Sixth Biennial Transmission Assessment 2010-2019

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APPENDIX A - GUIDING PRINCIPLES FOR DETERMINATION OF SYSTEM ADEQUACY AND RELIABILITY[1]

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 statutes or ACC rules.

1. Transmission facilities will be evaluated using Western Systems Coordinating Council (WECC), 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 WECC criteria.

3. Compliance with A.C.C. R14-2-1609.B[2] 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. Relying on remedial actions such as generator unit tripping or load shedding for single contingency outages will not be considered an acceptable means of complying with this rule.

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

[1] Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability: Arizona's Best Engineering Practices, Jerry D. Smith, ACC, pre-filed comments for the Gila Bend Power Plant Hearing, Docket No. E-00000V-00-0106, November 9, 2000

[2] 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.

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 statutes 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 WECC, or its successor, and filing a copy of its WECC 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)RS/jds:ESAR.doc

APPENDIX B – HISTORY OF COMMISSION ORDERED STUDIES

Local Area Transmission Import Study Requirements

In the First BTA, Staff identified five load pockets in Arizona that should be monitored for transmission import constraints: Phoenix, Tucson, Yuma, Mohave County and Santa Cruz County. The 2002 BTA added a sixth area located in Southeastern Arizona (Cochise County). The Cochise County area was added to the Commission's areas of concern due to a major blackout of the area in 2001. The 2004 BTA added Pinal County as a local area that needed to be monitored as well. Inclusion of Pinal County was prompted by the necessity of transmission providers to implement a remedial action scheme ("RAS") or special protection scheme ("SPS") for single contingencies with operation of the new Desert Basin and Sundance power plants and additional gas turbines at Saguaro Power Plant.

Cochise County and Santa Cruz County are served by radial transmission lines that result in interruption of service to significant numbers of customers for the outage of any one of the radial transmission lines serving these two counties. A study of the Cochise County Area was documented in the second BTA. At that time no Commission action was deemed necessary because local transmission switching capability was sufficient to minimize the outage time for customers. The Fourth BTA granted Southwest Transmission Cooperative ("SWTC") a time extension until January 2008 to resolve N-1 contingency violations for loss of the Apache to Butterfield or the Butterfield to San Rafael 230 kV line in its 2015 planning study and to file expansion plans to resolve those issues as part of its 2008-2017 ten year plan.

Santa Cruz County, on the other hand, is served by a single transmission line. The customer service and system impacts and risks associated with the loss of a single 115 kV line serving Santa Cruz County are well chronicled over prior BTA assessments and siting of the Gateway 345 kV transmission project.[3] A NEPA environmental impact study has been concluded but federal records of decision and a Presidential Permit for the new 345 kV transmission line are still pending with federal agencies. Therefore UNSE installed a 20 MW generator in Nogales in 2004 and plan to upgrade the existing 115 kV line to 138 kV as interim solutions to ensure the ability to restore service.

TEP was required to file comments by June 30, 2007 to resolve concerns inside neighboring New Mexico and Western Area Power Administration ("WAPA") facilities identified in its preliminary study results for 2016.[4] In addition, technical studies are to be performed and results filed with the

[3] ACC Decision #64356
[4] ACC Decision #69389, March 14, 2007, page 6, section 2.b.iii

Commission for the Cochise County Area to mitigate extended customer outages that resulted from an N-1-1 outage in 2007. A subcommittee of the Southern Arizona Transmission Study ("SATS") subregional planning group has untaken this later task.

The simultaneous import limit ("SIL") and maximum load serving limits ("MSLC") of each of the Arizona load pockets is generally established in conjunction with RMR studies. The Commission approved SIL and MLSC definitions and methodology for performing RMR studies is documented in Appendix C. Arizona's subregional planning forums have also been performing a tenth year snapshot study of the state's transmission system. Those studies have traditionally considered N-0 and N-1 contingencies and provide additional information regarding the transmission capability of each local load pocket.

The Third BTA required that future studies also demonstrate compliance with the WECC and NERC single contingency criteria overlapped with the bulk power system facilities maintenance ("N-1-1") for the first year of the BTA analysis. Staff agreed with the subregional planning groups to limit the N-1-1 analysis to the tenth year for the 4th BTA. The tenth year N-1-1 assessment now only considers designated 230 kV and above planned projects as not in service and then N-1 contingencies are performed. This analysis is more strenuous than the NERC N-1-1 criteria. However, it does determine the possible system impact of a planned project either not getting built as planned or being delayed beyond the tenth year of the plan. The 5th BTA ordered utilities to perform studies to determine how to achieve the Commission's "continuity of service" objective for Cochise County and Santa Cruz County.

Reliability Must-Run Study Requirements

Previous BTAs also identified several of the local load pockets in Arizona where the load cannot be served using a normal economic merit order generation dispatch due to transmission limitations. During some portions of the year, generation units within the load pocket must be operated out of merit order to serve a portion of the local load. Such a resource requirement is often referred to as Reliability-Must-Run ("RMR") generation. The RMR power generated from local generation may be more expensive than the power from outside resources; and may be environmentally less desirable. During RMR conditions, transmission providers must dispatch RMR generation to relieve the congestion on transmission lines.

The Commission's generic electric restructuring docket established that existing Arizona transmission constraints would limit APS' and TEP's ability to deliver competitively procured power to less than the required 50% of Standard Offer Service's load.[5] The Commission stayed this requirement in its Track B proceedings. However, each UDC is still obligated to assure that adequate transmission import capability

[5] Direct Testimony of Jerry D. Smith and rebuttal testimony of Cary Deise, Docket No. E-00000A-02-0051

is available to meet the load requirements of all distribution customers within its service area.[6] Known transmission constraints result in APS and TEP being dependent upon local RMR generation to serve their peak load during certain hours of the year.

In order to provide the Arizona load pockets access to potentially less costly power, the ACC Track A Decision No. 65154 ordered the Arizona utilities to work with Staff to develop a plan to resolve RMR concerns, and include the results of such a plan in the 2004 BTA. The same Decision ordered APS and TEP to file annual RMR study reports with the Commission in concert with their January 31 ten-year plan, for review prior to implementing any new RMR generation strategies, until the 2004 BTA is issued. The utilities readily responded and began providing RMR studies in 2003.

