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Sixth Biennial Transmission Assessment

2010-2019 Staff Report

Arizona Corporation Commission
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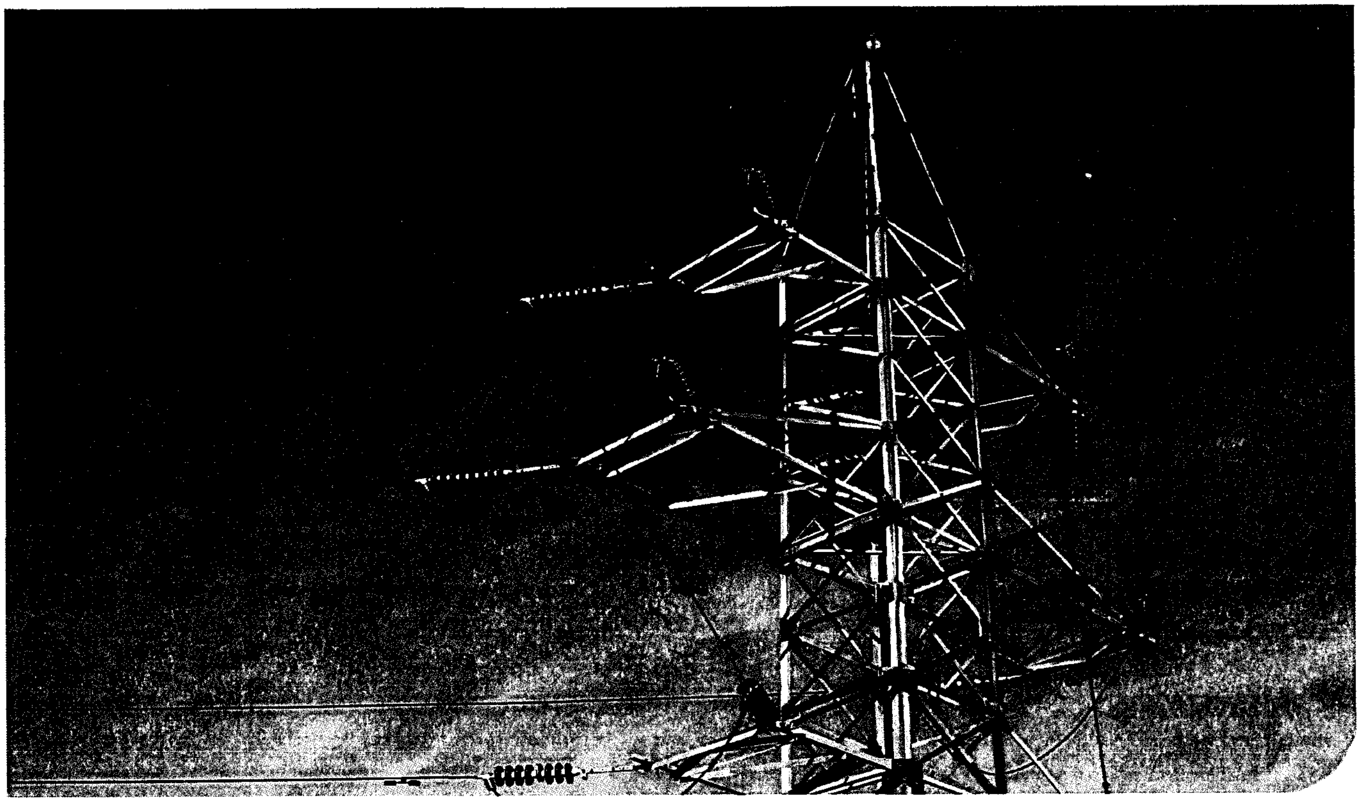

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Foreword

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- Arizona's Sixth Biennial Transmission Assessment ("BTA") is based upon ten-year plans filed with the Commission by parties in January 2010 and certain filings during 2009. It also incorporates information received through data requests, and comments provided by participants and attendees in the BTA workshops and report review process. The ACC Staff and KEMA are appreciative of the contributions, cooperation and support of industry participants throughout Arizona's Sixth Biennial Transmission Assessment process.
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Executive Summary

The Arizona Corporation Commission ("ACC" or "Commission") biennially reviews ten-year plans filed by parties intending to construct transmission facilities at 115 kV or above, and issues a written decision regarding the adequacy of the existing and planned transmission facilities to reliably meet the present and future needs of the state[1]. Staff of the Utilities Division of the Commission ("Staff"), with the assistance of the consulting firm of KEMA Inc. ("KEMA"), reviewed and analyzed the ten-year plans and related filings, issued data requests, conducted workshops for stakeholder input, and drafted this Sixth Biennial Transmission Assessment ("BTA") report. Neither Staff nor KEMA performed any technical studies during this process, but relied upon studies prepared and filed by other parties. Staff and KEMA used an open, transparent and collaborative process to obtain utility and stakeholder input, including two public workshops.[2]

Staff and KEMA reviewed all ten-year plans and filings submitted to Docket No. E-00000D-09-0020. The filings included technical studies previously ordered by the Commission: Reliability Must Run ("RMR") studies, N-1-1 study, Extreme Contingency study, and reliability of transmission supply to certain local load pockets. Staff and KEMA also reviewed the impacts of transmission projects proposed by utilities to accommodate renewable energy development in Arizona.[3] All entities which made presentations at the first workshop were asked to file the presentations in the docket. Staff and KEMA reviewed these presentations and the transcript of the first and second workshops. Preliminary and final drafts of this Sixth BTA report were prepared by KEMA and reviewed by Staff and were made available for industry and stakeholder comments. The collaborative local, sub regional and regional transmission planning processes used by Arizona utilities and other stakeholders have yielded a significant number of relevant technical studies and other filings that were reviewed for this BTA.

This assessment is not intended to establish Commission policy. It also is not intended to assess individual transmission providers' plans except in the context of their aggregate impact

[1] Arizona Revised Statute §40-360.02

[2] Some information submitted by utilities was provided subject to confidentiality restrictions.

[3] Including Renewable Transmission Projects filed pursuant to Docket E-01345A-10-0033 and/or presented by utilities during the 6th BTA at Workshop 1.

on Arizona electric transmission system adequacy, reliability, markets and renewable integration (e.g., aggregate ability to meet the existing and planned energy needs of the state). This BTA is not final unless and until approved by a written decision of the Commission.

Staff's assessment has addressed five fundamental issues during the course of this BTA:

- Adequacy of the system to reliably serve local load - Does the combination of the filed ten-year transmission plans meet the load serving needs of the state during the 2010-2019 timeframe in a reliable manner?
- Efficacy of Commission ordered studies - Do the study reports filed in response to Commission ordered RMR, N-1-1 and Extreme Contingency studies comply with, and sufficiently meet, the intended goals of the Commission's orders?
- Adequacy of system to reliably support the wholesale market - Do the transmission planning efforts effectively address concerns raised in previous BTAs about the adequacy of the state's transmission system to reliably support the competitive wholesale market in Arizona?
- Adequacy of renewable transmission plans - Do transmission providers' ten-year transmission expansion plans, including their renewable transmission project proposals, adequately address the overall needs for renewable resource development and integration into the Arizona and regional electric power system?
- Suitability of transmission planning processes utilized - Do the plans and planning activities comport with transmission planning principles and good utility practices accepted by the power industry and the reliability planning standards established by the North American Electricity Reliability Corporation ("NERC"), Western Electricity Coordinating Council ("WECC"), and Federal Energy Regulatory Commission ("FERC")?

General Conclusions

Staff and KEMA reached numerous conclusions during the 6th BTA, including the following key items:

1) As a result of current economic conditions, the statewide demand forecast for the 2010-2019 ten year planning period has shifted by about 4 years since the 5th BTA (i.e., it will take four years longer to reach the 2008 demand forecast levels).

2) A total of 33 transmission projects have been delayed since the 5th BTA, with an average delay of roughly 4 years. In addition, 18 other transmission projects were cancelled. The combination of cancelled and delayed projects represents less than half of the projects filed in the 5th BTA in 2008. These delays and cancellations are consistent with the reduction in statewide demand forecast since the 5th BTA and do not appear to threaten the adequacy of the system or its ability to reliably serve load.

3) Information on transmission reconductor projects, bulk power transformer replacements planned for the purpose of capacity upgrade, and reactive power compensation additions at 115 kV and above, if included in future ten-year plan filings, would assist the Commission in meeting its obligation "to biennially make a determination of the adequacy and reliability of existing and planned transmission facilities in the state of Arizona".

4) All Commission required studies related to adequacy and reliability have been filed. The following conclusions apply to the efficacy of the filed documents relative to the intent of the Commission ordered actions:

   a) The Phoenix, Tucson and Yuma area RMR studies for 2013 and 2019 were thorough and well documented. These RMR studies also indicate that local RMR generation will not be dispatched out of merit order[4] for a significant number of hours or yield RMR costs sufficient to warrant advancing transmission improvements. The Mohave County 2013 and 2018, and Santa Cruz County 2013 and 2019 RMR studies were also well documented. The Mohave County study showed no RMR requirement. However, Santa Cruz County RMR analysis for 2010 showed an RMR requirement of 24 MW. No Santa Cruz RMR requirement was found in 2013 or 2019.

   b) The Commission's concern in the 5th BTA regarding the need for broader stakeholder involvement in the Yuma Area and Mohave County RMR studies has been satisfactorily addressed through the RMR studies for 2013 and 2019 filed in

[4] In a merit order dispatch the most economic mix of dispatchable generating units is selected to run each hour. However, RMR units may be run out of merit order in order to satisfy reliability needs on the grid.

the 6th BTA. Affected utilities and stakeholders participated in the Yuma Area and Mohave County RMR study.

c) The "Ten Year Snapshot Study" (previously referred to as the "N-1-1 Study") was performed by the Central Arizona Transmission System – Extra High Voltage ("CATS-EHV") study group and represents a composite assessment of the statewide Arizona transmission system and the performance of the ten-year expansion plan under normal, single-contingency and certain overlapping contingencies. The Extreme Contingency Study was performed by Arizona Public Service Company ("APS") and examines more severe contingency scenarios such as corridor outages. These studies demonstrate the ten-year plan is robust and should provide adequate and reliable service to Arizona.

d) The proposed definition of "continuity of service" described in the Cochise County Study Group's ("CCSG") 2009 technical study report, as filed by Southwest Transmission Cooperative, Inc. ("SWTC") in January 2010, is appropriate for planning of the Cochise County system. The transmission plan identified in the CCSG 2009 report represents a reasonable set of transmission expansion projects to achieve the "continuity of service" objective in Cochise County. However, based on feedback received from CCSG participants during the 6th BTA workshops, possible changes in the Cochise County load forecast may allow delaying certain components of the plan of service in the 2013-18 time frame, discussed in the CCSG report, without jeopardizing Cochise County's continuity of service.

e) The Southeast Area Transmission Study Group ("SATS") report and the SWTC ten-year plan have both identified overload issues on the Apache-Butterfield 230 kV line beginning in 2012. An upgrade of the line is being deferred to 2016. Therefore, interim mitigation measures will be needed in 2012-2015 in order to maintain system reliability. Furthermore, the study has identified numerous 230 kV and 115 kV bus voltage deviations that may be unacceptable, and states that further analysis is needed to address these issues. This analysis will be completed in 2011.

f) Santa Cruz County remains exposed to extended customer outages during a contingency of the radial transmission line serving the county. Additional transmission line improvements outlined in the UniSource Energy Service's ("UNSE") ten-year plan for Santa Cruz County will mitigate this exposure, but are contingent upon resolution of a long-standing federal permitting matter.

g) The Central Arizona Transmission System - High Voltage ("CATS-HV") study of the planned 2019 Pinal County system assumed Southwest Public Power Resource's ("SPPR") "Three-Terminal" transmission plan (Pinal Central to ED5, ED5 to Test Track and ED5 to Marana 230 kV lines). However, at 6th BTA Workshop 1 it was announced that SPPR has deferred plans for two of these line additions indefinitely. The impact of these deferrals on the results of the CATS-HV study of 2019 is unknown and cannot be determined from the filed studies.

5) Arizona utilities have been extensively engaged in, and providing leadership to, Southwest Area Transmission ("SWAT") and WestConnect subregional planning processes. These utilities and other stakeholders have also participated and contributed valuable input during the 6th BTA process.

6) FERC has implemented mandatory reliability standards and audits over the past two to three years, including transmission planning standards, as discussed in the body of this report. It is still unclear to Staff how this should be recognized and integrated into the BTA process. Staff and KEMA have attempted to explore this question through data requests and stakeholder workshop discussion. Developing consensus on how to address these standards in the BTA process will take additional time and effort.

7) Technical studies filed in the 6th BTA indicate a generally robust study process for assessing transmission system performance (steady-state and transient) for the 2010-2019 planning period.

8) Regional and subregional planning studies have effectively addressed the interconnected EHV transmission that is critical to a functional interstate wholesale

market. Studies indicate the existing and planned Arizona EHV system is adequate to support a robust wholesale market.

9) Developing Arizona's vast renewable resource potential requires a coordinated and multi-faceted strategy involving stakeholders representing utility, government, economic, developer, environmental, and other interests. Decisions by the Commission and the actions taken by the Arizona utilities and regional stakeholders are important steps towards the state's goal of becoming a national and world leader in renewable energy development.

10) The 2009 utility filings in response to the 5th BTA order for the utilities to identify their top three Renewable Transmission Projects ("RTPs") are responsive to the Commission's order. An inclusive stakeholder process was developed and executed to identify the projects. In addition, the utilities are considering the impact of proposed utility-scale renewable projects as part of their normal planning processes.

11) Most of the transmission corridors identified in the utilities' initial RTP proposals to serve potential renewable generation are compatible with projects in the utilities' previously filed transmission plans. Furthermore, most of the RTPs identified by the utilities are actually advancements of projects already included in previous transmission plans. Such project advancement represents a relatively small incremental investment for a potentially significant renewable benefit.

12) Because the selected RTP projects are ones that have been identified in earlier transmission plans they should contribute to reinforcing the transmission system beyond the specific needs of renewable generation projects. We would expect them to be effective in enabling delivery of renewable resources developed close to either the Phoenix-Tucson regions or the Palo Verde hub. As projects are developed farther from these areas, completely new transmission plans will likely need to be identified and developed.

13) Even if the proposed RTPs filed by Arizona utilities in 2009 are approved and built, they will only provide for integration of a portion of the projected in-state renewable resource potential.

Recommendations

Based upon observations and concerns discussed in the conclusions, Staff submits the following recommendations for Commission consideration and action:

1) Staff recommends that the Commission continue to support the use of the:

   a) "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" (See Appendix A), and

   b) NERC reliability standards, WECC system performance criteria and FERC enforcement policies relative to transmission planning system planning reliability standards, and

   c) Collaborative planning processes in Arizona and throughout the western region that facilitate competitive wholesale markets, and are consistent with FERC Order 890 and the expected order on Transmission Planning and Cost Allocation.

2) Staff recommends that the Commission continue to support the policy that generation interconnections should be granted a Certificate of Environmental Compatibility by the Commission only when they meet regional and national reliability standards and the requirements of Commission decisions.

3) Staff recommends that the Commission order the jurisdictional utilities to report relevant findings in future BTAs regarding compliance with transmission planning standards (TPL-001 through TPL-004) from NERC/WECC reliability audits that have been finalized and filed with FERC.

4) Staff recommends that the Commission order SWTC to determine if an engineering "re-rating" of the Apache-Butterfield 230 kV line as proposed in the 6th BTA filings would be an acceptable measure until the line is upgraded in 2016, and to file the results of this assessment by January 31, 2011.

5) Staff recommends that the Commission order APS, SWTC and Tucson Electric Power Company ("TEP") to conduct additional analysis of potential 230 kV and 138

kV voltage deviations in Southeastern Arizona as noted in the 2009 SATS report, file an update based on the 2010 SATS by February 28, 2011, and finalize mitigation plans if needed for this voltage concern in ten-year plan filing(s) for the 7th BTA by January 31, 2012.[5]

6) Staff recommends that the Commission accept the definition of "continuity of service" following a transmission line outage as proposed in the Cochise County Study Group's 2009 technical study report filed by SWTC in January 2010, and that the Commission accept the recommended transmission plan of service presented in Section 4.2.1 of this BTA report in order to achieve this "continuity of service" objective in Cochise County.

    a) Staff further recommends that the Commission establish target dates for SWTC, APS, TEP and Sulphur Springs Valley Electric Cooperative ("SSVEC") to achieve certain milestones and file progress reports with the Commission (as delineated in Section 7, Item 6 of this report) in order to ensure timely progress on the plan of service consistent with the intent of Commission Order 70635 in this regard.

7) Staff recommends that the Commission order UNSE to update its assessment of long term alternatives for Santa Cruz County continuity of service, as part of UNSE's 2012-2021 ten-year planning studies, and file a report on the updated assessment in the 7th BTA in 2012. Furthermore, if any approvals or permits from federal agencies related to the Gateway Transmission Project are still pending at that time, Staff recommends that the Commission require the 7th BTA filings to include a clear action plan and proposed schedule to obtain such approvals.

8) Staff recommends that Commission regulated utilities be required to continue to perform RMR studies in accordance with the methodology set forth in Appendix C to this Sixth BTA, and shall file such studies with ten-year plans for inclusion in future BTA reports.

[5] TEP plans to file updated SATS 2010 study results with Docket Control by January 1, 2011.

9) Staff recommends that the Commission order the jurisdictional utilities to include planned transmission reconductor projects, transformer capacity upgrade projects and reactive power compensation facility additions at 115 kV and above in future BTA plan filings starting in January 2011.

10) Staff recommends that the Commission accept the results of the following Commission ordered studies provided as part of the 6th BTA filings:

    a) "Extreme Contingency" outage study for Arizona's major transmission corridors and substations, and the associated risks and consequences of such overlapping contingencies.

    b) "N-1-1" (Ten-Year Snapshot) study results documenting the performance of Arizona's statewide transmission system in 2019 for a comprehensive set of N-1 contingencies, each tested with the absence of one of nine different major planned transmission projects (N-1-1).

    c) RMR studies for Phoenix, Tucson, Yuma, Mohave County and Santa Cruz County.

1. Overview

1.1 Assessment Authority

Arizona statutes require every entity considering construction of any transmission line equal to or greater than 115 kV within Arizona during the next ten year period to file a ten year plan with the Arizona Corporation Commission ("ACC" or "Commission") on or before January 31 of each year.[6] Every entity considering construction of a new power plant of 100 Megawatts ("MW") or greater within Arizona is required to file a plan with the Commission at least 90 days before filing an application for a Certificate of Environmental Compatibility ("CEC").[7] All such plans filed with the Commission must include power flow and stability analysis reports showing the effect of the planned facilities on the current and future Arizona electric transmission system.[8] The Commission is required to biennially examine the plans and "issue a written decision regarding the adequacy of the existing and planned transmission facilities in Arizona to meet the present and future energy needs of the state in a reliable manner".[9]

1.2 Sixth Biennial Assessment – Purpose and Framework

The purpose of this report is to inform the Commission of currently planned transmission facilities and offer an assessment of the adequacy of the existing and planned Arizona electrical transmission system. This Sixth Biennial Transmission Assessment ("BTA") evaluates the ten-year transmission plans filed with the Commission in Docket No. E-00000D-09-0020. This report fulfills the statutory obligation to review these transmission plans and assess whether the Arizona transmission system is and will remain adequate throughout the ten year timeframe.

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[6] Arizona Revised Statute § 40-360.02.A
[7] Arizona Revised Statute § 40-360.02.B
[8] Arizona Revised Statute § 40-360.02.C.7
[9] Arizona Revised Statute § 40-360.02.G

The Commission ordered that supplemental study work also be performed by the industry as a portion of this sixth BTA.[10] These include Reliability Must Run ("RMR"), N-1-1 and extreme contingency studies as required in prior BTAs. The Commission also required an assessment of transmission capacity available or required for renewable energy development in Arizona, as well as the determination of the top three transmission projects for renewables by each Arizona utility. This report examines the transmission plans filed by the industry to address these topics as well as other Commission ordered studies.[11]

In the Arizona BTA process, entities conduct their own technical studies or engage in joint studies, participate in collaborative and open regional planning processes, and present the study results in their ten-year plan reports and at public workshops. Commission Staff ("Staff") participates in a number of these collaborative processes and relies on the technical reports and documents filed with the Commission, and other publicly available industry reports, rather than performing independent technical study work. Staff continues to use a set of guiding principles in determining the adequacy and reliability of both transmission and generation systems.[12] Staff's guiding principles are based upon best engineering/planning practices established in Arizona coupled with the use of WECC planning principles, and are also intended to be consistent with applicable North American Electricity Reliability Corporation ("NERC") reliability standards (e.g., TPL-001 through TPL-004)[13], and FERC orders.

Staff retained KEMA, Inc. ("KEMA") to assist them with this Sixth BTA. Staff and KEMA critically reviewed and analyzed the filed transmission planning reports and ten-year plans and addressed the following five key issues:

1) Do the combined Arizona transmission system plans meet the load-serving requirements of the state during the 2010-2019 timeframe in a reliable manner?

[10] Decision No. 69389, Docket No. E-00000D-05-0040

[11] History of Commission Ordered Studies, Appendix B

[12] Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability: Appendix A - 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

[13] NERC Reliability Standards, Transmission Planning (TPL) at http://www.nerc.com/page.php?cid=2|20

2) Do the required Reliability Must Run, N-1-1, and Extreme Contingency studies comply with, and sufficiently meet, the intended goals of the Commission's orders?

3) Were steps taken in the most recent transmission planning studies to effectively address concerns raised in previous BTAs about the adequacy of the state's transmission system to reliably support the competitive wholesale market in Arizona?

4) Do transmission providers' ten-year expansion plans, including their renewable transmission project proposals, adequately support the overall needs for renewable resource development and integration into the Arizona and regional electric power system?

5) Do the plans and planning activities utilized comport with transmission planning principles and good utility practices accepted by the power industry and the reliability planning standards established by NERC, WECC, and FERC?

1.3 Assessment Process

A three-stage approach was used to prepare this BTA report. The first stage consisted of a workshop which offered participants the opportunity to make presentations supplementing their ten-year plan filings. During the second stage, Staff and KEMA prepared, distributed and posted to the Commission's website the first draft report for public comment. The next stage of the process consisted of a second workshop for Staff and KEMA to present their draft findings and facilitate discussion of the draft of the report. A revised, final draft of the report was prepared and posted on the website following the second workshop. A summary of each stage of the BTA process is described in the following sections.

1.3.1 Workshop I: Industry Presentations

KEMA assisted Staff in arranging a two-day public Workshop on June 3-4, 2010 in Phoenix, Arizona. A complete listing of the Workshop I attendees and presenters is in Appendix E. Transmission Providers and Subregional Planning Groups presented information regarding their respective transmission expansion plans and related planning activities. Merchant transmission and generation developers reported on their respective development plans. The Workshop provided an informal setting to promote effective discussion of each presentation.[14] Each presentation was followed by an open period of discussion including questions and comments from the audience. Staff and KEMA concluded the session with general comments and discussion of the schedule for completing the 6th BTA.

1.3.2 Review of Industry Filings in 6th BTA

In preparation for Workshop 1, Staff and KEMA reviewed all of the filings that had been made to date by parties in the 6th BTA. Table 1 shows a matrix of the various categories of ten-year planning information filed by utilities during the 6th BTA. A complete list of entities that made ten-year plan filings in this BTA is shown in Table 2.

[14] The Workshop I agenda and presentation materials are located at http://www.cc.state.az.us/divisions/utilities/electric/biennial.asp

Table 1 - Matrix of Utility Filings in 6th BTA

Utility	Ten-Year Plan	2010-2019 Utility Technical Study Report	RMR Study Report	Planning Criteria & Ratings	Joint Study Report(s)
APS	X	X	X	X	Extreme Contingency Study[15]
Electric Districts ("ED") 3&4	X				
SRP	X	X	*(Participated in APS Phoenix RMR Study)*	X	10 Year Snapshot Study[16] & CATS-HV Study[17]
SSEVC	X[18]				
SWTC	X	X		X	Cochise County Report[19]
TEP	X	X	X	X	SATS[20]
UNSE	X	X	X	X	Santa Cruz County Report

The combination of individual studies and joint studies listed in Table 1 provides the main basis upon which Staff has assessed adequacy of the 2010-2019 ten-year plans. Although individual technical studies were not filed in this BTA by WAPA and some smaller utilities, Staff concludes that by-in-large their plans were modeled and analyzed as part of the joint studies that were filed.

[15] Filed on behalf of CATS-EHV study group.
[16] Ten-Year Snapshot Study (2019 system) filed on behalf of SRP, APS, WAPA, ED 3 & 4, et al.
[17] Filed on behalf of all study participants including SRP, APS, ED 2-5, SWTC, TEP, WAPA, et al.
[18] SSVEC's filing is limited to comments on the Cochise County Report.
[19] Filed on behalf of all study participants including SWTC, APS, TEP, WAPA, SSVEC, et al.
[20] Southeast Arizona Transmission System Study Report filed on behalf of SWTC, TEP/UNSE, WAPA, APS, et al.

Arizona Revised Statute § 40-360.02 (C) (7) requires that: "The plans for any new facilities shall include a power flow and stability analysis report showing the effect on the current Arizona electric transmission system. Transmission owners shall provide the technical reports, analysis or basis for projects that are included for serving customer load growth in their service territories." The Staff anticipates that technical analysis of this type, including both power flow and stability, will be included in the technical reports filed by utilities in the BTA. Some parties questioned during the workshops if filing of stability analysis for transmission plans beyond five years is of value due to the many uncertainties regarding loads, types of resources, and generator characteristics that must be assumed for stability modeling. In Staff's opinion, stability analysis during the initial five years of the plan should generally suffice for the BTA process, but stability analysis for the 6-10 year period is also informative for Staff's preliminary assessment of the longer term transmission plan if it's provided.

As indicated in Table 1, technical studies are augmented by other relevant information. APS, TEP, SWTC and UNSE included their internal transmission planning criteria and system ratings in the 6th BTA filings as required by Arizona Corporation Commission ("ACC") Decision No. 63876 (July 25, 2001). APS provided their planning criteria as part of their internal "Transmission Planning Process and Guidelines" included in their 6th BTA filing. SRP also provided their criteria and ratings. Such documents provide useful reference material for use by Staff.

1.3.3 Preparation of Draft Report, Workshop 2 and Industry Comment

Staff and KEMA provided an initial draft of the 2010 BTA report for industry review and comment in July 2010. The first draft report was based on the docketed ten-year plans and information gathered at Workshop I.[21] The first draft report was placed on the Commission's website and distributed via industry distribution lists to expedite the review process. Industry comments were docketed for other parties' review, comment and response. Oral comments on the draft report were received at Workshop 2 on August 4, 2010. A revised draft report reflecting this input was issued to stakeholders for review and comment on August 16, 2010. This round of comments was also reflected in the final report.

[21] Transcripts of Workshop I held June 3-4, 2010 are available on the ACC Docket Control site.

2. Ten-Year Plans

Table 2 provides a list of entities that filed ten-year transmission plans with the Commission in January 2010. The ten-year plans for proposed power plants and their associated transmission lines must be filed annually once an initial filing is made in advance of an application for a Certificate of Environmental Compatibility ("CEC") at the Commission. The 6th BTA assessment examines the aggregate ten-year plan.

Table 2 - List of Parties Filing Ten-Year Plans in 6th BTA

Abengoa Solar Inc.	Sempra Energy
Ajo Improvement Company[22]	Sonoran Solar Energy, LLC
Arizona Public Service Company	Southern California Edison
Bowie Power Station, LLC	Southwest Transmission Cooperative
Central Arizona Project[23]	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[24]	SunZia Southwest Transmission Project
Hualapai Valley Solar LLC	Tucson Electric Power
Public Service Co. of New Mexico	UNS Energy ("UNSE")
Salt River Project	Welton-Mohawk Irrigation & Drainage District ("WMIID")

Utilities in the United States are required by FERC to plan, design and operate their bulk transmission systems in accordance with the NERC Reliability Standards. In addition, utilities who are signatories to the WECC Reliability Agreement are also obligated to comply with certain technical performance standards. Furthermore, the utilities observe guidelines

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

established at the state level, and their own internal planning criteria, guidelines and methods. These planning practices are utilized to ensure that the WECC interconnection and individual member systems are planned for reliable service to customers under various system conditions and that plans are coordinated through a consistent set of standards, criteria and guidelines.

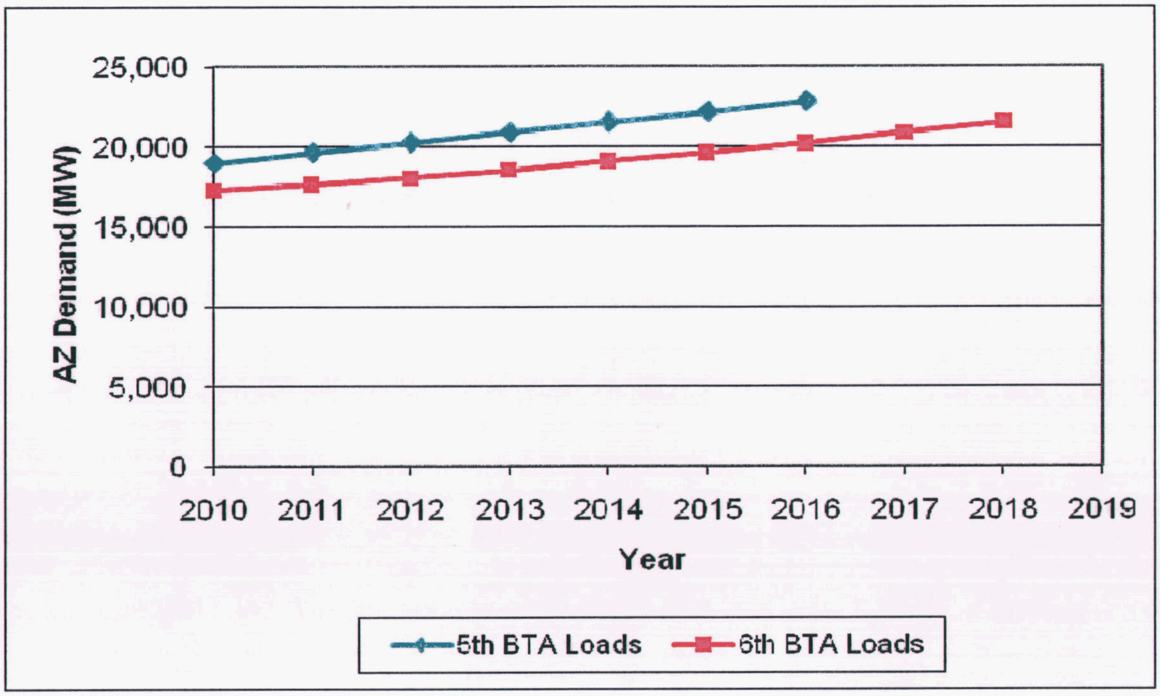
During Workshop I the following parties gave presentations regarding projects for which no ten-year plan was filed in the 6th BTA: High Plains Express Initiative, TransWest Express Transmission Line, Navajo Transmission Project, Southline Transmission Project, and Santa Fe Transmission Project. While such projects are described in this report, they were not considered as planned system elements for the purpose of Staff's assessment of adequacy and reliability in the 6th BTA.

2.1 Summary of Arizona Plan

The BTA examines the aggregation of all of the docketed projects as a coordinated transmission system expansion plan for Arizona projects from a system perspective, without regard to sponsorship or ownership. Projects that have not been filed are not included in this adequacy analysis for the BTA, but may still be depicted along with all other projects in the maps provided in Exhibits 1-6.

The principal driver for transmission plans filed by the utilities is reliability of supply to customers (e.g., "reliability-driven" projects). In the 6th BTA, a number of additional transmission proposals for integration of renewable resources have also been filed by the utilities, and those are addressed in Section 3 of Staff's report. In the current section Staff focuses on the reliability-driven projects. The need for and timing of reliability projects is driven primarily by the demand forecast. Figure 1 shows the change in the statewide demand forecast since the 5th BTA as a result of current economic conditions.

Figure 1: Change in Arizona Demand Forecast



As shown in Figure 1, the statewide demand forecast has shifted by about four (4) years since the 5th BTA (for detailed forecast data see Exhibit 8). All other factors being equal, this suggests that many planned reliability-driven transmission projects in Arizona could be delayed about four years from the in-service dates shown in the 5th BTA ten-year plans. However, this isn't universally true since the percent change in local area forecasts can vary significantly from the statewide percentages. In addition, there may be reliability drivers for certain projects other than the demand forecast. Nevertheless, the four-year shift shown in Figure 1 is useful in assessing the filed changes in the current ten-year plan.

A complete list of the individual projects filed as part of the 6th BTA ten-year plan(s) is shown in Exhibit 7. The list of project changes only since the 5th BTA is shown in Exhibit 18. Exhibits 20 and 21 sort the full list of projects in the 6th BTA by in-service date and voltage class, respectively.

Table 3 depicts the number of new transmission projects filed in the 6th BTA and the associated mileage by voltage class. Projects with a to-be-determined ("TBD") in-service date or that are beyond the Ten-Year Plan timeframe have been grouped together as a single category.

Phased projects with differing in-service dates for the respective phases were tabulated as separate projects.

Table 3 - Summary of New Projects by Voltage Class

Voltage Class	Number of Projects (2010 to 2019)	Number of Projects (Post 2019 and TBD)	Approximate Mileage[25]
500 kV	1	3	135
345 kV	0	3	27
230 kV	2	5	167
138 kV	3	0	28
115 kV	5	1	109
Total	11	12	466

The projects filed in the 6th BTA include planned transmission lines at 115 kV and higher, including major reconfigurations (e.g., loop-ins) and upgrades from a lower design voltage to a higher design voltage (e.g., 115 kV to 138 kV). In many cases, the filings also include planned additions of bulk power substations. However, several other significant classes of transmission system capital expansion utilized for the purpose of increasing capacity are (i) reconductoring of existing transmission lines, (ii) bulk power substation transformer bank replacements and (iii) certain reactive power compensation facility additions. Other than certain series capacitor installation/upgrade plans that were included, the ten-year plans filed in the current and prior BTAs overlook these three important categories of transmission system capacity upgrades. The Commission's Guiding Principles for Determination of System Adequacy and Reliability state that the ACC is obligated "to biennially make a determination of the adequacy and reliability of ***existing*** and planned transmission facilities in the state of Arizona."[26] (*Emphasis Added*) Therefore, Staff concludes that plans to reconductor existing transmission lines, upgrade bulk power transformer capacity and expand reactive power compensation to support transmission capacity upgrades should also be filed in the BTA so that the Commission can perform a more comprehensive assessment of transmission adequacy and reliability in the ten-year plan.

[25] The final mileage of many projects is still to be determined (TBD), so estimates were used for Table 3.
[26] From paragraph 2 of the Guiding Principles (see Appendix A to this report).

2.2 Plan Changes from Fifth BTA

Transmission plans inevitably evolve over time and are often in a state of flux. Significant changes can occur as a result of regulatory actions, state and federal policy developments, siting and permitting challenges, shifts in load forecasts, identification of new generating plants, third-party interconnection and delivery requests, and changes in the economic or financial climate faced by a project sponsor. A combined list of changes for all voltage levels 115 kV and above that have been filed since the 5th BTA is provided in Exhibit 18. For ease of reference a list of changes that have occurred at only 345 kV and above are provided in Table 4.

Table 4 - Significant EHV Project Changes since Fifth BTA

In-Service Date	Project	Voltage Class	Description of Change
2012	345/69 kV Interconnection at Western's Flagstaff 345kV bus	345 kV	Delayed from 2010
2013	Mazatzal Loop-in of Cholla-Pinnacle Peak 345 kV line	345 kV	Delayed from 2011
2013	Moenkopi-Eldorado 500 kV Series Capacitor Upgrade Project	500 kV	Delayed from 2012
2014	Delany-Sun Valley 500 kV line	500 kV	Delayed from 2010
2014	Palo Verde Hub-North Gila 500 kV #2 line	500 kV	Delayed from 2012
2014	Pinal Central-Tortolita 500 kV line	500 kV	Delayed from 2011
2014	Pinal West-Pinal Central – Randolph - Abel-Browning 500 kV line	500 kV	Delayed from 2011
2016	Sun Valley-Morgan 500 kV line	500 kV	Delayed from 2012
2012	Delany – Palo Verde 500kV line	500 kV	New Project
2015	Vail – Irvington 345 kV line	345 kV	New Project
2020	Pinal Central – Abel #2 500kV line	500 kV	New Project
TBD	Abel – RS20 500kV	500 kV	New Project
TBD	Interconnection of Greenlee-Winchester 345kV line with future Willow Substation	345 kV	New Project
TBD	Irvington – South 345 kV line	345 kV	New Project
TBD	RS20 – Coronado 500kV	500 kV	New Project
TBD	Winchester to Vail Double-Circuit 345 kV Line	345 kV	New Project

Table 5 shows the number of projects delayed (or advanced) since the 5th BTA by voltage level.

Table 5 - Summary of Project Schedule Changes since 5th BTA

Voltage Class	Advanced 1 Year or more	Delayed 1 Year	Delayed 2 Years	Delayed 3 Years	Delayed 4 Years	Delayed 5 Years or more
500 kV	0	1	1	2	2	0
345 kV	0	0	2	0	0	1
230 kV	0	0	2	2	1	5
138 kV	2	4	3	2	0	2
115 kV	2	2	0	0	0	1
Total	4	7	8	6	3	9

There were a total of 129 transmission projects listed in the previous ten-year plan.[27] Table 5 indicates that of this previous total, 37 projects have had a change in planned in-service date since the 5th BTA, including 33 that were delayed. Eighteen additional projects were cancelled. This means the balance of the projects from the 5th BTA have either been placed in-service since or are still planned for the same in-service date as before. The average delay for projects that have changed in-service dates is roughly four years. In Staff's opinion, these statistics on changes to the planned ten-year transmission projects are reasonable given the reduced demand forecast shown in Figure 1. In spite of the economy and demand forecast, many transmission projects have no change in schedule and four projects have actually been advanced. This may reflect the fact that load growth in local areas often varies significantly from system-wide averages.

Some projects or proposed substations have undergone a name change in recent filings as shown in Table 6.

[27] Fifth Biennial Transmission Assessment 2008-2017, Docket No. E-00000D-07-0376, page 15.

Table 6 - Project Name Changes or Aliases

Current Name	Formerly Known As
Delany	Harquahala Junction
Sun Valley	TS5
Pinal Central	Pinal South
Dinosaur	RS19
Trilby Wash	TS1
Sugarloaf	Second Knoll
Abel	Southeast Valley ("SEV")
Mineral Park	Mercator Mill
Scatter Wash	TS6
Morgan	TS9
Sun City	Catalina
Medina	SS NO 22

2.3 Interstate, Merchant and Generation Transmission Projects

Interstate transmission is essential to enabling a state's utilities access to the wholesale market for purchases and sales. Interstate and market driven transmission projects facilitate a more robust and viable wholesale market, complement the state's electric infrastructure and allow for additional power import/export. Various generation market access projects, merchant generation interconnections and merchant transmission projects are discussed in this section of the BTA.

2.3.1 Navajo Transmission Project

The Navajo Transmission Project ("NTP") is a 500 kV transmission line project proposed by the Dine Power Authority (an enterprise of the Navajo Nation), with an approximate total length of 478 miles.[28] The line will extend from a new substation located near the Four Corners Power Plant in northwestern New Mexico to the Marketplace Substation, south of Boulder City, Nevada. A new Desert Rock power plant will interconnect to the line in New Mexico near Four Corners. The NTP will be constructed in three segments which traverse Arizona.

- Segment 1 – About 180 miles of 500 kV single circuit transmission from Desert Rock Generating Facility in northwestern New Mexico crossing Navajo lands to the proposed Red Mesa West Substation near Navajo Generating Station in northern Arizona.
- Segment 2 – 62 mile 500 kV single circuit transmission line from a new Red Mesa West substation to the existing Moenkopi Substation. This segment generally parallels an existing Glen Canyon to Flagstaff 345 kV transmission line corridor.
- Segment 3 – About a 218 mile 500 kV single circuit transmission line from the existing Moenkopi Substation to Marketplace Substation in Nevada. Segment 3 generally parallels an existing Moenkopi to El Dorado 500 kV transmission line.

No ten-year plan was filed for this project in the 6th BTA. However, a project update was provided by Dine's Steve Begay at the BTA Workshop I on June 3, 2010. NTP is evaluating a

[28] CEC Case#103, Docket No. L-00000U-00-0103, approved under Decision #63197.

number of options for the design of the Desert Rock power plant including coal plus solar, or some other combination of resources including a blend of solar and natural gas fired generation. Regarding the 500 kV transmission segments, NTP believes that Segment 3 is currently the most needed due to existing congestion constraints in the system. An overview map showing the general routing of each segment is included as Exhibit 1. Project schedule is yet to be determined, and therefore it has been excluded in the 2010-2019 planning studies filed in the 6th BTA.

