Arizona Corporation Commission

Docket No. E-00000A-01-0120

REVISED BIENNIAL TRANSMISSION ASSESSMENT 2000 - 2009

Adequacy of Arizona's Existing and Planned Transmission Facilities

Prepared and Submitted by
Asher Emerson and Jerry D. Smith
ACC Staff

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Acknowledgements

The Arizona Corporation Commission does not have the necessary data, computer software and hardware, or sufficient human resources to perform its own technical studies required for a biennial transmission assessment. Therefore, Staff has relied upon the reports and technical study results of other parties to fulfill its statutory obligations to provide a biennial transmission assessment of Arizona's existing and planned transmission facilities. Staff is grateful for the professional efforts of the following organizations, committees and utilities for the broad spectrum of information and technical reports they have produced:

- North American Electric Reliability Council (NERC)– Regional Assessment Subcommittee
- Western System Coordinating Council (WSCC) - Operating Committee
- Committee on Regional Electric Power Coordination (CREPC)
- Western Interconnection Coordination Forum (WICF)
- Northwest Regional Transmission Association (NRTA)
- Southwest Regional Transmission Association (SWRTA)
- Western Regional Transmission Association (WRTA)
- Arizona Electric Power Cooperative (AEPCO)
- Arizona Public Service Company (APS)
- Citizens Utilities Company (CUC)
- Public Service Company of New Mexico (PNM)
- Salt River Project (SRP)
- Tucson Electric Power Company (TEP)
- Western Area Power Administration (WAPA)

The authors offer their personal thanks and gratitude to their colleagues and peers in the above organizations that contributed to the technical work product. Staff would have been unable to accomplish its task without their collective efforts, professional expertise and technical insights they provided in reports for the above entities.

Respectfully,

Asher Emerson and
Jerry D. Smith
Electric Utility Engineers
ACC Staff

Executive Summary

A.R.S. §40-360.02E states "The (Ten-Year) plans shall be reviewed biennially by the commission and the commission shall issue a written decision regarding the adequacy of the existing and planned transmission facilities in this state to meet the present and future energy needs of this state in a reliable manner." Staff has completed its first biennial assessment of Arizona's existing and planned transmission system. This report documents Staff's assessment and is submitted in compliance with the aforementioned statute requirement. Staff's report addresses the adequacy and reliability of Arizona's existing and planned transmission system and offers conclusions and recommendations for Commission consideration and action. This Transmission Assessment represents the professional opinion of Commission Staff, does not set Commission policy, and does not recommend any specific action by Arizona transmission providers. This Transmission Assessment will not be ACC policy unless and until adopted by Commission Decision.

Adequacy and reliability of a transmission system can not be determined by merely reviewing the Ten-Year Transmission Plans filed with the Commission. Technical studies are necessary to make the required assessment. The Commission does not currently have the data or means of performing the necessary technical studies. Therefore, Staff has relied upon its industry experience and knowledge of Arizona's transmission system to analyze technical reports published by others in formulating its conclusions and recommendations.

Staff concludes that the State of Arizona does not have adequate existing or planned transmission facilities to deliver the energy needs of the state in a reliable manner. The planned transmission enhancements are both inadequate and untimely. These conclusions are based upon the following findings:

- There is very little additional long-term firm regional transmission capacity available to export or import energy over Arizona's transmission system.
- Southeastern Arizona utilities rely upon restoration of service rather than continuity of service following transmission outages due to service via radial transmission lines.
- There are transmission import constraints for three geographical load zones in Arizona: Phoenix metropolitan area, Tucson, and Yuma. Planned transmission enhancements fail to resolve this situation in a timely manner.
- The existing and planned additions to the Palo Verde transmission system fail to accommodate the full output of all new power plants proposing to interconnect at Palo Verde Requiring curtailment and scheduling restriction procedures to be developed.
- Some proposed power plants are being interconnected to Arizona's bulk transmission system via a single transmission line or tie rather than continuing Arizona's best engineering practice of multiple lines emanating from power plants.

Concerns outlined by Staff in the above conclusions are not easily or quickly resolved. The public's best interest warrants effective and decisive remedies. Therefore, Staff offers the following recommendations for Commission consideration and action:

1. The Commission should advocate legislative changes to the Arizona Revised Statutes to require power plants to file a Ten-Year Plan. The plans submitted by transmission providers and power plants should also be accompanied by technical studies demonstrating the system impact of those planned additions. Similarly, due consideration should be given to data and budgetary pre-requisites for biennial transmission assessments if Staff is to perform independent technical studies in the future.
2. The Commission should become an advocate for and participant in an industry review and development of new reliability criteria more suited to a restructured electric industry. The large generation complex developing at Palo Verde will be the largest in the nation and will serve as the ultimate test for new reliability standards.
3. Transmission providers should be required to supplement their previous transmission plans to address the concerns outlined in this assessment. These supplements should be filed within three months of the date of this report and workshops held to assure they achieve the reliability required to deliver Arizona’s energy needs.

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Section 1: Overview of Assessment

1.1 Purpose of Transmission Assessment

With this report, the Arizona Corporation Commission (ACC or Commission) Staff has completed its first biennial transmission assessment. Adequacy of existing Arizona transmission lines and planned additions between 2000 and 2009 has been determined. Staff investigated the ability of Arizona's transmission system to adequately delivery energy to the state's retail consumer markets as well as import energy from or export energy to the regional transmission grid with which it is interconnected. This report documents Staff's findings and recommendations and is filed under Docket No. E-00000A-01-0120. Staff performed this transmission assessment for the purpose of complying with statutory obligations of the Commission.

1.2 Authorization of Assessment

Every person contemplating construction of any transmission line within Arizona during any ten-year period is required by A.R.S. §40-360.02 to file a ten-year plan with the Arizona Corporation Commission on or before January 31 of each year. Utility Distribution Companies also have an obligation to assure that "adequate" transmission import capability is available to meet the load requirements of all distribution customers in their service area.[1] In 1999, the Arizona state legislature modified A.R.S. §40-360.02 and placed additional responsibilities with the Commission. The ACC now has a statutory obligation[2] to biennially review the ten-year transmission plans and issue a written decision regarding the "adequacy" of the existing and planned transmission facilities in Arizona to meet the present and future energy needs of this state in a "reliable manner."

Arizona statutes do not specify or define the basis upon which "adequacy" is to be determined. Nor do state statutes define how Staff is to establish that the state's energy needs are met in a "reliable manner." Staff has chosen to utilize the North American Electric Reliability Council (NERC) definition of these transmission parameters for this assessment. **NERC characterizes the "reliability" of an electric utility system as being comprised of two components: adequacy and security.** Any discussion of adequacy or reliability must be put in the context that NERC and WSCC were established to provide a forum for the coordination of planning and operation of the member systems to promote reliability of the interconnected bulk power systems. (WSCC's Minimum Operating Reliability Criteria (revised August 8, 2000) pages III-6, III-7 and III-8 under 1.0 INTRODUCTION and 2.0 PHILOSOPHY OF CRITERIA). NERC and WSCC establish criteria that govern how members impact the interconnected bulk power system. Staff is participating and commenting in industry development of reliability criteria for the restructured electric industry.

[1] A.A.C Rule R14-2-1609.B

[2] A.R.S. §40-360.02E

It is important to understand that NERC and WSCC are organizations that deal with interconnected systems. Neither NERC nor WSCC establish criteria for planning or operational requirements internal to members systems. In fact, NERC and WSCC criteria allow blackouts, voltage collapse, or cascading - as long as the impacts are confined to a local network or a radial system. NERC and WSCC also allow less stringent criteria from one member, as long as the other systems are permitted to have the same impact on that individual system. In addressing the individual members' systems, NERC's planning standards state that "[t]hose entities also have the responsibility to develop their own appropriate or more detailed planning and operating reliability criteria and guides that are based on the **Planning Standards** and which reflect the diversity of individual electric system characteristics, geography and demographics for their areas.

Staff has grave concerns about blackouts, voltage collapse or cascading that is internal to Arizona systems as this could have a profound effect on customers. Therefore, Staff contends that there should be a higher standard than NERC and WSCC require for internal system planning and operations. It is Staff's position that all entities, WSCC members and nonmembers, should operate in accordance with the NERC or WSCC Reliability Criteria whichever is more specific or stringent. Since electric system reliability is so vital to Arizona, Staff contends that it is appropriate to apply the most specific and stringent criteria. (WSCC's Minimum Operating Reliability Criteria (revised August 8, 2000) page III-27.)

Staff notes that SRP applies the N-1 criteria internal to their system, which precludes radial transmission lines. This is a higher standard than is required by either NERC or WSCC for internal system planning. Staff believes that this indicates that SRP complies with the WSCC's philosophy that states " [c]ontinuity of service to loads is the primary objective of the Council Reliability Criteria." WSCC's Minimum Operating Reliability Criteria (revised August 8, 2000) under 2.0 PHILOSOPHY OF CRITERIA.

The NERC definition of Adequacy is "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." System adequacy is dependent upon system topography or configuration and operating conditions. This implies a need for sufficient transmission capacity to deliver energy between power plants and customers under all conceivable generation and load patterns. Supply is deficient or inadequate when the available generation capacity is less than the system load and associated generation reserve requirements. Transmission systems that constrain the delivery of energy under certain configurations or operating conditions are also viewed as inadequate. The degree of inadequacy is measured by the magnitude of the constraint or the frequency and duration of the constraint.

The NERC definition of Security is "The ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements." Security of a system is judged by its ability to accommodate the loss of a single system element, including its largest single hazard: a generator, transmission line or transformer. This is referred to as a single contingency criteria or N-1 criteria. The system is judged to be secure if the system response to even the most critical single contingency is such that system adequacy is maintained and system parameters such as frequency, voltage and power flows remain within predetermined acceptable ranges. System security is achieved by maintaining sufficient generation reserves and sufficient transmission capacity throughout the electric system to enable loss of the most critical single contingency while maintaining an adequate system supply and delivery of energy to all customers. A higher level of system security is achieved when an adequate supply and delivery of energy to consumers is maintained for disturbances involving the loss of multiple system components.

However, Staff contends that the above definitions of “transmission adequacy” and “security” are not suited to the restructured electric industry. These definitions also do not take into consideration the environmental impact of older and more polluting generation. Furthermore, the regional and federal reliability criteria do not apply to the internal systems of utilities. In order to address these shortcomings and enable effective competition in the State of Arizona, Staff has developed the following two different standards due to the different environment of electric restructuring, for measurement of transmission adequacy and security:

1. 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.

    Staff is not suggesting that local generation or distributed generation should be excluded from a utility's resource mix. This is evidenced by the fact that Staff has supported local generation in the siting hearings for the Kyrene and Santan plants**.** Staff did not intervene in the West Phoenix siting hearing, but staff supports the project.

2. 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.

Staff believes that the better approach is to have standards of measuring transmission capacity instead of merely defining the terms “transmission adequacy” and “security.”

In addition, WSCC's Minimum Operating Reliability Criteria (revised August 8, 2000) states, "[a] single contingency means the loss of a single system element, however, the outage of multiple system elements should be treated as a single contingency if caused by a single event of sufficiently high likelihood". Staff has concerns with any utility placing multiple transmission lines, serving the same load, in a common corridor that could be interrupted by a single event. However, this concern must be balanced with the public’s interest in developing multiple utility corridors. There needs to be a balance between the environmentally driven practice of siting new lines adjacent to existing corridors and the increased system reliability by opening up new corridors

Staff does not believe that requiring generators to demonstrate, prior to receiving siting approval, the existence of available transmission capacity to reliably deliver their power to market without adverse effects to the state’s transmission grid in any way exceeds the Commission’s jurisdiction. Nor does Staff believe that requiring such a demonstration is a requirement that “excess transmission” be put in place. On the contrary, Staff believes that requiring generation siting applicants to demonstrate the existence of available transmission capacity to reliably deliver their power to market without adverse effects to the state's transmission grid falls squarely within the Commission's statutory balancing obligations under A.R.S. § 40-360.07.

Staff does not advocate "requiring Arizona consumers to pay for overbuilding transmission to allow every generator to access any market at any time." The Commission stated in its comments to FERC in the "Removing Obstacles" proceeding, Docket No. EL01-047-000 that "there needs to be a distinction between transmission enhancements needed for the purpose of serving local load or giving local markets access to generation, and transmission enhancements needed to facilitate interstate commerce." Staff fully supports that position.

1.3 Framework of Assessment

The adequacy and security of an electric system is demonstrated in an operational context by its real time performance. Adequacy and security of an existing or planned transmission system can not be determined by merely reviewing the Ten-Year Transmission Plans filed with the Commission. The reliability of an existing or planned electric system under existing, alternative or future operating conditions can be determined by technical simulation. Such studies require application of a set of study criteria to measure the system's performance. Staff has developed a set of guiding principles to aid in its determination of adequacy and reliability of power plant and transmission line projects.

The Guiding Principles represent the professional opinion of Commission Staff. At this time, Staff is not recommending that the Guiding Principles become Commission Rules. Clearly it is within the Commission's jurisdiction to direct a Rulemaking Docket to be opened so that the Guiding Principles could be codified. A copy of these guiding principles is attached as Appendix A.

Staff's guiding principles are based upon best engineering practices established in Arizona coupled with use of regional[3] and national reliability council[4] criteria and standards. Staff surveyed utilities operating in Arizona to establish the state's best engineering practices[5] relative to power plant switchyard bus configurations and the pre-requisite number of transmission lines emanating from such switchyards. Staff used these guiding principles, criteria and standards for this biennial transmission assessment.

To perform technical studies necessary for a biennial transmission assessment, one needs data regarding existing and planned generating plants and transmission facilities, and load and resource patterns to be simulated. Computer hardware and software are also needed to model the electric system being studied. Finally, human resources to staff such technical studies must also be arranged. These study requirements can result in a significant budgetary obligation for an organization. Unfortunately, the state statute placing the obligation for a biennial transmission assessment with the Commission made no provision for the aforementioned technical study pre-requisite data or budgetary funds for computer hardware, software and personnel.

[3] WSCC Reliability Criteria found at http://www.wscc.com

[4] NERC Planning Standards found at http://www.nerc.com

[5] Staff Comments filed for the Gila Bend Power Plant hearing, Docket No. L-00000V-00-0106

The Commission does not have the means to perform it own independent technical studies. Therefore, Staff reviewed reports and technical study results of other parties and relied upon the authors' industry experience and knowledge of Arizona's transmission system to fulfill its statutory obligations to provide a biennial transmission assessment of Arizona's existing and planned transmission facilities. Staff was able to assemble and review a broad spectrum of information and technical reports addressing transmission assessments from a national, Western Interconnection (WI), regional, state and local utility perspective. All referenced technical material is listed in this report's bibliography. Such reports may not always be present in such abundance in the future. Therefore, due consideration should be given to data and budgetary pre-requisites for biennial transmission assessments if Staff is to perform independent technical studies in the future.

1.4 Rating of Transmission Lines and Paths

Transmission facilities are rated in a variety of ways. Each transmission line or device has a thermal rating based upon its current carrying capacity measured in amperes. Such ratings are often converted to common power ratings in units of megawatts (MW) or megavolt-amperes (MVA) at nominal system voltage typically measured in kilovolts (kV). Thermal ratings are time dependent and may range from a short time emergency rating to a continuous rating. Such ratings are also dependent upon ambient weather and atmospheric conditions.

A series of devices are generally connected to either end of transmission lines for switching, protective control, voltage control, or metering purposes. The most restrictive device rating in series with the transmission line establishes the thermal rating used for that transmission line. The thermal ratings for many existing Arizona transmission lines are listed in Appendix B. These ratings were extracted from a Palo Verde Interconnection Study report.

Another means of rating transmission facilities is by determining the stability limit for a group or set of lines. A stability limit is established via technical studies that determine the maximum power that can be transferred over the group of lines. An electric system is considered stable when excursions in frequency, power and voltage remain within predetermined ranges over time during changing operating conditions or system disturbances.

A grouping or set of transmission lines is often referred to as a transmission path. Transmission paths consist of multiple transmission lines emanating from a common location or between two regions. The performance of each transmission line within a transmission path is interdependent upon the performance of other lines in the same path. The adequacy and security of the whole transmission system is often determined by the performance of key and critical transmission paths.

Transmission lines and paths are also rated in terms of their Total Transfer Capability (TTC). The TTC is the reliability limit of a transmission line or path at any point in time. This rating is established by technical studies that consider the network topology and operational conditions affecting the adequacy and seurity of the transmission line or path. The thermal rating and the stability limit of transmission lines are both considered when establishing the TTC of transmission facilities. In fact, the WSCC has an established process for determining the TTC of major transmission paths in the western interconnection. The transmission path consisting of lines between Arizona and California has the largest TTC of any established path in the Western Interconnection. The following map depicts the TTC for key WSCC paths.

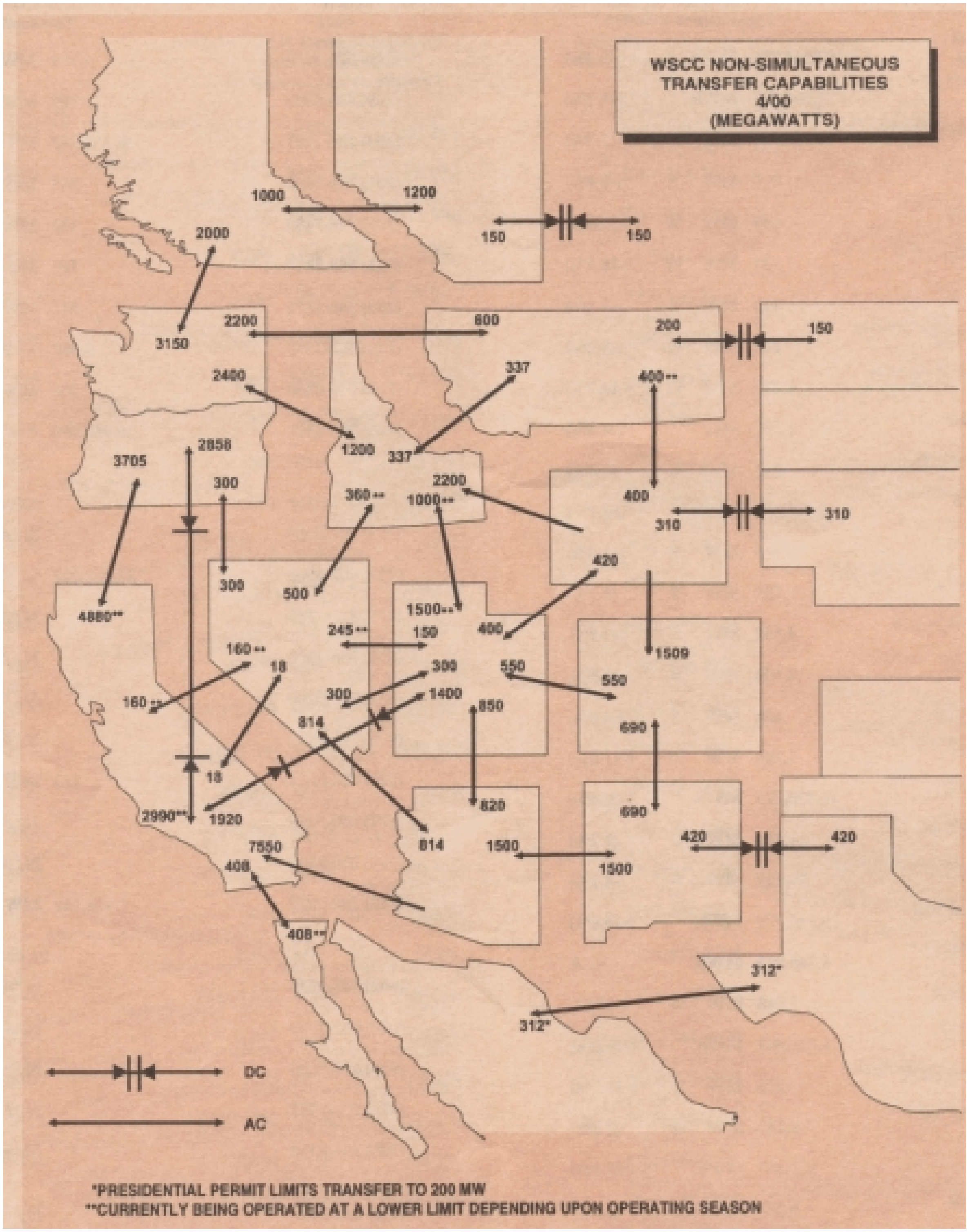

Figure 1

Section 2: Existing Transmission

2.1 Arizona's Best Engineering Practices

Staff has researched and documented the best utility practices of electric utilities that have constructed, owned, and operated power plants within the State of Arizona. On July 19, 2000, Staff formally requested AEPCO, APS, SRP, TEP and WAPA to supply one-line diagrams for each power plant transmission switchyard for which their company was an owner, project participant, or transmission service provider. They were asked to include existing facilities as well as any having an approved Certificate of Environmental Compatibility (CEC). Their responses are summarized in Tables 1 and 2. Copies of one-line diagrams provided by utilities in response to this data request are available from Staff upon request.

The 22 power plants presently located in Arizona consist of 80 generating units of various sizes totaling 15,935 MW of capacity. Arizona utilities own 73% of this capacity (11,708 MW). The remaining capacity is owned by utilities located in other states. The Four Corners and San Juan power plants in this data are physically located just east of the Arizona / New Mexico state line. Staff included these two plants because they play a prominent role in the energy supply and transmission delivery requirements of this state.

Of the 80 generating units located in Arizona, only five units have fewer than three transmission lines or transformer ties emanating from their switchyard. The 13 MW Stewart Mountain hydro unit and the 36 MW Roosevelt hydro unit are shown as having only one line in Table 1. However, the Roosevelt unit is actually connected to Frasier Substation via a single generator tie approximately two miles in length, while the Stewart Mountain unit is connected to Goldfield Substation via a generator tie approximately eight miles in length. Multiple lines and transformer ties are terminated at both Frasier and Goldfield. **From this data it is evident that utility practices in Arizona have resulted in two or more transmission lines or transformer ties emanating from all power plant transmission switchyards.**

In Staff's data request, utilities were also asked to identify what criteria was used to establish the switchyard bus configuration and the number of transmission lines required out of each power plant. A switchyard bus consists of various structural elements to which equipment and lines are connected. The bus configuration and number of transmission lines connected at a switchyard are known to play a significant role in the reliability, maintainability, and operability of a switchyard. The utilities' responses indicate that the generating units outlined in Table 1 have been installed over a large range of years. As one would expect, the switchyard designs have changed over the years. Therefore, the bus configuration and number of transmission lines have been established for each unique power plant situation.

As a general practice, the utilities have designed all facilities in Table 1 in accordance with the applicable WSCC / NERC criteria in existence at the time of construction. Generally, the transmission system must perform in such a manner that loss of one component will not overload any other component and voltages will remain at acceptable levels. However, no specific criterion has dictated the choice of bus configuration. Nor has the industry had specific criteria addressing the minimum number of lines required out of a power plant. Beyond the applicable WSCC / NERC criteria, system design practices have been a discretionary decision driven by a utility's consideration of prevailing planning, engineering, design, operation and business practices that affect its obligation to serve all of its customers in a reliable manner from generator to load.

In addition, utilities were asked to identify any criteria they use to establish the bus configuration and number of lines required out of a switchyard when a party seeks an interconnection. The utilities' responses indicate that no criteria exists that specifies the bus configuration or number of lines required out of a power plant switchyard for requested interconnections. They do however, rely on WSCC and NERC policies and criteria when responding to new interconnection requests.

The aforementioned facts substantiate the appropriateness of the ''Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" provided as Appendix A and used as the foundation for Staff's testimony and recommended conditions in Arizona Power Plant and Transmission Line Siting Committee (Siting Committee) hearings. Staff's position on bus configuration and two or more lines required out of a power plant switchyard is truly based on "best engineering practices" employed by utilities in Arizona over the course of many years of accountability for the reliable supply and delivery of energy to Arizona's consumers.

Jennifer Tripp of R.W. Beck gave expert testimony during the Santan Generating Station Expansion Project hearings that aligns with Staff's conclusions from its investigation of Arizona's Best Engineering Practices. Ms. Tripp was asked during her cross-examination whether she had studied alternative generating sites. Her response was - ''We did not examine other sites as part of our study. However, looking at the transmission system, a standard combined cycle plant would require a minimum of three 230 kV lines or two 500 kV lines. And if you want, we could go back to the figure showing the East Valley, and there's just not many sites there. I mean, you can look and see the map, and there's very few where you would not have to build new transmission."[1] Ms. Tripp's expert testimony serves as further evidence that Staff's position of requiring at least two transmission lines out of new power plants is both reasonable and prudent.

Restructuring the Arizona electric industry for retail competition via a deregulated energy market is no justification for relaxing the best engineering practices established by utilities in Arizona. To do so would jeopardize the present electric service reliability that is essential for Arizona's consumers. Such an approach would simply allow a greater financial gain for merchant power plants. Neither WSCC nor NERC are contemplating relaxing their reliability criteria. In fact, there is considerable political pressure to strengthen national reliability requirements in response to the widespread concern about blackouts that are becoming more prevalent throughout the nation.

[1] Docket No. L-00000B-00-0105, page 436.

Table 1
Summary of Existing Arizona Power Plants

Plant	Switchyard Voltage (kV)	No. Units	Capacity (MW)*	AZ Utility Capacity (MW)*	AZ Utility Capacity (%)	No. Lines / Xfrm Ties
Agua Fria	230	3	142	142	100.00%	7
	69	3	407	407	100.00%	6
Apache	230	2	350	350	100.00%	4
	115	2	140	140	100.00%	5
	69	2	30	30	100.00%	4
Cholla	500	3	995	615	61.81%	4
	230	1	116	116	100.00%	4
Coronado	500	2	730	730	100.00%	4
Four Corners	500	1	740	587	79.32%	2
	345	1	740	587	79.32%	8
	230	3	560	560	100.00%	7
Fairview	69	1	16	16	100.00%	1
Horse Mesa	115	4	128	128	100.00%	3
Irvington	138	4	310	310	100.00%	10
	46	2	162	162	100.00%	15
Kyrene	230	2	101	101	100.00%	11
	69	3	163	163	100.00%	9
Mormon Flat	115	2	58	58	100.00%	2
Navajo	500	3	2,255	1,522	67.49%	3
North Loop	46	3	73	73	100.00%	6
Ocotillo	230	1	54	54	100.00%	7
	69	3	275	275	100.00%	6
Palo Verde	500	3	3,810	2,377	62.39%	5
Roosevelt**	115	1	36	36	100.00%	1
Saguaro	115	4	313	313	100.00%	12
San Juan	345	4	1,614	314	19.45%	7
Santan	230	2	157	157	100.00%	5
	69	2	156	156	100.00%	9
Springerville	345	2	800	800	100.00%	6
Stewart Mountain***	115	1	13	13	100.00%	1
Yucca	69	5	173	98	56.65%	4
W. Phoenix	230	3	240	240	100.00%	3
	69	3	94	94	100.00%	6
22 Plants Total		**81**	**15,951**	**11,724**	**73.50%**	

* Per WSCC Existing Generation Data Base
** Gen tie connected to Fraiser Sub which has two 115 kV lines
*** Gen tie connected to Goldfield Sub having two115 kV lines & two 115/230 kV transformers

It is anticipated there will be five merchant power plants operating in Arizona, the summer of 2001. The merchant power plants are:

Griffith located southwest of Kingman.
Southpoint located north of I-40, near the California border.
Desert Basin located northwest of Casa Grande.
West Phoenix located in southwest Phoenix
Yuma Cogeneration Associations power plant in Yuma.

Table 2
Summary of Proposed Arizona Power Plants
2/26/2001

Plant	Switchyard Voltage (kV)	No. Units	Capacity (MW)*	Plant/Line CEC Status	ACC Decision No.(s)	No. Lines / Xfrm Ties
AES La Paz County	500	4 CC	2,000	Announced		2
Arlington Valley	500	1 CC	580	Approved	62740	5
Big Sandy	500	2 CC	720	Pending		2
Desert Basin	230	1 CC	520	Approved	61852/62426	2
Gila Bend	500	1 CC	845	Approved		1
Gila River	500	4 CC	2,080	Approved	62730	3
Griffith	230	1 CC	520	Approved	61295	3
Harquahala	500	4 CC	1,040	Approved	62655	1
Kyrene	230	1 CC	250	Approved	62989	2
Mesquite	230	4 CC	1,250	Approved	63232	1
Montezuma	500	1 CC	520	Announced		2
Redhawk	500	4 CC	2,120	Approved	62324	2 or more
Santan	230	2 CC	825	Pending		5
Toltec	500	4 CC	2,000	Announced		2
W. Phoenix	230	2 CC	650	Approved	62321	5
South Point	230	1 CC	540	NA	NA	2
Sun Dance	230	8 CT	580	Pending		2
17 Plants Total		**45**	**17,040**			

* Per CEC Application or ACC Decision

Table 2 reveals that Arizona is undergoing a major shift in its ownership and operation of power plants. All but two of the 17 proposed plants will be merchant plants or owned and operated by an affiliate of an ACC rate regulated utility. These 17 plants consist of 45 new combined cycle units or combustion turbines with an aggregate capacity of 17,040 MW. A combined cycle unit consists of a combination of combustion turbine generator units and a steam turbine generator unit. The aggregate capacity of the proposed plants is equivalent to the existing load in the State of Arizona and roughly one third greater then the load growth projected for the Desert Southwest region over the next decade.