The Third BTA Decision No. 65476 approved a collaborative RMR study plan agreed to by all Arizona transmission providers.[7] The 2003 RMR study forum included only the transmission providers. In contrast, since 2004 the RMR process has been open to all interested parties through Arizona's subregional study forums. The Fourth BTA required that "RMR studies continue to be performed and filed with ten year plans in even numbered years for inclusion in future BTA reports and that:

- Future RMR studies provide more transparent information on input data and economic dispatch assumptions, and
- Arizona utilities collaborate with the Staff to develop and effectively implement more stringent criteria as appropriate for RMR areas in the 2006 BTA."

"N-1-1" (Ten-Year Snapshot) Study Requirements

The N-1-1 study has been included in the set of Commission ordered studies since the 2nd BTA. The objective of the study is to analyze how the participants' ten year plans perform as whole in a regional environment and the effect of omitting an individual planned transmission project from the plan. It assesses the performance of the Arizona system in the 10th year of the ten year planning period covered by the BTA and examines system performance for all bulk power single contingency (N-1) outage events in the study area, together with the removal of major planned transmission projects from the expansion plan, removed one at a time ("N-1-1"). It thus provides a "snapshot" of projected system performance in the final year of the BTA ten year planning period, even if any one of the planned major transmission

[6] A.A.C. R14-2-1609.B
[7] Appendix C

projects is delayed. The N-1-1 study has traditionally been performed by the CATS-EHV Subcommittee of SWAT. As of 2009 and the 6th BTA, the study has aptly been renamed the "Ten-Year Snapshot Study".

The study has historically focused on the central Arizona region (an area bounded by the Phoenix Metropolitan area to the north, the Tucson Metropolitan area to the south, the Palo Verde Generating Station to the west and the Arizona/New Mexico border to the east). However, beginning in 2009, SWAT expanded the assessment into a statewide review of N-1-1 impacts.

Extreme Contingency Study Requirements

Staff's concerns regarding the adequacy and reliability of the Arizona electric system began in 2000 with the rapid development of new generation projects interconnecting with the Palo Verde Nuclear Generating Station. These projects all proposed to interconnect at the new Hassayampa 500 kV switchyard but were not increasing the capacity of the existing transmission lines already connected to the Palo Verde marketing hub. Large quantities of generation capacity and energy were at risk of being interrupted or curtailed for single contingency outages or credible outages of multiple lines. In addition the generation projects were being developed solely for merchant's commercial interest without obligations to assure existing generation reserves were sufficient to cover the outage risks the projects posed.

Therefore the Utilities Division of the Commission developed "Guiding Principles for Determination of System Adequacy and Reliability"[8] for Staff's use in power plant and transmission line siting cases. The Commission endorsed this document via its Decision No. 65476 for the Second BTA. Then Condition No. 23 of the CEC was placed on APS and SRP in the Palo Verde to Rudd 500 kV siting case to formally require a study be performed to properly address the risks associated with interconnection developments at the Palo Verde Hub resulting in the 3rd BTA the adoption of the Palo Verde Hub interconnection criteria,

> "Require all future interconnections proposed at the Palo Verde Hub, either new generation or new transmission lines, must perform a risk assessment of the Hub to ascertain to what degree the proposed project mitigates the pre-existing risks to extreme outage events. This assessment must precede a project's application for a CEC with the Commission. The recommendations of the Palo Verde Risk Assessment report should be

[8] Appendix A

followed if a proposed project would otherwise exacerbate the existing risk at the Hub." [9]

Since the initiation of the Commission's first BTA process Arizona has experienced several fire seasons with exposure to loss of multiple lines in a common corridor on forested lands. These events heightened the Commission's awareness of the state's vulnerability to loss of transmission lines in common corridors. These events were then upstaged by the major 500/230 kV transformer and 230/69 kV fires that occurred at Westwing and Deer Valley in 2004 and the Westwing 500/345 kV transformer fire in 2006. Therefore the third BTA required that the fourth BTA address and document extreme contingency outages studied for Arizona's major generation hubs and major transmission stations including identification of associated risks and consequences if mitigating infrastructure improvements were not planned. This extreme contingency study requirement was reinforced further when the Commission ordered the same requirement for the fifth BTA.

Renewable Energy Transmission Assessment Requirement

In the Fourth BTA, the Commission ordered a Renewable Energy Assessment stating specifically, "in the next BTA, Commission regulated electric utilities, in consultation with the stakeholders, should prepare an assessment of ATC for renewable energy and prepare a plan, including a description of the location, amount and transmission needs of renewable resources in Arizona, to bring available renewable resources to load."[10] This study requirement is focused on exploring transmission delivery obstacles for renewable resources that may choose to develop within the state, and was intended to assure that Arizona utilities can successfully comply with the renewable portfolio standards adopted by the Commission in 2006.

In the Fifth BTA, the Commission significantly expanded the scope of Arizona Renewable Transmission assessment activities and filing requirements, including determination of an initial set of Renewable Transmission Projects ("RTPs") as described in detail in Section 3.0 of the 6th BTA Staff report. While a separate docket has been opened for this activity, discussion regarding the filings in that docket have also been included in the workshops for the 6th BTA, along with an assessment by Staff of the potential impact of the filed RTPs on Arizona's REST targets.

[9] ACC Decision No. 67457, December 14, 2004, page 4, section 7.e
[10] ACC Decision No. 69389, March 22, 2007, page 8

