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Barbara Klemstine
Director
Regulation & Pricing

Tel. 602-250-4563
Fax 602-250-3003
e-mail Barbara.Klemstine@aps.com

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999

January 17, 2007

Arizona Corporation Commission
DOCKETED
JAN 17 2007
DOCKETED BY

Mr. Prem Bahl
Arizona Corporation Commission
1200 W Washington Street
Phoenix AZ 85007

Mr. Jeff Palermo
KEMA Inc.
4400 Fair Lakes Court
Fairfax, VA 22033

Re: Comments on Draft for ACC Fourth Biennial Transmission Assessment
Docket No. E-00000D-05-0040

Dear Messrs Bahl and Palermo:

Enclosed are Arizona Public Service Company's ("APS") comments on the Final draft for the Biennial Transmission Assessment 2006 Report. Due to the voluminous nature of the report APS has only attached redlined pages with suggested edits.

Arizona Public Service Company ("APS" or "Company") appreciates the efforts by Arizona Corporation Commission ("Commission") Staff and KEMA in the development of the Biennial Transmission Assessment ("BTA") and the opportunity provided to the stakeholders to comment on this draft report. If you have any question, please feel free to contact Bob Smith at 602-250-1144.

Sincerely,

Barbara Klemstine
Director
Regulation & Pricing

BAK/dst

cc: Docket Control (Original, plus 15 copies)

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Arizona Corporation Commission Fourth Biennial Transmission Assessment – 2006-2015

Arizona Corporation Commission Fourth Biennial Transmission Assessment
for 2006-2015,
Docket No. E-00000D-05-0040

Arizona Corporation Commission Utilities Division

KEMA, Inc.

3. What steps were taken in the new transmission planning studies to effectively address the Commission's concerns raised in the earlier BTAS about the adequacy of the state's transmission system to reliably support the competitive wholesale market emerging in Arizona?
4. Do the generation interconnection practices in Arizona adequately reflect technical aspects of the generation interconnection policies as defined in Federal Energy Regulatory Commission (FERC) Orders?
5. Do the transmission plans adequately reflect North America Electric Reliability Council's (NERC) latest activities related to compliance with the transmission planning standards, as well as compliance with Western Electricity Coordinating Council (WECC) reliability standards?

This transmission assessment represents the professional opinion of Commission Staff and its Consultant, KEMA. The BTA is not an evaluation of individual transmission provider's facilities or quality of service. This BTA report does not set Commission policy and does not recommend specific action for any individual Arizona transmission provider. It assesses the adequacy of Arizona's transmission system to reliably meet existing and future energy needs of the state. This transmission assessment will not become official unless and until it is adopted by Commission Decision.

Some studies and projects were also included in this BTA beyond this mandatory study timeframe. Commission Staff is pleased to report that the collaborative process between the Commission and Arizona utilities, which began in previous BTA's, has continued to evolve in a constructive manner during the Fourth BTA. Transmission owners have been responsive to many issues raised by Staff in prior BTA's, including the level of ability of the Palo Verde transmission system to handle full generation output, Palo Verde Hub reliability issues and the economic viability of generators at the Hub, clarifying the criteria and study processes Arizona utilities utilize to formulate their reliability must run (RMR) plans, and a number of other issues that are discussed in the report.

Extensive regional planning studies have been conducted in a collaborative process for 2006-2015. Studies for more localized service areas within the state were also included. In addition to addressing normal system conditions with all lines in service (n-0), this year's filings also included analysis of significant overlapping or concurrent outage events (n-1-1 and n-2 events, respectively). Current and planned transmission projects are increasing the Palo Verde Hub transmission capacity to both the east and the west. Phoenix and Yuma area RMR concerns raised in the Third BTA have been satisfactorily addressed. ~~Transmission projects are planned and being built to increase the transmission capability to the east and the west from Palo Verde Hub.~~ In addition, several major future interstate projects were identified in this BTA for Commission and stakeholder review.

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Comment [JS1]: This sentence is a duplicate of a previous sentence.

As evidence of the collaborative long-term planning and expansion process taking place in Arizona, at least eight major projects in the ten year filing period have multiple utility sponsors. Collaborative long-term planning studies were also conducted by the utilities; including a study for permitting and the acquisition of rights-of-way, and a higher standard for construction costs;

b. For states with mandatory renewable portfolio standards, regulatory commissions should make public Interest findings associated with cost effective transmission projects that will enable states to attain energy policy goals;

c. Expand transmission in advance of generation to enable the modular development of location-constrained, clean and diversified resource areas to meet cost-effective RPS, IRP and state goals, similar to recent Texas and Minnesota legislation for new transmission and the renewable trunk line (Tehachapi) model for new transmission;

d. Coordinate multi-state review of transmission projects by developing common principles for cost allocation and cost recovery, and adopt a common Western procedural process that would identify and coordinate the applications, forms, analyses and deadlines; and

e. Promote cost-effective transmission expansion by accommodating both non-dispatchable and dispatchable resources.

4) Western Governors should collaborate with the appropriate federal agency to implement the Energy Policy Act provisions to designate energy corridors on federal lands by:

a. Committing state agency resources to participate in the federal effort and to identify contiguous corridors on adjacent state lands;

b. Urging Congress to fund federal land management agency corridor planning efforts; and

c. Fostering designation of corridors on lands not owned by the federal government or the states to ensure continuity in corridors. Designation and preservation of transmission corridors is important in rapidly urbanizing parts of the region.

d. Western Governors should encourage the Western electric power industry to:

i. Synchronize regional transmission planning efforts to resource acquisition plans of load-serving entities (LSE) and plans of generators;

ii. Support and collaborate with state infrastructure authorities that have been created to facilitate transmission expansion; and

iii. Ensure institutional homes for regional transmission planning."

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4. Adequacy of the existing system

Adequacy, as discussed earlier, 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. Adequacy is generally considered a planning issue related to the capability and amount of facilities installed. This section of the report addresses the adequacy of the existing Arizona transmission system.

The adequacy of an electric system is evaluated using computer simulation studies. These studies use: databases, assumptions, and reliability criteria. The Arizona transmission utilities conduct these studies, participate in the collaborative regional planning process, and present the study results in the ten-year plan reports and at public workshops. Staff and KEMA reviewed and analyzed all these study reports relying on these reports and documents filed with the Commission by the various organizations, rather than performing technical studies of their own.

4.1 System description

The demand for electricity continues to grow in Arizona reaching a 2006 non-coincident peak of 19,289 MW.[1] Installed generation has more than kept pace with the growth in demand. As of May of 2006, installed generating plants that deliver their generation to the transmission grid that were operating within the State of Arizona provided a total of 24,249 MW of summer capacity. Approximately 70% of this capacity is owned by Arizona or federal utilities. Non-utility generators and utilities that are not located in Arizona own the remainder. Data on the generating plants operated within the State of Arizona are provided in Appendix C.

With a few exceptions (e.g. Palo Verde to Devers 500kV, Hassayampa to North Gila 500kV & Navajo to Crystal 500 kV) the existing transmission facilities within the state of Arizona are owned and operated by APS, SRP, TEP, UniSource Energy Services, SWTC and WAPA. Figure 6 illustrates the existing EHV transmission facilities in the State of Arizona. EHV facilities, rated at a nominal system voltage of 345 kV and 500 kV, are the backbone of the Western Interconnection transmission system.