As of June 2001, three of the twelve approved power plants have single lines. Over one half of the proposed plants have an ACC decision approving their CEC with conditions. Staff's intervention in siting cases commenced with the Pinnacle West Energy Corporation (PWEC) Redhawk hearing.[2] The PWEC Redhawk project has committed to two or more lines emanating from the plant. At the time Table 2 was created, Sempra's Mesquite project and the Gila Bend power plant project were the only proposed projects that continue to challenge Arizona's established best engineering practice of multiple lines out of a power plant switchyard.

Staff has consistently taken the position that two or more transmission lines are required out of each plant's switchyard to meet a single contingency ("N-1") criteria without relying on remedial action such as generator tripping or load shedding. The evidence in Table 2 is an indicator that there is support of this practice even when Staff is not involved. Now is not the time to relax our reliability standards. It is interesting that all of the projects that have proposed a single transmission line have also sought an interconnection at the Palo Verde satellite switchyard named "Hassayampa."

2.2 Southern Arizona Transmission Study

The City of Nogales and customers in Santa Cruz County filed complaints with the ACC in 1999 regarding ongoing quality of service problems prevalent in Citizens Utilities Company's (CUC) electric system. The frequency and duration of outages caused by loss of the single 115 kV transmission line serving Santa Cruz County was no longer acceptable to CUC's customers. Staff investigated the complaints and found CUC's Electric Service Plan of distribution system upgrades to be appropriate, but not attendant to the root cause of prolonged customer outages. Staff judged CUC's single transmission line as deficient in delivering adequate and secure energy needs to its customers in Santa Cruz County. Therefore, the ACC ordered[3] CUC to construct a second transmission line to Nogales by December 2003.

On June 22, 1999, the Southeastern Arizona utilities experienced an extended outage affecting most communities in Southern Arizona. This caused Staff to take a closer look at the transmission system serving those communities. The transmission system serving Southeastern Arizona is depicted in Figure 2. It should be noted that the communities of Sierra Vista, Bisbee, Douglas, and Ft. Huachuca are each served by radial transmission lines rather than lines interconnected and operated as a network. For this reason, the ACC held a special open meeting in Tucson on August 19, 1999 for the purpose of discussing regional operational experiences, transmission constraints and transmission plans of utilities in Southern Arizona. Parties in attendance committed to completing a Southeast Arizona Regional Transmission Study that was in progress and to report their findings to the ACC.

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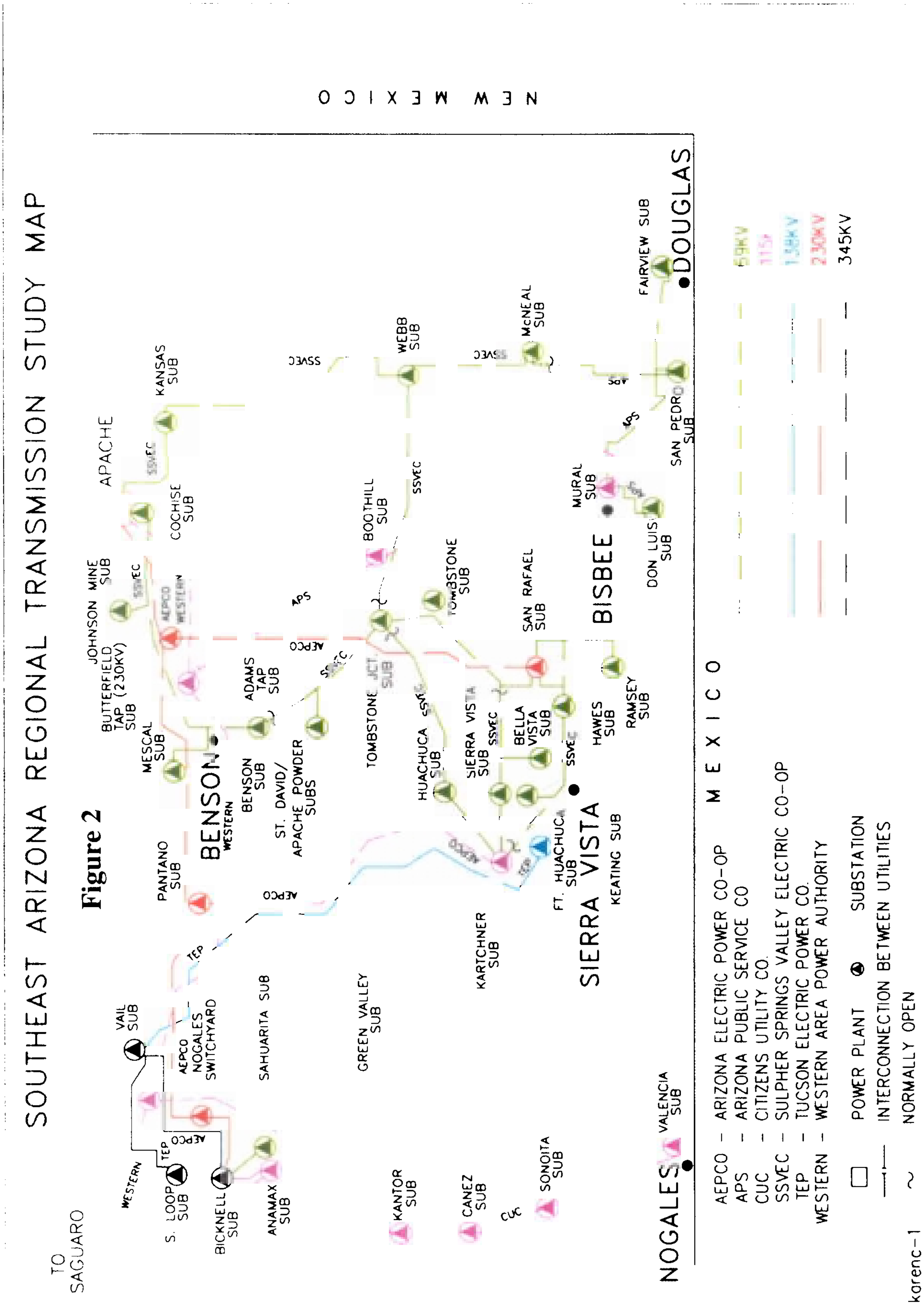
[2] Docket No. L-00000J-99-0095, ACC Decision No. 62324.

[3] Docket No. E-01032A-99-0401, Decision No. 62011, November 2, 1999.

Figure 2


SOUTHEAST ARIZONA REGIONAL TRANSMISSION STUDY MAP
TO SAGUARO
NEW MEXICO
MEXICO
NOGALES
BENSON
SIERRA VISTA
BISBEE
DOUGLAS
APACHE
VAIL SUB
S. LOOP SUB
BICKNELL SUB
ANAMAX SUB
AEPCO NOGALES SWITCHYARD
SAHUARITA SUB
GREEN VALLEY SUB
KANTOR SUB
CANEZ SUB
SONOITA SUB
VALENCIA SUB
PANTANO SUB
KARTCHNER SUB
FT. HUACHUCA SUB
KEATING SUB
MESCAL SUB
BUTTERFIELD TAP (230KV) SUB
JOHNSON MINE SUB
BENSON SUB
ST. DAVID/ APACHE POWDER SUBS
ADAMS TAP SUB
COCHISE SUB
KANSAS SUB
TOMBSTONE JCT SUB
BOOTHILL SUB
TOMBSTONE SUB
HUACHUCA SUB
SIERRA VISTA SUB
BELLA VISTA SUB
HAWES SUB
RAMSEY SUB
SAN RAFAEL SUB
WEBB SUB
MURAL SUB
DON LUIS SUB
McNEAL SUB
SAN PEDRO SUB
FAIRVIEW SUB
WESTERN
TEP
AEPCO
APS
SSVEC
CUC
AEPCO - ARIZONA ELECTRIC POWER CO-OP
APS - ARIZONA PUBLIC SERVICE CO
CUC - CITIZENS UTILITY CO.
SSVEC - SULPHER SPRINGS VALLEY ELECTRIC CO-OP
TEP - TUCSON ELECTRIC POWER CO.
WESTERN - WESTERN AREA POWER AUTHORITY
POWER PLANT
SUBSTATION
INTERCONNECTION BETWEEN UTILITIES
NORMALLY OPEN
69KV
115KV
138KV
230KV
345KV
karenc-1

On June 8, 2000, a number of utilities met with Staff to present and discuss the results of a Southeastern Arizona Regional Transmission Study report dated March 2000. The study participants included AEPCO, APS, CUC, PNM, TEP, and WAPA. The study encompassed the area east of Interstate 19 and south of Interstate 10. A variety of system improvements were studied and conclusions and recommendations are summarized below for each utility's service area.

APS serves the communities of Douglas and Bisbee via a 115 kV line from Adams Substation east of Benson. The study concludes the best solution for loss of the 115 kV line is to use the 16 MW Fairview Generator to restore service and close two 69 kV tie lines to Sulphur Springs Valley Electric Cooperative's (SSVEC) system. Remote operational control of equipment enables closing the two 69 kV ties: 1) the SSVEC 69 kV tie line from Tombstone Junction Substation to Webb Substation and 2) the APS 69 kV tie line between McNeal Substation and APS San Pedro Substation. Addition of 18 MVAR of 69 kV capacitors at the Mural Substation in 2001 is needed to maintain the proper voltage profile during outages.

AEPCO is the transmission provider for SSVEC's southern system serving Sierra Vista and surrounding communities. SSVEC's southern system is served by four transmission lines: 1) an AEPCO 230 kV line from Butterfield Substation east of Benson to San Rafael in Sierra Vista; 2) an AEPCO 115 kV line from Pantano Substation west of Benson to Kartchner Substation in Sierra Vista; 3) a SSVEC 69 kV line from Benson Substation to Tombstone; and 4) a SSVEC 69 kV line from Apache Generating Plant to Webb Substation. Each line is operated as a radial line with the ability to restore service by switching to another line. The study reports these four lines will provide reliable transmission service for the next ten years with the addition of a shunt capacitor at Kartchner by 2005 and a second transformer at Kartchner by 2009.

TEP serves Ft. Huachuca via a 138 kV line from Vail Substation southeast of Tucson. A 46 kV line backs up the 138 kV line from South Loop Substation. The study reports these two lines provide adequate service to Ft. Huachuca through 2009. As the study was being finalized, TEP indicated a potential transmission tie was being considered with Mexico. If TEP moves forward with the project, they will identify impacts of such a project on the results of this study.

The Southeastern Arizona Regional Transmission Study investigated numerous alternative transmission lines to Nogales as a means of increasing service reliability to CUC customers in Santa Cruz County. The most economical alternative studied was a new 115 kV line from either of AEPCO's Pantano or Bicknell substations. The best technical alternative was a 345/115 kV interconnection with TEP at its Vail Substation and a second 115 kV line to CUC's Valencia Substation. A Valencia 345 / 115 kV interconnection to PNM's proposed 345 kV tie to Mexico was found to perform well at lower power transfer levels to Mexico. Additional studies are required to determine the affect of operating CUC's 115 kV system in parallel with a 345 kV tie to Mexico with high levels of power transfer.

It is Staff's opinion that the Southeastern Arizona Regional Transmission Study was effective in establishing a sound operational plan for the region. The operational plan is based upon continuation of a common practice of restoring customer service following a transmission line outage by reconfiguring the system with service provided by an alternative transmission line.

However, if the frequency or duration of outages becomes onerous, then customers are likely to file complaints with the Commission, as was the case for CUC customers in Santa Cruz County. CUC does not have the capability to close tie lines to other systems and therefore a second transmission line to Nogales is warranted.

Staff remains concerned that customers in the region are vulnerable to interruptions of service because of transmission line outages. This fact alone means the transmission system is not adequate and secure. This is especially disconcerting when the existing system could be operated as an interconnected network with minor system improvements, such as switch and circuit breaker upgrades, and thereby truly comply with the WSCC transmission reliability requirements. Customers of Southeastern Arizona would benefit from such a change in system operation practices.

Staff has not proposed a "perfect" level of reliable service, but contends continuity of service should be the standard for level of service provided, and reflects the WSCC's Minimum Operating Reliability Criteria, PHILOSOPHY OF CRITERIA, which states:

> C**ontinuity 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. Although 100 percent reliability of power supply is impossible, each system will, insofar as practical, protect its customers against loss of service.** [Page III- 6; section 2.0; revised August 8, 2000]

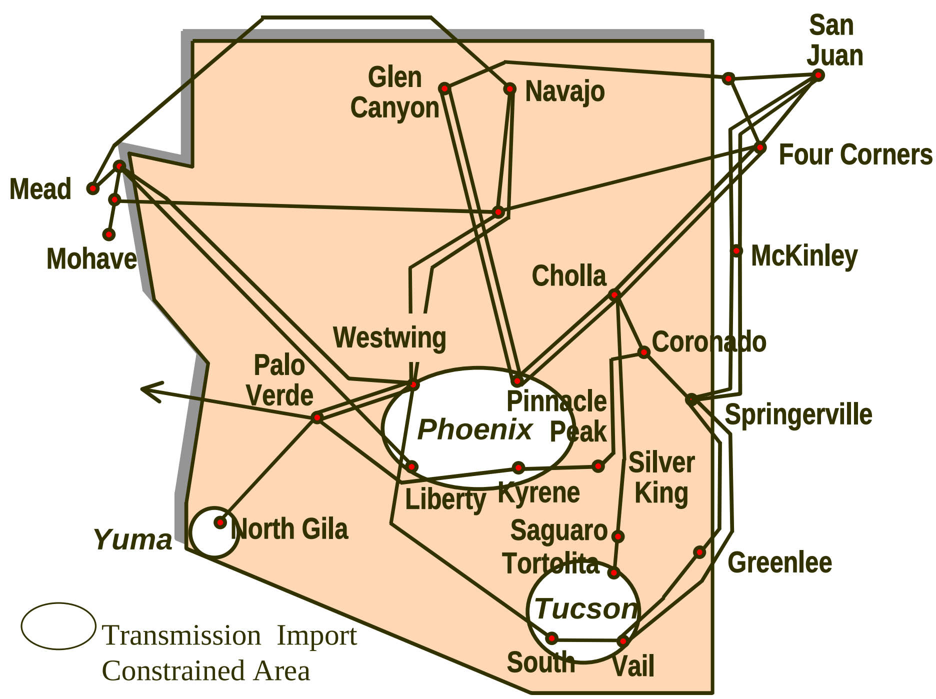
Staff agrees that in some circumstances, radial service is the most cost-effective service available to certain loads, but continues to assert that continuity of service should be the level of service to strive for.

2.3 Local Transmission Import Constraints

The next two or three years will be a critical period for Arizona electric utilities. The state currently has three local transmission import constrained areas: 1) the Phoenix metropolitan area served by APS and SRP; 2) the Tucson metropolitan area served by TEP; and 3) the Yuma area served by APS. These transmission import constrained areas are depicted in Figure 3. During peak load periods, energy consumption in each of the three transmission import constrained areas exceeds the respective utility's transmission import capability. On such occasions, utilities rely on local generation to meet their load requirements. As a last resort, utilities consider rolling blackouts in order to ensure system security if sufficient local generation is unavailable to meet its load requirements in excess of its transmission import capability.

All three utilities have been forthright in their declaration of current energy delivery constraints within their respective transmission systems. The Phoenix load zone has an APS transmission import capability of 2870 MW and a SRP import capability of 3625 MW. TEP's transmission import capability for Tucson is 1350 MW. The Yuma area has an APS transmission import capability of 175 MW.

Figure 3
Arizona EHV Transmission System



APS reported its exposure period requiring local generation for Summer 2000 was estimated to be 400 to 500 hours. The hours of exposure will increase as each transmission constrained area's population grows and the existing transmission system becomes loaded at its capacity for longer periods of time. Furthermore, local generating units are limited in the amount of power they can produce. APS and SRP explained at the Commission's Summer Peak 2000 Preparedness Workshop, held on May 17, 2000, that they would have to utilize all existing local generating units the summer of 2000 and could maintain sufficient local reserves to accommodate the loss of the largest local generating unit. SRP reported it would have the ability to accommodate loss of an additional 28 MW of local generation beyond the largest local unit. APS indicated that for Year 2000, the local load serving capability was 125 MW greater than the forecasted load. The collective local generation cushion of 153 MW for Summer 2000 allows very little margin for error in load forecasting. Therefore, both utilities took precautionary steps to prepare emergency operation plans that included provisions for rolling blackouts if circumstances dictated that action was necessary.

The Phoenix area is growing at a rate of approximately 500 MW annually. The collective unused local generating capacity (153 MW) in Summer 2000 falls short of accommodating this year's growth. Additional transmission lines, new local generating units or a combination of both must be built before the load exceeds the aggregate capacity of local generating units and the transmission system. SRP's transmission import limit has increased from 3,625 MW (year

2000) to 4,134 MW (year 2001) for a net improvement of 509 MW. This conclusion also applies to the Tucson and Yuma constrained areas. Otherwise, Arizona's three transmission import constrained areas will be subject to rolling blackouts. It is Staff's opinion that there is a small possibility that such an occurrence could happen in the Phoenix area during the summer of 2001 with an increasing likelihood in 2002. This exposure exists even with the timely expansion of West Phoenix and Kyrene power plants if no new EHV transmission lines are constructed and terminated in the Phoenix metropolitan area.

2.4 Palo Verde Interconnection Study

The Palo Verde Generating Station is located approximately 35 miles southwest of the Phoenix metropolitan area. It is comprised of three nuclear generating units with a net output of approximately 1270 MW each. The Palo Verde transmission system consists of five 500 kV transmission lines and is depicted in Figure 3. There are three lines to the Phoenix metropolitan area, one to Yuma and one west to California. The Palo Verde Switchyard is a commercial energy-trading hub for the Western Interconnection. For this reason, numerous new power plants and transmission line projects are proposing to interconnect with the Arizona Nuclear Power Project (ANPP) at this location.

Power plants and transmission projects proposing to interconnect at Palo Verde officially posted their requests on the Transmission Provider's OASIS web site. This initiated a FERC defined process requiring Transmission Provider's to perform System Impact Studies and Facility Studies for the interconnecting parties within a defined time period. In order to achieve an approval from the ANPP owners to interconnect to the Palo Verde Switchyard, technical studies and their subsequent approval by the ANPP owners are required. Palo Verde Interconnection Procedures also requires interconnecting parties (Interconnectors) to work with the Western Arizona Transmission System (WATS) Task Force in the performance of all technical studies, including the development of base cases, study plans, as well as the final review and acceptance of all technical study results.

At the time the study was initiated, there were ten interconnections being proposed for the Palo Verde 500kV Switchyard and the Palo Verde Transmission System Facilities. The ten proposed interconnections are summarized in Table 3 in the order in which the interconnection requests were received.

It was determined that a new 500kV switchyard, called Hassayampa, would need to be developed adjacent to the existing Palo Verde 500 kV switchyard to accommodate all of the proposed interconnections. Since the summer of 1999, the Interconnectors have worked with the ANPP owners to determine the switchyard arrangement and to develop an interconnection agreement between the Interconnectors and ANPP owners. The Interconnectors subsequently requested SRP to perform the required technical analysis on their behalf. Since the inception of the study effort, five of the original ten Interconnectors eventually elected to not participate in the initial development of the Hassayampa Switchyard. The Interconnectors choosing to not interconnect at this time are Delta Power Company, PNM / Merchant, NRG Energy Inc., APS / SRP Transmission, and Panda Gila River, LLP. The proposed Hassayampa Switchyard configuration is provided as Figure 4.

Table 3
Requested Transmission Interconnections

Company	Interconnection	Capacity (MW)	Interconnection Points	In-Service Date
PNM/Merchant	Lines	1000	PV-Santa Ana (Noroeste)	Summer 2002
APS/SRP Transmission	Line	1200	PV-Estrella	Summer 2003
PG&E Generating	Generation	1160	Harquahala-Palo Verde	May 2002
APS Generating	Generation	2000	Red Hawk – PV	January 2002
NRG Energy Inc.	Line	1000	PV-CFE CETYS (Baja)	Spring 2002
Sempra Energy Resources	Generation	1000	Mesquite– PV	June 2003
Duke Energy	Generation	650	Arlington–PV	June 2002
Power Development Enterprises	Generation	550-770	Gila Bend Area-PV	3rd Qtr. 2003
Delta Power Company	Generation	500	PV-Devers &/or PV-N. Gila	Unknown
Panda Gila River, LP	Generation	2000	Gila Bend Area-PV	June 2002

SRP issued a report dated December 2000 documenting the most recent Palo Verde interconnection studies. The most recent studies were performed with each proposed generating unit modeled with voltage regulation capability. The studies indicate the existing available Palo Verde transmission capacity is dependent upon the number of individual generating units that are in operation. The existing transmission system can accommodate 1800 MW to 3360 MW of new generation schedules out of the Palo Verde area. With 11 new generating units in operation, the additional available transfer capacity (ATC) is 1800 MW. This capacity is over and above the 3810 MW of transmission capacity committed for the Palo Verde units. The ATC can be increased to 3360 MW with all 37 proposed generating units in service. These levels of ATC are achieved as a result of the proposed generating units supplying reactive power support, ranging from 1300 to 3937 MVAR, that helps maintain system stability during major disturbances.

The addition of the proposed new generation will not exceed the fault duty capability of the 500 kV breakers at Palo Verde. Nor does the addition of the proposed new generation adversely impact the Palo Verde, Arizona, or WSCC Path 49 East of the River (EOR) transmission system or the Palo Verde plant. However, in the absence of additional transmission facilities or upgrades, the power plants proposing to interconnect at Palo Verde have a total output exceeding the maximum 3360 MW of additional power the existing Palo Verde transmission system can accommodate. Therefore, a curtailment procedure must be developed prior to the interconnection of new generation.

Table 4
Installed New Reactive Var Support Versus Scheduled Generation[1]

Number of New Units[2]	Installed Capacity		Constraint
	Reactive Capability Mvar	New Generation MW	
37	3937	3360	Stability/Power Flow
19	2259	2500	Stability
11	1300	1800	Stability

[1]Results with Existing System Transmission Configuration
[2]The aggregate of combustion turbine generators and steam turbine generators forming the various combined cycle generating units proposed by the seven new power plants.

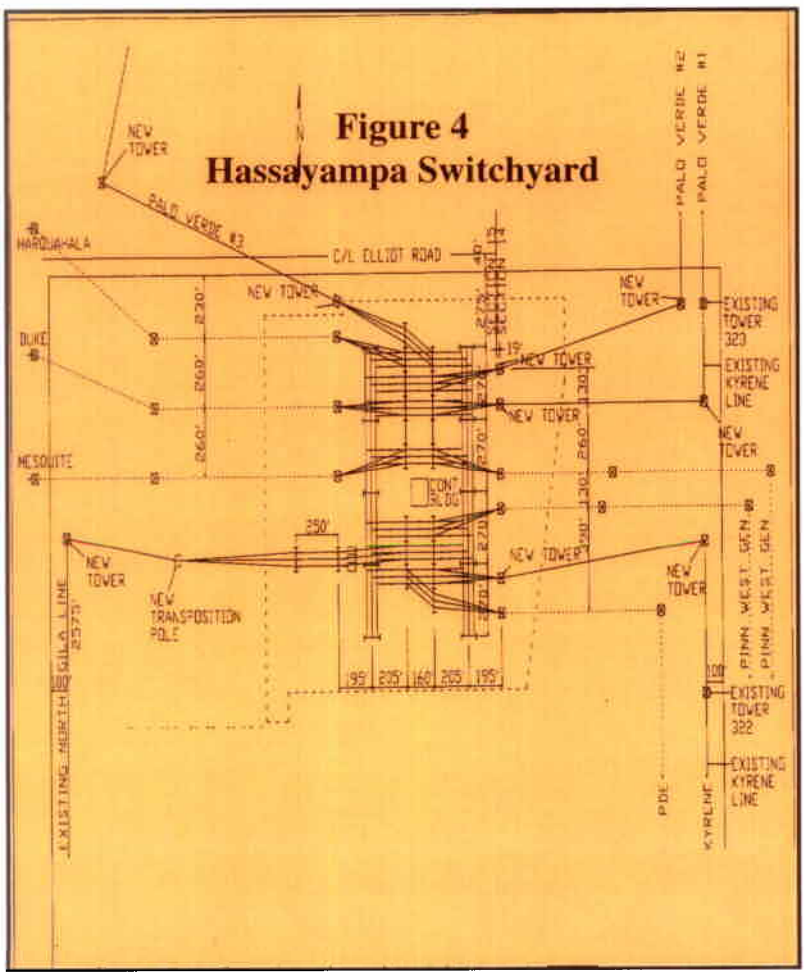


Figure 4
Hassayampa Switchyard

The ability to transmit power from Palo Verde and Hassayampa is dependent upon the pre-existing power flow on the EOR transmission lines. The least amount of power that can be scheduled out of Palo Verde and Hassayampa occurs when new generation is only scheduled to the west with the EOR path heavily stressed. The most power that can be scheduled out of Palo Verde and Hassayampa occurs when new generation is scheduled both to the east and west with the EOR system lightly loaded. As a result, generation scheduling capability out of Palo Verde and Hassayampa will vary depending on where the power is being scheduled and depending on the pre-existing loading of the EOR system.

The following conclusions concerning the existing Palo Verde transmission system were also derived from the results of the study. The capability of the existing transmission system is sufficient to accommodate the full output of existing generation at Palo Verde. Neither the outage of two Palo Verde-Westwing 500 kV lines nor the outage of two Palo Verde generators causes Palo Verde plant instability or Malin Substation voltage instability in the Pacific Northwest. Analysis also shows:

1. Adding new generation at Palo Verde / Hassayampa improves post transient performance at Palo Verde for all critical contingencies.
2. The stability limit is determined by a three-phase fault on the Palo Verde 500 kV bus cleared by loss of both Palo Verde-Westwing 500 kV lines. This stability limit is a function of the number of generating units on line and the transmission configuration at Palo Verde / Hassayampa. However, it is independent of EOR and Southern California Interconnected Transmission (SCIT) power transfer levels.
3. The loss of both Palo Verde–Westwing 500 kV lines is the most severe contingency when the Arizona and Palo Verde transmission systems are stressed. The loss of two Palo Verde units is the most severe contingency when both the Palo Verde system and the California Oregon Intertie (COI) path are stressed. Both of these disturbances have a significant impact on voltage dip requirements at critical Northwest locations such as Malin Substation.
4. The addition of new generation in the Palo Verde / Hassayampa vicinity will reduce the possibility of a potential voltage collapse problem in the Northwest in the event of an outage of two Palo Verde generators during EOR, SCIT and COI high simultaneous power transfers.

2.5 Western Interconnection Transmission Paths Assessment

A report entitled “Western Interconnection Biennial Transmission Plan” was issued in July 2000 by the Northwest Regional Transmission Association (NRTA), the Southwest Regional Transmission Association (SWRTA), and the Western Regional Transmission Association (WRTA) in cooperation with the Western Systems Coordinating Council (WSCC), the Committee on Regional Electric Power Coordination (CREPC), and the Colorado Coordinated Planning Group (CCPG). It documents an assessment of commercial uses of the Western Interconnection system during the Winter 98-99, Spring 99, and Summer 99 seasons. Staff has extracted information applicable to commercial uses of Arizona’s transmission facilities from that report and summarizes key findings in this subsection of our report.

The report documents transmission path utilization in the Western Interconnection using two indices: 1) the percentage of time the path exceeds 75% of its Operating Transfer Capability

(OTC), and 2) the percentage of time the path exceeds 90% of its OTC. Figure 5 depicts the transmission paths evaluated in the report. The paths of interest to Arizona are defined below.

Table 5
WSCC Paths in Arizona

WSCC Path #	WSCC Path Name
22	Southwest of Four Corners
23	Four Corners 345/500 kV Qualified Path
49	East of Colorado River (EOR)
50	Cholla - Pinnacle Peak
51	Southern Navajo

Figures 6, 7, and 8 depict the path utilization information available for paths of interest to Arizona. Path 22 consisting of lines west of Four Corners has historically been the most heavily used in Arizona. The posted WSCC path rating for this path is 2,325 MW. Actual flow and net schedules were the heaviest on this path during the Summer Light Load condition. Actual flow exceeded 75% of path rating, 60% of the time during this period. Actual flows and net scheduled flows are less than 90% of path rating during Winter and Spring conditions, but exceeded 90% of path rating 14% of the time during Summer Light Load conditions.