2.3.2 Palo Verde to Devers No. 2 500 kV Transmission Line

The Palo Verde to Devers No. 2 ("PVD2") 500 kV Project[29] is a SCE sponsored interstate transmission project. The overall scope of the project extends approximately 270 miles from the proposed Delany Substation[30] in Arizona to SCE's Devers Substation near Palm Springs, then continuing on to SCE's Valley Substation near Romoland, California. On June 6, 2007, the Arizona Corporation Commission denied SCE's application for a CEC for the portion of the PVD2 transmission line located in Arizona.[31] SCE's ten-year plan filing in the 6th BTA states that in November 2009, SCE received an order from the California PUC allowing SCE to proceed with construction of the California portion of PVD2. Based on the latest project configuration, the California portion extends eastward from Valley Substation via Devers to a newly proposed substation site referred to as Midpoint or the Colorado River 500 kV Switchyard in the vicinity of Blythe, California. Based on this reconfiguration, SCE must seek further California PUC authorization before reinitiating the CEC approval process with the ACC. An overview map showing the general routing of the PVD2 transmission line is included as Exhibit 10. Specific routing for the Arizona portion of PVD2 would be determined through the CEC process. This Arizona portion of the reconfigured project consists of a single transmission line segment as follows:

> Colorado River 500 kV Substation - Delany Substation: A new 500 kV transmission line between Arizona and California. This segment is approximately

[29] ACC Docket No. L-00000A-0295-00130.

[30] Delany Substation was previously known as Harquahala Junction.

[31] ACC Decision No. 69638.

104 miles long. The proposed transmission line routing parallels the existing Palo Verde to Devers 500 kV transmission line.

On May 16, 2008, SCE filed a pre-filing application with FERC under Section 50.6 - Transmission Line Siting process. This filing triggered a project-wide National Environmental Policy Act ("NEPA") review, preparation of a preliminary draft Environmental Impact Study ("EIS"), and a public notice process along the entire right-of-way. The Arizona Corporation Commission has responded to this FERC filing.[32] A project update posted by SCE in May 2009[33] stated that a recent update of the economic analysis for the project no longer demonstrates sufficient benefits to California customers to build the Arizona portion of the line. SCE gives the following reasons for this change in economics:

- The increase in California's mandated 2020 RPS target to 33%, together with the development of both renewable and conventional generation in the vicinity of the California River 500 kV Switchyard, which will decrease the need for imports from Arizona.
- A decrease in the expected differential in fuel prices between Arizona and California.
- Reduced load growth in California as a result of changed economic conditions.

Therefore, SCE has stated it will cease its pre-filing activities at the FERC and put its plans for re-filing with the ACC on hold.

2.3.3 Harcuvar Transmission Project

The Harcuvar Transmission Project ("HTP") is a proposed 230 kV transmission project located approximately 60 miles west of the Palo Verde Hub and is sponsored by various entities including renewable and thermal energy developers, merchant transmission providers, and load serving entities in Arizona. The Central Arizona Water Conservation District ("CAWCD"), as one

[32] http://elibrary.ferc.gov/idmws/nvcommon/NVViewer.asp?Doc=11687511:0 and http://elibrary.ferc.gov/idmws/nvcommon/NVViewer.asp?Doc=11709962:0

[33] http://www.sce.com/NR/rdonlyres/0A5F8FEB-5357-4C11-BD93-07387DE4B2C1/0/090515_DPV2ProjectUpdate_May2009.pdf

of the project sponsors, filed ten-year plans with the Commission in January 2009 and 2010.[34] The project consists of two principal components:

- Approximately a 90 mile 230 kV loop in La Paz County, Arizona.
- Joint ownership, together with SCE, of the Arizona segment of the PVD2 500 kV line.

In its latest BTA filing HTP notes that on May 15, 2009, SCE notified the ACC by letter that their latest economic "analysis does not support re-filing with the ACC, at this time, for authorization of the Arizona portion of [PVD2]." The BTA filing goes on to state that because the PVD2 line is "critical to the success of the HTP", the HTP must either await the renewal of SCE's filing with the ACC for PDV2, "or some other project offering equivalent value and functionality." Therefore, CAWCD is pursuing other options to enhance transmission capacity to its major pumping loads in La Paz and Mohave counties.

2.3.4 SunZia Southwest Transmission Project

The project is sponsored by Southwestern Power Group. SunZia proposes to permit and construct up to two interstate merchant EHV transmission lines from a new substation in Lincoln County, New Mexico, to Pinal Central Substation in Arizona. The project is intended to transport renewable generation from wind, solar and geothermal resources to markets in the Arizona and the Western region. The primary alternative would construct two 500 kV AC lines, but an option is also under study to build one of the lines as an HVDC (direct current) line. An overview map showing the general routing is included as Exhibit 9.[35] The total estimated corridor length is 471 miles, of which approximately 176 miles are located in Arizona. The project would be constructed in phases, with the initial phase placed in service in 2014.

The SunZia ten-year plan filed in January 2010 was not accompanied by power flow or stability studies. However, SunZia reports that a full set of technical studies will be prepared when the project's design is sufficiently finalized. It is involved in the regional and subregional planning process thru the following forums and activities:

[34] The filing is identified in the ACC E-Docket by "Central Arizona Project" as the filing party.

[35] Recently introduced southern route options (e.g., the "Tucson route") are not shown in Exhibit 9.

- The WECC path rating process (e.g., through Phase 3) is expected to be complete by the end of 2010 (based on the two 500 kV AC line option).
- Subregional Planning — Regular project updates are provided to SWAT and its subcommittees.
- Open Season — Six parties have now signed the participation agreement (SRP, TEP, Tri-State G&T, Shell WindEnergy, Southwestern Power Group and Energy Capital Partners).

2.3.5 High Plains Express Initiative

The project is sponsored by NextEra Energy. An update on the project was presented by Jerry Vaninetti of NextEra Energy at Workshop 1. High Plains Express ("HPX") is a multi-state, 500kV transmission initiative that extends from Wyoming to Arizona. The project's vision is to significantly strengthen the eastern portion of the WECC grid, especially along a north to south backbone. NextEra has not filed a ten-year plan for the project. Therefore, this project was not considered for the adequacy analysis nor included in the ten-year plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points is included as Exhibit 10.

According to NextEra, HPX could eventually incorporate many of the transmission projects already under development within its overall project footprint in eastern and southern WECC. A diagram depicting the potential impacts of the project on WECC transfer capabilities is shown in Exhibit 11.

2.3.6 TransWest Express Transmission Project

The project is currently owned by Anschutz Corporation. A ten-year plan filing was not made for this project in the 6th BTA, but consultant Gary Mirich of Energy Strategies gave an update on the project at Workshop 1 (no slides were presented). The project is currently conceptualized as a 600 kV bi-polar transmission line from southeastern Wyoming to the El Dorado Valley region (south of Las Vegas, NV) with a rating of approximately 3,000 MW. The targeted in-service date is 2015. Mr. Mirich described the project as renewable line that may be supplemented by gas-fired generation. He stated that the project is currently in Phase II of the WECC Path Rating Process. An overview map showing the general routing of the line, as published in the 5th BTA, is included as Exhibit 12.

2.3.7 San Luis Rio Colorado Plant and North Branch Transmission Project

The project is sponsored by Generadora del Desierto S.A. de C.V. (GDD) and Western Area Power Administration (WAPA). On August 21, 2008, the DOE published, in the Federal Register, notice of its decision to issue a Presidential Permit to construct, operate, maintain and connect a new double circuit 230 kV transmission line across the U.S.-Mexico border from Yuma County, North Gila Substation to San Luis Rio Colorado, Sonora, Mexico.[36]

The North Branch Transmission Project consists of two 230 kV transmission lines which will connect to a new 230 kV substation to be built next to WAPA's Gila 161 kV substation. The new double circuit 230 kV lines will continue north to the APS North Gila 500 kV station. WAPA will own the new transmission on the US side. GDD will own the short transmission on the Mexico side. According to Jim Charters of Western States Energy Solutions, project participation agreements are being developed between WAPA, North Branch and APS. No update on the project was filed in the 6th BTA.

2.3.8 Southline Project

The project is sponsored by Black Forest Partners. No filing was made in the 6th BTA, but Bill Kipp of Black Forest gave a slide presentation on this merchant transmission line at Workshop 1. He stated that the goal of the project is to accelerate the use of renewable energy. This project was not considered for the adequacy analysis nor included in the ten-year plan statistics compiled for this BTA. Southline is contemplated to be a combination of new and rebuilt EHV transmission elements, with 230 kV, 345 kV and 500kV segments, for renewable deliveries from southeastern New Mexico to the Palo Verde Hub area, passing through southeastern Arizona in route. In southern New Mexico, they plan to follow the route of an abandoned railroad track in order to minimize environmental impacts. From southeast Arizona to Palo Verde, they may participate in announced utility projects or procure contractual delivery arrangements in lieu of new physical line construction. Beyond Palo Verde, they believe the Southline could potentially fit well with other projects that are exploring options west of Palo Verde. Black Forest is

[36] Federal Register / Vol. 73, No. 163/ Thursday, August 21, 2008/Notices, page 49447. http://edocket.access.gpo.gov/2008/pdf/E8-19392.pdf

currently completing joint technical studies with TEP, SWTC, Western and other parties – which they plan to file with the Commission in the near future. Most of the east to west capacity is envisioned for renewable delivery, while much of the west to east capacity is envisioned for load serving purposes. A simplified one-line diagram of the project is shown in Exhibit 29.

2.3.9 Santa Fe Clean Line Project

The project is sponsored by Clean Line Energy Partners LLC ("Clean Line"). Keith Sparks of Clean Line gave a presentation on the project at Workshop 1, but no filing has been received to date. Therefore, the project was not considered for the adequacy analysis nor included in the ten-year plan statistics compiled for this BTA. Clean Line, an independent developer of high voltage transmission, provided supplemental information after the workshops, which are included below. The Santa Fe Clean Line transmission project ("Santa Fe") which will consist of one ±500 kV or ±600 kV High Voltage Direct Current ("HVDC") overhead transmission line capable of transmitting up to 3,500 MW of power from renewable projects in eastern New Mexico to Southern California, Southern Nevada, Arizona, and other areas in the Southwest.

Santa Fe is meeting with local and state authorities in Arizona, and other states to begin informal outreach efforts. Santa Fe has conducted an initial corridor feasibility study and is in the first phases of refining the corridors to identify preferred and alternative routes. A map of the "study area" is provided as Exhibit 30. Santa Fe will conduct an environmental impact statement pursuant to NEPA, and work closely with state and federal agencies.

Before the Project was acquired by Clean Line in May 2010, the previous developer (Integration Transmission Services) spent over 24 months developing the concept for the line, including various meetings with the ACC staff. Building on this work, the Santa Fe has completed a Memorandum of Understanding with Dine Power Authority, regularly engaged in SATS and WECC planning stakeholder meetings, submitted an application for Western's Transmission Infrastructure Program, and opened discussions with Western as a potential project partner.

2.3.10 Bowie Power Station

The Bowie Power Station owned by Southwestern Power Group ("SWPG") is a natural gas fired 1,000 MW electric generation facility planned for southeastern Arizona near the community of Bowie in Cochise County. The Bowie Power Station will connect with TEP's Greenlee-

Winchester-Vail 345 kV line at Willow Substation via two 345 kV transmission lines approximately 15 miles in length.

SWPG's filing in the 6th BTA notes that the Commission has extended the CEC for the project through December 31, 2010 in Decision No. 69339. SWPG has applied for an additional extension through December 31, 2020. The physical alignment of the line and Willow Substation were amended through Decision No. 70588 in November 2008. Exhibit 14 depicts the amended alignment.

PDS consulting gave a presentation on the project at Workshop 1. SWPG continues to be active in SWAT subcommittees, including SATS. A Final Facilities Study Report is expected from TEP in the third quarter 2010. The estimated operation date for the gen-tie is late 2013.

2.3.11 Hualapai Valley Solar

Mohave Sun Power LLC is sponsoring this project. Ten-year plans in 2009 and 2010 describe a conceptual 345 kV or 500 kV gen-tie from a solar power project to be built in northwestern Arizona to interconnect with an existing EHV transmission facility. No route has been determined. The line may connect into either the Mead Phoenix Project 500 kV transmission line, the Mead-Peacock-Liberty 345 kV transmission line, or the Moenkopi-Eldorado 500 kV transmission line. The proposed in-service date is the fourth quarter of 2013. Since a defined transmission plan of service hasn't been identified to date, the project wasn't modeled in any technical studies filed in the 6th BTA docket. However, power flow and stability analysis were filed as part of the power plant filings at the Commission in August 2009.[37]

2.3.12 Sonoran Solar Energy

Sonoran Solar Energy plans to build a 500 kV gen-tie to interconnect its proposed 375 MW solar generation project with SRP's Jojoba Substation. The 3 mile long line will be located in Maricopa County, Arizona and will be in service by summer 2013 to support plant start-up and testing. A map of the gen-tie route is shown in Exhibit 15. Sonoran states that technical study reports for this interconnection plan were included as part of the 90-day filing notice in November 2009.

[37] ACC Docket No. E-00000M-08-0170 and Docket No. L-00000NN-09-0541-00151.

2.3.13 Abengoa Solar

Abengoa Solar plans to build a 230 kV overhead gen-tie (approximately 20 mile) to interconnect its proposed 280 MW Solana solar generation project near Gila Bend, Arizona with APS' Gila River Substation.[38] A route map is shown in Exhibit 16. The project will use concentrated solar power ("CSP") technology with storage capability. Technical planning studies were filed with the project's 90-day notice in July 2008. The project and gen-tie received a CEC in December 2008.[39] APS will procure the output under a 30-year purchase agreement. Abengoa states that an interconnection facilities study was completed by APS in August 2009 and concludes that an additional loop-in of the line through Gila Bend Substation en route to Gila River Substation, as contemplated at the time of the CEC application, is not needed.[40] The facilities study was included in Abengoa's BTA filing.

2.3.14 Mesquite Solar Project

Sempra Energy filed a ten-year plan for its 230 kV gen-tie from their Mesquite Solar photovoltaic project to Hassayampa Substation, which includes expansion of switchyard facilities at the existing Mesquite Generating Station adjacent to Hassayampa Substation. The project one-line diagram is shown in Exhibit 17. Sempra advised Staff that the expected date for initial solar production at the plant has slipped to October 2011, with additional stages coming on-line shortly thereafter.

2.3.15 Starwood Solar I

Starwood Energy filed a ten-year plan for the Starwood Solar I project in June 2009. The plan describes a 500 kV gen-tie to connect the generating project to APS' planned Delany Substation. Starwood refers to APS as the surrogate for meeting the ACC's requirement for filing of transmission planning criteria and system ratings. Construction of the gen-tie to Delany Substation is expected to start in 2010 and be completed in 2013. A subsequent extension to Harquahala Substation is also mentioned in Starwood's ten-year plan, but the timing of this

[38] Also known as Panda Substation.

[39] ACC Docket No. L-00000GG-08-0407-00139, Decision No. 70638 and Docket No. L-00000GG-08-0407-00140, Decision No. 70639.

[40] The facilities study also specifies certain APS 69kV network upgrades that need to be completed.

segment is uncertain and dependent on an ongoing APS cluster interconnection study and commercial negotiations with the Harquahala Power Plant. No technical studies were filed. Starwood states that technical studies supporting its transmission plan will be filed upon study completion. Exhibit 35 provides more plan details.

2.3.16 Arlington Valley Solar Energy

AVSE LLC filed a Ten-Year Plan in January 2009, describing two 115 kV or 230 kV gen-tie lines from the project site to Hassayampa Substation, plus 500-1000 feet of 500 kV line on the high side of the step up transformer bank at Hassayampa. The gen-ties will be 3-7 miles in length and will originate at Arlington Valley Solar 1 and 2 Generating Plant switchyards, respectively. Aggregate generating plant capacity is approximately 250 MW. The estimated in-service date is 4th quarter 2012. No BTA update was filed in 2010.

2.3.17 Agua Caliente Solar Energy

The project developer, NextLight Renewable Power LLC, filed a ten-year plan in January 2009. The filing described a loop in of the existing Hassayampa – North Gila 500 kV line into a new 500 kV switchyard (Hoodoo Wash) to be built in the vicinity of the Agua Caliente Solar Project site approximately 10 miles north of Dateland, Arizona in Yuma County. The 280 MW concentrating solar power plant will be located about 2 miles north of the existing 500 kV line. The gen-tie voltage is not specified. A 90-day Plan filing was made in November 2008. The anticipated in-service date is mid-2012. No BTA filing was made in 2010.

2.4 Other Significant Transmission Projects

2.4.1 Welton-Mohawk Supply Project

WMIDD is planning to participate as a minority owner in the Hassayampa to North Gila No. 2 500 kV line project, to construct a new 500/230 kV receiving station that will intersect with the new 500 kV line in the vicinity of North Gila Substation (or connect at North Gila Sub), and to construct a 230 kV transmission project from the new receiving station about 35 miles to its existing WAPA Ligurta Substation, which serves as the delivery point to WMIDD. WMIDD is participating in subregional planning forums, including SWAT, to assure that its project plans are properly vetted and coordinated within the region. The project is needed to serve new load growth in WMIDD's service area.

2.4.2 Southwest Public Power Resources Project

Southwest Public Power Resources ("SPPR") is sponsoring a project to add transmission in Pinal County. No filing was made in the 6th BTA, but Dennis Delaney of K.R. Saline & Associates ("K.R. Saline") gave a presentation on the project at Workshop 1.

SPPR previously proposed the Three Terminal Plan ("TTP") transmission project during the 5th BTA in order to interconnect SPPR's Sawtooth Generation Project No. 1 located in Pinal County and deliver power to SPPR participants. However, Mr. Delaney advised that plans for the Sawtooth 620 MW combined cycle gas-fired plant have been cancelled and the transmission plan has been revised. The TTP project originally consisted of the following three new 230 kV transmission elements:

- Santa Rosa/Test Track to ED5 (Circuit 1)
- ED5 to Pinal Central (Circuit 2)
- ED5 to Marana (Circuit 3)

In place of the Sawtooth Generation Project, SPPR now plans to pursue a PPA for firm power at Palo Verde for delivery over the Southeast Valley Project ("SEV") to its load area. Based on this new approach, SPPR expects to change its ten-year plan as follows:

- Interconnect TTP Circuit 1 through new 500/230 kV transformation at Test Track
- Install a 230/115 kV transformer at ED5
- Delay TTP Circuits 2 and 3 (e.g., beyond ten-year plan)
- Utilize the extension of the Southeast Valley ("SEV") project from Pinal West to Test Track and Pinal Central

SPPR is negotiating with Western for a bi-directional transmission path between Palo Verde and Pinal County, as indicated in Exhibit 13. This would allow SPPR to integrate new renewable resources that are expected to connect to its local system, and deliver them to SEV busses and/or the Palo Verde hub (when the path is not being used for delivery of its PPA capacity from Palo Verde hub). At least 300MW of renewables are currently queued in the local system.

2.4.3 WECC Transfer Path Changes Affecting Arizona

Exhibit 8 provides a map of the WECC rated transmission paths in Arizona. Ratings of these transmission paths are increased in two ways - either a new line is constructed and integrated into an existing path, or one or more existing lines in a path are upgraded to achieve an increased path rating. Such path rating changes must go through an exhaustive WECC path rating process, which includes technical studies and peer review, in order to implement such path rating increases. The following path rating increases have been completed or in-progress since the 5th BTA:

- The rating of the East of the River ("EOR") Path or Path 49 increased by 1,245 MW due to upgrades to both the Navajo-Crystal and the Perkins-Mead 500 kV lines. The resulting east to west direction path rating changed to 9,300 MW.
- The Coronado to Silver King 500 kV path upgrade was completed in 2010 changing the original path rating from 1,100 MW to 1,494 MW in the East to West direction.
- The rating of Path 51 ("Navajo South Transmission System") was increased in 2009 from 2,264 MW to 2,800 MW[41] due to upgrades of the four series capacitors within the path. The rating is defined in the north to south direction, and the increase will take effect in late 2010 or early 2011.

No other WECC path rating changes in Arizona are currently approved for the 2010-2019 periods, but it is likely that some increases will occur in this period due to major interstate transmission projects described in this report. Future WECC path rating studies will determine the timing and amount of these increases.

[41] The Path 51 rating was inadvertently reported as 3,200 MW in the 5th BTA Staff Report.

3. Transmission Affecting Renewable Development

Developing Arizona's vast renewable resource potential requires a coordinated and multi-faceted strategy involving stakeholders representing many sectors and interests including utility, government, economic, developer, environmental, and others. Decisions by the Commission and the actions taken by the Arizona utilities and regional stakeholders are important factors that will affect how and when this potential is developed.

3.1 Background

The Commission's 5th BTA Decision directed Commission-regulated utilities to develop viable plans to identify future transmission projects and to propose funding mechanisms to construct the top three transmission projects in their respective service territories. In addition, the Commission directed the jurisdictional utilities to conduct a joint workshop or series of planning meetings to develop ways in which new transmission projects could be identified, approved for construction, and financed in a manner that supports renewable energy growth.

The Commission's 5th BTA (2008) Decision directed Commission-regulated utilities to:

- "[B]y April 30, 2009, conduct joint workshops or planning meetings to develop ways in which new transmission projects can be identified, approved for construction, and financed in a manner that will support the growth of renewables in Arizona."[42]
- "[T]ake the results of the Arizona Renewable Transmission Task Force and the SWAT Renewable Transmission Task Force Plans developed for the Fifth Biennial Transmission Assessment and identify the top three potential renewable transmission projects in their respective service territories."[43]
- "[E]ither alone or in cooperation with other interested utilities," "develop plans to identify future renewable transmission projects and develop plans and propose funding mechanisms to construct the top three renewable transmission projects. These plans

42. Arizona Corporation Commission, Order 70635, Docket E-00000D-07-0376; page 8.
43. Ibid.

and mechanisms" are to be "filed with the Commission no later than October 31, 2009 and shall be discussed in" the 6th BTA.[44]

SRP also participated in this process, including SWAT RTTF subcommittees, and voluntarily filed its top three RTPs with the Commission.

3.1.1 The Arizona Renewable Resource and Transmission Identification Subcommittee

In response to a prior Commission directive in the 4th BTA, the SWAT Sub-Regional Planning Group formed a Renewable Transmission Task Force ("RTTF") to consider transmission needs for developing renewable resources. In response to the directive of the 5th BTA, the RTTF established the Arizona Renewable Resource and Transmission Identification Subcommittee ("ARRTIS") to identify those areas in Arizona with the best potential for renewable generation project development to aid the utilities' response to the BTA Decision. The primary tasks of ARRTIS were to:

- Identify potential constraint areas for Arizona renewable resource development;
- Assist the RTTF by providing information to assess transmission options; and
- Inform and assist the regulated utilities in their response to the BTA Order.

The ARRTIS convened approximately a five-month process to gather, review and map renewable resource data and environmentally sensitive areas for the state of Arizona and to provide input and support to the RTTF renewable transmission planning efforts. The process identified areas within the state where solar and wind resources were technically ideal for utility-scale generation development, defined and located environmentally sensitive areas and those that would be excluded by statute or law from consideration for generation facilities.

ARRTIS created a four-tier system to characterize the environmental sensitivity of land areas within the state: low; moderate; high; and excluded. The ARRTIS took a position that (1) Exclusion Areas would be the only areas in the state that should be considered precluded for

44. Ibid, page 9.

utility-scale generation, and (2) no assumption of any specific renewable generation project's viability should be made based on its location.

The analysis found that approximately half of Arizona's land area could be appropriate for utility-scale generation. The further application of ARRTIS-defined sensitivity criteria allowed the RTTF to more strategically define the state's potential transmission network to support renewables. The RTTF used the information provided by the ARRTIS to identify transmission options that would link the resource areas to the existing transmission system and/or to load pockets within the state or to export markets.

3.1.2 The RTTF Finance Subcommittee

The RTTF also established a Finance Subcommittee to develop a methodology for identifying, planning, and facilitating renewable transmission projects ("RTP") development in Arizona, including methods for providing utilities with a means to effectively finance and construct RTPs.

The RTTF assigned the Finance Subcommittee the tasks of investigating and recommending financing methodologies for RTPs in Arizona. The findings and recommendations of the Subcommittee were to be submitted to the RTTF and the jurisdictional utilities subject to the fifth BTA Decision. In coordination with the RTTF subcommittee, and the ARRTIS, the Finance Subcommittee also supported the utilities responsible for the Workshops as directed by the ACC. This information was intended for the utilities' consideration as part of their response to an ACC decision requiring the utilities to identify and develop plans for the top three renewable transmission projects, submit a report by 31 October 2009, and have this report discussed in the Commission's next BTA.[45]

As part of this process the Renewable Transmission Action Plan ("RTAP") was proposed that could be used as part of the BTA process. The RTAP was conceived as a procedure for the Commission to review and approve a utility's identified RTAP within or in parallel with the BTA process.[46]

45. ACC Decision No. 70635, issued on December 11, 2008.

46. APS is the only utility that filed an RTAP with the Commission, pursuant to a separate proceeding (Docket No. E-01345A-10-0033).

In addition, a memorandum of proposed findings was proposed related to renewable transmission projects.[47] The intent was that the utilities consider using the memorandum as part of their response to the 5th BTA Decision. The ACC could then choose to include the proposed findings from the memorandum in future orders. The participants in the RTTF process generally agreed to accept the memorandum and RTAP as the recommended method for identifying action plans and financing for the RTPs in Arizona. Utility responses that were filed in October 2009 defined the first set of RTPs.

The memorandum recommended that:

- Each jurisdictional utility will file[48] an RTAP, concurrent with the filing of its ten-year plan;
- Jurisdictional utilities' RTAPs may include RTPs with ownership participation involving non-jurisdictional parties (i.e., merchants, independents, etc.); and
- The RTAP should:
    - Identify the RTPs that provide access to areas within Arizona that have renewable energy resources or facilities that enable renewable resources to be delivered to load centers;
    - Describe how each RTP is expected to advance renewable resource deployment;
    - Present the development approach and schedule for the proposed RTPs;
    - Estimate the expected costs of the RTPs, including the range of bill impacts for retail customers for each project;
    - Discuss cost recovery, including any special regulatory treatment that will be sought; and
    - Report the status of RTPs identified in the previous RTAP.

3.1.3 ARRTIS Findings

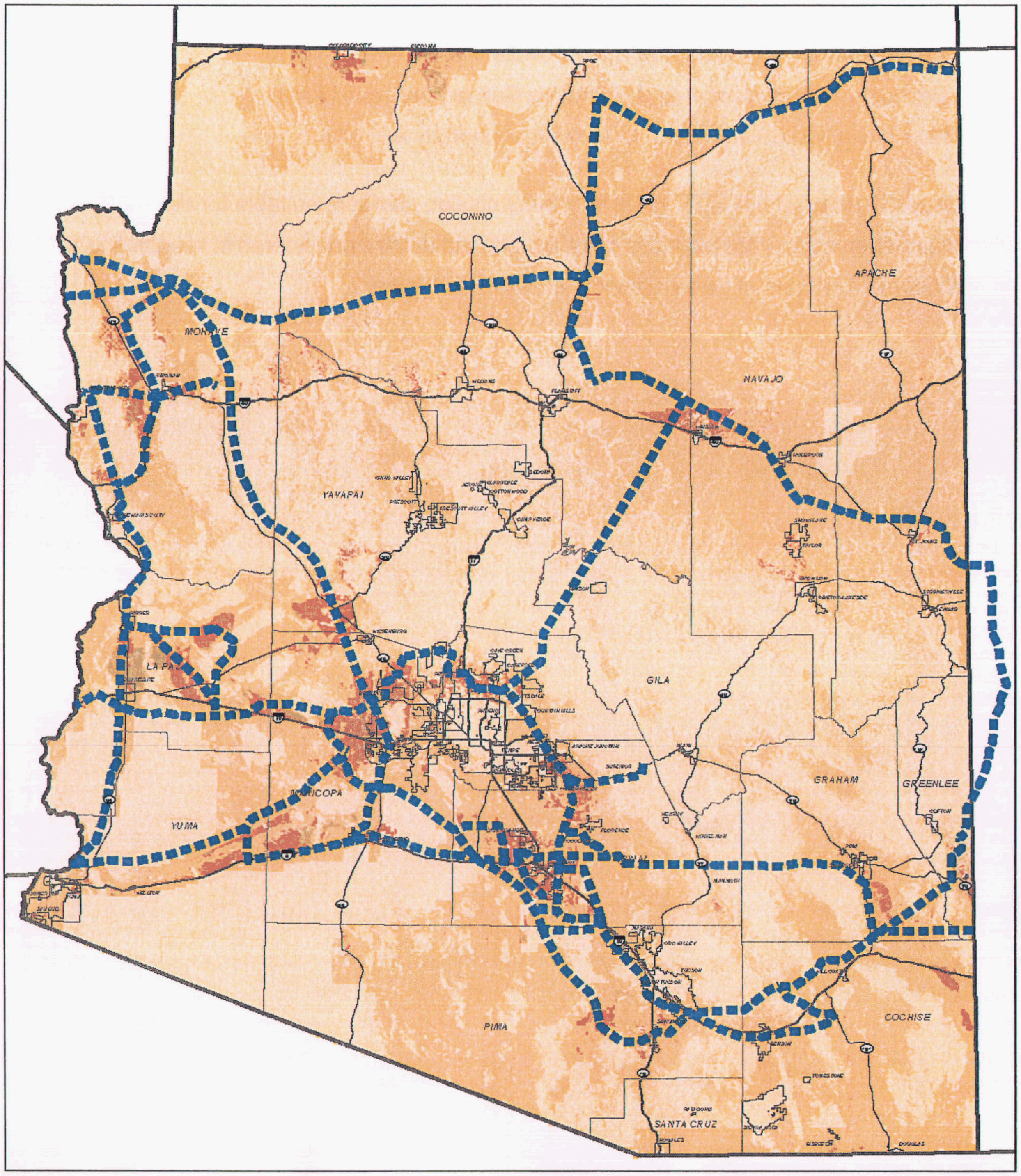
Five maps were developed as part of the ARRTIS process:

47. See *Final Report on the Activities of the Finance Subcommittee*, Renewable Energy Transmission Task Force, Southwest Area Transmission Planning Group, October 5, 2009, page 12.
48. The Subcommittee did not make any specific recommendations regarding the procedural mechanisms for filing the RTPs and RTAPs.

- Arizona Solar Resources
- Arizona Wind Resources
- Environmental Exclusion and Resource Sensitivity Areas (Solar)
- Environmental Exclusion and Resource Sensitivity Areas (Wind)
- Non-Exclusion Solar Resource Areas Identified by ARRTIS

These maps were used by RTTF to identify transmission corridors suitable for delivering renewable generation. These corridors are options the utilities considered in responding to the 5th BTA Order. The map of these corridors is shown in Figure 2.

Figure 2: Transmission Corridors for Renewable Generation Identified by ARRTIS



3.2 Utility RTP Filings

Each of the jurisdictional utilities filed responses by 31 October 2009. It is interesting to note that many of the corridors identified by ARRTIS as shown in Figure 2 are compatible with projects in the utilities' previous transmission plans.

3.2.1 Arizona Public Service

In determining its top RTPs APS considered the input from the two workshops, the ARRTIS' work, the Finance Subcommittee's work, and the RTTF's work. They assessed the comparative economic value of viable renewable resource and transmission line combinations. In addition to the economic analysis, APS conducted a qualitative analysis that included:

- Potential to support multiple renewable energy markets,
- Likelihood of attracting participants to the project,
- Expected permitting sensitivity (resource and transmission),
- Interconnection queue robustness,
- Expected near-term utilization,
- Potential to bring benefits beyond renewable integration.

Based upon its analysis, APS identified the RTPs that it believes were best suited to support the growth of renewable resources in Arizona while considering the costs and benefits to APS customers.

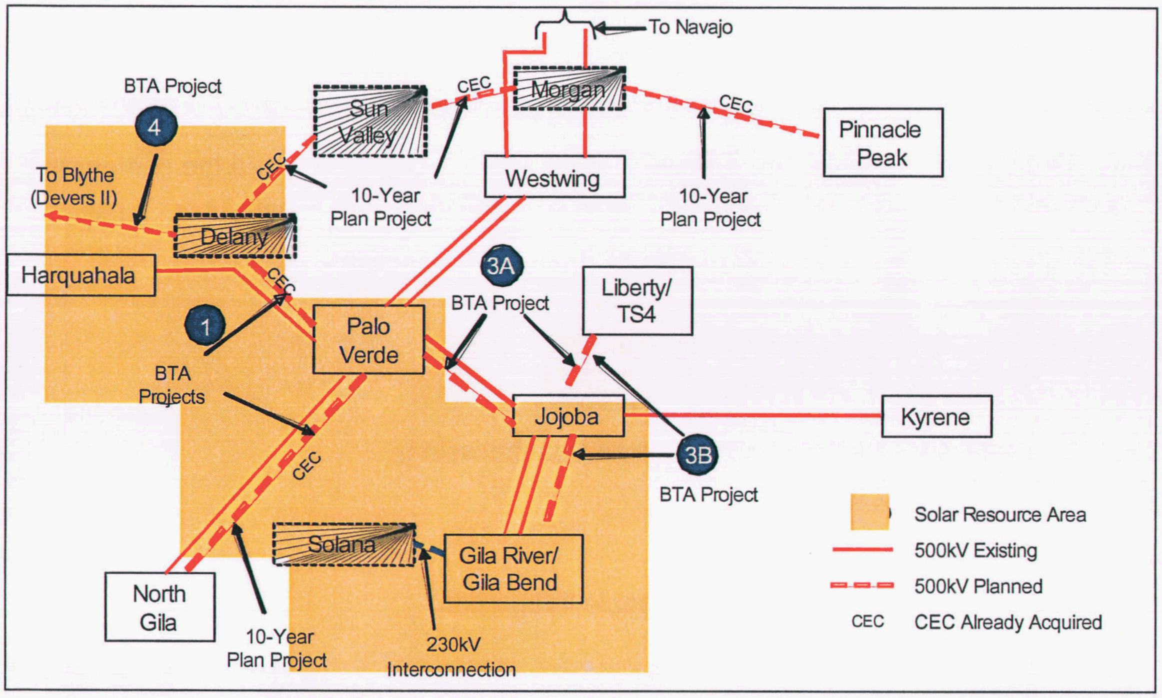
APS identified four RTP projects:

1. Delany to Palo Verde 500 kV;
2. Palo Verde to North Gila 500 kV #2;
3. a) Palo Verde to Liberty 500 kV,

   b) Gila Bend to Liberty 500 kV;
4. Delany to Blythe (e.g., SCE's proposed Colorado River 500 kV Substation)

A fourth project was included because APS believes it would significantly support development of renewable resources in Arizona for exports to California and to deliver solar resources to Arizona utilities at the Delany switchyard. These four projects are shown in Figure 3.

Figure 3: APS' identified RTP Projects



3.2.1.1 Delany to Palo Verde 500 kV

This project is a 500 kV transmission line from the Palo Verde hub to a new Delany switchyard, about 18 miles west of the Palo Verde hub. The new switchyard would be located along a 500kV loop that will eventually run from Palo Verde around the west and then north side of the Valley to the Pinnacle Peak substation.

The Delany area has excellent solar conditions, and there are interconnection requests for several thousand MW of renewable generation in the Delany area—a clear indicator that there is a robust interest in renewable resource development. This project also provides access to the Palo Verde hub allowing exports of renewable energy.

3.2.1.2 Palo Verde to North Gila 500 kV #2

This project is a potential 500 kV transmission line from the Palo Verde hub area to the North Gila Substation, located outside of Yuma. It is approximately 114 miles in length and would parallel an existing jointly owned 500 kV line. This project also provides access to the Palo Verde hub allowing exports of renewable energy.

The area has excellent solar conditions and there are interconnection requests to the area adjacent to this line indicating a robust interest in this renewable resource area. This line would also provide additional transmission to the Yuma load pocket, increasing load-serving capability in Yuma, and providing additional resource flexibility to serve both the Valley and Yuma load pockets.

Due to the magnitude of project costs, this project is conceived as a participant transmission project. SRP, the Imperial Irrigation District, and the Welton-Mohawk Irrigation and Drainage District are the other current participants, each holding a 20% share of the project. In addition, the Western Area Power Administration has expressed an interest in participating in the project. WAPA involvement would provide the potential for federal government funding for WAPA transmission expansions that foster renewable energy.

3.2.1.3 Palo Verde to Liberty and Gila Bend to Liberty 500 kV

This two-part conceptual transmission project includes a 500 kV transmission line from the Palo Verde hub to a new substation near the existing Liberty substation in the West Valley and a 500kV transmission line from the Gila Bend/Gila River area to a new substation near the existing Liberty substation.

The area around the Palo Verde hub and the Gila Bend area have excellent solar conditions, which could result in the development of significant solar generation facilities. APS believes that developing these projects would mitigate inconsistency between the periods required to construct transmission lines and renewable resource facilities—where transmission infrastructure takes longer to build than renewable resource facilities.

3.2.1.4 Delany to Blythe

This project was originally proposed by Southern California Edison. APS supports development of this transmission line because it could influence additional solar resource development in Arizona given the potential for additional export capability to California.

3.2.1.5 APS Cost Analysis

APS worked with the other utilities and interested stakeholders to develop plans to identify the best three RTPs. APS used the methodology developed by the Finance Subcommittee for identifying RTPs. APS selected the RTPs considering the costs and benefits to APS customers. APS established a plan to develop the project, proposed funding mechanisms, provided background explaining the value of the project in supporting renewable energy development in Arizona, and described potential rate impacts to APS's customers for the projects selected.

APS used the National Renewable Energy Laboratory's Western Wind Resource Dataset to estimate annual capacity factors of the four potential wind sites. Likewise, the Department of Energy's Solar Advisory Model was used to model concentrating solar power and solar photovoltaic plants at the twelve potential solar sites. Transmission costs were estimated using the capital costs for 500 kV transmission lines used in the Western Governors Association Western Renewable Energy Zone process, model, and report.

3.2.2 SRP

In selecting its top three RTP projects, SRP considered these factors:

- Closeness to renewable resources
- Permitting issues
- Ability to provide access to renewable resources and to serve multiple purposes
- Access to multiple resources, resource dense areas or energy hubs
- Relative cost and schedule
- Proximity to SRP's service territory
- Integration into local transmission & generation system
- Ability to align partnerships
- Likelihood of meeting permitting requirements
- Enhancing system reliability

The three projects identified by SRP, as shown in Figure 4, were:

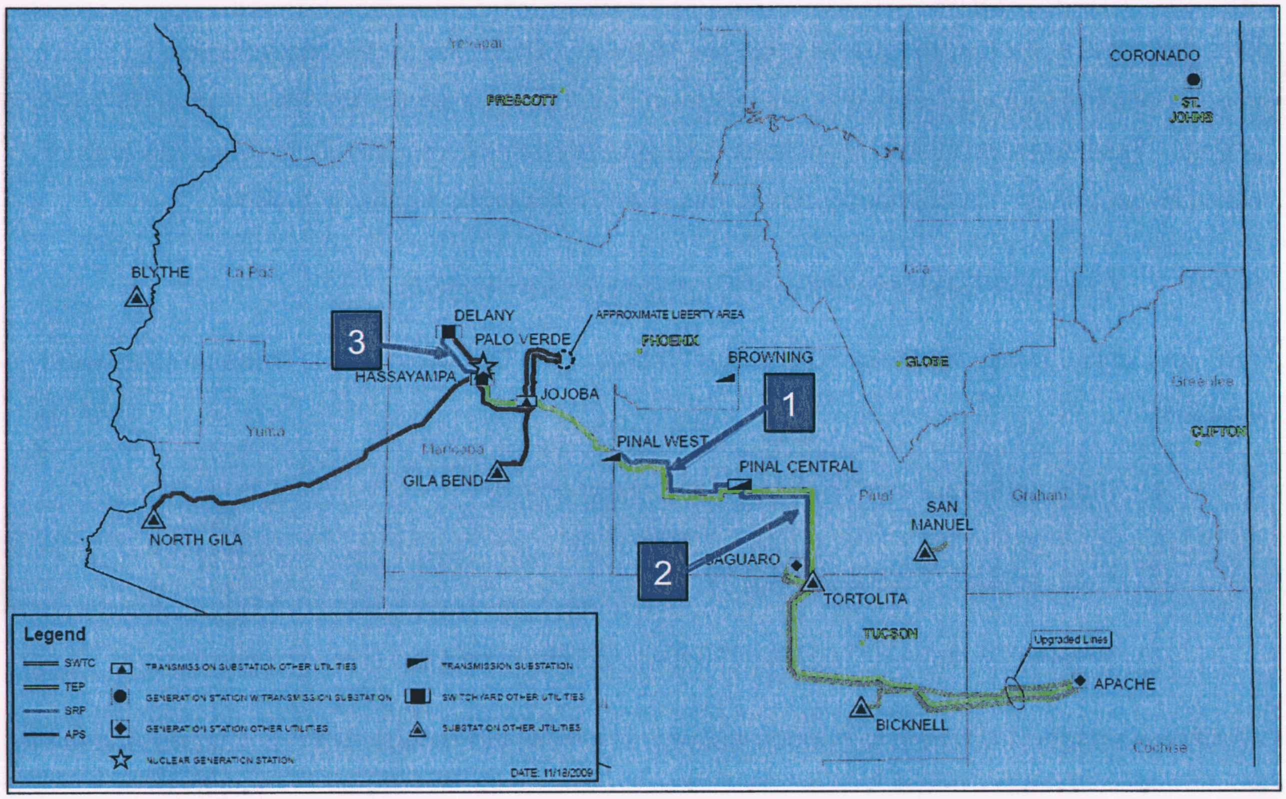
1) Pinal West – Pinal Central 500 kV

2) Pinal Central – Tortolita 500 kV

3) Delany – Palo Verde 500 kV

It should be noted that SRP's RTP #3 is the same as APS's RTP #1 (i.e., a joint participation project).

