storage systems</u>." [FS p. 41,emphasis added]

Figure 16, shows the hourly load profile differences between a Super-Peak and Non-super Peak day.

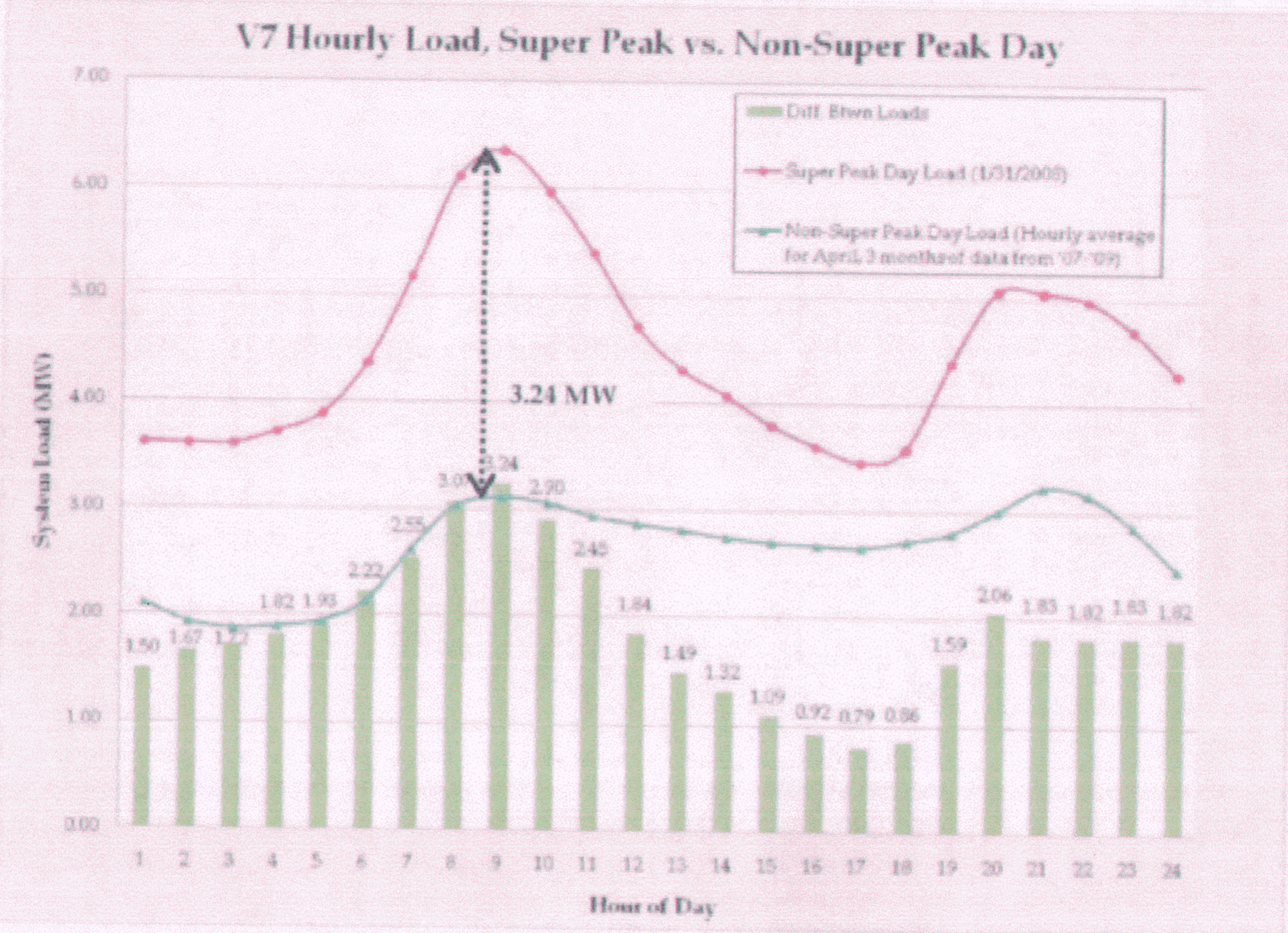


Figure 16 – Peak and Off-Peak Daily Load Profiles. **[FS p. 41,Fig. 21]**

Q. Did the FS reject this Alternative?

A. No, it stated <u>this program was the **most cost-effective of all the Alternatives**</u>.

Q. How could Heat Storage be implemented?

A. An aggressive DSM plan, an accomplished DSM Manager, and Cooperative senior management support would be needed. This DS2 Approach can be combined with DS4 (Space Heating and Fuel Conversions) to meet capacity. The FS states:

> "To meet capacity requirements, a feeder peak target of 5000 kW, net of losses, was chosen to determine the minimum number of units for conversion. Significantly, the number of units in 2010 exceeds 100; hence, an aggressive program would be needed to achieve this target. <u>Table [9] identifies the number of units that would need to be replaced by year."</u> [FS p. 62, emphasis added]

Table 9 shows that a total of 135 electric heat storage (Alt DS2) or space heating conversions (Alt DS4) are needed in 2010, a cumulative total of 357 in 2019, and 655 in 2019.

Table 9 – Cumulative Totals of Space Heating and Electric Storage (Alt DS2) and Space Heating Conversions to Meet V-7 Capacity Requirements.
[FS p. 62, Table 10]

Year	Capacity Reduction (kW)	Units Replaced (Cumulative)
2010	602	135
2019	1593	357
2029	2922	655

At present there are 1,675 residential customers (from Table 5) so in 2010, only <u>8.1% would be needed to either add electric heat storage or convert from electric heat to another source to meet heating needs</u>. Adding additional conversions for the 600 or so business customers, even fewer residential conversions would be required. New customer from growth in the V-7 Feeder area could be incentivized to not use electric heating. <u>Building contractors who construct "energy efficient" homes can receive a $5,000 per home tax credit from the state</u>. Unfortunately, I understood this <u>Cooperative provides building contractors $1,500</u> for construction an "all-electric" home. That has a negative effect on reducing demand.

Q. What are the costs associated with a Heat Storage (DS2) program?

A. The FS stated that a Heat Storage unit that uses propane, as an initial capital cost of $1,800 per unit. Thus, for 135 such units, the total cost in 2010 is $243,000. [FS Pp. 62, Table 11]

When viewed over a 20-year period, the total capital investment would be $1,788,000, with fuel, operations and maintenance costs of $350,000, and its **NPV is $2,061,000**.

This is the most economical means to meet all the present and future V-7 load demands that also saves another $77,000 in less line losses. [FS p. 63, Table 12]

5.3.3 Incentive Rates (DS3).

Q. What did the FS say about the use of Incentive Rates as a Supply Alternative?

A. The electric industry, including this Cooperative, uses incentive rates to encourage its customers to use less energy during Peak cost hours or to change usage patterns by shifting electric usage from high cost to lower cost hours. The Cooperative for almost all rate classes has established a Time-Of-Use (TOU) rate. The FS states:

> "... the price differential between the on and off peak hours must be sufficiently high to motivate customers to *significantly* reduce usage during peak hours to defer V-7 system upgrades. Currently, SSVEC offers a TOU rate with an on peak rate of about 14 cents and on off-peak rate of about 7 cents per kilowatt-hour." [FS p. 41, emphasis added]

Q. Did the FS reject Incentive Rates as a way to resolve the Supply issue?

A. The FS rejected the use of Incentive Rates as stated below:

> "Incentive rates, regardless of the rate differential, is very unlikely to have a measurable impact on peak usage. Industry studies indicate on versus off-peak ratio of two and three to one have a very minor impact on customer electric usage. SSVEC's current TOU rates, which have a two to one price differential has limited interest and participation for customers served by the V-7 feeder." [FS p. 56, emphasis added]

This assessment is most unfortunate because there has been almost no emphasis on TOU by the Cooperative. Only ONE residential customer has TOU rates in the V-7 service area, as shown in Table 5. Without effective DSM marketing, presentations to local organizations including business groups such as Chambers of Commerce, the present unsatisfactory state will continue with very low TOU participation. If 10% of the 2,355 customers in this area switched to TOU rates, a noticeable change in Peak customer demand should be noted. At present, only 0.06% of the residential customers in the V-7 participate in TOU rates. This is clearly subpar performance and is NOT SATISFACTORY for an area where known capacity issue exist.

5.3.4 Space Heating and Fuel Switching (DS4).

Q. What did the FS say about use of Space Heating/Fuel Switching as a Supply Alternative?

A. The highest demands on the V-7 Feeder are the winter morning and early evening as shown in Figures 10 and 16. The shapes of these curves "strongly suggest the peaks are driven by electric space heating." [FS p. 42] The FS further states:

> "The large percentage of residential and small commercial customers (over 80 percent) served by V-7) yields average coincident heating load of 2 to 3 kW per customer. <u>An aggressive conversion of electric heating system to propane or kerosene could reduce load during the hours of highest demand</u>." [FS p. 42, emphasis added]

Even though a natural gas pipeline passes through Sonoita, NCI did not investigate use of natural gas as an alternative fuel due to the long distances between customers. [FS p. 42, Fn 25] Unfortunately, NCI did not recognize that UNS Gas distributes natural gas in the only town in the V-7 area, which is Patagonia, where homes are much closer than Sonoita. Many have natural gas.

Use of direct venting modular heating units, such as shown in Figure 17 was suggested.