The reported Path 22 assessment is validated by the actual occurrence of ten unscheduled flow mitigation events over this path in 1999 that resulted in 62 hours of phase shifter operation and ten hours of schedule curtailments in September 1999. Path 23 (Four Corners 345/500 kV transformer) also experienced seven unscheduled flow mitigation events that resulted in 62 hours of phase shifter operation and two hours of schedule curtailment between December 1999 and February 2000.

Path 49 between Arizona and California was reported as lightly loaded for the three seasons investigated by the Western Interconnection biennial transmission assessment. A quite different conclusion can be drawn from Figure 9. It documents the actual hourly flow on Path 49 during the week of December 2 - 9, 2000. California experienced its first Stage 3 alert on Thursday of that week. Path 49 flows continuously ranged between 90% and 75% of the paths 7550 MW OTC rating on a daily basis for that week.

Information from each Transmission Provider's Open Access Same Time Information System (OASIS) web site was gathered during April 2000 as part of the Western Interconnection biennial assessment. The OASIS web site is the online transmission reservation system required of each Transmission Provider by FERC Order 888. The OASIS information provides an indication of whether a path is fully subscribed or if there is long-term firm capacity available for the period 2000 and 2001.

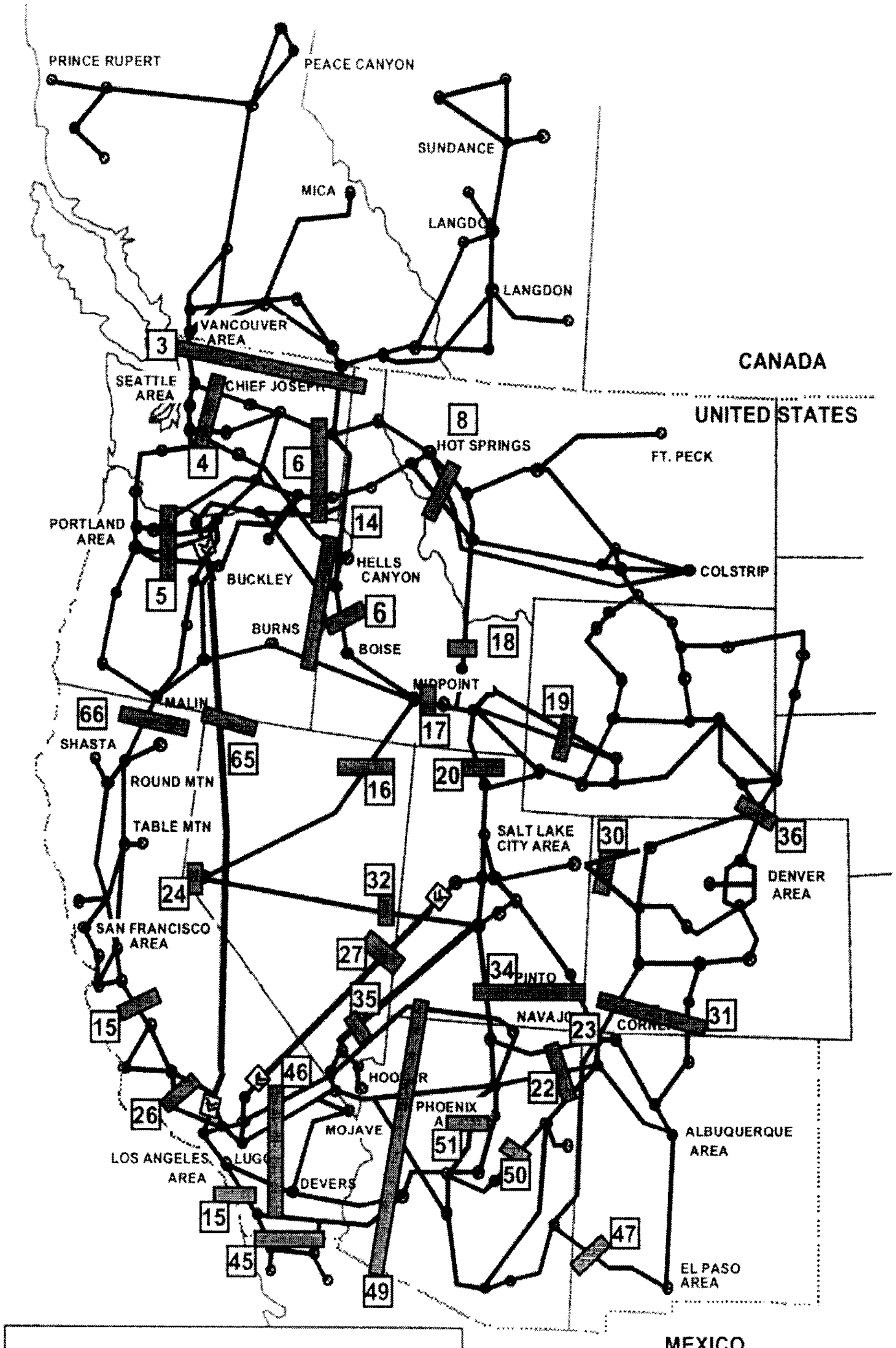


Figure 5

LOCATION OF TRANSMISSION PATHS ANALYZED IN BIENNIAL PLAN

Figure 6

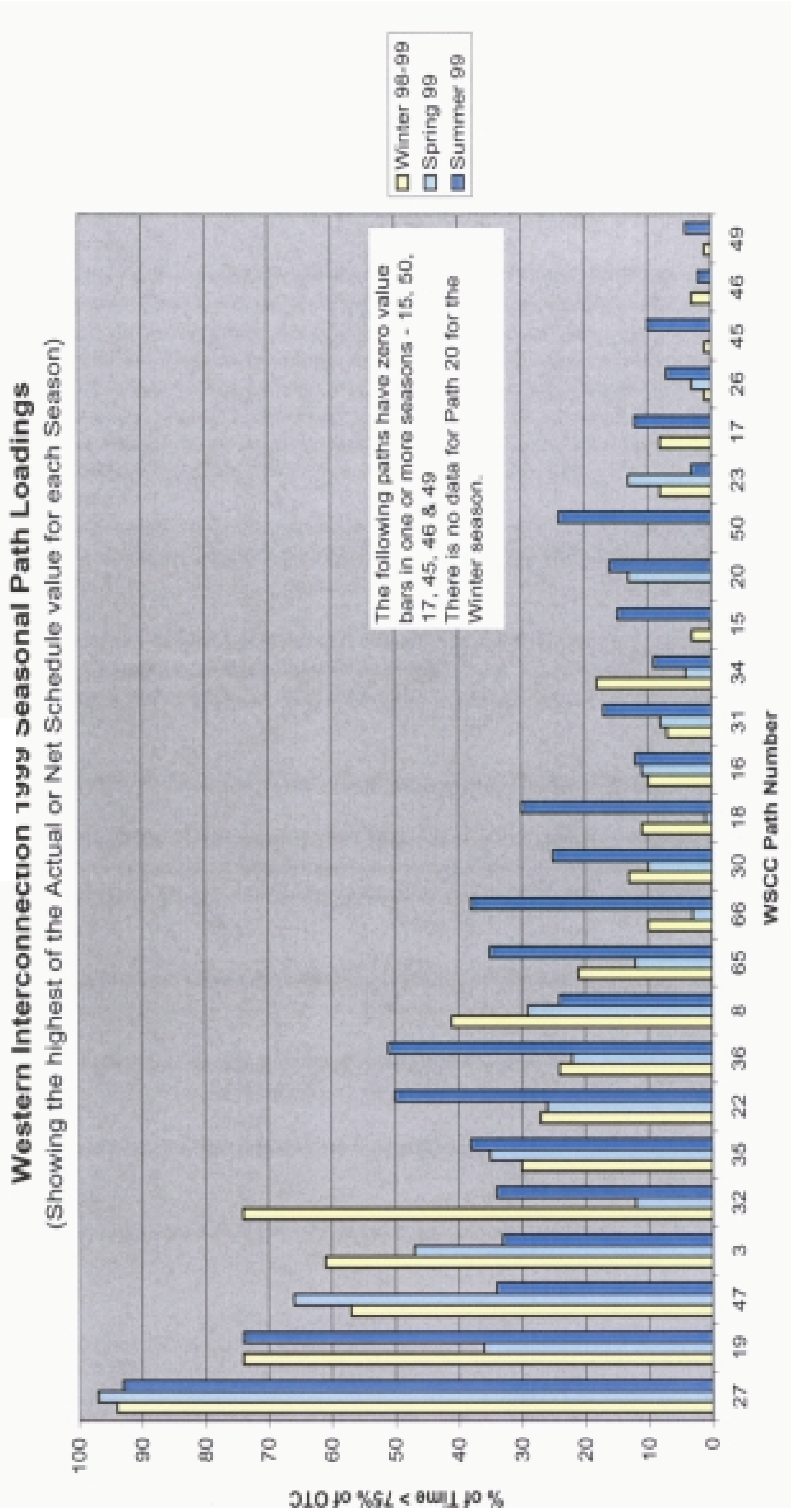

Western Interconnection 1999 Seasonal Path Loadings
(Showing the highest of the Actual or Net Schedule value for each Season)
% of Time > 75% of OTC
WSCC Path Number
Winter 98-99
Spring 99
Summer 99
The following paths have zero value bars in one or more seasons - 15, 50, 17, 45, 46 & 49
There is no data for Path 20 for the Winter season.
100
90
80
70
60
50
40
30
20
10
0
27
19
47
3
32
35
22
36
8
65
66
30
18
16
31
34
15
20
50
23
17
26
45
46
49

Figure 7

Path Loading - Actual and Net Schedule

Summer 1999

Percentage of time Exceeding 75% of Path OTC

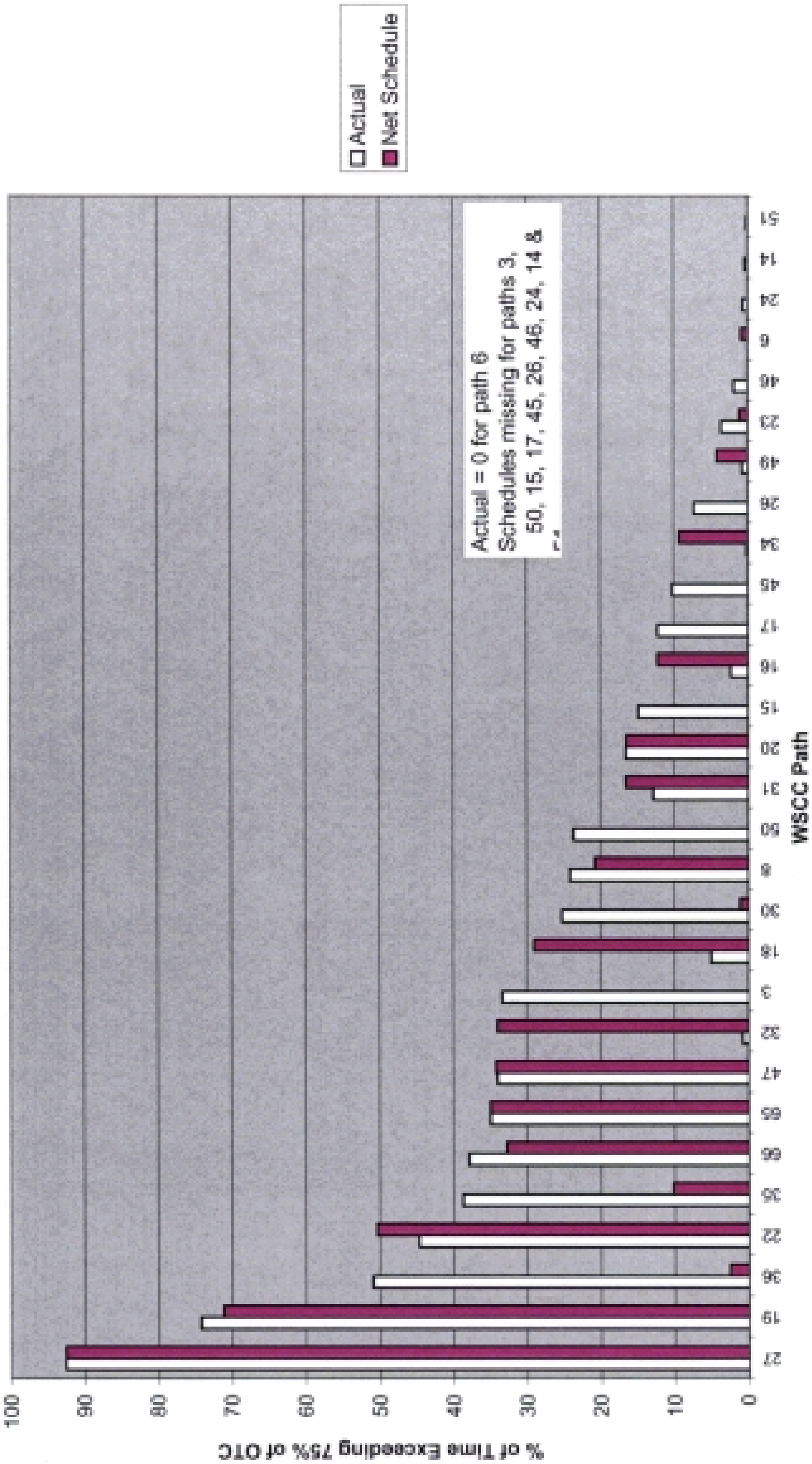


Figure 8
Peak Path Loadings
Spring 1999
(99 percentile point)

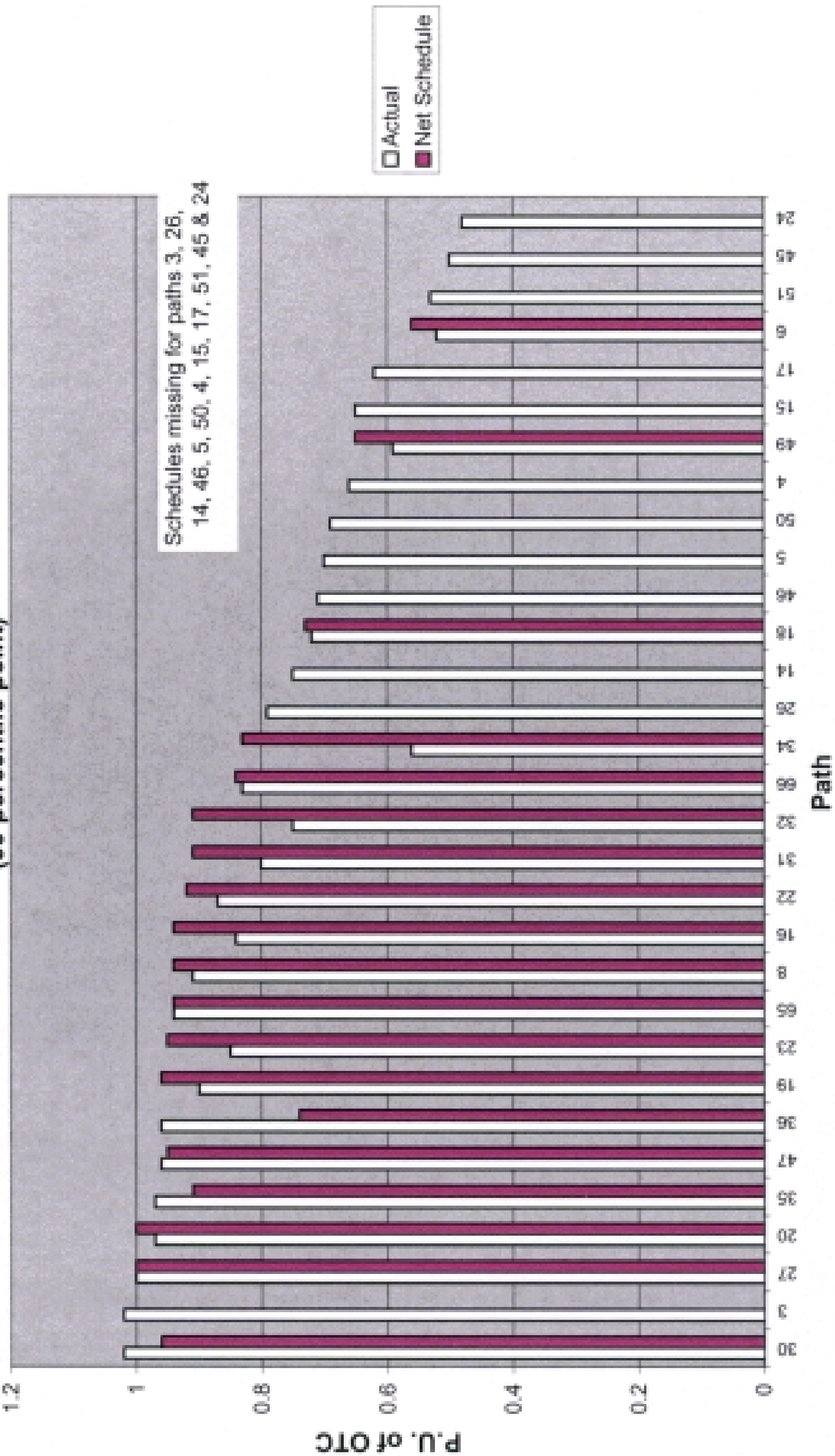
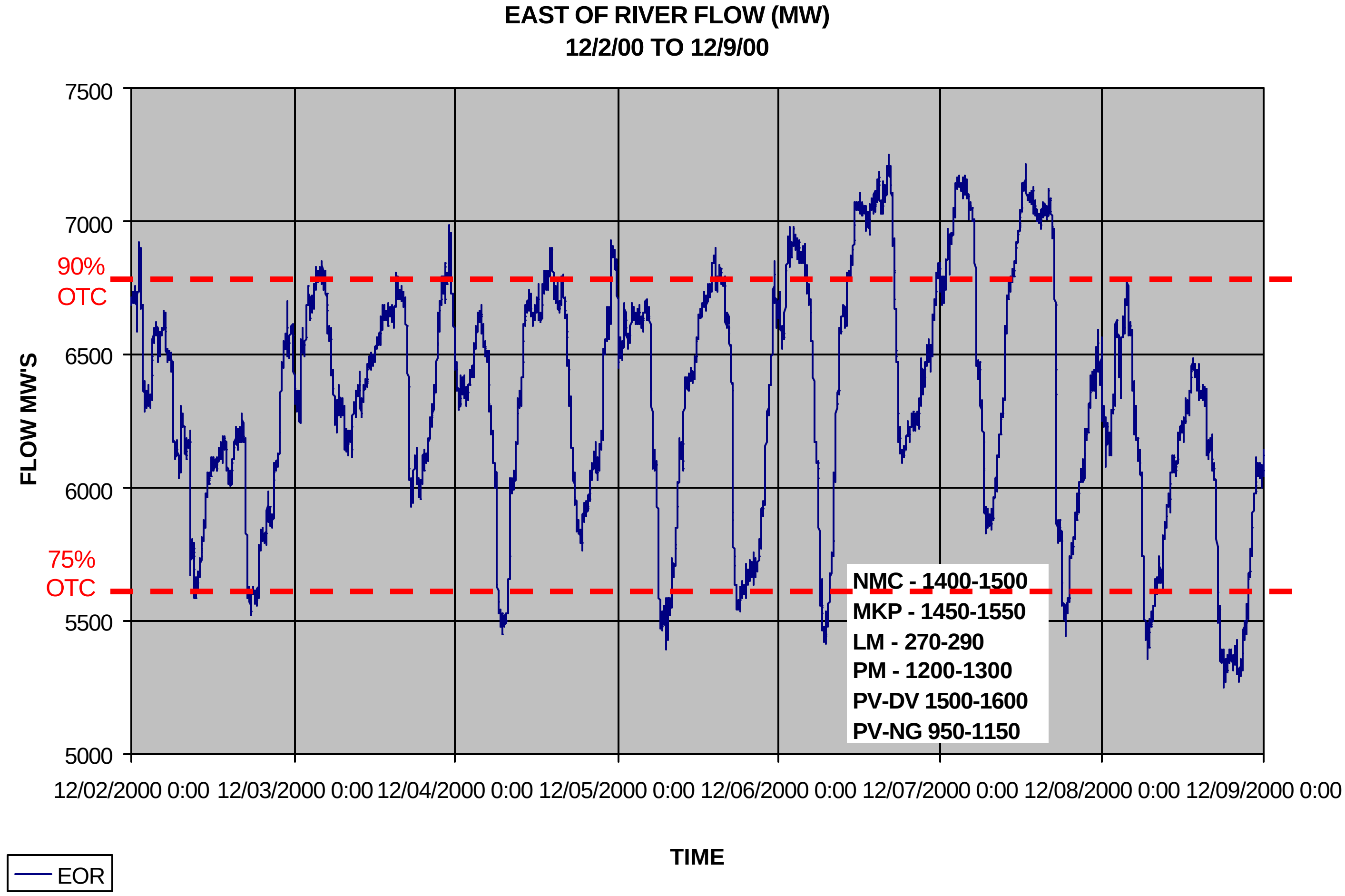


Figure 9



A summary of the long term firm Available Transfer Capability (ATC) values posted on OASIS in April 2000 for Arizona paths 22, 23, 49, 50 and 51 are provided in Table 6. ATC is determined by subtracting "Committed Uses" from the path's Total Transfer Capability (TTC) or Operating Transfer Capability (OTC). "Committed Uses" includes transmission reliability margin, capacity benefit margin and pre-existing transmission commitments. Customers desiring transmission services that are not available as ATC through OASIS need to make a Transmission Service Request. If the transmission service is not available, the Transmission Owner will perform a System Impact Study, if requested by the customer, to define how the service can be provided.

The Western Interconnection biennial assessment also documented a transmission customer survey conducted to determine customer experience during 1999 with transmission path congestion. Customers were asked to identify paths on which they either desired capacity that was not available or were refused reservation requests. Transmission Customers responded to the congestion survey by identifying the following four paths involving Arizona transmission facilities:

- California - Oregon Border (COB) to Palo Verde
- North of Oregon Border (NOB) to Palo Verde
- Palo Verde to Mead (East to West)
- Four Corners to Mead (East to West)

Table 6
Arizona OASIS Posted ATC
April 2000

WSCC Path	ATC - Long Term Firm
22 SW of Four Corners	APS posting 0 MW from N to S and 762 MW S to N
23 Four Corners 345/500 kV Xfrm	No OASIS postings
49 EOR: East of Colorado River - Navajo to McCullough 500 kV - Liberty to Mead 345kV - Moenkopi to Eldorado 500 kV - Mead to Phoenix 500 kV - Palo Verde to Devers 500 kV - Palo Verde to N. Gila 500 kV	SRP posting 236 MW bi-directional (Marketplace to Westwing and Palo Verde to Mead). LADWP posting 327 MW from Eldorado to Palo Verde. APS posting 140 MW from N. Gila to Palo Verde and 236 MW from Mead to Westwing.
50 Cholla to Pinnacle Peak	APS posting 421 MW (N to S) and 1876 MW (S to N).
51 Southern Navajo	APS posting 421 MW from Cholla to Navajo and 449 MW from Westwing to Navajo.

Each of the above paths offered transmission customers a common transmission congestion experience. For each of these paths, transmission customers:

1) requested and were refused access because of unavailable capacity;
2) wanted to request but did not request capacity because the posted ATC on OASIS was zero or not adequate to meet their needs; and
3) indicate a need for additional capacity in the future.

Transmission customers also reported a desire for additional capacity between the US market and the border towns of Mexico or a major transmission substation in Mexico. A similar need for capacity from the Pacific Northwest hydro facilities to load pockets in the Southwest was also identified.

Staff’s interpretation of the OASIS postings summarized in Table 6 is that there is very little long-term firm regional transmission capacity available to schedule and export additional energy from or import additional energy to Arizona. Exporting new or unused Arizona resources is limited to 236 MW to the west and is limited to 762 MW to the north via Four Corners or 449 MW via Navajo. The capability to schedule and import new energy resources to Arizona is limited to 236 MW from the west. This conclusion is substantiated by the transmission customer survey responses concerning transmission congestion.

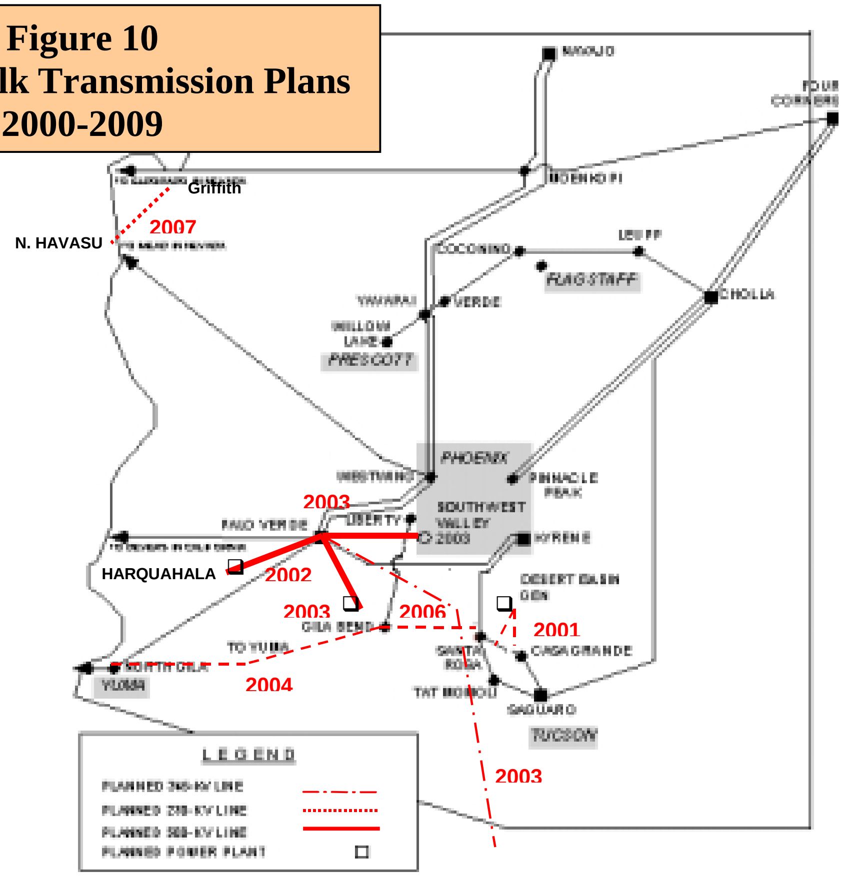
3.1 Ten Year Plans Filed January 2000

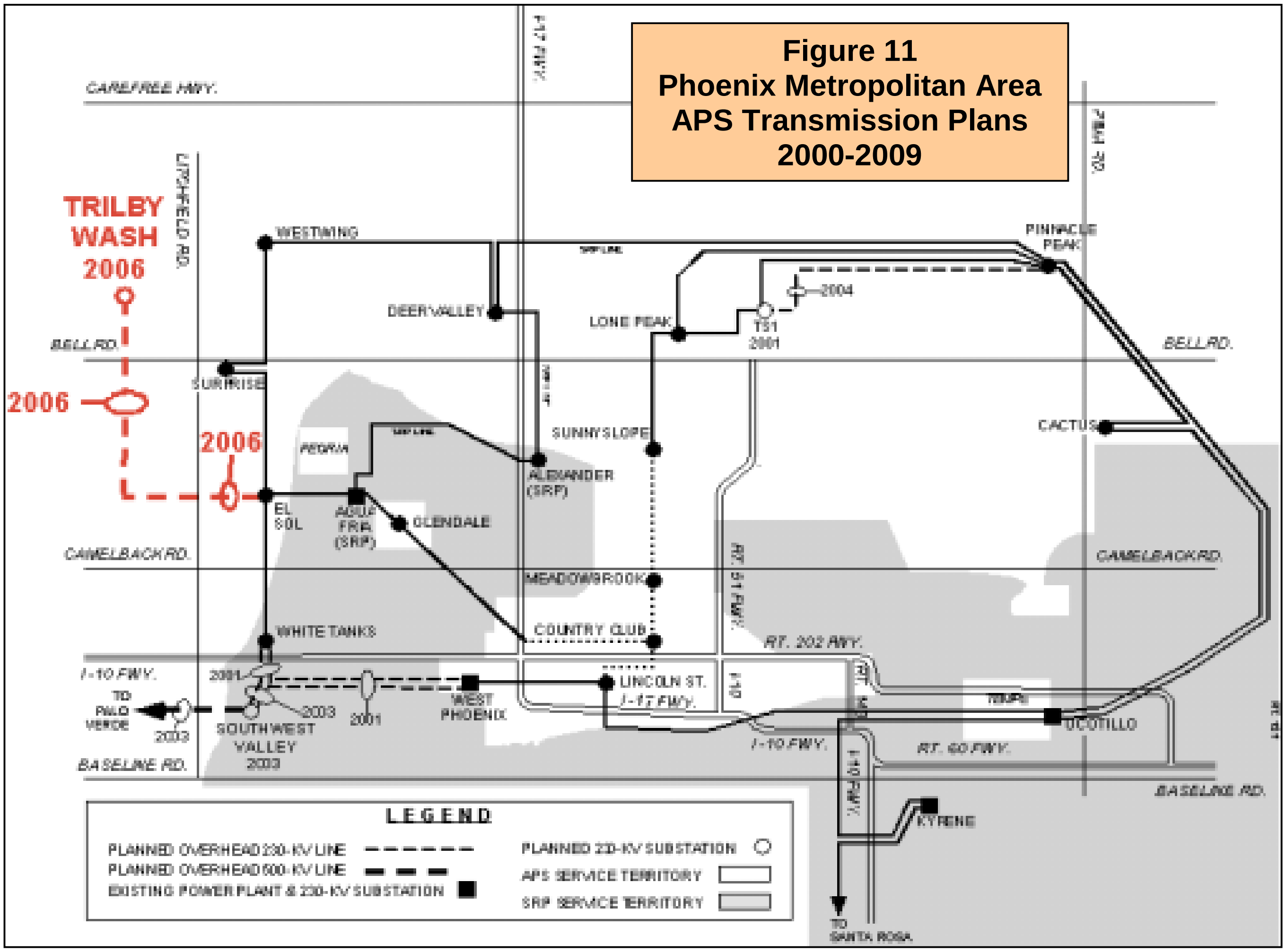
A.R.S. §40-360.02 states that every person contemplating construction of any transmission line within the state during any ten-year period shall file a ten-year plan with the commission on or before January 31 of each year. Each plan shall provide:

1. The size and proposed route of any transmission lines proposed to be constructed.
2. The purpose to be served by each proposed transmission line.
3. The estimated date by which each transmission line will be in operation.