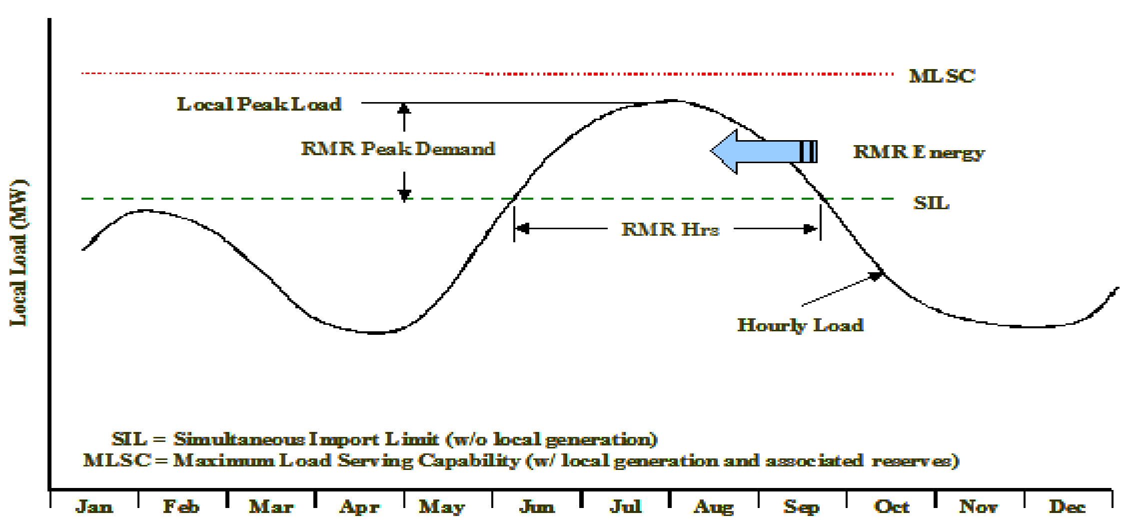
APPENDIX C - RMR CONDITIONS AND STUDY METHODOLOGY

In the 2002 BTA, Staff proposed that any UDC currently relying on local generation, or foreseeing a future time period when utilization of local generation may be required to assure reliable service for a local area, should perform and report the findings of an RMR study as a feature of their Ten-Year Plan filing with the Commission in January, 2003 and 2004. The 2002 BTA defined a Generic RMR Study Plan that required utilities to:

1. Define annual simultaneous import limits (SIL) for each transmission import limited area.
2. Provide a listing of all local generation and associated operational attributes.
3. Define RMR conditions for each year of the Ten-Year Plan.
4. Provide a local generation sensitivity analysis.
5. Identify and study alternative solutions.
6. Perform comparative analysis and present worth analysis of alternative solutions.

RMR conditions, required from RMR studies, are defined in the 2002 BTA and graphically presented in the following Figure 1.[11]

Figure 1 – RMR Conditions



[11] 2002 BTA, Page 74-76

Essential RMR indicators that the Commission intends to receive from the RMR studies are:

- RMR hours - The number of hours during which the local load is above the SIL,
- RMR energy - The amount of energy served from RMR generation,
- RMR peak demand - The maximum RMR amount of capacity that the RMR generators would be required to produce,
- RMR costs - The costs of out-of-merit-order dispatch from RMR

The 2002 BTA established specific RMR procedures. The transmission system's simultaneous import limit (SIL) for each local constrained area is established for single contingencies (n-1) with no local generation in operation. An RMR condition exists during those times when the local load served by a UDC, or group of UDCs, exceeds that SIL. If no local generation exists for an RMR condition then the UDC(s) would have to utilize a load-shedding scheme for those contingencies that establish the SIL. This would imply a violation of WECC planning criteria since reliability practices are founded on the principle of continuity of service for single contingency outages.

When local generating units within the local load pocket are owned or under the operational control of the UDC(s), they are viewed as RMR units for the duration of the RMR condition. A local generating unit that is neither owned or under operational control of the UDC(s) may be considered a non-RMR unit. In some instances, a non-RMR unit may have a "must-offer" requirement to assure that system reliability is maintained. A local non-RMR unit that is operational during the hours an RMR condition exists will have the automatic effect of mitigating the constraint to the extent it serves local load or its capacity and energy is scheduled out of the local load pocket.

Local generation, irrespective of its composition of RMR and non-RMR units, may offer an acceptable planning solution to RMR conditions. The local RMR condition is essentially mitigated when local generation capacity and its associated voltage regulation ability is equal to or greater than that required to reliably serve the local RMR peak load. The question that needs to be answered is whether such dependence on local generation is prudent and in the consumers' best interest.

The maximum load serving capability (MLSC) of the local system is established by operating all local units at capacity, less local reserve requirements. The local MLSC equals to the SIL when there is no local generation. When local generation exists, the local MLSC is greater than the SIL but may fail to exceed the RMR peak load requirement. Such an RMR condition would require new transmission improvements or new local generation to assure reliable service to local consumers. When the MLSC is greater than the local peak demand, then the RMR condition is mitigated and there is less risk that local load would be interrupted for local transmission or generation outages.

Utilization of reactive devices such as high voltage shunt capacitors, static or dynamic var compensators, or Flexible AC Transmission System (FACTS) control devices should be considered for voltage and var margin constrained SIL conditions. Similarly, maintaining a unity power factor at the sub-transmission bus of distribution substations and seasonal tap changes for transformers lacking automatic tap changer under load capability should be considered as a means of resolving voltage or var margin deficiencies. Advancing planned transmission lines or construction of previously unplanned lines should be among the alternatives studied for thermal and stability constrained SIL conditions.

A comparative analysis of all alternative solutions, including using local generation that mitigates the local RMR condition is to be documented. The following factors should be considered when documenting the merits of the various alternatives: impact on SIL, system reliability implications, system losses, operational flexibility, environmental effects, implementation requirements and lead-time, and opportunity for consumer benefits from competitive wholesale market. The following should also be identified in the comparative analysis of alternatives:

- The total expected cost, fixed and variable, for the local generation dispatch that results in the lowest local generation dispatch to mitigate annual RMR conditions.
- Total emission pollutants produced by the lowest local generation dispatch mitigating the annual RMR condition.

A present worth analysis of all alternative solutions is also to be performed. The cost analysis is to include an assessment of the total expected cost of operating local units versus remote units in combination with some transmission solution. Local and remote generation cost assumptions must be documented. The accuracy of RMR conditions depends upon technical studies, engineering assumptions and validity of data needed to determine:

1. Hourly load forecast for the future years.
2. SIL by ensuring that:
    - Aggregate local area load is the total substation load actually impacted by the transmission constraint;

- RMR generation within the local area is accurate; With RMR generation modeled out-of-service, the transmission system meets required normal (n-0) reliability criteria, showing no thermal and/or voltage limit violations;

- With RMR generation modeled out-of-service, the transmission system meets required reliability criteria for all single contingency outages showing no thermal and/or voltage criteria violations; and

- With RMR generation modeled out-of-service, the transmission system remains stable and shows no voltage instability.

3. RMR production costs by ensuring that:

    - Analysis is done using industry recognized production-cost model.