Figure 4: APS, SWTC, SRP and TEP Identified RTP Projects



3.2.2.1 Pinal West – Pinal Central 500 kV

This project is a 50-mile line that is an integral piece of the Hassayampa to Pinal West to Pinal Central to Browning project. Today there are 11 interconnection requests to that line—all solar—for 3,500 MW. The line adds a critical link from the SRP Southeast Valley to Palo Verde.

It also provides another parallel path from the Palo Verde area into the Valley, and gives access for Pinal County resources to Palo Verde.

3.2.2.2 Pinal Central to Tortolita 500 kV

SRP advised at Workshop 1 that there are about 500 MW of renewable transmission projects in the queue between Pinal Central and Tortolita. In addition to providing a means to integrate these projects, the addition of Pinal Central to Tortolita would help to support delivery of new renewable resources from western Arizona to load centers further east such as Pinal County and Tucson. The project is being proposed jointly with TEP.

3.2.2.3 Delany to Palo Verde

This project is a short transmission project—18 miles. There are seven requests for interconnection totaling 3,300 MW—all solar--in the area. It is part of the Palo Verde-TS-5 APS project. The proposed Delany Substation site is located in the very rich solar resource area of Harquahala Valley. As previously noted, this is a jointly-owned project with APS.

3.2.3 Tucson Electric Power Company and UNSE

TEP and UNSE jointly filed their RTP project report in the Docket in 2009. Three projects were selected:

1) Palo Verde to Pinal West to Pinal Central 500 kV
2) Pinal Central to Tortolita 500 kV
3) Western Apache to Tortolita 115 kV to 230 kV Line Upgrade

All of these projects will help to support delivery of renewable resources from western Arizona to load centers in southeastern Arizona, including Tucson. The Pinal West to Pinal Central and Pinal Central to Tortolita projects were also proposed by SRP, as discussed above (they are joint ownership projects). Only the third project is unique to TEP and is discussed in more detail below.

3.2.3.1 Western Apache to Tortolita 115 kV to 230 kV Upgrade

The third project is an upgrade of the existing 115 kV system that has been in service for many years. The project is shown in green in the bottom right of Figure 4, above. Originally it was to deliver power to preference customers from hydro units delivered over the 115 kV lines. Over the years the rest of the system and local load has grown up around these facilities.

TEP observes that efforts to move renewable resources across the existing 115 kV system will experience congestion due to single-contingency criteria. The upgrade of the selected line to 230 kV will remove those legacy limitations and facilitate renewable development. This third project would also interconnect with the radial lines reaching down into southeast Arizona and provide opportunities for renewables to connect to the system and be delivered throughout the state.

3.2.4 SWTC

SWTC selected its top three RTPs by recognizing that the upgrades that will support renewable resource development in southeastern Arizona are the same as those needed to meet NERC reliability standards and to support continued growth in the area. SWTC will contact developers as they announce intentions to build renewable resource projects in Southeast Arizona.

SWTC has worked with other utilities since the Order was issued in developing its top three RTPs. The selected projects are:

1) San Manuel Interconnect Project—involves interconnecting the SWTC Apache to Hayden 115 kV line into the APS San Manuel Substation;

2) Apache to Bicknell 230 kV Line Upgrades (see Figure 4) —involves upgrading the existing 795 ACSR conductor of this 230 kV line to a higher-ampacity rated conductor, to meet NERC Reliability Standards and support continued growth in the area; and

3) Western Saguaro to Apache 115 kV Line Upgrade—would provide additional transmission transfer capability of up to 1,000 MW that could be used for renewable generation in the area and could increase Western's customer's access to potential renewable areas identified by the RTTF.

A more detailed drawing showing these three projects is provided in Exhibit 34. The EHV 345 kV system (shown in green in Exhibit 34) is owned by TEP. SWTC's system is shown in yellow (230 kV) and purple (115 kV). The 230 kV facilities are a back-bone system extending from Greenlee to Bicknell. The 115 kV facilities extend from Bicknell to Marana Tap. SWTC also owns a 115 kV system extending from Apache to the SRP Hayden Substation. Both TEP and SWTC are part owners of the Southeast Valley 500 kV line (shown in red) which extends from the Palo Verde Hassayampa Switchyard to Pinal West and are also part owners of the portion proposed for extension from Pinal West to Pinal Central in 2013. Various facilities owned by APS and SRP are also shown.

There is only one renewable resource project that is currently in the active generator queue listing located near San Manuel, Arizona. Other projects have been in previous queue listings, but have been withdrawn for various reasons.

3.3 Related ACC Staff Observations and Conclusions

The proposed RTPs described above represent the first utility filings in response to the 5th BTA request for an analysis of the impact of renewables on transmission plans. On the whole the filings are responsive to the Commission's request. An inclusive stakeholder process was also developed and executed to identify the initial set of transmission RTPs. Most of the proposed RTPs are not entirely new proposals, but actually represent advancement of projects that have already been in planning for reasons other than renewable integration.

3.3.1 Effectiveness of RTP Projects Selected by the Utilities

As already noted many of the projects identified by the utilities are found in previous transmission plans of the utilities to meet various needs, including reliability, market access and renewable resource procurement plans. Since the majority of conceptual transmission corridors identified in the ARRTIS report were generally along existing and planned corridors, this initial set of RTPs should not be a surprise. They appear to be a reasonable set of initial renewable development projects that will facilitate renewable resource development in the southern half of the state, close to either the Phoenix or Tucson load regions or the resource rich Palo Verde hub region.

We conclude that the projects selected should be effective in enabling development and delivery of renewable resources to the load centers of the Arizona utilities or the Palo Verde hub.

3.3.2 Impact of RTP Projects on the Arizona Transmission System

Because many of the selected RTPs have been identified in earlier transmission plans, they should contribute to reinforcing the transmission system for general use in addition to facilitating the integration of renewable generation.

3.3.3 Impact of RTP Projects on Development of Renewable Resources

The identified projects should be effective in enabling delivery of renewable resources developed close to either the Phoenix-Tucson regions or the Palo Verde hub. As projects are developed farther from these areas, transmission facilities that were not proposed in earlier 10-year plans will likely need to be developed.

The RTP projects and the queued renewable generation in the areas the RTPs serve are shown in Table 7.

Table 7: RTP Projects and Queued Renewable Resources

RTP	RTP sponsor(s)	Estimated transfer capability (MW)[49]	Queued renewables in area served by RTP as of May 2010 (MW)
Delany – Palo Verde	APS, SRP	1,000	3,300[50]
Palo Verde – Pinal West 500kV	TEP	1,000	n/a[51]
Pinal West – Pinal Central 500kV	SRP, TEP	1,000	3,500
North Gila – Hassayampa 500kV #2	APS, SRP	1,000	4,468[52]
Pinal Central – Tortolita 500kV	SRP, TEP	1,000	500
Delany – Blythe 500kV	APS, SRP	1,000	n/a[53]
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**

[49] Actual value to be determined through future path rating studies.

[50] 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.

[51] 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.)

[52] Value quoted by APS in response to Data Request 1 in Docket E-01345A-10-0033.

[53] Same queue as Delany-PV.

3.3.4 Staff Comments on Questions raised by the RTTF Financing Subcommittee

1. ***Is the BTA the best forum for determining cost-recovery status of rate-based assets since there is no filing in a BTA?***

   The BTA and RTAP processes should not be used for cost-recovery or rate-base decisions by the Commission. The goal should be to identify transmission projects for Arizona, describe their justifications, to present a ranking or priority to the projects, and to inform the Commission of changes in the transmission plans from year-to-year.

   The RTAP and renewable needs analyses should also be largely for informational purposes. The Commission is seeking a better understanding as to how expanded renewable generation development would affect transmission plans. The economic analysis is also intended to establish a technical, procedural, and economic means for the utilities to identify, prioritize and incorporate changes to transmission plans that should be made due to potential renewable generation expansion.

2. ***Should RTPs be submitted annually (i.e. included in the 10-year plans) or biennially (i.e. as part of the BTA and 10-year plans)?***

   In the long run the RTAP should be developed and submitted biennially with the BTA. However, if the pace of renewable generation development warrants, then annual filings may be required.

3. ***How are legitimate RTPs that arise unannounced to be afforded RTAP treatment by the Commission?***

   The RTAP process should identify the top three RTPs, but as was done this year, additional projects can also be identified for informational purposes. The Commission would then have an expectation as to what transmission projects might be needed to support other renewable projects. In any case, the Commission would be open to applications for "unexpected" renewable resource developments that might require an *ad hoc* RTAP.

4. ***Do the Commission and Staff require further guidelines to assist with differentiation of a candidate RTP and transmission project proposed in the ordinary course of business?***

   The emphasis here should be on identifying projects that need priority handling/processing outside the ordinary course of business and that can be justified specifically to support renewable generation projects.

5. ***Do the Commission and Staff have the tools to make allocation decisions that might be required under '4.' above?***

   We believe the Commission and Staff have the capability, but will monitor their needs as the overall RTP/RTAP process evolves in the future.

3.3.5 Impact of RTP Implementation on REST Requirements

The Renewable Energy Standard and Tariff R14-2-1801 ("REST") became effective August 14, 2007, following approval by the Commission. Among other things, the REST rules require jurisdictional utilities to generate or purchase at least 15% of their total annual retail energy requirements from eligible renewable energy resources by 2025, with smaller amounts required in earlier years.the calendar year 2009, the Commission established a requirement of 2.0 percent of a utility's 2009 total retail kWh sales, with 15 percent of that requirement to be satisfied through energy received from distributed energy ("DE") resources. The REST requirements for the 2008-2025 periods are shown in Table 8.

Table 8: REST requirements 2008-2025

Year	REST goals	Year	REST goals
2008	1.75% (10% DE)	2017	7.00% (30% DE)
2009	2.00% (15% DE)	2018	8.00% (30% DE)
2010	2.50% (20% DE)	2019	9.00% (30% DE)
2011	3.00% (25% DE)	2020	10.00% (30% DE)
2012	3.50% (30% DE)	2021	11.00% (30% DE)
2013	4.00% (30% DE)	2022	12.00% (30% DE)
2014	4.50% (30% DE)	2023	13.00% (30% DE)
2015	5.00% (30% DE)	2024	14.00% (30% DE)
2016	6.00% (30% DE)	2025	15.00% (30% DE)

In general, the utilities have met or exceeded the overall REST goals—total renewable energy of 2.00% from renewables. The goal for DE to have been 15% of the total has generally not been met, though each of the utilities reports a surge in new DE added in 2009.

The REST requirements are likely to affect the transmission plans of Arizona utilities in two general ways—first, utility-scale renewable generation will likely require at least some transmission improvements that are different from those that would otherwise be needed; and, second, the DE component will, in effect, reduce the load on the distribution and transmission systems.

- The information in the utility REST reports can be used to make a comparison of the scale of the REST goals with the delivery capability of the transmission projects proposed in the Arizona utilities' 2009 RTAP filings. The 15% energy requirement by 2025 could require total renewable generating capacity equal to 24-41% of the system peak load. This assumes an annual capacity factor for all renewable sources to be 25-35% and a system load factor of 55%. So 10,000 MW peak load would be 48,180,000 MWh/year. A 15% renewable requirement would be 7,226,000 MWh annually or an average of 825 MW. If total renewable generation had an annual capacity factor or 20% (the low end of a reasonable range) then 4,125 MW of renewables would be needed to supply the 7,226,000 MWh of annual energy. If renewables have an annual capacity factor of 35% (the high end of a reasonable range) then only 2,357 MW of renewables would be required.

- The utility-scale renewable generation requirement could range from 17% to 29% (i.e., 70% of the total installed renewable capacity) of the system peak load. This is a significant amount of utility-scale generation and would require transmission reinforcement of some consequence. The amount of renewable generation today is still relatively low and so has not had a significant impact on transmission plans.

4. Other Commission Ordered Studies

4.1 History and Purpose

In addition to the assessment of transmission needs for renewable resource integration discussed in Section 3 above, over the years the Commission has ordered that certain other supplemental study work be performed by Arizona utilities to broaden and facilitate biennial assessments. Study work previously ordered by the Commission falls into three categories.

- The transmission load serving capability of specified local load pockets has been a study requirement since the First BTA.
- Reliability must run ("RMR") studies have been required for selected constrained transmission import areas with local generation since the Second BTA.
- N-1-1 and Extreme Contingency studies have been required to ascertain the transmission system's robustness to withstand more severe emergency scenarios since the Third BTA.

Such studies have a twofold purpose. First, the ordered studies are intended to improve the thoroughness and accuracy of the conclusions and recommendations resulting from the BTA. Second, the ordered studies are intended to better inform the Commission about areas of the transmission system that potentially need improvement, and identify if additional Commission focus on such areas is prudent. These three categories of results in the 6th BTA are discussed in more detail below.

4.2 Local Area Transmission Load Serving Capability Assessment

In the First BTA, Staff identified three load pockets in Arizona that should be monitored for transmission import constraints and reliability must-run ("RMR") generation requirements: Phoenix, Tucson and Yuma. The Second BTA added a fourth area located in Southeastern Arizona (Santa Cruz County). Subsequent BTAs added Mohave County. Updated RMR studies were filed for these five areas in the 6th BTA. Prior BTAs have also looked at import constraints in Pinal County, which have been analyzed through the SWAT CATS-HV Study. This study looks at import constraints, but not RMR requirements, per se. In addition, although the Commission did not order an RMR study for Cochise County, it directed in Decision No. 70635 that studies be filed for both Cochise County and Santa Cruz County addressing "continuity of service" issues. The transmission import capability for each of these local areas is addressed in this BTA report.

Utility distribution companies have the obligation to assure that adequate import capability is available to meet the load requirements of all distribution customers within their service areas.[54] The Commission has adopted the use of two terms as indicators of the load serving capability of local load pockets in RMR studies: Simultaneous Import Limit ("SIL") and Maximum Load Serving Capability ("MLSC").[55] In addition, the Commission coined the term "continuity of service" in Decision No. 70635, which is discussed further in this 6th BTA report.

In the following paragraphs, non-RMR import and continuity of service assessments are discussed first, followed by specific RMR studies done for this BTA.

4.2.1 Cochise County Import Assessment

The Cochise County load serving entities are APS, TEP, and Sulphur Springs Valley Electric Cooperative ("SSVEC"). The Cochise County load, from Ft. Huachuca to Douglas, is served via four radial transmission lines (115 kV, 138 kV and 230 kV). The loss of any one of these lines would require dropping of some customers until manual restoration procedures can be performed. Utilities serving Cochise County have historically had a "restoration of service"[56] paradigm in their planning and operating procedures for transmission outages. This has been of concern to Staff since the first BTA over a decade ago. The critical nature of Fort Huachuca's mission and the accompanying load growth in southern Cochise County[57] are strong

[54] Arizona Administrative Code R14-2—1609.B

[55] Appendix C, RMR Conditions and Study Methodology

[56] As defined in Appendix F of the Fifth BTA, the restoration of service paradigm relies on manual, operator initiated actions to restore load following most N-1 transmission contingencies. However, TEP does have an automatic scheme in place to restore 18 MW of load for loss of Vail-Ft. Huachuca 138kV.

[57] At the time of the CCSG report Cochise County load was forecast to grow by 13% from 2013 to 2018, but the impact of current economic conditions on this forecast is unknown.

justifications for transition to a "continuity of service"[58] planning and operating paradigm for transmission outages.

The 5th BTA Staff Report in 2008 noted that APS, SSVEC and TEP each have an obligation to assure that adequate transmission import capability is available to meet the load requirements of all distribution customers within their service areas.[59] Following the 5th BTA, the Commission determined that perpetuating a "restoration of service" paradigm for single contingency transmission outages in Cochise County is not in the public's interest. Therefore, the Commission ordered that APS, SSVEC and TEP perform studies in order to develop a transmission plan of service that assures "continuity of service" for single contingency transmission outages in Cochise County within five to ten years (e.g. 2013-2018).[60]

In response to the Commission's order, the Cochise County Study Group ("CCSG") of SATS conducted a new technical planning study in 2009. A map of the study area is shown in Exhibit 32. The report from this study was included in SWTC's 6th BTA filing dated January 2010. The summary report on that study filed by SWTC elaborates the following interpretation of "continuity of service" that has been promulgated by the Commission:

> "The CCSG agreed that a definition for continuity of service is that loss of any single transmission facility will not result in loss of load that requires subsequent System Operator intervention, either directly or through Energy Management System (action), to restore service. Specifying without Operator intervention reduces outage time to be within the timeframe that automated schemes typically operate (e.g. seconds to minutes). Implementing existing manual operational procedures could help restore at least partial power to the affected areas but this does not meet the continuity of service principle as defined by the ACC. The CCSG clarification offers significant improvement over historically experienced "restoration of service" by limiting potential interruptions to seconds or minutes versus historical outages lasting hours or days."

The CCSG 2009 study group primarily consisted of transmission planning staff from SSVEC, SWTC, TEP, Western, APS and Fort Huachuca. The study was performed using WECC

[58] Pursuant to Arizona Administrative Code R14-2-208(D) (1), "Each utility shall make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur."

[59] Arizona Administrative Code R14-2—1609.B

[60] Reference 5th Biennial Transmission Assessment (E-00000D-07-0376) (Section 5.1.3, pages 65-67); and Decision No. 70635 (5.d, page 3)

approved 2013 and 2018 system models and was completed in November 2009. The summary report filed by SWTC states:

"After a thorough technical analysis of the different potential transmission and/or generation alternatives proposed for resolving the continuity of service issue in the Cochise County, it became apparent that a combination of two or more initial alternatives would be needed to fully resolve the issue. The recommended transmission plan was tested and found to be technically capable of meeting the NERC Reliability Standards and the WECC System Performance Criteria as well as complying with the ACC Order 70635 to provide for continuity of service in Cochise County in both 2013 (or by a 308MW load level) and 2018 (or by a 348MW load level). The recommended transmission plan is detailed below:

- New Palominas - Hereford 69 kV line
- Proposed 50 MVA, 115/69 kV transformer at Boothill
- Loop Webb - Tombstone 69 kV line through Boothill
- Proposed Fort Huachuca 138 kV - Buffalo Soldier 69 kV tie (needed in 2018)
- Operate the following normally open circuits as normally closed circuits:
  - Charleston - Bella Vista 69 kV line
  - Keating Junction - Hawes 69 kV line
  - Mc Neal - San Pedro 69 kV line

- Install shunt capacitors at the following substations
  - 13.2 MVAR at Webb 69 kV substation
  - 8 MVAR at Ramsey 69 kV substation
  - 8 MVAR at Hawes 69 kV substation
  - 8 MVAR at Pueblo 69 kV substation
  - 6 MVAR at Webb 69 kV substation (needed in 2018)"

Although capital cost estimates are not provided for this list of projects in the CCSG report, in Staff's opinion based on generic costs, this set of capital expansion projects should turn out to be a reasonable level of expenditure to achieve the "continuity of service" paradigm in Cochise County. CCSG states that it intends to develop detailed cost estimates for these projects in 2010 and to open negotiations for the related contractual arrangements including "cost responsibility, wheeling arrangements, EPC (engineering, procurement, and construction), Operations and Maintenance (O&M), Load Serving agreement, etc." so that these can be completed in time to construct the facilities when needed. The CCSG report does not provide an implementation schedule for the plan of service. Based on feedback received from CCSG participants during the 6th BTA, pending changes in the Cochise County load forecast may allow delaying certain components of the plan of service without jeopardizing Cochise County's continuity of service.

4.2.2 Santa Cruz County Import Assessment

Santa Cruz County, similar to Cochise County, is served by a radial transmission line. UNSE is the load serving entity in Santa Cruz County. The customer service and system impacts and risks associated with the loss of the single transmission line serving Santa Cruz County are well chronicled in prior BTA assessments and siting proceedings of the Gateway 345 kV transmission project.[61] The Gateway Transmission Project was proposed as a solution and a Certificate of Environmental Compatibility was approved by the Commission. A NEPA environmental impact study has been concluded for the project but Federal Records of Decision and a Presidential Permit for the new 345 kV Gateway Transmission Project are still pending with federal agencies.

UNSE analyzed transmission needs in Santa Cruz County in 2009 to develop transmission plans that address the recommendations in the 2008 Biennial Transmission Assessment related to continuity of service. A Santa Cruz County Continuity of Service Summary Report and Reference Filing was made by UNSE in February, 2010.

The UNSE ten-year plan includes the Gateway Project and associated 138 kV line from Gateway to Valencia. UNSE received a CEC in 2009 (Case No. 144, Decision No. 71282) to rebuild and convert the existing 115 kV line between Western's Nogales switchyard and the UNSE Valencia substation to 138 kV. Part of this project includes transferring the point of interconnection of UNSE from Western's Nogales switchyard to a future interconnection in TEP's Vail Substation. However, this project alone will not achieve the continuity of service objective for Santa Cruz County until the 345 kV Gateway Project is completed. At present, Santa Cruz County remains exposed to service outages for all of its UNSE customers following the loss of the single transmission line serving the county. The most recent reported outage occurred on July 16, 2008 and resulted in 63,455 customer hours of service interruption.[62] The ten-year plan also includes a Gateway – Sonoita 138 kV line, which will improve local reliability but is still contingent upon permitting and completion of the Gateway Project.

[61] ACC Docket No. L-00000-01-0111

[62] Records of Arizona Corporation Commission, Outages Forms, Reported by Rick Molina with UNS Electric on July 17, 2008

Also note the discussion of Santa Cruz County RMR requirements in section 4.2.5 below.

4.2.3 Mohave County Import Assessment

As directed in the fifth Biennial Transmission Assessment, UNSE is working with the CRT to address issues in Mohave County. UNSE and Mohave Electric Cooperative ("MEC") are the load serving entities in Mohave County. UNSE still shows the Griffith – North Havasu 230 kV line in its ten-year plan and has an approved Certificate of Environmental Compatibility (CEC) (Case #88). The N. Havasu – Franconia section is built and operating temporarily at 69 kV, but the Franconia – Griffith section is not needed until 2016 or beyond, according to UNSE's 6th BTA filing. UNSE is considering a request for extension of the CEC to 2016 or beyond, pending further review of the results of the Mohave County RMR study. Other UNSE transmission projects in Mohave County are postponed indefinitely due to the economic downtown.

See section 4.2.5 below for discussion of the Mohave County RMR study.

4.2.4 Pinal County Import Assessment

The load serving entities providing electric service in Pinal County are APS, SRP, Electrical District Nos. 2, 3, 4, and 5, and the San Carlos Irrigation District ("SCIP"). These entities, other utilities and stakeholders participated in the Central Arizona Transmission System – High Voltage ("CATS-HV") Study for the area, which was filed in the 6th BTA by SWAT in September 2009. The CATS-HV Study provides a comprehensive analysis of all projects in the ten-year plan period for Pinal County, as well as the underlying 69 kV system, by analyzing the planned 2019 system.

The CATS-HV Study of 2019 addressed base case (NERC Category A) and N-1 (NERC Category B) conditions. It did not address other more severe overlapping contingency events, as was done in prior CATS-HV studies, because the ten-year plan has not changed significantly in the area for this BTA. The study performed power flow analysis, but did not address stability analysis. No overloads were identified within Pinal County in the study. Some 69 kV undervoltages were found for loss of the Coolidge – Valley Farms 115 kV line, but can be corrected by routine shunt capacitor additions during the planning cycle.

It should be noted that the study for 2019 assumed SPPR's "Three-Terminal" transmission plan (Pinal Central to ED5, ED5 to Test Track and ED5 to Marana 230 kV lines). As previously discussed in section 2, SPPR has now deferred plans for two of these line additions indefinitely. The impact of these project deferrals on the results of the CATS-HV study of 2019 is unknown.

4.2.5 Import Assessments Requiring RMR Studies

Five of Arizona's seven load pockets contain local generation with potential RMR conditions. An RMR condition exists when the local load served by a utility distribution company ("UDC"), or group of UDCs, exceeds the SIL of the local transmission system. The Commission has adopted a definition of RMR Conditions and Study Methodology to be utilized for RMR study requirements.[63] It requires that two representative years be studied for each RMR area in the BTA, and that the RMR studies identify the following four RMR metrics by area:

- 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[64] dispatch from RMR generation

A summary of the RMR study results filed in the 6th BTA is provided in Table 9.

[63] Appendix C, RMR Conditions and Study Methodology

[64] Out-of-merit order generation is more expensive than generation in the economic dispatch order

Table 9 - RMR Study Metrics

Area	Year	Peak Load (MW)	SIL (MW)	Import (MW) @ Peak	RMR Gen MW @ Peak	RMR Hours Per Yr	Annual RMR GWh	Annual Cost ($000)
Phoenix	2013	12,129	11,296	11,232	897	45	15	0
	2019	14,621	11,693	12,459	2,162	497	317	0
Tucson	2013	2,592	1,948	2,162	430	697	42	$624
	2019	2,883	2,442	2,853	30	252	15	$261
Yuma	2013	446	312	285	161	950	43	0
	2019	562	473	477	85	171	4	0
Mohave County[65]	2013	826	816[66]	816	10	n/a	n/a	0
	2018	935	889[67]	895	40	n/a	n/a	0
Santa Cruz County[68]	2010	93.5	51	n/a	24	n/a	n/a	n/a
	2013	100	127	100	0	0	0	0
	2018	117	127	117	0	0	0	0

4.2.5.1 Phoenix Metropolitan Area RMR Assessment

The interconnected transmission system serving the metropolitan Phoenix area is owned and operated by APS, SRP and WAPA. Approximately 99% of the Phoenix area electric energy requirements during the course of the year are served by imports of remote resources into the area over the transmission system. However, an RMR condition exists for the Phoenix area because the peak load for the area exceeds the SIL of the existing and planned transmission system serving the area.

The Phoenix area 2010-2019 RMR study performed detailed RMR analysis for 2013 and 2019. The study concludes that RMR requirements for the Phoenix metropolitan area are not significant and advancement of transmission projects to increase import capability is presently

[65] Mohave County RMR generation values quoted are less than the hydro plant output required at summer peak for water release requirements according to USBR
[66] Assumes Black Mesa 230kV bus is not connected to Parker Davis System
[67] Assumes Black Mesa 230kV bus is connected to Parker Davis System via Parker-N.Havasu 230kV
[68] Area peak load includes a 5% demand margin for voltage security analysis

not cost justified. The required metrics are shown in Table 9. Other key RMR study findings for the Phoenix metropolitan area are as follows:

1) Planned Phoenix area transmission and local generation can reliably serve Phoenix area peak load in 2013 and 2019. In addition, the projected local generation reserve margin exceeds the required reserve margin by 2,265 MW in 2013 and 1,000 MW in 2019.[69] This translates into a Loss of Load Probability of much less than one day in ten years.

2) Local generation is not expected to be dispatched out of economic dispatch order in 2013 and 2019.

3) There are no emission impacts due to RMR generation energy production in 2013 and 2019 because the local units are not dispatched out of economic dispatch order.

4) Phoenix area RMR conditions pose no impact to local generation capacity factor and total yearly natural gas consumption by the Phoenix area generators because the local units are already scheduled in economic dispatch order irrespective of the SIL being exceeded.

The Phoenix area RMR study is thorough and well documented. The study comports to the Commission's RMR study methodology and actually performs production cost simulations using industry accepted study tools and publicly available data. No flaws in assumptions or modeling are evident in the report.

4.2.5.2 Tucson Area RMR Assessment

The Tucson area is interconnected to the EHV transmission system via three substations: Tortolita 500/138 kV, South 345/138 kV and Vail 345/138 kV. These three stations interconnect and supply energy to the local TEP service area. An RMR condition exists for the Tucson area because the local TEP load exceeds the SIL of the existing and planned local TEP transmission system.

[69] The RMR area reserve requirement is based on a Loss of Load Probability (LOLP) criteria of one day in ten years (i.e., some unserved load is permitted 1 day in each 10 years).

As shown in Table 9, the Tucson area peak load forecast for 2013 and 2019 both exceed the reported SIL for the respective years. Therefore, an RMR condition will exist. TEP filed an amended Tucson area RMR Study report in February 2010 that contains the information necessary for Staff to complete its assessment of RMR needs. Staff has reviewed the amended report and finds the RMR study to be complete and a thorough representation of RMR conditions that exist in the Tucson area.

In the absence of RMR generation, the Tucson area is subject to voltage collapse and cascading overloads during transmission contingencies. TEP developed an estimate of the capital expenditures necessary to mitigate these reliability issues absent RMR generation. They concluded that $156.5 - $197.6 million in upgrades would be required in 2013, and $1.5 - $3.4 million would be required in 2019. Given the magnitude of the RMR costs as shown in Table 9 for 2013 and 2019, TEP concludes that the incremental capital expenditures are not justified. Staff concurs with this conclusion.

The Tucson area RMR study is thorough and well documented. The study comports to the Commission's RMR study methodology and the results of production cost simulations. Assumptions and modeling evident in the report are accurate and appropriate for the TEP system.

In addition, the study makes the following conclusions regarding operation of the Tucson area under 2010 peak load conditions, which were studied per Commission order in the 5th BTA.

- The TEP system can survive N-2 contingencies of parallel lines in the Springerville to Vail corridor at 2010 peak load levels.
- The TEP system can survive loss of all transformers at any given EHV substation 2010 peak load levels.

4.2.5.3 Yuma RMR Conditions and Import Assessment

The Yuma area is served by an internal APS 69 kV sub transmission network containing the entire APS load in the transmission import limited area. There are external ties to WAPA at Gila Substation and the Imperial Irrigation District ("IID") at Yucca Substation. There is also a 500 kV bulk power interface at North Gila with 500 kV lines running east to the Palo Verde Hub and west to Imperial Valley in California.

As part of the ACC Fifth BTA, Per Decision No. 70635, under Section 5.2 Efficacy of Commission Ordered Studies, item IC states: "There needs to be a system perspective of the RMR conditions for the entire Yuma County area in the future rather than limiting the RMR analysis solely to the APS 69 kV system. This is particularly true given that the SIL and MLSC import limits to the APS system are restricted by the overloads on other transmission providers' systems. This is underscored by the fact that major system changes are being proposed for that area by other interconnected entities such as WAPA, WMIID, IID and parties in the area seeking to connect under Large Generator Interconnection Agreement(s) ("LGIA") Yuma, Mohave County and Santa Cruz County."

For the 2010 RMR study effort, APS formed an open forum under the guidance of the Colorado River Transmission (CRT) sub-regional study group of SWAT and held several meetings to discuss the need to incorporate the plans of all entities in Yuma County. As a result of this stakeholder process WAPA, IID, WMIDD have all agreed that the cut plane for the Yuma RMR study should remain as previously defined.

The APS Yuma area 2010 RMR study concludes that RMR conditions do exist for the Yuma area and that there is some limited amount of RMR costs in 2011. The planned APS transmission improvements in the area are sufficient to mitigate RMR cost that would otherwise be associated with 2016 RMR conditions. APS reported that advancement of planned transmission projects to increase import capability in earlier years is not warranted. The following other key RMR study findings were reported for the APS Yuma area:

1) Planned Yuma area transmission and local generation can reliably serve area peak load in 2013 and 2019. In addition, the projected local generation reserve margin exceeds the required reserve margin by 152 MW in 2013 and 228 MW in 2019. This translates into a Loss of Load Probability of much less than one day in ten years.

2) The Yuma area load is expected to exceed the available transmission import capability for 950 hours in 2013 and 171 hours in 2019. The import constraint could cause APS Yuma generation to be dispatched out of economic dispatch order for 22 hours in 2013 and zero hours in 2019.

3) The estimated annual economic cost of Yuma area generation required to run out of economic dispatch order is negligible for 2013 and 2019.

4) Removing the transmission constraint would reduce total Yuma area air emissions by a minimal amount for 2013 and 2019.

5) Removing the transmission constraint could reduce total yearly natural gas consumption by 0.006 BCF for 2013 and has no impact on 2019.

The APS Yuma area RMR study is thorough and well documented. The study comports to the Commission's RMR study methodology and actually performs production cost simulations using industry accepted study tools and publicly available data. Assumptions and modeling evident in the report are accurate and appropriate for the APS system, and reflect stakeholder concurrence on modeling and cut plane definition as ordered by the Commission in the 5th BTA.

4.2.5.4 Santa Cruz County RMR Assessment

UNSE filed the 2010 RMR study of the Mohave County Study System on March 8, 2010. The existing Santa Cruz UNSE system was explicitly modeled within the 2010, 2013 and 2019 Arizona coordinated heavy summer cases prepared by the Southeast Arizona Transmission Study ("SATS") group. The cases were revised to include detailed representations of TEP's 138 kV system and UNSE 115 kV transmission radial line in Santa Cruz County. The 115 kV to 138 kV conversion is detailed in the 2013 and 2019 cases. Actual power factor data, representing UNS Electric's power factor improvement program, was used to model substation reactive demand in the 2010 study (unity power factor loads were assumed in the 2008 study).

For N-1 contingencies the SIL was calculated to be 51 MW in the 2010 case, prior to upgrade of the Nogales-Valencia line from 115 kV to 138 kV. Since the forecast load exceeds import capability there is an RMR requirement of 24 MW in 2010. The report[70] provides estimates of RMR emissions and RMR costs ($550,000 in 2010).

In 2013 and 2019 the SIL increases to 127 MW due to the line conversion to 138 kV and the improved voltage regulation afforded by the stiffer source served directly from TEP's Extra High

[70] UNSE's updated report on Santa Cruz County RMR analysis, dated Aug. 13, 2010.

Voltage ("EHV") system via a new 345/138 kV transformer, Vail T3, which is assumed to be in-service by 2013. There is no RMR requirement in 2013 or 2019.

4.2.5.5 Mohave County RMR Assessment

UNSE filed the 2010 RMR study of the Mohave County Study System on March 8, 2010.[71] The study was performed for 2013 and 2018 under the oversight of the Colorado River Transmission ("CRT") Study Group. The scope of this study required an assessment of the portion of the WAPA Desert Southwest Region ("DSW") transmission network within Mohave County, Arizona. DSW owns and operates all of the transmission network facilities within the Mohave County Study System.

In the 2008 RMR study, SIL calculations were based on the assumption that certain hydro units were operated in a base load condition. However, in the 2010 study, the SIL was calculated with no generation on line per ACC RMR study guidelines. Another key difference from the 2008 study is the change in the study interface shown in Exhibit 33. The 2008 cut plane passed through the Mead to White Hills, Round Valley to Peacock, and Peacock to Liberty transmission lines. The CRT agreed that the 2010 cut plane more accurately defines the transmission ties that supply the Study System. Thermal overloads outside of the study area were ignored because they were physically removed from the study area cut plane, and it is assumed the respective load serving entities ("LSE') will address such limitations in the supply plans for their own service areas.

Power flow simulations show the Study System is reliable and capable of serving all load within the specified cut plane. The SIL analysis indicates that a relatively small amount of generation may be required in the 2013 and 2018 planning horizon. Hydroelectric generation within the study system must be run regardless to meet minimum river flow requirements. No additional generation is needed to assure system reliability.

[71] Filed on behalf of various parties including Western, APS, Mohave Electric Coop, IID, TEP, et al

4.3 Ten Year Snapshot Study

The CATS EHV workgroup filed a report in September 2009 documenting results of its 2009 "Ten Year Snapshot Study" which looked at the 2019 system. The study is done every other year, and was previously referred to as the "N-1-1 Study". The CATS EHV workgroup included representatives from the following transmission owners: APS, SRP, SWTC, TEP, WAPA and Electrical District 3. The report was compiled by SRP on behalf of the workgroup. It was approved by SWAT in August 2009.

Whereas some of the Arizona transmission owners have filed technical study reports for their respective areas of the system as part of the 6th BTA, the CATS-EHV Ten Year Snapshot Study represents the only comprehensive assessment of 2019 Arizona transmission plans (i.e., the end of the ten-year plan). Furthermore, unlike prior Ten Year Snapshots that focused on the Central Arizona system, for the first time the Ten Year Snapshot Study done in 2009 includes all transmission and generation projects statewide. This makes the report uniquely valuable for assessing the overall adequacy of Arizona transmission plans in 2019.

The Ten Year Snap Shot Study consists of conducting N-0 and N-1 power flow analyses that determine the adequacy of the ten-year plan. In addition, fifteen base case project deferral scenarios (nine APS projects, four SRP projects, one TEP project and the Palo Verde-Devers #2 500 kV line) were analyzed under both N-0 and N-1 conditions to assess the impact of such deferrals on system performance. All Arizona transmission system facilities with design voltages of 115 kV or greater were monitored for compliance with thermal (loading) and voltage criteria for all contingencies tested. The 2009 Ten Year Snapshot Study reached the following major conclusions:

1) The 2019 transmission plan is robust.

2) There were no overloaded transmission system elements in the 2019 base case (e.g., the plan complies with the NERC TPL-001 reliability standard).

3) There were few overloads or voltage issues due to outages (in most cases operating solutions are available to resolve these; in some cases the utilities are still considering mitigation measures).

4) Even with delay or cancellation of any individual transmission project in the 2019 plan, loading levels and voltage deviations were acceptable for contingencies.

5) Delay of multiple projects in the planned 2019 system could have significant impacts on performance.

Additional Staff/KEMA observations regarding the study are as follows:

1) The 2019 base case (model) used for the study was based on the complete list of projects that were planned to be in service at the time of base case development, which took place from January-April 2009. In other words, there may be some differences between the 2009 Snapshot case and the current 2010-2019 plans covered by the maps and exhibits in the 6th BTA. This means that the projects modeled in the 2009 Snapshot Study are a "hybrid" of the 5th BTA and 6th BTA project plans. The impact of this on performance of the 2019 system is unknown, but in SRP's opinion the model is very close to the 6th BTA plan for 2019.

2) The 2009 Snapshot Study assumed a statewide peak demand forecast of 25,340 MW for 2019. This is a 689 MW (2.65%) reduction from the Arizona demand level assumed in the previous 2018 CATS EHV base case, and reflects the impact of the current economic recession. This 2.65% demand reduction is actually much smaller than the demand reduction reported by the Arizona utilities in response to data request(s) during the 6th BTA. Comparing the 2017 forecast from the 5th BTA vs. the 2018 forecast from the 6th BTA shows a drop in demand of 6-7%. This change is a much greater than the 2.65% drop modeled in the 2009 Snapshot Study, which tends to make the Snapshot Study a more "rigorous" test of 2019 system performance. This also helps offset the impact of any projects in the 2009 Snapshot Study model subsequently postponed or deleted in the 6th BTA plans filed in January 2010.

3) The 2009 Ten Year Snapshot Study includes a comprehensive set of "steady-state" analysis, but does not include any "dynamic" stability analysis. Both types of analysis are required by NERC reliability standards.

4.4 Extreme Contingency Study Work

The Commission directed that parties continue to address and document extreme contingency outage studies for Arizona's major generation hubs and major transmission stations, and identify associated risks and consequences, and possible mitigating infrastructure improvements as necessary. The 6th BTA Extreme Contingency Study was conducted by the SWAT Sub-Regional Transmission Planning Group and was filed by APS on May 27, 2010. The study examined steady-state performance (i.e., power flows and voltages) throughout the Arizona and sub-regional system for selected extreme contingencies in the 2011 and 2016 heavy summer system models which reflected the filed ten-year project plans. This analysis generally corresponds to NERC Category C and D events (e.g., NERC Reliability Standards TPL-003 and TPL-004), but did not include an assessment of transient stability performance as specified in the NERC standards.

The EHV common corridor and transformer outages analyzed were chosen based upon exposure to forest fires and other extreme common-mode contingency scenarios, and included the following multiple facility contingencies:

- Cholla-Saguaro and Coronado-Silver King 500 kV lines
- Navajo Westwing 500 kV lines
- Four Corners-Cholla-Pinnacle Peak 345 kV lines
- Glen Canyon-Flagstaff-Pinnacle Peak 345 kV lines
- Loss of all EHV transformer banks at Browning Substation

The details of these study results were provided to the Commission in the report filed by APS, which was provided under a Protective Agreement (due to Critical Electric Infrastructure concerns). Therefore, detailed study results could be made available for presentation to the Commission in closed session, but only a general summary is included in the public BTA report.

