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To:	Corridoreisarchives;
CC:	
Subject:	Energy Corridor Programmatic EIS Comment 80040
Date:	Monday, November 28, 2005 12:41:48 PM
Attachments:	SWAT_Comments_to_DOE_Western_Energy_Corridors_11-28-05_80040.pdf

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Thank you for your comment, Robert Kondziolka.

The comment tracking number that has been assigned to your comment is 80040. Please refer to the tracking number in all correspondence relating to this comment.

Comment Date: November 28, 2005 12:41:44PM CDT

Energy Corridor Programmatic EIS Scoping Comment: 80040

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Attachment: Y:\data\SWAT Comments on DOE Corridors\SWAT Comments to DOE Western Energy Corridors 11-28-05.pdf

Questions about submitting comments over the Web? Contact us at: corridoreiswebmaster@anl.gov or call the Energy Corridor Programmatic EIS Webmaster at (630)252-6182.

The United States Department of Energy
West-Wide Energy Corridor Programmatic EIS

Comments by
Southwest Area Transmission (SWAT) Sub-Regional Planning Group

Submitted November 28, 2005

The United States Department of Energy
West-Wide Energy Corridor Programmatic EIS
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I. INTRODUCTION

The Southwest Area Transmission (SWAT) sub-regional planning group promotes western regional transmission planning. SWAT is comprised of representatives from two states (Arizona and New Mexico) and parts of four others states (Southern California, West Texas, Southern Nevada, and Southern Colorado) who work to promote collaborative regional planning in the Desert Southwest region of the Western Interconnection. Participants in SWAT projects and technical subgroups variously include the Arizona Corporation Commission, Arizona Power Authority, Arizona Public Service, Western Area Power Administration, Southern California Edison, California Independent System Operator, Central Arizona Project, El Paso Electric, Electrical Districts 2, 3, 4 of Pinal County, Imperial Irrigation District, New Mexico Public Utilities Commission, Tucson Electric Power, PacifiCorp, Public Service of New Mexico, Tri-State GT, Dine Power Authority, BHP Billiton, Navajo Tribal Utility Authority, Nevada Power, Rocky Mountain/Desert Southwest Reliability Center, Salt River Project, Southwest Transmission Cooperative, and other interested Parties.

II. COMMENTS

Robert E. Kondziolka, on behalf of both Salt River Project and SWAT, provided verbal comments at the November 3, 2005 public scoping meeting in Phoenix, Arizona. These written comments supplement the record of his verbal comments at that public scoping meeting. Lastly, information on SWAT and Central Arizona Transmission System (CATS) regional planning studies can be accessed and downloaded from the following website: http://www.azpower.org/.

A. Regional and Sub-Regional Planning – Planning activity in the west is very active and there are multiple groups focused on identifying the most viable projects. Alternatives are studied in the planning stages prior to projects being proposed. We encourage the DOE to work with Western Electricity Coordinating Council (WECC) and the sub-regional planning groups in the Western Interconnection.

B. WECC Planning Process – WECC has a “Regional Planning Process” contained within a more comprehensive document entitled “Overview of Policies and Procedures for Regional Planning Project Review, Project Rating Review, and Progress Reports” that provides notice and invites other parties to consolidate their needs into a singular or fewer projects. This is an effort to minimize the impact and maximize the value of new transmission projects. The WECC regional planning process can be accessed and downloaded from the following website: http://www.wecc.biz.

We recommend that the DOE provide consideration to those projects that have undergone regional and sub-regional planning to determine specific project needs and benefits as demonstration to need, alternative solutions, and minimization.

C. Joint Owned Projects – A significant amount of transmission in the west is jointly owned to reduce the risk of the project and to consolidate needs. Most of the major projects that have been announced will be jointly owned. We recommend that the DOE provide consideration to those projects that are jointly sponsored and owned as demonstration to need, alternative evaluation, and minimization of impact.

D. Reliability – We recommend the DOE evaluate and consider a balance between the public desire for consolidation of facilities within corridors and the risk of placing too many facilities in a common corridor. We recommend the basis for determining this balance be a rational evaluation based on the types of events that may cause a loss of multiple facilities in a common corridor and the impact of the loss and its consequences.

E. Separation of Facilities in Common Corridors – We also recommend that consideration be given to the distances between the different pipelines and electric transmission lines when designating corridors and corridor widths. The basis of the evaluation should consider the safety and reliability impact of each facility upon the other facilities, not just previously used separation distances.

F. Global Needs Identified by SWAT – SWAT is evaluating long term needs for the southwest, not just what is needed during the next 5 to 10 years. We encourage the DOE to have a long-term perspective in their evaluation and consider future needs. SWAT studies have identified needs for additional transmission, but if action is not taken during this evaluation, the needed corridors may not be available in the future. These long term needs include transmission between the Arizona/New Mexico border near Springerville and St. Johns to the Phoenix metropolitan area; Benson area (Winchester Substation) and Coolidge area (Pinal South Substation); Four Corners and the Phoenix metropolitan area; eastern New Mexico wind farm areas and the Arizona/New Mexico border areas near Four Corners, Springerville/St Johns, and Benson; and Palo Verde Nuclear Generating Station area and Yuma (North Gila Substation).

G. Existing Corridors – We encourage the DOE to incorporate all previously designated corridors and man-made linear features on federal lands as energy corridors. This should include all transmission elements identified and referenced in the November 7, 2005 "Report to Congress: Corridors and Rights-of-Way on Federal Lands," by the U.S. Department of Agriculture, U.S. Department of the Interior, U.S. Department of Energy, and Council on Environmental Quality.

H. Connected Action, Cumulative Impacts, Emissions & EMF – We request the DOE to address these as global issues and not leave them to be needlessly studied on each and every project as area specific EA or EIS issues. The western interconnection is one large electrical grid and every project is tied to all previously constructed and future energized section. The reliability and effectiveness of the western interconnection as a whole is dependent upon the aggregate of all segments and cannot be isolated as independent projects. We recognize that cultural and biological resources are likely to be the focus of individual applications. However, we do request that Class III cultural resource surveys not be required during the permitting stage of a project. We recommend that Class III cultural resource surveys not be required until the time period prior to construction or earth disturbing activities.

III. ATTACHMENTS

Attached to these written comments are several reports, case studies and information on planning standards that illustrate the practical applicability of rational needs-based analysis that both ensures reliability and focuses on solutions that meet a region's near and long-term requirements for transmission. Attachment 1 contains a detailed presentation of the factors considered in the California-Oregon 500 kV Transmission Project. Attachment 2 presents a summary of the NERC/WECC planning standards. Attachments 3 and 4 contain two recent Arizona Corporation Commission staff analyses on siting a proposed 500 kV transmission line in Arizona. Lastly, Attachments 5 and 6 contain portions of studies on potential right-of-way for gas pipeline and electric power lines.

IV. CONTACT INFORMATION

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LIST OF ATTACHMENTS

1. California-Oregon Transmission Project: Power System Studies Committee Position on Corridor Separation in re: California-Oregon 500 kV Transmission Project (October 1985)

2. Summary of NERC/WECC Planning Standards by R.E. Kondziolka (from: SRP Pinal West – Southeast Valley 500 kV Transmission Project Siting Case (2005))

3. Arizona Corporation Commission: Staff Presentation on SRP Pinal West – Southeast Valley 500 kV Transmission Project Siting Case (November 2004)

4. Arizona Corporation Commission: Staff Presentation on SRP Pinal West – Southeast Valley 500 kV Transmission Project Siting Case (March 2005)

5. Computer Analysis of Potential Right-of-Way for Gas Pipeline and Electric Power Lines: Report to SRP by ELK Engineering Associates, Inc. (April 2004)

6. Executive Summary of Computer Analysis of Voltages and Currents Produced by Existing and Future Transmission Lines: Report to SRP by Electro Sciences, Inc., Gas Pipeline Mitigation Consulting Services (April 2004)

ATTACHMENT 1

CALIFORNIA OREGON

TRANSMISSION PROJECT

CORRIDOR SEPARATION FOR THE CALIFORNIA-OREGON TRANSMISSION PROJECT

OCTOBER 1985

POWER SYSTEM STUDIES COMMITTEE

CALIFORNIA-OREGON

500 kV TRANSMISSION PROJECT

POWER SYSTEM STUDIES COMMITTEE

POSITION ON CORRIDOR SEPARATION

October 1985

Executive Summary

This paper discusses the reliability issues associated with the option of building the new California-Oregon 500 kV transmission line (the Project) adjacent to the two existing 500 kV Pacific Intertie lines. Three findings are discussed; two are related to concern over paralleling the Project line with the existing Intertie lines; the third is related to the issue of concentrating large amounts of power flow through project line termination substations. The two corridor/right-of-way sections of concern are referred to as the Malin to Round Mountain corridor shown in Figure 1, and the south of the Sacramento River corridor, shown in Figure 2. The conclusions in this paper regarding the corridors are based on power flow and dynamic stability analyses of the interconnected transmission system of the Western Systems Coordinating Council (WSCC). The recommendations are based upon a comparison of technical conclusions with the necessity of the Project to comply with WSCC "Reliability Criteria for System Design" and North American Electric Reliability Council (NERC) guidelines for reliability. The Power System Studies Committee recommends acquisition of new right-of-way for both corridor sections a sufficient distance from the existing 500 AC Pacific Intertie lines that a credible three line outage cannot occur.

The Project represents a major addition to the bulk transmission system of California as well as the Western United States transmission system. WSCC members have pledged that new additions will not be planned, constructed or operated in such a manner as to adversely affect neighboring systems that are also part of the interconnected system. NERC, the national reliability council, has established United States guidelines and WSCC has established reliability criteria specifically for the Western United States. All interconnected operating utilities within WSCC have pledged to support both NERC and WSCC, and plan their systems accordingly.

This discussion does not extend beyond system planning issues. A complete evaluation of compliance with criteria would also include an evaluation of specific line design and substation design issues such as right-of-way separation, line crossings, tower angles, tower footing ground stability, terrain slope, maintenance accessability, climatology, etc. This evaluation pinpoints the specific corridors where association or proximity to existing facilities requires special considerations, and therefore should establish the basis for other disciplines to proceed toward a successful project.

The installation of significant system additions, such as this project, requires careful reliability considerations of two general types of electrical facilities, the bulk high voltage transmission additions and the bulk termination substation equipment additions.

In summary, for the bulk high voltage transmission additions, the Project should be so defined that a credible three line outage cannot occur. North of Round Mountain this will require separate right of way. South of the Sacramento River, this will require new right of way or costly transmission reinforcements. The Power System Studies Committee recommends acquisition of new right-of-way for both corridor sections a sufficient distance from the existing 500 kV AC Pacific Intertie lines that a credible three line outage cannot occur.

In summary, for the bulk termination substation equipment, the Project should comply with NERC guidelines and avoid termination of all three 500 kV AC transmission lines within a single substation. To meet this criteria, Malin and Round Mountain substations should not be used as terminals for the new line. Round Mountain is permissible as a crosstie terminal. Tesla substation, however, should continue to be reviewed for compliance to criteria and studied for the need for alternative transmission arrangements.

Utilizing the Malin to Round Mountain corridor (corridor sections N-10, N-11, N-8 in Figure 1) could require paralleling three 500 kV lines for a distance of 95 miles. Study results demonstrate that simultaneous loss of these three lines will result in a widespread power failure throughout the fourteen states in the WSCC system. Reduction of the Project line rating does not appear to be a solution, since the rating must be reduced to 0 MW (when the Arizona-California flows are 5,200 MW) to prevent system voltage collapse. A satisfactory engineering/operating solution to this problem has not been found which would permit building the new third line adjacent to the two Malin-Round Mountain 500 kV lines without jeopardizing the transfer rating required by the Project. To maintain the Project's 1600 MW transfer rating, the new 500 kV line must be constructed in a separate right of way at such a separation distance that a credible three line outage cannot occur.

The minimum separation between the existing right-of-way containing the two 500 kV AC Pacific Intertie lines and the right-of-way which will contain the Project's new 500 kV line should be maximized, and depending upon geographic terrain and environmental characteristics of the corridor section this distance should be measured in miles. This Committee prefers utilizing separate corridors such as the N-1 or the N-6 corridor rather than the N-10 corridor, primarily for reliability. The short crosstie appears to be more technically advantageous than the long crosstie and would utilize the N-8 corridor, which includes the two existing Pacific Intertie lines. The separation of right-of-ways which can be achieved in this corridor to maintain adequate reliability are of great concern to this committee. The PSS Committee recommends a close examination of the corridor by the Engineering/ Technical and Environmental Committees.

The second common corridor, south of the Sacramento River (corridor Section S-8 in Figure 2), already contains the Vaca Dixon to Tesla, and Table Mountain to Tesla 500 kV lines, and Western Area Power Administration's double circuit 230 kV line, which the project is considering for upgrade to a single 500 kV line. Study results indicate that loss of the three 500 kV lines in this corridor creates severe overloading problems in the Vaca Dixon area, which result in cascading outages, and widespread blackout.

The use of a common right-of-way south of the Sacramento River may be technically feasible provided that mitigation measures to the local overloading problem resulting from a three line outage can be found. The obvious "technical" solution would be to separate the third line from the other two. One alternative, which is costly both environmentally and financially, is to upgrade the local system, including 200 miles of 230 kV transmission upgrades or new construction. The cost of these upgrades has been estimated at $115 million, which may greatly exceed the cost of building a Project line on a new right-of-way south of the Sacramento River. All or part of these costs may or may not be the responsibility of the Project.

The minimum separation between the existing right-of-way containing the Vaca Dixon to Tesla and Table Mountain to Tesla 500 kV lines and the right-of-way which will contain the Project's 500 kV line should be maximized, and since the terrain is primarily developed agricultural land, this distance should be measured in thousands of feet.