    - Production-cost model database contains projected generation additions as accurate as possible, knowing in advance that future generation additions and unit commitments are dependent on many factors and are subject to change.

    - Hydro generation modeling reflects actual operating conditions as accurately as possible.

    - Thermal generation modeling reflects the current projection of variable operating and maintenance costs.

4. Comparison of the present worth of RMR production costs and present worth of transmission alternative costs.

APPENDIX D - QUESTIONS POSED TO INDUSTRY AND STAKEHOLDERS – WORKSHOP 2

Advance questions were not issued for Workshop 1, but questions were issued in advance for Workshop 2. Specific presentations and comments were also requested from the jurisdictional utilities and other stakeholders in advance of Workshop 2. A summary of the questions and requested items follows:

1. KEMA and Staff provided stakeholders with a preliminary draft of assumptions on the delivery capability of the currently proposed RTP projects, the amount of renewable generation in utility interconnection queues in the proximity of each RTP project, etc. Oral comments from utilities and stakeholders regarding the data, assumptions and methodology utilized by KEMA and Staff for this purpose were invited during Workshop No. 2. Based on extensive discussions about this topic at Workshop No. 2, the preliminary projections by KEMA/Staff were modified. The resulting projection of RTP impacts is shown in attached Table 1.

2. Utilities that filed designated RTPs were requested to provide a brief presentation for Workshop No. 2 addressing the following questions:
    a. Have you determined an estimate of the MW of renewable resource delivery each recommended transmission project would allow?
    b. How will you determine what portion of line capacity is available for renewable delivery vs. other uses?
    c. If the designated project(s) involve building transmission sooner than needed for other purposes (e.g., reliability needs), how will delivery capacity available for renewables be affected in the future when the other line uses materialize?

3. How should the Commission's BTA process take into account applicable NERC/WECC audit findings related to Arizona utilities' compliance with NERC transmission planning reliability standards (e.g., TPL-001 through TPL04)?

4. What scope of transient (dynamic) stability analyses were performed at the utility and joint study group level for the 2010-2019 ten year expansion plan of service, and what was the basis for selecting this set of stability analyses for the ten year plan?

5. How practical would it be for utilities to incorporate information on transmission reconductor projects and bulk power transformer replacements (e.g., being done for the purpose of capacity upgrades) into the ten year plans filed in future BTAs?

6. How might imposition of a cap and trade mechanism or carbon tax affect future BTA ten year plans?

Table 1 - Projected RTP Impacts on Renewable Integration

RTP	RTP sponsor(s)	Estimated transfer capability (MW)[12]	Queued renewables in area served by RTP as of May 2010 (MW)
Delany – Palo Verde	APS, SRP	1,000	3,300[13]
Palo Verde – Pinal West 500kV	TEP	1,000	n/a[14]
Pinal West – Pinal Central 500kV	SRP, TEP	1,000	3,500
North Gila – Hassayampa 500kV #2	APS, SRP	1,000	4,468[15]
Pinal Central – Tortolita 500kV	SRP, TEP	1,000	500
Delany – Blythe 500kV	APS, SRP	1,000	n/a[16]
Hassayampa – Jojoba – Palo Verde – Liberty area 500kV	APS	1,000	500
Gila Bend – Liberty area 500kV*	APS	1,000	890
Western Apache – Tortolita 230kV Saguaro – Apache 115kV Upgrade	TEP, SWTC	500	297
San Manuel Interconnect	SWTC	To be determined	0
Apache – Bicknell 230kV Upgrade	SWTC	To be determined	0
Total(s)		**9,500**	**13,455**

[12] Actual value to be determined through future path rating studies.
[13] The 3,300 MW figure reflects the amount of renewable generation in the queue at the time of the 6th BTA Workshop 1, but SRP advises that the amount in the queue has since dropped to 1,500MW. APS concurs that 1500 MW is queued at Delany in its response to Data Request 1 in Docket E-01345A-10-0033.
[14] No queue of renewables along this section, but still useful for deliveries of Delany-PV area MW to Arizona load centers further east (e.g., already accounted for in table and left out to avoid double counting - not intended to prejudice the choice between this RTP and other RTPs.)
[15] Value quoted by APS in response to Data Request 1 in Docket E-01345A-10-0033.
[16] Same queue as Delany-PV.

APPENDIX E - 2010 BTA WORKSHOP I AND II - LIST OF ATTENDEES[17]

Last	First	Title	Representing	Phone	Email	Workshop I	Workshop II
Aguayo	Stacy	Reg. Relations Manager	APS	602-250-2681	stacy.aguayo@aps.com	X	X
Amirali	Ali	SVP	Element Power	408-204-7630	ali.amirali@elpower.com	X	
Anderson	Travis	WAPA		602-605-2660	tanderson@wapa.gov	X	
Arnold	Linda	Lawyer	Pinnacle West Capital Corp.	602-250-3630		X	
Atkins	Steve	Engineer	NAU		steve.atkins@nau.edu	X	X
Beck	Ed	Director Siting	TEP	520-884-3615	ebeck@tep.com		X
Begay	Steven C.	General Manager DPA	Dine Power Authority	928-871-2133 928-797-1942	dpasteve@citlink.net	X	
Beujes	Stephanie		WAPA		beujes@wapa.gov	X	

[17] BTA Workshop I was held on June 3-4, 2010 and BTA Workshop II was held on August 4, 2008

Belval	Ron		TEP		rbelval@tep.com	X	X
Bicknell	Jerry	SRP Merchant		602-380-4323	jdbickne@srpnet.com	X	
Black	Patrick		F.C.		pblack@fclaw.com	X	
Brandt	Jana	Reg. Analyst	SRP	602-236-5028	jana.brandt@srpnet.com	X	X
Bratton	Brian		EC Source		bbratton@ecsourceservices.com	X	
Brown	Brenda	Community Activist	CAC	520-490-7095	kubush3333@yahoo.com	X	
Bryan	David	Engineer	SSVEC	520-720-6421	dbryan@ssvec.com		X
Calkins	Ian	Public Affairs	CopperState Consulting Group	602-229-1010	ian@copperstate.net	X	X
Charters	Jim	Manager	WSES	623-572-7972	j_charters@msn.com	X	X
Cole	Brian	Manager Resource Planning	APS	602-250-4332	brian.cole@aps.com	X	X
Darmitzel	Bill		TEP		bdarmitzel@tep.com	X	X
Deise	Cary	USE Consulting	Black Forest	602-751-8761	carydeise@useconsulting.com	X	X
Delaney	Dennis	Partner	K.R. Saline & Associates, PLC	480-610-8741	dld@krsaline.com	X	