In both the 2011 and 2016 extreme contingency analysis, all customer loads can be served (or restored), but some of the contingencies would require generation re-dispatch or a limited amount of local system reconfiguration to alleviate overloads.

5. National and Regional Transmission Issues

5.1 NERC Mandatory Reliability Standards

On July 26, 2006, the NERC was designated as the nation's ERO for the purpose of establishing and overseeing a system of mandatory and enforceable electric system reliability standards. These mandatory reliability standards apply to users, owners and operators of the bulk power system designated by NERC through its compliance registry procedures.

In the spring of 2007, FERC approved NERC's blueprint for the contractual relationship between NERC and eight regional reliability entities. This agreement includes a Compliance Monitoring and Enforcement Program to be used by NERC and regional entities to monitor, assess and enforce compliance with FERC approved mandatory reliability standards. The WECC was authorized as one of the eight regional entities, and a delegation agreement with the WECC was approved by FERC in June 2007. That same month, FERC approved eight proposed regional Reliability Standards for the WECC,[72] in addition to the 83 mandatory NERC reliability Standards.

Over the last three years, NERC has conducted numerous on-site audits and overseen compliance with its mandatory standards. Compliance and violation statistics are compiled monthly and posted on the NERC website (www.nerc.com). According to NERC, "These statistics provide...information regarding new violations that were identified during the current month, as well as updates to previous violations that are making their way through the compliance process." A review of these statistics shows that as of May 2010,[73]

- Total active violations (*i.e. all violations that have not been closed or dismissed*) at both NERC and the Regional Entities totaled almost 2,300.
- Many of these violations are related to NERC standards on critical infrastructure protection (in particular, Standards CIP-002 through CIP-009).

[72] http://www.ferc.gov/EventCalendar/Files/20070608171203-RR07-11-000.pdf

[73] http://www.nerc.com/files/Compliance%20Violations%20Statistics%20-%20May%202010.pdf (Compliance Trending – May 2010)

NERC also identifies the "Top 10 Most Violated Standards" for a rolling 12 month period for NERC as a whole and for each of the 8 regional entities. For WECC, it is interesting to note that:

- All of NERC's top 5 violations are included in WECC's top 6 violations, though not in the same order.
- The top 6 WECC violations include those standards related to:
  - Transmission and Generation Protection Systems (PRC-005)
  - System Restoration Plans (EOP-005)
  - Sabotage Reporting (CIP-001)
  - Normal Operations Planning (TOP-002)
  - Personnel & Training (CIP-004)
  - Systems Security Management (CIP-007)

None of the Top 10 Most Violated Standards for WECC (or NERC as a whole) is related to Transmission Planning (TPL).

5.2 FERC Siting Authority/National Interest Electric Transmission Corridor

As amended by the Energy Policy Act of 2005 ("EPAct 2005"), the Federal Power Act ("FPA"), provides for federal "backstop" siting of certain proposed electric transmission facilities that would be located within a National Interest Electric Transmission Corridor ("NIETC") established by the Department of Energy.[74] On October 2, 2007, DOE issued its National Electric Transmission Congestion Report and order formally designating the Mid-Atlantic and Southwest National Corridors.[75] The Southwest NIETC includes seven counties in Southern California and three counties in western Arizona. These NIETC designations became effective October 5, 2007, and will remain in effect until 2019 unless DOE rescinds, renews, or extends them.

[74] http://www.ferc.gov/industries/electric/indus-act/siting.asp

[75] Federal Register / Vol. 72, No. 193 / Friday, October 5, 2007 / Notices

On April 26, 2010, DOE released its 2009 *National Electric Transmission Congestion Study*, which reexamines transmission congestion in both the Eastern and Western Interconnections. This report notes both progress made and continuing concerns in and around key load centers.[76] Specifically, with regard to the Southwestern region of WECC, the report finds[77]:

- "...(T)he Southern California region remains challenged...Although many promising generation and transmission projects are now in the planning or regulatory approval stages...(s)low development of new generation and transmission facilities could compromise near-term grid reliability in Southern California, despite growing demand response and smart grid capabilities. For these reasons, the Department concludes that Southern California remains congested, and that it should retain its status as a Critical Congestion Area."
- "Based on the progress in addressing congestion issues, the Department no longer identifies the Phoenix-Tucson area as a Congestion Area of Concern." In supporting this statement, the DOE report specifically cites the Department's agreement with the ACC's Fifth Biennial Transmission Assessment that states, "The existing and planned transmission systems serving the Phoenix, Santa Cruz County, Tucson and Yuma areas are adequate and should reliably meet the local energy needs of the respective areas through 2017."

5.3 Regional Transmission Planning – WestConnect

WestConnect is composed of electric utility companies[78] providing transmission services throughout the southwestern United States. Its members work collaboratively to assess stakeholder and market needs and to develop cost-effective enhancements to the western wholesale electricity market. WestConnect is committed to coordinating its work with other regional industry efforts to achieve as much consistency as possible in the Western Interconnection. A WestConnect Steering Committee is charged with the task of overseeing development and implementation of a variety of initiatives for the above stated purpose on

[76] http://www.oe.energy.gov/1371.htm

[77] U.S. Department of Energy, *National Electric Transmission Congestion Study*, December 2009, pp xii-xiii, and page 96.

[78] The membership of WestConnect is available at: http://www.westconnect.com/about_steeringcomm.php

behalf of the WestConnect members.[79] A WestConnect Regional Planning Management Committee reports directly to the Steering Committee. Annually, WestConnect prepares a ten-year integrated regional transmission plan that is derived from the study efforts of its subregional planning groups.

Charles Reinhold of WestConnect presented an overview of their activities and an update on regional transmission planning processes at the 6th BTA Workshop 1 on June 3-4, 2010. A major objective of WestConnect is to address seams issues in appropriate forums through the WECC region. It also has an active work group on large generator interconnection processes.

The process for developing WestConnect's 2010-2019 transmission plan was approved by the Regional Planning Management Committee on April 26, 2010. The plan is expected to reflect about $15 billion in capital infrastructure expansion. Complete maps of the plan will be available on WestConnect's website. This includes 6,255 miles of "planned" lines above 100 kV of which 1,573 miles are in Arizona. It also includes another 4,145 miles of "conceptual" lines of which 830 miles are in Arizona.

5.3.1 SWAT Subregional Planning Group

WestConnect subregional transmission planning is performed by the Southwest Area Transmission Subregional Planning Group ("SWAT"), the Colorado Coordinated Planning Group ("CCPG") and any other subregional transmission planning ("STP") groups that comprise the WestConnect planning area. The goal of SWAT is to promote subregional planning in the Desert Southwest including Arizona. SWAT is comprised of transmission regulators/governmental entities, transmission users, transmission owners, transmission operators and environmental entities. APS, SRP, SWTC, TEP, Western, Tri-State Transmission and Generation Association, IID, El Paso Electric, Nevada Power, and Public Service Company of New Mexico are all transmission providers and SWAT participants.

SWAT subcommittees and study groups have been performing studies in response to Commission ordered study requirements for the BTA for a number of years. The SWAT regional planning group includes seven main subcommittees which are overseen by the SWAT

[79] 2007 WestConnect Planning Report, page 3

Oversight Committee. Separate web pages are provided for each of these subcommittees and the SWAT Oversight Committee on the WestConnect website.[80] SWAT subcommittees' meeting notices, notes, presentations and reports are posted on their respective web pages. As noted throughout this report, SWAT subcommittees contributed in substantive ways to the 6th BTA. The respective subcommittees, and chair-persons, are listed in Table 10

Table 10 - SWAT Subcommittees Contributing to 6th BTA

Oversight Committee – Robert Kondziolka
CRT Subcommittee – Josh Johnston
CATS Subcommittee – Joe Herrera*
CATS-EHV Subcommittee – LeeAnn Torkelson & CATS-HV Subcommittee – Joe Herrera*
(Note – CATS EHV & CATS HV have now consolidated as the CATS Subcommittee)
SATS Subcommittee – Gary Trent
NM Subcommittee – Tom Duane
Short Circuit Working Group – Kevin Salsbury
Renewable Energy Transmission Task Force – Peter Krzykos
Arizona Renewable Resources & Transmission Identification Subcommittee (ARRTIS)** - Amanda Ormond* and Greg Bernosky
Finance Subcommittee** - Tom Wray*
Common Corridor Structure Separation Task Force** – Brian Keel
Transmission Corridor Planning Committee – Greg Bernosky
Eldorado Valley Area Study Group – Chuck Russell
* Non Transmission Provider
** Task Force Work Completed – No Longer Active

In particular in this BTA, the Commission wishes to acknowledge the efforts of Mr. Robert Kondziolka, SWAT Steering Committee Chair who has announced his resignation of the chairmanship due to a new job assignment at SRP. His leadership in SWAT and many contributions to the BTA process over the years are greatly appreciated by the Commission.

The geographic area(s) covered by SWAT and various subcommittees are shown in Figure 5.

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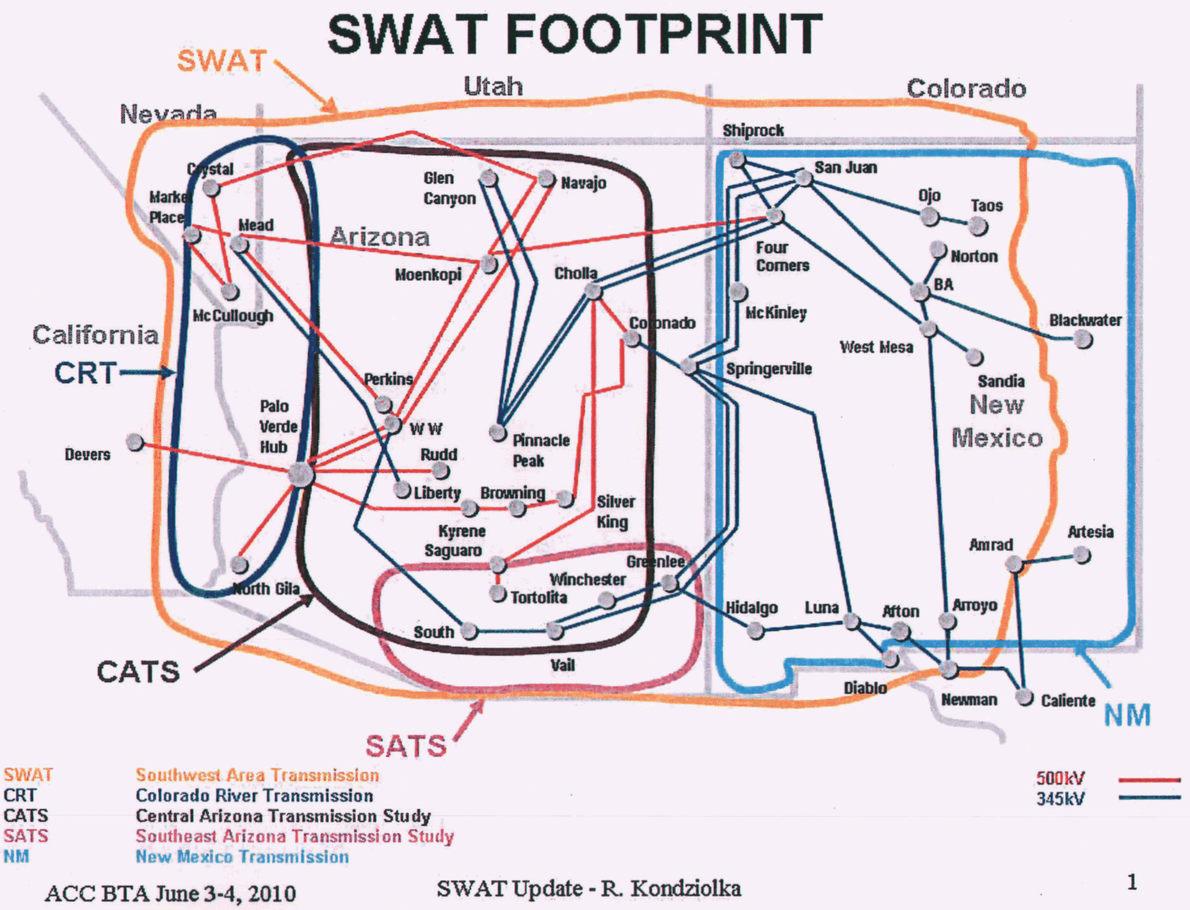
[80] SWAT website: http://westconnect.com/planning_swat.php

Figure 5: SWAT Footprint



The Commission acknowledges the 2009 reports of the ARRTIS and Finance subcommittees, as well as the Common Corridor Structure Separation Task Force, which have recently disbanded.

5.3.2 Colorado River Transmission Planning Group

The Colorado River Transmission subcommittee ("CRT") was formed to study the area within the geographic region straddling the Colorado River from southern Nevada to Yuma, Arizona. This study group includes the participation of: Arizona Power Authority, WAPA, Nevada Power Company, SCE, IID, California ISO, Los Angeles Department of Water and Power, APS, SRP, SWTC, TEP, CAP, and other interested Stakeholders. The CRT study group has been actively engaged in technical studies of the Harcuvar Project and its interconnection with the Palo Verde to Devers No. 2 500 kV project, as well as the 2010 RMR studies of the Yuma Area and Mohave County.

5.3.3 Central Arizona Transmission Study – High Voltage

Prior to merging with CATS-EHV, the CATS HV study area consisted of the high voltage transmission system in Pinal County. The CATS HV 2009 study report focused on generation development scenarios and transmission corridor development in Pinal County using a 2018 power flow base case.

5.3.4 Central Arizona Transmission Study – Extra High Voltage

The Central Arizona Transmission Study Extra High Voltage ("CATS EHV") study group has the most longevity as a coordinated transmission planning forum in Arizona. Arizona transmission providers that participate in the CATS EHV study group are APS, SRP, SWTC, TEP and WAPA. Over the past few years this SWAT study group has shouldered a large portion of the burden of performing the Commission ordered transmission studies for the BTA process.

The following studies were conducted by CATS EHV to establish the adequacy of the ten-year plans and were presented at the 6th BTA Workshop I.[81]

- Tenth Year Snap Shot Study (2019) – considers N-0, N-1 contingencies and N-1-1 analysis of the ten-year planned projects (e.g., NERC Category A and B scenarios).
- 2014 and 2018 RMR for the Metropolitan Phoenix Area filed with the APS Ten-Year Plan.
- A Common Corridor and Extreme Contingencies study report were filed by SWAT as a confidential document (NERC Category D).

Details of these study results are provided elsewhere in this Staff report.

[81] http://www.azcc.gov/Divisions/Utilities/Electric/Biennial/2008%20BTA/SRP%20ACC_BTA_Workshop-Directed%20Work.ppt

5.3.5 Short Circuit Working Group

The SWAT Short Circuit Working Group ("SCWG") was formed for the purpose of developing a coordinated short circuit study model of the SWAT subregional area transmission system. This study tool is needed to enable a consolidated and coordinated short circuit model that yields consistent and accurate short circuit results. The tools and model developed by the SCWG are needed by transmission planning groups and by transmission providers performing system impact studies for proposed interconnections. SCWG is currently expanding its model into California as needed for various studies.

5.3.6 Southeast Arizona Transmission Study

The SWAT Southeast Arizona Transmission Study ("SATS") Subcommittee was formed to study the Southeastern Arizona region. The SATS study area encompasses the southeastern portion of Pinal County, southern Graham County, most of Pima and all of Cochise Counties and Santa Cruz County. Table 11 lists the transmission providers who are participants in the study process.

Table 11 - SATS Participating Transmission Providers

Arizona Public Service Company	Southwest Transmission Cooperative
Central Arizona Project	Tucson Electric Power
El Paso Electric Company	Western Area Power Administration
Public Service Company of New Mexico	US Bureau of Reclamation

Numerous local load serving entities and other stakeholders have been participating in the SATS study process. These entities include Fort Huachuca Military Reservation, Sulphur Springs Valley Electric Cooperative, Trico Electric Cooperative, and UNSE. Graham County Electric Cooperative and Duncan Valley Electric Cooperative did not attend the SATS meetings, but they were represented by SWTC and their respective loads were included in the study.

SATS vision is a 20 year transmission plan covering the SATS study area, which is effected through an agreement between participants to conduct the study as a "single system" (i.e., non-parochial) approach. The 2009 SATS study was filed in the 6th BTA in March 2010 and compliments the Long Range Plan conceived for central Arizona by the original CATS study group. The study also impacts broader regional plans and the SATS 2009 final report is posted on the WestConnect website.

The 2009 SATS Study analyzed southeast Arizona transmission plans for 2010-2014 and 2019 based on NERC Category A-D scenarios. The report concludes that with the planned projects and the additional mitigation measures proposed for each year, the transmission system within the SATS footprint meets the NERC Reliability Standards and WECC System Performance Criteria. However, the report notes that up to ten 115, 138, and 230 kV buses have voltage deviations greater than 5% for a single contingency and up to six 115 and 230 kV buses had voltage deviations greater than 10% for Category C contingencies. The report says this voltage concern will continue to be evaluated, but does not give a timetable for resolving this concern. In addition, the report notes overloads of the SWTC Apache – Butterfield 230 kV line occurred for various contingencies in different study years and mentions the following mitigation options:

- Upgrade line capacity in 2016[82]
- Implement an interim "re-rating" of the line until actual upgrade, or
- Cross-tripping of the Winchester or Bicknell 345/230 kV transformers

In Staff's opinion the tripping of a 345/230 kV facility to mitigate a 230 kV line overload could further weaken the interconnected grid, and should only be used as a last resort.

5.3.7 Eldorado Valley Study Group

An informational presentation on this new SWAT study group was given by Chuck Russell of SRP at 6th BTA Workshop 1, but no filing has been made in the BTA. This SWAT work group is still in its formative stages and is open to all stakeholders. It is not associated with any particular merchant or utility transmission project, and will look collectively at system impacts of the various transmission projects proposing to terminate at one or more of the EHV substations in the Eldorado Valley (e.g., Marketplace, Eldorado or Mead). The study scope is still being developed. Among other deliverables, it is expected that the scope will include short circuit

[82] SWTC's Ten-Year Plan filed in January 2010 states they are also considering construction of a new Winchester-Vail 345kV line as an alternative to upgrading the Apache-Butterfield 230kV line

impacts. A preliminary diagram of transmission projects connecting into the Eldorado Valley is shown in Exhibit 31.

5.4 Western Area Power Administration Transmission Infrastructure Program

Western did not submit a filing in the 6th BTA, but gave a presentation on their Transmission Infrastructure Program ("TIP") at Workshop 1. The program derives from Western's responsibility to implement Section 402 of the American Recovery and Reinvestment Act, which grants Western borrowing authority of $3.25 billion for transmission projects that meet certain key project criteria including:

- Have at least one terminus in the area served by Western
- Be in the public interest
- Have a reasonable expectation of repayment of the loan (payments must be made solely from revenues accrued by the project)
- Use a public process to set rates for the facility
- Independently provides for generation ancillary services

Western is accepting proposals for projects that meet the above criteria, including projects intended to deliver (or facilitate delivery of) renewable resources. Over 200 project proposals have been received to date, including several major proposals that directly impact Arizona such as:

- TransWest Express
- SunZia
- Sonoran-Mohave Renewable Transmission ("SMRT") Project (see Exhibit 33)

Western is seeking projects with broad-based participation.

5.5 WGA/DOE Western Transmission and Renewable Energy Initiatives

5.5.1 Western Renewable Energy Zone Identification Process

The Western Governor's Association ("WGA") and DOE issued a joint Phase 1 report on renewable energy opportunities in the western region in June of 2009.[83] The report indentified Qualified Resource Areas, but not Western Renewable Energy Zones ("WREZ"). The report includes a map of renewable resource concentrations or "Hubs" that may be most cost-effective for integration through development of suitable regional transmission infrastructure. WREZ working groups are currently in the process of identifying Western Renewable Energy Zones based on the information from the Phase 1 report as well as environmental considerations that may limit development of some of the raw renewable resources identified at the Hubs. The report also states that a new modeling tool has been developed to assist in the Phase 2 process which:

> "...will allow load-serving entities, regional planners, renewable energy developers, state and provincial regulators and other interested parties to estimate the relative economic attractiveness of delivering power from specific Western Renewable Energy Zones to existing load centers across the Western Interconnection. The model assists users in identifying robust renewable resource portfolios and the transmission required to deliver the renewable energy. More specifically, the model allows users to examine different renewable resource development scenarios by allowing them to test the relative economic attractiveness of different renewable resource choices under user-customized assumptions."

The model will continue to be refined during Phase 2 of the WREZ initiative. The Phase 1 report is available on the WGA website.

5.5.2 Westwide/WGA Transmission Planning Initiatives

Amanda Ormond of Western Energy Group gave a presentation at the 6th BTA Workshop 1 on the status of Westwide transmission planning initiatives. Major funding allocations totaling some $16 million were announced in 2010 by the DOE for this activity in the west. A portion of

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[83] The report is available at http://www.westgov.org/index.php?option=com_content&view=article&id=55&Itemid=41

these funds are allocated to the WECC for interconnection wide transmission planning processes. WECC formed a Scenario Planning Steering Group ("SPSG") to provide strategic guidance to the TEPPC on scenarios, tools and modeling assumptions. DOE allocated $12 million to the WGA to expand the 2009 WREZ study on resource assessments and transmission planning, including integration of renewable generation. WGA has formed a State Provincial Steering Committee ("SPSC") to develop recommendations and guidance on how these funds should be utilized and has also assigned WGA representatives to the WECC SPSG.

The WECC SPSG has formulated the following set of goals for its portion of the DOE funding:

- Transmission planning: Develop sound interconnection-wide transmission plans that inform investment decisions and government policy decisions.
- Integration of variable generation: Promote technological and institutional improvements that minimize the cost of integrating variable renewable generation while maintaining system reliability.
- Efficient use of the grid: Evaluate and promote reforms to increase use of the existing transmission system ....to move renewable power.
- Better Integration of utility level resource and transmission plans.

The SPSC has submitted an initial scenario study request to the WECC TEPPC.

5.5.3 NREL/DOE Western Wind and Solar Integration Study

The National Renewable Energy Laboratory ("NREL") is the nation's primary laboratory for renewable energy and energy efficiency research and development. NREL's mission and strategy are focused on advancing the U.S. Department of Energy's and our nation's energy goals. The laboratory's scientists and researchers support critical market objectives to accelerate research from scientific innovations to market-viable alternative energy solutions.[84]

The focus of the Western Wind and Solar Integration Study (WWSIS), which was funded by the DOE, was to investigate the operational impact of up to 35% energy penetration of wind, photovoltaic (PV), and concentrating solar power (CSP) generation on the power system

[84] NREL Overview at: http://www.nrel.gov/overview/

operated by the WestConnect group of utilities in Arizona, Colorado, Nevada, New Mexico, and Wyoming (excluding the WestConnect member systems in California). The study concludes that:

> "...it is operationally feasible for WestConnect to accommodate 30% wind and 5% solar energy penetration, assuming the following changes to current practice could be made over time:

- Substantially increase balancing area cooperation or consolidation, real or virtual;
- Increase the use of sub-hourly scheduling for generation and interchanges;
- Increase utilization of transmission;
- Enable coordinated commitment and economic dispatch of generation over wider regions;
- Incorporate state-of-the-art wind and solar forecasts in unit commitment and grid operations;
- Increase the flexibility of dispatchable generation where appropriate (e.g., reduce minimum generation levels, increase ramp rates, reduce start/stop costs or minimum down time);
- Commit additional operating reserves as appropriate;
- Build transmission as appropriate to accommodate renewable energy expansion;
- Target new or existing demand response programs (load participation) to accommodate increased variability and uncertainty;
- Require wind plants to provide down reserves."[85]

APS, TEP, SRP, WAPA and Tri-State G&T had representatives on the technical review committee. In filed BTA comments with the Commission, SRP noted that there are also a number of important limitations acknowledged by the study as follows:[86]

- WWSIS is an operations study, not a transmission planning study.
- WWSIS is not a cost-benefit analysis, even though wind and solar capital costs were incorporated in scenario development.

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[85] See executive summary of report at: http://www.nrel.gov/docs/fy10osti/47781.pdf
[86] Ibid., p 6.

- WWSIS is not a reliability study, although analysis of the capacity value of wind and solar was conducted to assess their contributions to resource adequacy.
- WWSIS does not address dynamic stability issues.
- WWSIS does not attempt to optimize the balance between wind and solar resources.

5.6 WECC TEPPC Interconnection Wide Grid Planning Efforts

SRP's Robert Kondziolka gave an update on the WECC TEPPC efforts at the 6th BTA Workshop 1. He reiterated that TEPPC's analyses and studies focus on studies with Interconnection-wide implications including reliability, cost, and emissions. TEPPC's role does **not** include

- Detailed project-specific studies
- Advocating projects
- Identifying potential "winners" and "losers"
- Siting and cost allocation

One of TEPPC's key roles is to provide governance over the RTEP (Regional Transmission Expansion Project) process, which implements region-wide transmission planning activities pursuant to WECC's $14.5 million funding grant under DOE-FOA000068. This represents an extraordinary opportunity to expand the capability of planning processes in the West, provides for broader input from a wider range of stakeholders into planning processes, expands WECC's ability to study a broader range of scenarios, and to ascertain the impacts of policy and technology drivers. Mr. Kondziolka emphasized that this does not result in a change in TEPPC governance. Although TEPPC has an expanded range of responsibilities, WECC will not take on any role related to transmission siting or cost allocation issues.

RTEP's desired outcomes are:

- Increased coordination among entities in the Western Interconnection
- Increased awareness of how energy policy decisions impact reliability and cost
- Ability to answer key policy questions at State, Provincial and Federal levels
- Additional information for use by decision makers in siting and cost allocation proceedings

A flow chart of the TEPPC scenario planning process is shown in Exhibit 36.

5.7 DOE PEIS for Federal Energy Corridors in Western States

Section 368 of EPAct 2005 addresses energy right of way corridors on federal lands. Section 368 requires the Departments of Commerce, Defense, Energy and Interior to consult with each other and within 2 years:

1. Designate, under their respective authorities, corridors for energy facilities on Federal land in eleven contiguous Western States.
2. Perform any environmental reviews that may be required to complete the designation of such corridors.
3. Incorporate the designated corridors into the relevant agency land use and resource management plans or equivalent plans.

In November 2008, the Final West-wide Energy Corridor PEIS[87] was issued. It describes a Proposed Action Alternative that designates "131 Section 368 energy corridors, totaling approximately 6,112 miles in length....(These) corridors would occur in all 11 western states and would be designated for pipeline and transmission line (multimodal) use, with a width of 3,500 feet, unless specified otherwise because of environmental or management constraints or local designations." According to the PEIS, "The vast majority of the proposed corridors in each state fall on lands managed by BLM..." The numbers and lengths of corridors were designated for states in southwestern WECC:

- In Arizona, 16 corridors totaling 650 miles;
- In New Mexico, 4 corridors totaling 293 miles;
- In Nevada, 34 corridors totaling 1,622 miles; and
- In California, 20 corridors, totaling 823 miles.

[87] US Department of Energy, Programmatic Environmental Impact Statement, *Designation of Energy Corridors on Federal Land in the 11 Western States* (DOE/EIS-0386), November 2008.

Subsequently, in January 2009, Records of Decision ("ROD") were issued by both the Bureau of Land Management ("BLM")[88] and the USDA Forest Service ("FS")[89]. The only modification made by BLM was the exclusion of a segment of corridor 81-272 in the Mimbres planning area in New Mexico. However, BLM did offer numerous clarifications to the Final PEIS, including three in the State of Arizona. These are cited on page 9 of the ROD.

According to the Forest Services ROD, "Designation of the Section 368 energy corridors...requires the FS to amend specific land plans...Only those plans where Section 368 corridors are located are amended by this ROD." The ROD lists the specific forest or grassland land use plans affected for each of the 11 states. In Arizona, these include the Land Management Plans ("LMP") for: Apache-Sitgreaves National Forest ("NF"), Coronado NF, Kaibab NF, Prescott NF, and Tonto NF.

5.8 FERC 890 Planning Principles

On June 17, 2010, FERC issued a Notice of Proposed Rulemaking ("NOPR") addressing changes to its transmission planning and cost allocation policies[90]. This action was taken to remedy a preliminary finding that deficiencies continue to exist in the rules previously established in FERC Order 890. Interested parties were given through September 29, 2010 to file comments on the NOPR.

FERC's NOPR calls for reforms in three specific areas, including:

- **Participation in Regional Planning Processes.** Each transmission provider must participate in a regional transmission planning process that produces a regional transmission plan. The regional planning process should result in a plan that identifies

[88] *Approved Resource Management Plan Amendments/Record of Decision for Designation of Energy Corridors on Bureau of Land Management-Administered Lands in the 11 Western States*, January 2009, page 9.
[89] Record of Decision: *USDA Forest Service, Designation of Section 368 Energy Corridors on National Forest System Land in 10 Western States*, January 4, 2009, pages 28-29.
[90] Notice of Proposed Rulemaking, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 131 FERC ¶61, 253 (2010) (NOPR).

the facilities that cost-effectively meet the needs of transmission providers, their customers, and other stakeholders.

- **Public Policy Driven Projects**. In addition to evaluating proposed transmission enhancements based on considerations of reliability and overall cost reduction, transmission providers would be required to consider projects proposed to facilitate compliance with public policy requirements established by state or federal laws or regulations, such as renewable portfolio standards.
- **Non-incumbent Transmission Developers' Participation in the Transmission Development Process**. Provisions that establish a Federal right of first refusal for an incumbent transmission provider with respect to facilities that are included in a regional transmission plan would be eliminated. Non-incumbent transmission developers should have full opportunity to participate in the regional planning process.

6. Conclusions

The quality of industry reports and Commission ordered BTA study results available for the BTA process have progressively improved over the past ten years. The body of reference documents and presentations available for this BTA are among the best filed with the Commission to date. The industry's commitment to and focus on supplying transmission plans and associated information addressing issues and concerns of importance to the Commission are appreciated. A wide range of public policy concerns regarding reliable service to Arizona customers has been addressed during more than a decade that the BTA process has been active.

The conclusions of this BTA are organized to address five key issues:

- Adequacy of the system to reliably serve local load - Does the combination of the filed ten-year transmission plans meet the load serving needs of the state during the 2010-2019 timeframe in a reliable manner?
- Efficacy of Commission ordered studies - Do the study reports filed in response to Commission ordered RMR, N-1-1 and Extreme Contingency studies comply with, and sufficiently meet, the intended goals of the Commission's orders?
- Adequacy of system to reliably support the wholesale market - Do the transmission planning efforts effectively address concerns raised in previous BTAs about the adequacy of the state's transmission system to reliably support the competitive wholesale market in Arizona?
- Adequacy of renewable transmission plans - Do transmission providers' ten-year transmission expansion plans, including their renewable transmission project proposals, adequately support the overall needs for renewable resource development and integration into the Arizona and regional electric power system?
- Suitability of transmission planning processes utilized - Do the plans and planning activities comport with transmission planning principles and good utility practices accepted by the power industry and the reliability planning standards established by NERC, WECC and FERC?

These five issues are discussed in Sections 6.1 through 6.5, respectively.

6.1 Adequacy of System to Reliably Serve Local Load

Based on the ten-year plans, technical studies, criteria, and assumptions filed in the 6th BTA and/or obtained through subsequent data requests, Staff and KEMA reach the following conclusions:

1) As a result of current economic conditions, the statewide demand forecast for the 2010-2019 ten-year planning period has shifted by about four years since the 5th BTA (i.e., it will take four years longer to reach the 2008 demand forecast levels).

2) A total of 33 transmission projects have been delayed since the 5th BTA, with an average delay of roughly four years. In addition, 18 other transmission projects were cancelled. The combination of cancelled and delayed projects represents slightly more than one-third of the projects filed in the 5th BTA. These delays and cancellations are consistent with the reduction in statewide demand forecast since the 5th BTA and do not appear to threaten the adequacy of the system or its ability to reliably serve load. This conclusion is validated by the results of the studies filed in the 6th BTA.

3) Information on transmission reconductor projects, bulk power transformer capacity upgrades and reactive power compensation projects planned for the purpose of capacity upgrade at 115 kV and above, if included in future ten-year plan filings, would assist the Commission in meeting its obligation "to biennially make a determination of the adequacy and reliability of existing and planned transmission facilities in the state of Arizona".

4) The SATS report and the SWTC Ten-Year Plan have both identified overload issues on the Apache-Butterfield 230 kV line beginning in 2012. Although an upgrade of the line is planned for 2016, no clear resolution of this overload is provided for earlier years. Mitigation prior to 2016 is based on tripping of an upstream 345 kV EHV facility or possible implementation of an interim "uprate" (e.g., an engineering analysis to rerate the existing facility without any physical upgrading). An "uprate" of the line, if supported by thorough engineering analysis, would be preferable to tripping of EHV facilities as an interim mitigation. Furthermore, the study has

identified numerous 230 kV and 115 kV bus voltage deviations that may be unacceptable, and states that further analysis is needed to address this issue. Staff agrees and views this as a potential deficiency in the 2009 SATS report.

5) UNSE's long-standing effort to permit and construct a second line to Santa Cruz County remains stalled due to i) lack of a National Environmental Protection Act ("NEPA") Record of Decision from federal agencies and ii) delay in issuance of a Presidential Permit. UNSE has included an upgrade of the Nogales – Valencia 115kV line to 138 kV in its current ten-year plan, which will clearly help to support adequacy of supply to Santa Cruz County. However, Santa Cruz County remains exposed to extended outages for all of its UNSE customers following the loss of the radial transmission line serving the county. Additional transmission line improvements outlined in the UNSE Ten-Year Plan for Santa Cruz County are contingent upon resolving the pending federal permitting matter.

On a broader note, Staff and KEMA have some concern that certain additional information may be needed in future BTA filings in order to ensure that the Commission has adequate information "to biennially make a determination of the adequacy and reliability of existing and planned transmission facilities in the state of Arizona."[91] Specifically, we note the absence of information regarding planned transmission reconductor projects and bulk power transformer additions (including replacements) in existing substations. Ten-year transmission plans filed in the current (and prior) BTAs focus on projects that require a CEC (e.g., new transmission lines, transmission reconfigurations including taps and loop-ins, and upgrades of the design voltage of existing transmission lines such as 115 kV to 138 kV), but ignores certain other categories of transmission system upgrades that enhance reliability. Therefore, Staff and KEMA conclude that the filed plans in future BTAs should be augmented by additional information on planned projects at 115 kV and above related to transmission capacity upgrades including reconductor projects, substation transformer replacements and reactive compensation installations/upgrades.

[91] From paragraph 2 of the Guiding Principles (see Appendix A to this report)

6.2 Efficacy of Commission Ordered Studies

All Commission required studies related to adequacy and reliability have been filed. APS, SWTC and TEP filed RMR studies. SRP filed the study of N-1-1 contingencies (i.e., the "Ten Year Snapshot Study") performed by the CATS-EHV study group. APS filed the Extreme Contingency Study performed in conjunction with the SWAT Sub-Regional Transmission Planning Group. TEP filed the Southeast Arizona Transmission Study ("SATS" study) performed under SWAT. And, SWTC filed the Cochise County Study Group 2009 technical study performed under the oversight of SATS.

The following conclusions apply to the efficacy of the filed documents relative to the intent of the Commission ordered action:

1) The Phoenix area, Tucson area and Yuma area RMR studies of 2013 and 2019 were thorough and well documented. These studies comport with the Commission's RMR study methodology and production cost simulations were performed using industry accepted study tools and publicly available data. No flaws in assumptions or modeling are evident in these three reports. The studies show that each RMR area will have sufficient maximum load serving capability to reliably serve the respective area's load during the next ten year period. The RMR studies also indicate local RMR generation will not be dispatched out of merit order for significant hours or yield RMR costs sufficient to warrant advancing transmission improvements. The Mohave County 2013 and 2018, and Santa Cruz County 2013 and 2019 RMR studies were also well documented. The Mohave County study showed no RMR requirement. However, Santa Cruz County RMR analysis for 2010 showed an RMR requirement of 24 MW. No Santa Cruz RMR requirement was found in 2013 or 2019.

2) The Commission's concern expressed in the 5th BTA in regard to the need for additional stakeholder involvement in the Yuma area RMR study has been satisfactorily addressed in the RMR study of 2013 and 2019. WAPA, WMIID, IID and other stakeholders participated in the APS RMR study of the Yuma area and have concurred with the cut plane definition, study plan and results.

3) The Commission's concern expressed in the 5th BTA about the need for a coordinated RMR cut plane definition and joint study of Mohave County, including WAPA participation, has been satisfactorily addressed in the RMR study of 2013 and 2018.

4) A "Ten Year Snapshot Study" (previously referred to as the "N-1-1 Study") and an Extreme Contingency Study were performed by the CATS – EHV study group and APS, respectively. The filed studies were well documented and comport with the study scope previously directed by the Commission.[92] The studies comport with the study effort outlined by Commission Staff. These studies both represent a composite assessment of the Arizona system reflecting all filed projects in the ten-year plan, and the performance of the overall system under normal, single-contingency and selected more severe contingency scenarios. Staff and KEMA conclude that these studies demonstrate the ten-year plan is generally robust and should provide adequate and reliable service to Arizona as evidenced by the following observations from these studies:

   a) No thermal overloads or significant voltage problems occur in the 2019 base case.

   b) Eleven transmission facilities experience thermal overloads in the N-1 analysis of 2019. The report notes that these will be mitigated through transmission line reconductors or upratings, transformer replacements, and reconfigurations. Staff concludes these mitigation measures are reasonable, but additional data on such upgrades should be provided in future BTAs.

   c) Excessive voltage deviations are noted in about two dozen N-1 scenarios, but the report states these will be addressed through routine measures such as corrections to system modeling, operational measures and selected substation shunt capacitor additions. Staff concludes this approach is reasonable for addressing the voltage violations.

[92] The Extreme Contingency Study is filed with the Commission under confidentiality

d) Although dynamic stability analysis was not included in the scope of these two studies, stability studies filed by the individual utilities in their ten-year plan filings demonstrate acceptable performance and/or reasonable mitigation measures that can be implemented.

5) Two EHV line overloads and five HV line overloads for N-1-1 conditions were unresolved by the Ten Year Snapshot study. Most of these overloads occur for the N-1-1 scenario that modeled deferral of the Morgan– Pinnacle Peak 500 kV line planned for completion in 2010. Given the advanced stage of construction on this project, Staff concludes that such delay is unlikely.

6) The CATS-HV study of the planned 2019 Pinal County system assumed SPPR's "Three-Terminal" transmission plan (Pinal Central to ED5, ED5 to Test Track and ED5 to Marana 230 kV lines). As previously discussed in Section 2.5.2, SPPR has now deferred plans for two of these line additions indefinitely. It is unclear when this deferral decision was made relative to the development of the CATS-HV study base cases and the impact of these project deferrals on the results of the CATS-HV study of 2019 is unknown and cannot be determined from the filed studies.

7) Staff concludes the proposed definition of "continuity of service" described in the Cochise County Study Group's (CCSG) 2009 technical study report, as filed by SWTC in January 2010, is appropriate for planning of the supply system to Cochise County and that the transmission system plan of expansion identified in the CCSG 2009 report represents a reasonable set of capital expansion projects to achieve the "continuity of service" paradigm in Cochise County. However, it is currently unclear if this plan of service will be implemented by the 2013-2018 timeframe as originally envisioned at the time of Commission Order 70635.

6.3 Adequacy of System to Reliably Support the Wholesale Market

Studies and information filed in the 6th BTA indicate the existing and planned Arizona EHV system is adequate to support a robust wholesale market in the 2010-2019 timeframe. Two key factors that contribute to a robust market are the availability of sufficient generation (above and beyond local and statewide demand) and the availability of sufficient transmission capability for transferring power to meet the needs of the wholesale market both within Arizona and across state borders.

Regarding resource availability, the 2019 Ten-Year Snapshot Study base case shows approximately 33,000 MW of in-state generation capacity, some 11,000 MW more than required to serve Arizona's statewide demand forecast of roughly 22,000 MW. Even after accounting for generation reserve requirements, much of this excess will be available for sale on the wholesale market and for export out of Arizona. In addition, this excess generation augments the local resources of Arizona's utilities in the event of major forced power plant outages or other resource emergencies.

Regarding delivery capability, the Ten-Year Snapshot study looks at N-1-1 conditions and demonstrates that even after removing any one of the major planned EHV transmission projects in the current ten-year plan, the 2019 Arizona system will still perform with minimal problems. From this result it can be inferred that sufficient statewide transmission capacity will exist on a day to day basis to handle both native load requirements and wholesale power transactions without a significant risk of congestion on Arizona's EHV delivery paths.