The Project has the opportunity to establish new bulk power substations at Southern Oregon, Redding and Tracy. The new Southern Oregon substation avoids bringing the entire power transfer between Oregon and California through one power system element. NERC guidelines specifically recommend avoiding excessive concentration of power being carried through any one transmission station. The Power System Studies Committee recommends adherence to this principle by not expanding existing substations at Malin and Round Mountain.

The utilization of Tesla as the interconnection point of the Project to the existing Intertie may not comply with NERC's principle, however alternative transmission arrangements are possible and may be necessary (such as the Tesla bypass) to minimize the effects of a substation catastrophy.

For increased reliability, this committee also recommends that common substation terminations for three 500 kV lines be avoided, or provide alternative transmission arrangements or mitigating measures which allow compliance with design criteria.

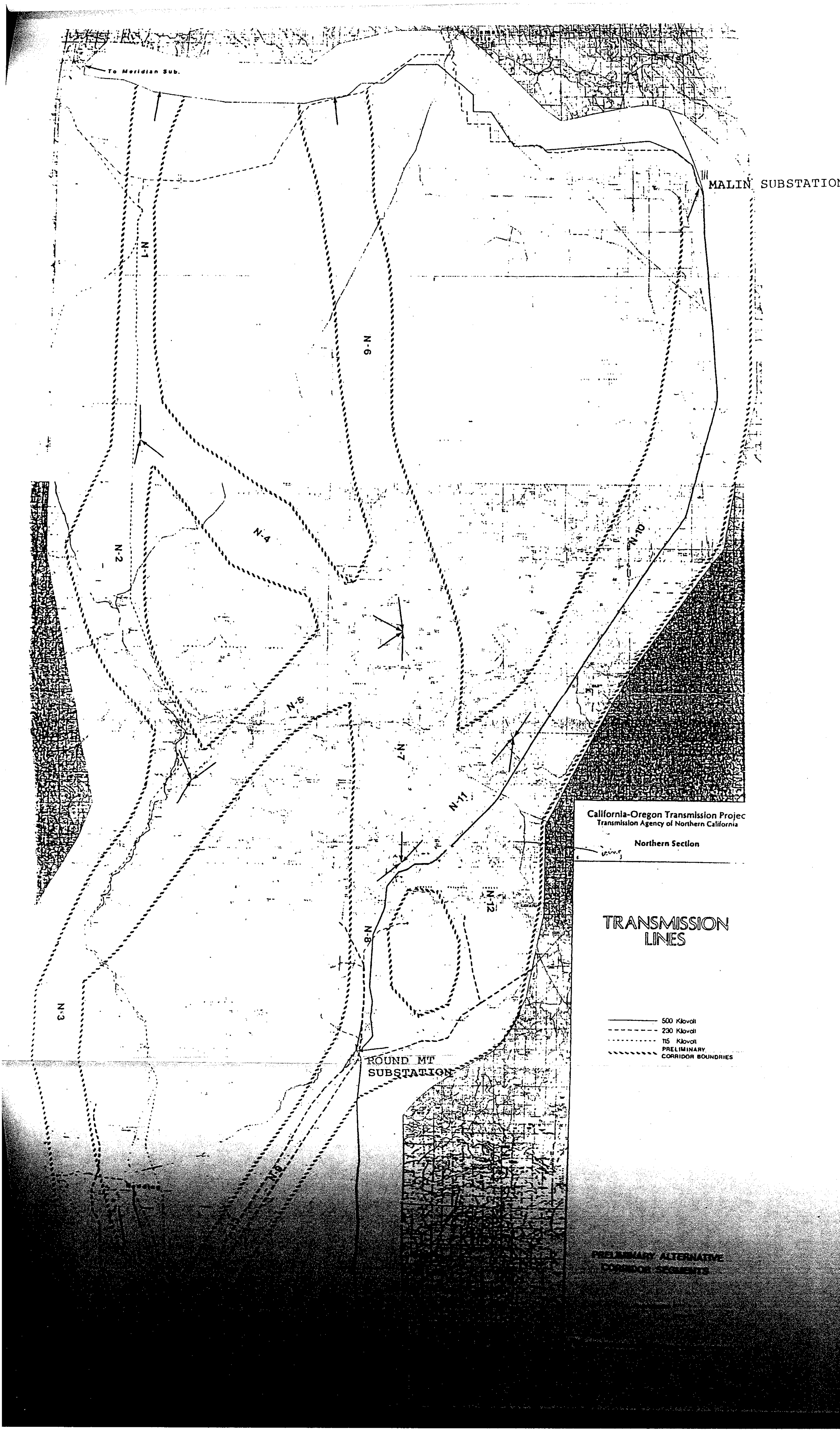
To Meridian Sub.
MALIN SUBSTATION
N-1
N-2
N-3
N-4
N-5
N-6
N-7
N-8
N-9
N-10
N-11
N-12
ROUND MT SUBSTATION
California-Oregon Transmission Projec
Transmission Agency of Northern California
Northern Section
TRANSMISSION LINES
500 Kilovolt
230 Kilovolt
115 Kilovolt
PRELIMINARY CORRIDOR BOUNDRIES
PRELIMINARY ALTERNATIVE CORRIDOR SEGMENTS

FIGURE 1

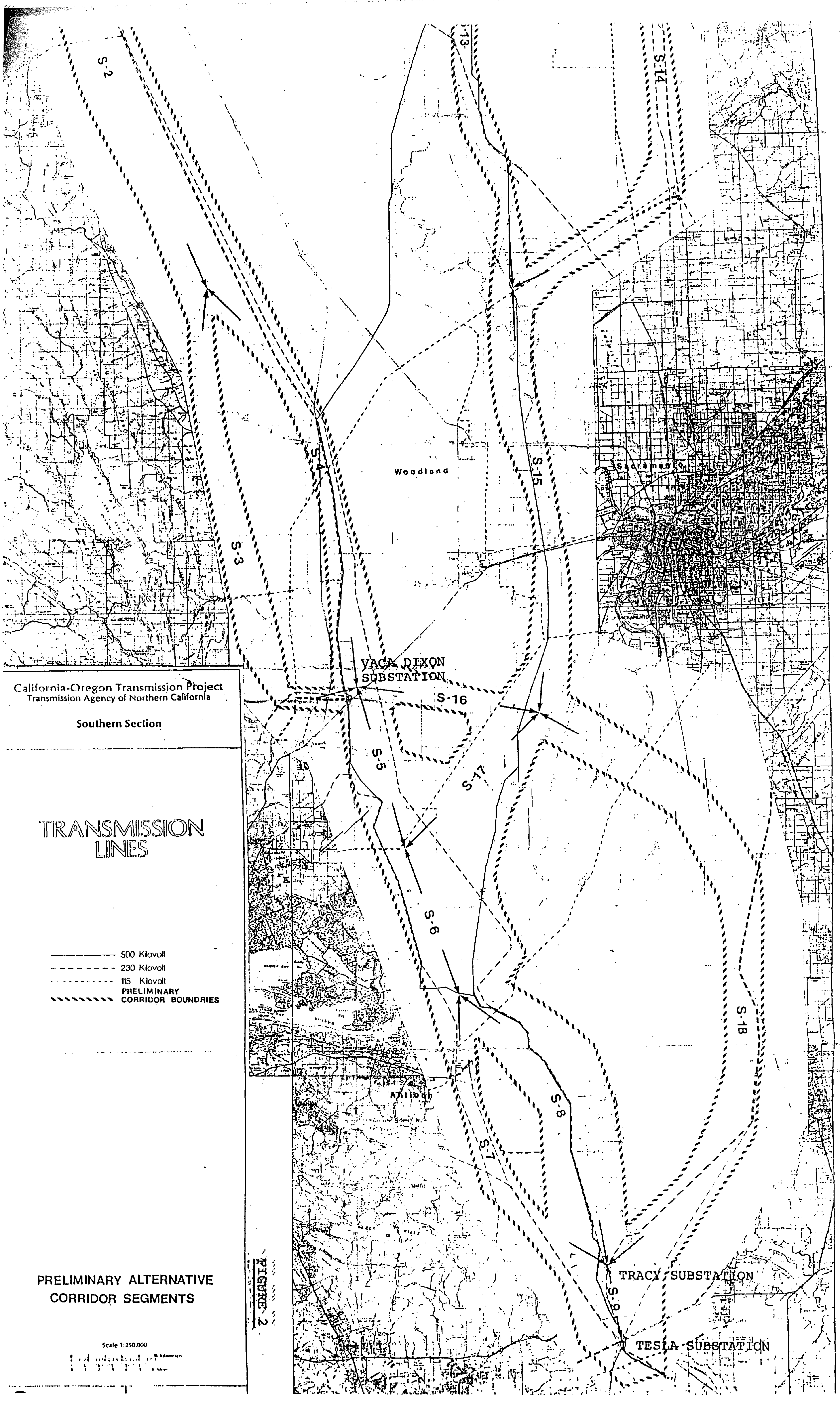
California-Oregon Transmission Project
Transmission Agency of Northern California
Southern Section
TRANSMISSION LINES
500 Kilovolt
230 Kilovolt
115 Kilovolt
PRELIMINARY CORRIDOR BOUNDRIES
PRELIMINARY ALTERNATIVE CORRIDOR SEGMENTS
Scale 1:250,000
S-2
S-3
S-4
S-5
S-6
S-7
S-8
S-9
S-14
S-15
S-16
S-17
S-18
Woodland
Sacramento
Antioch
VACA DIXON SUBSTATION
TRACY SUBSTATION
TESLA SUBSTATION

FIGURE 2

Introduction

The final corridor for the proposed California-Oregon 500 kV transmission line will be selected based on reliability, technical feasibility, cost, and environmental concerns. Two of these alternative corridor sections already contain two 500 kV lines and therefore introduces an additional technical concern regarding the reliability of paralleling three 500 kV lines in one corridor.

The first corridor contains two 500 kV AC Pacific Intertie lines from Malin to Round Mountain. The second corridor contains the Vaca Dixon to Tesla and Table Mountain to Tesla 500 kV lines. While non-technical arguments exist for use of these two common corridors, when adding a third 500 kV transmission line they each represent a different degree of risk to electric system reliability. This paper will address the technical feasibilty of each corridor in terms of overall system reliability.

Definitions

Transmission lines provide a path for electrical power to flow from generation sources to the diversity of load centers which exist on an electric system. Utilities must acquire the right to build a transmission line on the land over which it passes. The utility acquires rights by a number of legal means such as purchasing land, acquiring easements or signing leases. When a utility has acquired all of the legal rights to build, the land is referred to as a right-of-way. This right-of-way serves the additional purpose of separating the public-at-large from the transmission facilities for the protection of the public. The right-of-way may only have to be about 200 feet wide to provide adequate room to build a single circuit 500 kV line and provide adequate public protection.

When a utility is investigating the possibility of building a new transmission line, the land over which a line may pass is referred to as a corridor. The corridor may be two to five miles wide and may encompass many alternative paths for the line.

The region is evaluated for environmental sensitivities and land uses which may eliminate portions for siting a transmission line corridor. For example, a national park or monument, a military reserve, or wildlife refuge would be several land uses which could eliminate those lands from consideration as a potential corridor. When the route that the line will take is determined, within the selected corridor, the acquision of rights begin.

The term common corridor refers to the fact that an existing transmission line already occupies the corridor as defined. In the case of the new 500 kV line, only other existing 500 kV lines in the corridor are of concern. The proximity of 500 kV lines increases the probability of a common mode failure, which is a single event that interrupts power in more than one transmission line.

A single 500 kV transmission line is capable of carrying so much power that the interruption of only one such line causes a significant disturbance to the stability of the entire regional electric system. Multiple 500 kV line outages are extremely severe disturbances which can require special measures to lessen the electrical effect to the system. These measures, called remedial actions, are initiated upon detection of the outage.

Generator stability refers to the condition where the mechanical and electrical torques acting on an individual generator shaft are in equilibrium, and system stability refers to the condition where all the generators in the system are in synchronism. A generator is synchronized to the system when it produces a 60 Hertz (cycle per second) sinusoidal voltage waveform in phase with the system. When a generator loses synchronism with the system the resulting abnormal frequency conditions can cause damage to expensive generator/turbine equipment. The automatic protection on a generator will trip the unit before damage can occur, but, causing the overall system to be generation deficient.

Once generation has been tripped from the system by its automatic protection, then it may take several hours to re-synchronize the plant with the electric system. The plant operator must be satisfied that the cause of the unit trip was not due to an internal plant problem, and the system operators must be satisfied that they know what happened to the system before they can begin the process of coordinating restoration of generation and load, without risking equipment damage.

Electric System Reliability

The electric power industry has a mandatory obligation to maintain an adequate and reliable electric transmission system since reliable power service is very important to our society. The level of reliability of an electric system is measured by the frequency, duration and severity of interruption of service to the customer. The reliability desired in the system is based on the tolerance of the customer and the commitment of the utility to provide reliable service. The risk of a particular outage to system reliability is based on: 1) the potential severity of the interruption to customers; 2) the likelihood of occurrence and; 3) the cost and feasibility of mitigating the consequences by design or operating measures. An outage which would interrupt service to a few customers, or perhaps interruptible industrial load, does not warrant the same concern as would an outage which would interrupt service to millions of customers and numerous critical services and industries.

The risk of having three 500 kV lines in a common right-of-way is that a single event could disrupt power in all lines simultaneously, and depending on the ability of the system to withstand the electrical shock, this contingency could result in an immediate catastrophic widespread blackout, which could spread to many of the major population centers of the West.

In the electric utility industry, a primary concern involves "cascading outages." The term "cascading" refers to the domino effect of circuit breaker openings, whereby the transmission system is separated into islands and consequently electrical loads may be completely shut off from generating plants. With widespread cascading, the disruption of major portions of the bulk power supply network occurs. A classic example of a cascading outage was the Northeast Blackout of November, 1965.