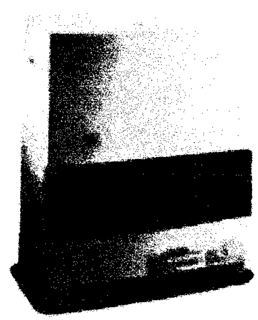


Figure 17 – Typical Direct Venting Modular Heating Unit. **[FS p. 42, Fig. 22]**

For this kind of program to be successful, short-term DSM incentives with aggressive marketing (something this Cooperative seems to avoid) will be necessary to reduce demand to avoid upgrading the V-7 Feeder system. The FS also states:

> "Assuming an average of 2 kW of coincident demand and a reduction in 200kW is needed to avoid feeder overloads, **<u>about 100 customers would need to participate in the first year for this option to be viable</u>**. Each successive year would require 50 to 75 participants to offset load growth. <u>Program costs include incentives designed to offset the cost of modular heating systems and dismantling of electric heating controls</u>. The program could be structured similar to the targeted DSM programs described above, which includes incentives based on the value of T&D deferrals." [FS p. 42, emphasis added]

Q. Did the FS reject Incentive Rates as a way to resolve the Supply issue?

A. No, it stated this prog am was the second most cost-effective of the Alternatives.

Q. How could Space Heating/Fuel Conversion (DS4) be implemented?

A. An aggressive DSM plan is required. This DS4 Approach can combine with DS2 (Heat Storage) as discussed in 5.3.2. Table 9 has the number of units to be converted from electric.

Q. What are the costs associated with a Space Heating/Fuel Switching (DS4) program?

A. The FS states that a Heat Storage unit that uses propane, has an initial capital cost of $1,800 per unit. Thus, for 100 such units, the total cost in 2010 is $180,000. [FS Pp. 62, Table 11] This table also indicated that setting up an Electric Heating program might cost $250,000, even more than the cost of all of the proposed heaters.

When viewed over a 20-year period, the total capital investment would be $1,386,000, with fuel, operations and maintenance costs of $1,428,000, with a **NPV of $2,355,000**.

This is the second most economical means to meet all the present and future V-7 load demands that also saves another $460,000 in less line losses. [FS p. 63, Table 12]

5.3.5 Combinations of the DS1 to DS4 (DS5).

Q. What did the FS say about Combinations of the DS1 to DS4 as a Supply Alternative?

A. The FS states that

> "This option includes combinations of the above four alternatives, as the contribution of any single option would likely be insufficient to meet capacity deficits. For example, the amount of lighting demand may be too small to have a major impact on demand, but nonetheless may be cost-effective. When energy efficiency is combined with incentive rates and fuel conversions, there may be greater amounts of capacity reduction, and in sufficient quantities to defer capacity need dates." [FS p. 42]

Q. Did the FS reject Incentive Rates as a way to resolve the Supply issue?

A. This Alternative was not discussed other than the above paragraph. This Alternative was dropped without any real consideration, even though DSM programs DS2 and DS4 were jointly discussed elsewhere. Even the above statement about reduction in demand due to decreased "lighting demand" should not be overlooked, as EVERY action done by customers to reduce demand, i.e., DSM, should be included. Other DSM programs include those in later supplemental testimonial filings.

5.4 Distribution Supply Alternatives.

This paragraph and its subparagraphs below will be filed in a later supplemental testimony. The selection of Alternatives is not the purpose of the A.R.S. §40-252 hearings.

5.4.1 Reinforce the Existing System (D1).

5.4.2 Reconductor the 25 kV Line (D2).

5.4.3 Install New 25 kV Feeder from Huachuca (D3).

5.4.4 Create Tie to UNS Electric in Patagonia (D4).

5.4.5 Install Distribution Static VAR Compensator (D5).

5.5 Transmission Supply Alternatives.

This paragraph and its subparagraphs below will be filed in a later supplemental testimony. The selection of Alternatives is not the purpose of the A.R.S. §40-252 hearings.

5.5.1 New 69 kV Line and Sonoita Substation on Ranch Right of Way (T1).

5.5.2 New 69 kV Line and Sonoita Substation on SR-82 Right of Way (T2).

5.5.3 Tap 138 kV or 115 kV Transmission Lines (T3).

5.5.4 Create Tie to TEP 46 kV Lines (T4).

5.5.5 Underground Transmission Line Cable (T5).

5.6 Other Alternatives Not Considered.

This paragraph will be filed in a later supplemental testimony.

5.7 Cost Assessments.

This paragraph will be filed in a later supplemental testimony.

5.8 Criteria Used For Assessments.

This paragraph will be filed in a later supplemental testimony.

5.9 Trade-Offs Between Alternatives.

This paragraph will be filed in a later supplemental testimony.

5.10 Conclusions for Issue 3.

As shown in paragraphs 5.1, 5.2, and 5.3, there is ample evidence to support implementation of these Alternatives to improve reliability in Section 3 and meet the demand performance demands in Section 4. Some Alternatives in paragraphs 5.4 and 5.5 will also be shown to be viable in a later supplemental filing.

5.11 Recommendations for Issue 3.

This paragraph will be filed in a later supplemental testimony, as recommending an alternative is not the primary purpose of the A.R.S. §40-252 hearings.

For the purpose of the A.R.S. §40-252 hearings it recommended that some misunderstandings by NCI in the FS be considered for correction.

Also, it is abundantly clear implementation of combinations of the various DSM, RE, and DG Alternatives can solve the reliability, capacity and power quality issues for the V-7 Feeder Area without the more costly 69 kV line in Alternative T1 or T2.

Further, these Alternatives (other than T1 or T2) need actions to be taken by the Cooperative in order to be more cost effective than the Cooperative's preferred T1 and to be successful.

SECTION 6 - ISSUE 4

THE FEASIBILITY STUDY CORRECTED EXAGGERATED CLAIMS

Issue 4 – Throughout the process of resolving the issues in the V-7 Feeder service area, the Cooperative has made exaggerated and misleading claims that are refuted by information in the Feasibility Study.

6.1 Purpose of this Section.

Q. Why did you include this section in your testimony?

A. Over the course of the issues involved resolving these matters, there are so many statements that have been made by the Cooperative, either by its CEO or through its attorney, that appear to be exaggerated or misleading. These "partially true", erroneous, or false statements have been used to present a picture of the Intervenors as an adversary. The Cooperative's senior management is viewed by many as a management team that wants to collaborate with its customers, including all of its customers, to resolve issues.

In fact, some of the actions by the Cooperative and its attorney seem to this witness to have been beyond the norm of business-like behavior. These are my opinions as will be substantiated below for some of these that impact the ongoing A.R.S. §40-252 hearing process. Other such issues will be included in later supplemental filings. One of these is developed below, that is concerning the "270 hours of outage" in the V-7 Feeder area that has been used so many times but so clearly refuted by as exposed in Section 3 above.

Q. How has the Cooperative handled this situation?

A. The Cooperative seems to have put on a full-court press on this 69 kV issue. Much beyond its significance as the corporate management having this issue dominate so many actions, to the same degree of seriousness when a company declares war on another. Everyone knows that the last two years have seen multiple million-dollar losses in SSVEC's financial statements in its electricity business sector, so why aren't they working that issue? Why do they actively encourage dissention within the cooperative? Why should they create unrest among members is press releases and letters to its members? And all of this is contrary to a statement made by Mr. Creden Huber, the CEO, on 2 October 2009 in his letter to the Commission:

"Finally, SSVEC is intending upon working with the ACC, and the community, in a cooperative manner towards resolution of the power quality, reliability, and capacity problems in the area."

One of my goals with this testimony is to ensure that the Cooperative's management actually do read the Feasibility Study so they can learn new facts about their system and then follow through on the above quote. I hope that happens.

6.2 "270 hours of Outage"

R. What does "270 hours of annual outage in the V-7 Feeder Area mean?

A. Many times, too many to count, the Cooperative has stated that there have been 270 hours of annual outage in the V-7 feeder area.

Before quoting a few of these instances, it should be noted that the number "270" does NOT appear once in the Feasibility Study other than in the phone number for Navigant Consulting on the cover page. Whatever this is, it is NOT a measure of reliability, NOT used as an industry standard and is VERY misleading. In fact, it has NO technical meaning whatsoever other then to make it seem the V-7 Feeder area has 90 times the actual annual outage per customer of 3 hours per year per customer. In 3.1.1 and 3.1.2, Figures 1 and 2, Tables 1 to 3, have all shown that

- Annual outages in the V-7 Feeder area over the past then years was 3.0 hours per customer per year,
- V-7 Distribution Line standard Reliability Indices for number of outages, length of total outages, and duration of each outage were above the national average in 2008,
- V-7 Feeder outages were less than the 5 hours per customer per year that would be of concern to the Rural Utilities Service (RUS) standard.
- V-7 Feeder outages in 2008 were 1.3 outages per customer, for average total outage duration was 96 minutes, and the average outage duration was 72 minutes.
- Commission Staff reported in 2007, the Cooperative average customer had 3.52 hours of outage per customer per year compared to the ten-year V-7 outages of 3.0 hours.
- V-7 Feeder outages have been less than 0.03% of the time, or 99.97% of the time; all its customers have had electricity.

This performance is not perfect, but nothing meets that standard.