Diamond	Dan	Program Manager	Tessera Solar	602-689-3979	dan.diamond@tesserasolar.com	X	X
Dion	Phil		TEP		pdion@tep.com	X	
Etheridge	Randy		Tessera Solar		randy.etheridge@tesserasolar.com	X	
Etherton	Mark		PDS Consulting		mark@PDSPLC.com	X	
Evans	Bruce	Engineer	SWTC	570-586-5336	bevans@swtransco.coop	X	X
Foreman	John	Chairman	AZ Siting Committee		john.foreman@azag.gov	X	X
Frownfelter	Jennifer	VP	URS Corp.	602-861-7406	jennifer_frownfelter@urscorp.com	X	
Gazda	Mike		APA	602-542-4263	mike@powerauthority.org	X	X
Getts	David	General Manager	South Western Power	602-808-2004	dgetts@southwesternpower.com	X	
Gilkey	Melody		TEP		mgilkey@tep.com	X	
Grabel	Meghan		APS	602-250-2454	meghan.grabel@pinnaclewest.com	X	
Green	Adam	Development Manager	Solar Reserve LLC	310-315-2272	adam.green@solarreserve.com	X	X
Harwood	Patrick	WAPA		602-605-2883	harwood@wapa.gov	X	

Haunty	Jim		EC Source		jhaunty@forcecap.com	X	
Held	Matt	VP, Projects	Solar Reserve LLC	310-315-2275	mheld@solarreserve.com	X	
Hernandez	John		SRP	602-236-0968	Johnny.Hernandez@srpnet.com		X
Hutton	Phil		Kleinfelder	602-390-5065	phutton@kleinfelder.com	X	X
Isham	Tom		PDS Consulting	602-943-6104	tom.isham@pdsplc.com		X
John	Eric	VP Project Development	Sky Fuel	919-656-3495	ej100973@gmail.com		X
Johnston	Joshua	Engineer	Western Area Power Admin.	602-605-2634	jjohnston@wapa.gov	X	X
Keel	Brian	SRP	SRP	602-236-0970	brian.keel@srpnet.com	X	X
Kipnes	Jill	RS Lynch and Associates		602-291-5908	rslynch@rslynchaty.com	X	
Kipp	Bill		Black Forest		bill@blackforestpartners.com	X	X
Kondziolka	Robert		SRP	602-236-0971	robert.kondziolka@srpnet.com	X	
Korinek	David	Consultant	KEMA	858-740-6691	david.korinek@kema.com	X	X
Krzykos	Peter		APS	602-850-	peter.krzykos@aps.com	X	

				1649			
Lipman	Sam		EnFinity Corp.		slipman@enfinitycorp.com	X	X
Loehr	Jeff		BRP	602-236-0972	jeff.loehr@srpnet.com	X	
Lucas	John	Manager	APS	602-250-1144	john.lucas@aps.com	X	
Martin	Thomas	Manager	ED2	520-723-7741	tmartin@ed2.com	X	
McDonald	Jason	AZ Building Trades UA 469 IBEW 640	TCLG	602-626-8805	jason@thetorresfirm.com	X	X
McMinn	Barbra	Manger	APS	602-371-6383	barbara.mcminn@aps.com		X
Miller	Dean		Husk Partners	602-451-2729	dean@huskpartners.com	X	
Mirich	Gary	TWE		602-253-5581	gmirich@energystrat.com	X	
Olson	Mike		Western Area Power		olson@wapa.gov	X	
Ormond	Amanda		Ormond Group	480-491-3305	asormond@msn.com	X	X
Palermo	Jeff	Executive Consultant	KEMA	703-631-6912 X40173	jeff.palermo@kema.com	X	X

Percival	Milt	Manager	WSES	480-994-8695	mperc7439@aol.com	X	
Patterson	Greg	AZCPAORG		602-369-4368	greg@azcpa.org	X	
Pratt	Jim		SRP	602-236-5385	jim.pratt@srpnet.com	X	X
Rasmussen	Paul	ADEQ	Line Siting	480-991-3900	rasmussen.paul@azdeq.gov	X	X
Rein	Jim		SWTC		jrein@swtransco.coop	X	X
Reinhold	Charles		West Connect	208-253-6916	reinhold@ctcweb.net	X	
Rietz	DeAnne	Hydrologist	SWCA	602-274-3031	drietz@swca.com		X
Roberts	Cary	Senior Env. Planner	URS	602-228-2214	cary_roberts@urscorp.com		X
Romero	Gary	Lead Engineer	KRSA	480-610-8741	gtr@krsaline.com	X	X
Ruiz	Reuben	Senior Analyst	CAP	623-869-2370	rruiz@cap-az.com	X	X
Russell	Charles		SRP		chuck.russell@srpnet.com	X	X
Sandler	Vicki	Executive Director	AZ ISA	602-625-7879	vickisandler@gmail.com	X	X
See	Janice	Energy Assurance	AZ Energy Office	602-771-	janices@azcommerce.com		X

		Manger		1175			
Singh	Jagjit	VP	OATI	763-238-3707	jagjit.singh@oati.net	X	
Smith	Jeremy	WAPA		602-605-2667	jsmith@wapa.gov	X	
Smith	Jerry		P E Consulting		jsmithpe@cox.net	X	X
Souder	Julia		Clean Line Energy		jsouder@cleanlineenergy.com	X	
Sparks	Keith	Director	Clean Line Energy	281-687-9864	ksparks@cleanlineenergy.com	X	X
Spitzkoff	Jason	APS Engineer	APS	602-250-1651	jason.spitzkoff@aps.com		X
Sprague	Tiffany	Chapter Coordinator	Sierra Club	602-253-9140	tiffany.sprague@sierraclub.org		X
Stahlhut	Jon	Engineer	APS	602-250-1116	jonathan.stahlhut@aps.com		X
Stough	John		Exelon Transmission Co.		john.stough@exeloncorp.com	X	
Stuhan	Richard		URS		Richard.stuhan@urscorp.com	X	
Tang	Jim	Senior Engineer	CAP	623-869-2673	jtang@cap-az.com	X	X
Thor	Vincent	Engineer	APS	602-250-1647	vincent.thor@aps.com		X