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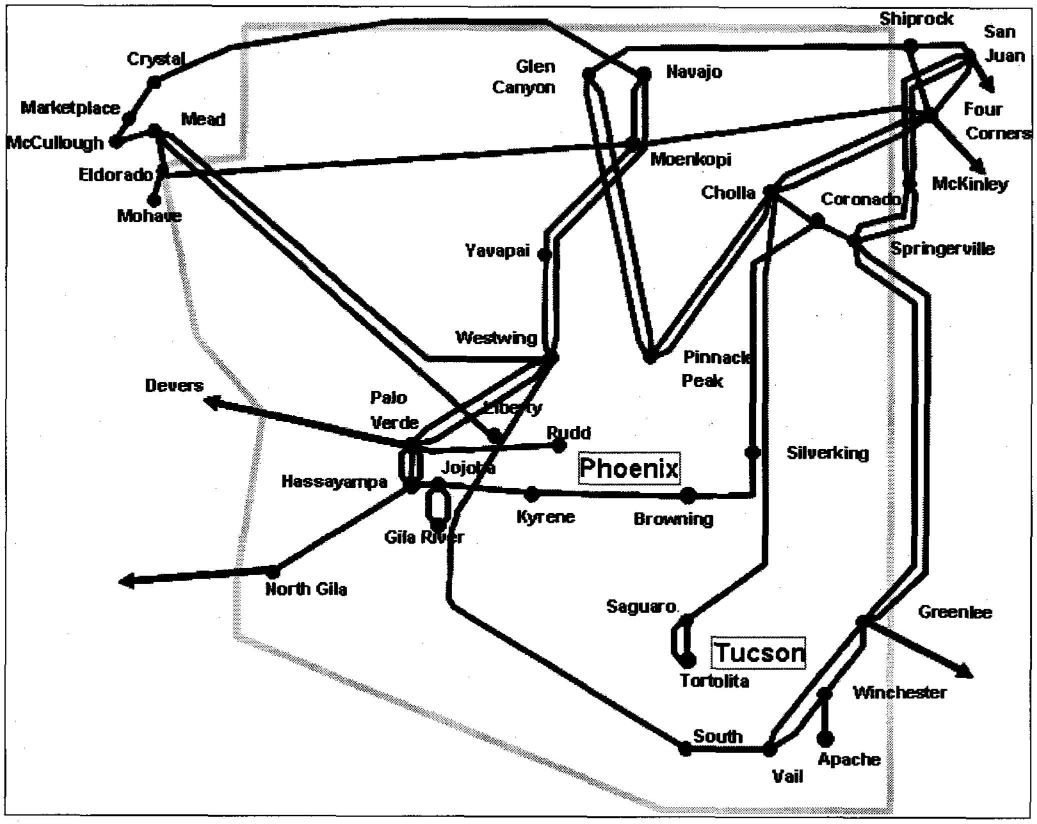
[1] Source: WECC preliminary 2006 summer loads and resources assessment of non-coincident July control area peaks.

Figure 6: Arizona EHV transmission system



All new transmission lines that have been added since the Third BTA are listed in Table 3.

Table 3: Major new transmission lines and stations added since the third BTA

Year	Description	Voltage
2004	Loop-in of existing Greenlee-Vail 345 kV line to new Winchester 345 kV switchyard	345 kV
2005	Saguaro-Tortolita #2 line	500 kV
	Gavillan peak loop-in of Pinnacle Peak- Prescott	230 kV
	~~Palm Valley (was called TS3) substation~~	~~230 kV~~
	Browning substation	230 kV
2006	Loop in of existing Irvington station to Vail substation #1 line through Robert Bills -Wilmot Substation.	138 kV

Comment [JS2]: This project is not in-service yet.

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Comment [h3]: Duplicate of item 3 lines up.

Deleted: Loop-in of existing Pinnacle Peak- Prescott 230 kV line to new Gavilan Peak 230kV switchyard

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Table 5: Palo Verde transmission and generation capability

Year	Generation capability (MW	Transmission capability (MW)			Reason for change
	Actual or expected	West path	East path	Combined total	
2000	3,810	2,800	3,810	6,610	No changes - historical values
2001	3,810	2,800	4,750	7,550	Study work by APS/SRP updated East path rating based on "actual" vs. "scheduled" flows
2002	5,600	2,800	4,750	7,550	Addition of Red Hawk & Arlington Valley generation
2003	7,971	2,800	5,120	7,920	Addition of Mesquite & Harquahalla generation., and refined Path rating study work by APS/SRP
	9,939	2,800	6,620	9,420	New PV to Rudd 500 kV line and addition of Gila River Power, L.P. Generation
	9,990	2,800	6,970	10,207	Gila River 230 kV interconnection added 437 MW to local transmission capacity
	10,045	2,800	6,970	10,207	PV 2- Generation upgrade (new steam generator)
2005	10,103	2,800	6,970	10,207	PV 1- Generation upgrade (new steam generator)
2006	10,172	3,305	6,970	10,712	Path 49 short term upgrade
2007	10,230	3,305	6,970	10,712	PV 3 generation upgrade (new steam generator)
2008	10,230	3,305	8,010	11,752	New PV–Pinal West–Santa Rosa line[1]
2009	10,230	3,305	8,550	12,292	New PV-TS5 lines[2]
	10,230	4,505	8,550	13,492	New PV – Devers II line[3]
2010	10,230	4,505	8,915	13,857	New Raceway– Pinnacle Peak line
2011	10,230	4,505	8,915	13,857	New Santa Rosa – Pinal South – Browning line[4]
2012	10,230	4,505	8,915	13,857	New TS5 – Raceway line [5]
	10,230	5,105	8,915	14,457	New Hassayampa – North Gila line[6]

Notes: (Estimates based on SRP and/or APS preliminary study results.)
1. Estimated 1,040 MW increase.
2. Estimated 540 MW increase.
3. Accepting rating of 1200 MW was approved by WECC.
4. Estimated 365 MW increase by extending the SEV line to Browning
5. Estimated 500 MW increase
6. Estimated 600 MW increase.

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Staff has been concerned in recent years that the Palo Verde transmission system needs to maintain adequate capability to deliver the full power output of interconnected generators. Consequently, ACC Staff has taken the position that, in addition to the transmission providers, merchant power plants, should share the responsibility and obligation to resolve Arizona transmission constraints.

4.3.2 Palo Verde risk assessment

Operation of the Palo Verde Hub and interconnected generation has been and continues to be a subject of much interest to Staff. In the Third BTA, Staff observed that the transmission outlet capacity at Palo Verde was inadequate for the delivery of all capacity from power plants located at this key Hub. Based on information provided during the Fourth BTA, it appears that this situation is being mitigated by transmission expansion plans from 2006-2009.

With the completion of WECC Path 49 upgrades this year, the West of Palo Verde Hub path capability has increased by 505 MW to a new limit of 3,305 MW. In combination with the East of Palo Verde path rating of 6,970 MW this yields a combined transmission capability out of the Hub of 10,712 MW. The total output of the existing generation at Palo Verde (Table 4) is 10,172 MW. Thus, the maximum transmission capability now slightly exceeds the available generation at the Hub. This is an encouraging development, however, Staff also observes that a portion of the transmission capability at the Hub will often be unavailable due to unscheduled flows ("loop flows") occurring on the WECC interconnection. These unscheduled flows result from power flowing from remote generators over the multiple parallel paths of the interstate grid. These flows can run in the hundreds of MW at the Hub. They are particularly prevalent in the westbound direction at Palo Verde. These unscheduled flows reduce the scheduling capability out of the Hub on a one for one basis.

Staff believes that such loop flows can still be expected to cause some level of transmission constraints at the Hub, even though it appears this situation will continue to improve with the planned transmission upgrades as shown in Table 5. Transmission outages and durations will also have some affect on the available transmission capability out of the Hub. However, Staff assumes that these will be offset by outages and durations of generation at the Hub. Finally, the Hub is located between two widely disparate markets (Arizona to the east vs. California to the west) and this will, to some extent, frustrate efforts to fully capture the simultaneous transmission capacity available out of the Hub. In summary, Staff concludes that more of the generation at the Hub will now get to market, but congestion (and market anomalies) will continue to constrain dispatch to some degree at the Hub. Furthermore, it appears this dispatch constraint should be fully mitigated with the completion of transmission projects out of the Hub in the next few years including Palo Verde-Devers 2.

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Comment [JS4]: This section does not appear to have much to do with Palo Verde Hub risk assessment. May want to consider moving it to another section?

- Hassayampa switchyard;
- Palo Verde Hub ties;
- Common gas pipeline; and
- Railroad event.

Although these are low probability events, if they were to occur, three to four thousand megawatts of generation at the hub would be lost, as well as the hub associated transmission lines. The study results show that the system will become unstable. It was determined that several thousand megawatts of load would have to be shed in order to maintain system stability. Consequently, in order to avoid increased risk at the hub, Staff recommends that:

- Future generation or transmission projects seeking interconnection with the Palo Verde system should consider risk mitigation for extreme events.
- For overall diversity, performance and risk mitigation, future transmission lines should consider terminating at generating stations interconnected at the hub rather than at the Palo Verde or Hassayampa Switchyards.
- Future generators desiring to interconnect at the Palo Verde hub should also be interconnected to at least one other location in the transmission network.