A compilation of planned transmission line additions filed in January 2000 that comprise the Ten-Year Plans for 2000-2009 is provided in Appendix C. The transmission lines are listed both chronologically by projected in-service dates and by the entity that filed the planned addition. Figures 10, 11, 12, and 13 depict planned transmission additions for the Arizona Bulk Transmission System, APS transmission additions for the Phoenix Area, TEP transmission additions for Tucson, and SRP transmission additions for the Phoenix Area. State statutes require that Staff determine the adequacy of these planned facilities to meet the energy delivery needs of Arizona in a reliable manner. This section of the report documents Staff's assessment of such facilities.

Figure 10
Arizona Bulk Transmission Plans
2000-2009





Proposed TEP Transmission Additions

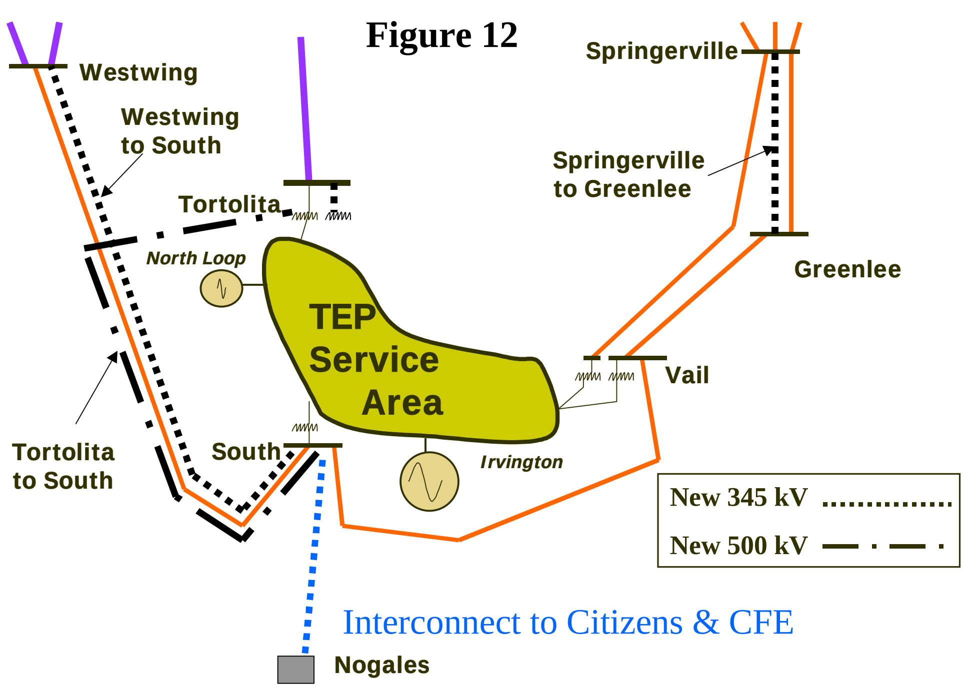
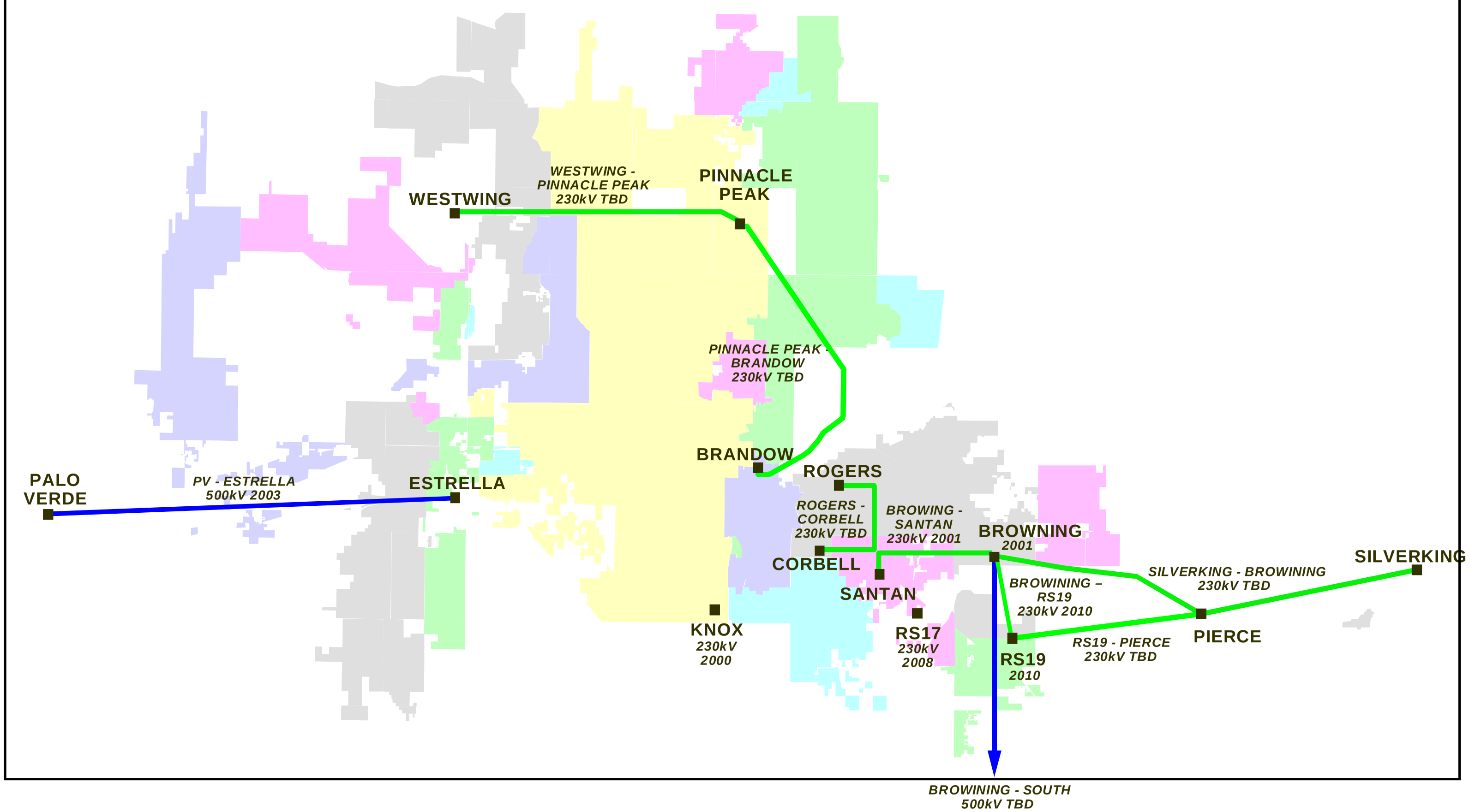


Figure 13
SRP Phoenix Metropolitan Area Transmission Plans 2000-2009



3.2 Planned Transmission Impact on Local Import Constraints

APS and SRP presented energy delivery plans to the ACC at a Transmission Issues Workshop held on March 20, 2000. Figures 14 and 15 show how the two utilities respectively rely upon new local generation and new transmission facilities to meet the load growth occurring in the Phoenix metropolitan area. Proposed local generation additions by Pinnacle West Energy Corp., APS's generation affiliate, included 120 MW at the West Phoenix Generating Station in 2001 and 525 MW in 2002. Pinnacle West Energy proposed local generation of 198 MW of mobile generation in 2001 and 2002 and 96 MW from the repowering of West Phoenix 4 and 6 steam units beginning in 2001. SRP's plans included 250 MW of new generation at its Kyrene Generating Station in the summer of 2002 and 825 MW at Santan in the summer of 2005. All three projects have encountered significant public opposition that may potentially delay or restrict each project's scope and compromise APS's and SRP's ability to serve customers without utilizing rolling blackouts.

The Siting Committee and the ACC have approved the West Phoenix Generating Station expansion.[1] The Siting Committee and ACC have also approved the Kyrene Generating Station expansion.[2] However, the scope of the expansion was reduced from 825 MW to 250 MW and operation of existing Kyrene units restricted to a rolling two-year average capacity factor of 1%. The Kyrene generating capacity reduction and restrictions were negotiated by the City of Tempe in response to local citizens' demand that there be no increase in emissions from the plant site, even though the original proposed project was in compliance with requirements for an Environmental Protection Agency air emissions non-attainment zone. In fact, reducing the Kyrene project's capacity from 825 MW to 250 MW proportionately reduced the 120% emission offsets benefit for the Phoenix metropolitan area. This action puts the Phoenix metropolitan area at greater risk of local rolling blackouts due to local transmission import constraints.[3] The Santan Generating Station expansion is now pending before the Commission in Docket No. L-00000B-00-0107. As of June 2001, all three of these plants have CECs approved by the Commission

APS and SRP also jointly plan a Palo Verde to Southwest Valley (Estrella) 500 kV transmission line for 2003. The Palo Verde to Southwest Valley (Estrella) 500 kV transmission line project has not filed a CEC application with the Siting Committee at present; but is expected to do so in 2001. News articles have documented that this line is encountering significant public opposition to the various routes under consideration. This line is critical to the delivery of energy to the Phoenix metropolitan area and will enable the reliable delivery of energy from new power plants seeking to interconnect with the Palo Verde transmission system. Every delay in this proposed 500 kV line, when coupled with the reduction in scope of the Kyrene plant expansion, puts the local area at an even higher risk of rolling blackouts. Revisiting Figure 14 and Figure 15 substantiates this view. Simply remove the new line's capacity from the two charts and reduce the Kyrene plant expansion capacity by 575 MW and the area load exceeds the combined capacity of the local transmission import limits and local generation.

[1] Docket No. L-00000J-99-0092 and approved in ACC Decision No. 62321.
[2] Docket No. L-00000B-00-0104 and approved in ACC Decision No. 62989.
[3] Jerry D. Smith, ACC Staff, Staff Pre-Filed Comments, Docket No. L-00000B-00-0104, August 11, 2000.

Figure 14

APS Phoenix Metropolitan Area Load Serving Capability

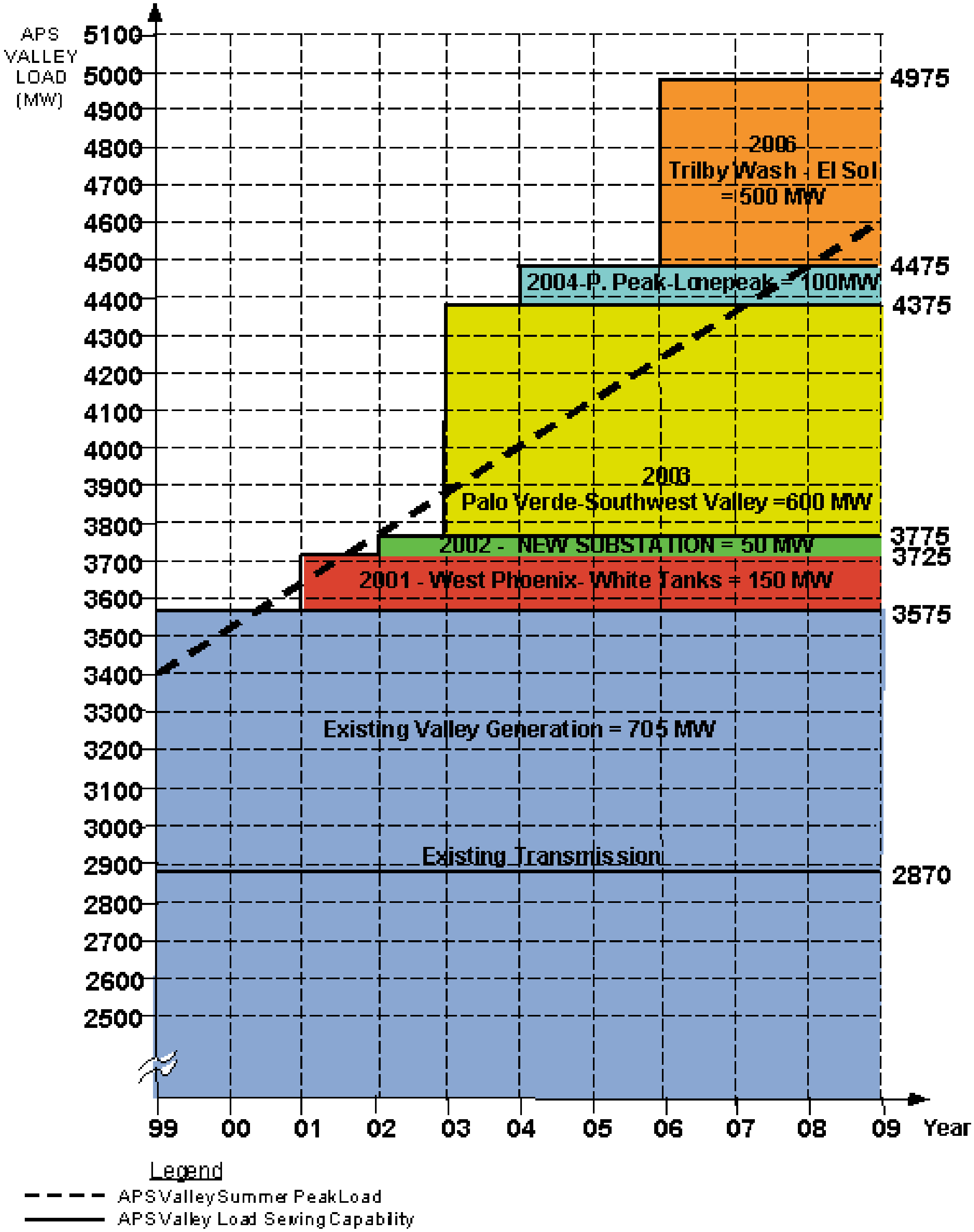
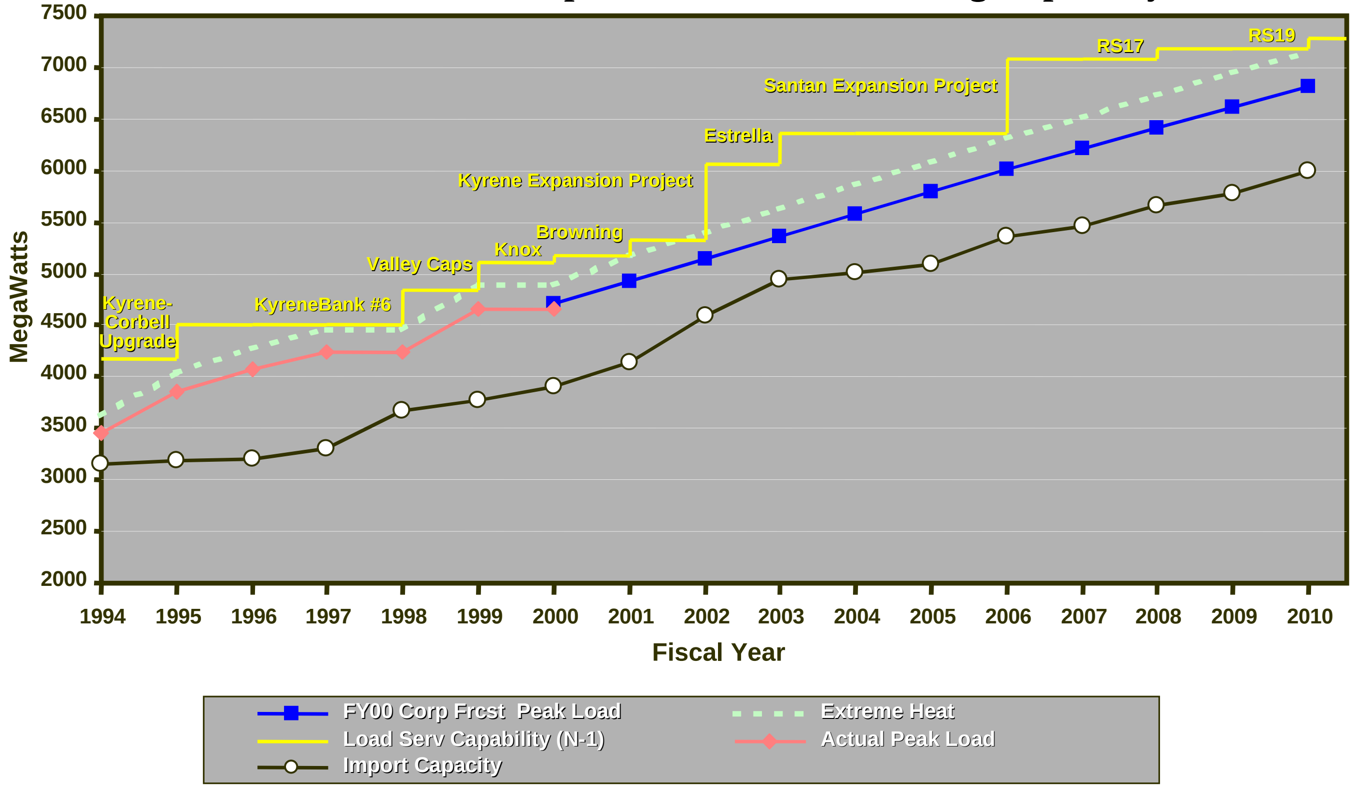


Figure 15
SRP Phoenix Metropolitan Area Load Serving Capability



Without the Palo Verde to Southwest Valley 500 kV line in 2003, APS peak load serving capability would be inadequate until construction of the Trilby Wash to El Sol 230 kV line in 2006. Similarly, without the Palo Verde to Southwest Valley 500 kV line in 2003 and the 575 MW reduction of the Kyrene plant expansion in 2002, SRP's load serving capability would be inadequate to meet its peak load obligations until the Santan plant expansion in 2006.

It could be argued that APS and SRP could rely upon the generation from the new West Phoenix plant expansion and the 250 MW Kyrene plant expansion to mitigate the lack of transmission import capability. However, Commission rules[4] require that each utility provide adequate transmission import capability to serve its local load requirements with sufficient flexibility to not rely solely upon local generation. Even more importantly, a transmission system is not considered adequate unless it is of sufficient capacity to accommodate the full range of load and generation conditions. Both utilities' transmission plans for the Phoenix metropolitan area fail to meet this requirement even with the addition of all planned transmission lines. It is Staff's professional opinion that the APS and SRP planned transmission system additions for the Phoenix metropolitan area are inadequate and not timely.

Similar circumstances exist for Arizona's other two transmission import constrained areas. APS does not plan transmission additions serving the Yuma area until 2004. As depicted in Figure 10, APS proposes to construct a 230 kV line from Gila Bend to Yuma at that time. In the

[4] ACC Rule 14-2-1609.B

meantime, the Yuma area must depend upon local generation to serve load growth above the transmission import capability for the Yuma area. Staff has not seen load projections for the Yuma area and cannot determine when local generation would no longer be sufficient to cover the deficiency in transmission import capability to serve all load in the area. We are left with the assumption that APS has determined that date to be 2004. At best, Staff's assessment is that the new APS transmission line to Yuma is not timely, due to dependence upon local generation until it is constructed.

The Tucson transmission import constrained area exhibits a slightly different challenge. TEP indicates that the transmission import constraint for Tucson is voltage instability. It has several short term local system improvements proposed that will help mitigate its local voltage support requirements until new transmission lines are constructed:

1. Capacitors at Tucson Station (50MVAR),
2. New Controls for Combustion Turbines,
3. New Voltage Regulator for Irvington #2,
4. New 138kV Transmission Line Between Snyder & Northeast, and
5. New Combustion Turbine generators at DeMos Petrie and North Loop.

As depicted in Figure 12, TEP plans three additional transmission lines to the Tucson area:

1. A second Westwing to South 345 kV line,
2. A 345 kV line from Tortolito to South, and
3. A 345 kV line from South to Nogales for interconnections to Citizens Utility Company and Mexico's Comision Federal de Electricidad (CFE).

It is Staff's opinion that the TEP proposed transmission lines will satisfactorily resolve the transmission import constraint for Tucson. However, all three proposed transmission lines traverse geographical regions subject to close public scrutiny and very vocal opposition. The line to Nogales is a transmission project competing with PNM for an intertie to Mexico. PNM has faced the wrath of negative public opinion as it has been seeking public comment via a federal environmental impact study of alternative routes to Mexico. A number of the routes being considered by PNM traverse the same geographical areas that TEP's transmission lines would utilize. It is reasonable to assume that all of the proposed transmission lines in the vicinity of Tucson will encounter considerable public opposition.

Staff's professional opinion is that TEP's transmission plans fail to comply with the ACC requirement that transmission import capacity must be maintained to adequately serve local customers. More importantly, TEP's transmission system lacks the flexibility exhibited by an adequate transmission system accommodating the full spectrum of load and generation patterns. The above short-term solutions result in TEP continuing its practice of depending upon local generation to resolve its deficiency in transmission load serving capability during peak demand periods. While Staff believes TEP's proposed transmission lines will adequately resolve local system constraints, the in-service dates of the lines are not timely. This opinion is supported by the emergency blackout experienced in Tucson on June 14, 2000 when a forest fire in New Mexico disrupted service via TEP's 345 kV lines into Vail.

TEP complied with WSCC criteria. However, because the WSCC criteria only deals with interconnected systems, it does not address internal loss of load. Nonetheless, **this outage was contrary to the basic philosophy and primary objective of WSCC, which states, "[c]ontinuity of service to loads is the primary objective of the Council Reliability Criteria**." (Page III-6, WSCC's Minimum Operating Reliability Criteria (revised August 8, 2000).

3.3 Palo Verde Interconnection Study of Planned Transmission

The Palo Verde Interconnection Studies concluded that in the absence of additional transmission facilities or upgrades, the new generation (8192 MW) proposing to interconnect at Palo Verde / Hassayampa would be restricted to <u>3360 MW</u>. The Palo Verde Interconnection Study also investigated the technical performance enhancements achievable with an upgrade of the Palo Verde to Kyrene 500 kV line and the Palo Verde to N. Gila 500 kV line along with the interconnection of three new transmission lines:

1. An APS and SRP Palo Verde to Southwest Valley (Estrella) 500 kV line,
2. A NRG Palo Verde to West Yuma 500 kV line, and
3. A PNM Palo Verde to Mexico (CFE).

The transmission capability to schedule all of the planned generation (8192 MW) out of Palo Verde is constrained by thermal, stability and post-disturbance voltage dip, even with the addition of all three new transmission lines. The maximum power that can be scheduled out of the Palo Verde vicinity to all areas with the three new lines is about <u>6750 MW</u>. This is due to a stability limit if there is a loss of two Palo Verde to Westwing 500 kV lines. The maximum power that can be scheduled out of the Palo Verde vicinity to the <u>east and south is 6500 MW</u>. This is due to a power flow thermal limit on the Palo Verde to Kyrene 500 kV line under base case conditions. The maximum power that can be scheduled out of the Palo Verde vicinity to the <u>west and south is 3850 MW</u>. This is due to a power flow thermal limit on the Palo Verde to N. Gila 500 kV line if there is a loss of the Palo Verde to Yuma West 500 kV line.

Addition of only the Palo Verde to Estrella 500 kV line to the existing transmission system increases the amount of new generation that can be scheduled out of Palo Verde from 3360 MW to <u>4850 MW</u>. If the Palo Verde to North Gila and Palo Verde to Kyrene lines are upgraded and stability mitigation is applied along with the addition of Palo Verde to Estrella, then up to <u>6050 MW</u> of the new generation can be accommodated.

Palo Verde Interconnection Studies also indicate that EOR/SCIT transfer capabilities can be increased by upgrading the Palo Verde to N. Gila 500kV line or by adding a new line to the west. A 400 MW increase in the EOR/SCIT limits is achieved if the Palo Verde to N. Gila 500 line is upgraded to 1800 amps (continuous rating) and 2400 amps (emergency rating). A 1000 MW increase in the EOR/SCIT limits is achievable with the addition of the Palo Verde to Yuma West 500 kV line.

Staff offers the following comments relative to the Palo Verde Study efforts and siting of all new power plants desiring to interconnect at Palo Verde. The technical study work done to date is exemplary. It shows that simply interconnecting to a market hub does not assure the power from new plants can be delivered to the intended consumer market. It further demonstrates that the existing Palo Verde transmission system falls considerably short of being able to accommodate all of the new power plants. It also shows that the addition of three new 500 kV transmission lines does not resolve the technical transmission deficiencies accompanying the addition of all proposed power plants. The studies do verify that the Palo Verde system is very crucial to the reliable operation of the whole Western Interconnection. This is demonstrated by the voltage stability of the Pacific Northwest being a limiting factor in the outage consideration of some Palo Verde system elements. On this basis, Staff considers the transmission plans for Palo Verde to be inadequate for the interconnection of all new proposed power plants.

It seems imprudent to approve the interconnection of any proposed power plant at Palo Verde until there is technical study evidence demonstrating the transmission system can accommodate it with all other previously interconnected plants operational. Staff has been successful in getting a CEC stipulation placed with new plant applicants requiring that technical studies performed no more that one year in advance of the intended operational date be filed with the ACC demonstrating they can reliably deliver their output to the intended consumer market. Given the evidence presented by the Palo Verde Interconnection Study, Staff must weigh how we will respond when such studies indicate the need for curtailments or restrictions on the plant's operations. The question presented here is should operation be allowed to commence without full compliance with the CEC conditions? Staff believes that adequate transmission must be in place to reliably deliver all of the plant's output and there should be full compliance with the CEC conditions.

At the time Palo Verde Nuclear Generating Station was being constructed, there was concern that the plant and units were too large and posed a formidable security risk for the industry and the state. The plant has three 1,270 MW units with a rated plant output of 3,810 MW. The plant's vulnerability to natural disasters, sabotage or normal system disturbances for which the system was ill equipped to accommodate was of paramount concern. The plant represented a major portion of the energy production capability for the region in the mid-80s. The Palo Verde units remain the "largest single hazard" for generating reserve requirements in the United States. Similarly, the simultaneous outage of two Palo Verde units remains a current system security concern for the whole Western Interconnection.

Given that Palo Verde is a nuclear generating plant, extraordinary measures were taken to minimize the security risks posed by the plant. The transmission system was designed to accommodate outages of multiple transmission elements without relying on the tripping of a Palo Verde generating unit. This is a more stringent requirement than the single contingency or "N-1" criteria normally used throughout the industry for planning electric facilities. Similarly, the transmission system was designed to deliver the full output of the plant to Arizona consumers, even though local supply requirements did not warrant such consideration. Then two transmission lines were also constructed to interconnect with the California transmission system to enable reliable delivery to non-Arizona plant owners and markets as well.

The regional security concerns raised in the mid-80s regarding Palo Verde are germane today in a setting where an additional 8200 MW of generation is contemplated in the immediate vicinity of the 3,810 MW Palo Verde plant. Such a mega-generation complex that interconnects all new generation at Hassayampa Switchyard, as depicted in Figure 4 on page 15, represents the present total power requirements of the State of Arizona and the new generation approximates the load growth anticipated in the Desert Southwest region over the next decade. This will be the largest generation complex in the United States. It is appropriate to consider several questions before deducing the wisdom of such a large mega-generation complex.