Furthermore, "NCI does not view current feeder outage performance to be unusual for a line with the distance and exposure of the V-7 feeder." [FS p. 1, paragraph 3]

Q. Can you provide some instances of when "270 hours of annual outage" or similar wording was used by the Cooperative?

A. First, in a letter from the Mr. Huber, SSVEC CEO, to Corporation Commissioner Newman on 2 October 2009, in the second paragraph, he states

> "The existing infrastructure has exceeded capacity, experienced a 10 year outage average of 270 hours per year." [emphasis added]

Second, in a letter from Mr. Jack Blair, the SSVEC Chief Member Services Officer, wrote to all the members of the Cooperative, dated 14 December 2009, in the second paragraph:

> "Sulphur Springs Valley Electric Cooperative (SSVEC) has proposed a 23 mile 69kV transmission line to serve that area [Elgin, Sonoita, Patagonia] because it experiences **270 hours of outages a year**, far more than the approximately 20 hours a year that our other members experience on average." [p. 1, emphasis added]

Third, in the Cooperative's Application for a Re-hearing of 28 September 2009, by the Cooperative's attorney, states:

> "...an average reliability occurrence of 270 outage hours per year over the last 10 years." [p. 25 at 17-18, emphasis added]

and

> "He [Mr. Creden Huber, CEO] presented uncontroverted evidence demonstrating that the Sonoita area has a 10-year average of 270 hours of outages per year adding to the total unreliability of the existing service line." [p. 26 at 1-2, emphasis added]

and

> "He [Creden] presented uncontroverted evidence demonstrating that the Sonoita area has had a 10-year average of 270 hours of outages per year adding to the total unreliability of the existing service line." [p. 42 at 8-10]

and

> "...and an average reliability occurrence of 270 outage hours per year over the last 10 years" [Attachment H, SSVEC "Moratorium" Application filing of 18 Sept 2009, p. 4 at 3-4]

Fourth, in a letter of 27 January 2010 to the Commission by SSVEC's CEO that provided a "Member Survey Report" of a poll of members filed this docket. In the Executive Summary dated 26 January 2010 from Jody Severson of Severson Associates, she states:

"Then we introduced the Sonoita line. We gave them some background information, explaining that only one feeder line serves the area, that **it has 270 hours or outages per year compared to under 3 for the rest of the system**, and that SSVEC requested a ban on new hookups because the line was overloaded. We told them that the co-op wants to build a second line to relieve the overloading and provide a backup route for power." [p. 3, emphasis added]

and the following questions 12 (which was rotated with a similar 13) was worded as follows:

"12. Opponents say that the new line will hurt their property values because it will interfere with their view of the mountains. <u>The cooperative says that it has owned the right-of-way to build that line for 28 years and that was public record when property owners bought their property</u>. <u>As regards concerns about the view of the mountains, which of these two sides do you most agree with -- the co-op or the opponents -- even if neither is exactly your opinion</u>? (IF UNDECIDED:) Well, which way do you lean?" [PDF p. 14, emphasis added]

and questions 15 continued to mislead as worded as follows:

"15. I'd like to ask your opinion on another issue. Opponents of the Sonoita Elgin/ Patagonia line asked the Arizona Corporate Commission, which regulates electric utilities, to order Sulphur Springs Valley Electric Cooperative to conduct an independent, third party study of the alternatives to building a new feeder line, including wind and solar power. <u>That study has just been completed and found that the proposed new feeder line is the most realistic, affordable and long-term way to solve the reliability and power quality problems</u>. Opponents are expected to criticize the study or ask for more studies of the various alternatives. Sonoita/ Elgin/ Patagonia area and that such cost increases are unfair to all other ratepayers who have to pay for the new line. -- The cooperative-says that further delays will significantly increase costs to put in the new line to the ~ Sonoita/ Elgin/ Patagonia area and that such cost increases are unfair to all other ratepayers who have to pay for the new line.

"As regards conducting more studies of the issue, which of these two views do you most agree with – the cooperative or the opponents -- even if neither is exactly your opinion? (IF UNDECIDED:) Well, which way do you lean?" [PDF p. 15, emphasis added]

and the verbal comments recorded during the polling included:

"270 hours out outages proves it is needed.
"270 vs 3 hours of outages seems like a good reason and they need power.
"Because we need a back-up power. It is more important than their view.
"Because of all the problems they are having, we need a new power line.
"Because of power outages!
"Because that's what the study concluded.
"Because they say it is required.

"Can't stop progress & coop has the right to do what they want.
"For less outages – would not want to be inconvienced.
"Help with the outages.
"If there is a power shortage, they need it. They have handled this wrong. They chose the wrong route.
"If they are having too many outages then they need the line no matter what the problem is.
"It is needed to take care of power outages and handle the growth.
"It is needed. Study has explained that it is the most realistic way to go.
"It seems they are experiencing a number of outages and that should be enough reason.
"It sounds like the most cost productive way to reduce outages in the area.
"It will help the outages from happening out there.
"Less outages. [twice]
"Less power outages and more people coming out to Elgin to pick fruit from farmers.
"Less power outages!!
"Less power outages. (twice)
"Less power outages. Cost effective.
"Lower our rates. Limit outages.
"More cost effective if they are having that many outages they must need it.
"More power access, less outages.
"More power is needed in the area. Too many outages.
"No new hook ups allowed right now.
"Not to have power outages.
"Outages.
"Outages are very stressful.
"People should not have to experience that much outage.
"Power outages are dangerous.
"Power requirements – Old people need that power more than anyone else.
"Provide power for more people with less outages.
"Reliability issues as far as it going on and off.
"Reliability of power.
"So people don't end up with power outages constantly.
"So they don't have power outages.
"So they won't be without power with that many outages.
"So they won't have so many power outages.
"So we don't have as many power outages. (twice)
"So we have less interruptions & power outages.
"Stop blackouts and help people. It won't interfere with the view of the mountains.
"Stop power outages. It's growing and it need to be done.
"That people are going through power outages.
"The coop says it's necessary. They wouldn't waste our money.
"The outages are the best reasons to build the line.
"The outages.
"The power outages, when not enough power in feed lines to cover it.
"The reliability of electricity in this area is required.
"There are a lot of people who have suffered a lot of outages.
"There will be more reliability.
"These people deserve better service than they are getting.
"They are having a power outage problems. They need a new line.
"They can't add any new customers to the area.
"They complain about the power outages. They're trying to mostly keep it out of sight.

"They have so many outages and not enough power.
"They have too many blackouts. It is needed.
"They have too many outages.
"They need electricity. (three times)
"They need it so there aren't as many outages.
"They need it. Too many outages.
"They need power. Too many outages.
"They need the service because of the outages.
"They need to do it to avoid more outages.
"They wouldn't have as many outages and better services.
"They are having burn outs.
"Tired of the outages.
"To avoid outages.
"To cut the outages down.
"To end outages in that area.
"To have less outages.
"To keep power outages to a minimum.
"To prevent more outages and give people electricity.
"To prevent the outages.
"To reduce the number of outages.
"To relieve the power outages in that area.
"To stop the power outages.
"Too many outages (four times)
"Too may power outages. It need to be done ASAP.
"To shorten outage time.
"We are expanding the area and if they want to cut down on power outages, they need to do it.
"We don't have a loop & need a loop.
"We have too many outages and too much growth.
"We keep losing power in Patagonia.
"We need electricity & it will stop outages.
"We have a very large business & it costs us thousands every time there is an outage. Been here since 1947. People should do their research.
"We receive too many outages.
"Will be less outages." [from Pp. 116 to 123 of Huber ltr of 27 January 2010]

Lastly, both Mr. Jack Blair and Ms. Deborah White, the two presenters, repeated the "**270 hours of annual outage**" including an exhibit titled "1999-2009 Average Annual Hours Out: SSVEC System" where there was a "270 hour" spike for the V-7 Feeder Area.

There are many additional instances of this very misleading statement in the record of these proceedings. The "poll" questions above and the verbal responses are a clear examples how using misleading information can extract the desired answer.

The local newspapers, including the *Arizona Daily Star* (on page 1), *Sierra Vista Herald, The Bulletin,* and others, have also reported the "**270 hours**".

The tragic part of this is that "<u>**270 hours**</u>" has been repeated by SSVEC upper management and its attorney so many times, <u>some are beginning to believe it is true</u>.

6.3 "The Capacity has been exceeded" or similar expressions.

Q. Can you provide instances of when this or similar expressions have been used?

A. A careful review of the entire Feasibility Study has resulted in NO instances where any claims or facts presented indicate that the capacities of the system (transformer or lines) have been exceeded.

In addition, as presented above in 4.1, the FS states: "the capacity of the transformer typically is higher than nameplate due to ambient cooling." [FS p. 31]

Further, NCI has not and apparently the Cooperative also has not computed the weather-adjusted transformer ratings. The FS also states: an additional 1000 kW [1 MW] of substation transformer capacity would be available at Huachuca [at Mustang Corners] substation if the winter rating is increased by at least 16 percent above the nameplate rating.

Q. What are some examples about misleading statement concerning exceeding capacity?

A. First, in the same letter from the CEO on 2 October 2009, Mr. Heber states

> "The existing infrastructure has exceeded its capacity" [as quoted above]

and later states:

> "The facts are the substation transformer has exceeded its capacity multiple times." [p. 1, second paragraph]

Second, in another letter to the Cooperative's membership, dated April 2009, Mr Heber states:

> "The V-7 feeder has reached its maximum capacity, and, in fact, has exceeded it several times recently, which resulted in reduced voltage (brownouts), blinks, and some outages. The new substation and 69kV line must be built now. Without this critical new infrastructure, SSVEC will have no choice but to invoke a moratorium on new services in this area –and keep in mind that this action would still not resolve the current reliability problems. [Page 10]

This letter was written to the Members after a concerted effort was made to bring possible alternatives to the attention of SSVEC at a meeting with approximately a dozen staff members and as many members from the V-7 Feeder communities, TEP, and Santa Cruz County in attendance. Rather than working and collaborating with this group to work out alternative and/or responding to this group; the Cooperative chose to ignore this group and instead sent out a letter to the members with their own conclusions.

Additional examples will be included in a supplemental filing.