In addition to the above Staff recommendations, presented to the Corporation Commission and the industry, Staff also recommends for WECC consideration a planning guide applicable to all generation hub station that includes:

- NERC Category B (n-1-1), C (n-1-2) [1] and D, risks and consequences, type evaluations should be performed on all generation hub substations. All types of initiating events applicable to a particular generation hub station should be considered in order to determine how to model the associated disturbances, likely duration of the common substation outage and the cumulative risk and consequences of such an outage. System consequences of hub substation outages may be severe and warrant mitigation measures. Evaluations of future generation or new transmission interconnections to such generation hub substations shall consider the effect of the proposed interconnection on the cumulative risk and consequences of a common event outage of the generation hub substation. Alternatives to be considered should include the following:
  - Terminating the new line at different power plant substations currently connected to the generation hub.
  - Interconnecting new generation at more than one substation.

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[1] "n-1-1" and "n-1-2 " refers to the criteria where a bulk facility is out of service before a single or double contingency occurs.

Mitigation measures include load-shedding schemes. The WECC process is still on going. However, Staff developed a generic model of a generation hub concept to be used for the generation interconnection at major hubs (See Figure 9).

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Figure 9: Generic model of hub concept

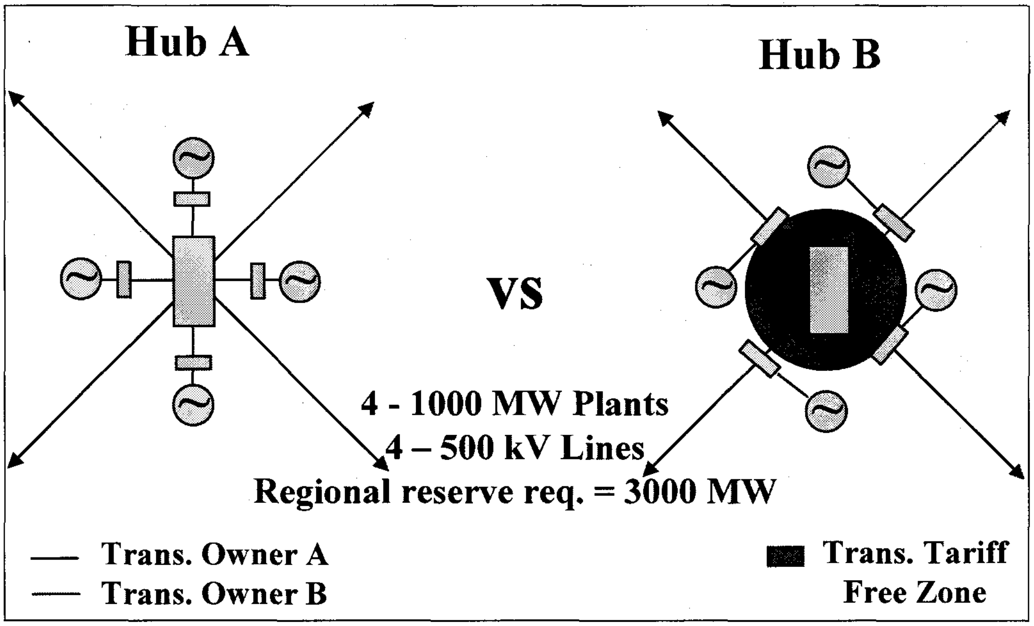

Figure 9 shows the Hub A concept, which has four power plants, each of 1,000 MW interconnected at a common switchyard. The switchyard has four 500 kV transmission lines interconnected. Two lines are owned by Transmission Provider A (shown in blue), and the other two are owned by Transmission Provider B (shown in red).

What will happen if that common switchyard is lost, assuming that the regional reserve requirement is 3,000 megawatts? The 4,000 megawatts of generation, which is in excess of the reserve criteria for the region, is lost with the loss of the switchyard. This jeopardizes security of the operation of the whole network. Consequently, Staff concluded that this type of hub configuration, as more generation is added, becomes flawed.

As an alternative, Staff proposes that the industry consider the Hub B concept. The transmission lines are still interconnected to a common switchyard, the hub, but the generators have the transmission lines looped through the generator power plant switchyards. Now when the common switchyard is lost, each of the power plants is still interconnected to

100 MW of new generation in Yuma in 2008 plus construction of second 500 kV line from the Palo Verde/Hassayampa area to North Gila in 2012, along with a 230 kV line from North Gila to the Yuma load center, will add 395 MW to serve the area's load growth.

The proposed Palo Verde/Hassayampa-North Gila 500 kV line offers a good example of the type of collaboration that can be achieved between transmission providers in Arizona. The project is sponsored by APS with participation from SRP. As previously discussed, APS proposes the line in order to increase Yuma's transmission import capability and serve growing peak demand in the Yuma area. On the other hand, SRP is participating in the line in order to access geothermal resources in the Yuma area that are available for export during off-peak load periods. Achieving such synergies increases the value of transmission projects to Arizona.

5.5 Arizona-California EHV system assessment

The transmission facilities between Arizona and southern California have been an important part of the western electric power grid for several decades. This importance has grown in recent years as considerable independent generation has been built in Arizona, Utah and Nevada to serve California load. Of particular importance, have been the transmission facilities that cross the Colorado River between Arizona, California and southern Nevada—known as Path 49. This Path continues to be an important factor limiting power transfers in the West. This Path was an important part of the analysis made by STEP, as discussed in the previous chapter. Arizona entities hold significant ownership interest in several of the key lines that make up this path (e.g., Mead-Liberty, Mead-Perkins and Navajo-Crystal). However, except for the APS share of the Hassayampa-North Gila 500kV line, which supplies APS loads in the Yuma area, the remainder of the Arizona-California EHV (PATH 49) transfer capability has no direct impact on supply to customers located in Arizona. Nevertheless, Path 49 is a major flowgate for the export of generation from Arizona to California, including resources in Arizona that are owned by California utilities.

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Comment [JS5]: Others share ownership. Ex. WAPA, which is not an "Arizona entity",

The area studied by STEP and the general options they identified are shown on Figure 13. The map reflects the three basic options identified by the STEP study team:

- Short-term upgrades on Path 49 – Series capacitor upgrades, second Devers 500/230 kV transformer, voltage support, and installation of flow control apparatus on Imperial Valley to El Centro 230kV (in California);
- Palo Verde-Devers #2 500 kV Line; and
- Upgrade of Path 49 to 9300 MW—(series capacitor upgrades on Mead-Perkins and Navajo-Crystal 500kV lines, etc.)

- Develop base case (starting with 2012)
- Develop "long-term" AZ-NM system
- Study particular "common interest" projects of Interested parties
- Bring results together for technical review and comments
- Incorporate into a single plan report

They are evaluating several specific projects including three coal projects (2,400 MW total), one wind project (100 MW), one new 500 kV line (NTP), and one new 345 kV line (PNM). Various parties are interested in a number of new generation possibilities for the region to serve load in Arizona, New Mexico, Utah, Colorado, and Nevada as shown in Table 6.

Table 6: Long-range transmission "needs" of parties in the AZ-NM region

Interested party	Delivery amount desired	Desired market
AZ Electrical Districts	200 MW	Four Corners to CATS Area
Tri-State	200 MW	Springerville to Colorado
APS	1,000 MW	Four Corners to Phoenix
SRP	600 MW	Springerville to Phoenix
EPE	300 MW	Upgrade on WECC Path 47
TEP	500 MW	Springerville to Tucson
PNM	400 MW	Four Corners to Albuquerque
Pacific Corp.	500 MW	Four Corners to Utah
WAPA (SLC)	100 MW	Four Corners to Glen Canyon
SWTC	200 MW	Four Corners towards Tucson
NTP	1,500 MW	Four Corners to PHX and LV
BHP (Merchant Generator)	500 MW	Four Corners to PHX and ALB
STEAG (Merchant Generator)	1,400 MW	Four Corners to Phoenix
Western Wind (Merchant Generator)	100 MW	Coronado to Phoenix

5.7 Navajo Transmission Project

The Navajo Transmission Project is a 460- mile, 500 kV line with an expected capacity of 1,200 to 1,800 MW. It will interconnect the Four Corners, Moenkopi and Market Place substations, and traverse portions of three states as shown in red on Figure 16. The Diné Power Authority (DPA) is developing the transmission project in conjunction with its coal-fired Desert Rock

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Energy Project in the Four Corners area of New Mexico.[1] DPA is partnering with Sithe Global Power on the transmission project. A significant portion of the right-of-way in Arizona is within the Navajo Nation, which includes 60% of the line length from Four Corners to Moenkopi substation.