Following the Northeast Blackout and similar instances, the Federal Energy Regulatory Commission (formerly the Federal Power Commission), with the assistance of technical personnel from the electric utility industry, reported to the President of the United States on the prevention of power failures. The Report to the President contained an analysis of the causes and effects of the blackout and set out guidelines and recommendations designed to assure that major system interruptions and cascading outages would not recur. "The power failure of November 9 and 10 has made a deep impression on the public because of its widespread nature and because of the difficulty and delay in discovering the origin . . . . The problem arises not because service is poor but because the universal and increasing dependence of the American public on this form of energy makes any widescale interruption seriously disruptive. The prime lesson of the blackout is that the utility industry must strive not merely for good but for virtually perfect service."

One recommendation made for transmission system planning was to avoid locating critical transmission circuits on any one common right-of-way. Another recommendation was to form regional reliability councils, and as a result the Western Systems Coordinating Council (WSCC) was formed which today encompasses fourteen western states, the Canadian Provinces of British Columbia and Alberta, northern Baja Mexico, and is comprised of fifty-nine member systems. The WSCC has established design criteria to avoid cascading out ages. All electric utilities in the WSCC have pledged to examin the possibility of cascading outages, to consider the possible effects, and to design their systems to prevent outages from becoming widespread.

The North American Electric Reliability Council (NERC), comprised of nine regional reliability councils, was formed in 1968 to promote reliability of the bulk power system in the electric utility industry. One of NERC's planning principles (Attachment 1) addresses the development of a reliable electric system and is stated below:

"A balanced relationship should be maintained among power system elements in terms of size of load, size of generating units and plants, strength of interconnections, and the concentration of power at any point on the bulk transmission system. Adherence to this principle implies:

Avoiding excessive concentration of generating capacity in one unit, at one location, or in one area.

Avoiding excessive concentration of power being carried on any single transmission circuit, tower line, or right-of-way, as well as through any one transmission station."

Multi-circuit outages of 500 kV lines do not occur frequently, but because they can have such widespread effects, it is utility industry practice, a WSCC criteria and a NERC guideline to design the transmission system so that the risk of a major blackout is minimized. The WSCC criteria states:

"Continuity of service to loads is the primary objective of the Council Reliability Criteria. Preservation of interconnected operation during disturbances is secondary to the primary requirement of preservation of service to loads."

The NERC guideline states, "It is expected that they (guidelines) be used by Regional Reliability Councils and their member systems to provide a reliable bulk power system having effective safeguards against the occurrence of uncontrolled area-wide power interruptions ..."

The primary concern over cascading outages is the uncontrolled disruption of power in various areas of the electric system for extended periods. Immediately following a major blackout, the state of the system must be assessed as quickly as possible by system operators.

Following restoration of power to critical areas of the electric system, operators will restore load to the system while insuring that the on-line generators are able to maintain synchronism. The process of assessment, communication and load restoration may take a few minutes to many hours, depending upon the extent and nature of the original disturbance. Load restoration is an incremental process which, following the New York blackout of 1965 took 13 hours to complete.

Causes of Multi-Circuit Outages

There are a variety of incidents that cause the simultaneous or overlapping loss of two or more transmission lines adjacent to each other, which typically include fire, flooding, aircraft contact, adverse weather conditions, lightning, equipment failure, human error, sabotage, among others.

The WSCC PAST (Pacific Northwest and Southwest Transfer) Committee's Intertie Outage Credibility Work Group has prepared a summary of the system events which have resulted in the simultaneous loss of both 500 kV AC lines of the Pacific Intertie (from John Day to Vincent) or the initiation of the NE/SE (Northeat/Southeast between Utah/ Colorado and New Mexico/Arizona) islanding scheme. The report describes 32 incidents in the past 15 years which were initiated as a result of equipment failure, natural causes, and/or human error. The Malin to Round Mountain 500 kV lines were involved in 18 incidents.

A few notable examples of multi-circuit outages are discussed in the following paragraphs.

On September 13, 1973, an airplane struck an overhead groundwire and dragged it across a transmission right-of-way near Mira Loma Substation causing the simultaneous outage of two 500 kV circuits, three 230 kV circuits, and a 66 kV circuit. Due to the location of the disturbance and the fortuitous system conditions at the time, no system instability or interruption of customer load occurred. However, line overloading problems and difficulties in serving isolated customers occurred for several hours. This type of accident would be much less likely to disturb more than two circuits if pairs of circuits were separated by an average span length.

Sabotage and/or vandalism is another hazard to which multiple transmission circuits on one corridor are increasingly exposed. Several incidents involving bulk power transmission circuits have been recorded on utility systems over the past few years. A notable example is a case of an extortionist who dynamited 11 towers on the 230 kV and 500 kV system of the Bonneville Power Administration over a period of several days in October, 1974. At one site, a transmission tower narrowly missed falling into an adjacent line. Increased circuit separation obviously would lessen the probability of this type of multiple circuit outage. At another site, the saboteur felled two transmission towers in close proximity on a corridor. Again, when lines are this close together on a corridor, it is relatively easy for a saboteur to damage a number of circuits simultaneously, or in a relatively short period of time.

Numerous simultaneous and overlapping outages of adjacent transmission lines have been recorded as having been caused by smoke contamination due to brush or other types of fire. Including 220 kV right-of-way as well as 500 kV right-of-way, nearly two fire-related multi-circuit outages have occurred per year over the past 11 years on the Edison system. The PAST Committee's Outage Credibility Work Group report states that there have been six incidents of simultaneous outage of two 500 kV lines on the Pacific Intertie between Malin and Table Mountain which occurred as a result of forest fire. These outages typically last an hour, but may last 48 hours or longer if permanent damage is sustained.

Since brush and forest fires often cover large areas, rather than simply separating pairs of circuits by distances of 2,000 feet or so, Edison's guidelines call for fire breaks, river beds, mountain ridges, and other natural barriers to be utilized to provide isolation between critical transmission lines.

Lightning strikes frequently cause single-circuit outages, particularly in California's high desert areas where lightning incidents are high, and occasionally they cause double-circuit outages as well. Eleven incidents of simultaneous and overlapping outages have been recorded in the Edison system in the last 11 years. Simultaneous line outages can result when a lightning strike and resulting arc-over on one line creates electrical fluctuations of sufficient magnitude to cause a sympathetic arc-over of adjacent circuits. This occurred on May 1, 1979 on the Malin-Round Mountain 500 kV lines, even though each circuit is on a separate tower, with a 150-foot center line to center line separation.

Wind and ice are other natural phenomena that have accounted for multi-circuit outages on common right-of-way. On December 17, 1970, snow and ice caused the outage of both Malin to Round Mt. 500 kV lines. Line No. 1 was out for 34 days and Line No. 2 was out for 44 days. Line repairs could not be made because of heavy snow conditions. On January 1, 1973, wind caused an eight hour overlapping outage of the Rio Hondo-Vincent Nos. 1 and 2 220 kV transmission lines. On January 10, 1975, wind and ice caused a 22-1/2 hour overlapping outage of the Midway-Vincent No. 3 500 kV line and the Antelope-Magunden No. 1 220 kV line. The Antelope-Magunden No. 2 220 kV line, which also shares the same right-of-way, also was out for over an hour at the same time for the same reason.

On December 20, 1977, high winds in the San Joaquin Valley toppled seven 500 kV towers causing outages of all three Midway-Vincent 500 kV circuits for over a week. Two of the towers were toppled when towers of the adjacent circuits fell into them. With the only remaining portion of the Pacific Intertie being the HVDC line between the Los Angeles and the Pacific Northwest, it was fortunate that Edison was not relying on heavy deliveries of power from the Pacific Northwest as it commonly does. Had this been the case, breakup of the WSCC interconnected systems could have occurred.

The following paragraph describes the December 22, 1982 system disturbance, where wind was again a factor.

"On Wednesday, December 22, 1982, a storm of gale force winds swept through the area surrounding PGandE's Tesla Substation, about 50 miles east of San Francisco. At 16:29 hours, PST, these high winds toppled a 500 kV tower on the Tesla-Vaca Dixon 500 kV line one half mile north of the Tesla substation. This tower fell laterally into a 500 kV tower on the parallel Tesla Table Mountain 500 kV line causing it to fall. The conductors of the two 500 kV lines then fell on two double circuit 230 kV line and one 115 kV line crossing below them."

This event, where 12,350 MW of customer load was shed, occurred in the vicinity of the corridor where the third 500 kV line is planned to be built.

In addition to the natural and man-related causes mentioned above, a dramatic example of the type of incidents that can affect multiple circuits in a common right-of-way occurred on January 1, 1976, when a Pacific Lighting Company 26" gas line ruptured one-half mile north of Pardee Substation causing a fire and explosion. One single-circuit 220 kV transmission line tower was completely destroyed, two double-circuit towers were severely damaged, and five 220 kV circuits were forced out of service. Customer load was interrupted for five and one quarter hours due to damage to two 66 kV lines.

Existing System

The rating of the two existing 500 kV AC Pacific Intertie lines is 2,800 MW. Today, there are a number of remedial actions necessary to maintain stable system performance when two 500 kV Pacific Intertie lines are lost. These remedial actions are aimed at achieving a balance between Northwest load and generation in order to decrease the magnitude of the dynamic power surge around the eastern side of the WSCC loop created by the interruption of power being exported to California.

The primary remedial action is the Northeast/Southeast Separation Scheme. This scheme is activated by a signal from Grizzly Substation in the Pacific Northwest to Four Corners in New Mexico. The signal initiates the automatic opening of eight transmission ties on the southeastern side of the system to separate the WSCC system into northern and southern islands. The Northeast/Southeast separation scheme is becoming more unwieldy as additional lines are built across the separation boundary. Also, the consequences of misoperation of this scheme can be as severe as loss of the AC Intertie.

In recent years outages of both Pacific AC Intertie 500 kV lines have averaged approximately 2 to 3 times a year. As a result of this outage frequency and the incorrect operation of planned remedial action schemes during several of these outages, many non-Intertie utilities and elected officials have expressed serious concern about the adverse effects of these outages on their systems. These effects have included load shedding, unit tripping and uncontrolled opening of transmission ties. Several letters are attached to this report (Attachments 2a-c) which express grave concerns over unanticipated power disruptions, which were initiated by disturbances on the Pacific Intertie, the most critical path in WSCC.

Planned System

The rating of the two existing 500 kV AC Pacific Intertie lines is planned to be uprated to 3200 MW before the third 500 kV line becomes operational in 1990.

The addition of the third 500 kV line is expected to increase the rating of the three line Intertie system to approximately 4,800 MW, and eliminate the need for the Northeast/Southeast Separation Scheme. This line is expected to add reliability to the system by reducing dependence on remedial measures to provide stability.

The WSCC member systems have agreed to specific reliability criteria to protect the interconnected system against cascading outages and uncontrolled loss of firm load. One such condition covered by this requirement is loss of all lines in adjacent right-of-ways. If three high capacity lines composing the AC Intertie occupy the same corridor, it is possible to meet this requirement only under severe transfer limitations or imposition of extreme and impractical remedial actions. Because of past remedial action scheme failures WSCC utilities strongly urge improved reliability of remedial action schemes.

MALIN-ROUND MOUNTAIN CORRIDOR ALTERNATIVE

The new Southern Oregon-Redding 500 kV line section could potentially occupy the same corridor as two Malin-Round Mountain 500 kV lines. The two existing 500 kV lines are adjacent to each other for a distance of 95 miles with a line separation of about 150 feet center line to center line, and a conductor separation of 62.5 feet. The new third line could potentially be built on an adjacent or nearby right-of-way with inadequate separation from the existing lines.

The terrain through which this corridor passes makes the line vulnerable to forest fires, icing damage and high winds. Based upon performance records this corridor also appears to be vulnerable to human error and hardware types of failures (initiated within a substation) which have caused frequent outages of both 500 kV lines. The existing lines have experienced longer outages when natural events have been the cause of the disturbance.

There presently is an effort underway by BPA and the Pacific Intertie participants to improve the reliability of the Pacific Intertie lines, but two 500 kV right-of-ways with inadequate separation in this corridor would still result in vulnerability to human caused and natural events which could take out all three lines simultaneously.

Loss of these three lines is an extremely severe contingency which would have the same type of effects on the dynamic behavior of the system as loss of the two Pacific Intertie lines (before the third line is built), except that the effects would be much faster, much more widespread and more severe, because the hazard has become 4800 MW rather than 3200 MW.

Simulation of Loss of the Malin-Round Mountain Corridor

Case 1 (Attachments 3-5) with 1992 Heavy Summer, is a simulation of the simultaneous loss of the Southern Oregon-Redding and the Malin-Round Mountain circuits 1 and 2 500 kV lines with the Four Corners islanding scheme activated and 3,200 MW of Northwest generation dropped. The Northwest to California flow is 4,875 MW and the Arizona to California flow is 5,160 MW. This contingency is identical to loss of three Malin-Round Mountain 500 kV lines.

The relative rotor angle plot shows the acceleration of the units in both islands, which will result in further uncontrolled separation within the two islands. The voltage plot shows voltage collapse between Arizona and California before any load shedding occurs, while the Northwest experiences severe over voltages at the Malin and Alvey 500 kV busses. This simulation shows that for loss of all three 500 kV lines on the Malin-Round Mountain corridor, although the maximum feasible remedial action has been taken, the system has gone unstable. In other words, the system has undergone an uncontrolled loss of generation and widespread blackout.