EXHIBIT MM-1

RESUME OF MARSHALL MAGRUDER

Education

MS in Systems Management, University of Southern California, Los Angles, California (1981)
Majors in Managing Research and Development and in Human Factors (grade A in every course)
MS in Physical Oceanography, Naval Postgraduate School, Monterey, California (1970)
Honor roll 4 times (two years, 5 terms a year)
BS, US Naval Academy, Annapolis, Maryland (1962)
Special courses in Operational Analysis and History of Russian Military Tactics

Experience

Over 25 years as Senior Systems Engineer with and an associated contractor, consultant to Raytheon-Hughes in systems engineering, training and naval systems, simulation and modeling in C4I; with over 20 years of service with the US Navy, a total over 40 years experience in this field

- **Large-system development** at all levels
  From pursuit, analysis, winning strategy, Request for Proposal evaluation, proposal management, system requirements analysis, architectures, specifications, design synthesis, trade-off studies, requirements allocation tracking,
  To system, level test planning, deployment, implementation, through sign-off, and
  For technical systems of all complexities.

- **Developed** Antisubmarine Warfare (ASW), Electronic Warfare (EW), Command, Control, Communications, Computers, Intelligence, Surveillance, and Reconnaissance (C4ISR) operational concepts, procedures, and tactical employment.

- **Used, operated, and planned** Navy, Army, Air Force, Coast Guard, Joint systems, world-wide.

- **Coordinated multi-platform employment** from sensor to unit to Battle Force to Theater levels.

- **Qualified systems engineer/manager** for trainers, artillery, Command and Control (C2), countermeasures, for any platform.

- **Specialties:** environmental analysis, documentation, sensor/weapon predictions, C4ISR, Electromagnetic and Emission Control decision criteria.

- **Battle Force/Group Tactical Action Officer** (TAO) on 8 aircraft carriers, TAO Instructor for 4 years, 20 months combat experience.

Recent Positions
at ImagineCBT Inc., ISIS Inc., Raytheon ,and Hughes Aircraft Company

C4I Architect and **C4I Support Plan Lead** for the Carrier for the 21st Century (CVNX) Task Order.

- Completed *CVX C4I Support Plan, v1.0,* Joint Operational Architecture development for Joint and Naval staff space allocations for CVX (1999) and Joint Command and Control ship (2002).
- Drafted *CVN 77 Electronics System Integrator Statement of Work (SOW)* for WBS Group 400 tasks and IPTs (1999), *Integrated Management Plan*; Royal Navy CVF WBS proposal (2002)

Lead Systems Engineer, Operations Analyst and **Site Survey Leader** for Saudi Arabian Minister of Defense National Operational Command Centers and C4I System (completed August 1997).

- Completed *System Specification, System Description Document, Site Survey, Interface Requirements Documents*

Proposal Technical Volume Manager for the following **winning proposals**:

- Vessel Traffic Service 2000 system, US Coast Guard command center for surface surveillance using radar, visual, communications links. (proposal evaluated A++, won Phase I, Phase II delayed then restructured)
- Anti-submarine Warfare Team Trainer (Device 20A66), an integrated, multi-ship, submarine and aircraft training system for Naval Task Groups. ($56M contract, best technical, lowest cost)
- Electronic Warfare Coordination Module, an Intelligence/EW spectrum planning and management system for Task Force Command Centers. (won Phase I, best technical)

Assistant Program Manager for the Training Effectiveness Subsystem, Device 20A66

- Performance Measurement Subsystem, observed real-time performance of operators, teams, multi-ship and aircraft units during exercises and compared to the standard

Senior Systems Engineer responsible for writing **specifications** in following **proposals**:

- Fire Support Combined Arms Team Trainer (FSCATT) *System Specification*, a US Army artillery multiple cannon and battery training system. (awarded $118M contract, still under contract)
- Warfighter's Simulation 2000 (WARSIM 2000) *System Specification*, a US Army Force XXI Century battalion to theater levels, and training system with actual C4I systems. (won Phase I)
- Tactical Combat Training System, *Exercise Execution Software Requirements Specification* (SRS) for simulation and computer models to run real-time, driving sensors, weapons and links on 35 ships, 100 aircraft and submarines (won Phase I contract, wrote SRS in Phase 2 proposal)

Detailed Descriptions of Experience

The following are more information, arranged chronologically, with dates, duration, position title, program name, followed by accomplishments, and then an overview of the project.

April 2000 to present – ISIS, Inc., primarily as Senior Scientist, Information System Architect, Systems Engineer, Training Systems Analyst and **Requirements Analyst.**

General Accounting Office (GAO) (May 2005 – June 2006), reviewed and prepared training system development and professional engineering services (PES processes and job descriptions for category 69 (training) proposal.

Strategic Services and Support (April 2005-Sept. 2006), attended pre-solicitation conference for the Army Communications-Electronics Command (CECOM), Ft. Monmouth, New Jersey, waiting for formal request for a part of this $19.25 billion program proposal.

Department of Interior Management, Organization and Business Improvement Services (MOBIS) and Professional Engineering Services (PES) proposal analysis (June 2005), prepared a detailed requirements and tasks analysis of the RFP) and proposal plan.

Total Engineering Information Services (TEIS) (Feb. – March, 2005), participated as proposal writer, pink and red team member with another company which is prime for an approximately $12 million, multi-year, contract for the Army Information Systems Engineering Command, Ft. Huachuca, Arizona. Prepared TEIS Risk Management Plan for prime contractor. Presently ISIS is waiting for announcement of selected winners.

Networthiness Certification (Jan. 2005 – Sept. 2006), prepared proposal for the Army Network Command (NETCOM), awaiting RFP to respond for this several million dollar program involving over 3,200 Army computer programs at all Army installations, worldwide. Prepared Quality Control (QC) and Risk Management Plan.

Cryptologic Support and Logistic Analysis (Oct. 2004 – Sept. 2006), prepared proposal for the Army Communications-Electronics Command (CECOM), Ft. Huachuca, Arizona, waiting for formal request for proposal.

Information Warfare Training (2001 - 2005), USAF Small Innovative Business R&D (SBIR) Phase I contract, to determine IW training requirements and measure performance in an intelligence, wargaming system, awaiting possible award for development of an Information Warfare training system for the USAF Information Warfare Aggressor Squadron.

US Army Virtual Proving Ground (2001-2002) - Performed *C4ISR Architecture Framework* development, implementation and documentation using the DoD *C4ISR Architecture Framework, v2.0* and for Operational, Technical and Systems architecture products.

Prepared C4ISR architecture framework proposals for US South Command (USSOUTHCOM) Command Center (2003), DoD Threat Reduction Agency (DTRA) Operational Command Center at an Army Command, Virginia (2002), and Government Enterprise Architecture development for Department of Health and Human Services Command Center (2002) programs.

Raytheon Naval and Maritime Systems, San Diego, California, for various programs, a consultant for ImagineCBT, systems engineer.

April 2001 to June 2005 – C4I Architect, Operations Analyst/Systems Engineer for Minister of Defence (UK) Future Aircraft Carrier (CVF) program, Raytheon Naval and Maritime Ship Systems, San Diego.

Prepared for Raytheon Naval Ship & Integrated Systems (San Diego) proposals in April and June 2003 with Statement of Work (SOW), Data Item Descriptions (DIDs) and CDRLs for Architecture Assessments (Requirements, Testing) for ten functional mission areas, Global Information Grid Evaluations in order for CVF to be interoperable with US forces, and Levels of Information System Interoperability (LISI) using DoD LISI PAID (procedures, applications, infrastructure, data) attributes to determine internal and external interoperability assessments

Prepared proposal and performed contract for Raytheon C3I Systems (Fullerton, CA) for the Joint Command and Control Ship (JCC) *JCC Interoperability Study*, including report drafting and preparation, conference presentations and making recommendations to JCC Program Office for ensuring over 400 tactical, logistic, administrative, C4ISR applications work. (2001-02)

Prepared proposal and performed contract for Raytheon NAMS (San Diego) for *JCC Reconfiguration Study* to determine requirements to most effectively manage command (C4ISR) onboard JCC. (2001-02)

Provided architecture framework proposal inputs and evaluation for US Army Landwarrior III (Future Combat System) for Raytheon C3I Systems (Plano Texas)

Provided C4ISR and engineering analysis and proposal preparation for LHA(R), JCC, CVF and other Raytheon, San Diego ship programs (2000-03)

October 2000 to 2003 (now inactive) – MBA Instructor, University of Phoenix, "Operations Management for Total Quality" and "Managing R&D and Innovation Processes" courses.

Taught these courses in Nogales to Mexican maquilladores managers and in Tucson to Americans managers.

Qualified to teach "Program Management" course.

Plan to qualify as FlexNet (online) Instructor, presently inactive instructor status.

April 1998 to September 2000 – CVNX C4I Architect, C4I Support Plan Leader also **Lead Systems Engineer** and **Requirements Analyst** for CVN 77 and CVNX Programs, at Raytheon, San Diego, CA

Performed C4I Support analysis to prepare requirements for the DoD C4I Support Plan. Led several teams to understand the *DoD C4ISR Architecture Framework*, v2.0 and Operational, Technical and Systems architecture products.