Comment [JS6]: This doesn't sound accurate. Should confirm with DPA

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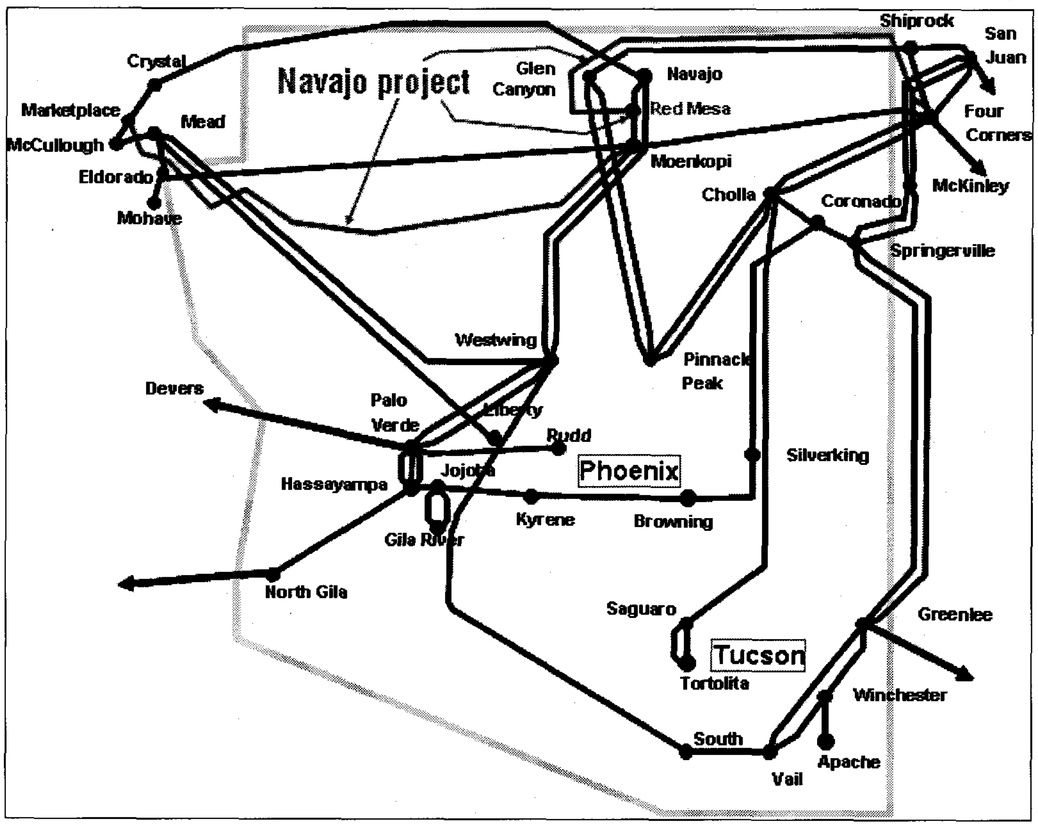
Figure 16: Navajo Transmission Project concept



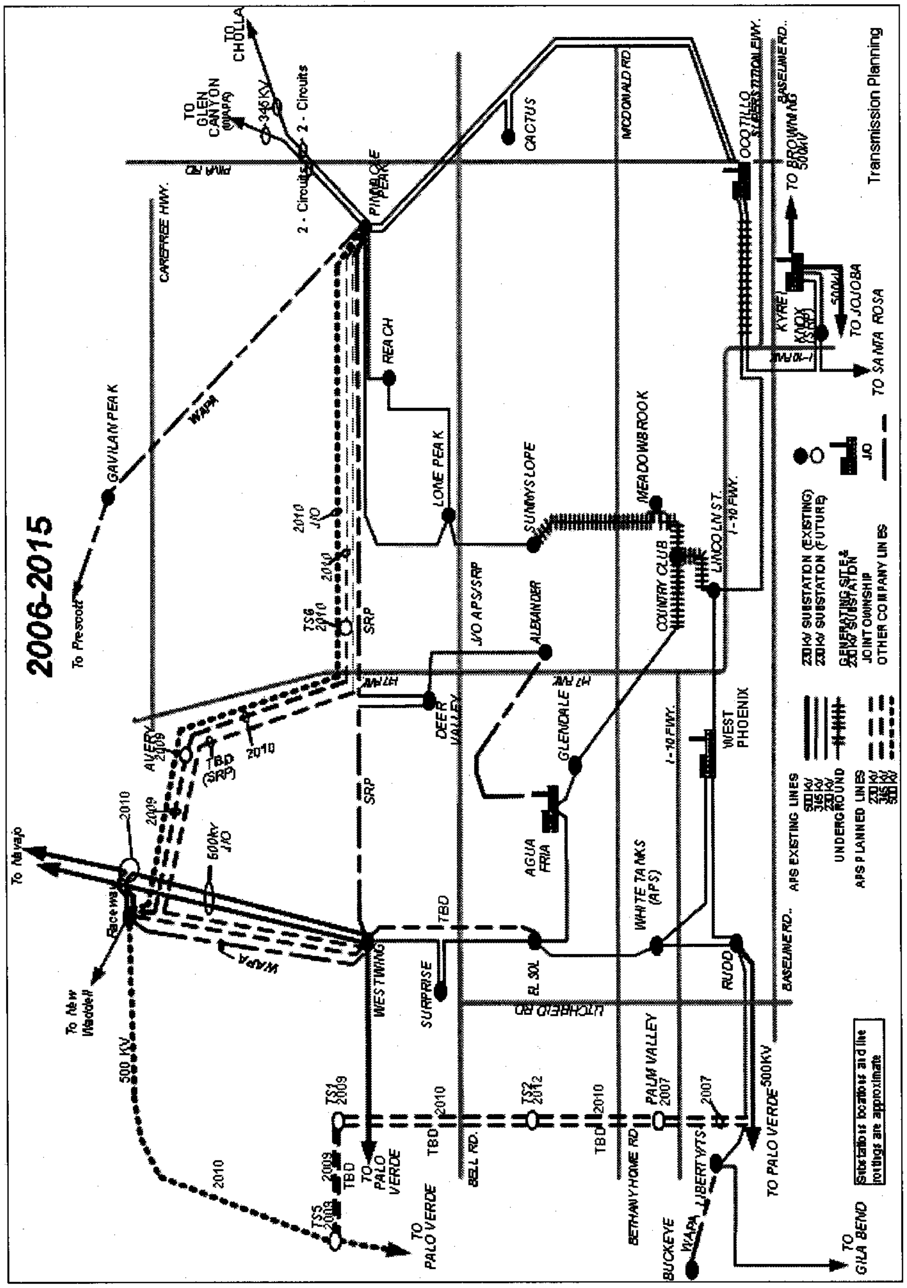
The Navajo Transmission Project has three distinct segments or phases, which are all being permitted together at this time. The sequence of the three segments is as follows:

- A 500 kV circuit from Four Corners (or a new station nearby) to Red Mesa (or a new substation nearby) to be place in-service in 2010;

[1] Diné Power Authority is an enterprise of the Navajo Nation. It was created in 1985 by the Navajo Tribal Council for the purpose of developing electric transmission and generation projects within the Navajo Nation. RockPort Capital Partners (RockPort) is a venture capital firm that is assisting DPA in the Project Development Activities. Steven Begay is the DPA General Manager and Alexander (Hap) Ellis III is a Partner in RockPort.

Figure 22: New projects strengthening the Phoenix-area transmission system

Comment [JS7]: The reference to this map implies that it is covering all of the projects in the Phoenix area. This is an APS-centric map and is skewed to APS' service territory.



The difference between the production costs from these two cases shows the RMR cost of the transmission constraint.

These two cases were simulated with a detailed regional production-costing model that includes the generation and transmission system of the entire WECC. The model dispatches all generators on an economic basis to meet the overall WECC system load within constraints for control area reserve requirements and transmission limitations. The model also determines sales of economic generation to, and economic purchases from, other utilities in the region subject to regional transmission constraints. The accuracy of the RMR costs depends upon accuracy of the forecasts for load, generation heat rates and forced outage rates, fuel costs, and other costs. Because these costs are not easy to predict, Staff recommends that for the 2008 RMR Study, production cost analysis be conducted assuming low and high fuel cost scenarios, as well as a variation of the other cost components.