Are the reliability standards of the past suitable for a mega-generation complex of this size? Is it prudent to allow this mega-generation complex to commence operation without adequate transmission in place for reliable operation of all units? Are the natural gas supply, storage and delivery system sufficient to accommodate such a huge generating complex? Does this extensive new gas infrastructure pose an additional new exposure to sabotage or catastrophic events, such as the gas pipeline explosion that occurred in Carlsbad, New Mexico in 2000? What is the risk of a natural disaster or sabotage wiping out the entire mega-generation complex? The societal consequences of such an outage would be grave and suggests it would be wise to endorse more stringent security and reliability standards for such a facility or dispersion of the proposed new power plants to other locations.

Staff's comments are intended to highlight that any proposed project requesting a CEC to construct and interconnect with Palo Verde should be evaluated relative to security and reliability issues. The merchant plant industry has taken the position that they are assuming all of the risk involved in the construction, operation and marketing of power from the generating units. But there are risks other than the financial welfare of the various plant applicants that must be considered.

Just as with the siting of Palo Verde, the Commission should ensure steps are taken to properly manage the public and societal risks associated with the construction of a mega-generation complex such as that emerging at the Palo Verde / Hassayampa hub. This will be the largest generation complex in the nation. For these reasons, there must be stringent application of reliability criteria. We can ill afford the consequences if we fail to get this one right. The Commission should be active in the regional review and development of new reliability criteria for the restructured electric industry. There may even be a need for Arizona to take the lead in new reliability regulatory efforts because our state will have the largest generation complex in the nation from which to test the merits of emerging criteria.

3.4 Staff Regional Concerns

Unfortunately, the construction of power plants and transmission lines in the entire Western Interconnection depicted by Figure 5 on page 18 has failed to keep pace with the population growth of the last decade. Utilities have been reluctant to invest in capital improvements given the uncertainties of restructuring of the electric industry. As a result, transmission constraints have become more prominent and act as an impediment to energy delivery when it is most needed. Concurrently, installed generating reserve capacity has been on the decline. This is depicted graphically as the narrowing space between the two curves of Figure 16. The load growth and generation reserve requirement for Arizona, New Mexico and Southern Nevada is shown in Table 7.

Supply deficiencies in periods of high demand result in wholesale energy price volatility. Unfortunately, utilities that have not arranged adequate long-term energy supplies at stable prices find themselves vulnerable to such volatile market conditions. An efficient, robust energy market offers electric service providers and affected utilities an opportunity to arrange an appropriate mix of long term and spot market energy resources.

Is the electric utility industry in Arizona positioned to accomplish what California has not? Staff is optimistic that Arizona can avoid California's energy perils. However, the proposed power plants and associated transmission improvements must be built in sufficient numbers, at a rate exceeding load growth, and provide sufficient capacity to allow a robust and competitive energy market to flourish in Arizona.

Fortunately, Arizona has a large number of power plants being sited in the state that will enable service providers to avoid dependency on importation of their future energy requirements. A summary list of those plants is provided as Table 8. These plants are expected to provide sufficient near-term generating capacity and energy reserves for Arizona. However, construction of these plants alone does not ensure competitive energy pricing in Arizona.

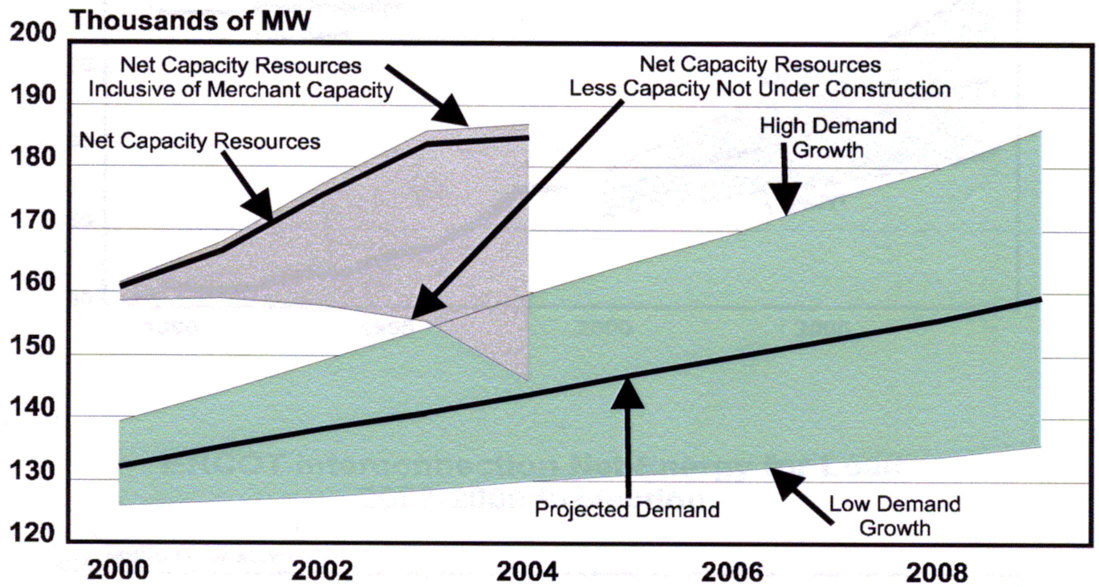
For the envisioned robust and competitive Arizona energy market to become a reality there must be adequate transmission capacity to reliably deliver the energy from proposed power plants to Arizona's load centers. Transmission limitations existing in the state pose an obstacle to delivering the energy from all of the new proposed plants to Arizona's consumers. This has been a major concern posed by Staff for many of the power plant projects appearing before the Arizona Power Plant and Transmission Line Siting Committee.

The lead-time to site and construct a power plant is considerably shorter than the lead-time to plan, site and construct required associated transmission lines. A power plant can be sited and constructed within 2-3 years of its application for a CEC. The typical lead-time to site, obtain right of way, and construct a transmission line is 3-5 years. Independent Power Producers have effectively committed the full production schedule capability of generation manufactures and are simply looking to locate those units when and where they perceive the best financial opportunity exists. As a result, Transmission Providers are presently encumbered with an endless barrage of power plant interconnection study requests that have distracted them from studying, planning, and siting the transmission lines needed to deliver the energy from proposed power plants to local consumer markets.

Arizona's Transmission Providers have recently initiated technical studies, called the Central Arizona Transmission Study (CATS), to define future transmission improvements that will enable delivery of energy from the new plants to Arizona's major load centers. Those transmission improvements must be identified, sited, and constructed in a relatively short time frame to avoid transmission constraints to new power plants trying to serve Arizona's growing energy needs. For proper transmission planning, it is necessary to know where future power plants are going to be located. The Arizona Revised Statutes no longer require power plants to be identified in the Ten-Year plans. Staff recommends that these Arizona Revises Statutes be changed to require power plants to file a ten-year plan.

Figure 16

Western Interconnection
Capacity vs Demand – Summer



(Reference: NERC Reliability Assessment 2000-2009)

Table 7
Arizona / New Mexico / S. Nevada Area
Load Forecast and Generation Reserve Requirements (MW)[1]

Year	Total Resources	Min. Requirements	Reserve Load Responsibility
2000	20,932	20,834	18,244
2001	22,187	22,060	19,486
2002	26,581	24,757	21,930
2003	31,521	25,454	22,541
2004	31,576	26,379	23,367
2005	32,076	27,348	24,225
2006	32,076	28,256	25,030
2007	32,576	29,140	25,813
2008	32,576	30,048	26,617
2009	32,576	30,966	27,430

9,186

[1]Per WSCCInformation Summary, June 2000

Table 8
PROPOSED ARIZONA POWER PLANTS (as of June 2000)

STATUS *	PLANT NAME	MW	YEAR
1	SOUTH POINT	500	2001
1	GRIFFITH	520	2001
1	DESERT BASIN	500	2001
1	WEST PHOENIX (Ph 1)	120	2001
1	REDHAWK (Ph 1)	530	2003
1	REDHAWK (Ph 2)	530	2003
2	ARLINGTON VALLEY	580	2002
2	WEST PHOENIX (Ph2)	530	2002
2	GILA RIVER	2,080	2002
2	HARQUAHALA	1,040	2003
2	MESQUITE	1,000	2003
2	KYRENE	250	2004
2	REDHAWK (Ph 3)	530	2006
2	REDHAWK (Ph 4)	530	2007
		9,240	

STATUS *	PLANT NAME	MW	YEAR
3	BIG SANDY (Ph 1)	500	2002
3	SUNDANCE	600	2002
3	BIG SANDY (Ph2)	220	2003
3	GILA BEND	845	2004
3	SANTAN	825	2005
5	BEAVER DAM	500	2003
5	DESERT BASIN (Ph 2)	900	2004
5	SPRINGERVILLE (Unit 3)	380	2003
5	SPRINGERVILLE (Unit 4)	380	2004
5	LA PAZ	1,080	2004
5	WHITE TANK MOUNTAIN	1,250	2007
5	TOLTEC	2,000	2007
5	MONTEZUMA	600	2007
5	MAESTROS - NOGALES	500	TBD
		10,580	

* Notes:
1 - Under Construction or completed
2 - Regulatory approval/denial received
3 - Application under review
4 - Application filed
5 - Announced

One of the most significant risks to successful implementation of electric competition in Arizona is the degree to which the general public, individual property owners, private companies, neighborhoods, and local communities support the power plant and transmission improvement projects that emerge. Our public processes and siting processes must consider each project regarding its need, its technical adequacy and reliability, and environmental compliance to ensure it is in the public's best interest. In addition, the impact of newly designated national monuments in Arizona in the siting and construction of new power plants and transmission lines is unknown. Staff believes that this topic may warrant a Commission workshop given the numerous proposed projects that may be affected by the designation of new national monuments.

Public opposition to new power plants and transmission lines is sometimes accompanied by a lack of economic incentive for Transmission Providers to construct new transmission lines. Transmission Providers view transmission congestion as a means of protecting their own transmission rights. Transmission congestion also offers those with firm transmission rights (FTR) the opportunity to adopt transmission pricing mechanisms that establishes a market value for the constrained limited transmission path. This practice is contrary to the regulated cost based pricing framework of transmission. Why should a party build new lines to remedy the constrained path when they can make more money off of market based congestion management pricing mechanisms? In affect, these new trends in transmission pricing can be a barrier to the construction of new transmission facilities.

utility transmission reliability obligations are assumed voluntarily without federal mandate. This places a regulatory burden regarding reliability with states. Often these same states are ill prepared or equipped to respond to the enormous changes occurring in the industry. This situation is exacerbated by the fact that there is a major national shift to merchant power plants which may not have the traditional obligation to serve. Maximizing commercial profit and assuring affordable and reliable service to customers are counterpoised industry objectives that were previously reconciled by the traditional obligation to serve. Having a merchant generation industry requires states to remain vigilant that reliability, quality of service and reasonable consumer costs do not suffer as we go about restructuring the industry and accommodating a portfolio of competitive services.

Section 4: Conclusions and Recommendations

4.1 Adequacy of Existing Transmission System

It is Staff's opinion that the Southeastern Arizona Regional Transmission Study conducted in 2000 was effective in establishing a sound operational plan for the region. The operational plan is based upon continuation of a common practice of restoring customer service following a transmission line outage by reconfiguring the system with service provided by an alternative transmission line. However, if the frequency or duration of outages becomes onerous then customers are likely to file complaints with the Commission, as was the case for CUC customers in Santa Cruz County. CUC does not have the capability to close tie lines to other systems and therefore a second transmission line to Nogales is warranted.

Staff remains concerned that customers in Southeastern Arizona are vulnerable to interruptions of service for a transmission line outage. This fact alone means the transmission system is not adequate and secure. This is especially disconcerting when the existing system could be operated as an interconnected network with minor system improvements, such as switch and circuit breaker upgrades, and thereby truly comply with the WSCC transmission reliability requirements. Customers of Southeastern Arizona would benefit from such a change in system operation practices.

Arizona currently has three transmission import constrained zones (Phoenix, Tucson and Yuma). The existing transmission systems serving these three areas are inadequate. The associated utilities serving these three areas have not fulfilled their obligation to provide adequate transmission to serve local customers.[5] More importantly, the transmission systems serving these areas lack the ability to reliably serve local customers under all load and generation patterns. Additional transmission lines, new local generating units or a combination of both must be built for the three areas before the local load exceeds the aggregate capacity of local generating units and the transmission system. Otherwise, Arizona's three transmission import constrained areas will be subject to rolling blackouts. It is Staff's opinion that there is a small possibility that such an occurrence could happen in the Phoenix Area the summer of 2001 with an increasing likelihood in 2002. This exposure exists even with the timely expansion of West Phoenix and Kyrene power plants if no new EHV transmission lines are constructed and terminated in the Phoenix metropolitan area.

Palo Verde transmission studies have concluded that the existing Palo Verde transmission system can accommodate a maximum of 3360 MW of additional power over and above the output of the Palo Verde nuclear units. Generating capacity of the power plants proposing to interconnect have a total output (8200 MW) far exceeding the limits of the existing system. Therefore, a curtailment procedure must be developed prior to the interconnection of new generation. Staff concludes that the existing Palo Verde transmission system is inadequate given that curtailment procedures will limit the output of the new power plants.

[5] A.A.C. Rule R14-2-1609.B.

This is exemplified by the actual flow recorded on Path 49 between Arizona and California during the week of December 2 - 9, 2000. Figure 9 on page 22 documents that actual hourly flow continuously ranged between 90% and 75% of the path's 7550 MW OTC rating on a daily basis for that week. California experienced its first Stage 3 alert on Thursday of that week. Arizona could have exported very little additional power to California during peak hours of the day during that week due to this transmission constraint.

Staff's interpretation of the OASIS postings summarized by the July 2000 Western Interconnection Biennial Transmission Plan for April 2000 is that there is very little long-term firm regional transmission capacity available to schedule and export additional energy from or import additional energy to Arizona. On that date, exporting Arizona resources was limited to 236 MW to the west and 762 MW to the north via Four Corners or 449 MW north via Navajo. The capability to schedule and import new energy resources to Arizona was limited to 236 MW from the west. This conclusion is substantiated by the transmission customer survey responses concerning transmission congestion. Therefore, Staff concludes Arizona's existing transmission export and import capability is marginal at best.

4.2 Adequacy of Planned Transmission Additions

It is Staff's assessment that the transmission plans for the state's three transmission import constrained areas are deficient. APS and SRP planned transmission system additions for the Phoenix metropolitan area are inadequate and not timely. Staff's assessment is that the new APS transmission line to Yuma is not timely due to dependence upon local generation until it is constructed. While Staff believes TEP's proposed transmission lines will adequately resolve local system constraints, the in-service dates of the lines are not timely. This opinion is supported by the emergency blackout experienced in Tucson on June 14, 2000 when a forest fire in New Mexico disrupted service via TEP 345 kV lines into Vail.

Staff offers the following comments relative to the Palo Verde Study efforts and siting of all new power plants desiring to interconnect at Palo Verde. The technical study work done to date is exemplary. It shows that simply interconnecting to a market hub does not assure the power from new plants can be delivered to the intended consumer market. It further determines the existing Palo Verde transmission system falls considerably short of being able to accommodate all of the new power plants. Studies show that the addition of three new 500 kV transmission lines does not resolve the technical transmission deficiencies accompanying the addition of all proposed power plants. The studies do verify that the Palo Verde system is very crucial to the reliable operation of the whole Western Interconnection. This is demonstrated by the voltage stability of the Pacific Northwest being a limiting factor in the outage consideration of some Palo Verde system elements. On this basis, Staff considers the transmission plans for Palo Verde to be inadequate for the interconnection of all new proposed power plants.

4.3 Is Regulatory Reform Needed

Staff has established the appropriateness of the ‘‘Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability” used as the foundation for Staff’s testimony and recommended Siting Committee conditions in prior power plant hearings. Staff’s position on bus configuration and number of lines required out of a power plant switchyard is truly based on “best engineering practices” established by utilities in Arizona over the course of many years of accountability for the reliable supply and delivery of energy to Arizona’s consumers.

Restructuring the Arizona electric industry for retail competition via a deregulated energy market is no justification for relaxing the best engineering practices established by utilities in Arizona. To do so would jeopardize the present electric service reliability that is essential for Arizona’s consumers. Such an approach would simply allow a greater financial gain for merchant power plants. Neither WSCC nor NERC are contemplating relaxing their reliability criteria. In fact, there is considerable political pressure to strengthen national reliability requirements in response to the widespread concern about blackouts that are becoming more prevalent throughout the nation.

Staff has consistently taken the position that two or more transmission lines are required out of each plant’s switchyard to meet a single contingency (“N-1”) criteria without relying on remedial action such as generator tripping or load shedding. The evidence in Table 2 on page 8 is an indicator that there is support of this practice even when Staff is not involved. Now is not the time to relax our reliability standards. It is interesting that all of the projects that have proposed a single transmission line have also sought an interconnection at Hassayampa, the Palo Verde satellite switchyard. It is at this same location that existing transmission capacity to accommodate those same plants is in question.

Given the evidence presented by the Palo Verde Interconnection Study, the Commission must weigh how it will respond when stipulated transmission studies submitted no more than one year prior to the operation date of a plant indicate the need for curtailments or restrictions on the plant’s operations. The Commission should not allow operation to commence until such time that adequate transmission is in place to reliably deliver all of the plant’s output and all conditions of the CEC are met. Arizona, regional or national legislative reforms of reliability standards for a restructuring electric industry may not occur in time to be of assistance.

Just as with the siting of the original Palo Verde nuclear plant, steps should be taken to properly manage the public and societal risks associated with the construction of a mega-generation complex, such as that emerging at the Palo Verde/ Hassayampa hub. This will be the largest generation complex in the nation. For these reasons, there must be stringent application of reliability criteria. We can ill afford the consequences if we fail to get this one right. The Commission needs to be active in the regional review and development of new reliability criteria for the restructured electric industry. There may even be a need for Arizona to take the lead in new reliability regulatory efforts because our state will have the largest generation complex in the nation from which to test the merits of emerging criteria.

4.4 Staff Recommendations

Lack of system data, computer hardware and software, and sufficient staff resources limited the efforts of this first biennial assessment to a review of the work documented by others. It is presumed that the intent of the statute placing this obligation with the Commission was to establish an independent assessment of the reliability of the existing and planned transmission systems. This implies Staff needs the ability to perform independent technical studies. Therefore, due consideration should be given to data and budgetary pre-requisites for biennial transmission assessments if Staff is to perform independent technical studies in the future.

For proper transmission planning, it is necessary to know where future power plants are going to be located. The Arizona Revised Statutes no longer require power plants to submit Ten-Year Plans. Staff recommends that the Arizona Revised Statutes be changed to require power plants to file a Ten-Year Plan. The plans submitted by transmission providers and power plants should also be accompanied by technical studies demonstrating the system impact of those planned additions. In 2001, House Bill 2040 was passed that required plants to file a plan with the Commission 90 days prior to filing an application for a Certificate of Environmental Compatibility. In addition, "The plans for any new facilities shall include a power flow and stability analysis report showing the effect on the planned Arizona electric transmission system."

Having a merchant generation industry requires states to remain vigilant that reliability, quality of service and reasonable consumer costs do not suffer as we go about restructuring the industry and accommodating a portfolio of competitive services. It is recommended that the Commission become an advocate for and participant in an industry review and development of new reliability criteria more suited to a restructured electric industry.

The final Staff recommendation speaks directly to the conclusion that the state's existing and planned transmission systems are inadequate and planned improvements are not timely. Some of the state's utilities rely upon restoration of service following a transmission line outage, others implement curtailment plans and remedial action schemes limiting the output of energy from new plants, and all depend upon congestion path operating practices to mitigate overstressed transmission facilities. There should be accountability for inadequate coordinated system planning and delayed implementation of known transmission solutions. Staff recommends that transmission providers be required to supplement their previous plans to address the concerns and recommendations stated in this assessment. These supplements should be filed within three months of the date of this report and workshops held to assure they achieve the reliability required to deliver Arizona's energy needs.

Staff acknowledges that there may be additional issues that could be examined in assessing the transmission system in Arizona. However, the lack of information and resources has limited the analysis that Staff is able to provide.

Section 5: Bibliography

Reliability Criteria

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Section 6: About the Authors

Asher Emerson
Utilities Engineer

Asher has been with the Commission as an Electrical Engineer since May 2000. His responsibilities include providing technical support for Power Plant and Transmission Line Sitings; investigating contact violations of the Overhead Powerline Safety Law; investigating consumer complaints referred by Consumer Services; performing engineering inspections for financing and rate applications; and preparing the Biennial Transmission Assessment that is required by law.

Asher is a member of the Arizona Independent Scheduling Administration Association and the Process Standardization Working Group. He is also a member of the ACC Staff's Electric Policy Team. Mr. Emerson's prior experience includes 23 years with the Salt River Project where he worked as an Electrical Engineer in Engineering, Design, Construction, Maintenance and Project Management.

Jerry D. Smith
Utilities Engineer

Jerry joined the Commission Staff in February 1999, following a lengthy career with the Salt River Project, one of the state's largest electric utilities. He is a registered professional engineer in the state of Arizona and has a MSEE degree in Electric Utility Management.

Jerry's responsibilities have included involvement in Arizona's regulatory rulemaking and rate processes regarding retail electric competition and direct access of transmission and distribution facilities. He is actively participating in the organizational development of an Arizona Independent Scheduling Administrator and a Regional Transmission Organization called Desert STAR. Jerry is also responsible for the Commission's investigation of distributed generation and interconnections for potential rulemaking consideration. His experience with the Commission includes providing analysis and testimony regarding quality of service issues, utility planning and siting requirements, system adequacy assessments and cost of service studies. Mr. Smith has been the Commission's primary staff witness for recent power plant and transmission line siting cases.

During Jerry's thirty years of engineering and management experience with the Salt River Project, he analyzed and planned transmission and distribution system improvements. He also managed the design and consultation services required for retail customer projects. Mr. Smith also developed and managed capital improvement budgets, and the formation and modification of system planning, operational and maintenance policies, procedures and practices.

Appendix A

Guiding Principles
For ACC Staff's Determination of
Electric System Adequacy and Reliability

Guiding Principles for
ACC Staff Determination of
Electric System Adequacy and Reliability

This document serves the dual purpose of providing the guiding principles for ACC Staff determination of electric system adequacy and reliability in the two areas of transmission and generation.

Transmission

A.R.S §40-360.02E obligates the Arizona Corporation Commission (ACC) to biennially make a determination of the adequacy and reliability of existing and planned transmission facilities in the state of Arizona. Current state statutes and ACC rules do not establish the basis upon which such a determination is to be made. Therefore, ACC Staff will use the following guiding principles to make the required adequacy and reliability determination until otherwise directed by state statues or ACC rules.

1. Transmission facilities will be evaluated using Western Systems Coordinating Council (WSCC), or its successor's, Reliability Criteria for System Planning and Minimum Operating Reliability Criteria.
2. Transmission planning and operating practices traditionally utilized by Arizona electric utilities will apply when more restrictive than WSCC criteria.
3. Compliance with A.C.C. R14-2-1609.B[1] will be established by analysis of power flow and transient stability simulation of single contingency outages (N-1) of generating units, EHV and local transmission lines of greater than 100 kV nominal system voltage, and associated transformers. Reliance on remedial action such as generator unit tripping or load shedding for single contingency outages will not be considered an acceptable means of compliance with this rule.

[1] R14-2-1609.B refers to the obligation of Utility Distribution Companies to assure that adequate transmission import capability and distribution system capacity are available to meet the load requirements of all distribution customers within their service area.

Generation

Pursuant to A.R.S. §40-360.07, the ACC must balance, in the broad public interest, the need for adequate, economical, and reliable supply of electric power with the desire to minimize the effect on the environment and ecology of the state when considering the siting of a power plant or transmission line. The laws of physics dictate that generation and transmission facilities are inextricably linked when considering the reliability of service to consumers. Therefore, it is appropriate that both components must be considered when siting a power plant. ACC Staff will use the following guiding principles to make the required adequacy and reliability determination for siting generation until otherwise directed by state statues or ACC rules.

The best utility practices historically exhibited in the evolution of Arizona's generation and transmission facilities should be continued in order to promote development of a robust energy market. Non-discriminatory access to transmission and fair and equitable business practices must also be maintained and the service reliability to which the state is accustomed must not be compromised. Therefore, Staff support of power plant Certificate of Environmental Compatibility applications will be conditioned as set forth below.

ACC Staff support of power plant Certificate of Environmental Compatibility applications will be contingent upon the applicant providing, either in the application or at the hearing, evidence of items 1-3 below:

1. Two or more transmission lines must emanate from each power plant switchyard and interconnect with the existing transmission system. This plant interconnection must satisfy the single contingency outage criteria (N-1) without reliance on remedial action such as generator unit tripping or load shedding.
2. A power plant applicant must provide technical study evidence that sufficient transmission capacity exists to accommodate the plant and that it will not compromise the reliable operation of the interconnected transmission system.
3. All plants located inside a transmission import limited zone "must offer" all Electric Service Providers and Affected Utilities serving load in the constrained load zone, or their designated Scheduling Coordinators, sufficient energy to meet load requirements in excess of the transmission import limit.

ACC Staff support of power plant Certificate of Environmental Compatibility applications will further be contingent upon the Certificate of Environmental Compatibility being conditioned as provided in items 4-6 below:

4. The Certificate of Environmental Compatibility is conditioned upon the plant applicant submitting to the ACC an interconnection agreement with the transmission provider with whom they are interconnecting.
5. The Certificate of Environmental Compatibility is conditioned upon the plant applicant becoming a member of WSCC, or its successor, and filing a copy of its WSCC Reliability Criteria Agreement or Reliability Management System (RMS) Generator Agreement with the ACC.
6. The Certificate of Environmental Compatibility is conditioned upon the plant applicant becoming a member of the Southwest Reserve Sharing Group, or its successor, thereby making its units available for reserve sharing purposes.