Managed team for CVN 77 combat requirements analysis 3 months to draft and submit plan to NAVSEA (PMS-378) for two customer reviews.
Provided interface to combine CVNX and Joint Command and Control (JCCX) Ship architecture development for NAVSEA (PMS-377), drafted task schedule but funding then not provided.
Proposed an approved Technical Instruction for "Reconfigurable Joint and Naval Staff Space Allocations" in order to start the CVX/JCC *Operational Architecture* and *Mission Essential Tasks* processes - completed early 1999. (3 of 14 proposed were approved for study)
Coordinated the AFCEA "Architecture Implementation Course" at the Raytheon San Diego site.
Created and drafted CVN 77 *Electronic Systems Integrator (ESI) Statement of Work (SOW)* for the CVN 77 ESI role and RFP in Spring 1999.
Provided trade studies and options for performing this task for Newport News Shipbuilding.
Established a draft CVN 77/CVX "Total Ship Systems Engineering (TSSE) Plan for our team.
Implemented the Raytheon and Newport News Shipbuilding *Integrated Product and Process Development* processes to structure IPTs, tasks, and work descriptions.
Provided interoperability inputs to UK Future Aircraft Carrier (CVF) Raytheon Qualification letter.
Participated in establishing teaming arrangements with SPAWAR Systems Center, San Diego.

The CVN 77 is the transition aircraft carrier from the *Nimitz* class, to be commissioned in FY 2008. Two other evolutionary aircraft carriers, CVNX-1 and CVNX-2 are to be commissioned in FY 2013 and FY 2018, respectively. The tenth CVNX is planned for disposal in April 2111. Overall manning will be reduced up to 1,740 personnel. Up to 12 Joint, Naval, Combined and Coalition staffs may embark up to 1,000 augmentation personnel beyond the present capabilities. CVNX can embark a Joint (Task) Force Commander with command and control systems for Operational-Theater and Tactical (service) levels. The ESI role involves integration of all C4ISR equipment, internal and external communications, navigation, sensors, fire control, weapons, and associated display and processing systems.

January 1998 to present – H&R Block, Tax Advisor Level 3, seasonal tax preparer (annually, January to April 15), AARP Tax Consulting for the Elderly (pro bono) tax preparer, IRS qualified, over 450 hours of H&R Block classroom and CBT training courses.

August 1997 to April 1998 – DD 21 Requirements IPT Lead, Systems Verification and Test IPT Lead, and **Initial Lead Systems Engineer** for the Hughes, then Raytheon, DD 21 Program for NAVSEA, PMS-500 – assigned the CVX Reduced Manning (Automation) Study that led to CVX C4I Support Plan after Raytheon sent "no bid" letter in April 1998.
Provided IPPD plans for all systems engineering functions, including workshop participation, for subsystem to total Ship System levels.
Managed two Integrated Product Teams (IPTs), as additional DD 21 personnel were assigned.
Conducted a weekly VTC with IPTs, issued Agenda, Minutes, and led team meetings.
Attended Risk Management course and recommended Raytheon's Prophet™ risk management software tool for DD 21 and other integration programs.
Provided the initial *DD 21 Total Ship Systems Engineering (TSSE) Plan.*
Coordinated systems engineering modeling and simulation planning.

The Future Surface Combatant of the 21st Century (SC-21) Program consisted of both destroyers and cruisers, with the Land Attack Destroyer (DD 21) to be commissioned in FY2009 and an Air Dominance Cruiser in FY2018. I participated in the program implementation and maintenance of collaborative and synergy with both CVNX and SC-21 programs and the emergent JCC and USCG Deep Water Programs. [SC 21 is DDGX Program]

June 1995 to August 1997 (26 months) – Operations Analyst and **Site Survey Team Leader** also **Naval Operations Analyst** and **Joint Training Analyst,** *C4I System for National Defense Operations Center and Area Command Centers Definition Study* - **completed August 1997.**
Performed pre-contract planning analysis for site survey from battalion to national level.

Managed budget for 3 months deployment for the 12 engineers in Saudi Arabia.
Conducted interviews and briefs with members of all joint Minister of Defense and Aviation (MODA) staff and all armed forces, including schools and topographic commands.
Provided reports, program reviews and TGMIRs for survey and design efforts for the 2 years, including the coordination of all Action Items and Program Management Review Minutes.
Created significant inputs to the *System Description Document, System Specification* as Lead Systems Engineer, emphasized operational concepts including staffing and workstation operator tasks; operations center and support facility layouts; specifications for a transportable operations center (TOC); system-level communications interfaces including ATM, SATCOM, PTT and RF communications; system hardware and software interfaces including JMCIS, TADIL-S and IDL; operator training; selected over 100 formatted messages (using USMTF) for integration, and overall system performance characteristics.
Drafted System Specification for Land Forces Operations Center, deemed excellent by customer.
Prepared *Site Survey Report* and participated in drafting the *Communications Interface Requirements Document*, presented multiple customer briefs.
Only engineer to start and complete this contract (over $10M), most of the others were replaced.
The MODA C4I System will provide 13 operations centers, nation-wide, to form a joint service, C4I system, integrating the four services through 3 command echelons and, for the Land Force will provide their digital command and control system through 4 echelons.

1995 – Systems Engineer, for an AirHawk Concept of Operations.
Drafted a preliminary "*Operations Concept Document (OCD) for the Air HAWK*" system for HMSC, provided a systems approach to integrate the subsystems with the missile, for the Command and Control Division, using the MIL-STD-498(B) DID as a guide.
AirHawk provides an air-launch system capability for the U.K. Tomahawk cruise missile.

1995 (5 months) - Lead Systems Requirements Engineer, Warfighters' Simulation 2000 (WARSIM 2000), US Army training system.
Performed system functional requirements analysis for command and control levels from battalion through echelons above corps and Theater-levels
Responsible Engineer for the analysis and writing of the system specification for the entire system in accordance with MIL-STD-498(B) (System Engineering). (Hughes won Phase I)
WARSIM 2000 C4I training system to stimulate all present and emerging Force XXI digital C4I systems with operational data for entire staffs in their Tactical Operations Centers in the field, in classrooms and at the War Colleges. WARSIM 2000 integrates with other joint systems through protocol standardization and object-oriented design features.

1994 – System Requirements Compliance Engineer, Theater Battle Management Core System (TBMCS), US Air Force C4I system.
Ensured compliance with the contract and requirements documents integrating different systems into the TBMCS proposal, including the Global Command and Control System.
Drafted a compliance matrix with 200 pages in the Executive Volume to meet demanding RFP compliance requirements (Proposal vs. IFPP vs. SOW vs. CDRL vs. WBS vs. CLIN vs. TRD).
TBMCS is the US Air Force Theater to squadron level C4I system. (Hughes lost)

1994 (7 months) – Proposal Technical Volume Manager for the Vessel Tracking Services 2000 (VTS 2000), US Coast Guard C3 system.
Led the technical and engineering proposal efforts to comply with the RFP and proposal requirements, based on Hughes themes and proposal strategy decisions.
Managed systems, hardware, communications, software, and logistics engineers writing the responsive proposal. (Ten corporate teams bid; Hughes won Phase I with two others including Raytheon, Hughes performed Phase I, Congress delayed Phase II, program later restructured)

VTS interfaces radar, visual surveillance, environmental, and voice communications data with differential Global Positioning System (dGPS) information from automated and human input to enhance safety and commerce on waterways and for major port regions.

1993-1994 (10 months) – Lead Systems Engineer, Fire Support Combined Arms Tactical Trainer (FSCATT), US Army training system.

Team Leader for the requirements analysis, design, and system engineering and proposal efforts.

Drafted and led several pre-RFP System Requirements Reviews for the System Specification.

Developed a technique with Distributed Interactive Simulation (DIS) protocols whereby a thousand or more cannons can perform exercises from multiple sites in same exercise.

FSCATT integrates artillery and fire control with a Forward Observer visual training system, provides Fire Direction Center simulation and stimulation interfaces with Close Combat Team Trainer (CCTT) M1 tank and M2 systems. (Hughes won $118M program, still ongoing)

1990-1991 (20 months) – Systems Requirements Engineer, Tactical Combat Training System (TCTS), US Navy C4I training system.

Led the simulation and modeling, system requirements analysis for all real-time operations for the proposal and Phase I development efforts. (Hughes won Phase I)

Wrote most of the *Exercise Execution CSCI SRS* for real-time system execution software for all simulations and sensor, weapons and platform models (over 100).

TCTS provides a task group training data link for 100 aircraft, 24 ships and submarines, 6 ashore installations and ranges, with real-time targets (to 780). TCTS uses participant "pods" with a data link between platforms; stimulates platform sensors with the real-time targets; maintains data link communications; collects data for feedback and rapid after action reviews. (Hughes team won Phase I, Raytheon Phase II)

1991 - Human Factors SE for Land Warrior 2000 proposal, US Army infantryman C4I system.

Human Factor Engineer for proposal effort for the helmet display overload analysis with computer text and graphic display resolution. Left to lead FSCATT Systems Engineering and Proposal teams.

Land Warrior 2000 system provides infantrymen with an integrated C4I System for an infantry brigade, with computer-driven displays, messages, GPS, and other C2 features. (Hughes won)

1988-1991 (4 years) – Assistant Program Manager for the Training Effectiveness Subsystem, Device 20A66.

Created Performance Measurement Subsystem, used subcontractor to provide analysis, documentation, and design details.

Managed subcontract ($1.2M), conducted subcontractor reviews, and wrote SOWs, evaluated products and a subcontractor.

The Performance Measurement Subsystem determines operational performance (real time) for trainees from Admiral to sensor operators and for ship teams, multi-ship and tactical units.

1988-1991 (4 years) – Senior Systems Engineer, Device 20A66.

Lead Systems Engineer, provided significant inputs for models, simulations, communication data link interfaces, user displays, and I/O; consultant to software team as ASW expert.

Designed to real-time Links 4A/11/16 with ships in port and ships/aircraft at sea.

The Device 20A66 trains a Battle Group Commander in a Task Force Command Center (TFCC), staff and subordinate staffs (in 20 ships and submarines and 15 aircraft in 35 mockups using 186 different workstations with 61 large screen displays) to use data links, communications, and good decision making practices.