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Based on the results of the 2006 Phoenix area RMR economic analysis as summarized in Table 8 below, ACC Staff concludes that it will have a negligible impact on Arizona ratepayers in the 2006-2015 timeframe:

Table 8: Phoenix area RMR conditions and costs

Year	SIL[1] (MW)	Peak Demand (MW)	Max RMR[2] (MW)	RMR[3] Hours	RMR Energy[4] (GWH)	RMR Energy (% of total)	RMR Cost[5] ($M)
2008	9,700	12,625	2,853	845	650	1.1	0.0
2015	13,004	16,100	2,811	548	419	0.6	0.0

Table Key:

[1] SIL – System Simultaneous Import Limit is the maximum amount of capacity that can be reliably imported into the area with no local generation operating.

[2] Max RMR – The amount of local generation required to meet the area peak demand (Peak Demand minus Import Capability).

[3] RMR Hours – The number of hours that the area's demand exceeds the SIL, thus requiring the use of local generation to meet load, even if otherwise economically dispatched.

[4] RMR Energy – The annual energy that must be met by local generation (in excess of the SIL).

[5] RMR Cost – The difference in annual generation cost with and without the transmission limitation.

In the 3rd BTA, Staff recommended that APS (and others required to perform the 2006 RMR Studies) make available to the Staff the list of the actual generation unit data used in the model and generation units energy production calculated by the model. The Phoenix area generation summary from the 2006 RMR report is shown in Table 9.

7.2 Impacts of renewable energy sources on the transmission network

The BTA does not specifically address the implementation of renewable energy resources. This information is included in the studies as projected resources to match projected loads and to be consistent with the resources requirements of the Environmental Portfolio Standards (EPS), and the recently approved Renewable Energy Standard and Tariff (REST) rules. While this is consistent with the requirements of the BTA, it could be useful to include a summary in future BTAs, , to the extent such information is known and is not confidential, the location of the resources, amounts included in the studies, and any specific transmission used to enable them

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In Europe, substantial wind penetration exists today and is likely to increase over time. The impacts on the transmission network are viewed not as an obstacle to development, but rather as "speed bumps" that must be addressed.

Issues related to integrating larger amounts of renewable resources into utility plans have received increasing interest during the past few years. As an example a 2006 report to the Western Governors' Association made three transmission-related recommendations regarding incorporating renewable energy resources:[1]

1. "Ensure that targeted energy efficiency, central heating and power, and other demand-side resources are incorporated into state transmission planning.
2. "Ensure that utility interconnection policies best facilitate the use of a wide range of clean energy resources.
3. "Urge utilities to assess available transmission capacity and opportunities to make better use of the existing transmission systems."2

Many parties around the world are developing equipment and techniques to mitigate the variability of wind power (and some other types of renewable) output. Even so, intermittent wind power on a large scale (typical larger than 20% of generation meeting load) affects the network in a number of that requires further study in detail:

- Power flow - ensure that the interconnecting transmission or distribution lines will not be over-loaded. This type of analysis is needed to ensure that the introduction of additional generation will not overload the lines and other electrical equipment. Both active and reactive power requirements should be investigated. Reactive power should be generated not only at the interconnection point, but throughout the network, and should locally be compensated.

[1] *Clean Energy, a Strong Economy and a Healthy Environment*, a report of the Clean and Diversified Energy Advisory Committee to the Western Governors Association, 11 June 2006.

[2] *ibid*, page 4.

8. Study of n-1-1 and extreme contingencies

The Commission directed that as part of the 3rd BTA parties address and document:

Comment [JS8]: Should say the 4th BTA?

1. Compliance with single contingency events overlapping bulk power system maintenance outages (n-1-1) criteria for the first year of the BTA study period, consistent with WECC and NERC requirements.

    1. Extreme contingency outage studies for Arizona's major generation hubs and major transmission stations, and associated risks and consequences, if mitigating infrastructure improvements are not planned.

APS, SRP and TEP filed n-1-1 studies of planned pre-summer 2006 maintenance conditions with the Commission in the first quarter 2006, pursuant to Protective Agreements.

TEP included selected overlapping and extreme contingency analysis for the Tucson area in its Ten Year Plan filing dated February 2, 2006. In addition, APS and TEP made presentations on overlapping and extreme contingency analysis at Workshop I of the 4th BTA held at the Commission on June 6, 2006. SRP service area results were included in the APS analysis. The extreme contingency cases are intended to address the consequence of two categories of events, specifically (1) common corridor line outages, and (2) concurrent transformer outages at major EHV substations. The February 2, 2006 and June 6, 2006 reports were released as non-protected, public information; the results are summarized in Table 15 and Table 16.

Table 16: Extreme contingency results

Company	Area(s) Studied	Year(s) Studied	Conditions Studied	Results	Action Plan (if applicable)
APS	Phoenix area (including SRP loads)	2006 & 2016 (summer peak)	Cholla-Saguaro & Coronado-Silverking 500kV corridor outage	All load served and reserve requirements met.	Redispatch generation if needed
			Navajo South 500kV corridor outage	All load served and reserve requirements met.	Redispatch generation if needed
			Four Corners-Cholla-Pinnacle Peak 345kV corridor	All load served and reserve requirements met.	Redispatch generation, reconfigure system or shed up to 200 MW of load.
			Glen Canyon-Flagstaff-Pinnacle Peak 345kV corridor	All load served and reserve requirements met.	Redispatch generation, reconfigure system or shed up to 200 MW of load.
			Loss of all Kyrene 500/230kV banks	All load served and reserve requirements met.	Redispatch generation if needed
			Loss of all Browning 500/230kV banks	All load served and reserve requirements met.	Redispatch generation if needed
TEP	Tucson area	2008 (summer peak)	Loss of all Tortolita 500/138kV banks	No problems reported	
			Loss of all Vail 345/138kV banks	Shiprock transformer overload	Under review
			Loss of all South 345/138kV banks	No problems reported	

Outage of the Palo Verde East corridor was not studied because there is no forestation. Westwing 500/230 kV multiple bank outage was not studied because they have additional spacing, fire walls, fire suppression and oil retention pits. Rudd 500/230 kV multiple bank outage was not studied because it is equivalent to loss of the Palo Verde-Rudd 500 kV line. Pinnacle Peak 345/230 kV multiple bank outage was not studied because it's equivalent to outages of the 345 kV common corridor lines into the substation.

Staff concludes that these cases adequately address the key extreme contingencies of interest, but TEP should continue its review of the specific items as noted in the table(s) above and inform the Staff of their conclusions. It should be noted that the TEP n-2 line outages included in Table 15 are also extreme contingency events.

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transmission projects are regional in nature. In fact many smaller projects which are essential to serve local load areas or generators, by their very nature, do not require the participation of other stakeholders.

5. Transmission providers have performed updated reliability-must-run studies for each local transmission import constrained area (except Santa Cruz County and Mohave County) and have addressed the Third BTA RMR requirements. Uncertainty exists regarding RMR requirements in Santa Cruz County beginning 2008 and Mohave County beginning 2012, which should be addressed in filings for the 5th BTA by January 2008.

6. In general, the existing and proposed Arizona transmission system meets the load serving requirements of the state in a reliable manner:

   a. Many planned Extra High Voltage ("EHV") and High Voltage ("HV") projects will increase transmission system capability to support increased interstate power transfers and provide reliable transfers within the state of Arizona.

   b. The EHV system appears to be adequate throughout the study period and the planned facilities identified in the ten-year planning process appear to be consistent with good utility practice. As is often the case, plans for the later years of the period are less well defined than those in the early years. As requested in the Third BTA, this new round of reports includes more discussion of alternate additions considered for the final five years of the study period. Given the number of alternative projects identified in the longer range plans it should be possible to supply future Arizona electric system loads in an economical and reliable fashion. Early identification of such alternatives in the BTA process allows the Staff and public to be better informed regarding future possibilities and should continue in future filings.

   c. The RMR studies show that the RMR areas will have load-serving capacity sufficient to provide reliable supply during the next ten-year period (with the exceptions noted in Conclusion 5.) Problems identified during the Third BTA in the Yuma area in 2004 and the Phoenix area in 2013 are addressed and resolved in the 2006 RMR study.

   d. For the Phoenix and Yuma areas, based upon the study results reported for the two years examined (2008 and 2015), ACC Staff concludes that the RMR costs and emission impacts should be negligible throughout the 2006-2015 period. For the Phoenix metropolitan area, Staff concludes the SIL and MLSC increases are

Comment [h9]: Was duplicate of #3

Deleted: <#>Numerous new transmission and generation projects have been constructed, announced, and filed with the Commission since the prior BTAs. Some transmission projects filed in prior BTA's have been cancelled, delayed or advanced based on changes in load, generation and import conditions. Staff finds these changes acceptable.¶