Exhibit 11 provides a summary of transmission delivery capability currently available across Arizona's borders. As shown, the bi-directional transfer capability between Arizona and neighboring states in aggregate is over 12,000 MW. This represents over 50% of Arizona's projected 2019 statewide demand and more than 35% of Arizona's projected 2019 generating capacity. In addition, the exhibit shows a bi-directional transfer capability of approximately 8,000 MW between the Palo Verde Hub and Arizona load centers. This represents a significant transmission capacity available for wholesale transactions and other uses within Arizona from this extremely important energy trading hub, in addition to the export capability available over westbound transmission paths from Palo Verde Hub to California and Nevada. Furthermore, the delivery capabilities shown in Exhibit 11 do not include expected increases from the proposed EHV transmission projects shown in the current ten-year plan.

6.4 Adequacy of Transmission Projects Affecting Renewable Development

Staff and KEMA reached the following conclusions in this regard:

1) Developing Arizona's vast renewable resource potential requires a coordinated and multi-faceted strategy involving stakeholders representing utility, government, economic, developer, environmental, and other interests. Decisions by the Commission and the actions taken by the Arizona utilities and regional stakeholders are important factors that will affect how and when this potential is developed.

2) The 2009 utility filings in response to the 5th BTA request for the utilities to each identify their top three transmission projects are responsive to Commission request. An inclusive stakeholder process was developed and executed to identify the projects.

3) Most of the transmission corridors identified in the utilities' initial transmission proposals to serve potential renewable generation are compatible with projects in the utilities' previous transmission plans. Therefore, the transmission lines identified by the utilities are actually advancements of projects already found in previous transmission plans. Such project advancement represents a relatively small incremental investment for a potentially significant renewable benefit.

4) Since most of the proposed renewable transmission projects have been identified in earlier transmission plans, they should contribute to reinforcing the transmission for general use beyond the specific needs of renewable generation project. Furthermore, we would expect them to be effective in enabling delivery of renewable resources developed close to either the Phoenix-Tucson regions or the Palo Verde hub. As projects are developed farther from these areas, completely new transmission plans will likely need to be identified and developed.

5) Even if the proposed RTPs filed by Arizona utilities in 2009 are approved and built, they will only provide for integration of a portion of the projected in-state renewable resource potential.

6) The impact of utility-scale renewable generation is being incorporated into the utilities' transmission plans as part of their normal planning process. Each utility's ten-year (i.e., BTA) plans, RTP filings and RTAP reports should keep the Commission informed as the situation evolves.

6.5 Suitability of Transmission Planning Processes Utilized

The State of Arizona is fortunate that its transmission providers are engaged in and providing leadership to the SWAT and WestConnect subregional planning processes. These planning forums utilize an open, transparent and collaborative approach to transmission planning. Stakeholder participation has been broad-based and inclusive of other interested parties that desire to engage in the planning process.

Staff/KEMA also makes the following observations and conclusions as regards the suitability of study processes and technical reports in the 6th BTA:

1) Technical studies filed in the 6th BTA indicate a generally robust study process for assessing transmission system performance (steady-state and transient)[93] for the 2010-2019 planning period. This included stability study results[94] from APS, SRP, TEP and SWTC.

2) SATS is the first SWAT Subcommittee to study and coordinate local HV and EHV transmission system plans in a common forum. This approach to subregional planning has produced useful study results in the 6th BTA and may be well suited for other local areas in Arizona.

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[93] For the purpose of this report, Staff uses the terms "dynamic stability" and "transient stability" interchangeably in reference to time domain studies that model fault events or other disturbances.

[94] Some of the filings showed poor "damping" of oscillations on Apache GT Unit 1 for various contingencies in 2009 cases, which SWTC speculated was due to erroneous modeling data from the GT manufacturer. At Workshop 2, SWTC provided Staff with stability case results for the 2010 SATS Heavy Summer Case showing damped response of Apache GT Unit 1.

3) While Arizona's transmission providers have effectively addressed a broad range of study requirements in this BTA, Staff recognizes that these may differ from the studies required for the utilities to comply with mandatory reliability standards implemented by FERC over the past two years (as discussed in section 5.1). Even so, this information may apply to some extent in the BTA process. In an effort to explore these impacts, Staff issued the following data request during the 6th BTA:

    - Has a NERC/WECC reliability standards audit been conducted that assessed your utility's compliance with the NERC Transmission Planning Standards (i.e., TPL-001 through TPL-004)? If so, advise when the most recent set of audit findings were issued and provide a summary of such findings as regards TPL-001 through TPL-004.
    - If your most recent NERC/WECC audit reached a finding of non-compliance with any part(s) of TPL-001 through TPL-004, have such findings been accepted by the utility? If the findings have been accepted, describe your mitigation plan(s) to correct such non-compliance, as well as the status and timetable for completing such mitigation. If the finding(s) are in dispute, describe the nature and status of the dispute.

APS, TEP/UNSE and SWTC all responded they are currently compliant with all applicable NERC transmission planning reliability standards based on the results of their latest audit by NERC/WECC. SRP also voluntarily responded that their audit results were compliant. All of the utilities were audited on TPL-001 through TPL-003, and some were audited on TPL-004 as well. In addition, Staff and KEMA observed that technical studies filed in the 6th BTA covered a range of NERC planning standards/contingency categories, as shown below in Table 12.

Table 12 - NERC Planning Standards/Contingency Categories Covered by 6th BTA

Study	Category A (TPL-001)	Category B (TPL-002)	Category C (TPL-003)	Category D (TPL-004)
SWAT Ten-Year Snapshot Study	X	X		
SWAT Extreme Contingency Study				X
SATS Study	X	X	X	X
APS Internal Study	X	X		
SRP Internal Study	X	X		
TEP Internal Study	X	X	X	X
SWTC Internal Study	X	X	X	X

Developing consensus on how to address the results of NERC/WECC reliability audits in the BTA process will take additional time and effort, but as a minimum it would be informative for utility filings in future BTAs to include confirmed findings regarding TPL-001 through TPL-004 compliance from NERC/WECC reliability audits that have been finalized and filed with FERC, as well as a description of any associated mitigation plan(s) filed with the FERC since the most recent BTA.

7. Recommendations

Based upon the observations and questions discussed in the conclusions, Staff submits the following recommendations for Commission consideration and action:

1) Staff recommends that the Commission continue to support the use of the:

   a) Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" (see Appendix A),.

   b) NERC reliability standards, WECC system performance criteria and FERC enforcement policies regarding transmission system planning reliability standards, and

   c) Collaborative planning processes in Arizona and throughout the western region that facilitate competitive wholesale markets, and are consistent with FERC Order 890 and the expected order on Transmission Planning and Cost Allocation.

2) Staff recommends that Commission continue to support the policy that generation interconnections should be granted a Certificate of Environmental Compatibility by the Commission only when they meet regional and national reliability standards and the requirements of Commission decisions.

3) Staff recommends that the Commission order the jurisdictional utilities to report relevant findings in future BTAs regarding compliance with transmission planning standards (e.g., TPL-001 through TPL-004) from NERC/WECC reliability audits that have been finalized and filed with FERC.

4) Staff recommends that the Commission order SWTC to determine if an engineering "re-rating" of the Apache-Butterfield 230 kV line as proposed in the 6th BTA filings would be an acceptable measure until the line is upgraded in 2016, and to file the results of this assessment by January 31, 2011.

KEMA

5) Staff recommends that the Commission order APS, SWTC and TEP to conduct additional analysis of potential 230 kV and 138 kV voltage deviations in Southeastern Arizona as noted in the 2009 SATS report, file an update based on the 2010 SATS study by February 28, 2011, and finalize mitigation plans if needed for this voltage concern in ten-year plan filing(s) for the 7th BTA by January 31, 2012.

6) Staff recommends that the Commission accept the definition of "continuity of service" following a transmission line outage as proposed in the Cochise County Study Group's 2009 technical study report filed by SWTC in January 2010, and that the Commission accept the recommended transmission plan of service as shown in Section 4.2.1 of this 6th BTA report in order to achieve this "continuity of service" objective in Cochise County. Staff further recommends that the Commission establish target dates for SWTC, APS, TEP and SSVEC as follows:

    a) June 30, 2011, to identify the components of the plan in a facility study that provide the most benefit to customer reliability and can be implemented in the shortest timeframe, and to file a progress report with the Commission that includes planned in-service dates for all relevant elements of the plan reflecting these priorities.

    b) September 30, 2011, to submit a progress report including in-service dates for the components of the plan of service identified in the June 30, 2011, facility study. This schedule shall reflect the most recent load forecast.

    c) December 31, 2011, to substantially complete contractual negotiations with affected parties over cost responsibility, wheeling arrangements, Engineering, Procurement and Construction ("EPC"), operations and maintenance, etc. (described as a pending items in the CCSG 2009 report), and to file a draft memorandum of understanding among affected parties addressing these items with the Commission.

    d) June 30, 2012, to file a progress report with the Commission including an executed memorandum of understanding between the parties that includes planned in-service dates for all remaining elements of the plan in the 2013-2018 timeframe. If applicable, in-service dates beyond 2013-2018 may be proposed for later stages of the plan if justified by documented changes in the load forecast[95].

e) December 31, 2012, to receive all required approvals and permits needed to complete remaining components of the plan, and file a progress report on plan implementation with the Commission. If any related approvals or permits from appropriate regulatory agencies are still pending at that time, the progress report shall identify a clear action plan and proposed schedule to obtain such approvals.

7) Staff recommends that the Commission order UNSE to update its assessment of long term alternatives for Santa Cruz County continuity of service, as part of UNSE's 2012-2021 ten-year planning studies, and file a report on the updated assessment in the 7th BTA in 2012. Furthermore, if any approvals or permits from federal agencies related to the Gateway Transmission Project are still pending at that time, Staff recommends that the Commission require the 7th BTA filings to include a clear action plan and proposed schedule to obtain such approvals.

8) Staff recommends that Commission regulated utilities be required to continue to perform RMR studies in accordance with the methodology set forth in Appendix C to this Sixth BTA, and shall file such studies with ten-year plans for inclusion in future BTA reports.

9) Staff recommends that the Commission order the jurisdictional utilities to include planned transmission reconductor projects, transformer capacity upgrade projects and reactive power compensation facility additions at 115 kV and above in future BTA plan filings starting in January 2011.

10) Staff recommends that the Commission accept the results of the following Commission ordered studies provided as part of the 6th BTA filings:

[95] Load forecast updates may include the impacts of demand side management, demand response, energy efficiency improvements, distributed generation and other applicable factors.

a) Extreme contingency outage study for Arizona's major transmission corridors and substations, and the associated risks and consequences of such overlapping contingencies.

b) "N-1-1" (Ten-Year Snapshot) study results documenting the performance of Arizona's statewide transmission system in 2019 for a comprehensive set of N-1 contingencies, each tested with the absence of one of nine different major planned transmission projects.

c) RMR studies for Phoenix, Tucson, Yuma, Mohave County and Santa Cruz County.

1

Exhibit 1 – Arizona Transmission System Map

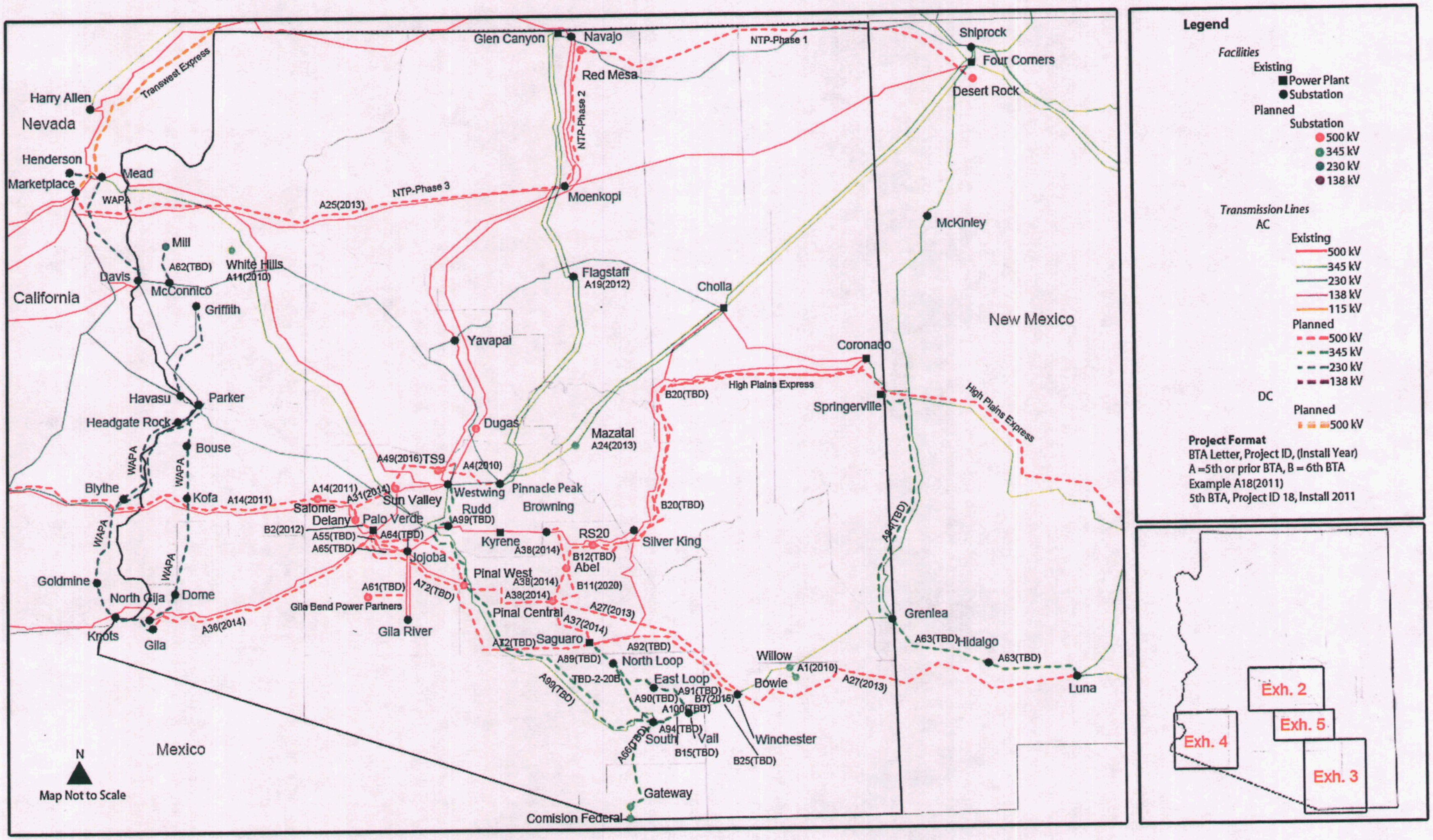


Exhibit 2 – Phoenix Metro Transmission System Map

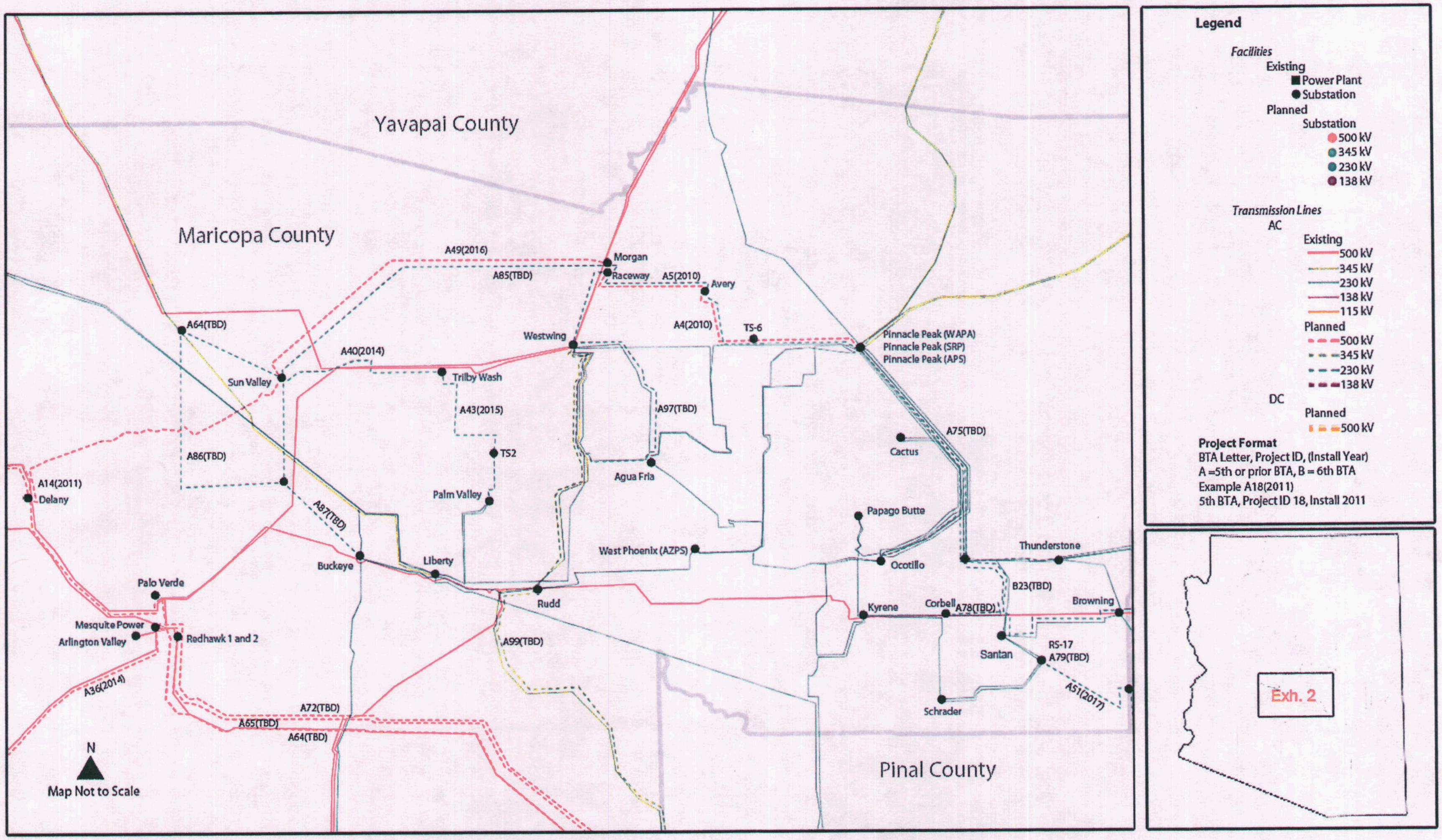


Exhibit 3 – Southeastern Transmission System Map

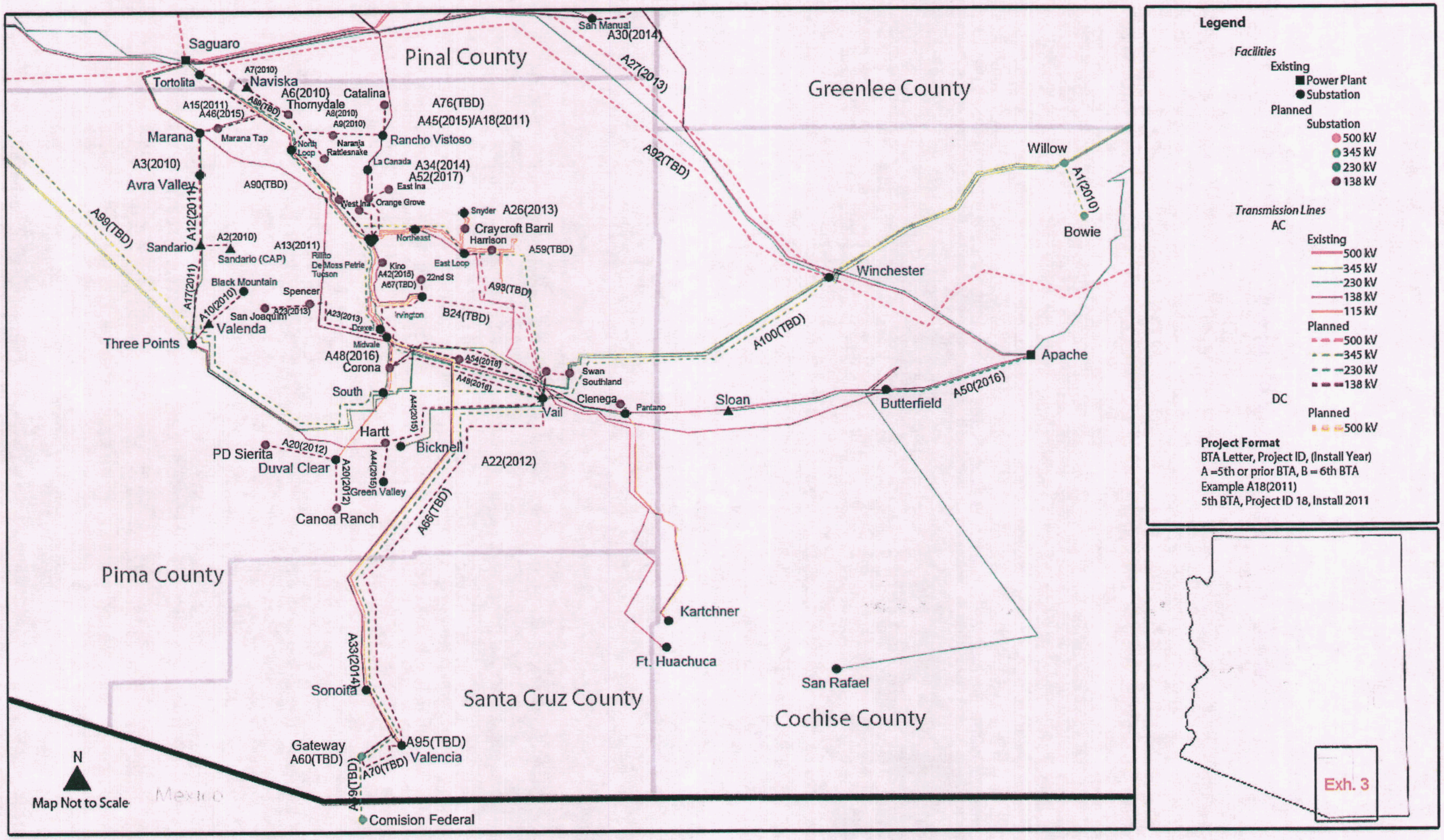


Exhibit 4 – Yuma Transmission System Map

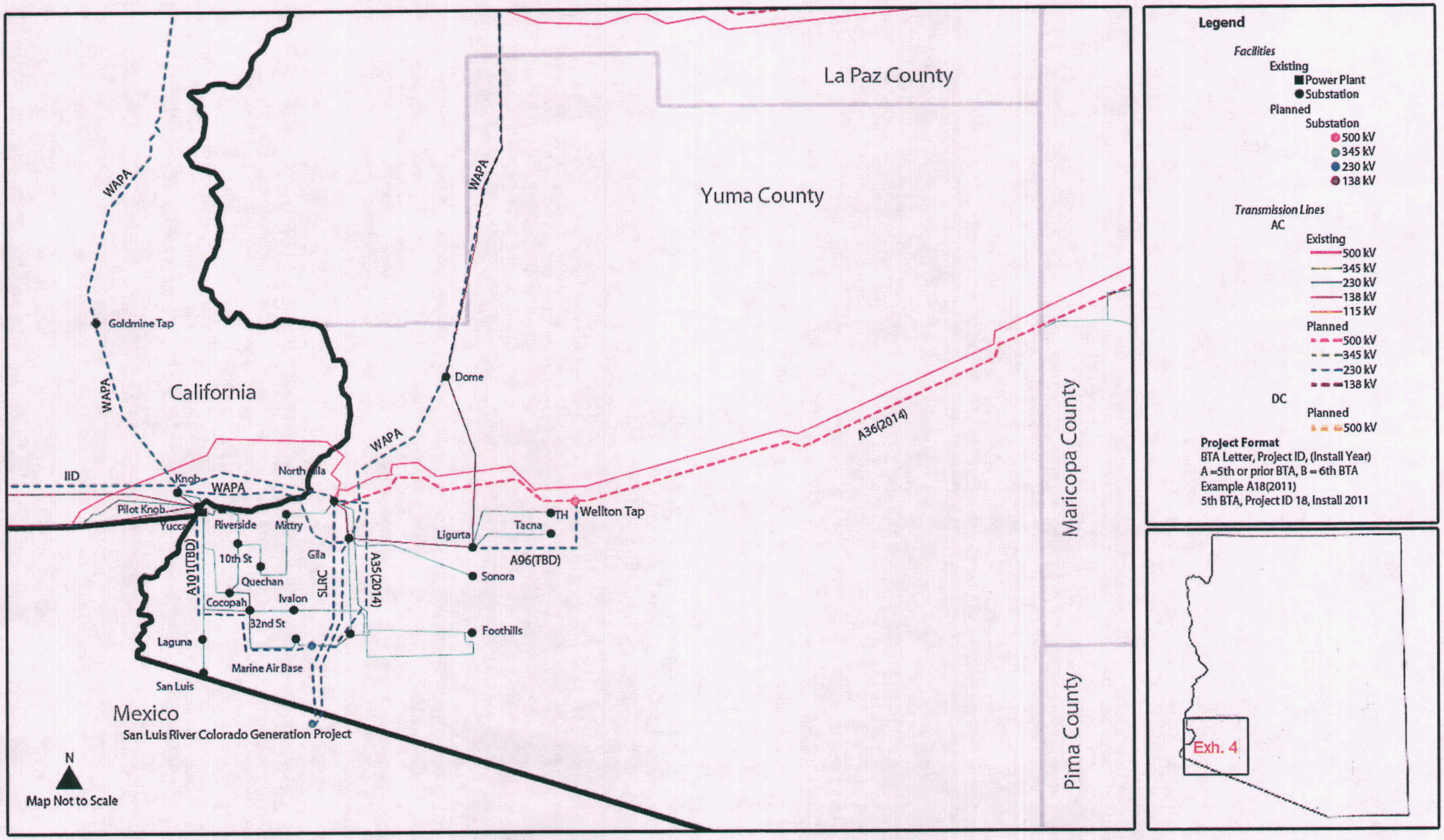


Exhibit 5 – Pinal County Transmission System Map

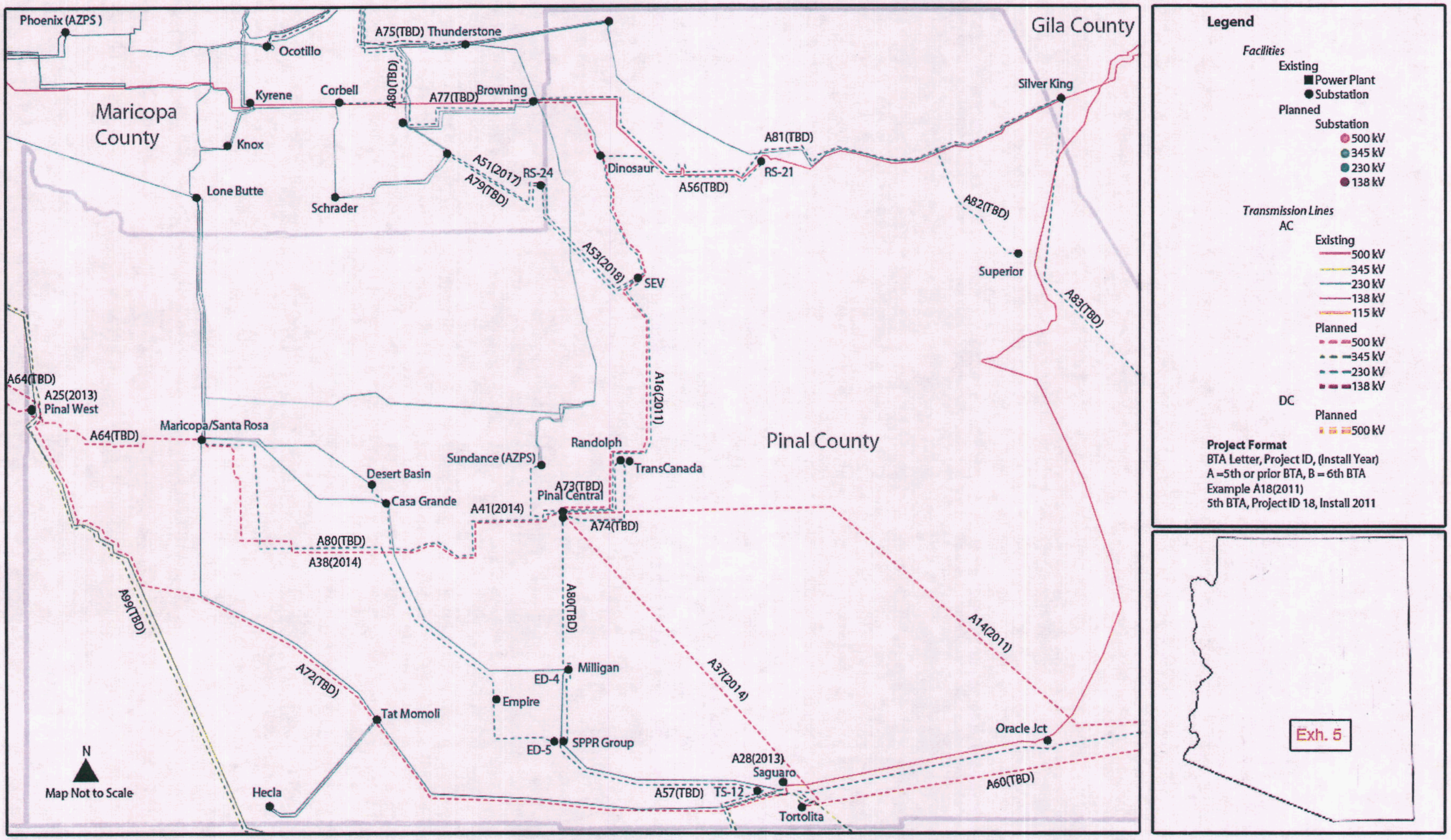


Exhibit 6 – WECC Paths Affecting Arizona

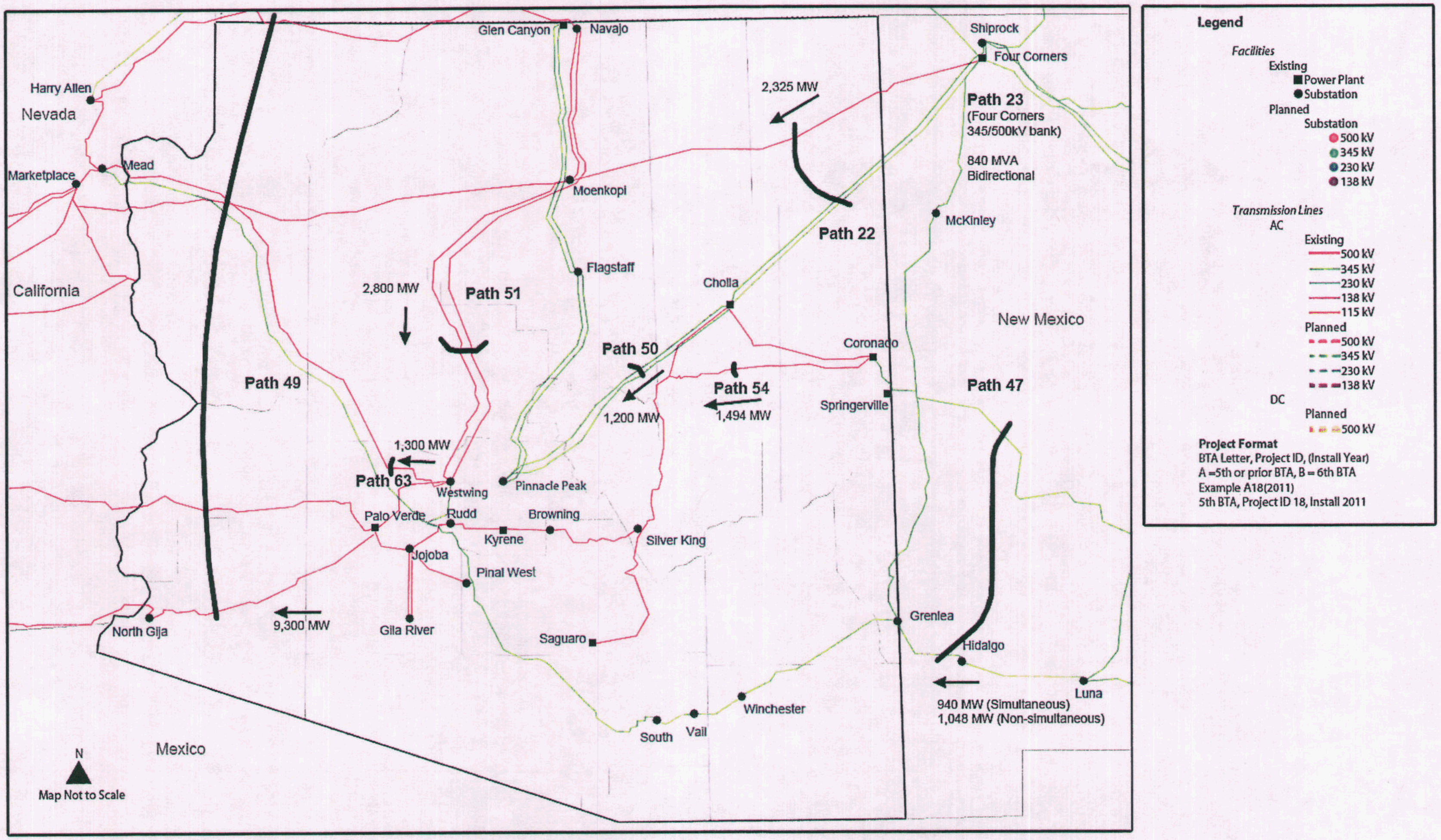


Exhibit 7 – Arizona Planned Project Lookup Table

Project ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	Voltage (kV)
A1	Bowie Power Project	BOWIE	15	CEC Approved – Decision #64626	2010	345
A2	CAP 115 kV line loop-in to SWTC Sandario	SWTC	0.6	CEC Approved – Case #152	2010	115
A3	Marana-Avra Valley 115 kV Line Upgrade	SWTC	8.75	CEC Not Yet Filed	2010	115
A4	Morgan-Pinnacle Peak 500 KV line	APS, SRP	26	CEC Approved – Decision #69343	2010	500
A5	Morgan-Raceway-Avery-Scatter Wash-Pinnacle Peak 230 kV line	APS	27	CEC Approved – Decision #69343	2010	230
A6	Naviska-Thornydale 115 kV line	SWTC	7	CEC Approved – Case #149	2010	115
A7	Saguaro to North Loop	SWTC	3.2	CEC approved – Case #149	2010	115
A8	Thornydale-Rattlesnake 115 kV line	SWTC	19	CEC Approved – Case #152	2010	115
A9	Tortolita-North Loop-Rancho Vistoso and Tortolita-Rancho Vistoso corridor expansion and reconfiguration Project - Phase 2	TEP	11.1	CEC Approved – Case #149	2011	138
A10	Valencia-CAP Black Mountain 115 kV line	SWTC	2.6	CEC Approved – Case #152	2010	115
A11	White Hills substation	UNISOURCE	0	CEC Not Required	2010	345/69
A12	Avra Valley-Sandario Tap 115 kV Line Upgrade	SWTC	2.8	CEC Not Yet Filed	2011	115
A13	DeMoss Petrie-Tucson 138 kV line	TEP	4.5	CEC Not Yet Filed	2011	138
A14	Devers - Palo Verde 500 kV #2 line	SCE	230	CEC Denied - Case #130	2011	500
B1	Dinosaur – Abel – Randolph 230kV line	SRP	TBD	CEC Approved – Case #126	2011	230
A15	Marana Tap-Marana 115 kV Line Upgrade	SWTC	0.2	CEC Not Required	2011	115
A16	Pinal South-Southeast Valley/RS22	SRP	30	CEC Approved - Decisions #68093 and #69291	2011	230
A17	Sandario Tap-Three Points 115 kV Line Upgrade	SWTC	13.71	CEC Not Yet Filed	2011	115
B22	TEP System – Rosemont 138 kV line	TEP	24	CEC Not Yet Filed	2011	138
A19	345/69 kV Interconnection at Western's Flagstaff 345kV bus	APS	0.95	CEC Not Required	2012	345
B2	Delany – Palo Verde 500kV line	APS	15	CEC Approved – Decision #68063	2012	500

A22	Upgrade existing 115 kV transmission line to Nogales	UNISOURCE	60	CEC Approved – Case #111	2012	115
A20	South-Duval CLEAR - Phase 2b - Extend 138 kV line from Canoa Ranch-(Future) Duval	TEP	24	CEC Approved - Case #84	2013	138
A24	Mazatzal Loop-in of Cholla-Pinnacle Peak 345 kV line	APS	0.95	CEC Not Required	2013	345
A25	Moenkopi-Eldorado 500 kV Series Capacitor Upgrade Project	SCE, APS	0	CEC Not Required	2013	500
A26	Northeast-Snyder 138 kV Tap for Craycroft-Barril substations	TEP	8	CEC Not Required	2013	138
A27	SunZia Project	SWPG, SRP, TEP, ECP, Shell, TSGT	500	CEC Not Yet Filed	2013	500
A28	TS12 Loop-in of Saguaro-Casa Grande 230 kV line	APS	0.95	Not Required	2013	230
A29	Vail-East Loop - Phase 4 - Harrison Tap of Roberts-East Loop 138 kV line	TEP	0	CEC Approved - Case #8	2013	138
A30	Apache/Hayden-San Manuel 115 kV line	SWTC	4.5	CEC Approved – Case #142	2014	115
A31	Delany-Sun Valley 500 kV line	APS, SRP, CAWCD	28	CEC Approved – Decision #68063	2014	500
A32	Desert Basin-Pinal Central 230 kV	APS, SRP	21	CEC Approved – Decisions #68093, #68291, #69183 and #69647	2014	230
A33	Gateway-Sonoita 138 kV line	UNISOURCE	10	CEC Not Yet Filed	2014	138
A34	La Canada-Orange Grove-Rillito 138 kV line	TEP	5.4	CEC Not Yet Filed	2014	138
A35	North Gila-TS8 230 kV line	APS	15	To be Filed in 2008	2014	230
A36	Palo Verde Hub-North Gila 500 kV #2 line	APS, SRP, IID, WMIDD	110	CEC Approved – Decision #70127	2014	500
A37	Pinal Central-Tortolita 500 kV line	TEP, SWTC, SRP, SunZia	40	CEC Not Yet Filed	2014	500
A38	Pinal West-Pinal Central – Randolph - Abel-Browning 500 kV line	SRP, TEP, SWTC, ED2, ED3, ED4	50	CEC Approved - Case #126 - Decisions #68093 and #69291	2014	500
A39	RS26-Fountain Hill substation	SRP	TBD	CEC Not Yet Filed	2014	115/230/345
A40	Sun Valley-Trilby Wash - 230 kV line	APS	15	CEC Approved – Decision #67828	2014	230
A41	Sundance-Pinal Central 230 kV line	APS, ED2	6	CEC Filed – Case #136	2014	230
B3	Three Terminal Plan Circuit 1 Participation	SWTC	23	CEC Not Yet Filed	2014	115
B4	Three Terminal Plan Circuit 2 Participation	SWTC	31	CEC Not Yet Filed	2014	115

B5	Three Terminal Plan Circuit 3 Participation	SWTC	19	CEC Not Yet Filed	2014	115
A23	Interconnection of South – Midvale 138 kV circuit with future Spencer, Raytheon, Medina 138kV substations - Phase 1.	TEP	20	CEC Not Yet Filed	2015	138
A42	Irvington Substation –Tucson Station #2 138 kV Phase 1	TEP	10.9	CEC Not Yet Filed	2015	138
A42	Irvington Substation –Tucson Station #2 138 kV Phase 2	TEP	10.9	CEC Not Yet Filed	2019	138
A43	Palm Valley-TS2-Trilby Wash 230 kV line	APS	12	CEC Approved - Decisions #66646 and #67828	2015	230
B6	Saguaro to Adonis 115 kV Line Loop-in to Naviska	SWTC	0	CEC Not Required	2015	115
A44	South-Hartt-Green Valley 138 kV line	TEP	14.5	CEC Not Yet Filed	2015	138
A45	Tortolita - Rancho Vistoso 138kV line tap for future Naranja substation.	TEP	24.5	CEC Not Yet Filed	2015	138
A46	Interconnection of Tortolita – North Loop 138 kV with future Marana 138 kV Substation.	TEP	22	CEC Not Yet Filed	2015	138
B24	Vail-UA Tech Park-Irvington 138 kV line	TEP	2	CEC Not Yet Filed	2015	138
B8	Del Cerro-Anklam-Tucson 138 kV line	TEP	2	CEC Not Yet Filed	2016	138
A47	Griffith-North Havasu 230 kV line	UNISOURCE	40	CEC Approved/Extended - Case #88, CEC Extension request not yet filled	2016	230
A48	Irvington Substation – Corona Substation – South Substation 138kV.	TEP	16.1	CEC Not Yet Filed	2016	138
A49	Sun Valley-Morgan 500 kV line	APS, SRP, CAWCD	TBD	CEC Approved – Decision #70850	2016	500
A50	Upgrade of Apache-Butterfield 230 kV line	SWTC	16	CEC Not Yet Filed	2016	230
A51	Abel (RS24)-Moody (RS17) 230 kV #1	SRP	20	CEC Approved – Decision #71441	2017	230
B9	Butterfield to Bicknell 230 kV Line Upgrade	SWTC	68.7	CEC Not Yet Filed	2017	230
A52	Orange Grove-East Ina 138 kV line	TEP	3.6	CEC Not Yet Filed	2017	138
A53	Abel (RS24)-Mody (RS17) 230 kV #2	SRP	20	CEC Approved – Decision #71441	2018	230
B10	CAP 115 kV Line Loop-in to Picture Rocks	SWTC	0	CEC Not Required	2018	115
A54	Interconnection of South – Midvale 138 kV circuit with future Spencer, Raytheon, Medina 138kV substations - Phase 2	TEP	13	CEC Not Yet Filed	2018	138
	Midvale - Spencer - Medina - Raytheon - South 138kV Line - Phase 3.				2019	
B11	Pinal Central – Abel #2 500kV line	SRP	TBD	CEC Not Yet Filed	2020	500