Approved by:

(Original Signed by Deborah R. Scott)

Deborah R. Scott
Director
Utilities Division

This date: (2/8/00)

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Appendix B

Existing
Transmission Facility
Ratings

A List of Arizona and California Major Transmission Facilities Ratings

CONTINUOUS AND EMERGENCY RATINGS OF MAJOR TRANSMISSION LINES

	Continuous		Emergency	
Line	(MVA)	(AMP)	(MVA)	(AMP)
Adelanto-Marketplace 5OOkV	1640	(1800)	2210	(2430)
Adelanto-Rinaldi 5OOkV	1600	(1760)	2000	(2200)
Adelanto-RSE 5OOkV	1600	(1760)	2000	(2200)
Ambrosia-Pajarito 525kV	2500	(2750)	-----	-----
BA-Guadalupe-Blackwater 345kV	220	(368)	220	(368)
BA-Norton 345kV	478	(800)	956	(1600)
BA-West Mesa 345kV	478	(800)	756	(1280)
Cholla-Pinnacle Peak 345kV 1&2	600	(1004)	783	(1310)
Cholla-Saguaro 5OOkV	933	(1062)	1399	(1539)
Coronado-Cholla 5OOkV	1732	(2000)	1732	(2000)
Coronado-Silver King 5OOkV	1233	(1424)	1233	(1424)
Coyote-Los Alamos-Ojo-Norton 345kV	1075	(1800)	-----	-----
DC Intermountain-Adelanto 5OOkV	1920	(1920)	2400	(2400)
Devers-Palo Verde 5OOkV	1728	(1900)	2210	(2430)
Devers-Valley 5OOkV (1986)	2730	(3000)	3000	(3300)
Eldorado-Lugo 5OOkV	1450	(1600)	2360	(2600)
Eldorado-Moenkopi 5OOiV	1728	(1900)	2360	(2750)
Eldorado-Mohave 5OOkV	1820	(2000)	2360	(2600)
Flagstaff-Pinnacle Peak 345kV	747	(1350)	1004	(1680)
Four Corners-Ambrosia 23OkV	319	(800)	319	(800)
Four Corners-Ambrosia 525kV	2500	(2750)	-----	-----
Four Corners-Cholla 345kv 1 & 2	621	(1040)	843	(1410)
Four Corners-Moenkopi 5OOkV	1646	(1810)	2292	(2750)

Four Corners-San Juan 345kV	945	(1600)	956	(1600)
Four Corners-West Mesa 345kV	717	(1200)	717	(1200)
Glen Canyon-Flagstaff 345kV 1&2	807	(1500)	1088	(1820)
Greenlee-Hidalgo 345kV No. 1	478	(800)	717	(1200)
Greenlee-Vail 345kv	896	(1500)	1220	(2042)
Hidalgo-Luna 345kV No. 1	478	(800)	956	(1600)
Imperial Valley-North Gila 5OOkV	1273	(1400)	1819	(2000)
Liberty-Mead 345kV	500	(887)	597	(1000)
Lugo-Mira Loma 5OOkV No. 1	1820	(2000)	2360	(2600)
Lugo-Mira Loma 5OOkV No. 2	1820	(2000)	2360	(2600)
Lugo-Mira Loma 5OOkV No. 3	1820	(2000)	2360	(2600)
Lugo-Mohave 50dkV	1450	(1600)	2360	(2600)
Lugo-Serrano 5OOkV	2730	(3000)	3000	(3300)
Lugo-Victorville 5OOkV	2730	(3000)	2730	(3000)
Lugo-Vincent 5OOkV No. 1	1820	(2000)	2360	(2600)
Lugo-Vincent 5OOkV No. 2	1820	(2000)	2360	(2600)
McCullough-Eldorado 5OOkV	2728	(3000)	2728	(3000)
McCullough-Victorville 5OOkV 1 & 2	1455	(1600)	2182	(2400)
McKinley-Springerville 345kV 1 & 2	925	(1548)	1110	(1858)
Mead-Westwing 5OOkV	1300	(1430)	1750	(1930)
Miguel-Imperial Valley 5OOkV	1120	(1232)	1389	(1530)
Mira Loma-Serrano 5OOkV	2730	(3000)	3000	(3000)
Moenkopi-Eldorado 5OOkV	1482	(1630)	2501	(2750)
Moenkopi-Westwing 5OOkV	1109	(1219)	1496	(1645)
Navajo-McCullough 5OOkV	1482	(1630)	2501	(2750)
Navajo-Moenkopi 5OOkV	1482	(1630)	1887	(2075)
Navajo-Westwing 5OOkV	1034	(1137)	1391	(1530)

North Gila-Palo Verde 5OOkV	1273	(1400)	1719	(1890)
Palo Verde-Kyrene 5OOkV	1233	(1424)	-----	-----
Palo Verde-North Gila 5OOkV	1273	(1400)	1719	(1890)
Palo Verde-Westwing 5OOkV	2598	(3000)	2598	(3000)
Saguaro-Tortolita 5OOkV	672	(739)	807	(887)
San Juan-BA 345kV	478	(800)	717	(1200)
San Juan-McKinley 345kV 1&2	777	(1300)	101.6	(1700)
San Juan-ojo 345kV	478	(800)	717	(1200)
San Juan-Shiprock 345kV	478	(800)	717	(1200)
Serrano-valley 5OOkV	2730	(3000)	3000	(3300)
Springerville-Coronado 345kV	672	(1125)	807	(1350)
Springerville-Greenlee 345kV	745	(1247)	1010	(1690)
Springerville-Vail 345kv	666	(1115)	807	(1350)
Vail-South 345kV	860	(1440)	1033	(1728)
Victorville-Adelanto 5OOkV 1&2	2728	(3000)	2728	(3000)
Victorville-Lugo 5OOkV	2728	(3000)	2728	(3000)
Miguel-Imperial Valley 5OOkV	1120	(1232)	1389	(1530)
Victorville-Rinaldi 5OOkV	1600	(1760)	2000	(2200)
West Mesa-Ambrosia 23OkV	319	(800)	319	(800)
West Mesa-Arroyo (Pajaritc) 345kV	478	(800)	717	(1200)
West Mesa-Pajarito 345kV	478	(800)	717	(1200)
Westwing-South 345kV	672	(1125)	807	(1350)
Julian Hinds-Mirage 23OkV	357	(895)	410	(1029)
Imperial Valley-El Centro 23OkV	225	(565)	262	(656)
Coachella-Mirage 23OkV	494	(1240)	569	(1426)
Coachella-Devers 23OkV	494	(1240)	569	(1426)

CONTINUOUS AND EMERGENCY RATINGS
OF PHOENIX AREA 23OkV LINES

Line	Rating (MVA) Continuous	Emergency
Agua Fria-Alexander	725	797
Agua Fria-El Sol	438	539
Agua Fria-Glendale	450	570
Agua Fria-Westwing	526	526
Agua Fria-White Tanks	725	797
Alexander-Deer Valley	683	852
Anderson-Orme	637	637
Anderson-Kyrene	637	637
Brandow-Kyrene	637	637
Brandow-Papago Buttes	637	637
Brandow-Pinnacle Peak (Two Lines)	363 ea.	438 ea.
Cactus-Ocotillo	363	430
Cactus-Pinnacle Peak	363	430
Corbell-Kyrene	637	637
Corbell-Santan	363	438
Country Club-Glendale	363	530
Country Club-Lincoln Street	350	514
Country Club-Sunnyslope	324	490
Deer Valley-Pinnacle Peak	478	478
Deer Valley-Westwing	725	797
El Sol-Surprise	600	783
El Sol-White Tanks	717	869
Kyrene-Papago Buttes	637	637
Kyrene (New) - Santa Rosa	301	363

Liberty-Coolidge	367	403
Liberty-Gila Bend	438	537
Liberty-Hassayampa-Harcuvar-Parker	438	482
Liberty-Eagle Eye-Parker	438	482
Liberty-Orme	725	876
Lib,erty-Westwing	733	806
Lincoln Street-Ocotillo	311	401
Lincoln Street-West Phoenix	363	447
Lone Peak-Paradise	717	880
Lone Peak-Sunnyslope	438	539
Mesa-Coolidge	335	368
Mesa-Pinnacle Peak (Two Lines)	375 ea.	412 ea.
Mesa-Thunderstone	363	438
Ocotillo-Kyrene (New)	301	363
ocotillo-Pinnacle Peak	363	-430
Orme-White Tanks	725	797
Paradise-Pinnacle Peak	717	880
Pinnacle Peak-Westwing	733	806
Pinnacle Peak-Prescott-Davis	335	368
Santan-Thunderstone	363	438
Surprise-Westwing	637	802
Thunderstone-Goldfield (Two Lines)	363 ea.	438 ea.
West Phoenix-White Tanks	717	809

Appendix C

Ten Year Transmission Plans Filed January 2001

TEN YEAR PLANS: 2001-2010 - SORTED BY DATE

IN SERVICE DATE	COMPANY	TRANSMISSION DESCRIPTION	VOLTAGE	MILES	LOCATION	CEC STATUS
2001	APS	White Tanks-Estrella-West Phoenix	230kV	15.8	West Phoenix	ISSUED
2001	APS	Redhawk - Hassayampa	500kV	1.5	West Phoenix	ISSUED
2001	SRP	Browning - Santan	230kV	11	SE of Phoenix	ISSUED
2002	APS	Gila River - Jojoba	500kV	21	West Phoenix	ISSUED
2002	SRP	Palo Verde - Hassayampa	500kV	2	Palo Verde	ISSUED
2002	TEP	DeMoss Petrie - Fort Lowell and Mountain - Northeast	138kV	0.05	Central Tucson	NOT REQUIRED
2003	APS/SRP	Palo Verde - Southwest Valley (1)	500kV	33	West of Phoenix	REQUIRED
2003	Citizens/ TEP	Nogales Second Transmission	115kV	50	South of Tucson	REQUIRED
2003	IPT	Gila Bend - Palo Verde	500kV	30	West of Phoenix	ISSUED
2003	SRP/APS	Palo Verde - Southwest Valley (1)	500kV	33	West of Phoenix	REQUIRED
2003	Citizens	South to Gateway	345kV	70	South of Tucson	REQUIRED
2004	APS	Pinnacle Peak - TS1	230kV	5	Paradise Valley	REQUIRED
2004	PNM	Arizona - Sonora	345kV AC	300	Phoenix to Tucson	REQUIRED
2005	APS	Gila Bend - Yuma	230kV	115	SW Arizona	REQUIRED
2005	APS	Pinal - Ice House	115kV	4	South of Globe	REQUIRED
2005	SRP	Rogers - Coolidge	500kV	35	Southeast of Phoenix	REQUIRED
2005	TEP	East Loop - Northeast	138kV	13	Central Tucson	ISSUED
2005	TEP	Irvington - Littletown - Vail	138kV	4	SE Tucson	ISSUED
2005	TEP	South Loop - Green Valley - Cyprus Sierrita	138kV	24	South of Tucson	ISSUED
2005	TEP	Rancho Vistoso - Catalina	138kV	4	North of Tucson	REQUIRED
2006	APS	Tribley Wash - El Sol	230kV	15	NW Phoenix	REQUIRED
2006	APS	Santa Rosa - Gila Bend	230kV	55	Southern Arizona	Decision 53389
2006	TEP	North Loop - Del Cerro - DeMoss Petrie	138kV	0.75	West of Tucson	ISSUED
2007	APS	Raceway - Pioneer	230kV	12	North of Phoenix	REQUIRED

(1) Joint Project between APS & SRP

TEN YEAR PLANS: 2001-2010 - SORTED BY DATE

IN SERVICE DATE	COMPANY	TRANSMISSION DESCRIPTION	VOLTAGE	MILES	LOCATION	CEC STATUS
2007	APS	White Tanks-TS3-Buckeye	230kV	17	Buckeye	REQUIRED
2007	Citizens	Griffith - North Havasu	230kV	40	Western Arizona	ISSUED
2007	TEP	Green Valley - Cyprus Raw Water - Cyprus Sierrita	138kV	0.05	South of Tucson	NOT REQUIRED
2008	APS	Westwing - El Sol	230kV	11	NW Phoenix	REQUIRED
2008	APS	Pinnacle Peak - Pioneer	230kV	16	North of Phoenix	REQUIRED
2009	APS	Westwing - Pioneer	230kV	16	NW Phoenix	REQUIRED
2009	APS	TS2 - TS3	230kV	7	SW Phoenix	REQUIRED
2009	TEP	Vail - Robert Bills - Los Reales - East Loop	138kV	0.05	SE Tucson	NOT REQUIRED
2010	SRP	Browning - RS-19	230kV	30	East of Phoenix	REQUIRED
N/A	AEPCO	None Planned	N/A	N/A	N/A	N/A
UNDER STUDY	SRP	Westwing to Pinnacle Peak	230kV	22	North of Phoenix	REQUIRED
POSTPONED	EPE	Greenlee - Deming	345kV	28	SE Arizona	ISSUED
UNDER STUDY	TEP	Tortolita - South	345kV	68	West of Tucson	ISSUED
UNDER STUDY	TEP	Midvale - San Joaquin	138kV	6	SW Tucson	N/A
UNDER STUDY	TEP	South - DeMoss Petrie	138kV	18	SE Tucson	REQUIRED
UNDER STUDY	TEP	Irvington - 22nd Street - East Loop	138kV	9	Central Tucson	ISSUED
UNDER REVIEW	TEP	Vail - Houghton Loop Switching - Spanish Trail - Roberts - East Loop	138kV	22	Central Tucson	ISSUED
UNDER STUDY	TEP	Westwing - South	345kV	178	Phoenix to Tucson	CONTEST (2)

(2) Tucson's note under Is Certificate Necessary "No (Path established before 1971)"

TEN YEAR PLANS (2001 - 2010) SORTED BY COMPANY

IN SERVICE DATE	COMPANY	TRANSMISSION DESCRIPTION	VOLTAGE	MILES	LOCATION	CEC STATUS
N/A	AEPCO	None Planned	N/A	N/A	N/A	N/A
2001	APS	Redhawk - Hassayampa	500kV	1.5	West Phoenix	ISSUED
2001	APS	White Tanks-Estrella-West Phoenix	230kV	15.8	West Phoenix	ISSUED
2002	APS	Gila River - Jojoba	500kV	21	West of Phoenix	ISSUED
2003	APS/SRP	Palo Verde - Southwest Valley (1)	500kV	33	West of Phoenix	REQUIRED
2004	APS	Pinnacle Peak - TS1	230kV	5	Paradise Valley	REQUIRED
2005	APS	Gila Bend - Yuma	230kV	115	SW Arizona	REQUIRED
2005	APS	Pinal - Ice House	115kV	4	Near Globe	REQUIRED
2006	APS	Tribley Wash - El Sol	230kV	15	NW Phoenix	REQUIRED
2006	APS	Santa Rosa - Gila Bend	230kV	55	Southern Arizona	Decision 53389
2007	APS	Raceway - Pioneer	230kV	12	North of Phoenix	REQUIRED
2007	APS	White Tanks-TS3-Buckeye	230kV	17	Buckeye	ISSUED
2008	APS	Westwing - El Sol	230kV	11	NW Phoenix	REQUIRED
2008	APS	Pinnacle Peak - Pioneer	230kV	16	North of Phoenix	REQUIRED
2009	APS	Westwing - Pioneer	230kV	16	NW Phoenix	REQUIRED
2009	APS	TS2 - TS3	230kV	7	SW Phoenix	REQUIRED
2003	Citizens/ TEP	Nogales Second Transmission	115kV	50	South of Tucson	REQUIRED
2007	Citizens	Griffith - North Havasu	230kV	40	Western Arizona	ISSUED
POSTPO	EPE	Greenlee - Deming	345kV	28	SE Arizona	ISSUED
2003	IPT	Gila Bend - Palo Verde	500kV	30	West of Phoenix	ISSUED
2004	PNM	Arizona - Sonora	345kV	300	Phoenix to Tucsor	REQUIRED
2001	SRP	Browning - Santan	230kV	11	SE of Phoenix	ISSUED
2002	SRP	Palo Verde -	500kV	2	Palo Verde	ISSUED
2003	SRP/APS	Palo Verde - Southwest Valley (1)	500kV	33	West of Phoenix	REQUIRED
2005	SRP	Rogers to Coolidge	230kV	35	SE of Phoenix	REQUIRED
2010	SRP	Silver King to Browning	230kV	38	SE of Phoenix	REQUIRED
2012	SRP	Silver King to Browning/Superior Tie	230kV	0.5	East of Phoenix	REQUIRED
2012	SRP	RS19 to Pierce	230kV	20	SE of Phoenix	REQUIRED
2012	SRP	Pinnacle Peak to Brandow	230kV	30	NE of Phoenix	REQUIRED
2012	SRP	Rogers to Corbell	230kV	12	East of Phoenix	REQUIRED
2012	SRP	Silver King - Knoll - New Hayden	230kV	35	SE of Phoenix	REQUIRED
2012	SRP	Kearny - Hayden - New Hayden	115kV	0.75	SE of Phoenix	REQUIRED

(1) Joint Project between APS & SRP

TEN YEAR PLANS (2001 - 2010) SORTED BY COMPANY

IN SERVICE DATE	COMPANY	TRANSMISSION DESCRIPTION	TRANSMISSION VOLTAGE	MILES	LOCATION	CEC STATUS
UNDER STUDY	SRP	Westwing to Pinnacle Peak	230kV	22	North of Phoenix	REQUIRED
2002	TEP	DeMoss Petrie - Fort Lowell and Mountain - Northeast	138kV	0.05	Central Tucson	NOT REQUIRED
2003	TEP	South to Gateway	345kV	70	South of Tucson	REQUIRED
2005	TEP	East Loop - Northeast	138kV	13	Central Tucson	ISSUED
2005	TEP	Irvington - Littletown - Vail	138kV	4	SE Tucson	ISSUED
2005	TEP	South Loop - Green Valley - Cyprus Sierrita	138kV	24	South of Tucson	ISSUED
2005	TEP	Rancho Vistoso - Catalina	138kV	4	North of Tucson	REQUIRED
2006	TEP	North Loop - Del Cerro - DeMoss Petrie	138kV	0.75	West of Tucson	ISSUED
2007	TEP	Green Valley - Cyprus Raw Water - Cyprus Sierrita	138kV	0.05	South of Tucson	NOT REQUIRED
2009	TEP	Vail - Robert Bills - Los Reales - East Loop	138kV	0.05	SE Tucson	NOT REQUIRED
UNDER STUDY	TEP	Tortolita - South	345kV	68	West of Tucson	ISSUED
UNDER STUDY	TEP	Midvale - San Joaquin	138kV	6	SW Tucson	REQUIRED
UNDER STUDY	TEP	South - DeMoss Petrie	138kV	18	SE Tucson	REQUIRED
UNDER STUDY	TEP	Westwing - South	345kV	178	Phoenix to Tucsor	CONTEST (2)
UNDER STUDY	TEP	Springerville to Greenlee	345kV	100	Phoenix to Tucsor	ISSUED
IDER STUI	TEP	Irvington - 22nd Street - East Loop	138kV	9	Central Tucson	ISSUED
UNDER REVIEW	TEP	Vail - Houghton Loop Switching - Spanish Trail - Roberts - East Loop	138kV	22	Central Tucson	ISSUED
UNDER STUDY	TEP	Saguaro - Tortolita	500kV	Unknown	Northwest of Tucs	REQUIRED

(2) Tucson's note under Is Certificate Necessary "No (Path established before 1971)"

Appendix D

Industry Comments To Biennial Transmission Assessment (2000 To 2009)

Proposed Changes* to the Biennial Transmission Assessment Report 2000-2009 Docket No. E-00000A-01-0120 [For discussion at July 23, 2001 Open Meeting]

(*Incorporates comments docketed through July 9, 2001)

INTRODUCTION:

The Arizona Legislature has mandated that on a biennial basis the Arizona Corporation Commission must review ten year plans filed by any person contemplating construction of any transmission line within the state, and issue a written decision addressing "the adequacy of the existing and planned transmission facilities in this state to meet the present and future energy needs of this state in a reliable manner." A.R.S. § 40-360.02(E). To comply with this statutory mandate, the Arizona Corporation Commission Staff completed its first biennial assessment of Arizona's existing and planned transmission system and filed the Biennial Transmission Assessment, 2000 – 2009 ("Assessment") on March 1, 2001.

It is Staff's position that a thorough assessment of the adequacy and reliability of Arizona's transmission system requires actual technical studies. However, the Commission had neither the required data nor the resources to perform the necessary technical studies. Therefore, Staff, in formulating its findings and recommendations, relied upon its industry experience and knowledge of Arizona's transmission system to analyze the technical reports that had been published by others.

The Commission reviewed and discussed the Assessment at its March 27th Open Meeting. Based upon that review and comments from the industry and the public, the Commissioners directed Staff to schedule workshops with the interested parties for further discussion of the issues. Prior to the first workshop, parties were to file comments addressing the findings and conclusions of the Assessment. Staff convened the 1st workshop on May 10, 2001. At that workshop, the parties advocated their positions and voiced their opinions regarding the Assessment. Because a number of issues remained unresolved, a 2nd workshop was held on Friday, June 22, 2001.

Staff has prepared this document to facilitate a complete and effective discussion of the issues at the scheduled July 23rd Open Meeting before the Commissioners. Staff has incorporated the comments of the parties, organizing them to coincide with the relevant issues in the Assessment. In addition, this document reflects Staff's position on the issues, having considered the comments of the parties.

ISSUES:

ISSUE #1 - USE OF ASSESSMENT
(Executive Summary)

Arizona Public Service noted in its comments that "[t]he Assessment should clarify that it represents an opinion of Commission Staff, for use in compliance with A.R.S. § 40-360.02(E), but is not intended to set Commission policy or require any specific action by Arizona transmission providers."

After the 2nd workshop, APS filed the following additional comments:

Proposed Commission Action on the Assessment.

Although no proposed form of order was provided with the Proposed Changes, several of the changes suggest that Staff will request more action from the Commission than is either necessary or appropriate in this matter. Given the significant disagreements between Staff and stakeholders over many of the policy issues in the Assessment and the obligation that substantive requirements be developed in a rulemaking proceeding, APS does not believe that the Commission should "adopt" the Assessment as Commission policy. At most, the Commission should "accept" the Assessment and determine that it complies with A.R.S. § 40-360.02.

Additionally, Staff had proposed a clarifying paragraph stating that the Assessment was the professional opinion of Staff, and not Commission policy. (*See* Proposed Changes at p. 2.) In the Proposed Changes, however, an additional sentence was added to that paragraph: "This Transmission Assessment will not be ACC policy unless and until adopted by Commission Decision." (*Id.*) That addition arguably nullifies the concerns that APS believed Staff was trying to address. Further, it places into question the scope and extent of "ACC policy" that is intended to result from the Assessment. For example, will the Guiding Principles, which are specifically described as being only an opinion of Staff, nonetheless become "ACC policy" following a Commission decision in this docket? Accordingly, the additional language added to the insert on Page 2 of the Proposed Changes should be deleted.

Finally, the "Next Steps" included on the final page of the Proposed Changes could be construed to require transmission providers to propose additional transmission facilities without any further analysis of costs or benefits associated with such facilities. As discussed above, specific decisions regarding additional transmission facilities involve more than simply an analysis of the marginal cost of any given merchant generator. Accordingly, the third bullet of the Next Steps should be revised to request:

Technical Study Reports with Ten-Year filings identifying potential transmission enhancements that could address local constraints and their associated costs.

Once the various options and cost estimates are prepared, Staff and transmission providers can more accurately make effective and economical planning decisions.

Staff does not disagree with the APS comments, and will insert the following statement in the Executive Summary:

This Transmission Assessment represents the professional opinion of Commission Staff, does not set Commission policy, and does not recommend any specific action by Arizona transmission providers. This Transmission Assessment will not be ACC policy unless and until adopted by Commission Decision.

[Insert at page iii, at the end of paragraph 1.]

ISSUE #2 - ADEQUACY / RELIABILITY

Use of NERC or WSCC Standards to Determine Adequacy; Reliability Criteria; NERC definition of "Adequacy" and "Security" (Section 1.2)

APS expressed concerns regarding the methodology of assessing adequacy and reliability. The Company commented:

> The Assessment initially refers to the North American Electric Reliability Council's ("NERC") definition for the terms "adequacy" as well as "reliability." These terms, however, are not fully developed using applicable NERC criteria.
>
> The Assessment should use a methodology of assessing adequacy (and reliability) that is recognized in the industry. Although NERC and WSCC terminology and standards are similar, APS recommends that the Assessment adopt WSCC terminology and reliability criteria because Arizona is located within the WSCC. This would include the recent WSCC amendments adopted in December 2000 and the Reliability Criteria for Transmission System Planning, Minimum Operating Reliability Criteria and Power Supply Assessment Policy. The Assessment should evaluate the existing and planned Arizona transmission system using these criteria.
>
> The Assessment should also indicate where the existing or planned transmission system fails to meet the applicable criteria, or whether Staff believes that the WSCC criteria is inadequate, along with any supporting analysis."

In addressing the reliability criteria utilized by Staff, SRP asked:

> Are the reliability criteria being developed by NERC for a restructured electric utility industry adequate for the transmission system in Arizona, or is more required?
>
> Are additional reliability criteria, beyond those required by WSCC and unique to Arizona, compatible with regional grid approaches being recommended by FERC?

APS also noted that Staff's quotation of the National Electric Reliability Council's definition of "Adequacy" in the Assessment was inaccurate.

In its comments, Salt River Project explained that:

> SRP bases its design on prudent utility practices and on meeting applicable NERC and WSCC planning and operating criteria. The application of the N-1 criteria ensures that the demand and energy requirements of SRP's customers can be met with the expected loss of a single transmission element or generation unit. As per the NERC Criteria, this is done "taking into account scheduled and reasonably expected unscheduled outages of system elements." The objective of SRP's planning effort is to discover and address those generation and load patterns that are the most restrictive under the applied criteria. This ensures that SRP will operate its system within the established criteria at all times, assuring energy deliveries to its customers."

In response to the concerns raised regarding adequacy and reliability, Staff will insert the following statement in the Assessment:

Any discussion of adequacy or reliability must be put in the context that NERC and WSCC were established to provide a forum for the coordination of planning and operation of the member systems to promote reliability of the interconnected bulk power systems. (WSCC's Minimum Operating Reliability Criteria (revised August 8, 2000) pages III-6, III-7 and III-8 under 1.0 INTRODUCTION and 2.0 PHILOSOPHY OF CRITERIA). NERC and WSCC establish criteria that govern how members impact the interconnected bulk power system. Staff is participating and commenting in industry development of reliability criteria for the restructured electric industry.

It is important to understand that NERC and WSCC are organizations that deal with interconnected systems. Neither NERC nor WSCC establish criteria for planning or operational requirements internal to members systems. In fact, NERC and WSCC criteria allow blackouts, voltage collapse, or cascading - as long as the impacts are confined to a local network or a radial system. NERC and WSCC also allow less stringent criteria from one member, as long as the other systems are permitted to have the same impact on that individual system. In addressing the individual members' systems, NERC's planning standards state that "[t]hose entities also have the responsibility to develop their own appropriate or more detailed planning and operating reliability criteria and guides that are based on the ***Planning Standards*** *and which reflect the diversity of individual electric system characteristics, geography and demographics for their areas.*

Staff has grave concerns about blackouts, voltage collapse or cascading that is internal to Arizona systems as this could have a profound effect on customers. Therefore, Staff contends that there should be a higher standard than NERC and WSCC require for internal system planning and operations. It is Staff's position that all entities, WSCC members and nonmembers, should operate in accordance with the NERC or WSCC Reliability Criteria whichever is more specific or stringent. Since electric system reliability is so vital to Arizona, Staff contends that it is appropriate to apply the most specific and stringent criteria. (WSCC's Minimum Operating Reliability Criteria (revised August 8, 2000) page III-27.)

Staff notes that SRP applies the N-1 criteria internal to their system, which precludes radial transmission lines. This is a higher standard than is required by either NERC or WSCC for internal system planning. Staff believes that this indicates that SRP complies with the WSCC's philosophy that states " [c]ontinuity of service to loads is the primary objective of the Council Reliability Criteria." WSCC's Minimum Operating Reliability Criteria (revised August 8, 2000) under 2.0 PHILOSOPHY OF CRITERIA.

[Insert in Section 1.2, on page 1, at the end of paragraph 2.]

In response to the issue of NERC definitions, Staff acknowledges that it did paraphrase the definitions in an attempt to be succinct. However, to avoid any misunderstanding, Staff will insert the NERC definitions verbatim, as follows:

> *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.*
>
> [Insert in Section 1.2, on page 1, at the start of paragraph 3.]
>
> *Security - The ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.*
>
> [Insert on page 2, before the start of the last paragraph of Section 1.2.]

However, Staff contends that the above definitions of "transmission adequacy" and "security" are not suited to the restructured electric industry. These definitions also do not take into consideration the environmental impact of older and more polluting generation. Furthermore, the regional and federal reliability criteria do not apply to the internal systems of utilities. In order to address these shortcomings and enable effective competition in the State of Arizona, Staff has developed the following two different standards due to the different environment of electric restructuring, for measurement of transmission adequacy and security:

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.

Staff feels that the better approach is to have standards of measuring transmission capacity instead of merely defining the terms "transmission adequacy" and "security."

> [Insert on page 2, as the last paragraphs of Section 1.2.]

Relaxing of WSCC Reliability Standards (Section 2.1, page 6, ¶ 5)

APS has commented that currently WSCC reliability standards are considered to be more stringent than NERC standards, but that there have been recent discussions as to whether the WSCC should migrate to the NERC standards.

Staff is participating and commenting in industry development of reliability criteria for the restructured electric industry, but it should be noted that present WSCC criteria state that "[a]ll entities, WSCC members and nonmembers, shall operate in accordance with the NERC or WSCC Reliability Criteria, whichever is more specific or stringent." Since electric system reliability is vital to Arizona, Staff will continue to recommend that the most specific and stringent criteria be applied. (WSCC's Minimum Operating Reliability Criteria (revised August 8, 2000) page III-27.)

NERC definition of "Adequacy" (Section 3.2, page 31, ¶ 3)

Tucson Electric Power raised concerns about Staff's reference to the forest fire that occurred in 2000 because it appeared that Staff cited this as an indication of transmission inadequacy. TEP stated:

> As Staff stated in its report, security of a system should accommodate the loss of a single system component. The forest fire referred to by Staff was actually a situation that would be considered a double contingency that is not something that would be designed to be survived without remedial action. TEP's implementation of remedial action to deal with the fire and resulting outages on its system were determined to be in compliance with WSCC/NERC criteria in a follow up investigation by the WSCC.

After the 2nd workshop, SRP filed the following additional comments:

> **Duplicate Transmission Corridors**
>
> With respect to ACC staff proposed changes outlined at the top of page 6 (to be inserted in original report as final paragraph in section 3.2 on page 31), SRP recommends inserting the following sentence at the end of the paragraph: *"However, this concern must be balanced with the public's interest in developing multiple utility corridors."*
>
> SRP concurs that there should be judicious use of common corridors. Typically, lines serving the same source to load are not placed on the same structure. They are placed sufficiently far enough apart so as not to be subject to common mode events. When sufficient separation cannot be provided, the practice is to consider both lines out as a single event. When this occurs, the transmission owner should include this scenario in their system analysis and appropriately incorporate it in their plans.
>
> However, SRP believes that Staff must balance its desire for separate utility corridors for reliability purposes with the clear public policy of co-locating utilities to reduce their impact on neighborhoods. Throughout the legislative discussions on "Growing Smarter" and other growth management initiatives, many called for less disruptive, co-location of utility facilities, along with advance notice of the corridors' location to the local communities.