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attributable to the transmission improvements described in the 2006 BTA filings by APS and SRP. Installation of a second North Gila 500/69kV transformer in 2005, along with the proposed Yucca 100MW generation addition and second 500kV Palo Verde-North Gila line appear to effectively meet RMR requirements in the Yuma area.[1] It is possible that Tucson area RMR requirements could be eliminated and the load area could have unlimited access to lower cost resources from the outside market if incremental upgrades are economically justified. ACC Staff requests that TEP provide an economic analysis of this option in its 2008 BTA filing.

e. The planned Arizona transmission system meets the WECC and NERC single contingency criteria (n-1). Performance of the system has also been demonstrated during the Fourth BTA for significant overlapping contingencies (n-1-1 and n-2) as requested in the Third BTA.

f. Arizona transmission providers are doing an effective job of planning transmission upgrades and additions that improve access to capacity from merchant plants at Palo Verde in a reliable manner, which in the past has been stranded to some extent when the market has desired access. Some improvement has already been achieved in 2006 and significant improvement is expected with the addition of the Hassayampa-Pinal West-Santa Rosa 500kV and Palo Verde-TS5 500kV line additions in 2008 and 2009, respectively. In conjunction with other proposed transmission upgrades such as SCE's Palo Verde-Devers #2 line, these projects should significantly mitigate market limitations between Arizona, California and southern Nevada.

g. The Fourth BTA also concludes that after the addition of Hassayampa-Pinal West-Santa Rosa 500kV and Palo Verde-TS5 500kV lines the need for load shedding in Arizona following a common corridor outage of 500kV lines leaving the Palo Verde Hub will be eliminated.

7. Studies investigating transmission expansion options between Arizona, southern Nevada and New Mexico continue to explore the scope, participation and timing of alternative projects. Other transmission expansion projects proposed in Nevada may bring additional resources closer to the borders of Arizona. APS has also initiated regional stakeholder discussions for a conceptual TransWest Express 500kV

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[1] It should be noted that APS's Yucca generation solicitation is the subject of a separate proceeding before the Commission.

Project that could significantly increase import capability into Arizona from future coal and wind resources in Wyoming. Such regional projects may provide both economic and reliability benefits to Arizona consumers and increase import/export capabilities between Arizona and surrounding markets. ACC Staff welcomes such proposals which could bring significant benefits to Arizona in the 2006-2015 timeframe or beyond.

8. Some new power plants have interconnected to Arizona's bulk transmission system via a single transmission line or tie rather than continuing Arizona's best engineering practices of multiple lines emanating from power plants. As interconnection of new transmission lines are considered for the Palo Verde Hub, they should be encouraged to terminate at these new power plant switchyards in order to mitigate this regional reliability concern.

9. Certain n-1 contingency violations occurring in the SWTC 2015 planning study and certain n-2 and extreme contingency results in TEP's 2016 case still need to be resolved. These issues occur at or beyond the end year of the current 10-year plan and there is still sufficient time to satisfactorily resolve these concerns.

10. The Commission Staff concludes that the direction of collaborative planning processes by transmission providers and stakeholders in Arizona is consistent with the spirit of the requirements for transmission planning described in EPAct-05 and FERC Order 888. This is reinforced by the recent decision of the WECC to form a Transmission Expansion Planning Policy Committee to provide a transparent West-wide stakeholder process for related data and studies.

11. Regarding the CATS-HV interim study; since the rate of population and load growth in the area of study could be quite rapid, revisiting the study every 3-5 years would be preferable to the 5-10 year cycle suggested in the report.

12. Based on the 2006 RMR study results Staff recommends that:

- Arizona utilities should continue performing RMR studies for all transmission import constrained local areas:
    - Utilizing a collaborative study forum;
    - Improving economic analysis of RMR mitigation;

consequences documented if mitigating infrastructure improvements are not planned.

c. Generation interconnections should be granted a Certificate of Environmental Compatibility by the Commission only when they meet regional and national reliability criteria and the requirements of the Commission's decisions in the 2002 Biennial Transmission Assessment and Track A related to power plant interconnections.

d. Grant SWTC an extension to January 2007 to resolve certain n-1 contingency violations in its 2015 planning study and to file expansion plans to resolve these issues as part of its 2007-2016 plan.

e. Regarding uncertainties related to RMR requirements in Santa Cruz County beginning 2008 and Mohave County beginning 2012, UNS and SWTC, with input from APS should be directed to resolve these questions in their filings for the 5th BTA by January 2008.

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Comment [h10]: APS doesn't have much in these two counties

Appendix B: 2006 BTA Workshops 1 and 2 list attendees

	Name		Representing	Phone number	E-mail address	Workshops attended[1]
1	Jerry D.	Smith	ACC	(602) 542-7271	jsmith@cc.state.az.us	1
2	Ken	Bagley	Genesee	(480) 367-4282	kbagley@cox.net	1 & 2
3	Prem	Bahl	ACC	(602) 542-7269	pbahl@cc.state.az.us	1 & 2
4	Ed	Beck	TEP	(520) 745-3276	ebeck@tep.com	1 & 2
5	Steven C.	Begay	Dine Power Authority		dpasteve@citlink.net	1
6	Patrick	Black	Fennemore Craig		pblack@felaw.com	1 & 2
7	Jane	Brandt	SRP		jkbrandt@srpnet.com	1 & 2
8	Ian	Calkins	Copper State Consulting Group		ian@copperstate.net	1
9	Jim	Charters	Retired	(623) 572-7972	j_charters@msn.com	1 & 2
10	Brian	Cole	APS		Brian.Cole@aps.com	1 & 2
11	David	Couture	TEP		dcouture@tep.com	1 & 2
12	Michael	Curtis	Mohave Electric	(602) 248-0392	mcurtis401@aol.com	1
13	Cary	Deise	APS	(602) 250-1232	cary.deise@aps.com	1 & 2
14	Chris Clark	DeSchene	Dine Power Authority		clarkdeschene@att.net	1
15	Mark	Etherton	SWAT/AZNM	(602) 809-0707	mle@krsaline.com	1
16	Bruce	Evans	SWTC	(520) 586-5336	bevans@swtransco.coop	1 & 2
17	Linda	Fisher	Corp. Commission - Legal		Lfisher@AZCC.gov	1
18	Commissioner	Gleason				1
19	Charles	Hains	Corp. Commission - Legal		Chaines@AZCC.gov	1 & 2
20	Thomas A.	Hine	Mohave Electric		thineesq@yahoo.com	1
21	Chairman	Hatch-Miller				1
22	Gary T.	Ijams	CAWCD	(623) 869-2362	gijams@cap-93.com	2
23	Joshua	Johnston	Western Area Power Admin.		jjohnston@wapa.gov	1
24	Robert	Kondozoilka	SRP	(602) 236-0971	rekondzi@srpnet.com	1 & 2
25	David M.	Korinek	KEMA		David.Korinek@kema.com	1 & 2
26	Peter	Krzykos	APS		Peter.Krzykos@aps.com	1 & 2
27	Steven	Mavis	sce	(626) 302-8175	steven.mavis@sce.com	1
28	Gary	Minich	Energy Strategies	(602) 369-4368	greg@azcpa.org	2
29	Jeff	Palermo	KEMA	(703) 631-6912	jpalermo@kema.com	1 & 2
30	Greg	Patterson	AZCPA		greg@azcpa.org	1 & 2
31	Milt	Percival	WSES for 3M	(602) 352-2794	mperc7439@aol.com	1 & 2

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[1] Workshop I was held on June 6, 2006; Workshop II was held on September 8, 2006

Appendix C: Existing Arizona power plants

Plant name	Switchyard voltage (kV)	No. units	Primary energy source	Total summer capacity (MW)	AZ capacity under contract (MW)	AZ capacity share (%)	2005 annual net generation (MWh)
Abitibi Consolidated Snowflake		1	SUB	27.2	0	0%	411,664
		1	SUB	43.3	0	0%	
Agua Fria		1	NG	113	113	100%	141,617
		1	NG	113	113	100%	
		1	NG	181	181	100%	
		1	NG	73	73	100%	
		1	NG	73	73	100%	
		1	NG	73	73	100%	
		1	SUN	0.2	0.2	100%	
Apache Station		1	NG	10.2	10.2	100%	2,876,049
		1	NG	18.5	18.5	100%	
		1	NG	60	60	100%	
		1	NG	40	40	100%	
		1	NG	72	72	100%	
		1	SUB	175	175	100%	
		1	SUB	175	175	100%	
Arlington Valley Energy Facility		1	NG	165	165	0%	1,336,932
		1	NG	165	165	0%	
		1	NG	250	250	0%	
Biosphere 2 Center		1	DFO	1.5	0	0%	n/a
		1	NG	1.6	0	0%	
Childs		1	WAT	1.4	1.4	100%	n/a
		1	WAT	1.4	1.4	100%	
		1	WAT	1.4	1.4	100%	
Cholla		1	SUB	110	110.0	100%	7,577,568
		1	SUB	260	260.0	100%	
		1	SUB	260	260.0	100 %	
		1	SUB	380	0	0%	
Cogeneration 1		1	NG	8.3	0	0%	n/a
Coronado		1	SUB	395	395	100%	6,070,915
		1	SUB	390	390	100%	
Davis Dam		1	WAT	51.7	51.7	100%	992,230
		1	WAT	51.7	51.7	100%	
		1	WAT	48	48	100%	
		1	WAT	51.7	51.7	100%	
		1	WAT	51.7	51.7	100%	
Demoss Petrie		1	NG	72.2	72.2	100%	18,762

Comment [h11]: This plant should be deleted or at least noted that it no longer is able to generate electricity.