The measures which would have to be taken in an attempt to provide some protection against this catastrophic outage would involve tripping massive amounts of generation in the Northwest and tripping massive amounts of load in California with no guarantee of a quick restoration of service to any of the interrupted loads. Provided that some remedial actions could be found that would be sufficient to maintain synchronism, their extent and magnitude would be unacceptable. The Pacific Northwest would be reluctant for technical reasons to drop more than 3,200 MW of generation and, in fact, is trying to reduce generation dropping in this time frame, to mitigate the frequency decline problem in the Northwest. California utilities would also be reluctant to direct drop such massive amounts of load. Any failure of these remedial measures would result in complete uncontrolled collapse of interconnected operation throughout the WSCC system. Any false operation of these remedials measures could have an equally devastating effect.

In order for the system to be able to withstand this contingency without the extreme remedial actions previously mentioned, the rating of the new line would have to be reduced.

It is possible to define an operating nomogram which would result in stable system performance for this three line outage. This operating region or nomogram identifies several critical system flows such as Northwest to California and Arizona to California. Nomograms have been developed since the December 22, 1982 disturbance revealed an interdependence or simultaneous import limit. Cases 2 and 3 are an attempt to define the curtailment or reduced transfer capability if the system were required to withstand the simultaneous loss of three 500 kV lines.

Case 2 (Attachments 6-8) with 1992 Heavy Summer conditions and Arizona to California flows equal to 5,200 MW shows the dynamic behavior of the system with the total Northwest to California flow equal to 3,350 MW. The simulation is loss of the Southern Oregon-Redding and the Malin-Round Mountain circuits 1 and 2 500 kV lines, with the Four Corners islanding scheme activated and 3,200 MW of Northwest generation dropped. The results indicate growing oscillations which are not acceptable, since this will lead to eventual instability. The results also indicate that a reduction in schedules on the third line to 0 MW would probably result in stable system performance.

Case 3 (Attachments 9-11) simulates loss of the Southern Oregon-Redding and Malin-Round Mountain circuits 1 and 2 500 kV lines, with 3,200 MW of Northwest generation dropped with the Four Corners islanding scheme activated. The initial conditions are with 1,600 MW on the third line, the total Northwest to California flow equal to 4,800 MW, and with 4,300 MW of Arizona to California flow. Case 3 exhibits a stable and damped response to loss of the three 500 kV lines.

Cases 4 and 5 (Attachments 12-17), simulate loss of the Southern Oregon-Redding and Malin-Round Mountain circuits 1 and 2 500 kV lines, with 3,200 MW of Northwest generation dropped, but without the Four Corners islanding scheme activated. Case 4 initial conditions are with the Northwest to California equal to 4,800 MW, and the Arizona to California flow equal to 4,300 MW. Case 5 initial conditions are with 100 MW scheduled on the third line (the total Northwest to California flow is 3,300 MW), and the Arizona to California flow is 5,200 MW.

Both Case 4 and Case 5 exhibit a transiently unstable response thereby demonstrating that the islanding scheme cannot be eliminated for loss of the three lines. The required islanding remedial action and the nomogram restrictions demonstrate that the third 500 kV line would provide no operating benefits compared to the way the WSCC system is operated today and few economic benefits compared to the cost of the Project.

The study results indicate that it would be possible to operate the system with a nomogram provided the Four Corners islanding scheme is maintained. Operating nomogram restrictions for the simultaneous transfer of power into California from the Northwest and from Arizona are severe. The third line could only carry 1,600 MW only during the times when the Arizona-California flows are below 4,300 MW. The Northwest to California scheduled transfer would have to be reduced to 3,200 MW, and there would be no increased transfer capability added by the additional line, when the Arizona-California flows are at 5,200 MW. The severe operating restrictions drastically alter the economics of the Project, and therefore a nomogram is an unacceptable solution for allowing a three line outage. Operation outside of this nomogram would risk widespread blackout, should loss of these three lines ever occur.

A significant reliability benefit of the third 500 kV line is the elimination of the Four Corners Islanding Scheme for a double line outage. Several misoperations in the past have caused unfrequency load shedding in areas outside of California and focused the attention of WSCC members on the Pacific Intertie. The compliance to the WSCC reliability criteria by the Project will be closely examined by WSCC member utilities, who will have to be convinced that construction of the new line in close proximity to the existing two 500 kV lines would not jeopardize overall system reliability.

The alternative to reducing the line rating or imposing severe operating restrictions is to separate the new 500 kV line from the existing 500 kV lines on a new right-of-way at a distance which reduces the probability of a three line outage to an extremely low level. The distance would be dependent on the environment through which the line would pass and the types of outage causing events to which the line would be subjected.

Table 1
Loss of Three 500 kV Lines South of Malin

Case	Northwest to California	Arizona to California	Islanding	Result
1 (Heavy Summer)	4,875 MW	5,160	Yes	Unstable
2 (Heavy Summer)	3,354 MW	5,147	Yes	Growing oscillations
3 (Heavy Summer)	4,793 MW	4,327	Yes	Stable
4 (Heavy Summer)	4,793 MW	4,327	No	Unstable
5 (Heavy Summer)	3,354 MW	5,147	No	Unstable

Conclusions

Constructing the new line in close proximity to the two existing 500 kV Intertie lines would unnecessarily degrade the reliability of the entire WSCC electric system and jeopardize the ability of the new 500 kV line to transfer 1,600 MW of Northwest power to California, because of the possibility of an outage of three 500 kV lines. The use of this common corridor would undermine all efforts currently underway to improve the reliability of the Pacific Intertie transmission system.

A corridor containing three 500 kV lines would become the most critical and the most vulnerable single corridor in the entire WSCC system. An event involving three lines would not only result in the loss of electric service to most of the customers in California, but would blackout many areas outside of California. The degradation to the reliability of the electric system and the consequences of any event involving these three lines would be intolerable to the public.

This common corridor jeopardizes completion of this Project because of the consequences of simultaneous loss of all three 500 kV lines. The system ramifications would be totally unacceptable to many WSCC member systems, and the threatened reduction of the new line rating from 1600 MW to 0 MW would be unacceptable to the Project participants.

SOUTH OF THE SACRAMENTO RIVER RIGHT-OF-WAY

The new Redding-Tracy 500 kV line section involves the upgrade of Western's double circuit 230 kV line to single circuit 500 kV. This 230 kV line parallels PGandE's Table Mountain-Tesla and Vaca Dixon-Tesla 500 kV lines in a common rights-of-way for a distance of 18.9 miles.

The common right-of-way begins at the Sacramento River where all three lines converge, and run parallel to each other to just north of the existing Tracy 230 kV Substation. The minimum line separation that exists between the 230 kV line and the 500 kV lines is 162.5 feet (center line to center line). This separation is maintained for a distance of 8.7 miles. The 230 kV tower structures are 137 to 166 feet high within the 8.7 mile line segment.

A separation of 212.5 feet is maintained for 8.9 miles with tower heights of 121 to 140 feet. The remainder of the common right-of-way has much wider line separation. These measurements have been documented by Western Area Power Administration (Sacramento) and are attached (Attachment 18).

This right-of-way passes through terrain which is primarily rolling hills and cultivated farmland. In the past 17 years there has been one incident where high winds took out two 500 kV lines in this area. Historically, hardware has not caused any double line outages of the two existing 500 kV lines in this right-of-way.

Simulation of Loss of the South of the Sacramento River Rights-of-Way

Case 6 is a simulation of the loss of the South of the Sacramento River Corridor without a fault and without islanding with 1992 Heavy Summer conditions. The Northwest to California flow is 4,875 MW and the Arizona to California flow is 5,160 MW. The Chief Joseph braking resistor was not applied, but a Malin Static Var Device was on-line, and 3,200 MW of Northwest Generation was dropped. Attachments 19 - 21 show generator rotor angles and 500 kV voltages during the simulation which are well damped during the first 10 seconds. At 10 seconds the Vaca Dixon 500/230 kV transformer was tripped on overcurrent. This transformer is equipped with overcurrent protection which will sense current in excess of 2000 amperes and trip the unit as fast as four seconds if the current exceeds 3000 amperes. The rating of the transformer bank is 1120 MVA and at the end of 10 seconds the bank is carrying about 2000 MW and about 2400 amperes (Attachments 22 and 23). Attachments 24 and 25, are plots of the electric network at 10 seconds before the Vaca Dixon 500/230 kV transformer is tripped The current flowing through the transformer is in excess of 2,400 amperes. In addition to the transformer overload, a number of 230 kV transmission lines are also overloaded by as much as 100% of the emergency rating of the lines.

The system is well damped at the end of 10 seconds and although it may take several minutes before the Vaca Dixon 500/230 kV transformer is tripped, the system cannot withstand the loss of this element. Within two seconds of loss of this transformer the system begins an uncontrolled cascade resulting in widespread system blackout. High overloads may cause damage to equipment which would further delay restoration of service to the customer.

Case 7, with Heavy Winter conditions, is a simulation of loss of the same corridor without a fault and with 3200 MW of NW generation tripped (Attachments 26 - 28). The Northwest to California flow is 4,884 MW and the Arizona to California flow is 4,300 MW. Although the Chief Joseph braking resistor was applied and the Static Var Device at Malin was not used, these two factors do not affect the amount of power flowing into the Vaca Dixon 500/230 kV transformer. Attachment 28 shows a plot of the power flowing down the Table Mountain to Vaca Dixon 500 kV line after loss of the corridor. This line is carring about 2300 MW at the end of 10 seconds or about 2600 amperes, which will overload the Vaca Dixon 500/230 kV transformer. The case appears to be dynamically unstable, however use of the Malin SVC may help damp the growing oscillations, but would not affect the Vaca Dixon transformer loading. This case will probably go unstable if this transformer were tripped on overcurrent.

Case 8, with 1992 Light Spring conditions, is a simulation of loss of the same corridor with a 3-phase, 4-cycle fault at Tesla 500 kV bus, with 3175 MW of NW generation tripped and 645 MW of PGandE Feather River Generation tripped (Attachments 29 - 31). The case is stable and damped. Although the Vaca Dixon 500/230 kV transformer is carrying 1767 MW (2000 amperes) at the end of 10 seconds, it is likely that this case would go unstable if the transformer were tripped on overcurrent. Attachment 32 shows the load conditions at 10 seconds for this case. Case 9 (Attachment 33) shows the conditions at 10 seconds for an identical simulation except the Feather River generation was not tripped. Dropping the Feather River Generation appears to have the effect of unloading this transformer, but in this case, not enough to prevent the over current protection from possibly tripping the transformer.

Table 2
Loss of Three 500 kV Lines South of the Sacramento River

Case	Northwest to California	Arizona to California	Islanding	Results
6 (Heavy Summer)	4,875 MW	5,160	No	Unstable
7 (Heavy Winter)	4,884 MW	4,300	No	Growing oscillations
8 (Light Spring)	4,891 MW	5,168	No	Unstable
9 (Light Spring)	4,891 MW	5,168	No	Unstable

Conclusions

This common right-of-way appears to be critical because of the potential of cascading outages should all three 500 kV lines be lost. There appears to be little potential for mitigating the consequences of this contingency by increased generator dropping in the Northwest and continued use of the Four Corners islanding scheme. Also, the islanding scheme presents a great danger to the entire WSCC system should this scheme be inadvertently activated.

The system could potentially withstand this contingency if the local system problems around the Vaca Dixon area were solved by local system upgrades such as adding additional transformers and rebuilding or adding 230 kV transmission lines. A preliminary estimate for 1120 MVA of additional transformer capability and about 200 miles of rebuilt 230 kV transmission lines would be about $115 million.

The decision to use this common right-of-way is dependent on the cost of and willingness to apply mitigating measures to relieve local system overloads following the loss of the lines south of the Sacramento River versus the cost of finding an alternative route to Tracy avoiding the south of the Sacramento River common right-of-way.

COMMON SUBSTATION TERMINATION

The selection of the Malin to Round Mountain (the eastern corridor) alternative for the new segment of the 500 kV line could result in two common substation terminations at Malin and Round Mountain. Regardless of the miles of line separation between the two existing 500 kV lines and the new 500 kV line, all three lines could potentially converge into a common substation both at Malin and Round Mountain, violating the recommended line separation criteria.

The 4,800 MW substations at Malin and Round Mountain would be subjected to the same types of incidents which cause transmission line outages. A substation contains a great variety and quantity of equipment to accomplish the basic tasks of line switching and voltage transformation, which includes protective relays, circuit breakers, transformers, reactive power compensation, control and monitoring equipment.

A substation catastrophy has the potential to cause an outage of all the lines which terminate at that substation. In the case of the Malin and Round Mountain 4,800 MW substations, the consequences would be similar to the loss of the three 500 kV lines and subsequent cascading outages discussed earlier in this paper. However, complete failure of the protection schemes at either of these substations is unlikely with the proper substation configuration and protection equipment.

The substation configuration will be critical in eliminating the possibility of an outage of all lines which terminate at that substation. The full breaker and one-half scheme has proven itself adequate and reliable for backup protection at 500 kV substations. The types of events which the breaker-and-a-half configuration will not provide complete protection against would be aircraft, explosive types of equipment failures and fires.

The Tesla substation is also planned to be expanded as a part of this project. The new eight mile 500 kV line south of Tracy will terminate at Telsa. A catastrophic failure at the Tesla substation would be similar to loss of three 500 kV lines into Tesla and was simulated with Case 10.

Case 10 (Attachments 34 - 38) is a simulation of loss of three lines north of Tesla on a 1992 Heavy Winter case. The Northwest to California flow was 4,800 MW and the Arizona to California flow was 4,300 MW. The results indicate a stable system response; however, the Tracy 500/230 kV transformer bank is loaded to 6,143 Amps (255%) and the Vaca Dixon 500 kV transformer bank is loaded to 6,306 Amps (224%). These banks are severly overloaded and will immediately trip on overcurrent protection resulting in cascading outages.