Torkelson	LeeAnn	Senior Engineer	SRP	602-236-0973	leeann.torkelson@srpnet.com	X	
Trent	Gary	Senior	TEP	520-745-3168	gtrent@tep.com		X
Vaninetti	Jerry	Western Transmission Development	High Plains Express - Nextera	303-790-0513	jerry.vaninetti@nexteraenergy.com	X	
Vega	Jennie	Group Leader Regulatory	APS	602-250-2038		X	
Wang	Andrew		Solar Reserve		andrew@solarreserve.com	X	
Webb	Elizabeth	Community Activist/UNSE Citizen Advisory Council	Empire-Fagan Coalition		vailaz@hotmail.com	X	
Williamson	Ray	Engineer	ACC			X	X
Woodall	Laurie	Consultant	KRSA	480-610-8741	law@krsaline.com	X	X
Wray	Tom	SWPG SUNZIA	SWPG	602-808-2004	twray@southwesternpower.com		X
Wright	Bill		EC Source		bwright@tanddpower.com	X	

APPENDIX F – LISTING OF TERMINOLOGY[18] AND ACRONYMS[19]

Terminology

Arizona Power Plant and Transmission Line Siting Committee: The committee that reviews proposals to construct power plants and transmission lines in Arizona. In 1971, the Arizona Legislature required that the Commission establish a power plant and line siting committee. The Committee provides a single, independent forum to evaluate applications to build power plants (of 100 megawatts or more) or transmission projects (of 115,000 volts or more) in the state. The Committee holds meetings and hearings that are open to the public. More information about the Siting Committee can be found at www.cc.state.az.us/divisions/utilities/electric/linesiting-faqs.asp.

Bundled service: Electric service provided as a package to the consumer including all generation, transmission, distribution, ancillary and other services necessary to deliver and measure useful electric energy and power to consumers.

Certificate of Convenience & Necessity (CC & N): A document granting operating authority to utilities.

Competitive services: All aspects of retail electric service except those services specifically defined as "Noncompetitive Services" pursuant to Corporation Commission Rules R14-2-1601(29) or noncompetitive services as defined by the Federal Energy Regulatory Commission.

Continuity of Service[20]: Each utility shall make reasonable efforts to supply a satisfactory and continuous level of service. With respect to the Fifth BTA, use of this term describes the desire for "continuity of service" following the loss of a transmission line.

Demand: The rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes or other suitable units.

Distribution lines: The utility lines operated at distribution voltage, which are constructed along public roadways or other bona fide rights-of-way, including easements on customer's property.

Distribution service: The delivery of electricity to a retail consumer through wires, transformers, and other devices that are not classified as transmission services subject to the jurisdiction of the Federal Energy Regulatory Commission. Distribution service excludes metering services, meter reading services and billing and collection services, as those terms are used herein.

Electric Service Provider (ESP): A company supplying, marketing or brokering at retail any competitive services pursuant to a Certificate of Convenience and Necessity approved by the Corporation Commission.

Environmental Portfolio Standard (EPS): A ruling by the Commission that requires any company serving electricity to an end-user to generate a portion of that electricity through renewable technologies such as wind, solar, biomass generators or landfill gas recovery.

Federal Energy Regulatory Commission (FERC): An independent regulatory agency within the US Department of Energy that, among other things, regulates interstate oil, natural gas and power

[18] http://www.cc.state.az.us/divisions/utilities/electric/terms.asp
[19] Listing of Acronyms obtained from Fourth Biennial Transmission Assessment, Page 1
[20] Except from Arizona Administrative Code, R14-2-208(C)
http://www.azsos.gov/public_services/Title_14/14-02.pdf

transmission sales.

Generation: The production of the actual megawatts of electricity or purchase of electricity through the wholesale market.

Green pricing: A program offered by an Electric Service Provider where customers elect to pay a rate premium for renewable generated electricity.

Pancaking: A term used to describe the layering of multiple tariff rates in point to point transactions.

PV Hub: Palo Verde power plant and switchyard, the Hassayampa switchyard, and the there 500 kV tie lines connecting the two switchyards.

Interruptible electric service: Electric service that is subject to interruption as specified in the utility's tariff.

Kilowatt (kW): A unit of power equal to 1,000 watts.

Kilowatt-hour (kWh): The electric energy equivalent to the amount of electric energy delivered in 1 hour when delivery is at a constant rate of 1 kilowatt.

Megawatt (MW): A unit of power equal to 1,000,000 watts.

Meter service: All functions related to measuring electricity consumption, including installation and repair of meters, but not including meter reading.

Point of Delivery: The point where facilities owned, leased or under license by a customer connects to the utility's facilities.

Power: The quantity of electricity being generated, transferred or used at any instant in time, usually expressed in kilowatts.

Renewable Transmission Project: Refers to any proposed/planned electric transmission project at 115kV or above, designated and sponsored by the jurisdictional utilities in response to the Commission's order in the 5th BTA for projects that facilitate the delivery or integration of renewables in Arizona.

Service area: The territory in which the utility has been granted a Certificate of Convenience and Necessity and is authorized by the Commission to provide electric service.

Tariffs: The documents filed with the Corporation Commission which list the services and products offered by the utility and which set forth the terms and conditions and a schedule of the rates and charges for those services and products.

Transmission Planning Reliability Standards: Refers to NERC reliability standards related to electric transmission planning; part of the overall portfolio of NERC mandatory reliability standards which apply to users, owners and operators of the bulk power system designated by NERC through its compliance registry procedures.

Transmission service: Refers to the transmission of electricity at high voltage to retail electric customers or to electric distribution facilities as defined by the Federal Energy Regulatory Commission (FERC) or Arizona Corporation Commission.

Utility: The public service corporation providing electric service to the public in compliance with state law, except in those instances set forth in Corporation Commission Rules, R14-2-1612 (A) and (B).

Utility Distribution Company (UDC): The electric utility entity regulated by the Commission that operates, constructs, and maintains the distribution system for the delivery of power to the end user point of delivery on the distribution system.