1986-1988 (1.5 years) – Proposal Technical Volume Manager, Device 20A66.

Evaluated Draft-RFP and System Specification, provided 229 change pages, and was acknowledged to be most significant pre-proposal action by any bidding contractor.

Led pre-proposal, technical design and development effort as the only engineer for 1 year.

Led, as Technical Volume Manager, team of systems, simulation, hardware, courseware, facility, logistics and software engineers in the synthesis and drafting of the 500-page technical volume, with final technical volume cost less than B&P estimate.

After proposal submittal, replied to questions, gave briefs. (Hughes won, beat 2 incumbents)

1987-1988 (6 months) – Proposal Manager, California Law Enforcement Driver Trainer System

Led pre-proposal and proposal team to develop a design for high-technology driver trainer systems for the Peace Officers and Safety Training (POST) Commission. (Hughes won)

Participated during contract, as systems engineer in-charge of design, to verify the POST training objective(s), standard(s) and criteria would be met for the drivers of the system.

1987 (4 months) – Lead Engineer, Advanced Fuels Auxiliaries Test System for USAF

Provided initial engineering requirements analysis leading to joint venture with Allison Gas Turbines to bid this major USAF test system.

Drafted initial System/Subsystem Design Document, the basis for design.

Hughes bid, after I left project; however, USAF declined to award contract.

1986-1987 (3 months) – Proposal Coordinator, USAF LANTIRN training system.

Led proposal compliance review for real-time video and infrared technical requirements using the Hughes RealScene™ 3-dimensional (voxel-based), interactive system instead of the Hughes (formerly Honeywell)-developed, GBU-15 training system.

LANTIRN trainer provides real-time displays of video and IR images to cockpit and weapons systems for F-15, F-16 flight simulators and the AGM-130 missile. (Hughes no-bid)

1985-1986 (9 months) – Senior System Engineer for the Electronic Warfare Coordination Module (EWCM) program with responsibility for the environmental effects design.

Led technical proposal effort, coordinated proposal outline, reviewed storyboards and topics, determined compliance, edited technical volume, and synchronized with other volumes.

Responsible engineer for atmospheric and acoustic effects on propagation and degradation from countermeasures, provided customer briefs and proposal topics.

EWCM provides full spectrum management capabilities for the Electronic Warfare Commander to coordinate operational and intelligence EW information and databases. (Hughes won Phase I, lost Phase II)

1982-1985 (2.5 years) – Systems Engineer for the training subsystem, Device 14A12 ASW Tactical Ship Training System.

Led technical proposal effort for the Performance Measurement and Monitoring training subsystem, sonar modeling and simulation, operator displays, fire control, data links, and sensor, weapon and platform modeling.

Designed PMM subsystem, pushing the state of the art, later implemented in Device 20A66.

All ASW ships and ASW aircraft were simulated in a single-ship, multi-dimensional (anti-air, anti-surface, anti-submarine) environment, as a C2 and sensor operator training system.

Papers

Presented papers to the Industry/Inter-Service Training Systems Conferences (I/ITSC):

"Design Concepts for a Performance Measurement System" [nominated for best paper top 5 of 105]

"A Performance Measurement System Design", based on Device 20A66 results.

Prepared and presented three reports to the National Security Industrial Association (NSIA), ASW Committee, as Vice-Chairman of Training and Interoperability Subcommittee; Study Leader for following Reports:

"Training Commonality for Oceanography and Acoustic Environment Study Results"
"Training Commonality for Detection and Classification Study Results"
"Proposed Standard Sonar Equation for Technical, Tactical, and Training Communities"

Received NSIA Meritorious Award for leading these ASW industry and government studies)

Presented paper to the Hughes Advanced Technology and Studies Group describing the use of "Distributed Interactive Simulation (DIS) Protocols in C4I Systems".

Raytheon and Hughes Aircraft Company Courses

Taught "Introduction to ASW Tactics" course, at Hughes (four times) and for the *Advanced Training Institute* at Naval Underwater Systems Center (New London and Newport RI) 10 times at the Naval Surface Weapons Center (White Oak), Naval Civil Engineering R&D Center (Oxnard), and others.

Attended "C4I Architecture Implementation" (4 days, AFCEA Course), "Risk Management" (3 days), "Front-End of the Business" (1 week), "Systems Engineering" (HITS/HMSC processes), "Global Command and Control Seminars" (APL)

Attended ATEP Courses:

Software Risk Analysis, Software Estimating and Prediction, Database Modeling, Object-Oriented Software Methodologies, Proposal Development, How to Interview Candidates, Microsoft Word, Creating a Web Browser, Netscape User's Courses

Participated in the NSIA Industry War Games at Naval War College (Newport RI) and Marine Corps Command and Development Center (Quantico).

Military Schools

Attended US Naval schools including Destroyer School Department Head Course, Gunnery Officer, Anti-submarine Warfare (ASW) Officer, Communications Security (COMSEC), Naval War College Wargaming Course, and Naval Tactical Data Systems User Courses.

Military Qualifications

Qualified for Command of Destroyer, Tactical Action Officer (Battle Group and Warship), Officer of the Deck (cruiser and destroyer), Ship Command Duty Officer, and Surface Warfare Officer.

Proven Subspecialist (post Master Degree) in Geophysics, Oceanography, and ASW Systems Technology, Board selected (about 10 in each of these subspecialties per year in US Navy).

Significant Military And Operational C4i Experience

Active duty commissioned officer in the US Navy serving in the following assignments (homeported twice with each of the four fleets):

Area ASW Force, Sixth Fleet (CTF 66) as Staff Plans Officer coordinated all surface ships, aircraft carriers, submarines and ASW/EW aircraft in the Sixth Fleet area on a daily basis; conducted operational ASW with real targets; coordinated (simulated) daily submarine, surface ship and air-launched anti-ship Harpoon attacks on targets. (Awarded Meritorious Service Medal for highest Fleet-level ASW performance ever)

Fleet ASW Training Center, Pacific Fleet, the lead Coordinated ASW Tactics Instructor and Staff Oceanographer, and at sea as an Anti-Submarine Warfare Commander Instructor and ASWC Watch Officer during Fleet Exercises, augmenting Destroyer Squadron staffs. Also taught coordinated ASW tactics at Fleet Combat Training Center (Point Loma) as a guest instructor to TAO classes for three years.

Commander Carrier Group Three, as staff ASW Surface Operations and Geophysics/ Environment Officer, deployed twice to Western Pacific and Indian Ocean; planned and conducted RIMPAC 77 with Japan, Australia, New Zealand, and Canadian ships, 3 aircraft carriers, 7 submarines and over 150 aircraft; planned Persian Gulf CENTO MIDLINK-77 with UK, Iran and Pakistan; qualified as Battle Force TAO on 5 different aircraft carriers.

Naval Surface Warfare Officers Schools Command/Naval Destroyer School as the ASW Tactics and TAO Instructor for Prospective COs, XOs, Department Heads and Free World Navies Courses for mid-grade officers from over 30 countries; co-developed Naval Tactical Analysis Wargame and used it to evaluate tactical concepts including Harpoon anti-ship tactical development; used ASW team and sonar trainers for exercises; trainers for anti-PT boat interactive team exercises; taught anti-submarine/anti-surface warfare tactics, EW, communications, and EMCON decision making classes. Taught surface ship ASW at Submarine School was a guest instructor at the Naval War College and used the War College wargaming facilities to evaluate new systems and ship classes being designed by NAVSEA. (Awarded Navy Commendation Medal with Gold Star for second award)

Commander Cruiser-Destroyer Flotilla Ten, as ASW Plans Officer, deployed to Sixth Fleet, embarked on 3 aircraft carriers and 2 cruisers including USS *Albany*. Planned and executed many Sixth Fleet and NATO exercises and a CENTO air defense exercise. Engaged in more than 50 Soviet bomber over-flights of the Battle Group, 100% successfully intercepted by fighters and missile lock -on prior to 100 miles from the aircraft carrier. (Awarded Meritorious Unit Commendation for validating anti-SSBN tactics and developing SSN direct support procedures)

USS *Hollister* (DD788), Operations Officer, deployed for 2 years, 19 months of consecutive combat operations off Vietnam in the Seventh Fleet, provided naval gunfire support (over 28,000 5/38 rounds), maritime surveillance, SAR, *Gemini VIII* NASA space craft rescue ship, and EW intelligence gathering and Korean operations. (Awarded Secretary of Navy Unit Commendation, Navy Commendation Medal with Combat "V")

USS *Robert L. Wilson* (DD748), ASW Officer, deployed to Sixth Fleet for ASW operations, UN rescue ship off Cyprus, NATO exercises, *Gemini IV* NASA space craft rescue ship, participated in the Dominican Republic operations. (Armed Forces Expedition Service Medal, National Defense Service Medal)

USS *Springfield* (CLG7), Main Battery Fire Control Officer and Missile Fire Control Officer, deployed in the Sixth Fleet Flagship, home ported in Villefranche-sur-Mer, France.

State of Arizona, Industry Association, Company, and Military Awards

Friends of the Santa Cruz River, "Volunteer of the Year" award and certification from Sherry Sass, President of the Friends of the Santa Cruz River for service involving transmission line sitings to protect the Santa Cruz River and support for the Arizona Department of Water Resources, Santa Cruz Active Management Area (SCAMA) Ground Water User's Group in Nogales, Arizona. (2010)

Arizona Secretary of State "Arizona Golden Rule Citizen Certificate" and plaque from Janice K. Brewer, Secretary of State, for "exemplifying the spirit of the Golden Rule daily: "Treat others as you would like to be treated", nominated by former Santa Cruz County Supervisor Ron Morriss, for his work as a voluntary Energy Commissioner and his work for the county before the Arizona Corporation Commission. (2004)

National Security Industrial Association. (NSIA) Anti-Submarine Warfare Committee, Meritorious Award from the NSIA President, Admiral Hogg USN (Ret.), for leading several ASW training industry and government studies. (1992)

Merit Awards. Raytheon and Hughes, four times, for achievement and excellence in performance.