B7	Vail – Irvington 345 kV line	TEP	11	CEC Not Yet Filed	TBD	345
B12	Abel – RS20 500kV	SRP	TBD	CEC Not Yet Filed	TBD	500
A55	Arlington Power Plant	Dynegy Arlington Valley	TBD	CEC Approved – Decision #64357	TBD	500
B13	CS2 Substation	SWTC	0	CEC Not Yet Filed	TBD	230/115
A56	Dinosaur-RS21 230 kV line	SRP	TBD	CEC Not Yet Filed	TBD	230
A57	ED5-Marana 230 kV line	SCWPDA, SPPR	28	CEC Not Yet Filed	TBD	230
A58	ED5-Pinal South (Pinal Central) 230 kV line	SCWPDA, SPPR	18	CEC Not Yet Filed	TBD	230
A59	Future Gateway-Comision Federale de Electricidad 345 kV line	TEP	2	CEC Approved - Case #111	TBD	345
A60	Gateway 345/115 kV or 345/138 kV substations	UNISOURCE	60	CEC Approved - Case #111	TBD	345/138
A61	Gila Bend Power Plant	GBPP	0	CEC Approved – Case#109 – Extension Request Pending	TBD	500
A62	Golden Valley 230 kV Project - McConico-Mercator Mill 230 kV line	UNISOURCE	20	CEC Not Yet Filed	TBD	230
A63	Greenlee switching station through Hidalgo to Luna	ELPE, PNM, TXNMPC	28	CEC Approved – Case #21	TBD	345
A64	Hassayampa - Pinal West 500 kV #2 line	SRP, TEP, SWTC, ED2, ED3, ED4	51	CEC Approved – Case #124	TBD	500
A65	Hassayampa-Jojoba 500 kV line	GBPP	19	CEC Not Required	TBD	500
A66	Interconnection line -South-future Gateway 345 kV line	TEP, UNISOURCE	60	CEC Approved - Case #111	TBD	345
B14	Interconnection of Greenlee-Winchester 345kV line with future Willow Substation	TEP, Bowie	0	CEC obtained by Southwestern Power Group – Case #118	TBD	345
B15	Irvington – South 345 kV line	TEP	16	CEC Not Yet Filed	TBD	345
A67	Irvington-East Loop Project - Phase 3 - Irvington-22nd Street 2nd Circuit	TEP	9	CEC Approved - Case #66	TBD	138
A68	Jojoba Loop-in of TS4-Panda 230 kV line	APS	0.95	CEC Approved – Decision #62960	TBD	230
B16	Kartchner to CS2 230 kV Line	SWTC	2	CEC Not Yet Filed	TBD	230
B17	Mural – San Rafael 230kV line	APS, ED3	TBD	CEC Not Yet Filed	TBD	230
A69	New Hayden 115 kV Station Loop-in	SRP	0.75	CEC Not Yet Filed	TBD	115
A70	Nogales Transmission line #2 (Gateway – Valencia)	UNISOURCE	3	CEC Approved - Case #111	TBD	115/138
B18	North Gila-Ligurta 230kV Line	WMIID	35	CEC Not Yet Filed	TBD	230

A71	Palm Valley-TS2-Trilby Wash 230 kV line # 2	APS	12	CEC Approved – Decision #67828	TBD	230
A72	Palo Verde-Saguaro 500 kV line	CATS Sub-regional Planning Group	130	CEC Approved – Decision#46802	TBD	500
B19	Pantano to Kartchner 115 kV Line Upgrade	SWTC	36	CEC Not Yet Filed	TBD	115
A73	Pinal Central (Pinal South) – Future substation 6 miles northeast 230 kV line #1	SCWPDA, SPPR	6	CEC Not Yet Filed	TBD	230
A74	Pinal Central (Pinal South) – Future substation 6 miles northeast 230 kV line #2	SCWPDA, SPPR	6	CEC Not Yet Filed	TBD	230
A75	Pinnacle Peak-Brandow 230 kV line	SRP	TBD	CEC Approved - Case #69	TBD	230
A76	Rancho Vistoso-(Future) Sun City 138 kV line	TEP	3.5	CEC Not Required	TBD	138
A77	Rogers-Browning 230 kV line	SRP	9	CEC Not Yet Filed	TBD	230
A78	Rogers-Corbell 230 kV line	SRP	12	CEC Not Required	TBD	230
A79	RS17 230 kV Loop-in line	SRP	0.95	CEC Approved - Decisions #59791 and #60099	TBD	230
B20	RS20 – Coronado 500kV	SRP	TBD	CEC Not Yet Filed	TBD	500
B21	San Rafael to CS2 230 kV Line	SWTC	8	CEC Not Yet Filed	TBD	230
A80	Santa Rosa-ED5 230 kV line	SCWPDA, SPPR	38	CEC Not Yet Filed	TBD	230
A81	Silver King-Browning 230 kV line	SRP	38	CEC Approved - Case #20	TBD	230
A82	Silver King-Browning/Superior 230 kV tie	SRP	0.5	CEC Not Yet Filed	TBD	230
A83	Silver King-Knoll-Future Hayden 230 kV line	SRP	35	CEC Not Yet Filed	TBD	230
A84	Springerville-Greenlee 345 kV line - 2nd circuit	TEP	110	CEC Not Yet Filed	TBD	345
A85	Sun Valley-Morgan 230 kV line	APS	TBD	CEC Approved – Decision #70850	TBD	230
A86	Sun Valley-TS10-TS11 230 kV line	APS	TBD	CEC Not Yet Filed	TBD	230
A87	Sun Valley-TS11-Buckeye 230 kV line	APS	TBD	CEC Not Yet Filed	TBD	230
A88	Test Track-Empire-ED4 230 kV line	WAPA, SCWPDA	20	CEC Not Yet Filed	TBD	230
B23	Thunderstone-Santan 230 kV line #2	SRP	13	CEC Not Yet Filed	TBD	230
A89	Tortolita North Loop 345 kV line	TEP	60	CEC Not Yet Filed	TBD	345
A90	Tortolita-South 345 kV line	TEP	68	CEC Approved - Case #50	TBD	345
A92	Tortolita-Winchester 500 kV line	TEP	80	CEC Approved - Case #23	TBD	500
A93	Vail-East Loop - Phase 3 - Third Vail-East Loop 138 kV line	TEP	22	CEC Approved - Case #8	TBD	138
A94	Vail-South 345 kV line - 2nd circuit	TEP	14	CEC Not Required	TBD	345

A96	Wellton-Mohawk 230 kV Line Project	WMIDD	35	CEC Not Yet Filed	TBD	230
A97	Westwing-El Sol 230 kV line	APS	11	CEC Approved – Docket#U-1345	TBD	230
A98	Westwing-Raceway 230 kV line	APS	7	CEC Approved – Decision#64473	TBD	230
A99	Westwing-South 345 kV line - 2nd circuit	TEP	178	CEC Approved - Case #15	TBD	345
A100	Winchester-Vail 345 kV line #2 and #3	TEP	40	CEC Not Yet Filed	TBD	345
A101	Yucca-TS8 230 kV line	APS	TBD	CEC Not Yet Filed	TBD	230

Exhibit 8 – Arizona Demand Forecast Data (5^{th} BTA vs. 6^{th} BTA)[1]

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
APS										
5th BTA Loads (MW)	8,041	8,314	8,575	8,834	9,096	9,355	9,624	9,888	NA	NA
6th BTA Loads (MW)	7,299	7,403	7,536	7,764	8,047	8,264	8,591	8,922	9,229	9,539
Change (MW)	-742	-911	-1,039	-1,070	-1,049	-1,091	-1,033	-966	NA	NA
Change (% of 5th BTA)	-9.2%	-11.0%	-12.1%	-12.1%	-11.5%	-11.7%	-10.7%	-9.8%	NA	NA
SRP										
5th BTA Loads (MW)	7,726	7,989	8,253	8,519	8,786	9,054	9,323	NA	NA	NA
6th BTA Loads (MW)	7,100	7,295	7,502	7,720	7,955	8,194	8,428	8,702	8,984	NA
Change (MW)	-626	-694	-751	-799	-831	-860	-895	NA	NA	NA
Change (% of 5th BTA)	-8.1%	-8.7%	-9.1%	-9.4%	-9.5%	-9.5%	-9.6%	NA	NA	NA
TEP										
5th BTA Loads (MW)	2,556	2,629	2,702	2,777	2,853	2,931	3,010	3,091	NA	NA
6th BTA Loads (MW)	2,384	2,430	2,484	2,527	2,572	2,618	2,662	2,707	2,750	2,792
Change (MW)	-172	-199	-218	-250	-281	-313	-348	-384	NA	NA
Change (% of 5th BTA)	-6.7%	-7.6%	-8.1%	-9.0%	-9.8%	-10.7%	-11.6%	-12.4%	NA	NA
UNSE										
5th BTA Loads (MW)	616	652	690	725	759	791	819	845	NA	NA
6th BTA Loads (MW)	460	483	493	502	515	526	535	544	554	563
Change (MW)	-156	-169	-197	-223	-244	-265	-284	-301	NA	NA
Change (% of 5th BTA)	-25.3%	-25.9%	-28.6%	-30.8%	-32.1%	-33.5%	-34.7%	-35.6%	NA	NA
AZ TOTAL										
5th BTA Loads (MW)	18,939	19,584	20,220	20,855	21,494	22,131	22,776	NA	NA	NA
6th BTA Loads (MW)	17,243	17,611	18,015	18,513	19,089	19,602	20,216	20,875	21,517	NA
Change (MW)	-1,696	-1,973	-2,205	-2,342	-2,405	-2,529	-2,560	NA	NA	NA
Change (% of 5th BTA)	-9.0%	-10.1%	-10.9%	-11.2%	-11.2%	-11.4%	-11.2%	NA	NA	NA

[1] AZ TOTAL does not include the demand forecast for the Cooperatives in the State.

Exhibit 9 – SunZia Southwest Transmission Project

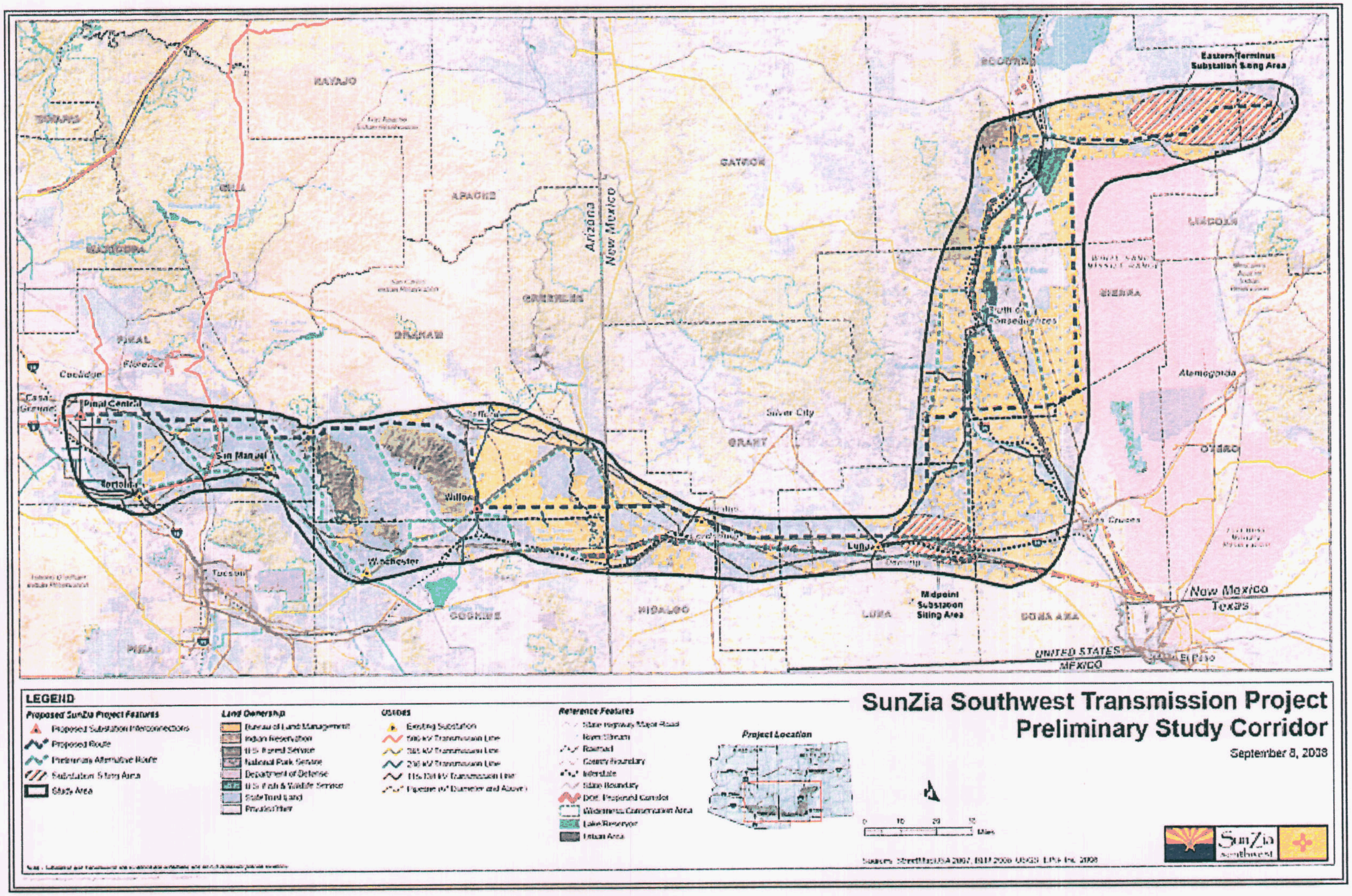


Exhibit 10 – High Plains Express (HPX) Map

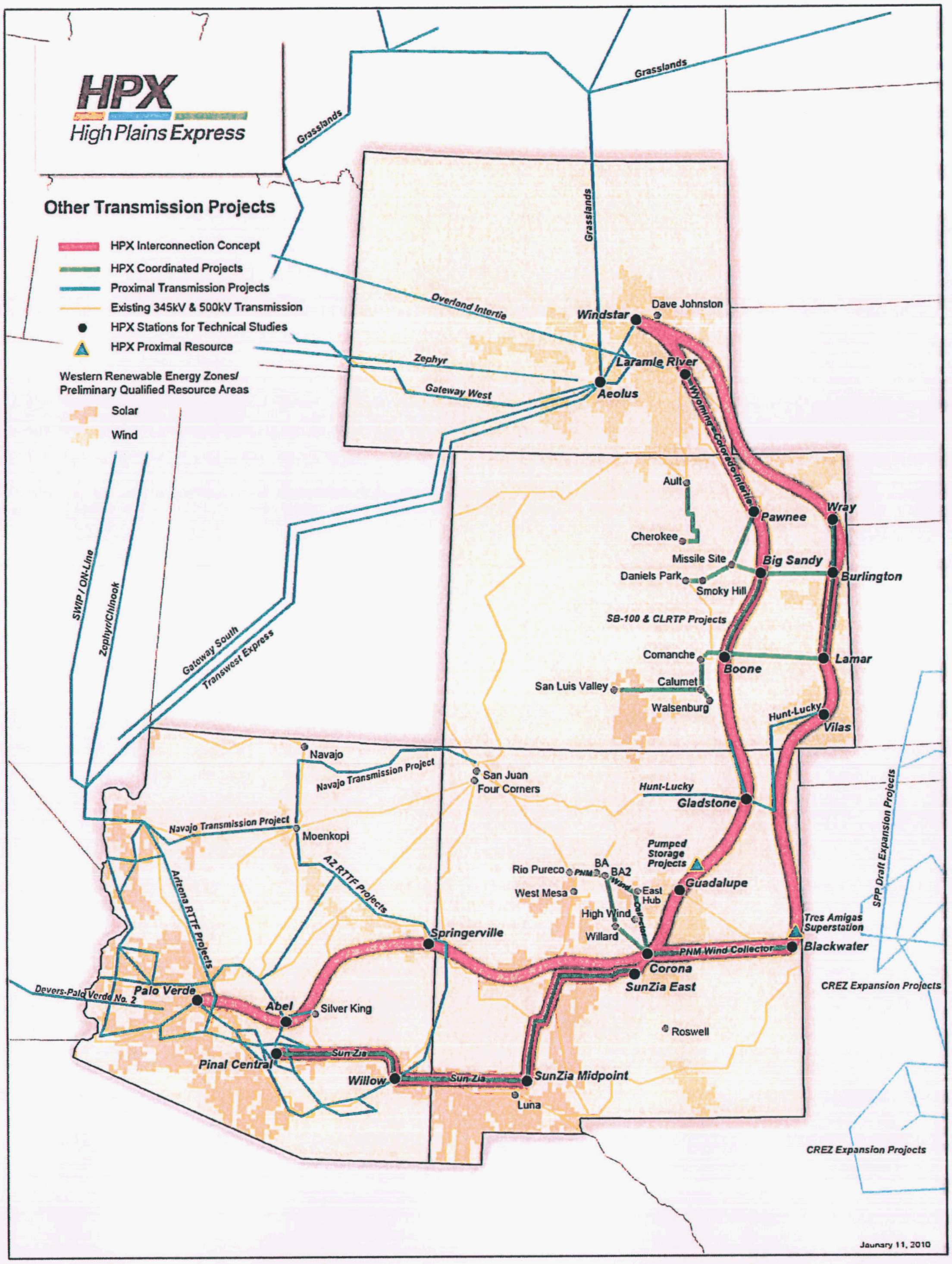
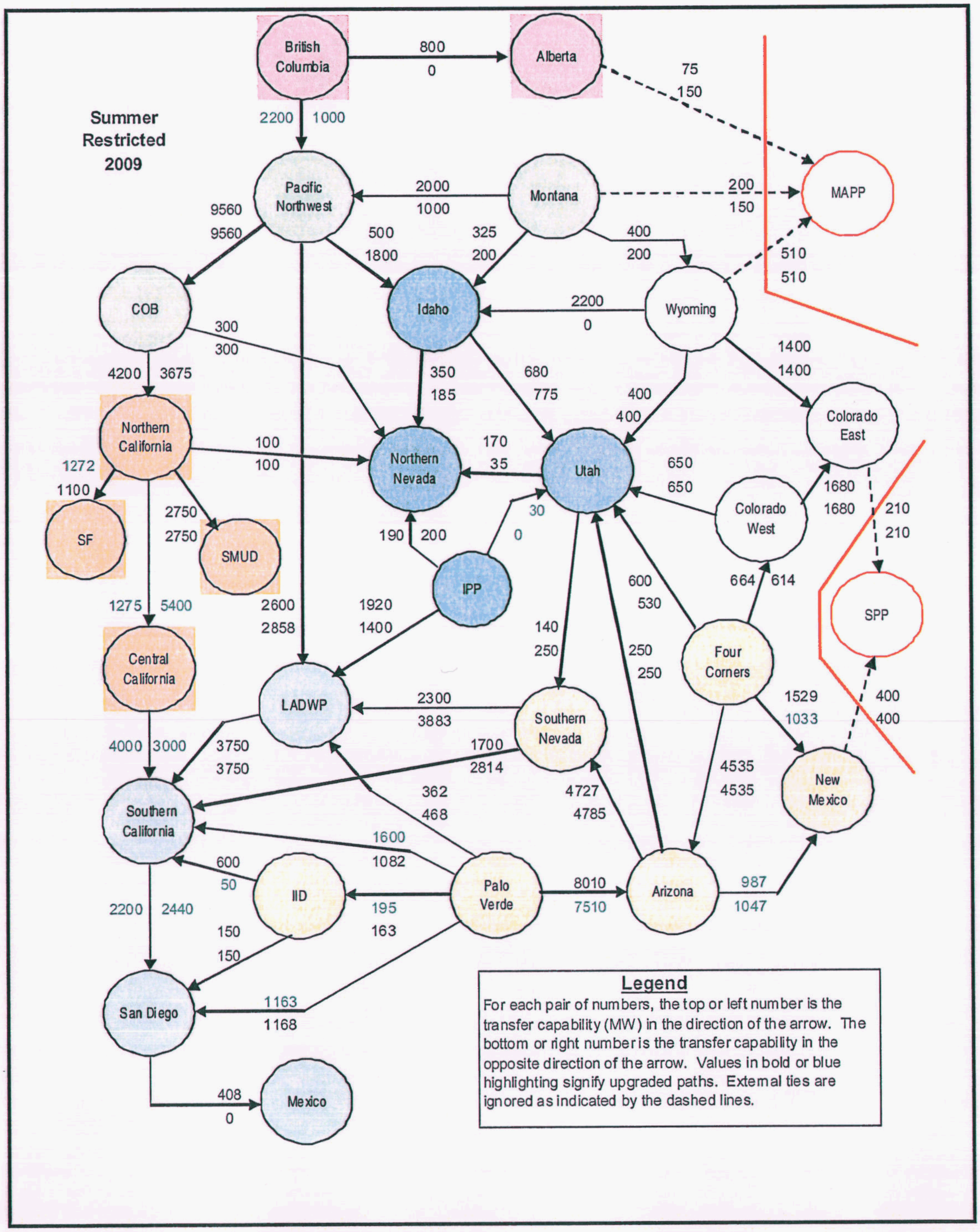


Exhibit 11 – WECC Transfer Path "Bubble Diagram" (2009)



Source – WECC Power Supply Study, Draft Report, Aug. 19, 2009

Exhibit 12 – TransWest Express Project Map

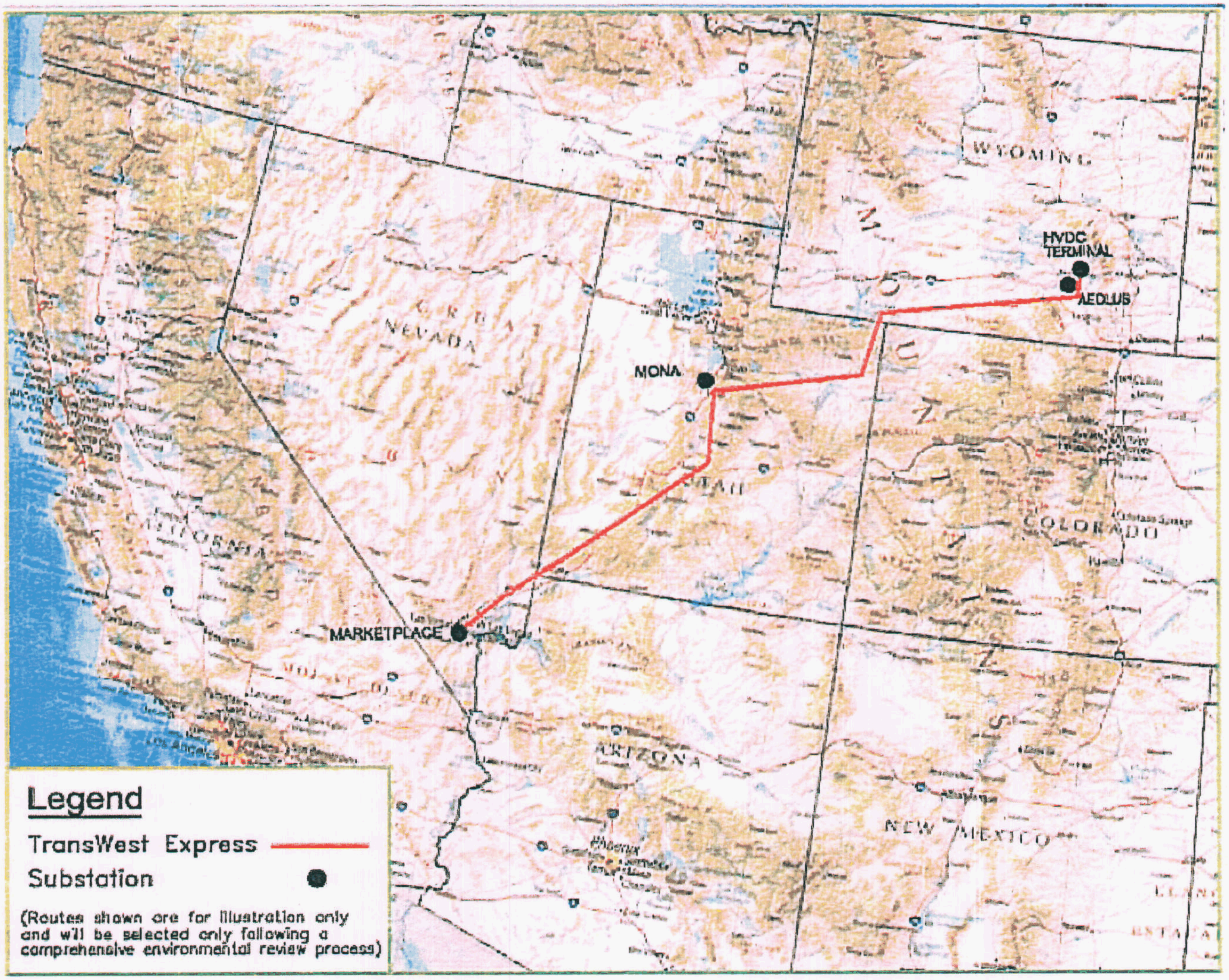


Exhibit 13 – ED5-PV Project

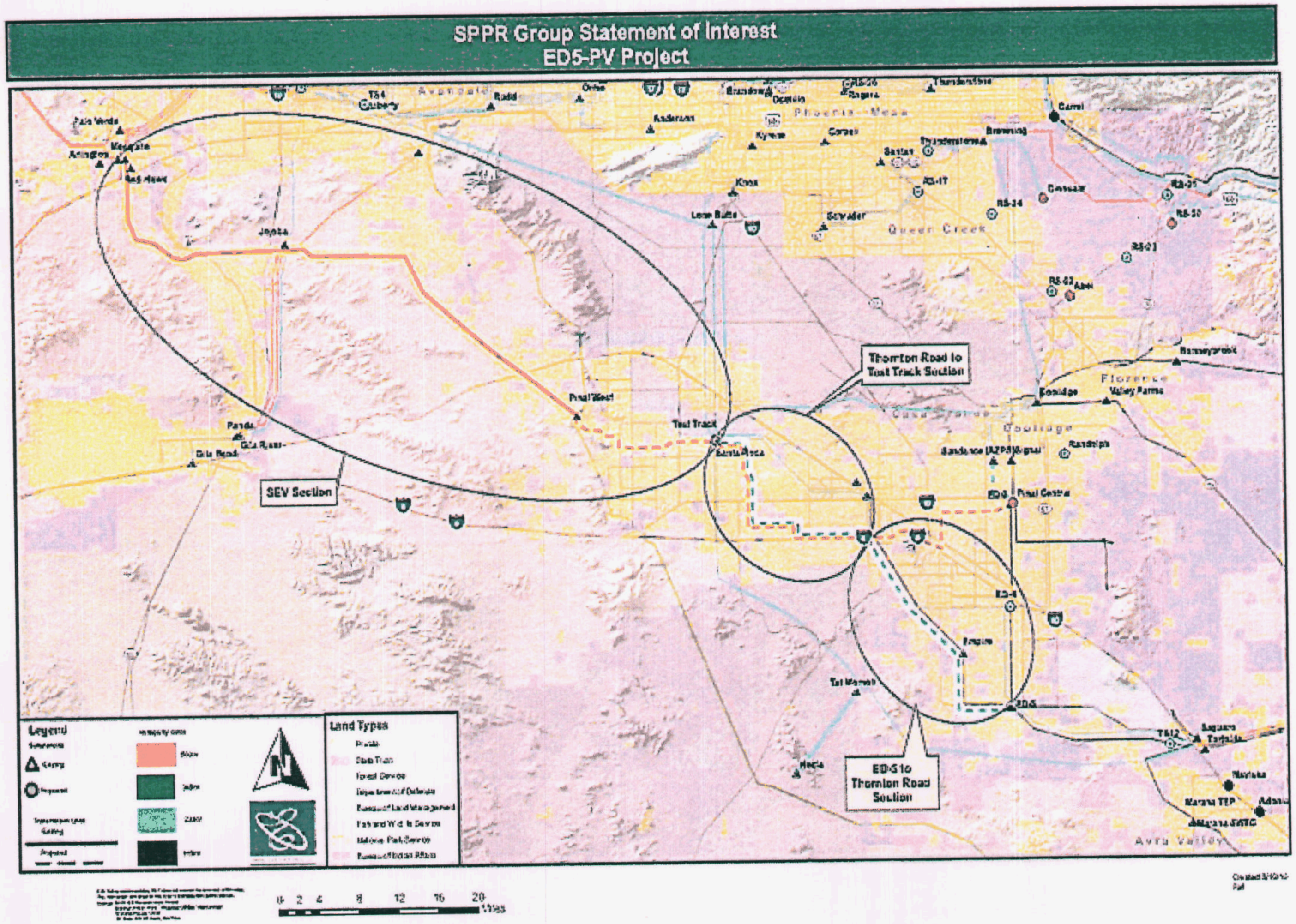


Exhibit 14 – Bowie Power Project

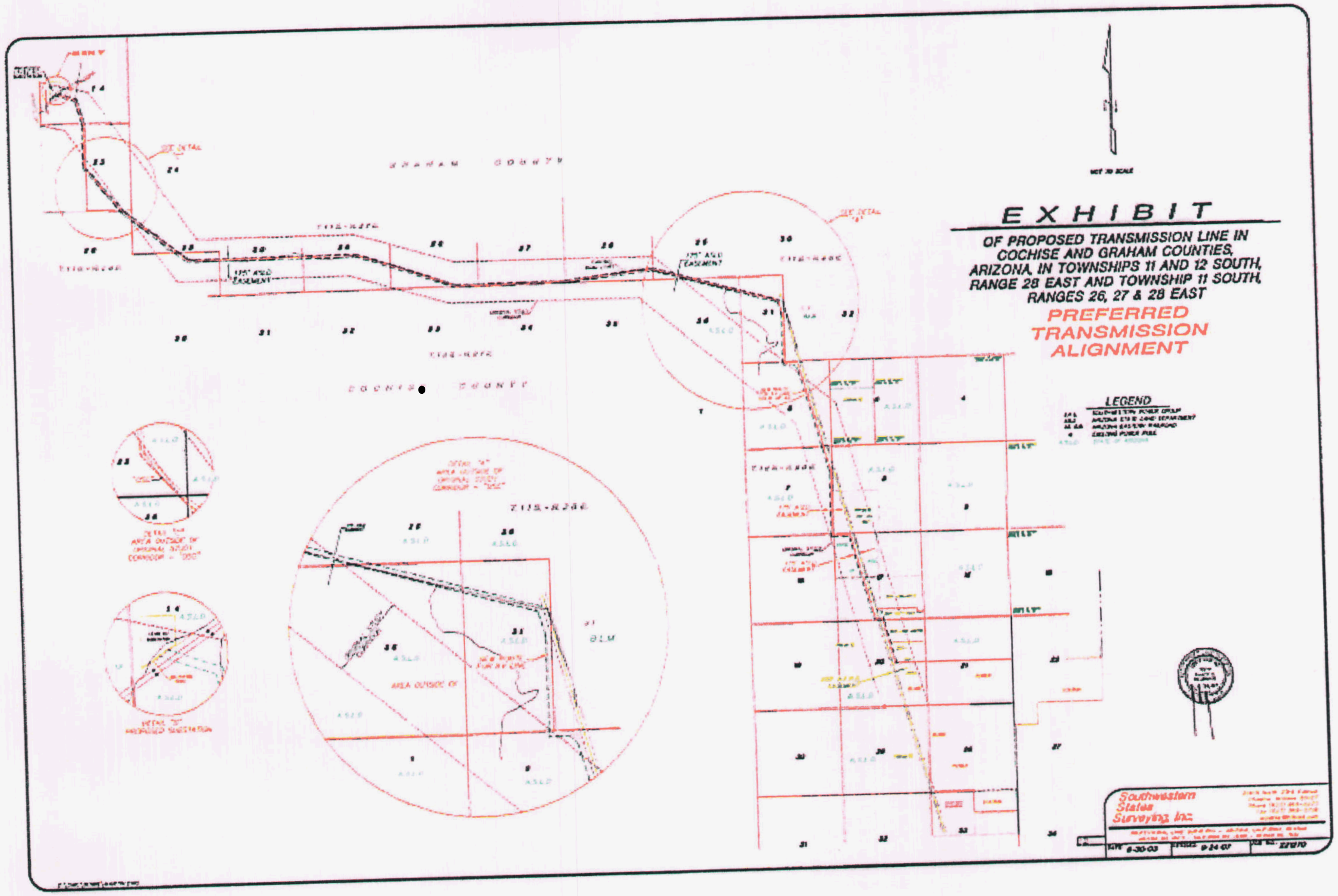


Exhibit 15 – Sonoran Solar Energy Project

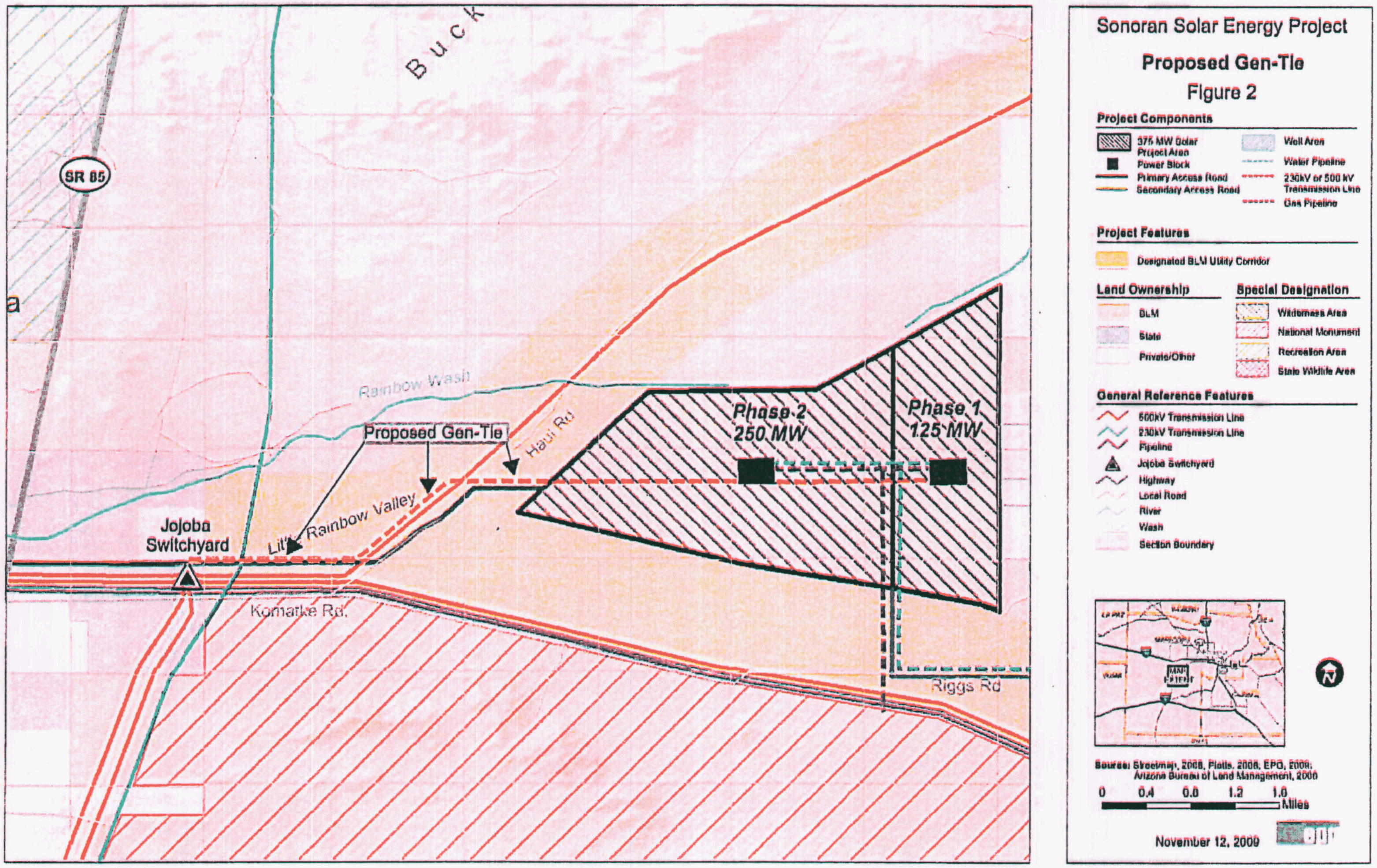
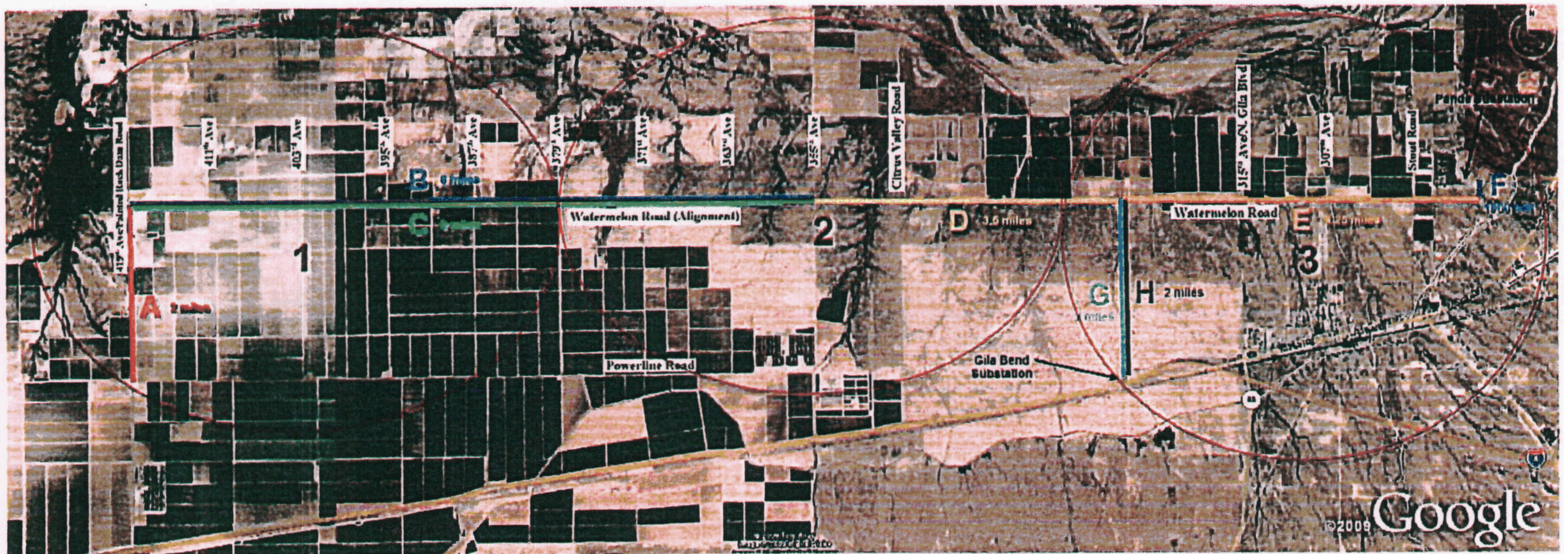


Exhibit 16 – Abengoa Solar Project

Q44 (280MW) - Facilities Study



A 200 foot corridor East of Painted Rock Dam Road Centerline

B

C

D 1200 foot corridor South of Section Line (Watermelon Road Alignment Centerline)

E

F 500 foot corridor extending 1000 feet North of Watermelon Road Centerline Adjacent to Panda Substation