Acronyms

AC	Alternating Current	**HVDC**	High Voltage Direct Current
ACC	Arizona Corporation Commission	**HY**	Hydro
ANPP	Arizona Nuclear Power Plant	**I/S**	In-Service
APS	Arizona Public Service	**IID**	Imperial Irrigation District
ARRTIS	Arizona Renewable Resource and Transmission Identification Subcommittee	**IPP**	Independent Power Producer
ATC	Available Transfer Capability	**ISO**	Independent System Operator
AZ	Arizona	**KEMA**	KEMA, Inc
AZNM	AZ-NM EHV Subcommittee	**kV**	Kilovolt
BA	Balancing Authority	**kWh**	Kilowatt-Hour
BLM	Bureau of Land Management	**LMP**	Land Management Plan
BTA	Biennial Transmission Assessment	**LSE**	Load Serving Entity
BTU	British Thermal Unit	**MISO**	Midwest Independent System Operator
CA	California	**MLSC**	Maximum Load Serving Capability
CATS	Central Arizona Transmission System	**MORC**	Minimum Operating Reliability Criteria
CAWCD	Central AZ Water Conservation District	**MOU**	Memorandum of Understanding
CC	Combined Cycle	**MVA**	Megavolt-Ampere
CC&N	Certificate of Convenience & Necessity	**MVAR**	Megavolt-Ampere Reactive
CCSG	Cochise County Study Group	**MW**	Megawatt
CDEAC	Clean and Diversified Energy Advisory Committee	**n-0**	No Contingency
CEC	Certificate of Environmental Compatibility	**n-1**	Single Contingency
CO	Colorado	**n-1-1**	Overlapping Contingency
CRT	Colorado River Transmission Subcommittee	**n-2**	Double Contingency
CSP	Concentrating Solar Power	**NERC**	North American Electric Reliability Corporation
DOE	Department of Energy	**NF**	National Forest
DPA	Dine Power Authority	**NG**	Natural Gas
DSW	Desert Southwest Region	**NM**	New Mexico
ED	Electric District	**NOI**	Notice of Inquiry
EFOR	Equivalent Forced Outage Rate	**NOPR**	Notice of Proposed Rulemaking
EHV	Extra High Voltage	**NREL**	National Renewable Energy Laboratory
EOR	East of (Colorado) River	**NTP**	Navajo Transmission Project
EPS	Environmental Portfolio Standards	**NV**	Nevada
ERO	Electric Reliability Organization	**OASIS**	Open Access Same Time Information System
FACTS	Flexible AC Transmission System	**OATT**	Open Access Transmission Tariff
FERC	Federal Energy Regulatory Commission	**PEIS**	Programmatic Environmental Impact Statement
FOR	Forced Outage Rate	**PJM**	Pennsylvania-New Jersey-Maryland (ISO)
FPA	Federal Power Act	**PNM**	Public Service of New Mexico
FS	Forest City	**PURPA**	Public Utilities Regulatory Policy Act
GT	Gas Turbine	**PV**	Palo Verde and/or Photovoltaic
HV	High Voltage	**ROD**	Record of Decision

RETAAC	Renewable Energy Transmission Access Advisory Committee (NV)
RETI	Renewable Energy Transmission Initiative (CA)
RMR	Reliability Must Run
RMS	Reliability Management System
RTAP	Renewable Transmission Action Plan
RTEP	Regional Transmission Expansion Project
RTTF	Renewable Transmission Task Force
RTO	Regional Transmission Organization
RTP	Renewable Transmission Project
SATS	Southeastern Arizona Transmission Study
SCE	Southern California Edison
SCED	Security Constrained Economic Dispatch
SDG&E	San Diego Gas and Electric
SEV	South East Valley
SIL	Simultaneous Import Limit
SRP	Salt River Project
SSG-WI	Seams Steering Group – Western Interconnection
SSVEC	Sulphur Springs Valley Electric Cooperative
ST	Steam Turbine
SWAT	Southwest Area Transmission Study Group
SWPG	Southwest Power Group
SWTC	Southwest Transmission Cooperative
TEP	Tucson Electric Power
TEPPC	Transmission Expansion Planning Policy Committee
TNMP	Texas-New Mexico Power Company
TTC	Total Transfer Capability
UDC	Utility Distribution Company
UNSE	UNS Electric, Inc.
WAPA	Western Area Power Administration ("Western")
WECC	Western Electricity Coordinating Council
WGA	Western Governors' Association
WWMID	Welton-Mohawk Irrigation & Drainage District
WWSIS	Western Wind and Solar Integration Study

APPENDIX G – WESTCONNECT ANNUAL ADEQUACY STUDY

Purpose

This document describes a WestConnect subregional transmission study that will be performed annually. The study results and associated report will be incorporated in the subsequent WestConnect Transmission Report.

Study Scope

WestConnect will annually perform a study to test the adequacy of its most recently published WestConnect Transmission Plan ("Plan") excluding conceptual projects. The adequacy of the Plan will be determined by documenting system performance relative to WECC / NERC planning requirements. Traditional N-0, N-1 and N-2 contingency outages will be performed for the 5th and 10th year of the current planning period. Any deficiencies in the Plan will be noted with sufficient lead time for WestConnect subregional transmission planning participants to investigate solutions for incorporation into the subsequent WestConnect Transmission Plan.

In addition, potential corridor outages involving planned facilities will be modeled and the resulting system performance documented. These corridor outages will only be performed in the 10th year of the current planning period. The purpose is to ascertain what degree of system reliability risk is associated with placing proposed projects in common corridors with other facilities. Identification of such risks in advance of siting of new facilities is needed with sufficient lead time to explore alternative routes. It is not believed that studying such corridor outages in the 5th year of the study period would offer sufficient lead time to pursue alternates routes.

Required Base Cases

This study will utilize a 5th and 10th year base case developed and coordinated for use in WestConnect's current subregional transmission planning cycle. The base case will incorporate the "sponsored and committed" transmission projects contained in the previously published WestConnect Transmission Plan. The base cases will not include the "conceptual" transmission projects contained in the WestConnect Transmission Plan because they either have no sponsorship or there is no firm commitment to build the projects by a specific date.

APPENDIX H – WESTCONNECT BIENNIAL LONG RANGE STUDY

Purpose

This document describes a long range subregional transmission study that will be performed biennially for the WestConnect subregion. The study results and associated report will be summarized in even numbered year WestConnect Transmission Reports.