The failure of the Malin, Round Mountain or Tesla substations with three 500 kV line terminations will be intolerable to the system. The likelihood of a substation problem causing a failure can be greatly reduced by proper configuration and protection. However, because the three lines would have to converge into a common corridor and are in close proximity within the substation, the potential for a three line failure does exist.

Conclusion

It is recommended that common substation terminations of three 500 kV lines be avoided if possible because of the reliability concerns associated with the convergence of the three lines at a substation.

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ATTACHMENT 2

Robert E. Kondziolka

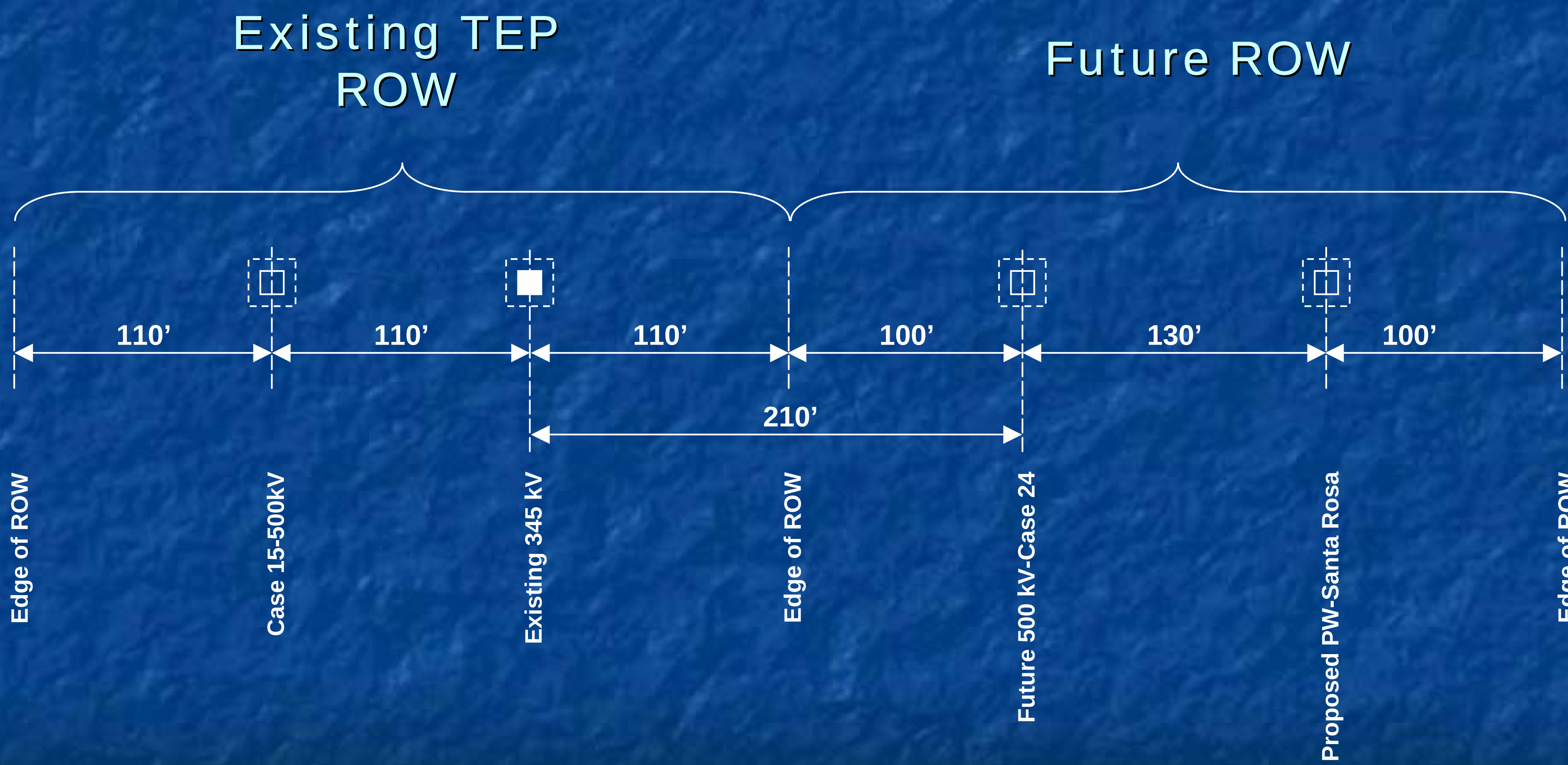
Manager
Salt River Project

PW - SEV/BRG PROJECT

Exhibit

BLM Corridor Looking North

Lattice Option



Exhibit

Reference: NERC/WECC Planning Standards Foreword

- **Adequacy – the ability of the electric system to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of the system.**

- **Security – the ability of the electric system to withstand sudden disturbances such as electric short circuit or unanticipated loss of system elements.**

Exhibit

Reference: NERC/WECC Planning Standards Introduction

- **To maintain the reliability of the bulk electric systems or interconnected transmission system or networks, the Regions and their members and all electric industry participants must comply with the NERC Planning Standards.**

Exhibit

Reference: NERC/WECC Planning Standards

I. System Adequacy and Security – Discussion

- These systems must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits while achieving their major purposes. These purposes are to:
- Deliver Electric Power to Areas of Customer Demand – Transmission systems provide for the integration of electric generation resources and electric system facilities to ensure the reliable delivery of electric power to continuously changing customer demand under a wide variety of system conditions.
- Provide Flexibility for Changing System Conditions – Transmission capacity must be available on the interconnected transmission systems to provide flexibility to handle the shift in facility loadings caused by the maintenance of generation and transmission equipment, the forced outages of such equipment, and a wide range of other system variable conditions, such as construction delays, higher than expected customer demands, and generating unit fuel shortages.
- Reduce Installed Generating Capacity
- Allow Economic Exchange of Electric Power Among Systems

Exhibit

PW - SEV/BRG PROJECT

Reference: NERC/WECC Planning Standards

I. System Adequacy and Security – Discussion

- All electric utilities, transmission providers, electricity suppliers, purchasers, marketers, brokers, and society at large benefit from having reliable interconnected bulk systems. To ensure that these benefits continue, all industry participants must recognize the importance of planning these systems in a manner that promotes reliability.

Exhibit

Reference: NERC/WECC Planning Standards

I. System Adequacy and Security

A. Transmission Systems - Introduction

- **Extreme but less probable contingencies measure the robustness of the electric systems and should be evaluated for risks and consequences. The risks and consequences of these contingencies should be reviewed by the entities responsible for the reliability of the interconnected transmission systems. Actions to mitigate or eliminate the risks and consequences are at the discretion of those entities.**

Exhibit

Reference: NERC/WECC Planning Standards

I. System Adequacy and Security

A. Transmission Systems – S4

- **The interconnected transmission system shall be evaluated for the risks and consequences of a number of the extreme contingencies that are listed under Category D of Table I.**

Exhibit

Reference: NERC/WECC Planning Standards

I. System Adequacy and Security
A. Transmission Systems – WECC-S2

- **The NERC Category C.5 initiating event of a non-three phase fault with normal clearing shall also apply to the common mode contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.**

Exhibit

Reference: NERC/WECC Planning Standards

I. System Adequacy and Security

A. Transmission Systems – WECC-S5

- **For contingencies involving existing or planned facilities, the Table W-I performance category can be adjusted based on on actual or expected performance (e.g. event outage frequency and consideration of impact) after going through the WECC Phase I Probabilistic Based Reliability Criteria (PBRC) Performance Category Evaluation (PCE) Process.**

Exhibit

Reference: NERC/WECC Planning Standards

I. System Adequacy and Security
A. Transmission Systems – WECC-S6

- Any contingency adjusted to Category D must not result in a cascading outage unless the MTBF is greater than 300 years (frequency less than 0.0033 outages/year) or the initiating disturbances and corresponding impacts are confined to either a radial system or a local network.

Exhibit

Reference: NERC/WECC Planning Standards

I. System Adequacy and Security

A. Transmission Systems – WECC-G6

- **The interconnected transmission systems should be planned to avoid excessive dependence on any one circuit, structure, right-of-way, or substation.**

Exhibit

Reference: NERC/WECC Planning Standards

I. System Adequacy and Security

A. Transmission Systems – WECC-G5

- **Consideration in determining the probability of occurrence of an outage of two adjacent circuits on separate towers should include line design; length; location, environmental factors; outage history; operational guidelines; and separation between circuits.**

Exhibit

Table I. Transmission System Standards –Normal and Contingency Conditions

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading[c] Outages
A - No Contingencies	All Facilities in Service	None	Applicable Rating [a] (A/R)	Applicable Rating [a] (A/R)	Yes	No	No
B – Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Single Single Single Single	A/R A/R A/R A/R	A/R A/R A/R A/R	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [f]: 4. Single Pole (dc) Line Loss of an Element without a Fault.	Single	A/R	A/R	Yes	No[b]	No
C – Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [f]: 1. Bus Section 2. Breaker (failure or internal fault)	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG or 3Ø Fault, with Normal Clearing [f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Bipolar Block, with Normal Clearing [f]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [f]: 5. Any two circuits of a multiple Circuit towerline [g]	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No

Reference: NERC/WECC Planning Standards

I. System Adequacy and Security – A. Transmission Systems

Exhibit

Table I. Transmission System Standards – Normal and Contingency Conditions

D[e] – Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section	Evaluate for risks and consequences. ▪ May involve substantial loss of customer demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.
	3Ø Fault, with Normal Clearing[f]: 5. Breaker (failure or internal fault)	
	Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of-way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	

Reference: NERC/WECC Planning Standards

I. System Adequacy and Security – A. Transmission Systems

Exhibit

Footnotes to Table I.

Table I. Transmission System Standards – Normal and Contingency Conditions

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.

c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.

g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria

Reference: NERC/WECC Planning Standards

I. System Adequacy and Security – A. Transmission Systems

Exhibit

ATTACHMENT 3

Arizona
Corporation
Commission

Docket No. L-00000B-04-0126

Pinal West to SEV/Browning 500 kV Line Siting

Presentation of Staff Witness
Jerry D. Smith

November 30, 2004

ACC Staff Witness

Name: Jerry D. Smith

Title: Electric Utility Engineer

Employer: Arizona Corporation Commission

Address: Utilities Division
1200 W. Washington
Phoenix, AZ 85007

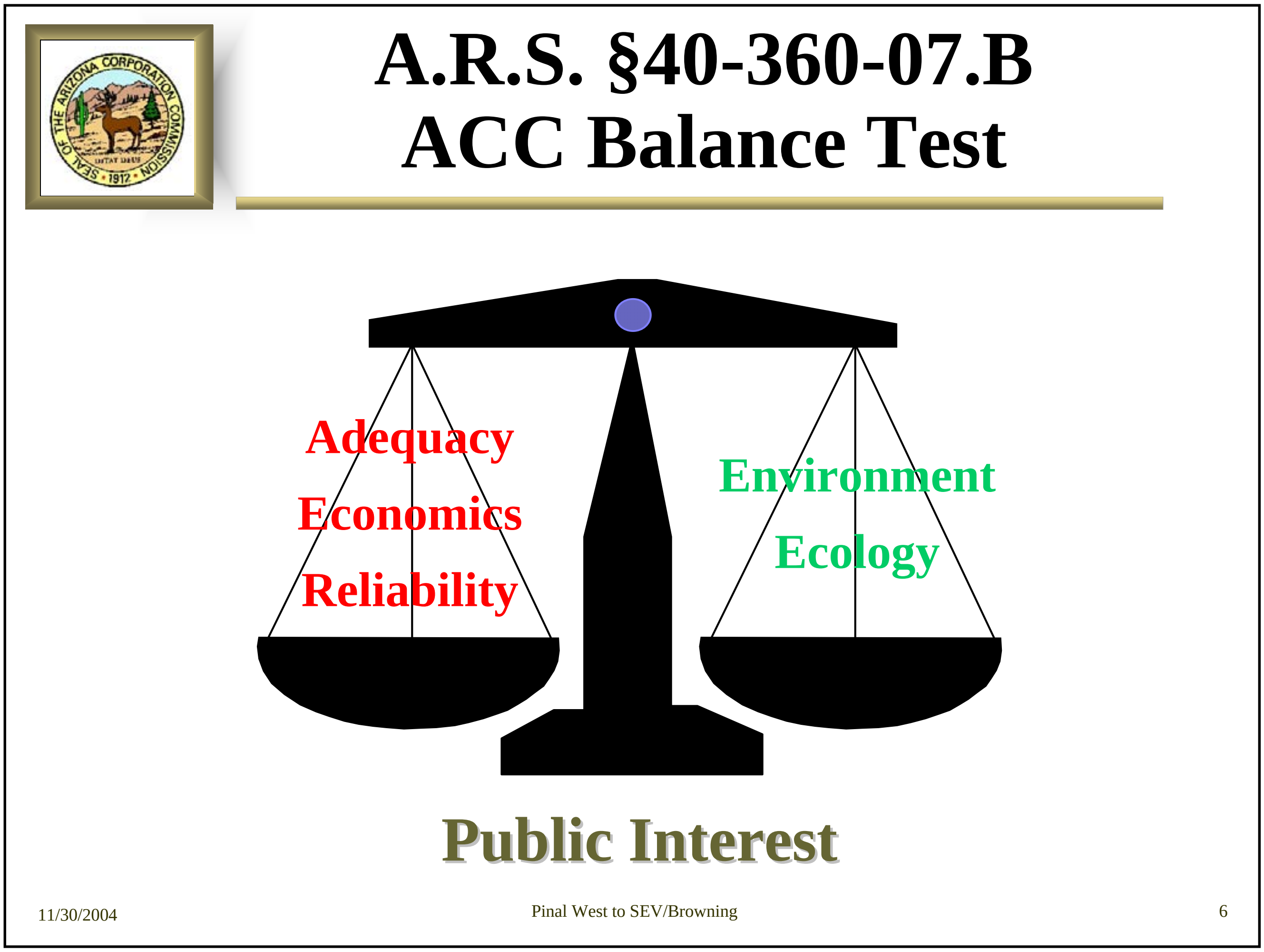
Professional Background

- B.S.E.E. - University of New Mexico
- M.S.E.E. - New Mexico State University
- Registered Arizona P.E. - Electrical
- 27 Yrs. Engineering and Management Experience with the Salt River Project
- Utility Regulatory Experience Since 2/99

11/30/2004 Pinal West to SEV/Browning 4

Purpose of Testimony

- **Establish Hearing Record for Commission Consideration of its Balancing Test**
- **Contrast Project with Current 10 Year Plan and 2004 Biennial Transmission Assessment**
- **Staff Technical Assessment of Project**
  - Justification of Need
  - Reliability of Common Corridor or Consolidated Facilities


A.R.S. §40-360-07.B
ACC Balance Test
Adequacy
Economics
Reliability
Environment
Ecology
Public Interest
11/30/2004
Pinal West to SEV/Browning
6

Adequacy and Reliability

Reliability is comprised of two components:

"Adequacy - The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."