Military Awards include Meritorious Service Medal, Naval Commendation Medal with Combat "V" and Gold Star for second award, Navy Unit Commendation, Navy Meritorious Unit Commendation, National Defense Medal, Armed Forces Expeditionary Medal (Dominican Republic), Vietnam Service Medal with three Bronze Stars, Vietnam Campaign Medal with "1960-", Overseas Service Ribbon (Italy).

Community Service

Joint Santa Cruz County and City of Nogales Energy Commission from February 2001 to present – Member and Vice-Chairman and periodically report to both the Santa Cruz County Board of Supervisors, P&Z Commission and City of Nogales Council on various energy matters.

Marauder Historical Society from 2002 to present – Board Member and Vice-President, Chairman of the Living Legacy Fund Raising and Archive Donation Campaigns, semi-annual Board meetings, annual "Gathering of the Eagles" Martin B-26 medium bomber reunions since 2006, leading proponent of the "Heritage Flight" so the first World War II generation legacy is passed to later generations

Tubac Community Center Foundation from 1998 to 2000 – Member of the Board of Directors, wrote Bylaws for this IRS Code 501(c)3 organization that operates and maintains the Community Center for Santa Cruz County, softball field and play ground.

High School "All American" Swimmer in Breaststroke on 200 Yard Medley Relay Team, Coral Gables High School, Florida, State Champions (3 years), Undefeated in Dual Meets (3 years),

Scoutmaster, Troop 502. From 1992 to 1997 – reinvigorated a Scout Troop with 5 Scouts to 32 Scouts so that it would make it's 50th Anniversary in La Cañada-Flintridge, CA. Troop graded as "best" in District Camporee, Qualified "Honor Troop" for three years, with 7 or first 8 new Scouts in troop awarded Eagle Scout, graduate of Scoutmasters Training Course, member of "Hi-Tech" Patrol.

Boys State (Florida) in 1958.

Eagle Scout, with Bronze and Silver Palms, Troops 32 (Miami) and Troop 7 (Coral Gables) in Florida.

Security Clearance

Active DoD Secret Clearance

Exhibit MM-2

Marshall Magruder
PO Box 1267
Tubac, Arizona 85646

17 August 2009

Public Comments

Re: SSVEC Rate Case, ACC Docket No. E-01575A-08-0328

1. Since last fall, I have been working with a group of concerned citizens in the Mountain Empire of communities of Sonoita, Elgin and Patagonia who want to improve electric reliability though use of today's technologies instead of those decided by SSVEC over a quarter century ago. And as an Energy Commissioner for Santa Cruz County, considered this my obligation.

2. The company proposed a radial 69-kV subtransmission line because these communities are near the 7 MW capacity of its present 25 kV distribution line and to provide a distribution substation with four reliability loops for at least $13.5 million. The 25 kV line will be a loop.

3. Initially, several powerline alternatives were considered, including backup support from TEP on its 46 kV line and an option to tie UNS Electric and SSVEC distribution lines south of Patagonia. Both remain as valid options but more importantly provide two second sources instead of only one at present or as proposed.

4. The most inexpensive and obvious solution is to double-circuit the existing 25 kV line to provide 14 MW for these communities.

5. In the January-February timeframe, it became obvious that renewable energy options would greatly enhance local reliability on the V-7 feeder line when reasonably inexpensive generators could handle "sunless" or "windless" excursions. Interconnections to a nearly adjacent EPNG natural gas line in UNS Gas service area could service if demand exceeds 7 MW.

6. The community has fully supported becoming independent with clean distributed generation to reduce its dependence on coal-power electricity generated from Wilcox.

7. There are many residential and business owners who have or plan to apply for solar PV and heating systems, at least 1 MW, that will reduce demand. Further, several small solar arrays or biogas 1 to 3 MW generation units are under active discussions. This will significantly reduce load on the existing 25 kV line.

8. The ACC REST, netmetering and DSM programs being implemented by this utility improve reliability and distributed generation. Stimulus funding options was not discussed until about six months ago and can provide funding not available last year.

9. What does this mean? MANY <u>new options</u> are now on the table, with more expected in the near term, and from our view, <u>all appear less expensive than the utility's 1982 proposal</u>.

10. In May-June we suggested that a FEASIBILITY STUDY be conducted to collaboratively work with these communities to determine their best solution. In July we discussed this with the utility to see if they agreed to conduct such a study. If they had, I wouldn't be here today.

11. Thus, we are here today requesting that an INDEPENDENT organization, acceptable to the ACC Staff, be funded by the utility to conduct a FEASIBILITY STUDY we outlined.

12. This FEASIBILITY STUDY must look at all aspects of the issue, from technical and environmental views, including public relations and financial, and summarized so management can make a decision. Our outline has all these elements and includes biweekly reviews with the public to baseline results as the study progresses with written monthly status reports to SSVEC Board of Directors and to the ACC Staff.

13. I have read Commissioner Newman's Proposed Amendment No. 1. It establishes a requirement for SSVEC to conduct such a FEASIBILITY STUDY by an independent third party. This amendment requires the study filed with the ACC in a (new) docket, and monthly progress status reviews and reports are also filed for additional public review and comment.

14. The community's proposal for frequent public reviews should be in a forum atmosphere, as proposed in Commissioner Mayes Amendment No. 1. These public progress status review forums should be coordinated by the third party during the FEASIBILITY STUDY as community participation will lead to better understandings between the utility and the public and create the basis necessary to implement a renewable distributed energy "model" for these and other rural communities "at the end of the line."

15. From my role as consultant to the Mountain Empire communities, the Commission should approve both Commissioners Mayes No. 1 and Newman No. 1 AMENDMENTS as they are based on what these communities believe are the best approach towards resolution of these issues and are in the public interest.

16. Commissioner Newman's Amendment orders that the 69 kV line construction not be commenced until the FEASIBILITY STUDY has been reviewed. SSVEC is concerned it will not have adequate power for these communities this winter. Because electricity consumption has decreased for past two years for most Arizona utilities, less than a dozen homes were built in the past 12 months, local renewable energy systems are being installed today, public participation in energy efficiency programs is reducing demand, and since 7 MW was not exceeded last winter, there should be a very low risk of exceeding the 7 MW capacity on the existing 25 kV line. Further, and if such a risk is deemed, then renting a 500 kW generation set for backup would be a simple, cost-effective way to resolve any such risk while more prudent and cost-effective options are being fully evaluated in an ongoing FEASIBILITY STUDY.

17. RECOMMEND APPROVAL of both the NEWMAN and MAYES AMENDMENTS No. 1.

Sincerely,

Marshall Magruder

Exhibit MM-3

Marshall Magruder
PO Box 1267
Tubac, Arizona 85646

27 January 2009

Arizona Corporation Commission
Chairman Kristan K. Mayes
Commissioner Gary Pierce
Commissioner Paul Newman
Commissioner Sandra D. Kennedy
Commissioner Bob Stump
1200 West Washington Street
Phoenix, Arizona 85007

Subject: Impact of the Feasibility Study on SSVEC's V-7 Feeder Area (preliminary)

Re: ACC Dockets Nos. E-01-0575A-08-0328

Dear Commissioners:

As an Energy Commissioner in Santa Cruz County between 2001 and 2008, I have worked to help resolve various energy issues in this county.

The long standing issues concerning the feeder line to the Santa Cruz County communities of Patagonia, Sonoita, Elgin, and Canelo Hills has been discussed in several proceedings before this Commission in the past two years. I am not a party to these proceedings but have followed them closely due to my interest in ensuring reliability and satisfactory service in my county.

This letter provides a few preliminary facts uncovered while reading the Feasibility Study for this area.

The local utility company for this area is Sulphur Springs Valley Electric Cooperative (SSVEC) was ordered to delay starting construction of a 23-mile 69 kV subtransmission line to Sonoita. This is one of the two elements of the SSVEC proposed Sonoita Reliability Project (SRP). The second element is for a distribution substation to be installed in Sonoita with four feeders from each cardinal direction to improve reliability. This distribution substation was approved for construction by the Santa Cruz County Board of Adjustment last spring as its interconnection to the 69 kV line could be added later. There is no reason why that construction has not started which will also include a local 750 kW solar array. The Feasibility Study found that "new supply alternatives which reduce line exposure by creating new feeder segments would improve reliability by 15 to 30 percent beyond current levels" [p. 2]

In the decision by the Commission to delay the first element, due to over 200 letters and comments received during public comments in Sierra Vista last spring, at the SSVEC Rate Case hearings, and via various dockets requesting a review of the first element of the SRP, the 69 kV line, a Feasibility Study was requested by the Commission to be conducted by an independent third-party to be completed by the end of 2009, then to reviewed during public forums in these local communities during six months, followed by a meeting of the Commission to then decide which of the options would be fair and reasonable for the SSVEC customers in these communities. This decision is expected to occur in the summer of 2010. The overall result, if the proposed 69 kV line were determined to be the best for SSVEC's ratepayers, would be a one-year delay from its original schedule.