Study Scope

WestConnect will biennially perform a technical study to explore conceptual long range transmission needs within the WestConnect planning area. The goal of the study is to develop and refine conceptual long range transmission options within the WestConnect planning area for the 10^{th} year study time period and beyond. This study will focus solely on the WestConnect planning area's system performance for load forecasts and generation scenarios representative of this study period. Therefore, the study will be limited to power flow studies that investigate the system's performance for single contingency outages (N-1).

The scope of the WestConnect long range study will vary over time in order to address contemporary issues facing the industry. The conceptual projects studied in response to those contemporary issues will serve as an incubator for alternative transmission projects that may eventually become sponsored and added to a future WestConnect Transmission Plan. More importantly, the long range study process will broaden and extend the vision of future transmission line corridor needs in the WestConnect planning area.

The initial WestConnect long range study will serve a two fold purpose. The first relates to the transmission planning interface between the Transmission Expansion Planning Policy Committee's (TEPPC) economic studies of the Western Interconnection and subregional transmission planning groups. This functional study requirement will be a routine feature of the WestConnect long range study scope. The second initial long range study effort is exemplary of a contemporary industry issue: system wide integration of renewable energy projects.

1. The WestConnect long range study will provide traditional reliability oriented studies that investigate transmission solutions to long range congestion concerns raised by the annual TEPPC economic transmission expansion study report. This reliability based study effort will essentially complement and supplement the TEPPC transmission congestion study effort. As a result the study will need to explore a variety of generation expansion scenarios consistent with the prior TEPPC study. Results of this reliability based long range study will enable WestConnect to offer definitive conceptual transmission solution proposals for the subsequent TEPPC study cycle.

2. The initial long range study will explore conceptual transmission improvements needed to accommodate fully developed renewable resources located within the WestConnect planning area. This study effort will incorporate the findings of the NREL wind and solar integration study, the Colorado Energy Zones study, the New Mexico renewable energy collector study and the new SWAT AZ/NM renewable energy task force study effort.

Required Base Cases

This study will utilize a 10^{th} year base case developed and coordinated for use in WestConnect's current subregional transmission planning cycle. The base case will incorporate the "sponsored and committed" transmission projects contained in the previously published WestConnect Transmission Plan. Additional bases cases will be developed from the 10th year base case to model alternative renewable energy development scenarios and load forecast within the WestConnect planning area beyond the 10th year. These additional base cases will also model the "conceptual" transmission projects contained in the WestConnect Transmission Plan in a status "off" mode. The "conceptual' transmission projects will serve as a starter pool of potential transmission projects that could be called upon to ensure reliable service at higher load levels. Other conceptual transmission projects may be added to the pool of candidate projects as dictated by load and resource placement within the WestConnect study area.

APPENDIX I – SOURCES OF INFORMATION REFERENCED

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

Utilities' 2010 Ten-Year Transmission Plans

Abengoa Solar Inc.	Sempra Energy
Ajo Improvement Company[21]	Sonoran Solar Energy, LLC
Arizona Public Service Company	Southern California Edison
Bowie Power Station, LLC	Southwest Transmission Cooperative
Central Arizona Project[22]	Southwestern Power Group
El Paso Electric Company	Starwood Solar I, LLC
Electric Districts No. 3 and 4	Sulphur Springs Valley Electric Cooperative
Gila Bend Power Partners[23]	SunZia Southwest Transmission Project
Hualapai Valley Solar LLC	Tucson Electric Power
Public Service Co. of New Mexico	UNS Electric
Salt River Project	Welton-Mohawk Irrigation & Drainage District

First Draft Comments and Workshop 1 and 2 Comment Summary Presentation
All comment in their entirety or the summary presentation can be found in the Commission's docket site http://edocket.azcc.gov/)

Prior BTA Reports
These reports can be found on the Commission website (www.cc.state.az.us/utility/electric/index.htm)

Reliability Must-Run Documents
ACC 2010 BTA RMR Filings and Workshop Presentations

N-1-1 and Extreme Contingency Study Documents
ACC 2010 BTA N-1-1 ("Ten-Year Snapshot Study") and Extreme Contingency Filings and Workshop Presentations

Regional Committees and Working Groups Materials
WestConnect Documents (www.westconnect.com)

[21] Ajo's filing simply reported no change in the status of its load serving projects since the 5th BTA
[22] Contains a filing by the Central Arizona Water Conservation District regarding the Harcuvar project
[23] The sponsor's January 2010 filing states the project is on hold due to current market conditions

Southwest Area Transmission (SWAT) Reports
Arizona Renewable Task Force
Central Arizona Transmission Study - High Voltage (CATS-HV)
Central Arizona Transmission Study - Extra High Voltage (CATS-EHV) "Ten-Year Snapshot" Study
Colorado River Transmission (CRT)
Southeastern Arizona Transmission Study (SATS)
Short Circuit Working Group (SCWG)

Federal Energy Regulatory Commission (FERC)
FERC Reliability Standards (www.ferc.gov)

North America Electric Reliability Council (NERC)
NERC Reliability Standards (www.nerc.com)

Western Electricity Coordinating Council (WECC) Standards and studies
The standards can be found on the WECC website (www.wecc.biz) under "Click here for library".

National Renewable Energy Laboratory
Support documents and reports (www.nrel.gov)

Western Governors Association (WGA)
Support documents and Report documents (www.westgov.org)

California Energy Commission Website
Information relating to RETI and California renewable activities (www.energy.ca.gov)

Nevada Renewable Energy Transmission Access Advisory Committee Website
Information relating to RETAAC and Nevada renewable activities (http://gov.state.nv.us/Energy/)

Colorado Clean Energy Development Authority Website
Information relating to CEDA and Colorado renewable activities
(http://www.colorado.gov/energy/utilities/clean-energy-development-authority.asp)

Large Generator Interconnection Queues (http://www.oatioasis.com/cwo_default.htm)[24]
Arizona Public Service Company
Salt River Project
Tucson Electric Power/UNS Electric
Western Area Power Administration

Data Responses to 6th BTA Data Requests
Arizona Public Service Company
Salt River Project
Tucson Electric Power
UNS Electric
Southwest Transmission Cooperative

[24] Jurisdictional utilities also provided queue information in response to Staff's data request(s), as shown in Exhibit 19 of the 6th BTA report.