G

H

230kV ROUTE OPTIONS & ACQUISITION ESTIMATE		
	Route A Total	235K
	Route B Total	760K
	Route C Total	840K
	Route D Total	505K
	Route E Total	465K
	Route F Total	50K
Option 1	A, B, D, E, F	2,015K
Option 2	A, C, D, E, F	2,095K
Average of Options 1 & 2		2,055K
G or H - South to Gila Bend Sub.	Route G Total	130K
G or H - South to Gila Bend Sub.	Route H Total	130K
Acquisition Time Required:	12 to 24 Months	

Valuation Zone 1

Valuation Zone 2

Valuation Zone 3

Exhibit 17 – Mesquite Solar Project

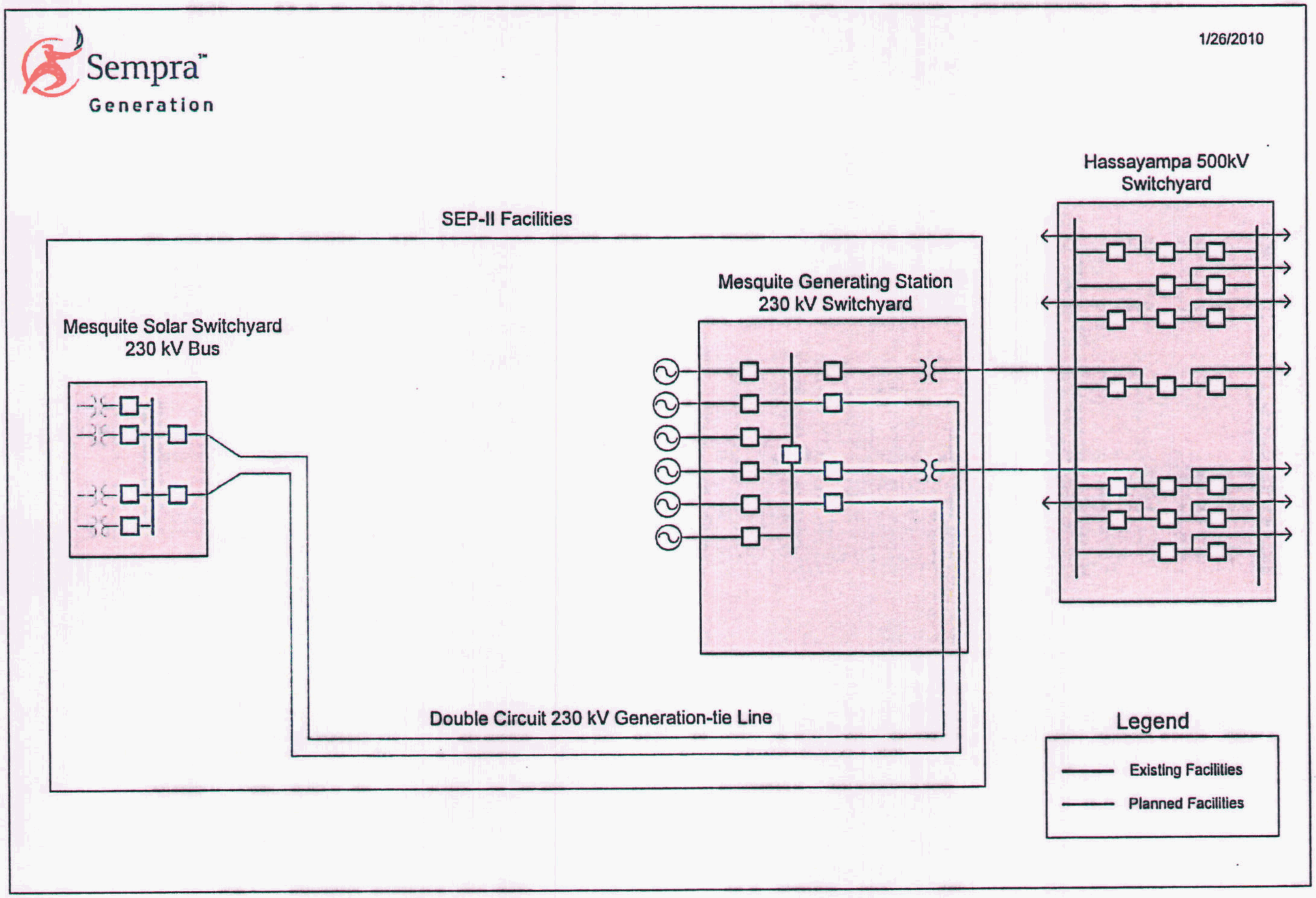


Figure 2: Sempra Generation (SEP-II) Ten-Year Transmission Plan

Exhibit 18 – Plan Changes Between Fifth and Sixth BTA

Description	Year	Changes
Hassayampa-Pinal West 500 kV #1 line	2008	Project Completed
Interconnection of Westwing-South 345kV with future Hassayampa-Pinal West 500 kV	2008	Project Completed
Loop existing West Ina -Tucson 138 kV line	2008	Project Completed
Northeast 138 kV Static Var Compensator (SVC)	2008	Project Completed
Tortolita-North Loop-Rancho Vistoso and Tortolita-Rancho Vistoso corridor expansion and reconfiguration Project - Phase 1	2008	Project Completed
Milligan Loop-in of Saguaro-Casa Grande 230 kV line	2009	Project Cancelled
Sugarloaf Loop-in of Coronado-Cholla 500 kV line	2009	Project Completed
VV01 Loop-in of Navajo-Westwing 500 kV line	2009	Project Cancelled
Western 115 kV line loop-in to Pantano	2009	Project Cancelled
Morgan-Pinnacle Peak 500 KV line	2010	Description Updated
Morgan-Raceway-Avery-Scatter Wash-Pinnacle Peak 230 kV line	2010	Description Updated
Saguaro to North Loop	2010	Description, Permitting/Siting Status, Year Updated
CAP 115 kV line loop-in to SWTC Sandario	2010	Permitting/Siting Status, Year Updated
Naviska-Thornydale 115 kV line	2010	Permitting/Siting Status, Year Updated
Thornydale-Rattlesnake 115 kV line	2010	Permitting/Siting Status, Year Updated
Valencia-CAP Black Mountain 115 kV line	2010	Permitting/Siting Status, Year Updated
Vail-Cienega-Spanish Trail Project - Phase 1 - Vail-Cienega 138 kV line	2010	Project Completed
Tortolita-North Loop-Rancho Vistoso and Tortolita-Rancho Vistoso corridor expansion and reconfiguration Project - Phase 2	2011	Description, Permitting/Siting Status, Year Updated
Dinosaur – Abel – Randolph 230kV line	2011	New Project
DeMoss Petrie-Tucson 138 kV line	2011	Year Updated
Marana Tap-Marana 115 kV Line Upgrade	2011	Year Updated
Delany – Palo Verde 500kV line	2012	New Project
Upgrade existing 115 kV transmission line to Nogales	2012	Permitting/Siting Status, Year Updated
345/69 kV Interconnection at Western's Flagstaff 345kV bus	2012	Year Updated
South-Duval CLEAR - Phase 2b - Extend 138 kV line from Canoa Ranch-(Future) Duval	2013	Year Updated

TS12 Loop-in of Saguaro-Casa Grande 230 kV line	2013	Description, Year Updated
SunZia Project	2013	Participants Updated
CS1-Three Points 115 kV line	2013	Project Cancelled
Future CS1-Bicknell 230 kV line	2013	Project Cancelled
Irvington-Vail 138 kV #2 line	2013	Project Cancelled
Mazatzal Loop-in of Cholla-Pinnacle Peak 345 kV line	2013	Year Updated
Moenkopi-Eldorado 500 kV Series Capacitor Upgrade Project	2013	Year Updated
Northeast-Snyder 138 kV Tap for Craycroft-Barril substations	2013	Year Updated
Vail-East Loop - Phase 4 - Harrison Tap of Roberts-East Loop 138 kV line	2013	Year Updated
Delany-Sun Valley 500 kV line	2014	Description, Length, Year Updated
Pinal West-Pinal Central – Randolph - Abel-Browning 500 kV line	2014	Description, Permitting/Siting Status, Year Updated
Desert Basin-Pinal Central 230 kV	2014	Description, Year Updated
Sun Valley-Trilby Wash - 230 kV line	2014	Description, Year Updated
Sundance-Pinal Central 230 kV line	2014	Description, Year Updated
Three Terminal Plan Circuit 1 Participation	2014	New Project
Three Terminal Plan Circuit 2 Participation	2014	New Project
Three Terminal Plan Circuit 3 Participation	2014	New Project
Pinal Central-Tortolita 500 kV line	2014	Participants, Year Updated
Apache/Hayden-San Manuel 115 kV line	2014	Permitting/Siting Status, Year Updated
La Canada-Orange Grove-Rillito 138 kV line	2014	Year Updated
North Gila-TS8 230 kV line	2014	Year Updated
Palo Verde Hub-North Gila 500 kV #2 line	2014	Year Updated
RS26-Fountain Hill substation	2014	Year Updated
Irvington-Kino–UA Med-Tucson 138 kV line	2015	Description, Year Updated
Palm Valley-TS2-Trilby Wash 230 kV line	2015	Description, Year Updated
Tortolita Rancho Vistoso 138 kV tap for future Naranja substation	2015	Description, Year Updated
Saguaro to Adonis 115 kV Line Loop-in to Naviska	2015	New Project
Vail – Irvington 345 kV line	2015	New Project
South-Hartt-Green Valley 138 kV line	2015	Year Updated
Tortolita-Marana-North Loop Project - Phase 1 - Tortolita-Marana 138 kV line	2015	Year Updated
Sun Valley-Morgan 500 kV line	2016	Description, Permitting/Siting Status, Year Updated
Del Cerro-Anklam-Tucson 138 kV line	2016	New Project

Griffith-North Havasu 230 kV line	2016	Permitting/Siting Status, Year Updated
Hartt-SS N029 138 kV line	2016	Project Cancelled
Irvington-South Project - Phase 2 - Corona-SS N026-South 138 kV line	2016	Project Cancelled
Irvington-South Project - Phase 1 - Irvington-Corona-South 138 kV line	2016	Year Updated
Upgrade of Apache-Butterfield 230 kV line	2016	Year Updated
Orange Grove-East Ina 138 kV line	2017	Description Updated
Abel (RS24)-Moody (RS17) 230 kV #1	2017	Description, Length, Permitting/Siting Status, Year Updated
Butterfield to Bicknell 230 kV Line Upgrade	2017	New Project
Abel (RS24)-Moody (RS17) 230 kV #2	2018	Description, Length, Permitting/Siting Status, Year Updated
CAP 115 kV Line Loop-in to Picture Rocks	2018	New Project
Midvale-Spencer-Medina-Raytheon-South 138 kV line	2019	Description, Year Updated
Irvington-South Project - Phase 3 - Corona-Swan Southlands and Swan Southlands-SS NO 26 138 kV lines	2019	Project Cancelled
Pinal Central – Abel #2 500kV line	2020	New Project
Vail-SS N017-Irvington 138 kV line	2020	Project Cancelled
Vail-SSNO27-Cienega-SSNO22-Spanish Trail Project - Phase 2 - Vail-SSN027 138 kV line	2020	Project Cancelled
Tortolita-Marana-North Loop Project - Phase 2 - Marana-SSN01-North Loop 138 kV line	2023	Project Cancelled
Vail-SSNO27-Cienega-SSNo22-Spanish Trail Project - Phase 3 - Cienega-SSN020 138 kV line	2023	Project Cancelled
DeMoss Petrie-SS N014-Northeast 138 kV line	2026	Project Cancelled
North Loop-SS N04-Demoss Petrie 138 kV line	2030	Project Cancelled
New Hayden 115 kV Station Loop-in	TBD	Description Updated
Nogales Transmission line #2 (Gateway – Valencia)	TBD	Description Updated
Pinal Central (Pinal South) – Future substation 6 miles northeast 230 kV line #1	TBD	Description Updated
Pinal Central (Pinal South) – Future substation 6 miles northeast 230 kV line #2	TBD	Description Updated
Winchester-Vail 345 kV line #2 and #3	TBD	Description Updated
Sun Valley-Morgan 230 kV line	TBD	Description, Permitting/Siting Status Updated
Rancho Vistoso-(Future) Sun City 138 kV line	TBD	Description, Year Updated
Tortolita North Loop 345 kV line	TBD	Description, Year Updated
Abel – RS20 500kV	TBD	New Project
CS2 Substation	TBD	New Project

Interconnection of Greenlee-Winchester 345kV line with future Willow Substation	TBD	New Project
Irvington – South 345 kV line	TBD	New Project
Kartchner to CS2 230 kV Line	TBD	New Project
Mural – San Rafael 230kV line	TBD	New Project
Pantano to Kartchner 115 kV Line Upgrade	TBD	New Project
RS20 – Coronado 500kV	TBD	New Project
San Rafael to CS2 230 kV Line	TBD	New Project
TEP System – Rosemont 138 kV line	TBD	New Project
Thunderstone-Santan 230 kV line #2	TBD	New Project
Vail-UA Tech Park-Irvington 138 kV line	TBD	New Project
Winchester to Vail Double-Circuit 345 kV Line	TBD	New Project
Future Cienega-Mountain View 138 kV line	TBD	Project Cancelled
Future Sloan-Huachuca 230 kV line	TBD	Project Cancelled
North Gila-Yucca 230 kV line	TBD	Project Cancelled
Sun Valley-Trilby Wash – 230 kV line # 2	TBD	Project Cancelled
Tortolita-Rillito 138 kV line	TBD	Project Cancelled
Tortolita-Vail 345 kV Project - Phase 2 - North Loop-East Loop line	TBD	Project Cancelled
Westwing-Pinnacle Peak 230 kV line	TBD	Project Cancelled
East Loop-Northeast 138 kV line	TBD	Project Completed
Golden Valley 230 kV Project - McConico-Mercator Mill 230 kV line	TBD	Year Updated
Jojoba Loop-in of TS4-Panda 230 kV line	TBD	Year Updated

Exhibit 19 – Generation Interconnection Queue(s)

Interconnecting Utility and Queue list	Maximum Output	Interconnection Location	In-Service Date	Technology
SRP Transmission	562	Randolph	9/1/2010	Natural Gas
SRP-ANPP	720	Hassayampa 500 kV	3/1 / 2010 – 2014 (one 180MW unit per year)	Photovoltaic
SRP-ANPP	500	Jojoba	12/1/2012	Concentrated Solar Power
SRP-ANPP	125	Hassayampa 500 kV	2011	Concentrated Solar Power
SRP-ANPP	125	Hassayampa 500 kV	2011	Concentrated Solar Power
SRP-ANPP	200	Hassayampa 500 kV	5/12013	Photovoltaic
SRP-ANPP	250	Jojoba	1/1/2013	Concentrated Solar Power
SRP-MP	500	Mead-Perkins	10/1/2009	Wind
SRP-MP	250	Mead-Perkins	10/1/2013	Concentrated Solar Power
SRP-MP	250	Mead-Perkins	4/8/2013	Concentrated Solar Power
SRP Transmission	700	Coronado 500kV	9/15/2012	Wind
SRP Transmission	658	Abel 230	9/1/2011	Natural Gas
SRP Transmission	304	Abel 69	9/1/2011	Natural Gas
SRP Transmission	1315	Pinal New Sub	9/1/2013	Natural Gas
SRP Transmission	200	CO-CH	12/1/2013	Wind
SRP Transmission	150	Cholla-Sugarloaf 500kV	12/31/2012	Wind
SRP Transmission	150	Cholla-Sugarloaf 500kV	12/31/2012	Wind
SRP-Joint Participation	125	Pinal Central 230kV	11/1/2012	Solar (steam)
SRP-Joint Participation	520	Pinal Central 500kV	6/15/2012	Natural Gas
SRP-Joint Participation	125	Pinal Central 500kV	6/15/2012	Natural Gas
SRP-Joint Participation	125	Pinal Central 500kV	6/15/2012	Natural Gas
APS	Unit 1 – 700	Four Corners 500kV Switchyard	8/1/2015	Coal
	Unit 2 – 700		8/1/2015	
APS	128	Cholla/Zeniff/Show Low Western 69kV line and Cholla/Show Low Eastern 69kV line	West = 8/17/2009 East = 10/1/2010	Wind
APS	22	Cholla/Zeniff/Show Low Western 36kV line	Q2 2008	Biomass
APS	100	Existing Yucca 36kV substation	6/1/2008	Gas Combustion Turbine
APS	Units 1-4 – 583 each (63 MW Net Increase per Unit)	Gila River 500kV		Gas Combined Cycle
APS	260	Ashfork-Pollock 69kV System and Seligman 230 kV to be studied	3/13/2012	Wind
APS	125	Cholla/Show Low Eastern 69 kV line	12/1/2012	Wind
APS	100	Adams – Mural 115kV line	12/31/2010	Wind
APS	102	Proposed Harquahala Junction (Delany) Switchyard	10/1/10-	Solar

			12/1/2011	
APS	87	Paloma 69kV Substation	10/1/10-12/1/2011	Solar
APS	400	North Gila Substation	Q4 2012	Solar
APS	1000	Moenkopi 500kV	2015	Wind
APS	300	Cholla 500kV Substation	11/1/2010	Wind
APS	400	Proposed Harquahala Junction (Delany) Switchyard	7/31/2011-12/31/2012	Solar
APS	800	Proposed Harquahala Junction (Delany) Switchyard	1/1/2013-12/31/2014	Solar
APS	500	Moenkopi – El Dorado 500kV line	7/1/2010	Wind
APS	250	North Gila Substation	Q4 2012	Solar Thermal
APS	500	Proposed Harquahala Junction (Delany) Switchyard	6/30/2012	Solar
APS	500	PV-NG1 500kV line (New Hoodoo Wash 500kV Switchyard)	12/2011	Solar
APS	280	Panda 230 kV Substation	12/1/2011	Solar
APS	300	PV-NG1 500kV Line	10/1/2011 11/1/2011 3/1/2012	Solar
APS	250	Gila Bend 230kV Switchyard or Panda 230kV Switchyard	Q2 2013	Solar
APS	80	SW6 Substation	3/1/2013	Solar
APS	150	North Gila System	7/1/2012	Solar
APS	150	Cholla-PNPK 345 kV line	12/31/2013	Wind
APS	300	Proposed Delany Switchyard	9/1/2012	Solar
APS	99	Hassayampa-N Gila 500 kV line	Q2 and Q4 2012	Solar
APS	99	Hassayampa-N Gila 500 kV line	Q2 and Q4 2013	Solar
APS	40	Hassayampa-N Gila 500 kV line	Q2 2012	Solar
APS	500	Moenkopi 500 kV Switchyard	Q2 2012	Wind
APS	150	Gila Bend 230kV Substation	7/1/2013	Solar
APS	480	Hassayampa-N Gila 500 kV line	1/1/2014	Solar
APS	200	Panda Switchyard 230 kV or Gila Bend Substation 230 kV	PH-1 – 100MW 12/2014 PH2 – 100MW 12/2015	Solar
APS	600	PV-NG 500 kV Line (Q43 Switchyard)	6/1/2013	Solar
APS	300	Sun Valley 230 kV Switchyard	6/1/2015	Solar
APS	480	Hassayampa-N Gila 500 kV line	1/1/2014	Solar
APS	297	San Manuel 115kV Switchyard	12/30/2011	Solar
APS	20	Aztec Substation	3/31/2011	Solar
APS	20	Hyder Substation	3/31/2011	Solar
APS	20	Cotton Center Substation	3/31/2011	Solar
APS	20	Cotton Center Substation	3/31/2011	Solar

APS	70	Buckeye – Desert Sky 69 kV line	8/31/2013	Solar
APS	390	Four Corners – Cholla 345 kV line	12/31/2012	Wind
APS	20	Hyder-Saddle Mountain 69 kV line	6/1/2011	Solar
APS	20	ASARCO-SantaRosa 69 kV line	1/31/2011	Solar
APS	20	12 kV Interconnection – Buckeye	11/30/2011	Solar
APS	20	12 kV Interconnection – Ehrenberg	Q4 2010	Solar
APS	20	Vicksburg Area 69 kV	12/31/2012	Solar
APS	200	Cholla – Pinnacle Peak 345 kV line	12/31/2012	Wind
APS	50	69 kV Interconnection – Gila Bend Area	12/31/2011	Solar
APS	50	69 kV Interconnection – Tonopah Area	12/31/2011	Solar
APS	20	12 kV Interconnection – Ehrenberg	Q4 2010	Solar
APS	20	69 kV Interconnection 335 Ave & Dobbins Rd	12/31/2011	Solar
APS	20	69 kV Interconnection 335 Ave & Dobbins Rd	12/31/2011	Solar
APS	20	69 kV Interconnection – Gillespie Sub Area	1/1/2012	Solar
APS	20	69 kV Interconnection – Lower River Sub/or 12 kV *into Baseline Sub*	11/30/2011	Solar
APS	200	69 kV Interconnection – Sugarloaf Sub Area	12/2012 and 12/2013	Wind
APS	120	Bagdad Area 115 kV Transmission System	12/1/2012	Wind
APS	30	Cotton Center 69 kV Substation	12/15/2012	Solar
APS	30	Tonopah 69 kV Substation	12/15/2012	Solar
APS	101	Moenkopi – Yavapai 500 kV line	8/1/2011	Wind
APS	60	Salome 69kV Substation	12/21/12 6/30/13	Solar
APS	20	69 kV Interconnection – Gila Bend Area	10/1/2012	Solar
APS	20	69 kV Interconnection – Gila Bend Substation Area	2/28/2012	Solar
APS	20	69 kV Interconnection – Gila Bend Substation Area	3/31/2012	Solar
APS	20	69 kV Interconnection – Gila Bend Substation Area	4/30/2012	Solar
APS	20	69 kV Interconnection – Hwy 60 & Farm Access Road	12/31/2011	Solar
APS	20	69 kV Interconnection – Hwy 60 & Farm Access Road	12/31/2011	Solar
APS	20	Lower River – Wintersburg 69 kV line	4/15/2012	Solar
APS	20	Lower River – Wintersburg 69 kV line	12/31/2011	Solar
APS	20	W. Riggs Rd & 170th Ave	9/1/2011	Solar
APS	20	Indian School Rd & 355th Ave	9/1/2011	Solar
APS	20	I-10 & 507th Ave	9/1/2011	Solar
APS	20	12 or 69 kV Interconnection – Hyder Substation	11/30/2011	Solar
APS	20	12 or 69 kV Interconnection – Harquahala Substation	2/28/2012	Solar
APS	20	12 or 69 kV Interconnection – Salome Substation	2/28/2012	Solar
APS	20	12 or 69 kV Interconnection – Arlington Substation	2/28/2012	Solar
APS	20	69 kV Interconnection – 69kV line Palmas Rd and Dateland Rd	12/31/2010	Solar

APS	20	69 kV Interconnection – Gila Bend 69kV Watermelon Rd and 307 Ave	12/31/2010	Solar
APS	20	12 kV bus-bar, transformer at Baseline Substation	11/30/2011	Solar
APS	20	12 or 69 kV Interconnection – Patterson Substation	12/31/2012	Solar
APS	50	Sugarloaf 69 kV Substation	12/1/2012	Solar
APS	20	69 kV between Hyder and Saddle Mountain Sub	2/28/2012	Solar
APS	20	Baseline Substation Area	2/28/2012	Solar
APS	20	69 kV line between Tonopah and Harquahala Subs	2/28/2012	Solar
APS	20	Saddle Mountain 69 kV Substation	81/2011	Solar
APS	99	Show Low 69 kV Substation	1/10/2012	Wind
APS	50	Hyder 69 kV Substation	8/1/2011	Solar
APS	20	Harqualaha 69 kV to 12 kV Switch location	5/1/2010	Solar
APS	50	69 kV line between Wintersburg & Lower River	12/31/2012	Solar
APS	20	69 kV Vicksburg Substation	3/31/2011	Solar
APS	20	Wintersburg 69 kV Substation Area	2/28/2012	Solar
APS	20	69 kV Cotton Center Substation	6/5/2012	Solar
TEP	430	Springerville, AZ	Q2 2004	Generator
TEP	95	Between Coronado & Springerville	12/31/2007	Wind
TEP	500	Greenlee-Vail 345 kV line	N/A	Wind
TEP	700	Various	12/31/2010	Wind
TEP	700	Various	12/31/2010	Wind
TEP	250	South-Green Valley 138 kV line	Q4 2012	Solar
TEP	500	Greenlee-Winchester 345 kV line	S 2009	Generator
TEP	700	Springerville 345 kV Yard	Dec 2010	Wind
TEP	150	Springerville 345 kV line	3/15/2013	Wind
TEP	200	Springerville 345 kV line	1/10/2012	Wind
UNSE	80	Dolan Springs Substation	9/12/2005	Wind
UNSE	50	Industrial Substation 69 kV Bus	5/1/2011	Solar
UNSE	20	Steel Park, Old Trails Rd, Kingman, AZ	3/31/2011	Wind/Solar

Exhibit 20 – Listing of Projects by In-Service Date

Year	Project ID	Description	Participants	Length (mi)	Permitting/Siting Status	Voltage (kV)
2010	A1	Bowie Power Project	BOWIE	15	CEC Approved – Decision #64626	345
2010	A2	CAP 115 kV line loop-in to SWTC Sandario	SWTC	0.6	CEC Approved – Case #152	115
2010	A3	Marana-Avra Valley 115 kV Line Upgrade	SWTC	8.75	CEC Not Yet Filed	115
2010	A4	Morgan-Pinnacle Peak 500 KV line	APS, SRP	26	CEC Approved – Decision #69343	500
2010	A5	Morgan-Raceway-Avery-Scatter Wash-Pinnacle Peak 230 kV line	APS	27	CEC Approved – Decision #69343	230
2010	A6	Naviska-Thornydale 115 kV line	SWTC	7	CEC Approved – Case #149	115
2010	A7	Saguaro to North Loop	SWTC	3.2	CEC approved – Case #149	115
2010	A8	Thornydale-Rattlesnake 115 kV line	SWTC	19	CEC Approved – Case #152	115
2011	A9	Tortolita-North Loop-Rancho Vistoso and Tortolita-Rancho Vistoso corridor expansion and reconfiguration Project - Phase 2	TEP	11.1	CEC Approved – Case #149	138
2010	A10	Valencia-CAP Black Mountain 115 kV line	SWTC	2.6	CEC Approved – Case #152	115
2010	A11	White Hills substation	UNISOURCE	0	CEC Not Required	345/69
2011	A12	Avra Valley-Sandario Tap 115 kV Line Upgrade	SWTC	2.8	CEC Not Yet Filed	115
2011	A13	DeMoss Petrie-Tucson 138 kV line	TEP	4.5	CEC Not Yet Filed	138
2011	A14	Devers - Palo Verde 500 kV #2 line	SCE	230	CEC Denied - Case #130	500
2011	B1	Dinosaur – Abel – Randolph 230kV line	SRP	TBD	CEC Approved – Case #126	230
2011	A15	Marana Tap-Marana 115 kV Line Upgrade	SWTC	0.2	CEC Not Required	115
2011	A16	Pinal South-Southeast Valley/RS22	SRP	30	CEC Approved - Decisions #68093 and #69291	230
2011	A17	Sandario Tap-Three Points 115 kV Line Upgrade	SWTC	13.71	CEC Not Yet Filed	115
2012	A19	345/69 kV Interconnection at Western's Flagstaff 345kV bus	APS	0.95	CEC Not Required	345
2012	B2	Delany – Palo Verde 500kV line	APS	15	CEC Approved – Decision #68063	500
2013	A20	South-Duval CLEAR - Phase 2b - Extend 138 kV line from Canoa Ranch-(Future) Duval	TEP	24	CEC Approved - Case #84	138

2012	A22	Upgrade existing 115 kV transmission line to Nogales	UNISOURCE	60	CEC Approved – Case #111	115
2013	A23	Interconnection of South – Midvale 138 kV circuit with future Spencer, Raytheon, Medina 138kV substations - Phase 1.	TEP	20	CEC Not Yet Filed	138
2013	A24	Mazatzal Loop-in of Cholla-Pinnacle Peak 345 kV line	APS	0.95	CEC Not Required	345
2013	A25	Moenkopi-Eldorado 500 kV Series Capacitor Upgrade Project	SCE, APS	0	CEC Not Required	500
2013	A26	Northeast-Snyder 138 kV Tap for Craycroft-Barril substations	TEP	8	CEC Not Required	138
2013	A27	SunZia Project	SWPG, SRP, TEP, ECP, Shell, TSGT	500	CEC Not Yet Filed	500
2013	A28	TS12 Loop-in of Saguaro-Casa Grande 230 kV line	APS	0.95	Not Required	230
2013	A29	Vail-East Loop - Phase 4 - Harrison Tap of Roberts-East Loop 138 kV line	TEP	0	CEC Approved - Case #8	138
2014	A30	Apache/Hayden-San Manuel 115 kV line	SWTC	4.5	CEC Approved – Case #142	115
2014	A31	Delany-Sun Valley 500 kV line	APS, SRP, CAWCD	28	CEC Approved – Decision #68063	500
2014	A32	Desert Basin-Pinal Central 230 kV	APS, SRP	21	CEC Approved – Decisions #68093, #68291, #69183 and #69647	230
2014	A33	Gateway-Sonoita 138 kV line	UNISOURCE	10	CEC Not Yet Filed	138
2014	A34	La Canada-Orange Grove-Rillito 138 kV line	TEP	5.4	CEC Not Yet Filed	138
2014	A35	North Gila-TS8 230 kV line	APS	15	To be Filed in 2008	230
2014	A36	Palo Verde Hub-North Gila 500 kV #2 line	APS, SRP, IID, WMIDD	110	CEC Approved – Decision #70127	500
2014	A37	Pinal Central-Tortolita 500 kV line	TEP, SWTC, SRP, SunZia	40	CEC Not Yet Filed	500
2014	A38	Pinal West-Pinal Central – Randolph - Abel-Browning 500 kV line	SRP, TEP, SWTC, ED2, ED3, ED4	50	CEC Approved - Case #126 - Decisions #68093 and #69291	500
2014	A39	RS26-Fountain Hill substation	SRP	TBD	CEC Not Yet Filed	115/230/345
2014	A40	Sun Valley-Trilby Wash - 230 kV line	APS	15	CEC Approved – Decision #67828	230
2014	A41	Sundance-Pinal Central 230 kV line	APS, ED2	6	CEC Filed – Case #136	230
2014	B3	Three Terminal Plan Circuit 1 Participation	SWTC	23	CEC Not Yet Filed	115
2014	B4	Three Terminal Plan Circuit 2 Participation	SWTC	31	CEC Not Yet Filed	115

2014	B5	Three Terminal Plan Circuit 3 Participation	SWTC	19	CEC Not Yet Filed	115
2015	A42	Irvington-Kino–UA Med-Tucson 138 kV line	TEP	10.9	CEC Not Yet Filed	138
2015	A43	Palm Valley-TS2-Trilby Wash 230 kV line	APS	12	CEC Approved - Decisions #66646 and #67828	230
2015	B6	Saguaro to Adonis 115 kV Line Loop-in to Naviska	SWTC	0	CEC Not Required	115
2015	A44	South-Hartt-Green Valley 138 kV line	TEP	14.5	CEC Not Yet Filed	138
2015	A45	Tortolita - Rancho Vistoso 138kV line tap for future Naranja substation.	TEP	24.5	CEC Not Yet Filed	138
2015	A46	Interconnection of Tortolita – North Loop 138 kV with future Marana 138 kV Substation.	TEP	22	CEC Not Yet Filed	138
2015	B7	Vail – Irvington 345 kV line	TEP	11	CEC Not Yet Filed	345
2016	B8	Del Cerro-Anklam-Tucson 138 kV line	TEP	2	CEC Not Yet Filed	138
2016	A47	Griffith-North Havasu 230 kV line	UNISOURCE	40	CEC Approved/Extended - Case #88, CEC Extension request not yet filled	230
2016	A48	Irvington Substation – Corona Substation – South Substation 138kV.	TEP	16.1	CEC Not Yet Filed	138
2016	A49	Sun Valley-Morgan 500 kV line	APS, SRP, CAWCD	TBD	CEC Approved – Decision #70850	500
2016	A50	Upgrade of Apache-Butterfield 230 kV line	SWTC	16	CEC Not Yet Filed	230
2017	A51	Abel (RS24)-Moody (RS17) 230 kV #1	SRP	20	CEC Approved – Decision #71441	230
2017	B9	Butterfield to Bicknell 230 kV Line Upgrade	SWTC	68.7	CEC Not Yet Filed	230
2017	A52	Orange Grove-East Ina 138 kV line	TEP	3.6	CEC Not Yet Filed	138
2018	A53	Abel (RS24)-Moody (RS17) 230 kV #2	SRP	20	CEC Approved – Decision #71441	230
2018	B10	CAP 115 kV Line Loop-in to Picture Rocks	SWTC	0	CEC Not Required	115
2018	A54	Interconnection of South – Midvale 138 kV circuit with future Spencer, Raytheon, Medina 138kV substations - Phase 2	TEP	13	CEC Not Yet Filed	138
2019		Interconnection of South – Midvale 138 kV circuit with future Spencer, Raytheon, Medina 138kV substations - Phase 3				
2020	B11	Pinal Central – Abel #2 500kV line	SRP	TBD	CEC Not Yet Filed	500
TBD	B12	Abel – RS20 500kV	SRP	TBD	CEC Not Yet Filed	500
TBD	A55	Arlington Power Plant	Dynegy Arlington Valley	TBD	CEC Approved – Decision #64357	500
TBD	B13	CS2 Substation	SWTC	0	CEC Not Yet Filed	230/115

TBD	A56	Dinosaur-RS21 230 kV line	SRP	TBD	CEC Not Yet Filed	230
TBD	A57	ED5-Marana 230 kV line	SCWPDA, SPPR	28	CEC Not Yet Filed	230
TBD	A58	ED5-Pinal South (Pinal Central) 230 kV line	SCWPDA, SPPR	18	CEC Not Yet Filed	230
TBD	A59	Future Gateway-Comision Federale de Electricidad 345 kV line	TEP	2	CEC Approved - Case #111	345
TBD	A60	Gateway 345/115 kV or 345/138 kV substations	UNISOURCE	60	CEC Approved - Case #111	345/138
TBD	A61	Gila Bend Power Plant	GBPP	0	CEC Approved – Case#109 – Extension Request Pending	500
TBD	A62	Golden Valley 230 kV Project - McConico-Mercator Mill 230 kV line	UNISOURCE	20	CEC Not Yet Filed	230
TBD	A63	Greenlee switching station through Hidalgo to Luna	ELPE, PNM, TXNMPC	28	CEC Approved – Case #21	345
TBD	A64	Hassayampa - Pinal West 500 kV #2 line	SRP, TEP, SWTC, ED2, ED3, ED4	51	CEC Approved – Case #124	500
TBD	A65	Hassayampa-Jojoba 500 kV line	GBPP	19	CEC Not Required	500
TBD	A66	Interconnection line -South-future Gateway 345 kV line	TEP, UNISOURCE	60	CEC Approved - Case #111	345
TBD	B14	Interconnection of Greenlee-Winchester 345kV line with future Willow Substation	TEP, Bowie	0	CEC obtained by Southwestern Power Group – Case #118	345
TBD	B15	Irvington – South 345 kV line	TEP	16	CEC Not Yet Filed	345
TBD	A67	Irvington-East Loop Project - Phase 3 - Irvington-22nd Street 2nd Circuit	TEP	9	CEC Approved - Case #66	138
TBD	A68	Jojoba Loop-in of TS4-Panda 230 kV line	APS	0.95	CEC Approved – Decision #62960	230
TBD	B16	Kartchner to CS2 230 kV Line	SWTC	2	CEC Not Yet Filed	230
TBD	B17	Mural – San Rafael 230kV line	APS	TBD	CEC Not Yet Filed	230
TBD	A69	New Hayden 115 kV Station Loop-in	SRP	0.75	CEC Not Yet Filed	115
TBD	A70	Nogales Transmission line #2 (Gateway – Valencia)	UNISOURCE	3	CEC Approved - Case #111	115/138
TBD	B18	North Gila-Ligurta 230kV Line	WMIID	35	CEC Not Yet Filed	230
TBD	A71	Palm Valley-TS2-Trilby Wash 230 kV line # 2	APS	12	CEC Approved – Decision #67828	230
TBD	A72	Palo Verde-Saguaro 500 kV line	CATS Sub-regional Planning Group	130	CEC Approved – Decision#46802	500
TBD	B19	Pantano to Kartchner 115 kV Line Upgrade	SWTC	36	CEC Not Yet Filed	115

TBD	A73	Pinal Central (Pinal South) – Future substation 6 miles northeast 230 kV line #1	SCWPDA, SPPR	6	CEC Not Yet Filed	230
TBD	A74	Pinal Central (Pinal South) – Future substation 6 miles northeast 230 kV line #2	SCWPDA, SPPR	6	CEC Not Yet Filed	230
TBD	A75	Pinnacle Peak-Brandow 230 kV line	SRP	TBD	CEC Approved - Case #69	230
TBD	A76	Rancho Vistoso-(Future) Sun City 138 kV line	TEP	3.5	CEC Not Required	138
TBD	A77	Rogers-Browning 230 kV line	SRP	9	CEC Not Yet Filed	230
TBD	A78	Rogers-Corbell 230 kV line	SRP	12	CEC Not Required	230
TBD	A79	RS17 230 kV Loop-in line	SRP	0.95	CEC Approved - Decisions #59791 and #60099	230
TBD	B20	RS20 – Coronado 500kV	SRP	TBD	CEC Not Yet Filed	500
TBD	B21	San Rafael to CS2 230 kV Line	SWTC	8	CEC Not Yet Filed	230
TBD	A80	Santa Rosa-ED5 230 kV line	SCWPDA, SPPR	38	CEC Not Yet Filed	230
TBD	A81	Silver King-Browning 230 kV line	SRP	38	CEC Approved - Case #20	230
TBD	A82	Silver King-Browning/Superior 230 kV tie	SRP	0.5	CEC Not Yet Filed	230
TBD	A83	Silver King-Knoll-Future Hayden 230 kV line	SRP	35	CEC Not Yet Filed	230
TBD	A84	Springerville-Greenlee 345 kV line - 2nd circuit	TEP	110	CEC Not Yet Filed	345
TBD	A85	Sun Valley-Morgan 230 kV line	APS	TBD	CEC Approved – Decision #70850	230
TBD	A86	Sun Valley-TS10-TS11 230 kV line	APS	TBD	CEC Not Yet Filed	230
TBD	A87	Sun Valley-TS11-Buckeye 230 kV line	APS	TBD	CEC Not Yet Filed	230
2011	B22	TEP System – Rosemont 138 kV line	TEP	24	CEC Not Yet Filed	138
TBD	A88	Test Track-Empire-ED4 230 kV line	WAPA, SCWPDA	20	CEC Not Yet Filed	230
TBD	B23	Thunderstone-Santan 230 kV line #2	SRP	13	CEC Not Yet Filed	230
TBD	A89	Tortolita North Loop 345 kV line	TEP	60	CEC Not Yet Filed	345
TBD	A90	Tortolita-South 345 kV line	TEP	68	CEC Approved - Case #50	345
TBD	A91	Tortolita-Vail 345 kV Project - Phase 3 - East Loop-Vail line	TEP	0	CEC Not Yet Filed	345
TBD	A92	Tortolita-Winchester 500 kV line	TEP	80	CEC Approved - Case #23	500
TBD	A93	Vail-East Loop - Phase 3 - Third Vail-East Loop 138 kV line	TEP	22	CEC Approved - Case #8	138
TBD	A94	Vail-South 345 kV line - 2nd circuit	TEP	14	CEC Not Required	345
TBD	B24	Vail-UA Tech Park-Irvington 138 kV line	TEP	2	CEC Not Yet Filed	138

TBD	A95	Valencia 115 kV substation expansion	UNISOURCE	0	CEC Approved - Case #111	115
TBD	A96	Wellton-Mohawk 230 kV Line Project	WMIDD	35	CEC Not Yet Filed	230
TBD	A97	Westwing-El Sol 230 kV line	APS	11	CEC Approved – Docket#U-1345	230
TBD	A98	Westwing-Raceway 230 kV line	APS	7	CEC Approved – Decision#64473	230
TBD	A99	Westwing-South 345 kV line - 2nd circuit	TEP	178	CEC Approved - Case #15	345
TBD	B25	Winchester to Vail Double-Circuit 345 kV Line	SWTC, TEP	41	CEC Not Yet Filed	345
TBD	A100	Winchester-Vail 345 kV line #2 and #3	TEP	40	CEC Not Yet Filed	345
TBD	A101	Yucca-TS8 230 kV line	APS	TBD	CEC Not Yet Filed	230