Confidence in SSVEC's "facts". There are many statements in the resultant Feasibility Study that do not support the company's rationale for the proposed 69 kV line element of the SRP. When reading the below, suggest considering is the "69 kV line" going to impact this statement, in most cases the answer is no. Some more glaring include:

1. The Average Customer Lost Electricity 3.0 hours per year based on the past 10 years of data. [see Feasibility Study at Fig 2, p. 11] The standard for rural areas used by the USDA for RUS loans in 5.0 hours of outage per year per customer. The Company seems to believe that some 240 (or 270) hours of customer outage per year and keeps promoting that number which the Feasibility Study does NOT support. In fact, if one windstorm in 1999 were deleted, then the average outage would have been 2.4 hours per customer. This is very good for rural areas, where the distances are much longer than urban area for repair crews to travel. As also noted in other data, the V-7 feeder area is also not SSVEC's worst.

2. Voltage Anomalies may continue Even if Upgrades are implemented. [Pp. 2-3] Resolution of voltage anomalies were beyond the scope of this study but should be addressed if the V-7 feeder remains in its current configuration.

3. Long Lines can create Power Quality Events [p. 2] Mostly voltage sags can occur in long lines and even protective devices may have difficulties as "end of line" currents approach normal trip settings. Local or Distributed Generation (DG) within the V-7 feeder area thus should reduce voltage sags and improve reliability since these lines are much shorter.

4. SSVEC should address Current Performance and Capacity Issues. [p. 3] No one disagrees with this comment; however, the erroneous "customer requests for new or expanded service" has been erroneous in the data proved by SSVEC to the study team and to the Commission. The "Urgency" of the frantic calls by this company has NO basis.

5. Cost of Mitigating Reliability and Performance Issues was NOT included in the Feasibility Study. [p. 5, footnote 3] This study did not consider the cost to mitigate reliability and performance issues. Unfortunately, "cost" is a key determinate when decisions are involved. This condition was established by SSVEC when it provided study constraints to the Feasibility Study Contractor.

6. Present "reliability" in the V-7 feeder area is better than average. [Table 1, p. 11] Based on the data in this study, during 2008, the three most common distribution line reliability indices (SAIFI, SAIDI, CAIDI) were in the second quartile, compared to national averages for reliability in the IEEE Standard for these indices.

7. The Number of Outages in the V-7 Area is Decreasing. [Fig. 3, p. 12] In general, the number of outages in this area shows a decreasing trend during the past ten years. This is one of the three largest distribution areas for SSVEC, thus it's "total" number of outages will be high compared to most other 25 or so much smaller SSVEC feeder areas.

8. The Cause of Outages in the V-7 area is mostly Natural Causes. [Fig. 4, p. 13] The six most common causes for outages in the past ten years has been lightning, birds, animals, and wind other than "unknown" or "other". The company's increasing use of lightning arrestors is reducing the highest cause. The 69 kV line may have minor, if any, impacts on reducing outages.

9. The Number of Customers impacted by Outages is Low. [Fig. 5, p. 13]. Over 90% of the outages in the V-7 area involved three or fewer customers. As stated on page 20, full feeder outages have been very low. Less than 1 such outage a year has been experienced.

10. The Equipment Failures were Mostly Non-Distribution Line Failures. [Fig. 6, p. 14] Fuse failures for Transformer and Line/Riser dominated equipment failures, which was unexpected. Footnote 8 indicated that SSVEC standard for line transformer arrester placement does not agree with industry research for industry placement. This anomaly might be a major cause of failures, as distribution line overloading was insignificant.

11. Techniques could reduce Lightning Failures. [Figs 7 and 8, p. 15] Since lightning failures peak during the summer and early morning/late afternoon, pre-positioning crews was suggested as a way that might reduce travel time to correct outages. Some additional equipment were recommended [p. 16]. Further, replacement utility poles by SSVEC on several V-7 sections have installed lightning protection and "have been effective in the decline in number of outages over the past 10 years." [p. 16]

12. Cost of Mitigating Reliability and Performance Issues was NOT included in the Feasibility Study. [p. 5, footnote 3] This study did not consider the cost to mitigate reliability and performance issues. Unfortunately, "cost" is a key determinate when decisions are involved. This condition was established by SSVEC when it provided study constraints to the Feasibility Study Contractor.

13. New Construction is Minimal in the V-7 Area. [Table 5, p. 26] As shown, only ONE pre-meter construction customer was in this area. SSVEC has used unrealistic numbers to account for new customers, including 222 in three bankrupt developments in foreclosure, without buyers.

14. SSVEC does NOT have Realistic Time of Use (TOU) Programs. [Table 5, p. 26] Only ONE residential customer has TOU rates out of over 1,675 residential customers. This is one area where peak demand can be significantly decreased. Obviously, an effective Demand Side Management (DSM) program would have been stressing TOU for this area.

15. About 30% of the Feeder Load was due to Line and Equipment Losses. [Pp. 3, 27] Some $230,000 annually cost is required for excess electricity power to compensate for line losses to this area. Local distributed generation would greatly reduce this wasted electricity and its resultant generation impacts on the environment.

16. Line and Equipment Losses Increase at Higher Customer Demands. [Fig. 13, p. 27] As the customer load increases, then there are more losses.

17. Most of this Feeder load is Less than 5 MW. [Fig. 13, p. 27] If the desired maximum loading limit is 4.5 MW, then use of Distributed Resources or Demand Response would need to be operated or enabled for a minimum of about 500 hours.

18. Peak Loads are Predictable in the V-7 Area. [Fig. 14, p. 27-28] There is a high degree of consistency among peak load days that allows system planners to design programs to reduce daily peaks by targeting load reduction programs, e.g., DSM programs.

19. Peak Demand Forecasts in the Study appear Highly Optimistic. [Pp. 28-30] Unfortunately, the 2006 data were old and did not reflect the present very slow growth and failed to account for limitations on growth that water resources require for these areas.

20. Weather Adjusted Transformer Rating are Higher than Nameplate Data. [p. 31] The Study did not calculate higher winter ratings used by many companies; however, the existing 7.0 MW upper limit for the transformer maybe actually higher that its stated nameplate data.

21. By Removing Losses, then total Capacity Deficits will be 1.5 MW in 10 years and 3.5 MW in 20 years. [p. 32] IF SSVEC actively removed demand 10 to 15 percent to reasonable levels, then an additional 1.5 MW of local distribution in 2019 and 3.5 MW in 2029 would meet the capacity demands for this area.

22. Demand Side Management for Space Heating/Fuel Switching with Resolve Capacity Issues. [p. 42] MANY ways to remove demand were in this study, such as having 100 customers switch from electric heat to gas (propane or natural gas) would alleviate today's problems, and 50 to 75 per year to offset load growth.

23. Solar Photovoltaic was Not Really Considered in the Study. [Pp. 43-44] Apparently due to winter peak issues, the study did not go into PV options; however, several excellent storage devices were discussed that would resolve this issue. [Pp. 48-50] A Sodium-Sulfur (NaC) was recommended for this area that is compact, and as shown in Fig. 21 (p. 50) would "fill in" the valley between the winter peaks. Due to "lead time" to order such a device, this option was not considered; and its popularity should also drive down its future costs.

24. Distributed Generation with Generator Sets is a Viable Option. [Pp. 51-52] This is a relatively inexpensive option, and can easily meet the 1.5 MW demand for 2019 at minimal capital costs (1MW = $700,000). Unfortunately, the study team did not contact UNS Gas, the natural gas distributor for Santa Cruz County that could develop a substation on the El Paso Natural Gas line that runs through Patagonia and very close to the Sonoita substation location.

25. Analysis for Renewable Energy or Solar Technical or Economic Analysis were NOT in this Study. [p. 33, footnote 19] As noted, this analysis was not conducted as a part of this study nor provide by SSVEC to the study contractor. Without such details, then additional work is necessary to properly evaluate renewable energy options and solar installations.

26. Support to Patagonia from UNS Electric. [p. 36] The study stated that UES does not have "sufficient capacity on the Valencia feeder to provide firm capacity to serve Patagonia load. This is confusing as two UNSE feeders from Valencia and Cañez stations are "tied" so there are two sources, the UNSE-SSVEC tie is to provide "backup" or additional power, and not to be a full-time provider meeting a firm delivery requirement. Somehow the study team was misled.

27. Only 3 MW is required to Unload the V-7 Feeder to Acceptable Levels. [p. 38] There are several plans for 1 to 3 MW solar arrays that could support the V-7 feeder area, including one that could be near the UNSE-SSVEC tie. Obviously, a peaker generator set would met this requirement, maybe at the Sonoita or Patagonia areas, at much less cost than for the 69 kV line.

These are only very preliminary comments on the Feasibility Study that is still being digested; however, in general, it is an excellent point of departure for some stimulating Forums expected in the next six months.

Recommendations.

1. That evidentiary hearings with a Recommended Opinion and Order (ROO) be held to review this study before reviewing the prior decisions concerning the 69 kV line.

2. That the recent Staff proposed schedule be seriously considered.

3. That the forums be held in an 'informative' atmosphere, without the high-pressures and misleading influences of SSVEC, as discussed in the following paragraph.

These forums need to be led by an impartial person/team, and would suggest that SSVEC NOT be the one who controls inputs to these forums. I would like to suggest that the Feasibility Study team be the ones who lead the "town hall" type of forum. Further, would suggest that two such forum be held in each community (Patagonia, Elgin, Sonoita) with the first primarily being a presentation of the study to these customers with some questions and answers, and that the second being Questions and Answers with the Public and SSVEC using the Study Team as moderators.

I hope this letter has provided some additional information in this very important matter. If additional information is requested, please feel free to contact me.

Sincerely,

Marshall Magruder
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[Note: corrected in the mailed version several insignificant typos in an emailed version]

CC.

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