After the 2nd workshop, APS filed the following additional comments:

> **The Assessment Should Not Adopt or Discuss a Policy Limiting the Use of Utility Corridors.**
>
> Based on a single, anecdotal conclusion arising from comments made to the Assessment—and without supporting evidence or stakeholder comment—Staff's

Proposed Changes include what might be construed as a major policy shift in the use of utility corridors to site transmission lines. (Proposed Changes pp. 5-6.) Specifically, Staff proposes to add language to the Assessment expressing their concern for placing multiple transmission lines serving the same load in common corridors. Staff goes on to suggest that there must be a "balance" between the "environmentally-driven practice" of using utility corridors and system reliability. (*Id.* at p. 6.)

On the one hand, Staff advocates siting and constructing more transmission lines in the Assessment t. On the other hand, they now appear to propose language that may make it more difficult to site such lines. Indeed, such a position on utility corridors would increase the environmental impacts of the transmission lines in derogation of the Commission's responsibilities in A.R.S. § 40-360.07. Further, the discussion leading up to this position does not indicate that Staff has considered any material factors regarding common corridors. For example, there is no discussion about transmission tower design and spacing, which prevent the failure of one transmission line from impacting a parallel transmission line. There is no probabilistic assessment of the likelihood of an event that could cause the failure of more than one transmission line. In fact, in many circumstances the loss of even two transmission lines serving the same load would not result in a direct impact to that load. And there is no assessment of how quickly a failure could be remedied by constructing a temporary "shoefly" around the failed transmission structures. Without such a detailed analysis, it is impossible to reject the concept of utility corridors and justify the use of new transmission routes with additional environmental impacts.

Ultimately, this is not an issue that needs to be addressed at all in the Assessment. Staff intervenes in every transmission line siting case before the Arizona Power Plant and Transmission Line Siting Committee. Staff can raise any concerns it may have on specific transmission line routing before the Siting Committee (and subsequently the Commission) and the merits can be addressed on a case-by-case basis. Accordingly, APS recommends deleting the last paragraph proposed for insertion on pp. 5-6 of the Proposed Changes.

To address the above stated concerns, Staff will insert the following statement:

TEP complied with WSCC criteria. However, because the WSCC criteria only deals with interconnected systems, it does not address internal loss of load. Nonetheless, ***this outage was contrary to the basic philosophy and primary objective of WSCC, which states, "[c] ontinuity of service to loads is the primary objective of the Council Reliability Criteria****." (Page III-6, WSCC's Minimum Operating Reliability Criteria (revised August 8, 2000).*

In addition, WSCC's Minimum Operating Reliability Criteria (revised August 8, 2000) states, "[a] single contingency means the loss of a single system element, however, the outage of multiple system elements should be treated as a single contingency if caused by a single event of sufficiently high likelihood". Staff has concerns with any utility placing multiple transmission lines, serving the same load, in a common corridor that could be interrupted by a single event. However, this concern must be balanced with the public's interest in developing multiple utility corridors. There needs to be a balance between the *environmentally driven practice of siting new lines adjacent to existing corridors and the increased system reliability by opening up new corridors.*

[To be inserted as the final paragraph in Section 3.2 on page 31.]

ISSUE #3 - GUIDING PRINCIPLES

Guiding Principles (Section 2.1, page 6, ¶ 3 - located in Appendix A)

Both Arizona Electric Power Cooperative and APS opined that the Guiding Principles that Staff applies in line siting cases should be subject to industry and public comment. APS stated:

> The Assessment's analysis should be based on generally accepted baselines rather than on informal guidelines or policies that have not been subject to rulemaking or are subject to significant disagreement among stakeholders. This will help avoid the risk of conflicting standards and requirements between the entities responsible for transmission planning and reliability analysis. Further, if "accountability" is to be imposed on transmission providers, any assessment of adequacy must involve measurable and objective metrics, and not merely subjective assessments. If Staff desires to codify its informal policies and guidelines, it could recommend in the Assessment that an appropriate rulemaking be initiated.

Guiding Principles (Section 2.1, page 6, ¶ 3- Appendix A) - Two-line Requirement

APS also expressed concerns about the two-line requirement in the Guiding Principles:

> The number of transmission lines emanating from a power plant has no necessary connection to the ability to provide reliable service to native load customers. Thus, this Staff guideline should not be addressed in the Assessment at all, because A.R.S. § 40-360.02(E), which directs the assessment to focus on the "energy needs" (i.e., load) of "this State."
>
> Additionally, the Assessment's position on a "blanket" requirement for two transmission lines from every power plant, and blanket requirement of N-1 reliability without remedial action schemes, is unreasonable and not required by current industry guidelines or standards. A two-line requirement has been vigorously (and successfully) contested by several merchant generators. The Commission itself has rejected the Assessment's position when system topology, economics and environmental impacts warranted construction of only a single transmission line.
>
> Table 2 of the Assessment, a listing of power plants with the number of transmission lines, does not support the two-line requirement because it does not consider the circumstances underlying each power plant's transmission

configuration. For example, some of the plants on the list agreed on two transmission lines to settle with Staff prior to a CEC hearing, not because of an industry standard. Also, the generating capacity of many of the plants is of such magnitude that two transmission lines would be necessary, not for reliability purposes, but simply to carry the output of the plant. For example, Panda's Gila River project is a 2,080 MW plant. Two 500 kV transmission lines are required to support this much capacity. Further, some of the older plants may simply reflect then-current system issues or the phenomenon of multiple, joint-ownership interests in power plants which often resulted in separate transmission paths from the plant to various load centers. What Table 2 does show, however, is that the number of transmission lines and transformer ties from any specific power plant is a very case-specific determination.

Although this may appear to be simply a generator issue, APS is concerned about any Commission policy that restricts or inhibits power plant development in Arizona and increases APS' costs to procure generation for its customers. The determination of how many transmission lines should emanate from any specific power plant is and should be a case-specific inquiry. The Assessment should not implicitly create policy for such a requirement, particularly given the lack of evidence for the requirement and the amount of stakeholder disagreement with the policy.

After the 2nd workshop, APS filed the following additional comments:

The "Two Line" Rule and Staff's Guiding Principles.

Despite overwhelming and persuasive comments from a variety of parties criticizing the "two line" requirement for the interconnection of new generators to the transmission grid, the Proposed Changes still do not appear to adequately address this issue. Rather than recognizing that the Guiding Principles are not appropriate for inclusion in the Assessment, the Proposed Changes merely include a statement that Staff was not recommending that the Guiding Principles become "Commission Rules. " (Proposed Changes at p. 7.) At the same time, Staff is apparently asking the Commission to adopt the Assessment as "policy." (*Id.* at 2.) This could result in some parties construing the "two line" requirement to be more than just the "professional opinion of Commission Staff." (*Id.* at 7.)

Accordingly, the Guiding Principles should be omitted entirely from the final Assessment. Alternatively, the insert to Section 1.3 of the Assessment should be clarified to read:

The Guiding Principles represent the professional opinion of Commission Staff. As such, the Guiding Principles are not intended to be Commission Rules or policy. However, Staff or the Commission reserves the right to open a rulemaking docket in the future to codify the Guiding Principles.

Like the utility corridor issue discussed above, the "two line" requirement should be addressed on a case-by-case basis before the Siting Committee and should not become a Staff or Commission "policy."

PG&E National Energy Group also responded "[r]equiring all power plants to connect to the system with multiple transmission line is not 'Arizona's best engineering practice.'"

In response to the comments addressing the Guiding Principles, Staff will insert the following statement:

> *The Guiding Principles represent the professional opinion of Commission Staff. At this time, Staff is not recommending that the Guiding Principles become Commission Rules. Clearly it is within the Commission's jurisdiction to direct a Rulemaking Docket to be opened so that the Guiding Principles could be codified.*
>
> [Insert in Section 1.3, on page 2, before the last sentence of paragraph 1.]

ISSUE #4 - RESTORATION VERSUS CONTINUITY OF SERVICE
(Section 2.2)

Both APS and AEPCO raised concerns about this section of the Assessment. APS stated:

> APS provides service to Bisbee and Douglas, as is noted in the Assessment. APS is implementing the planned additions identified in the Southwest Arizona Transmission Study to further improve its ability to reliably serve these customers. But, in reaching its conclusion, the Assessment fails to consider prudent remedial schemes that avoid overbuilding transmission systems. One can always spend more money and add protections to address every conceivable risk. Additional reliability always has some value, but society has many other interests and with limited resources available, priorities must be established. Thus, the cost to provide an "perfect" level of reliable service may at times exceed the social utility of such service.

Section 2.2, page 9, ¶ 4 - APS Service to Douglas and Bisbee.

APS also requested that Staff add to the first sentence of the last paragraph the words in italics: "APS serves the communities of Douglas and Bisbee via a 115 kV line from Adams Substation east of Benson and use of the 16 MW Fairview local generator."

APS also addressed Staff's position regarding the acceptability of radial facilities:

> Similarly, the Assessment appears to conclude that radial service is per se inadequate. In some circumstances, radial service is the most cost-effective service available to certain loads. The Assessment does not provide an analysis as to why radial facilities fail to comply with accepted reliability and adequacy standards or why such facilities, in all cases, must be considered inadequate.

There was a request for clarification from AEPCO:

> "… the communities of Sierra Vista, Bisbee, Douglas, and Ft. Huachuca are each served by radial transmission lines rather than lines interconnected and operated

> as a network. Because several utilities are mentioned in that section, it is unclear whether that statement is intended to apply to AEPCO, ….”

AEPCO also requested a correction in the text:

> “… reference is made to an outage which occurred on June 22, 1999. … the Assessment states that ‘This is similar to the circumstances persisting in CUC’s service to Santa Cruz County.’ This is inaccurate and it is important that the Commission understand the circumstances surrounding the June 22, 1999 outage.”

In response the comments on Restoration and Continuity of Service, Staff will insert the following statement:

> *Staff has not proposed a "perfect" level of reliable service, but contends continuity of service should be the standard for level of service provided, and reflects the WSCC's Minimum Operating Reliability Criteria, PHILOSOPHY OF CRITERIA, which 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. Although 100 percent reliability of power supply is impossible, each system will, insofar as practical, protect its customers against loss of service.*** *[Page III- 6; section 2.0; revised August 8, 2000]*
>
> *Staff agrees that in some circumstances, radial service is the most cost-effective service available to certain loads, but continues to assert that continuity of service should be the level of service to strive for.*
>
> [Insert in Section 2.2, page 9.]

To clarify, the statement regarding the communities of Sierra Vista, Bisbee, Douglas and Ft. Huachuca being serviced by radial transmission lines was intended to refer to AEPCO.

Staff will delete the statement regarding Citizens Utilities Company’s service to Santa Cruz County from the report, because the issue is lack of continuity of service and not about comparing outages of different systems.

Section 2.2, page 10, ¶ 6 - Southeastern Arizona.

The suggestion that service via radial lines “means the transmission system is not adequate and secure” is not supported by commonly accepted reliability standards. Radial lines are recognized by WSCC and use of radial lines does not imply non-compliance with WSCC adequacy or security standards.

The statement “with minor system improvements, such as switch and circuit breaker upgrades” as an alternative for supplying customers in Southeastern Arizona is incorrect. Studies have shown that when the Adams 115 kV line is in service and McNeal is closed, there will be unacceptable AEPCO system loadings.

ISSUE # 5 - LOCAL GENERATION

Several parties commented on Staff's treatment of local generation in the Assessment.

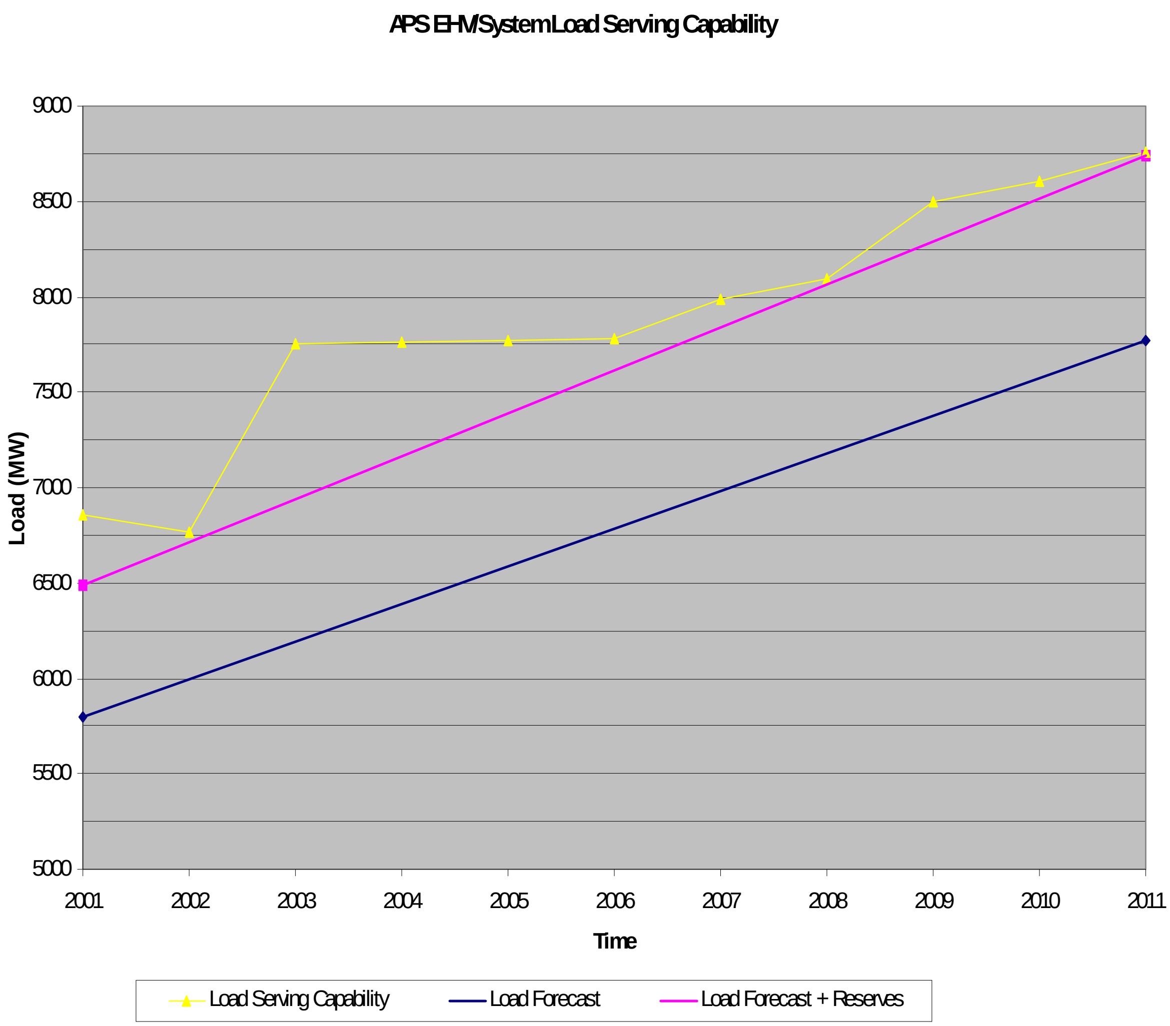
APS stated:

> Generation cannot be divorced from transmission adequacy, as both high-voltage transmission and generation together comprise the bulk power system. It is standard industry practice to consider both transmission and local generation when assessing system load serving adequacy. The Assessment, however, states that Commission rules require "that each utility provide adequate transmission import capability to serve its local load requirements with sufficient flexibility *to not rely solely upon local generation*." (Emphasis added).
>
> The pertinent portion of Rule R14-2-1609(B) states:
>
>> Utility Distribution Companies shall retain the obligation to assure that adequate transmission import capacity is available to meet the load requirements of all distribution customers within their service areas.
>
> There is no reference in this rule to any restrictions on the role of local generation in meeting a Utility Distribution Company's obligations to customers, nor has the Commission previously articulated this interpretation. To the contrary, Decision No. 61969, adopting the rule, states:
>
>> Because the ability of an UDC to meet this obligation [to deliver reliable electric service] depends upon the adequacy of its distribution system, <u>local generation</u> and interconnections with the bulk transmission system, this Section's reference to transmission import capability does not exceed the Commission's jurisdiction.
>
> Decision No. 61969 (Sep. 29, 1999) (emphasis added); *See also* Staff's Responsive Comments Regarding Proposed Rules, Docket No. RE-00000C-94-0165 (June 4, 1999) at 23.
>
> Staff's current characterization of Rule R14-2-1609 as excluding local generation is inconsistent with the prior position of both Staff and the Commission. Such generation can displace transmission in a more socially acceptable and cost-effective manner in many cases. Accordingly, given the load and resource analysis presented above, there is no basis to conclude that APS' service to Yuma and Phoenix is inadequate solely due to the reliance by APS on local generation as well as transmission import capability.

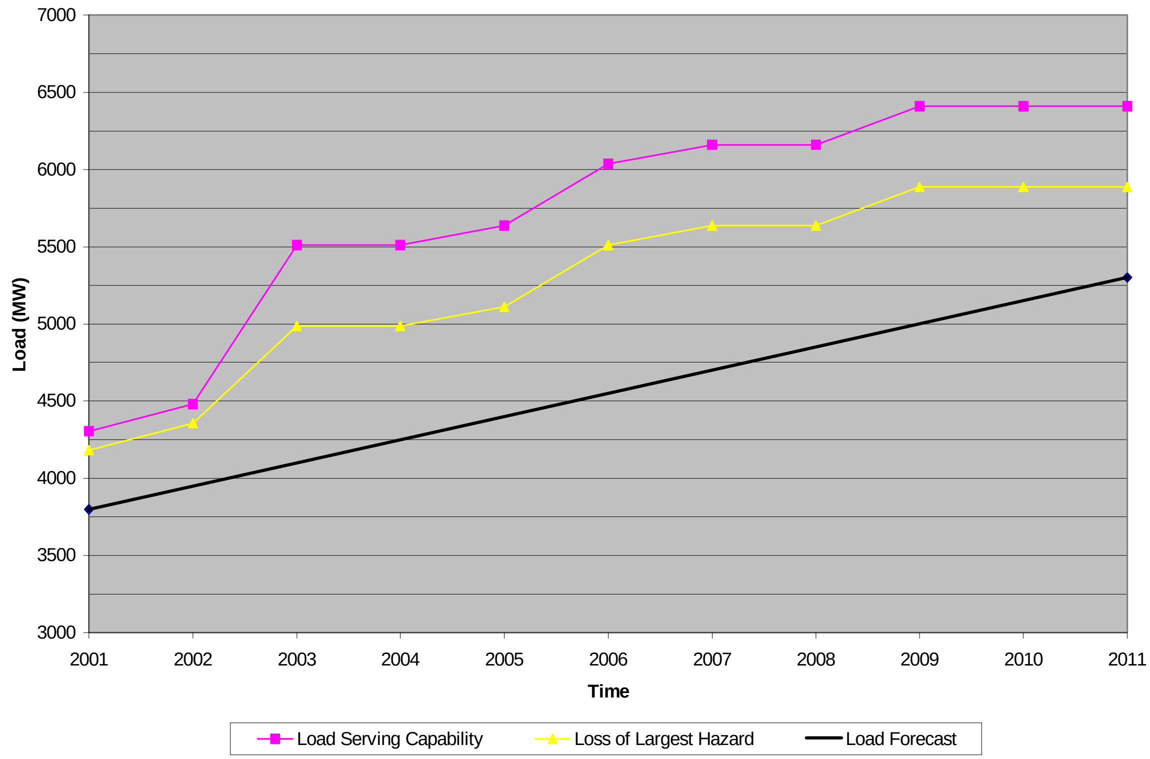
APS also addressed the adequacy of it transmission system:

Based on Staff's discussions with APS, it is not clear whether the Assessment was intended to make specific findings regarding the adequacy of APS' existing and planned transmission system. APS' transmission system today and as planned for the future, meets all applicable WSCC criteria. The Assessment must identify any specific violations of applicable WSCC criteria before making any general conclusions regarding APS' transmission adequacy.

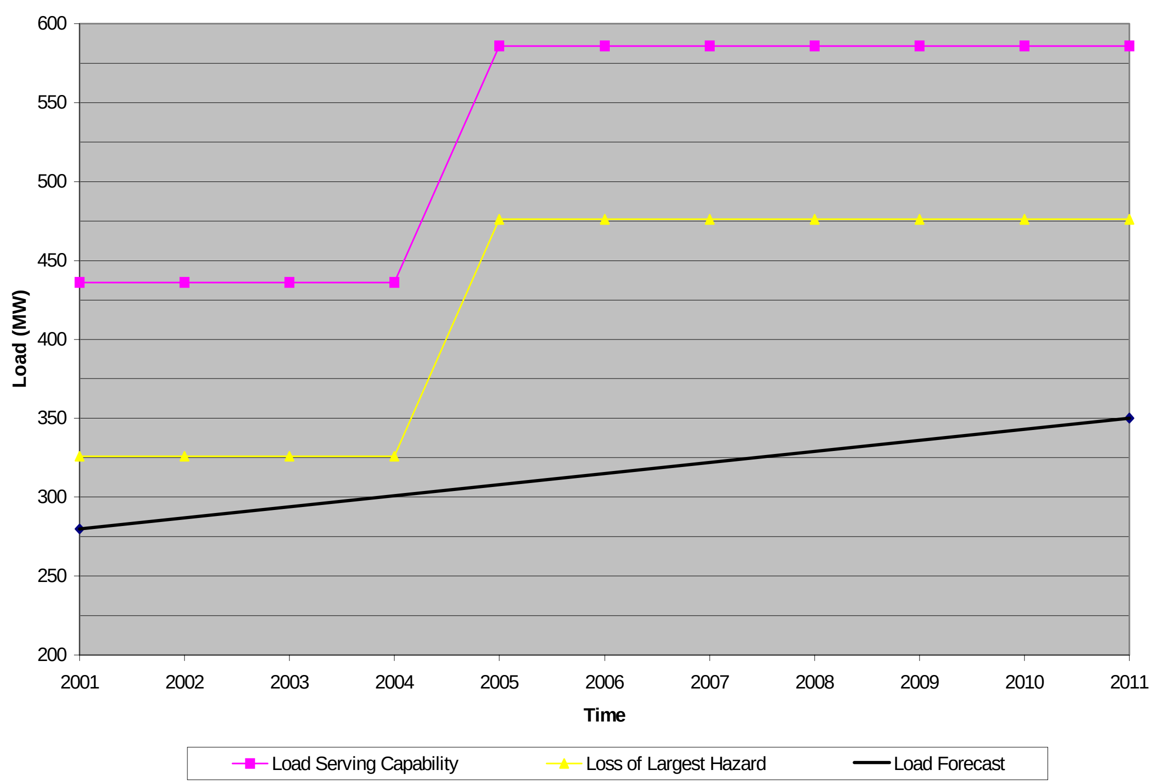
The adequacy of APS' existing and planned transmission system is provided for in APS 10-year Plan, and is illustrated by the following load and resource graphs for APS' bulk power system, the Phoenix metropolitan area, the Yuma area, and the Douglas-Bisbee area.

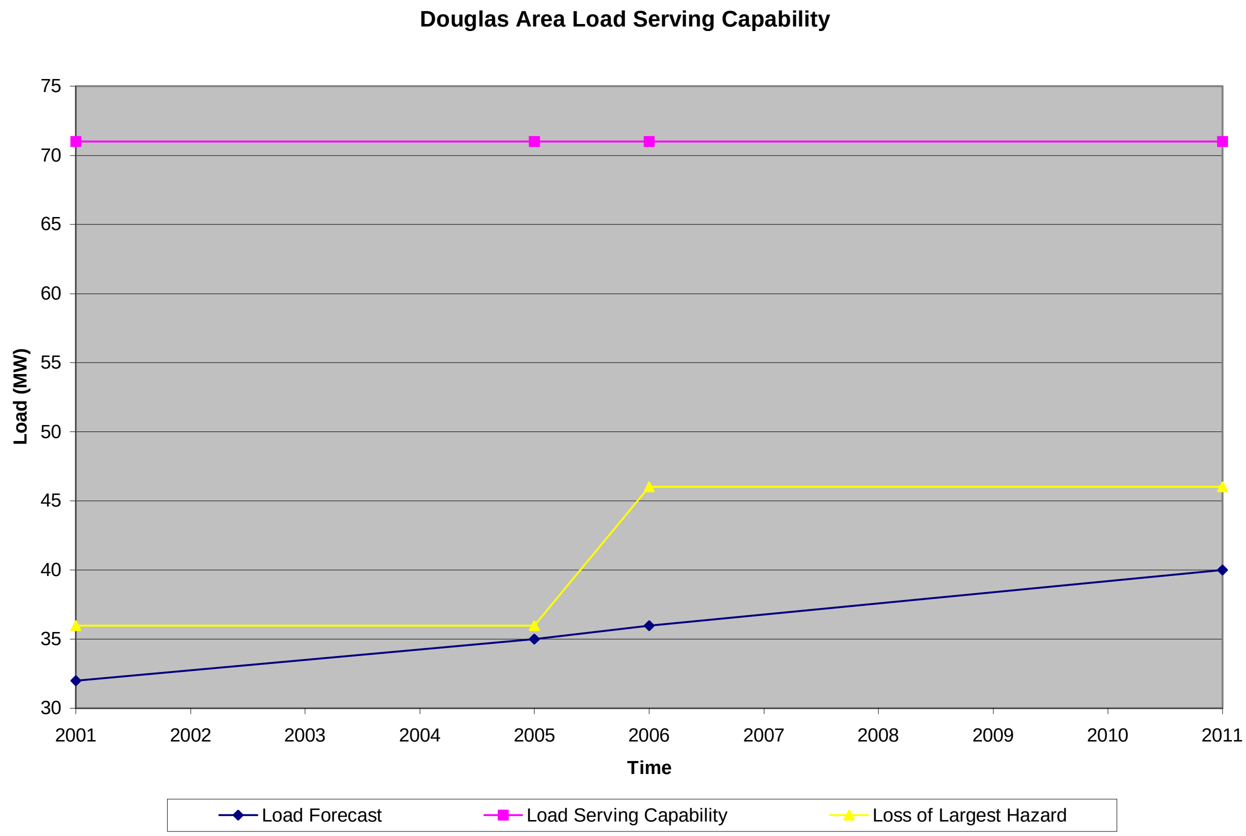


Phoenix (APS) Area Load Serving Capability



Yuma Area Load Serving Capability





These load and resources graphs illustrate that, even accounting for N-1 contingencies and system reserve requirements, APS has more than adequate transmission resources to meet its reliability obligations. The changes in load service capability shown on the graphs are tied to projects included in APS' 10-Year Plan. APS does agree that without the system improvements proposed in its 10-Year Plan, the transmission system will reach its operational limits. However, these graphs show that APS' transmission plans adequately address projected load growth in APS' service area.

Accordingly, the Assessment should conclude that APS' existing and planned transmission system is adequate, and that the additions set forth in APS' 10-Year Plan are timely, based on generally-accepted reliability criteria.

After the 2nd workshop, APS filed the following additional comments:

The Assessment's Proposed Standard for Determining Transmission Import Capacity Must Be Modified.

In response to comments on its initial Assessment, Staff has proposed a new standard for measuring transmission adequacy. The new standard provides that:

> 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.

(Proposed Changes at p. 4.) At the workshop, APS noted that the term "more economical" in the new standard could not refer simply to the marginal cost of any given remote power plant, but must consider the cost to construct additional transmission lines to access local loads. Of course, any standard must also consider additional issues such as transmission line losses and costs, ancillary services, and reliability. Staff agreed that the cost of transmission lines should be considered, but indicated that its proposed standard was intended to address concerns over the use of "must run" generation in the Valley. (6/22/01 Tr. at pp. 24-26, 28.)

A superficial consideration of "must-run" requirements for local generation, however, does not provide an acceptable standard for determining transmission adequacy. Nor has staff demonstrated that a "new" standard that could result in significant overbuilding of transmission lines is warranted. For example, APS' "must-run" requirements for the year 2000 in the Valley are provided below:

Must Run Requirements (MW)	Hours/Year
500-880	178
250-500	320
1-250	458

This table shows that APS' Valley generation was "must run" for 956 hours in the year 2000, with peak "must run" capacity of 880 MW. However, the table also shows that almost 50 percent of APS' "must run" hours for the Valley was for less than 250 MW. Moreover, out of all 956 hours of "must run," local generation was out of the market for only 6 hours. APS (and possibly the Federal Energy Regulatory Commission) would not consider it prudent to expend tens or hundreds of millions of dollars —and impose other environmental and social impacts— constructing new transmission lines to resolve a 6 hour per year problem.