"Security - The ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements."

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Additional Staff Proposed Measures of Reliability

- There should be sufficient transmission import capacity to reliably serve all loads in a utility's service area without limiting access to more economical or less polluting remote generation
- New power plants must have sufficient interconnected transmission capacity to reliably deliver its full output without use of remedial action schemes or displacing apriori generation at the same interconnection for single contingency (N-1) outages

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BTA vs. 10 Year Plan

- **Biennial Transmission Assessment (BTA):**
  - Occurs on Even Numbered Years
  - Covers a Ten Year Period
  - Utilizes Most Recent Ten Year Plans
- **Third BTA Filed for Approval Nov. 30, 2004**
- **Ten Year Transmission Plans Filed Annually with Commission by January 31**
  - Most Recent Plans Filed January 2004
  - Covers 2004 thru 2013

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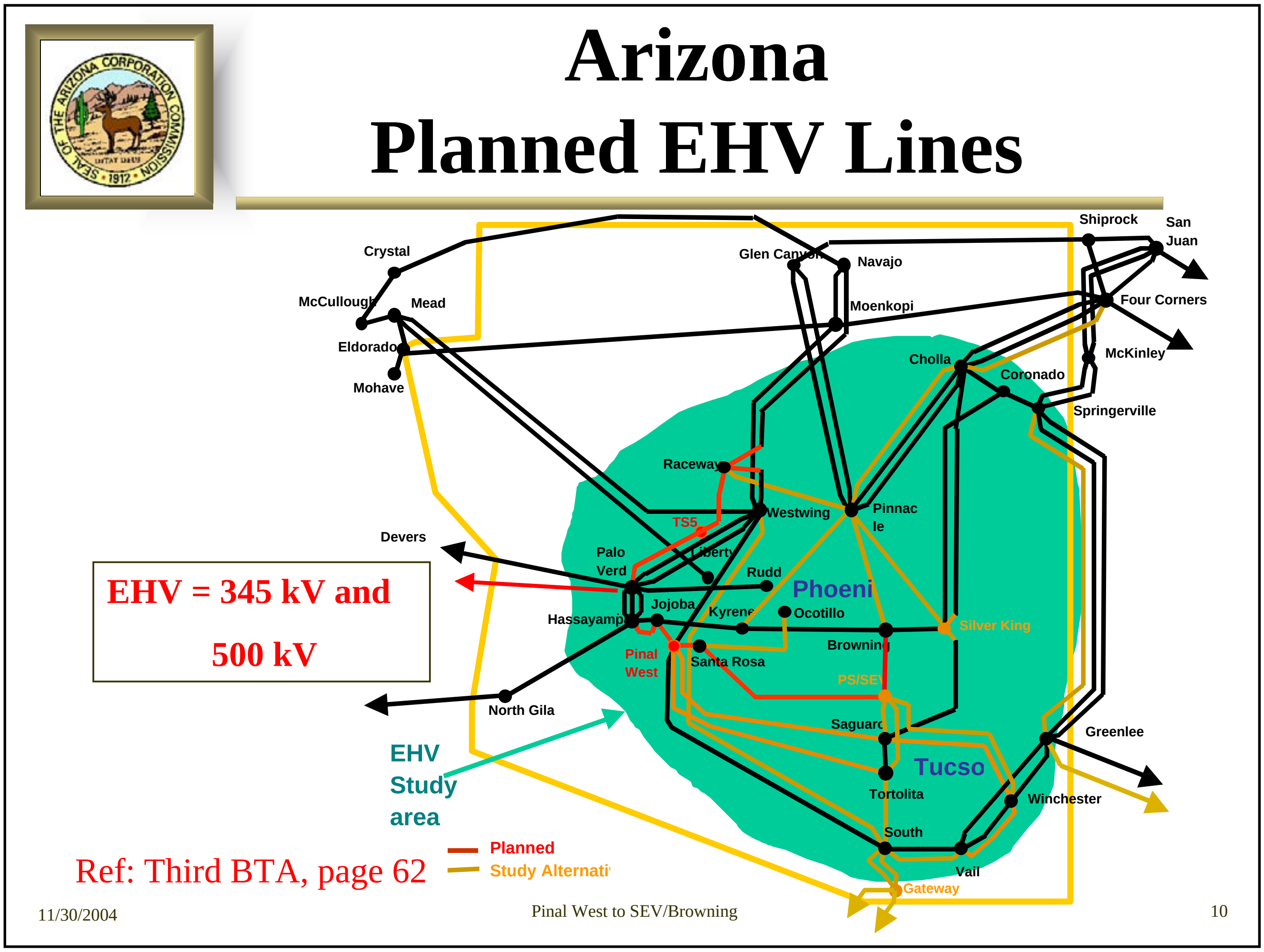
Arizona
Planned EHV Lines
Crystal
McCullough
Mead
Eldorado
Mohave
Glen Canyon
Navajo
Moenkopi
Shiprock
San Juan
Four Corners
McKinley
Cholla
Coronado
Springerville
Raceway
Westwing
Pinnacle
TS5
Liberty
Devers
Palo Verd
Rudd
Phoeni
Jojoba
Kyrene
Ocotillo
Hassayamp
Silver King
Browning
Pinal West
Santa Rosa
PS/SEV
North Gila
Saguaro
Greenlee
Tucso
Tortolita
Winchester
South
Vail
Gateway
EHV = 345 kV and 500 kV
EHV Study area
Ref: Third BTA, page 62
Planned
Study Alternati
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Ten Year Plan Filings By Project Participants

Per A.R.S. §40-360.02.A Statutory Requirement:

Project Participant	Jan. 31, 2003	Jan. 31, 2004
SRP	Yes	Yes
APS	Yes	Yes
ED-2	No	No
Santa Cruz Water & Power	No	Yes
SWTC	Yes	Yes
TEP	Yes	Yes[1]

[1] Notice of Errata correcting date of facility dated February 12, 2004.

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2004 Ten Year Plan Filings By Project Elements

Per A.R.S. §40-360.02.A Statutory Requirement:

Project Element	Service Date[1]	2004
Palo Verde - Pinal West 500 kV	2006	Yes
Pinal West – Santa Rosa 500 k V	2007	Yes
Santa Rosa – Pinal South/SEV 500 kV	2011	Yes
Santa Rosa – Pinal South/SEV 230 kV	?	No
SEV-Browning 500 kV	2011	Yes
SEV-RS19-Browning 230 KV	TBD/2008	Yes

[1] Per CEC applications.

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3rd Biennial Transmission Assessment - Key Conclusions

- **Existing and Planned Transmission Facilities Meet Load Serving Requirements of Arizona in a Reliable Manner. (Without the Planned Facilities A Different Conclusion May Have Been Reached)**

- **The Palo Verde to TS5 to Raceway and Palo Verde to Browning Projects Will Significantly Increase the Outlet Capability of the Palo Verde Hub to Arizona.**

- **Existing Transmission from Palo Verde to California is Inadequate to Allow All New Palo Verde Hub Generation Full Access to the California Market Under Weak Arizona Market Conditions.**

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Benefits of Proposed Project

- **New Line Capacity Meeting Local Consumer Needs:**
  - Metropolitan Phoenix Area (APS and SRP)
  - Pinal County (APS, SRP, Santa Cruz Water & Power Districts Association)
  - Cochise and Pima County (SWTC, TEP)
- **Wholesale Market Opportunities**
  - Improves Merchant Power Plants' Access to Multiple Markets
- **Helps Mitigate Existing Palo Verde Hub Reliability Risks and Local RMR Constraints**

Staff Assessment (1 of 2)

- **Staff Believes the Proposed Facilities are Needed and Applicant Has Met The Need Justification Burden for**
  - 500 kV Line From Pinal West to Browning
  - 230 kV Line From SEV – RS19 – Browning
- **Do Not Support Approval of a 230 kV Line From Santa Rosa to SEV via this Project for the Following Reasons:**
  - No Specific 230 kV Line Has Been Identified
  - Fails to Comply with A.R.S. §40-360.02.A Since No Ten-Year Plan Has Been Submitted for Such a Line
  - Fails to Comply with A.R.S. §40-360.02.C.7 Since No Technical Studies Have Been Submitted for Such Line

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Staff Assessment (2 of 2)

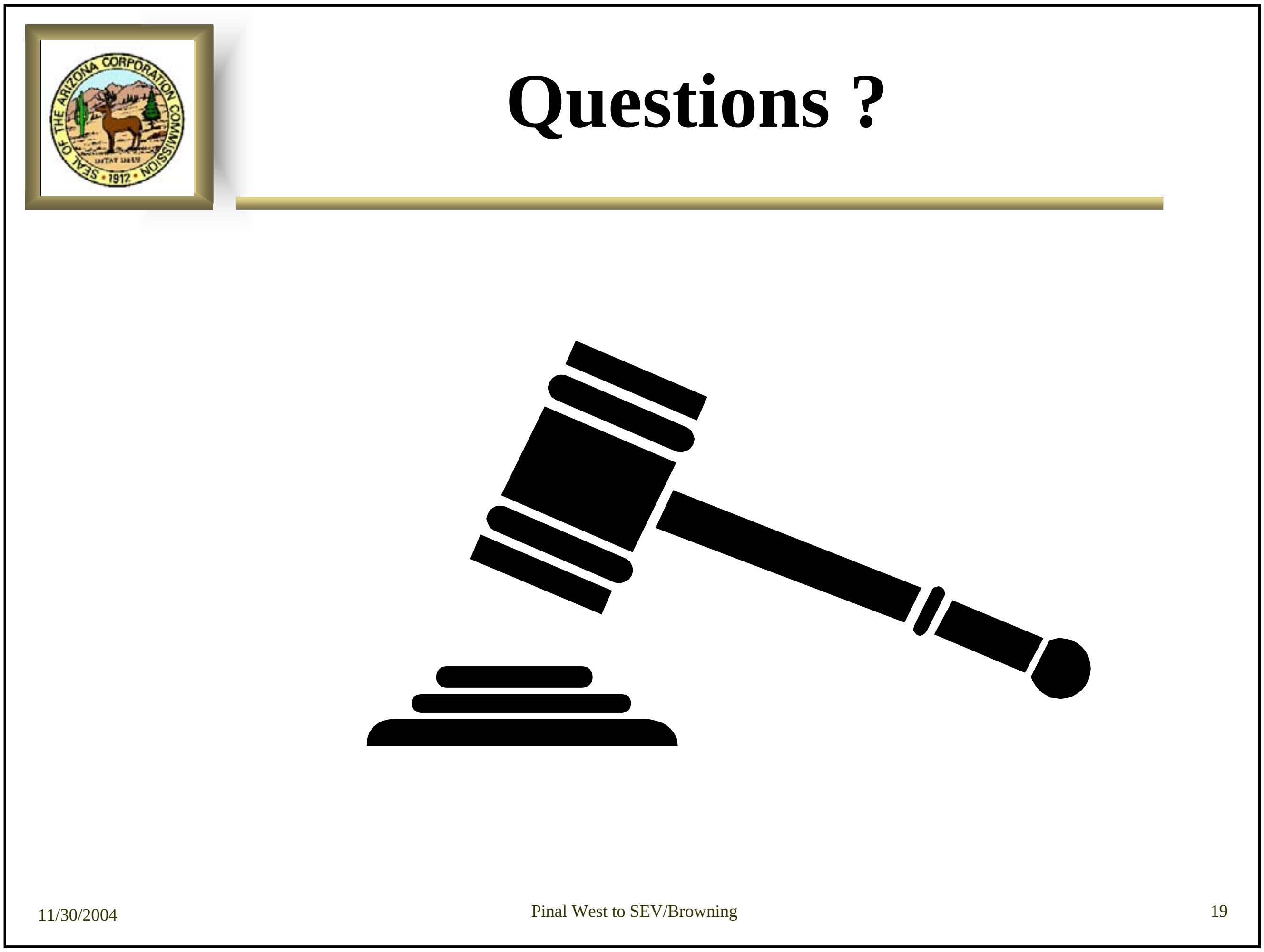
- **Support Provision for Future 500 kV Interconnection With the Pinal West to Browning 500 kV Line at:**
  - **Santa Rosa Substation (Exhibit G-10)**
  - **Pinal South Substation (Exhibit G-11)**
  - **South East Valley Substation (Exhibit G-12)**
- **Support Use of Vertical 500 kV Poles (per Exhibit G-1) From Santa Rosa to SEV as Needed to Accommodate Consolidation of Future Lines (per Exhibit G-2) Not Yet Planned, Studied or Sited Provided Such Future Lines Do Not Pose Unreasonable System Reliability Risk**
- **Staff Supports the Proposed Route Given There Are No Compelling Arguments an Alternative is Superior.**