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Plant name	Switchyard voltage (kV)	No. units	Primary energy source	Total summer capacity (MW)	AZ capacity under contract (MW)	AZ capacity share (%)	2005 annual net generation (MWh)
Hoover Dam		1	WAT	2.7	2.7	100%	1,879,235
		1	WAT	130	130	100%	
		1	WAT	130	130	100%	
		1	WAT	130	130	100%	
		1	WAT	130	130	100%	
		1	WAT	127	127	100%	
		1	WAT	130	130	100%	
		1	WAT	130	130	100%	
		1	WAT	61.5	61.5	100%	
		1	WAT	68.5	68.5	100%	
Horse Mesa		1	WAT	10	10	100%	63,065
		1	WAT	10	10	100%	
		1	WAT	10	10	100%	
		1	WAT	119	119	100%	
Irving		1	WAT	1.4	1.4	100%	n/a
Kyrene		1	NG	34	34	100%	828,589
		1	NG	72	72	100%	
		1	NG	59	59	100%	
		1	NG	53	53	100%	
		1	NG	53	53	100%	
		1	NG	144	144	100%	
		1	NG	107	107	100%	
Mesquite Generating Station		1	NG	146.2	0	0%	6,724,135
		1	NG	144.5	0	0%	
		1	NG	146.2	0	0%	
		1	NG	146.2	0	0%	
		1	NG	245.1	0	0%	
		1	NG	245.1	0	0%	
Mormon Flat		1	WAT	11	11	100%	27,229
		1	WAT	57	57	100%	
Navajo		1	BIT	750	506.2	67.49%	17,030,674
		1	BIT	750	506.2	67.49%	
		1	BIT	750	506.2	67.49%	
North Loop		1	NG	25	25	100%	n/a
		1	NG	25	25	100%	
		1	NG	23	23	100%	
		1	NG	23	23	100%	

Comment [h12]: This plant should be deleted or at least noted that it no longer is able to generate electricity.

Plant name	Switchyard voltage (kV)	No. units	Primary energy source	Total summer capacity (MW)	AZ capacity under contract (MW)	AZ capacity share (%)	2005 annual net generation (MWh)
Ocotillo		1	NG	110	110	100%	145,500
		1	NG	110	110	100%	
		1	NG	50	50	100%	
		1	NG	50	50	100%	
		1	SUN	0.1	0.1	100%	
		1	SUN	0.1	0.1	100%	
		1	SUN	0.4	0.4	100%	
Palo Verde		1	NUC	1243	775.5	62.39%	25,807,446
		1	NUC	1314	819.8	62.39%	
		1	NUC	1247	778.0	62.39%	
PPL Griffith Energy Project		1	NG	148	0	0%	786,882
		1	NG	148	0	0%	
		1	NG	292	0	0%	
Sundance		1	NG	41	41	100%	63,993
		1	NG	41	41	100%	
		1	NG	41	41	100%	
		1	NG	41	41	100%	
		1	NG	41	41	100%	
		1	NG	41	41	100%	
		1	NG	41	41	100%	
		1	NG	41	41	100%	
		1	NG	41	41	100%	
		1	NG	41	41	100%	
Prescott Airport		1	SUN	2.1	0	100%	n/a
Red Hawk		1	NG	163.5	0	100%	3,849,124
		1	NG	163.5	0	100%	
		1	NG	163.5	0	100%	
		1	NG	163.5	0	100%	
		1	NG	183	0	100%	
		1	NG	183	0	100%	
Roosevelt		1	WAT	36	36	100%	n/a
Saguaro		1	NG	110	110	100%	50,334
		1	NG	110	110	100%	
		1	NG	76	76	100%	
		1	NG	50	50	100%	
		1	NG	50	50	100%	

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Plant name	Switchyard voltage (kV)	No. units	Primary energy source	Total summer capacity (MW)	AZ capacity under contract (MW)	AZ capacity share (%)	2005 annual net generation (MWh)
Santan		1	NG	92	92	100%	2,078,088
		1	NG	92	92	100%	
		1	NG	92	92	100%	
		1	NG	92	92	100%	
South Consolidated		1	WAT	1.4	1.4	100%	n/a
South Point Energy Center		1	NG	180	0	0%	1,481,306
		1	NG	180	0	0%	
		1	NG	190	0	0%	
Springerville		1	SUB	400	400	100%	5,577,373
		1	SUB	400	400	100%	
		1	SUN	5.1	5.1	100%	
Stewart Mountain		1	WAT	13	13	100%	n/a
Sundt		1	SUB	156	156	100%	1,152,849
		1	NG	24	24	100%	
		1	NG	25	25	100%	
		1	NG	81	81	100%	
		1	NG	81	81	100%	
		1	NG	105	105	100%	
Tri Cities		1	LFG	0.8	0.8	100%	n/a
		1	LFG	0.8	0.8	100%	
		1	LFG	0.8	0.8	100%	
		1	LFG	0.8	0.8	100%	
		1	LFG	0.8	0.8	100%	
Valencia		1	NG	14.7	14.7	100%	n/a
		1	NG	14.7	14.7	100%	
		1	NG	14.7	14.7	100%	
Waddell		1	WAT	10	10	100%	n/a
		1	WAT	10	10	100%	
		1	WAT	10	10	100%	
		1	WAT	10	10	100%	
West Phoenix		1	NG	80	80	100%	2,299,621
		1	NG	80	80	100%	
		1	NG	80	80	100%	
		1	NG	71	71	100%	
		1	NG	36	36	100%	
		1	NG	172	172	100%	
		1	NG	172	172	100%	
		1	NG	186	186	100%	
		1	NG	50	50	100%	
		1	NG	50	50	100%	
Yucca		1	NG	18	18	100%	245,392

Comment [h13]: Santan #5 and #6 are missing. Santan #6 might not have any 2005 values, but it is now an existing plant.

Plant name	Switchyard voltage (kV)	No. units	Primary energy source	Total summer capacity (MW)	AZ capacity under contract (MW)	AZ capacity share (%)	2005 annual net generation (MWh)
		1	NG	18	18	100%	
		1	DFO	20	0.0	0%	
		1	NG	52	52	100%	
		1	DFO	51	51	100%	
		1	NG	75	42.5	56.65%	
Yuma Axis		1	DFO	22	22	100%	n/a
Yuma Cogeneration Associates		1	NG	35.14	0	0%	n/a
		1	NG	17.12	0	0%	
46 Plants Total		**192**		**24,249**	**13,539.7**	**70.6%**	**100,270,606**

Comment [h14]: This is an IID plant and AZ Cap & share are 0

Source: U.S. Department of Energy, Energy Information Administration, Form EIA-860, Form EIA-906, Form EIA-920.

Primary energy sources:

BIT Anthracite Coal, Bituminous Coal
DFO Distillate Fuel Oil (includes all Diesel and No. 1, No. 2, and No. 4 Fuel Oils)
LFG Landfill Gas
NG Natural Gas
NUC Nuclear (Uranium, Plutonium, Thorium)
SUB Subbituminous Coal
SUN Solar (Photovoltaic, Thermal)
WAT Water (Conventional, Pumped Storage)

Appendix D: Information resources

Transmission Planning Studies and related documents, used to develop this Third BTA report, were assembled from the following reports, presentations, and dockets:

D.1 Utilities' 2004 Ten-Year Transmission Plans

Comment [h15]: Should this be 2005 and 2006?