Additionally, the reference in the proposed new standard to using "less polluting" remote generation is, put simply, unmanageable. For example, would this standard suggest a need to balance the environmental impacts of a local state-of-the-art natural gas plant and a more remote coal facility when making economic dispatch decisions? What if a facility is "more" polluting but located in an attainment area, as opposed to a "less" polluting source located in a non-attainment area? Moreover, when APS makes wholesale power purchases it does not (and generally cannot) know whether the generator providing such energy is more or less polluting than any other merchant generator, or any generator in APS' economic dispatch schedule. The federal Clean Air Act establishes standards to protect human health, and these standards apply to generators. There is no justification to intercede in non-jurisdictional emissions issues by adopting an overly vague standard.

Finally, from a legal standpoint, the new "standard" proposed by Staff cannot be adopted as policy by the Commission without complying with the rulemaking requirements in the Arizona Administrative Procedure Act. *See, e.g.*, *Appalachian Power Co. v. EPA*, 208 F.3d 1015 (D.C. Cir. 2000) (EPA "guidelines" required rulemaking under analogous federal Administrative Procedure Act). Moreover, the potential for the new standard to require the construction of non-load justified transmission to merchant generators treads dangerously close to FERC's exclusive jurisdiction over bulk power facilities. Transmission pricing, cost recovery, interconnection requirements, and ratemaking are exclusively controlled by FERC, and federal law preempts inconsistent state laws and regulations. *See*, *e.g.*, 16 U.S.C. § 821(b)(1) (2001); *California Public Utilities Commission v. FERC*, 900 F.2d 269, 274 (D.C. Cir. 1990) (citing cases and noting that "cases are legion affirming the exclusive character of FERC jurisdiction where it applies. . .").

To resolve these various issues, APS recommends that the standard be modified to more accurately address the issues raised in this proceeding and to avoid intruding on FERC's exclusive jurisdiction. A better and more reasonable standard for purposes of the Assessment is:

> There should be sufficient transmission import capability to economically and reliably serve retail load requirements in utility service areas.

Alternatively, the Assessment should clarify that the proposed "standard" for transmission adequacy is not a rule or a policy, but merely a Staff recommendation, which does not require any specific action now or in the future on the part of transmission owners. Thus, clarifying language should be appended to the proposed standard stating:

> This standard is a Staff guideline and is not intended to be a Commission rule or policy, or itself require specific action by any transmission provider or power plant operator.

SRP raised a number of questions regarding local generation, distributed generation, transmission constraints and congestion management:

> If incorporating local generation is interpreted to be inadequate, should there be a plan to build a transmission system that solely relies on remote generation? How many transmission lines will be appropriate to create a transmission system to import all the energy into a geographic load zone such as Phoenix and what would be the basis for resource assumptions?

How will the benefits of new technology that helps in providing self sufficiency, such as locally provided distributed generation or other renewable portfolio options, be obtained if they are not incorporated in the transmission plans?

Should additional lines be built so that congestion and constraints never exist on the transmission system? Should more lines be built when generation plants change the market to which they want their energy delivered?

Is the approach proposed by DSTAR (Desert STAR) in dealing with the market issues of congestion management and local generation a reasonable way to address these issues?

After the 2nd workshop, APS filed the following additional comments:

Adequacy and Reliability

With respect to ACC staff's proposed changes outlined on pages 4 and 5 (to be inserted in original report as the last paragraphs of section 1.2):

SRP recommends deleting the words "*without limiting access to more economical or less polluting remote generation*" from the first sentence of the 2nd paragraph to be inserted: "*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.*" In a deregulated and restructured electric industry environment, generation is market-based, not cost-based. As discussed at the workshop, SRP fails to understand how the various combinations of air emissions, water usage, noise and visual obstructions are to be evaluated when scheduling and dispatching energy from different generation plants. SRP is not aware of any superior transmission rights associated with specific types of generation.

SRP recommends that if ACC staff desires to have transmission capacity beyond the NERC and WSCC minimum requirements, staff should explore how to define *transmission capacity* along with the desirable level of capacity.

Tucson Electric took exception to the Staff's comments regarding their system:

ACC staff takes the position that TEP's proposed transmission additions are not scheduled to be in-service in a timely manner because TEP is "*continuing its practice of depending upon local generation to resolve its deficiency in transmission load serving capability during peak demand periods*". Staff goes on to support their finding by referencing an emergency blackout experienced by TEP on June 12, 2000 when a forest fire in New Mexico disrupted service via TEP's 345 kV lines into Vail.

TEP takes exception to the position of Staff that TEP's transmission additions are not timely. TEP has undertaken the construction of peaking resources as part of its integrated resource plan in order to meet its obligation to serve load in the most

> economic fashion. Due to voltage constraint issues on TEP's system local generation has been the more effective solution up to and including the current turbine being built at TEP's Demoss Petrie site.

Transmission Constraints.

APS strongly disagrees with Staff's apparent assertion that any transmission constraints are "also viewed as inadequate". There is no citation to authority for this proposition, and APS does not believe that the NERC Planning Manual supports this characterization. Transmission constraints are a factor in maintaining overall system reliability, but attempting to relieve all transmission constraints by overbuilding new transmission would result in a fundamental misallocation of resources.

In response to the comments and concerns raised by the parties, Staff will insert the following statement:

> *Staff position is that 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. Staff is not suggesting that local generation or distributed generation should be excluded from a utility's resource mix. This is evidenced by the fact that Staff has supported local generation in the siting hearings for the Kyrene and Santan plants**. Staff did not intervene in the West Phoenix siting hearing, but staff supports the project.***
>
> [Insert in Section 1.3, on page 2, before the last sentence of paragraph 1.]

ISSUE #6 - PLANNED TRANSMISSION

APS expressed its concerns about addressing the adequacy of transmission for merchant generators in the Assessment:

> Like the two-line requirement, the adequacy of transmission export capacity for merchant generators is outside the scope of A.R.S. § 40-360.02(E), which directs the assessment to focus on the adequacy of transmission to serve Arizona native load. Thus, this section should be omitted from the final Assessment.
>
> With the above caveat, the Assessment does correctly note that if all proposed new generation is constructed at Palo Verde, the existing transmission system would not be able to accommodate the full output of <u>every</u> plant <u>all</u> of the time. But the Assessment's conclusion that a new power plant should not be allowed to interconnect until there is "evidence demonstrating the transmission system can accommodate it with all other previously interconnected plants operational" is unwise policy for several reasons.
>
> First, just because a power plant has obtained a CEC does not mean that the plant—or all the units—will be constructed. Some of the proposed power plants

in Arizona may never be constructed; some will likely construct only one (or perhaps two) of several approved units.

Second, not all power plants will operate 100 percent of the time (at a 100 percent capacity factor). Some plants will inevitably be down for maintenance, some will be needed for spinning reserve, and some may be off-line for other reasons. The Assessment's requirement that transmission should be built to accommodate every power plant all of the time simply ignores reality.

Third, FERC Order No. 888 addresses additions to the bulk transmission system caused by the interconnection of new generation. FERC has been very clear that new merchant plants can request interconnection under Order No. 888 without <u>any</u> request for transmission service. *See Re Tennessee Power Co.*, 90 FERC ¶61,238 (2000). While the Commission is obviously involved in the siting of any new transmission lines required for a merchant plant, the Commission could not order a generator to pay for bulk transmission system additions, as is perhaps suggested in the Assessment. This would directly contradict the cost-recovery provisions of Order No. 888. Also, if multiple generators are competing for economically scarce transmission resources, competition will simply result in the most efficient generator getting to the market.

Similarly, the Assessment's suggestion that generating plant owners must obtain their own firm transmission rights or that there be existing uncommitted, i.e., excess, transmission capacity sufficient to assure that their generation can get to market ignores the fact that many of the potential purchasers of this generation already have firm transmission rights and that existing transmission rights presently committed to other markets can be reallocated if the economics of the new generators warrant this.

The Commission should not address this issue by requiring Arizona consumers to pay for overbuilding transmission to allow every generator to access any market at any time. In fact, this is the exact point raised by the Commission in its comments to FERC in the "Removing Obstacles" proceeding, Docket No. EL01-047-000. Neither should it arbitrarily turn away new power projects, because that could have the same long-term result as in California.

The scope of review of the transmission adequacy reports required by Staff's Guiding Principles as conditions in recent power plant CECs should also not be conducted in a manner that delays or deters power plants from interconnecting to the grid. Requiring excess transmission to be in place before generation is even on-line exceeds the Commission's jurisdiction and is simply impractical given the realities of merchant power plant operations. Further, such a requirement would impose significant, unnecessary economic costs and cause environmental impacts contrary to the Commission's statutory balancing obligations under A.R.S. § 40-360.07.

Panda Gila River L.P. also responded "Panda, however, believes that further consideration need be given to several of the issues addressed in the Assessment such as the responsibility for planning and the adequacy of the transmission infrastructure."

After the 2nd workshop, SRP filed the following additional comments:

> **Analysis of Cost and Responsibility for Construction**
>
> In its first set of comments to the Staff report, SRP raised a number of policy questions that it believed needed to be addressed prior to the completion of the report. The primary policy question remains -- should transmission owners be responsible for expanding the system to meet the needs of their customers and/or should they expand the system to meet the needs of merchant generation facilities (<u>before</u> those facilities are completed or even fully permitted)?
>
> SRP is concerned that this fundamental policy question was not addressed during the workshop process. In fact, participants were requested not to address cost or construction responsibility in their comments or recommendations. Consequently, these issues still have not been resolved even though it was indicated early on that these issues would be addressed at a later workshop. The resolution of these core policy issues is essential before finalizing this report.
>
> **Conclusion**
>
> SRP still believes that its transmission plan, upon execution, will be timely and adequate. SRP is committed to coordinated regional transmission planning and supports options that minimize the total amount of transmission while maximizing regional benefits. SRP will participate, in conjunction with other interested parties, in developing transmission alternatives that meet these objectives. At SRP, we will continue to make the transmission additions necessary to provide an adequate supply of low cost, reliable power to our customers.

Staff does not believe that requiring generators to demonstrate, prior to receiving siting approval, the existence of available transmission capacity to reliably deliver their power to market without adverse effects to the state's transmission grid in any way exceeds the Commission's jurisdiction. Nor does Staff believe that requiring such a demonstration is a requirement that "excess transmission" be put in place. On the contrary, Staff believes that requiring generation siting applicants to demonstrate the existence of available transmission capacity to reliably deliver their power to market without adverse effects to the state's transmission grid falls squarely within the Commission's statutory balancing obligations under A.R.S. § 40-360.07.

Staff does not advocate "requiring Arizona consumers to pay for overbuilding transmission to allow every generator to access any market at any time." The Commission stated in its comments to FERC in the "Removing Obstacles" proceeding, Docket No. EL01-047-000 that "there needs to be a distinction between transmission enhancements needed for the purpose of serving local *load or giving local markets access to generation, and transmission enhancements needed to facilitate interstate commerce." Staff fully supports that position.*

[Insert in Section 3.2, on page 31, after the last paragraph of the section.]

ISSUE #7 - MISCELLANEOUS ISSUES:

The following are issues that were raised by the parties at the workshop or in comments.

- **ACC's LEVEL OF OVERSIGHT AND ANALYSIS OF TRANSMISSION SYSTEM** ***(Section 4.4, p. 41 ¶ 1)***

A question was raised whether the Commission had determined the level of personnel staffing and funding that would be required to meet the Staff's proposal to provide more oversight and analysis of the transmission system.

The Commission has not specifically addressed this issue to date. Some possible options for future assessments include:

- Have existing Staff continue to do an independent assessment using industry-provided information.
- Hire a new staff member to perform the independent assessment. Below are the estimated costs to perform the assessment.

Description of Costs	1st year	Ongoing
Engineer/Planner (with loadings)	**80,000**	**80,000**
Laptop Computer and Software	**39,000**	**-**
Travel for industry meetings	**9,000**	**9,000**
Training/subscriptions, etc.	**1,000**	**1,000**
	129,000	**90,000**

- Hire a consultant. Staff has been quoted estimates that start at $200,000.
- Staff obtain information from the public and industry and conducts workshops, as appropriate.

- **CONSIDERATION of NON-RELIABLITY ISSUES** ***(No reference in report)***

APS addressed a number of issues related to transmission systems:

> A "perfectly" reliable transmission system cannot be implemented. Incremental reliability improvements may be obtained on any transmission system, but often at a cost that exceeds the social benefit of improved reliability.

> Accordingly, the economics of transmission additions must be carefully studied. It is not prudent industry practice to construct transmission lines that ultimately serve no purpose, or are needed for only an extremely limited period and could be avoided entirely by transmission displacing facilities or procedures. Transmission lines that are not truly needed or that are constructed too early impose unnecessary environmental impacts. The Commission's obligations under the Siting Act specifically direct a balancing of these types of impacts—A.R.S. § 40-360.07(B) provides that the Commission shall 'balance, in the broad public interest, the need for an adequate, economical and reliable supply of electric power with the desire to *minimize* the effect thereof on the environment and ecology of the state.' (Emphasis added.)
>
> Likewise, the timing of transmission additions, often involving a multi-year federal process, State Land Department involvement, tribal entities, lengthy route surveys and selection and long construction lead times, must be carefully planned and executed. Constructing excess transmission too early, however, results in unnecessary costs for the utility (and ultimately its customers) and for society (who must accept a transmission line before it is necessary). Constructing lines too early may also cause a utility to miss the opportunity for system upgrades, local generation, or other transmission displacing projects that could develop.
>
> Ultimately, some theoretically beneficial system improvements may prove to be impracticable or untimely due to the inability to site or construct the facilities. The Assessment candidly acknowledges that it did not consider cost or other impacts in its transmission adequacy analysis. The Assessment, however, should address (even if at a very general level) economic, environmental, social, and timing issues concurrently with its adequacy analysis, as such elements are a necessary and unavoidable component of transmission system planning.

Staff acknowledges that there may be additional issues that could be examined in assessing the transmission system in Arizona. However, the lack of information and resources has limited the analysis that Staff is able to provide.

[Insert in Section 4.4, on page 42, after the last paragraph of the section.]

- **NATIONAL MONUMENT DESIGNATIONS**
  (No reference in report)

APS has raised concerns about the impact of national monument designations on Arizona's transmission needs:

> As one of President Clinton's final acts, several National Monuments were designated in Arizona, including the Sonoran Desert National Monument and the Ironwood National Monument. Under federal law, the agency responsible for the National Monuments (primarily the Bureau of Land Management ("BLM") will develop a Management Plan for each National Monument. The preparation of a Management Plan will require compliance with the National Environmental

Policy Act, and will thus require an Environmental Impact Statement or Environmental Assessment.

The BLM has indicated in public correspondence that the National Monument designations should not eliminate the continued use of designated utility corridors through these areas. However, the several year process required to prepare Monument Management Plans may effectively delay any projects seeking to use such corridors. Generally, the BLM will not approve right of way permits until a Management Plan is in place. Both the Palo Verde to Saguaro project (Case No. 24) and the Santa Rosa to Gila Bend project (Case No. 61) may thus be affected by the National Monument designations. However, APS has implemented minor design changes to the Gila River Transmission Project (Case No. 102) to entirely avoid the Sonoran Desert National Monument with only a minor modification to its CEC.

APS intends to continue to work closely with the BLM and other affected federal agencies to address and resolve any issues related to the National Monuments' impact on transmission planning and the continued use of recognized utility corridors. Nonetheless, the Commission should monitor this issue.

Staff has had discussions with Department of Energy, Bureau of Land Management and the Forest Service in an attempt to facilitate the complex and time-consuming Federal processes.

[Insert in Section 3.4, on page 37, before the last sentence in paragraph 2.]

- **CURTAILMENT PROCEDURES FOR NEW GENERATORS.**
  Section 2.4, page 16, ¶ 1

APS found that the statement that "a curtailment procedure must be developed prior to the interconnection of new generation" was misleading. APS contends that an operating procedure to ensure system reliability will be developed and pointed out that operating procedures have been developed for many power plants prior to the plant's going into commercial operations.

Staff understands that operating procedures are developed for standard operations. However, the curtailment plan Staff envisions is more than just standard operations. It is intended to address situations where there is more generation available than corresponding transmission export capacity.

CORRECTIONS, UPDATES & CLARIFICATIONS:

Since the issuance of the original Assessment in early March, there have been a number of factual updates that have been brought to Staff's attention. The parties have also requested clarification on some issues, and pointed out where corrections needed to be made in the Assessment. This section covers those types of issues.

Merchant Power Plants
(Section 2.1, page 6)

The Assessment had stated that “Currently, no merchant plants are operating in Arizona.” APS pointed out that there is a merchant power plant in Yuma, Arizona that is currently being operated by Yuma Cogeneration Associates.

At the time the report was written, the APS single line diagram showed that Imperial Irrigation District owned that plant. With this new information, and the four merchant power plants that have been constructed recently, the total is now five.

Staff will insert the following in Section 2.1, at the start of the last paragraph of page 6.

> *It is anticipated there will be five merchant power plants operating in Arizona, the summer of 2001. The merchant power plants are:*
>
> > *Griffith located southwest of Kingman.*
> > *Southpoint located north of I-40, near the California border.*
> > *Desert Basin located northwest of Casa Grande.*
> > *West Phoenix located in southwest Phoenix*
> > *Yuma Cogeneration Associations power plant in Yuma (APS is to provide additional information.)*

> [Insert in Section 2.1, on page 6, at the beginning of the last paragraph.]

Number of Transmission Lines from Approved Power Plants.
(Section 2.1, page 8, ¶ 2)

APS noted that the statement in the Assessment that “[a]ll but one approved plant has two or more transmission lines” contradicts the contents of Table 2, Summary of Proposed Arizona Power Plants. According to Table 2, there are three approved plants with 1 line/transformer tie.

Staff agrees there is a contradiction. At the time the report was written, two of the plants had been approved - Gila Bend had not been approved. At this time, all three plants have been approved. Staff will correct the statement to read:

> *As of June 2001, three of the twelve approved power plants have single lines."*

> [Insert in Section 2.1, on page 8, at the beginning of the last paragraph.]

Existing Arizona Power Plants.
(Section 2.1, page 7)

APS was concerned that several plants had been omitted from Table 1, *Summary of Existing Arizona Power Plants*. These plants include Douglas, Childs, Irving, Citizens Utility Company’s generator in Nogales and the merchant power plant in Yuma. Additionally, the information cited for the Yucca power plant should be corrected as follows: Switchyard Voltage (kV) = 161 and 69; No. Units = 6; Capacity (MW) = 256; and AZ Utility Capacity (MW) = 161.

Staff did not include the above listed generators for the following reasons:

- The generator at Douglas is a backup generator and does not normally operate unless the radial line it is connected to is out of service. Cary Deise, of APS, stated that the Fairview generator is able to operate for load serving purposes - which staff interprets to mean it is not limited to operation only when the radial transmission line is out of service. With this understanding, staff will include the Fairview generator in Table 1.
-
- Childs' output of 1 MW is insignificant; the hours of operation are limited and do not impact the transmission system because it is a small hydro unit on the Verde River.
- Irving's output of 3 MW is insignificant and the hours of operation are limited because it is a small hydro unit on the Verde River.
- Citizens Utility Company's generator at Nogales is a backup generator and does not normally operate unless the radial line it is connected to is out of service.
- The one-line diagram of the Yucca switchyard, provided by APS, shows 5 units - not 6 - units connected at Yucca.

  APS will provide Staff a corrected copy of the Yucca switchyard.
  Staff will add the Douglas generator to Table 1 - Summary of Existing Arizona Power Plants.

Yuma Area Import Capability.
(Section 2.3, page 12, ¶ 2)

APS has pointed out that the APS transmission import capability to Yuma should be increased from 140 MW to 175 MW. APS has contracted with Western Area Power Administration for 35 MW of firm transmission rights to Yuma.

Staff will insert this updated information**:**

> *APS indicated the Yuma area presently has an import capacity of 175MW.*
>
> [Insert in Section 2.3, page 12, 2nd paragraph.]

Summer 2000 Forecast.
(Section 2.3, page 13, ¶ 1)

APS requested clarification of the statement "APS indicated that its summer 2000 peak load forecast for the Valley fell 125 MW short of its local load serving capability." APS indicated that for 2000, the local load serving capability was 125 MW greater than the forecasted load.

Staff agrees the statement is confusing. Staff will revise statement to read:

> *APS indicated that for Year 2000, the local load serving capability was 125 MW greater than the forecasted load.*

Salt River Project reported that SRP's import capability has increased from summer 2000 to summer 2001 as a result of capital investments in transmission enhancements. SRP's transmission import limit has increased from 3,625 MW to 4,134 MW for a net improvement of 509 MW.

Staff will insert the additional information:

> *SRP's transmission import limit has increased from 3,625 MW (year 2000) to 4,134 MW (year 2001) for a net improvement of 509 MW.*
>
> [Insert in Section 2.3, page 13, paragraph 2.]

OASIS ATC Postings.
(Section 2.5, page 23, Table 6)

APS commented that:

> [T]o ascertain export capability available for off-system transactions or import capability (in excess of that reserved to serve load), the OASIS of all transmission owner/operator must be queried. It appears that the ATC available from the California Independent System Operator (CAISO) was not included in the analysis. For example, the quoted amount of 0 MW available from APS SW of Four Corners does not include capacity the CAISO may have had available from Four Corners to the Southwest. The East of the River path and Southern Navajo system also have additional owners/operators who were not listed in Table 6, Arizona OASIS Posted ATC and the East of River path has additional lines which were not listed in Table 6. The 236 MW amount quoted for to the west and from the west appears to be only on APS' system. There are numerous other owner/operators who may have had ATC available for import/export to the west.

It is important to understand that ACC Staff did not perform the OASIS posted firm ATC analysis. Information regarding this matter was extracted from the "Western Interconnection Biennial Transmission Plan" report authored by the Regional Transmission Association (RTA). The contents of Table 6 of Staff's Report were lifted from Table II, on pages 83-84, of the referenced RTA report. Similarly, comments on page 23 of Staff's report document responds to the Transmission Congestion Survey contained in the same RTA report (on pages 74-77).

Staff assumes no responsibility for the accuracy of the RTA report. However, Staff did fail to include the Liberty to Mead 345kV line in the WSCC Path 49 EOR listing in Table 6 and will make such correction. Staff inadvertently left the Liberty to Mead 345kV line to the EROR List in Table 6.

> Liberty to Mead 345kV
>
> [Insert in Section 2.5, page 23, as last item under 49 EOR: East of Colorado River]

Staff does not intend to change other data listed in Table 6, as it represents the findings of parties that actually investigated the OASIS firm ATC available on April 2000. APS may be correct regarding exclusion of CAISO available ATC. But the 236 MW amount quoted (to the west and from the west) does not appear to be only on APS' system given the RTA listing 236 MW bi-directional via SRP.

SRP has pointed out that:

> *Customers desiring transmission services that are not available as ATC through OASIS need to make a Transmission Service Request. If the transmission service is not available, the Transmission Owner will perform a System Impact Study, if requested by the customer, to define how the service can be provided.*
>
> [Insert in Section 2.3, page 13, paragraph 2]

Staff agrees that an explanation of what to do if ATC is not available should be included in the Assessment and will insert the above language in the Assessment.

Pinnacle West Energy Local Generation.
(Section 3.2, page 28, ¶ 1)

APS commented that paragraph one should also include the following additions to local generation: Pinnacle West Energy proposed local generation of 198 MW of mobile generation in 2001 and 2002 and 96 MW from the repowering of West Phoenix 4 and 6 steam units beginning in 2001.

Staff will insert the addition language:

> *Pinnacle West Energy proposed local generation of 198 MW of mobile generation in 2001 and 2002 and 96 MW from the repowering of West Phoenix 4 and 6 steam units beginning in 2001.*
>
> [Insert in Section 3.2, page 28, after the 3rd sentence in paragraph 1.]

Public Opposition to West Phoenix Project.
(Section 3.2, page 28, ¶ 1)

APS expressed concerns because the Assessment stated that the West Phoenix Generating Station expansion project has "encountered significant public opposition that may potentially delay or restrict [the] project's scope and compromise [the] . . . ability to serve customers without utilizing rolling blackouts." APS contends that:

> APS and the project sponsor, Pinnacle West Energy, are unaware of any current public opposition to the West Phoenix expansion project. A recent intervention by a labor union and environmental advocacy group—brought after Pinnacle West Energy obtained its CEC for the expansion project—was successfully settled.

As of June 2001, all three of these plants have CECs approved by the Commission.

[Insert in Section 3.2, page 28, after the 2nd paragraph.]

In-service dates for Kyrene and Santan
(Section 3.2, page 28, ¶ 1)

SRP pointed out that the scheduled in-service dates for the Kyrene Expansion Project and Santan Expansion Project were not stated correctly in the Assessment. (The referenced SRP load serving capability chart noted fiscal years and not calendar years). SRP stated that the:

> Kyrene Expansion Project is scheduled for summer 2002 and Santan Expansion Project is scheduled for summer 2005. Both projects have received ACC approval. Although Kyrene Expansion Project was reduced in scope from 825 MW to 250 MW, a long-term energy purchase has been made for the full output of the Reliant Desert Basin Plant to offset the reduction. APS is providing firm transmission service for the plant output with delivery to SRP at the Kyrene Switchyard.

Staff did notice the chart was labeled "Fiscal Year". Staff will make the following correction:

> *Kyrene Expansion Project is scheduled for summer 2002 and Santan Expansion Project is scheduled for summer 2005".*
>
> [Replace 4th sentence, 1st paragraph, in Section 3.2, page 28.]

Regional Concerns
Section 3.4, page 36, ¶ 2

SRP provided an update of the progress of the Central Arizona Transmission Study:

> SRP, APS and TEP have been working with the Governor's staff and the Secretary of the Interior regarding the use of the recently declared National Monuments in Arizona to accommodate transmission that has been proposed and planned by the Transmission Owners. A tremendous amount of progress has been made to ensure that the corridors required for the needed transmission facilities are available as planned. SRP is also interested in developing regional transmission solutions that serve its customers and provide benefits to others in Arizona. SRP is deeply involved in the CATS study and stated in its last Ten-Year Plan that, "*SRP plans to participate, in conjunction with other interested parties, in developing some or all of the transmission systems that result in meeting the stated objectives of the CATS study … projects to be constructed by SRP will be reflected in the appropriate Ten-Year Plan submission*". At SRP we have made, we are making, and we will continue to make transmission additions necessary to provide an adequate supply of low cost reliable power to our customers.
>
> Commission staff and the subject report correctly point out the critical importance of transmission, that transmission issues are not easily or quickly resolved, the inherent consequences of inaction, that transmission plans are highly dependent

upon generation plans and market assumptions, and that overall transmission plans are not coordinated with overall generation plans.

Staff will insert the updated information:

> *The Central Arizona Transmission Study group was formed in August 2000. The work the utilities are doing in CATS is vital to Arizona's future energy needs and is to be commended as a first step. A June 2001 Phase I CATS draft report documents APS, SRP and TEP preliminary study results. WAPA study results are still pending.*
>
> [Insert in Section 3.4, page 37.]

House Bill 2040
(Section 4.4, page 42, ¶ 2)

APS commented that the Assessment should be corrected to reflect the fact that the Arizona Legislature has adopted the statutory change regarding information from merchant power plants.

Staff agrees that this correction should be made and will insert the following:

> *In 2001, House Bill 2040 was passed that required plants to file a plan with the Commission 90 days prior to filing an application for a Certificate of Environmental Compatibility. In addition, "The plans for any new facilities shall include a power flow and stability analysis report showing the effect on the planned Arizona electric transmission system."*
>
> [Insert in Section 4.4, page 42, at the end of paragraph 2.]

Addition to TEP's Ten-Year Plan

Tucson Electric has supplemented its ten-year plan with the following information:

> The next increment of system construction that is planned to be constructed to meet load is the Saguaro to Tortolita 500 kV line. This line installation has been timed to coincide with the next capacity requirement of TEP and will add approximately 275mw of import capability to TEP's system. In addition this new line interconnection will also result in additional benefits to TEP's system besides this increase in import capability. This project was intended to be added in TEP's 2001 ten-year plan that was filed in January of 2001. This page was inadvertently left out of TEP's 2001 ten-year plan and TEP will be sending this sheet in to the ACC shortly. This is a new project that had not been identified in TEP's 2000 ten-year plan. This project was added when TEP determined that it had the ability to build this line under an existing contract with APS without impact on TEP two county bonding."

Staff will add TEP's Saguaro to Tortolita 500kV line to Appendix C, as well as the updated information all parties filed in the 2001 Ten-Year plans.

NEXT STEPS

As a follow-up to BTA, staff will:

Document Workshop Process and Results

Request Transmission Owners to File

- **Internal Planning Criteria**
- **System Ratings with Limiting Element Identified**
- **Technical Study Reports with Ten-Year filings Identifying Transmission Enhancements Resolving Local Constraints at the Earliest Possible Date**

Resubmit Staff Report and Proposed Order for Commission Consideration and Decision.