Consolidated Facilities and Common Corridors (1 of 2)

- Staff Supports Consolidation of Facilities For Environmental and Aesthetic Purposes if System Reliability is Not Compromised
- Staff Also Supports Use of Common Corridors if System Reliability is Not Compromised
- Consolidation of Proposed Facilities or Use of Common Corridors w/o Consideration of Technical Consequences Is Inappropriate Planning

Consolidated Facilities and Common Corridors (2 of 2)

- **Reliability Impacts of Consolidating Facilities or Using A Common Corridor are Generally Lessened When:**
  - Lines Are of a Different Voltage Class (ie. 230 kV vs. 500 kV)
  - Lines Do Not Share a Common Terminus
  - Lines Connect to Segregated Service Areas or Geographical Areas (ie. TEP's Tucson Service Area and SRP's Phoenix Service Area)


Questions ?
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ATTACHMENT 4

Arizona Corporation Commission

Docket No. L-00000B-04-0126

Pinal West to SEV/Browning 500 kV Line Siting

Concluding Presentation of Staff Witness
Jerry D. Smith

March 9, 2005

Concluding Staff Remarks

- **Consumer Benefits vs. Cost**
- **Long Range System Needs**
  - Planning Deficiencies
  - Siting Considerations and Accommodation
- **Staff Position Regarding Use of Gas Pipeline Corridor's for Siting Transmission Lines**
- **Staff Refined Position Regarding Routes:**
  - Modification of Original Staff Position
  - Reliability Refinements to Area A, Area B, Area C
- **Staff Conclusions and Recommended Route**

Consumer Benefits vs Cost

- **Commission Balancing Test (A.R.S. § 40-360-07.B)**

  Weighs, in the Public's Interest, the Need for Economical, Adequate and Reliable Service with the Environmental Impact of Such Facilities

- **Proposed Facilities Address the Following Needs:**
  - New Line Capacity For Metropolitan Phoenix Area, Pinal County, Pima County, and Cochise County Growth
  - Improves Merchant Power Plants' Access to Multiple Wholesale Markets
  - Helps Mitigate Existing Palo Verde Hub Reliability Risks and Local RMR Constraints

Consumer Benefits vs Cost (Continued)

- No Proposed Route has Been Excluded For Posing a Detrimental Environmental Impact
- The Cost Differential of Alternative Routes Is Reasonable and Not Viewed By Staff as Justification for Elimination of Any Route
- Staff Offers Reliability Recommendations Regarding Proposed Route Alternatives While Acknowledging the Benefit and Costs Accompanying the Proposed Facilities

Long Range System Needs

- **This Project is But The "Visible Tip of the Iceberg" of Future Transmission Construction Likely Required for Pinal County:**
  - Anchoring 500 kV Delivery to An Undefined Future 115 and 230 kV System at Santa Rosa and Pinal South is Technically Sound.
  - Both a Northern and Southern Transmission Line Route is Ultimately Needed for Local Growth. Approval of One Route for This Project Does Not Forego the Long Term Need for The Other Route.
  - Local Power Plant Expansions or New Plants Will Require Additional Local Transmission.

Planning Deficiencies For Pinal County Electric Needs

- **Short Term System Needs are Being Meet by Upgrading WAPA 115 kV Lines to 230 kV and Local Utilities Installation of Capacitors.**
- **No Transmission Plans Have Been Filed with The Commission Commensurate with Growth Defined by Intervening Developers' Projects.**
- **Local Municipalities are Approving Planned Area Developments without Consideration of Transmission Infrastructure Required to Collectively Serve Such Developments.**

Action Needed for Pinal County Electric Plan

- Resolve Overlapping Service Areas of APS, Electric and Irrigation Improvement Districts, and San Carlos Irrigation Project.
- Develop Comprehensive Transmission Plan via Local Study by Involved Utilities, Existing and Planned Developments and Municipalities.
- File Ten-Year Transmission Plan with ACC.
- Incorporate Conceptual Transmission Corridors in Municipalities' General Plans and Planned Area Developments.

Siting Committee Considerations

- **Consider All Information Available For Near Term (< 10 Yrs) and Long Term (> 10 Yrs):**
  – Site Facilities With Consideration of Impact on Both Existing and Future Developments.
- **In Absence of Formal Transmission Plans:**
  – Generously Allow for Unplanned and Unforeseen Future System Needs For Areas Transitioning from Rural to Urban Service.
  – Require Future Projects to Justify Reliability and Environment Impacts for Use of Common Corridor or Consolidation of Facilities.

Use of Natural Gas Pipeline Corridors for Transmission

- **Staff continues to conditionally support use of gas pipeline corridor's for siting transmission lines provided:**
  - No adverse operational impacts result for either the gas pipeline or the new transmission line
  - Separation of corridor facilities is sufficient to assure respective equipment and personnel safety
- **Staff generally supports use of gas pipeline corridors over existing transmission corridors for reliability purposes when siting new lines**

Refined Staff Position Regarding Routes

- **Original Position - Generally Support the Proposed Route Given There Are No Compelling Arguments an Alternative is Superior.**

- **Modified Position – Route Refinements are Necessary to Resolve Staff Reliability Concerns in Each of The Three Areas: A, B, and C.**

Area A
Staff Route Recommendation

- **For Reliability Purposes Staff Opposes:**
  - Preferred Route from Pinal West to Node N205
  - SOV Route from Pinal West to Node N22
- **Recommend an Alternate Route Connecting Pinal West to Node N205 via:**
  - Nodes N147 to N148
  - An Alternative Route Between Nodes N148 to N151
  - Add a New Alternative Route Segment Between Nodes N151 and N205
- **Support Applicant's Preferred Route from Node N205 to Santa Rosa Substation**

Area B
Staff Route Recommendation

- **For Reliability Purposes Staff Opposes:**
  – Santa Rosa to N122 to N108 to N206.
- **Recommend Santa Rosa to N158 to N159 for Both Northern and Southern Routes. (Consolidation with Either WAPA line on Parker Rd Or Future 230 kV is Acceptable to Staff)**
- **Recommend N159 to N197 to N196 to N206 for Primary Northern Route.**
- **Support Casa Grande Mtn’s Realignment Proposal North & East of I-8 / I-10 Interchange.**

Area C
Staff Route Recommendation

- **For Reliability Purposes Staff Opposes:**
  – N33 to N31 to N203 to N202 for Both the Northern and Southern Routes in Area B.
- **Support Applicant’s Recommended Route from Browning to SEV.**
- **Recommend the Alternate Route from SEV (N44) to Pinal South (N183).**
- **If Area B Northern Route is Selected:**
  – Staff Recommends use of N137 to N125 to N181 to N182 to Pinal South (N183).

Staff Conclusions (1 of 3)

- **Staff Believes the Proposed Facilities are Needed and Applicant Has Met The Need Justification Burden for**
  - 500 kV Line From Pinal West to Browning
  - 230 kV Line From SEV – RS19 – Browning
- **Supports Provision for Future 500 kV Interconnection With the Pinal West to Browning 500 kV Line at:**
  - **Santa Rosa Substation (Exhibit G-10)**
  - **Pinal South Substation (Exhibit G-11)**
  - **South East Valley Substation (Exhibit G-12)**

Staff Conclusions (2 of 3)

Regarding Future 230 kV Line From Santa Rosa to SEV:

- **Support Use of Vertical 500 kV Poles (per Exhibit G-1) as Needed to Accommodate Consolidation of Future 230 kV Line (per Exhibit G-2).**
- **Proposed CEC Conditions Enables Staff Support for Attachment of a Future 230 kV Line From Santa Rosa to SEV via this Project provided SRP:**
  - Files a Ten-Year Plan for The 230 kV Line in January 2006,
  - Files With ACC Staff Prior to 230 kV Construction - Technical Study and Reports Regarding Reliability of Proposed Consolidation With the 500 kV Line, and
  - Obtains ACC Authorization to Construct The Future 230 kV Line on Any Portion of The 500 kV Line Prior to Construction.

Staff Conclusions (3 of 3)

- **Recommend Northern Route in Area B:**
  - Provides Best Opportunity for Resolving Existing Transmission Constraints at Desert Basin and Sun Dance Power Plants,
  - Provides Interconnection Opportunity for Future Generation Expansion at Either Desert Basin or Sun Dance, and
  - Provides Opportunity to Attach Future 230 kV Line Likely Needed for Intensive Development in Pinal County.

Questions ?

ATTACHMENT 5

GAS PIPELINE - INDUCED AC MITIGATION

CONSULTING SERVICES

ON

EL PASO NATURAL GAS 27 INCH AND 30 INCH PIPELINES

FOR

SALT RIVER PROJECT

PHOENIX, ARIZONA

BY

ELK ENGINEERING ASSOCIATES, INC.

JOB NUMBER 2242

28 APRIL 2004

TABLE OF CONTENTS

Gas Pipeline - Induced AC Mitigation

Consulting Services

on

El Paso Natural Gas 27 Inch and 30 Inch Pipelines

for

Salt River Project

Phoenix, Arizona

by

ELK Engineering Associates, Inc.

Job Number 2242

28 April 2004

A. INTRODUCTION

In accordance with the terms of Salt River Project (SRP) R.F.P. No. II-135794.IDE, ELK Engineering Associates, Inc., 8950 Forum Way, Fort Worth, Texas 76140 (ELK), performed a Gas Pipeline Mitigation Study on multiple El Paso Natural Gas (EPNG) pipelines with existing and/or proposed collocations with SRP 525kV power lines.

ELK has employed the services of Electro Sciences, Inc. Crystal Lake, Illinois (ESI) to perform computer modeling of the existing pipeline and power line right-of-way (R/W) configuration and up to two (2) additional 525 kV circuits. The ESI executive summary provides a description of the present and proposed R/W configurations. This report sets forth the results of our field investigations, calculations and induced AC mitigation recommendations. A support document, Appendix B, “Induced AC-Pipeline Safety Issues” is appended to the report.

Two engineers from ELK commenced the field work on 16 December 2003 with a follow-up trip for additional data on 12 February 2004. Working with Mr. Tom H. Hervol, EPNG on 12 February 2004, we determined the need for a test lead installation on Line 2000 at the power line crossing at mile post number 415.771. Mr. Hervol subsequently installed the test lead and provided us with induced AC P/S measurements.

B. FIELD TEST WORK AND INVESTIGATIONS

The following field tests, investigations and observations were made during this survey:

1. Soil resistivity measurements.
2. Visual inspection of the power line and pipeline rights-of-way.
3. Still photographs.
4. Review of available for-construction power line records.
5. Review of available pipeline records.
6. Longitudinal electrical field measurements.
7. Induced AC pipe-to-soil potential measurements.
8. Other tests deemed necessary by the engineer in charge of the field testing.

The data obtained from these survey tests are presented on the data sheets appended to this report.

C. SOIL RESISTIVITY

Average soil resistivity measurements were made utilizing the standard Wenner four pin method utilizing an Associated Research Model Number 293A Vibroground instrument at selected locations along the right-of-way (R/W) under investigation. Because of AC skin effect, no soil resistivity measurements deeper than 100 feet were taken. All test equipment is maintained in calibration to NIST traceable standards. The soil resistivity readings are presented on the data sheets contained in the Appendix.

Soil resistivity measurements are essential for induced AC potential calculations and for design of induced AC mitigation grounding facilities, where required. An analysis of the soil resistivity measurements taken on the R/W shows considerable variation along the length of the line at pipeline depth. Soil resistivity at pipeline depths ranged from very low to ultra high throughout the length of the pipeline. Resistivity increased considerably with depth at some locations. Highest surface resistivities were measured in well drained sandy soils. Increasing resistivity with depth is indicative of solid rock underlying the desert soils. Soil resistivity will impact the apparent coating resistance of the installed pipeline. A total of thirty-nine (39) soil resistivity measurements were taken along the length of the pipeline R/W. An analysis of the measured soil resistivities shows the following percentages at the average pipe depths tested.

Range of Soil Resistivity (ohm-cm)	Depth of Reading (Feet)							
	0-2.5	0-5	0-10	0-15	0-20	0-30	0-50	0-100
100- 1,000	2.8%	2.6%	5.1%	5.4%	5.6%	12.5%	0%	0%
1,001- 5,000	5.4%	10.5%	33.4%	62.2%	72.2%	25.%	25.%	0%
5,001- 10,000	10.8%	29.%	28.2%	21.6%	8.3%	12.5%	25.%	40.%
10,001- 25,000	35.1%	42.1%	28.2%	10.8%	13.9%	50.%	25.%	0%
25,001- 100,000	35.1%	15.8%	5.1%	0%	0%	0%	25.%	60.%
100,001-1,000,000	10.8%	0%	0%	0%	0%	0%	0%	0%
TOTAL	100%	100%	100%	100%	100%	100%	100%	100%

The very low, random surface soil resistivities are probably due to migration of alkali to the surface. Low resistivity surface soil conditions (0 to 2.5 foot measurements) adversely affect tolerable step and touch potentials on the right-of-way.

D. STRUCTURE-TO-SOIL POTENTIALS

Pipeline induced AC potentials vary with time and are dependent upon, in addition to line current, geometry, powerline loading and phase imbalances. Previous investigations by IIT Research Institute, 10 West 35th Street, Chicago, Illinois 60615 (hereinafter referred to as IITRI) and others have demonstrated a four to one variation in electric field intensity and consequent induced pipeline voltage with essentially balanced phases and constant line load. This is to say that small, almost imperceptible, line current variations may have a major influence upon the voltages actually induced in a parallel pipeline. Therefore, single, point in time AC readings are of somewhat limited value unless they can be correlated with the powerline currents at the time the measurements were taken. AC pipe-to-soil (P/S) potentials were measured at selected locations on the pipeline. The AC P/S potentials were measured with a Fluke Model Number 87 FET multimeter against a steel pin in the earth at each test station. Voltage readings were recorded for time intervals ranging from 10 minutes to 27 minutes at each location. We have documented low, high and average values with time of day.