1. Arizona Public Service Company (APS)
2. Salt River Project (SRP)
3. Southwest Transmission Cooperative (SWTC)
4. Southwestern Power Group II (SWPG)
   a. Toltec
   b. Bowie
5. Southern California Edison (SCE)
6. Texas – New Mexico Power Company (TNMP)
7. Tucson Electric Power Company (TE")
8. UniSource Electric (UNS)

D.2 Generation interconnection studies and related FERC interconnection standards and compliance documents

9. FERC Order 2003 and 2003-A, Standard Interconnection Agreements & Procedures for Large Generators
10. Arizona Utilities Compliance Documents regarding the FERC Order 2003 and 2003-A

D.3 Arizona Corporate Commission documents

11. ACC Docket No. E-0000A-02-0051, Decision 65743, Track B

D.4 Reliability Must Run workshop

12. ACC 2004 RMR Workshop Presentations and Reports

Comment [h16]: Should this be 2006 RMR workshop presentation?

13. FERC Related orders (PL04-2 policy related to bid based market)

D.5 Transmission projects reports

14. Central Arizona Transmission System ("CATS") Phase 3 Report[1]

[1] http://www.azpower.org/cats/

Appendix E: List of new projects and project changes

Comment [h17]: This table contain conflicting, repetitive and overlapping information

In service date	Project	Voltage	Status
2005	Gavilan Peak	230kV	Completed
2005	TS3 230/69kV substation	230/69kV	Named Palm Valley
2005	Irvington Station - Vail Substation #1 loop-in through Robert Bills -Wilmot (formerly Littletown) Substation.	138-kV	Placed in-service August 26,2005
2006	South East Valley 500kV project - Hassayampa-Pinal West & Pinal West-Santa Rosa-Browning	500kV	Removed from APS plan - APS no longer participating
2007	Dinosaur (RS19)	230kV	Advanced from 2008
2007	Rudd-Palm Valley-TS4 230kV	230kV	Changed to I/S date of 2007
2007	Hassayampa to Pinal West	500 kV	Delayed from 2007 to 2008
2007	Hackberry 230/69 kV Substation	230/69 kV	New Project
2007	Vail - East Loop cut-in of line through future Pantano and Los Reales Substations.	138-kV	2006 (Phase II, Phase I completed)
2007	West Ina Substation - Tucson Station cut-in through Del Cerro (formerly Sweetwater) Substation.	138-kV	New Project?
2008	Palo Verde Pinal West	500 kV	Delayed from 2006
2008	Pinal West – Santa Rosa	500 kV	Delayed from 2007
2008	PV Hub-TS5 500kV	500kV	Changed to I/S date of 2009 and added interconnection options (AVGS & HQJNT)
2008	TS1-TS2-Palm Valley 230kV w/TS2 I/S of 2012	230kV	Changed to I/S date of 2010 w/TS2 I/S date of 2011
2008	RY-AV 230kV	230kV	Changed to I/S date of 2009
2008	Red Rock to Saguaro	230 kV	Scope change; in-service date changed to 2008; 30 kV changed to 115 kV; Red Rock changed to Naviska 115 kV Projects
2008	Gordon Sloan 230/69 kV Substation	230/69 kV	New Project
2008	Pinal West to Santa Rosa	500 kV	New SWTC participation
2009	Palo Verde – TS5	500 kV	Delayed from 2007
2009	Second Knoll	500 kV	SRP (APS)
2009	Flagstaff 345/69kV interconnection	345/69kV	Changed to I/S date of 2009
2009	TS5-TS1 230kV	230kV	Changed to I/S date of 2009
2009	RY-AV 230kV	230kV	Changed to I/S date of 2009
2009	Second Knoll 500/69kV	500/69kV	Interconnect moved from CO-SK line to CO-CH line
2009	TS5-TS1 230kV	230kV	Changed to I/S date of 2009
2009	Second Knoll 500/69kV	500/69kV	Interconnect moved from CO-SK line to CO-CH line
2009	VV1 500/69kV	500/69kV	New Project
2009	Naviska to Thornydale 115 kV Line	115 kV	New Project
2009	Pinal West - Southeast Valley 500 kV	500 kV	New?
2009	Devers-Palo Verde No. 2	500 kV	Delayed from 2008 to 2009
2009	Rancho Vistoso Substation to future Catalina Substation	138 kV	New Project?
2010	Raceway – Pinnacle Peak	500 kV	New project
2010	TS1-TS2-Palm Valley 230kV w/TS2 I/S of 2012	230kV	Changed to I/S date of 2010 w/TS2 I/S date of 2011
2010	PP-TS6-AV 230kV	230kV	Changed to I/S date of 2010
2010	PP-TS6-AV 230kV	230kV	Changed to I/S date of 2010
2010	TS9-PP 500kV	500kV	New Project
2010	Palo Verde Hub to IID Service area, Northern (Reference SCE DPV2 Line Designation)	500kV	New
2010	Palo Verde Hub to IID Service area, Southern (Reference APS Palo Verde to Yuma Project)	500kV	New
2010	Moenkopi –Eldorado capacitor upgrade	500 kV	Delayed from 2006 to 2010
2010	Vail - Wentworth 138 kV - two circuits	138 kV	New Project?
2011	Pinal South	500 kV	Additional facility to SEV Project
2011	Desert Basin – Pinal South	230kV	New project
2011	Desert Basin – Santa Rosa	230kV	New project
2011	Jojoba cut-in of TS4-Panda 230kV	230kV	Changed to I/S date of 2011

Appendix F: Arizona planned EHV transmission additions

Comment [h18]: This table contains conflicting, repetitive and overlapping information

Status	Project	Justification	CEC needed
2006 completion			
2005 construction start	Palo Verde-Devers and Hassayampa–North Gilla 500 kV line upgrades	The upgrading of the series capacitors allows for the increase in transfer capability among Arizona, Southern Nevada and Southern California and has an economic value from an adequacy stand point.	No information filed
2008 completion			
2007 construction start	Hassayampa-Pinal West 500kV line	To accommodate load growth and access to energy sources in the central Arizona area.	Siting Case #124, issued May 2004
2007 construction start	Interconnection of Westwing - South 345 kV via new Pinal West 500/345 kV Substation	To reinforce Tucson Electric Power Company's EHV system and to provide a higher capacity link for the flow of power from the Palo Verde area into TEP's service territory. SWTC, ED2, ED3, and ED4 are also participants.	Included in Siting Case #124
2007 construction start	EOR 9300MW Upgrade Project	To increase East of River (Path 49) transfer capability by 1250MW by upgrading series compensation on Mead-Perkins & Navajo-Crystal 500kV lines, by-passing Perkins phase-shifting transformer, etc. SRP is project sponsor representing 16 owners.	Not required
2007 construction start	Palo Verde-Pinal West 500kV	To provide access to resources from the Palo Verde area generation to the Pinal West Substation	CEC Ordered in Case 124, Issued May 24, 2004
2007 construction start	Pinal West-Santa Rosa 500kV	To provide access to resources from the Palo Verde area generation to the Santa Rosa Substation	CEC Ordered in Case 126, Issued August 25, 2005
2007 construction start	Palo Verde - Pinal West 500 kV (Reference SRP Ten-Year Plan 2006 filing)	To provide access to resources from the Palo Verde area generation to the future (beyond this Ten-Year Plan) 500/69 kV station located at the Pinal West substation.	CEC Ordered in Case 124, Issued May 24, 2004
2007 construction start	Pinal West - Southeast Valley 500 kV (Reference SRP Ten-Year Plan 2006 filing)	To Palo Verde area generation to the Santa Rosa 500 / 230 kV Substation	CEC Ordered in Case 126, Issued August 25,2005
2009 completion			
2008 construction start	Flagstaff 345/69kV Interconnection	This project will serve projected need for electric energy in APS' northern service area. The project will improve reliability and continuity of service for the growing communities in northern Arizona.	A Certificate of Environmental Compatibility is not needed for this project.
2009 construction start	Palo Verde-TS5 500kV line	This line will serve projected need for electric energy in the area immediately north and west of the Phoenix Metropolitan area. It will increase the import capability to the Phoenix Metropolitan area as well as increase the export capability from the Palo Verde hub. This is a joint participation project with APS as the project manager.	Certificate of Environmental Compatibility issued 8/17/05 (Case No. 128, Decision No. 68063, Palo Verde Hub to TS5 500kV Transmission project). APS, as project manager, holds the CEC.