We also measured the longitudinal electric field (LEF) at the surface of the earth under the centerline of the existing power line at selected locations where the pipelines were not paralleling the existing circuit. LEF voltage measurements were obtained with a Fluke Model Number 87 FET multimeter and a ten meter shielded cable placed directly under the centerline of the power line. The LEF measurements behave exactly as pipeline induced AC pipe-to-soil potentials would. That is, they vary in direct proportion to the line currents in the overhead conductors. Voltage readings were recorded for time intervals ranging from 13 minutes to 36 minutes at each location. We have recorded low, high and average values with the time of day on the data sheet contained in the Appendix.

E. COATING RESISTANCE

A buried pipeline with a dielectric protective coating is characterized by electrical engineers as a "lossey transmission line." The pipeline is considered to be an insulated conductor with multiple, parallel leakage resistances to ground. Leakage occurs at individual holidays, but also directly through aged coatings. The summation of these leakage resistances is considered to be the coating resistance.

Pipeline coating resistance (in ohms per square foot) is an essential value for computation of propagation constants and characteristic impedances which are required for calculations of the induced AC potentials as discussed in greater detail later in this report. Apparent coating resistance will vary somewhat over the length of the pipeline. Assuming a uniform coating quality, apparent coating resistance will be lower in low resistivity soils and higher in high resistivity soils.

EPNG has not measured coating resistances for the pipelines under investigation in this study. They did provide us with a copy of the most recent DC P/S potential survey for the pipelines in question. From these data, we have been able to make crude estimates of apparent coating resistance for the four pipelines in question. We selected the pipeline segment from line 1100 mile post (M.P.) number 592.132, at cathodic protection rectifier (CPR) 817 to M.P. 612.161 at CPR-1360. This 20.029 mile segment has all four pipelines on a common R-W and a total of six (6) rectifiers. Each rectifier has a negative connection (with a shunt) to each of the pipelines. This provided the current flow to each pipeline at each rectifier. We assumed a 50/50 current split upstream and downstream on each pipeline at CPR-817 and at CPR-1360, then added the outputs of CPR-884, CPR-306, CPR-1433 and CPR-1190 to obtain total current flow to each pipeline. From the annual survey data, we calculated the average voltage shift for each pipeline over the 20 mile interval. Dividing voltage shift by current for each pipeline calculates the resistance-to-remote earth value for each pipeline segment. Multiplying this value by the pipeline's external surface area yields the coating resistance in ohms per square foot. For the pipeline segment in question, the following values were calculated:

Pipeline No.	Coating Resistance (Ω/ft^2)
1,100	5,100
1,103	4,130
1,600	11,200
2,000	501,500

Over the pipeline interval in question, pipe depth soil resistivities ranged from 6,300 ohm-centimeter to 138,850 ohm-centimeter, or a ratio of 22 to 1. We may expect similar variations in apparent coating resistance over short intervals along these pipelines. Thus, it can be seen that the coating resistances of these pipelines are quite subjective. Nevertheless, these are important variables for the computer model.

The calculated coating resistance reflect the age of the coatings present on the individual pipelines. These data clearly show the effects of coating aging. Where line 2000 closely parallels the older lines and is crossbonded to them; the older pipelines behave as a horizontal mitigation wire, resulting in significantly reduced induced AC P/S potentials on line 2000.

At the western end of the common corridor, line 2000 was constructed largely in independent R/W with very limited cross bonding to the older pipelines. In order to improve the computer model, we calculated the pure DC resistance of individual rectifier groundbeds on line 2000. The computer simulation was then able to characterize the half-wave rectification leakage currents to ground at these locations. The following calculated groundbed resistance values were calculated from:

$$R = \frac{E - E_B}{I}$$

Where:

R = Groundbed DC resistance
E = Rectifier calibrated output voltage
E_B = Groundbed-to-pipeline polarized back EMF
I = Calibrated current flow to line 2000

CPR Number	Calculated DC Resistance (ohms)
1015	0.316
1974	0.325
1579	0.237
1924	0.5667
240	0.3773
1120	0.3344

F. PIPELINE INDUCED AC POTENTIAL

Whenever a coated pipeline and HVAC transmission circuit are in close proximity to each other, the magnetic field associated with the line currents in the power transmission line will induce a voltage in the pipeline. The actual magnitude of the induced AC potential depends upon many factors including the overall geometric configuration of all of the structures involved, soil resistivity, pipe coating effectiveness, pipeline propagation constant, magnitude of the line currents in the phase conductors and any current imbalance between the phases. If the line currents in the three phase power system were perfectly balanced and the pipeline were equidistant from each of the phase conductors and from each of the grounded shield wires, the total voltage induced in the pipeline would be zero. This ideal situation is seldom seen in practice. Therefore, one may generally anticipate the measurement of an actual AC voltage induced on the adjacent, parallel pipeline. Much greater potentials may be encountered on the pipeline during single-phase-to-ground or phase-to-phase fault currents in three phase power systems due to the magnitude of the fault currents and to the less than ideal circuit geometry under fault conditions.

Recognizing these factors, ELK investigated the configuration of the pipeline closely paralleling the circuit reported on herein. Particular emphasis was placed on obtaining LEF readings in areas where peak induced AC potentials would be anticipated and in areas where the general public might have access to the pipeline facilities. LEF measurements were made with the test equipment described above in Section D. Refer to the data sheets contained in the Appendix for the actual measurements obtained.

G. STEADY STATE PIPELINE INDUCED AC POTENTIAL

The magnitude of steady state AC potentials induced on an underground pipeline by parallel high voltage transmission lines may be estimated quite accurately using appropriate mathematical formulae. The formulae characterize the circuit in terms of the “steady state” line currents, phase relationships, pipeline to conductor distances, pipeline propagation constants, characteristic impedances, soil resistivity and other factors. The technique is able to predict, with reasonable accuracy, the areas where the maximum AC potentials will occur and to approximate the actual induced voltage at that point on the structure. These formulae were developed under grants from AGA and EPRI by IITRI. Additional refinements have been made since this earlier work was published.

While these formulae present results more precise than those produced by earlier methods (generally based upon Carson’s equations for mutual interference), they are still somewhat approximate in nature. Errors associated with the earlier calculations were order of magnitude or more, but produced results that were on the high side and, therefore, were considered to be safe. Calculations based upon the published IITRI methods will have errors of ten percent or less but are quite time consuming to perform on a hand held calculator.

The computer program that was used for analysis of the joint right-of-way is a program proprietary to ESI. The program algorithms are traceable to fundamental electromagnetic formulas. The results of the program have been extensively tested by direct field measurement and by comparison with other available programs, such as the Electric Power Research Institute’s program CORRIDOR. Results obtained are within a few percent of actual measurements and are among the most accurate available to the industry. ESI developed a mathematical model of the right-of-way and performed all necessary calculations. Refer to the ESI report appended to this report. Manual calculations have been held to a minimum.

The calculations are all made at anticipated peak induced AC voltage locations. Pipeline induced AC voltage will actually reach zero at the electrical mid-point between the voltage peaks for all simple cases of AC induction. Generally, the electrical mid-point will occur at or quite close to the physical mid-point between the voltage peaks. This is not the case for ground fault induced soil gradients where the voltage peak occurs opposite the faulted structure.

With these comments in mind, refer to the ESI Report, and the graphic presentations resulting from the computer modeling, which is appended to this report. Refer to the field data for actual steady state potentials measured in the field. All calculations and plotted curves are based upon present day normal maximum “steady state” and projected future line current magnitudes supplied by SRP.

H. GROUND FAULT TRANSIENT INDUCED VOLTAGES IN PIPELINES

For areas of parallelism, the induced potential hazards are twofold. First is the “steady state” condition discussed above. Second is the induction effect that occurs during ground fault conditions. This differs in that the current in the conductor(s) rise in magnitude, they may be single phase which changes the phase angle of the induced voltage/current and a sizable return current passes through the earth. Refer to the ESI Report for details of the individual calculations and the results.

I. GROUND FAULT INDUCED SOIL GRADIENTS

A final safety consideration of power system effects on nearby pipelines has to do with fault induced AC soil gradients that affect a nearby pipeline. A fault current flowing from a powerline structure into earth produces a potential gradient in the earth surrounding the faulted powerline structure. This can create hazardous voltages between the pipeline steel and the surrounding soil. These voltages can appear at aboveground appurtenances accessible to personnel such as valves, cathodic protection test leads and metering facilities. Gradient control mats and/or bonding can reduce these gradients to less than the tolerable step and touch potential levels in the immediate vicinity.

Due to the conductivity of the pipeline steel, ground fault induced gradient voltages may be seen on the pipeline at a considerable distance from the site. If the surrounding soil mass is at normal remote earth voltage, but the pipeline steel is influenced by the gradient voltage, a serious voltage difference will exist across the coating between the pipeline steel and the earth. This is known as “transfer voltage.” Grounding techniques must be employed to mitigate transfer voltage if calculations predict voltages above safe step and touch levels. Without effective mitigative measure, these voltages could be lethal. Currents flowing at the fault site or at remote current discharge sites from the pipeline can damage the pipeline coating or, if high enough, they can burn a hole through the steel wall of the pipeline. These current discharges do tend to limit the magnitude of the transfer voltage. Where the voltage of the pipeline steel is more than 1KV above the surrounding earth, corona arc discharges at coating holidays will tend to somewhat limit the voltage rise on the pipeline.

The safety grounding recommendations contained in this report are intended to address these issues. Gradient control mats are necessary at all test leads or other aboveground appurtenances due to step and touch voltage considerations under fault conditions. Refer to Drawing Number A-2064-3 for further details.

J. STEP AND TOUCH VOLTAGES

Calculated step and touch voltages on the affected pipeline determine the safe level of induced AC voltage that may be tolerated, under power system fault conditions, on the pipeline steel and appurtenances in order to assure a reasonable degree of personnel safety. Since fault currents are of very short duration, the human body can tolerate a much higher value than the 15 volt limit imposed for steady state conditions. Calculations are based upon predicted fault current, worst case clearing times and average measured soil resistivity from zero to 2.5 foot depth used for surface soil resistivity. When the fault current calculations reveal gradient induced AC voltages in excess of these values, mitigative measures for the affected pipeline must be considered. The ESI Report shows that the conservative maximum tolerable step or touch potential for this pipeline is 436 volts over the length of the right-of-way.

ATTACHMENT 6

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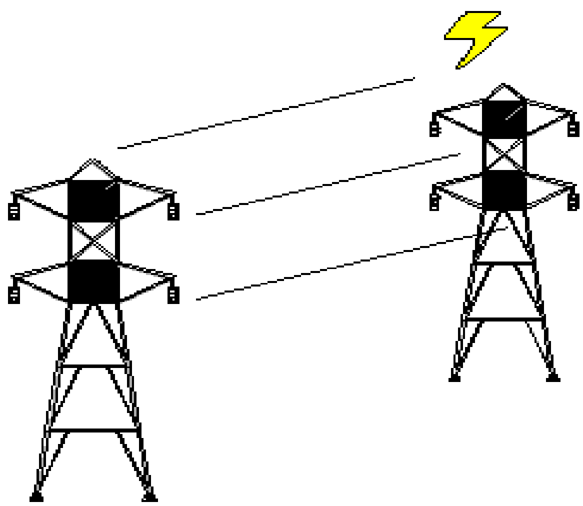
Palo Verde to Pinal West Transmission Project Alternative 'C' Route

Gas Pipeline Mitigation Consulting Services



Prepared for:
Salt River Project
Phoenix, AZ
April 26, 2004

Prepared by: John Dabkowski, Ph.D.

Executive Summary

The Palo Verde to Pinal West (PV-PW) 525 kV Project proposes to construct and operate two new parallel 525 kV transmission lines from the Hassayampa Switchyard to a new substation located in western Pinal County, Arizona. These new transmission lines will parallel an existing 525 kV transmission line from Hassayampa to a location just east of Jojoba Substation, which is referenced as the Divergence Point.

Four(4) El Paso natural gas pipelines parallel the 525 kV transmission corridor. The objective of this study was to determine the voltages and currents developed on these pipelines due to electromagnetic field coupling and earth conduction currents produced by the existing and future transmission lines. Computer simulation models were developed for this collocated corridor to determine pipeline induction levels for both steady state operation and fault conditions.

Four cases were investigated, namely,

- Case 1: The existing transmission line only,
- Case 2: The existing and first new transmission line,
- Case 3: All three transmission lines with the second new line bypassing the Jojoba Substation, and
- Case 4: All three transmission lines with the second new line looping in and out of Jojoba Substation.

Simulation results for these cases are presented in Report Sections 1 through 4, respectively.

The computer simulations indicate that pipe touch potentials for steady state and fault conditions can exceed safe criteria. Attempting to reduce these potentials to safe levels by increasing the separation between the transmission lines and the pipelines does not appear feasible. Separations on the order of 500 feet are required for the steady state and 1,200 feet for the fault scenario. Hence, the following mitigation measures are recommended.

1. Introduce optimum conductor phasing between the three transmission lines.
2. Provide gradient control mats at pipeline test stations and at locations where pipe or pipe appurtenances can be contacted by personnel. The addition of a gravel overlay will increase the margin of safety.

It should be noted that the conclusions reached in this study are right-of-way specific and should not be extrapolated to other joint corridors. This is especially true for pipelines with larger coating resistivities, and hence, increased induced voltage levels.