Exhibit 21 – Listing of Projects by Voltage Class

Project ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	Voltage (kV)
A11	White Hills substation	UNISOURCE	0	CEC Not Required	2010	345/69
A60	Gateway 345/115 kV or 345/138 kV substations	UNISOURCE	60	CEC Approved - Case #111	TBD	345/138
A39	RS26-Fountain Hill substation	SRP	TBD	CEC Not Yet Filed	2014	115/230/345
A70	Nogales Transmission line #2 (Gateway – Valencia)	UNISOURCE	3	CEC Approved - Case #111	TBD	115/138
A4	Morgan-Pinnacle Peak 500 KV line	APS, SRP	26	CEC Approved – Decision #69343	2010	500
A14	Devers - Palo Verde 500 kV #2 line	SCE	230	CEC Denied - Case #130	2011	500
B2	Delany – Palo Verde 500kV line	APS	15	CEC Approved – Decision #68063	2012	500
A25	Moenkopi-Eldorado 500 kV Series Capacitor Upgrade Project	SCE, APS	0	CEC Not Required	2013	500
A27	SunZia Project	SWPG, SRP, TEP, ECP, Shell, TSGT	500	CEC Not Yet Filed	2013	500
A31	Delany-Sun Valley 500 kV line	APS, SRP, CAWCD	28	CEC Approved – Decision #68063	2014	500
A36	Palo Verde Hub-North Gila 500 kV #2 line	APS, SRP, IID, WMIDD	110	CEC Approved – Decision #70127	2014	500
A37	Pinal Central-Tortolita 500 kV line	TEP, SWTC, SRP, SunZia	40	CEC Not Yet Filed	2014	500
A38	Pinal West-Pinal Central – Randolph - Abel-Browning 500 kV line	SRP, TEP, SWTC, ED2, ED3, ED4	50	CEC Approved - Case #126 - Decisions #68093 and #69291	2014	500
A49	Sun Valley-Morgan 500 kV line	APS, SRP, CAWCD	TBD	CEC Approved – Decision #70850	2016	500
B11	Pinal Central – Abel #2 500kV line	SRP	TBD	CEC Not Yet Filed	2020	500
B12	Abel – RS20 500kV	SRP	TBD	CEC Not Yet Filed	TBD	500
A55	Arlington Power Plant	Dynegy Arlington Valley	TBD	CEC Approved – Decision #64357	TBD	500
A61	Gila Bend Power Plant	GBPP	0	CEC Approved – Case#109 – Extension Request Pending	TBD	500
A64	Hassayampa - Pinal West 500 kV #2 line	SRP, TEP, SWTC, ED2, ED3, ED4	51	CEC Approved – Case #124	TBD	500

A65	Hassayampa-Jojoba 500 kV line	GBPP	19	CEC Not Required	TBD	500
A72	Palo Verde-Saguaro 500 kV line	CATS Sub-regional Planning Group	130	CEC Approved – Decision#46802	TBD	500
B20	RS20 – Coronado 500kV	SRP	TBD	CEC Not Yet Filed	TBD	500
A92	Tortolita-Winchester 500 kV line	TEP	80	CEC Approved - Case #23	TBD	500
A1	Bowie Power Project	BOWIE	15	CEC Approved – Decision #64626	2010	345
A19	345/69 kV Interconnection at Western's Flagstaff 345kV bus	APS	0.95	CEC Not Required	2012	345
A24	Mazatzal Loop-in of Cholla-Pinnacle Peak 345 kV line	APS	0.95	CEC Not Required	2013	345
B7	Vail – Irvington 345 kV line	TEP	11	CEC Not Yet Filed	TBD	345
A59	Future Gateway-Comision Federale de Electricidad 345 kV line	TEP	2	CEC Approved - Case #111	TBD	345
A63	Greenlee switching station through Hidalgo to Luna	ELPE, PNM, TXNMPC	28	CEC Approved – Case #21	TBD	345
A66	Interconnection line -South-future Gateway 345 kV line	TEP, UNISOURCE	60	CEC Approved - Case #111	TBD	345
B14	Interconnection of Greenlee-Winchester 345kV line with future Willow Substation	TEP, Bowie	0	CEC obtained by Southwestern Power Group – Case #118	TBD	345
B15	Irvington – South 345 kV line	TEP	16	CEC Not Yet Filed	TBD	345
A84	Springerville-Greenlee 345 kV line - 2nd circuit	TEP	110	CEC Not Yet Filed	TBD	345
A89	Tortolita North Loop 345 kV line	TEP	60	CEC Not Yet Filed	TBD	345
A90	Tortolita-South 345 kV line	TEP	68	CEC Approved - Case #50	TBD	345
A91	Tortolita-Vail 345 kV Project - Phase 3 - East Loop-Vail line	TEP	0	CEC Not Yet Filed	TBD	345
A94	Vail-South 345 kV line - 2nd circuit	TEP	14	CEC Not Required	TBD	345
A99	Westwing-South 345 kV line - 2nd circuit	TEP	178	CEC Approved - Case #15	TBD	345
B25	Winchester to Vail Double-Circuit 345 kV Line	SWTC, TEP	41	CEC Not Yet Filed	TBD	345
A100	Winchester-Vail 345 kV line #2 and #3	TEP	40	CEC Not Yet Filed	TBD	345
A5	Morgan-Raceway-Avery-Scatter Wash-Pinnacle Peak 230 kV line	APS	27	CEC Approved – Decision #69343	2010	230
B1	Dinosaur – Abel – Randolph 230kV line	SRP	TBD	CEC Approved – Case #126	2011	230

A16	Pinal South-Southeast Valley/RS22	SRP	30	CEC Approved - Decisions #68093 and #69291	2011	230
A28	TS12 Loop-in of Saguaro-Casa Grande 230 kV line	APS	0.95	Not Required	2013	230
A32	Desert Basin-Pinal Central 230 kV	APS, SRP	21	CEC Approved – Decisions #68093, #68291, #69183 and #69647	2014	230
A35	North Gila-TS8 230 kV line	APS	15	To be Filed in 2008	2014	230
A40	Sun Valley-Trilby Wash - 230 kV line	APS	15	CEC Approved – Decision #67828	2014	230
A41	Sundance-Pinal Central 230 kV line	APS, ED2	6	CEC Filed – Case #136	2014	230
A43	Palm Valley-TS2-Trilby Wash 230 kV line	APS	12	CEC Approved - Decisions #66646 and #67828	2015	230
A47	Griffith-North Havasu 230 kV line	UNISOURCE	40	CEC Approved/Extended - Case #88, CEC Extension request not yet filled	2016	230
A50	Upgrade of Apache-Butterfield 230 kV line	SWTC	16	CEC Not Yet Filed	2016	230
A51	Abel (RS24)-Moody (RS17) 230 kV #1	SRP	20	CEC Approved – Decision #71441	2017	230
B9	Butterfield to Bicknell 230 kV Line Upgrade	SWTC	68.7	CEC Not Yet Filed	2017	230
A53	Abel (RS24)-Moody (RS17) 230 kV #2	SRP	20	CEC Approved – Decision #71441	2018	230
A56	Dinosaur-RS21 230 kV line	SRP	TBD	CEC Not Yet Filed	TBD	230
A57	ED5-Marana 230 kV line	SCWPDA, SPPR	28	CEC Not Yet Filed	TBD	230
A58	ED5-Pinal South (Pinal Central) 230 kV line	SCWPDA, SPPR	18	CEC Not Yet Filed	TBD	230
A62	Golden Valley 230 kV Project - McConico-Mercator Mill 230 kV line	UNISOURCE	20	CEC Not Yet Filed	TBD	230
A68	Jojoba Loop-in of TS4-Panda 230 kV line	APS	0.95	CEC Approved – Decision #62960	TBD	230
B16	Kartchner to CS2 230 kV Line	SWTC	2	CEC Not Yet Filed	TBD	230
B17	Mural – San Rafael 230kV line	APS	TBD	CEC Not Yet Filed	TBD	230
B18	North Gila-Ligurta 230kV Line	WMIID	35	CEC Not Yet Filed	TBD	230
A71	Palm Valley-TS2-Trilby Wash 230 kV line # 2	APS	12	CEC Approved – Decision #67828	TBD	230
A73	Pinal Central (Pinal South) – Future substation 6 miles northeast 230 kV line #1	SCWPDA, SPPR	6	CEC Not Yet Filed	TBD	230
A74	Pinal Central (Pinal South) – Future substation 6 miles northeast 230 kV line #2	SCWPDA, SPPR	6	CEC Not Yet Filed	TBD	230
A75	Pinnacle Peak-Brandow 230 kV line	SRP	TBD	CEC Approved - Case #69	TBD	230
A77	Rogers-Browning 230 kV line	SRP	9	CEC Not Yet Filed	TBD	230
A78	Rogers-Corbell 230 kV line	SRP	12	CEC Not Required	TBD	230

A79	RS17 230 kV Loop-in line	SRP	0.95	CEC Approved - Decisions #59791 and #60099	TBD	230
B21	San Rafael to CS2 230 kV Line	SWTC	8	CEC Not Yet Filed	TBD	230
A80	Santa Rosa-ED5 230 kV line	SCWPDA, SPPR	38	CEC Not Yet Filed	TBD	230
A81	Silver King-Browning 230 kV line	SRP	38	CEC Approved - Case #20	TBD	230
A82	Silver King-Browning/Superior 230 kV tie	SRP	0.5	CEC Not Yet Filed	TBD	230
A83	Silver King-Knoll-Future Hayden 230 kV line	SRP	35	CEC Not Yet Filed	TBD	230
A85	Sun Valley-Morgan 230 kV line	APS	TBD	CEC Approved – Decision #70850	TBD	230
A86	Sun Valley-TS10-TS11 230 kV line	APS	TBD	CEC Not Yet Filed	TBD	230
A87	Sun Valley-TS11-Buckeye 230 kV line	APS	TBD	CEC Not Yet Filed	TBD	230
A88	Test Track-Empire-ED4 230 kV line	WAPA, SCWPDA	20	CEC Not Yet Filed	TBD	230
B23	Thunderstone-Santan 230 kV line #2	SRP	13	CEC Not Yet Filed	TBD	230
A96	Wellton-Mohawk 230 kV Line Project	WMIDD	35	CEC Not Yet Filed	TBD	230
A97	Westwing-El Sol 230 kV line	APS	11	CEC Approved – Docket#U-1345	TBD	230
A98	Westwing-Raceway 230 kV line	APS	7	CEC Approved – Decision#64473	TBD	230
A101	Yucca-TS8 230 kV line	APS	TBD	CEC Not Yet Filed	TBD	230
A9	Tortolita-North Loop-Rancho Vistoso and Tortolita-Rancho Vistoso corridor expansion and reconfiguration Project - Phase 2	TEP	11.1	CEC Approved – Case #149	2011	138
A13	DeMoss Petrie-Tucson 138 kV line	TEP	4.5	CEC Not Yet Filed	2011	138
A20	South-Duval CLEAR - Phase 2b - Extend 138 kV line from Canoa Ranch-(Future) Duval	TEP	24	CEC Approved - Case #84	2013	138
A23	Interconnection of South – Midvale 138 kV circuit with future Spencer, Raytheon, Medina 138kV substations - Phase 1.	TEP	20	CEC Not Yet Filed	2015	138
A26	Northeast-Snyder 138 kV Tap for Craycroft-Barril substations	TEP	8	CEC Not Required	2013	138
A29	Vail-East Loop - Phase 4 - Harrison Tap of Roberts-East Loop 138 kV line	TEP	0	CEC Approved - Case #8	2013	138
A33	Gateway-Sonoita 138 kV line	UNISOURCE	10	CEC Not Yet Filed	2014	138
A34	La Canada-Orange Grove-Rillito 138 kV line	TEP	5.4	CEC Not Yet Filed	2014	138
A42	Irvington-Kino–UA Med-Tucson 138 kV line	TEP	10.9	CEC Not Yet Filed	2015	138
A44	South-Hartt-Green Valley 138 kV line	TEP	14.5	CEC Not Yet Filed	2015	138

A45	Tortolita - Rancho Vistoso 138kV line tap for future Naranja substation.	TEP	24.5	CEC Not Yet Filed	2015	138
A46	Interconnection of Tortolita – North Loop 138 kV with future Marana 138 kV Substation	TEP	22	CEC Not Yet Filed	2015	138
B8	Del Cerro-Anklam-Tucson 138 kV line	TEP	2	CEC Not Yet Filed	2016	138
A48	Irvington Substation – Corona Substation – South Substation 138kV.	TEP	16.1	CEC Not Yet Filed	2016	138
A52	Orange Grove-East Ina 138 kV line	TEP	3.6	CEC Not Yet Filed	2017	138
A54	Interconnection of South – Midvale 138 kV circuit with future Spencer, Raytheon, Medina 138kV substations - Phase 2	TEP	13	CEC Not Yet Filed	2018	138
	Midvale - Spencer - Medina - Raytheon - South 138kV Line - Phase 3	TEP		CEC Not Yet Filed	2019	138
A67	Irvington-East Loop Project - Phase 3 - Irvington-22nd Street 2nd Circuit	TEP	9	CEC Approved - Case #66	TBD	138
A76	Rancho Vistoso-(Future) Sun City 138 kV line	TEP	3.5	CEC Not Required	TBD	138
B22	TEP System – Rosemont 138 kV line	TEP	24	CEC Not Yet Filed	2011	138
A93	Vail-East Loop - Phase 3 - Third Vail-East Loop 138 kV line	TEP	22	CEC Approved - Case #8	TBD	138
B24	Vail-UA Tech Park-Irvington 138 kV line	TEP	2	CEC Not Yet Filed	TBD	138
A2	CAP 115 kV line loop-in to SWTC Sandario	SWTC	0.6	CEC Approved – Case #152	2010	115
A3	Marana-Avra Valley 115 kV Line Upgrade	SWTC	8.75	CEC Not Yet Filed	2010	115
A6	Naviska-Thornydale 115 kV line	SWTC	7	CEC Approved – Case #149	2010	115
A7	Saguaro to North Loop	SWTC	3.2	CEC approved – Case #149	2010	115
A8	Thornydale-Rattlesnake 115 kV line	SWTC	19	CEC Approved – Case #152	2010	115
A10	Valencia-CAP Black Mountain 115 kV line	SWTC	2.6	CEC Approved – Case #152	2010	115
A12	Avra Valley-Sandario Tap 115 kV Line Upgrade	SWTC	2.8	CEC Not Yet Filed	2011	115
A15	Marana Tap-Marana 115 kV Line Upgrade	SWTC	0.2	CEC Not Required	2011	115
A17	Sandario Tap-Three Points 115 kV Line Upgrade	SWTC	13.71	CEC Not Yet Filed	2011	115
A22	Upgrade existing 115 kV transmission line to Nogales	UNISOURCE	60	CEC Approved – Case #111	2012	115
A30	Apache/Hayden-San Manuel 115 kV line	SWTC	4.5	CEC Approved – Case #142	2014	115
B3	Three Terminal Plan Circuit 1 Participation	SWTC	23	CEC Not Yet Filed	2014	115

B4	Three Terminal Plan Circuit 2 Participation	SWTC	31	CEC Not Yet Filed	2014	115
B5	Three Terminal Plan Circuit 3 Participation	SWTC	19	CEC Not Yet Filed	2014	115
B6	Saguaro to Adonis 115 kV Line Loop-in to Naviska	SWTC	0	CEC Not Required	2015	115
B10	CAP 115 kV Line Loop-in to Picture Rocks	SWTC	0	CEC Not Required	2018	115
A69	New Hayden 115 kV Station Loop-in	SRP	0.75	CEC Not Yet Filed	TBD	115
B19	Pantano to Kartchner 115 kV Line Upgrade	SWTC	36	CEC Not Yet Filed	TBD	115
A95	Valencia 115 kV substation expansion	UNISOURCE	0	CEC Approved - Case #111	TBD	115
B13	CS2 Substation	SWTC	0	CEC Not Yet Filed	TBD	230/115

Exhibit 22 – Arizona Public Service Project Summary

Project ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	Voltage (kV)
A4	Morgan-Pinnacle Peak 500 KV line	APS, SRP	26	CEC Approved – Decision #69343	2010	500
A5	Morgan-Raceway-Avery-Scatter Wash-Pinnacle Peak 230 kV line	APS	27	CEC Approved – Decision #69343	2010	230
A19	345/69 kV Interconnection at Western's Flagstaff 345kV bus	APS	0.95	CEC Not Required	2012	345
B2	Delany – Palo Verde 500kV line	APS	15	CEC Approved – Decision #68063	2012	500
A24	Mazatzal Loop-in of Cholla-Pinnacle Peak 345 kV line	APS	0.95	CEC Not Required	2013	345
A25	Moenkopi-Eldorado 500 kV Series Capacitor Upgrade Project	SCE, APS	0	CEC Not Required	2013	500
A28	TS12 Loop-in of Saguaro-Casa Grande 230 kV line	APS	0.95	Not Required	2013	230
A31	Delany-Sun Valley 500 kV line	APS, SRP, CAWCD	28	CEC Approved – Decision #68063	2014	500
A32	Desert Basin-Pinal Central 230 kV	APS, SRP	21	CEC Approved – Decisions #68093, #68291, #69183 and #69647	2014	230
A35	North Gila-TS8 230 kV line	APS	15	To be Filed in 2008	2014	230
A36	Palo Verde Hub-North Gila 500 kV #2 line	APS, SRP, IID, WMIDD	110	CEC Approved – Decision #70127	2014	500
A40	Sun Valley-Trilby Wash - 230 kV line	APS	15	CEC Approved – Decision #67828	2014	230
A41	Sundance-Pinal Central 230 kV line	APS, ED2	6	CEC Filed – Case #136	2014	230
A43	Palm Valley-TS2-Trilby Wash 230 kV line	APS	12	CEC Approved - Decisions #66646 and #67828	2015	230
A49	Sun Valley-Morgan 500 kV line	APS, SRP, CAWCD	TBD	CEC Approved – Decision #70850	2016	500
A68	Jojoba Loop-in of TS4-Panda 230 kV line	APS	0.95	CEC Approved – Decision #62960	TBD	230
B17	Mural – San Rafael 230kV line	APS	TBD	CEC Not Yet Filed	TBD	230
A71	Palm Valley-TS2-Trilby Wash 230 kV line # 2	APS	12	CEC Approved – Decision #67828	TBD	230
A85	Sun Valley-Morgan 230 kV line	APS	TBD	CEC Approved – Decision #70850	TBD	230
A86	Sun Valley-TS10-TS11 230 kV line	APS	TBD	CEC Not Yet Filed	TBD	230
A87	Sun Valley-TS11-Buckeye 230 kV line	APS	TBD	CEC Not Yet Filed	TBD	230

A97	Westwing-El Sol 230 kV line	APS	11	CEC Approved – Docket#U-1345	TBD	230
A98	Westwing-Raceway 230 kV line	APS	7	CEC Approved – Decision#64473	TBD	230
A101	Yucca-TS8 230 kV line	APS	TBD	CEC Not Yet Filed	TBD	230

Exhibit 23 – Salt River Project Summary

Project ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	Voltage (kV)
A4	Morgan-Pinnacle Peak 500 KV line	APS, SRP	26	CEC Approved – Decision #69343	2010	500
B1	Dinosaur – Abel – Randolph 230kV line	SRP	TBD	CEC Approved – Case #126	2011	230
A16	Pinal South-Southeast Valley/RS22	SRP	30	CEC Approved - Decisions #68093 and #69291	2011	230
A27	SunZia Project	SWPG, SRP, TEP, ECP, Shell, TSGT	500	CEC Not Yet Filed	2013	500
A31	Delany-Sun Valley 500 kV line	APS, SRP, CAWCD	28	CEC Approved – Decision #68063	2014	500
A32	Desert Basin-Pinal Central 230 kV	APS, SRP	21	CEC Approved – Decisions #68093, #68291, #69183 and #69647	2014	230
A36	Palo Verde Hub-North Gila 500 kV #2 line	APS, SRP, IID, WMIDD	110	CEC Approved – Decision #70127	2014	500
A37	Pinal Central-Tortolita 500 kV line	TEP, SWTC, SRP, SunZia	40	CEC Not Yet Filed	2014	500
A38	Pinal West-Pinal Central – Randolph - Abel-Browning 500 kV line	SRP, TEP, SWTC, ED2, ED3, ED4	50	CEC Approved - Case #126 - Decisions #68093 and #69291	2014	500
A39	RS26-Fountain Hill substation	SRP	TBD	CEC Not Yet Filed	2014	115/230/345
A49	Sun Valley-Morgan 500 kV line	APS, SRP, CAWCD	TBD	CEC Approved – Decision #70850	2016	500
A51	Abel (RS24)-Moody (RS17) 230 kV #1	SRP	20	CEC Approved – Decision #71441	2017	230
A53	Abel (RS24)-Moody (RS17) 230 kV #2	SRP	20	CEC Approved – Decision #71441	2018	230
B11	Pinal Central – Abel #2 500kV line	SRP	TBD	CEC Not Yet Filed	2020	500
B12	Abel – RS20 500kV	SRP	TBD	CEC Not Yet Filed	TBD	500
A56	Dinosaur-RS21 230 kV line	SRP	TBD	CEC Not Yet Filed	TBD	230
A64	Hassayampa - Pinal West 500 kV #2 line	SRP, TEP, SWTC, ED2, ED3, ED4	51	CEC Approved – Case #124	TBD	500
A69	New Hayden 115 kV Station Loop-in	SRP	0.75	CEC Not Yet Filed	TBD	115
A75	Pinnacle Peak-Brandow 230 kV line	SRP	TBD	CEC Approved - Case #69	TBD	230

A77	Rogers-Browning 230 kV line	SRP	9	CEC Not Yet Filed	TBD	230
A78	Rogers-Corbell 230 kV line	SRP	12	CEC Not Required	TBD	230
A79	RS17 230 kV Loop-in line	SRP	0.95	CEC Approved - Decisions #59791 and #60099	TBD	230
B20	RS20 – Coronado 500kV	SRP	TBD	CEC Not Yet Filed	TBD	500
A81	Silver King-Browning 230 kV line	SRP	38	CEC Approved - Case #20	TBD	230
A82	Silver King-Browning/Superior 230 kV tie	SRP	0.5	CEC Not Yet Filed	TBD	230
A83	Silver King-Knoll-Future Hayden 230 kV line	SRP	35	CEC Not Yet Filed	TBD	230
B23	Thunderstone-Santan 230 kV line #2	SRP	13	CEC Not Yet Filed	TBD	230

Exhibit 24 – Santa Cruz Water and Power District Summary

Project ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	Voltage (kV)
A57	ED5-Marana 230 kV line	SCWPDA, SPPR	28	CEC Not Yet Filed	TBD	230
A58	ED5-Pinal South (Pinal Central) 230 kV line	SCWPDA, SPPR	18	CEC Not Yet Filed	TBD	230
A73	Pinal Central (Pinal South) – Future substation 6 miles northeast 230 kV line #1	SCWPDA, SPPR	6	CEC Not Yet Filed	TBD	230
A74	Pinal Central (Pinal South) – Future substation 6 miles northeast 230 kV line #2	SCWPDA, SPPR	6	CEC Not Yet Filed	TBD	230
A80	Santa Rosa-ED5 230 kV line	SCWPDA, SPPR	38	CEC Not Yet Filed	TBD	230
A88	Test Track-Empire-ED4 230 kV line	WAPA, SCWPDA	20	CEC Not Yet Filed	TBD	230

Exhibit 25 – Southwest Transmission Cooperative Project Summary

Project ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	Voltage (kV)
A2	CAP 115 kV line loop-in to SWTC Sandario	SWTC	0.6	CEC Approved – Case #152	2010	115
A3	Marana-Avra Valley 115 kV Line Upgrade	SWTC	8.75	CEC Not Yet Filed	2010	115
A6	Naviska-Thornydale 115 kV line	SWTC	7	CEC Approved – Case #149	2010	115
A7	Saguaro to North Loop	SWTC	3.2	CEC approved – Case #149	2010	115
A8	Thornydale-Rattlesnake 115 kV line	SWTC	19	CEC Approved – Case #152	2010	115
A10	Valencia-CAP Black Mountain 115 kV line	SWTC	2.6	CEC Approved – Case #152	2010	115
A12	Avra Valley-Sandario Tap 115 kV Line Upgrade	SWTC	2.8	CEC Not Yet Filed	2011	115
A15	Marana Tap-Marana 115 kV Line Upgrade	SWTC	0.2	CEC Not Required	2011	115
A17	Sandario Tap-Three Points 115 kV Line Upgrade	SWTC	13.71	CEC Not Yet Filed	2011	115
A30	Apache/Hayden-San Manuel 115 kV line	SWTC	4.5	CEC Approved – Case #142	2014	115
A37	Pinal Central-Tortolita 500 kV line	TEP, SWTC, SRP, SunZia	40	CEC Not Yet Filed	2014	500
A38	Pinal West-Pinal Central – Randolph - Abel-Browning 500 kV line	SRP, TEP, SWTC, ED2, ED3, ED4	50	CEC Approved - Case #126 - Decisions #68093 and #69291	2014	500
B3	Three Terminal Plan Circuit 1 Participation	SWTC	23	CEC Not Yet Filed	2014	115
B4	Three Terminal Plan Circuit 2 Participation	SWTC	31	CEC Not Yet Filed	2014	115
B5	Three Terminal Plan Circuit 3 Participation	SWTC	19	CEC Not Yet Filed	2014	115
B6	Saguaro to Adonis 115 kV Line Loop-in to Naviska	SWTC	0	CEC Not Required	2015	115
A50	Upgrade of Apache-Butterfield 230 kV line	SWTC	16	CEC Not Yet Filed	2016	230
B9	Butterfield to Bicknell 230 kV Line Upgrade	SWTC	68.7	CEC Not Yet Filed	2017	230
B10	CAP 115 kV Line Loop-in to Picture Rocks	SWTC	0	CEC Not Required	2018	115
B13	CS2 Substation	SWTC	0	CEC Not Yet Filed	TBD	230/115
A64	Hassayampa - Pinal West 500 kV #2 line	SRP, TEP, SWTC, ED2, ED3, ED4	51	CEC Approved – Case #124	TBD	500
B16	Kartchner to CS2 230 kV Line	SWTC	2	CEC Not Yet Filed	TBD	230

B19	Pantano to Kartchner 115 kV Line Upgrade	SWTC	36	CEC Not Yet Filed	TBD	115
B21	San Rafael to CS2 230 kV Line	SWTC	8	CEC Not Yet Filed	TBD	230
B25	Winchester to Vail Double-Circuit 345 kV Line	SWTC, TEP	41	CEC Not Yet Filed	TBD	345

Exhibit 26 – Tucson Electric Power Project Summary

Project ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	Voltage (kV)
A9	Tortolita-North Loop-Rancho Vistoso and Tortolita-Rancho Vistoso corridor expansion and reconfiguration Project - Phase 2	TEP	11.1	CEC Approved – Case #149	2010	138
A13	DeMoss Petrie-Tucson 138 kV line	TEP	4.5	CEC Not Yet Filed	2011	138
A18	Tortolita-North Loop-Rancho Vistoso Project - Phase 3 - Corridor Expansion	TEP	18	CEC Not Yet Filed	2011	138
A20	South-Duval CLEAR - Phase 2b - Extend 138 kV line from Canoa Ranch-(Future) Duval	TEP	24	CEC Approved - Case #84	2012	138
A21	Tucson-Downtown 138 kV line	TEP	1	CEC Not Yet Filed	2012	138
A23	Extend Midvale-(Future) Spencer-(Future) San Joaquin 138 kV line	TEP	20	CEC Not Yet Filed	2013	138
A26	Northeast-Snyder 138 kV Tap for Craycroft-Barril substations	TEP	8	CEC Not Required	2013	138
A27	SunZia Project	SWPG, SRP, TEP, ECP, Shell, TSGT	500	CEC Not Yet Filed	2013	500
A29	Vail-East Loop - Phase 4 - Harrison Tap of Roberts-East Loop 138 kV line	TEP	0	CEC Approved - Case #8	2013	138
A34	La Canada-Orange Grove-Rillito 138 kV line	TEP	5.4	CEC Not Yet Filed	2014	138
A37	Pinal Central-Tortolita 500 kV line	TEP, SWTC, SRP, SunZia	40	CEC Not Yet Filed	2014	500
A38	Pinal West-Pinal Central – Randolph - Abel-Browning 500 kV line	SRP, TEP, SWTC, ED2, ED3, ED4	50	CEC Approved - Case #126 - Decisions #68093 and #69291	2014	500
A42	Irvington-Kino–UA Med-Tucson 138 kV line	TEP	10.9	CEC Not Yet Filed	2015	138
A44	South-Hartt-Green Valley 138 kV line	TEP	14.5	CEC Not Yet Filed	2015	138
A45	Tortolita Rancho Vistoso 138 kV tap for future Naranja substation	TEP	24.5	CEC Not Yet Filed	2015	138
A46	Tortolita-Marana-North Loop Project - Phase 1 - Tortolita-Marana 138 kV line	TEP	22	CEC Not Yet Filed	2015	138
B7	Vail – Irvington 345 kV line	TEP	11	CEC Not Yet Filed	2015	345

B8	Del Cerro-Anklam-Tucson 138 kV line	TEP	2	CEC Not Yet Filed	2016	138
A48	Irvington-South Project - Phase 1 - Irvington-Corona-South 138 kV line	TEP	16.1	CEC Not Yet Filed	2016	138
A52	Orange Grove-East Ina 138 kV line	TEP	3.6	CEC Not Yet Filed	2017	138
A54	Midvale-Spencer-Medina-Raytheon-South 138 kV line	TEP	13	CEC Not Yet Filed	2018	138
A59	Future Gateway-Comision Federale de Electricidad 345 kV line	TEP	2	CEC Approved - Case #111	TBD	345
A64	Hassayampa - Pinal West 500 kV #2 line	SRP, TEP, SWTC, ED2, ED3, ED4	51	CEC Approved – Case #124	TBD	500
A66	Interconnection line -South-future Gateway 345 kV line	TEP, UNISOURCE	60	CEC Approved - Case #111	TBD	345
B14	Interconnection of Greenlee-Winchester 345kV line with future Willow Substation	TEP, Bowie	0	CEC obtained by Southwestern Power Group – Case #118	TBD	345
B15	Irvington – South 345 kV line	TEP	16	CEC Not Yet Filed	TBD	345
A67	Irvington-East Loop Project - Phase 3 - Irvington-22nd Street 2nd Circuit	TEP	9	CEC Approved - Case #66	TBD	138
A76	Rancho Vistoso-(Future) Sun City 138 kV line	TEP	3.5	CEC Not Required	TBD	138
A84	Springerville-Greenlee 345 kV line - 2nd circuit	TEP	110	CEC Not Yet Filed	TBD	345
B22	TEP System – Rosemont 138 kV line	TEP	24	CEC Not Yet Filed	TBD	138
A89	Tortolita North Loop 345 kV line	TEP	60	CEC Not Yet Filed	TBD	345
A90	Tortolita-South 345 kV line	TEP	68	CEC Approved - Case #50	TBD	345
A91	Tortolita-Vail 345 kV Project - Phase 3 - East Loop-Vail line	TEP	0	CEC Not Yet Filed	TBD	345
A92	Tortolita-Winchester 500 kV line	TEP	80	CEC Approved - Case #23	TBD	500
A93	Vail-East Loop - Phase 3 - Third Vail-East Loop 138 kV line	TEP	22	CEC Approved - Case #8	TBD	138
A94	Vail-South 345 kV line - 2nd circuit	TEP	14	CEC Not Required	TBD	345
B24	Vail-UA Tech Park-Irvington 138 kV line	TEP	2	CEC Not Yet Filed	TBD	138
A99	Westwing-South 345 kV line - 2nd circuit	TEP	178	CEC Approved - Case #15	TBD	345
B25	Winchester to Vail Double-Circuit 345 kV Line	SWTC, TEP	41	CEC Not Yet Filed	TBD	345
A100	Winchester-Vail 345 kV line #2 and #3	TEP	40	CEC Not Yet Filed	TBD	345

Exhibit 27 – UNS Electric Project Summary

Project ID	Description	Participants	Length (mi)	Permitting/Siting Status	Year	Voltage (kV)
A11	White Hills substation	UNISOURCE	0	CEC Not Required	2010	345/69
A22	Upgrade existing 115 kV transmission line to Nogales	UNISOURCE	60	CEC Approved – Case #111	2012	115
A33	Gateway-Sonoita 138 kV line	UNISOURCE	10	CEC Not Yet Filed	2014	138
A47	Griffith-North Havasu 230 kV line	UNISOURCE	40	CEC Approved/Extended - Case #88, CEC Extension request not yet filled	2016	230
A60	Gateway 345/115 kV or 345/138 kV substations	UNISOURCE	60	CEC Approved - Case #111	TBD	345/138
A62	Golden Valley 230 kV Project - McConico-Mercator Mill 230 kV line	UNISOURCE	20	CEC Not Yet Filed	TBD	230
A66	Interconnection line -South-future Gateway 345 kV line	TEP, UNISOURCE	60	CEC Approved - Case #111	TBD	345
A70	Nogales Transmission line #2 (Gateway – Valencia)	UNISOURCE	3	CEC Approved - Case #111	TBD	115/138
A95	Valencia 115 kV substation expansion	UNISOURCE	0	CEC Approved - Case #111	TBD	115

Exhibit 28 – NEITC Corridor Map

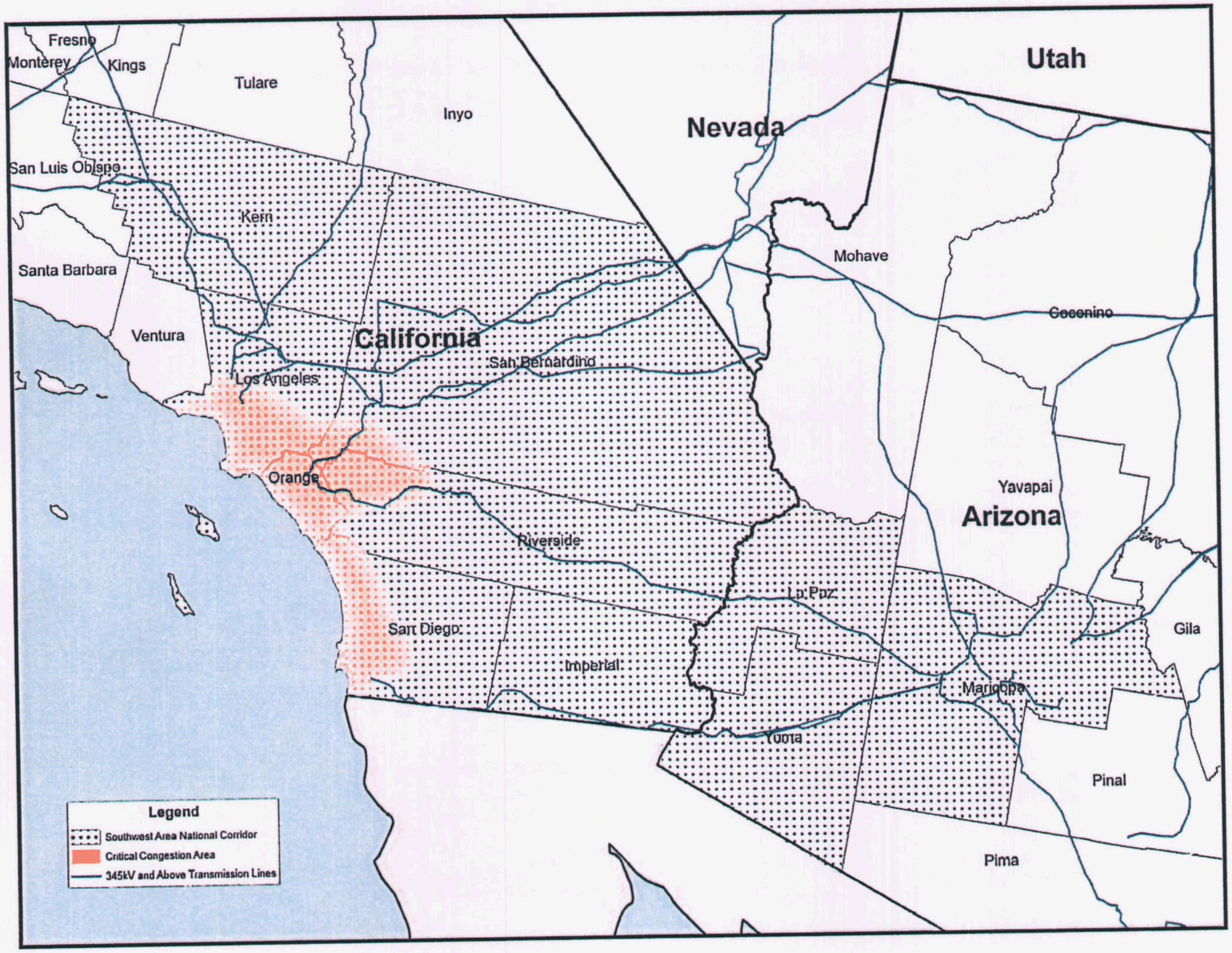


Exhibit 29 – Southline Transmission Project

The Southline

UPGRADE

Western Saguaro-Apache

- Direct, efficient means for solving Tucson bottleneck
- Heart of joint study with TEP, SWTC, WAPA, and others
- Helps regional utilities with reliability and load serving issues

NEW BUILD

Afton-Apache

- More than 85% Federal and State land
- Route parallels abandoned Railroad ROW, minimizing impact
- Interconnects with existing 345 KV system
- Excellent solar and geothermal resource
- No forests, wilderness study areas, riparian zones, etc…

COUNTERSCHEDULE & PARTICIPATION

Saguaro – Palo Verde

- 500 KV system into Phoenix Metro area & central trading hub
- Potential to use existing capacity and participate in new expansion
- Capacity from hub into California being expanded

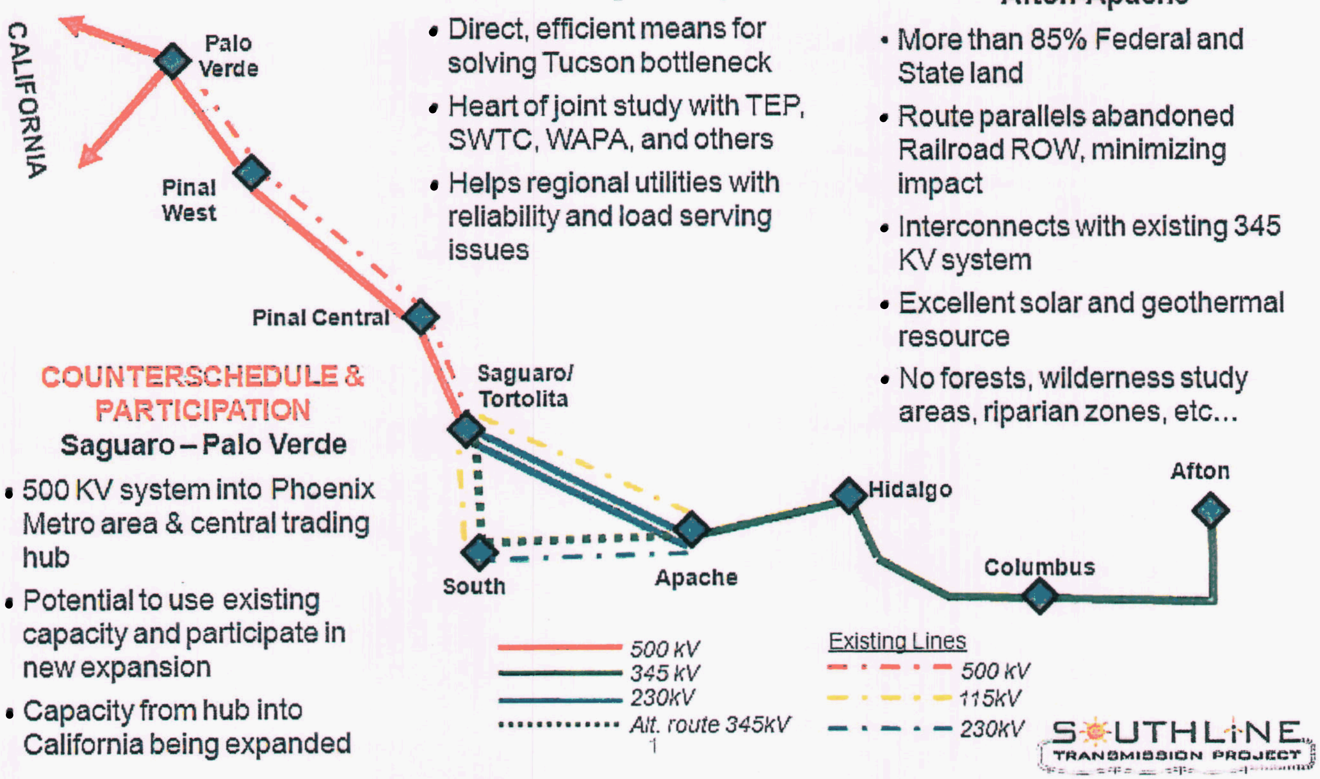


Exhibit 30 – Santa Fe Clean Line

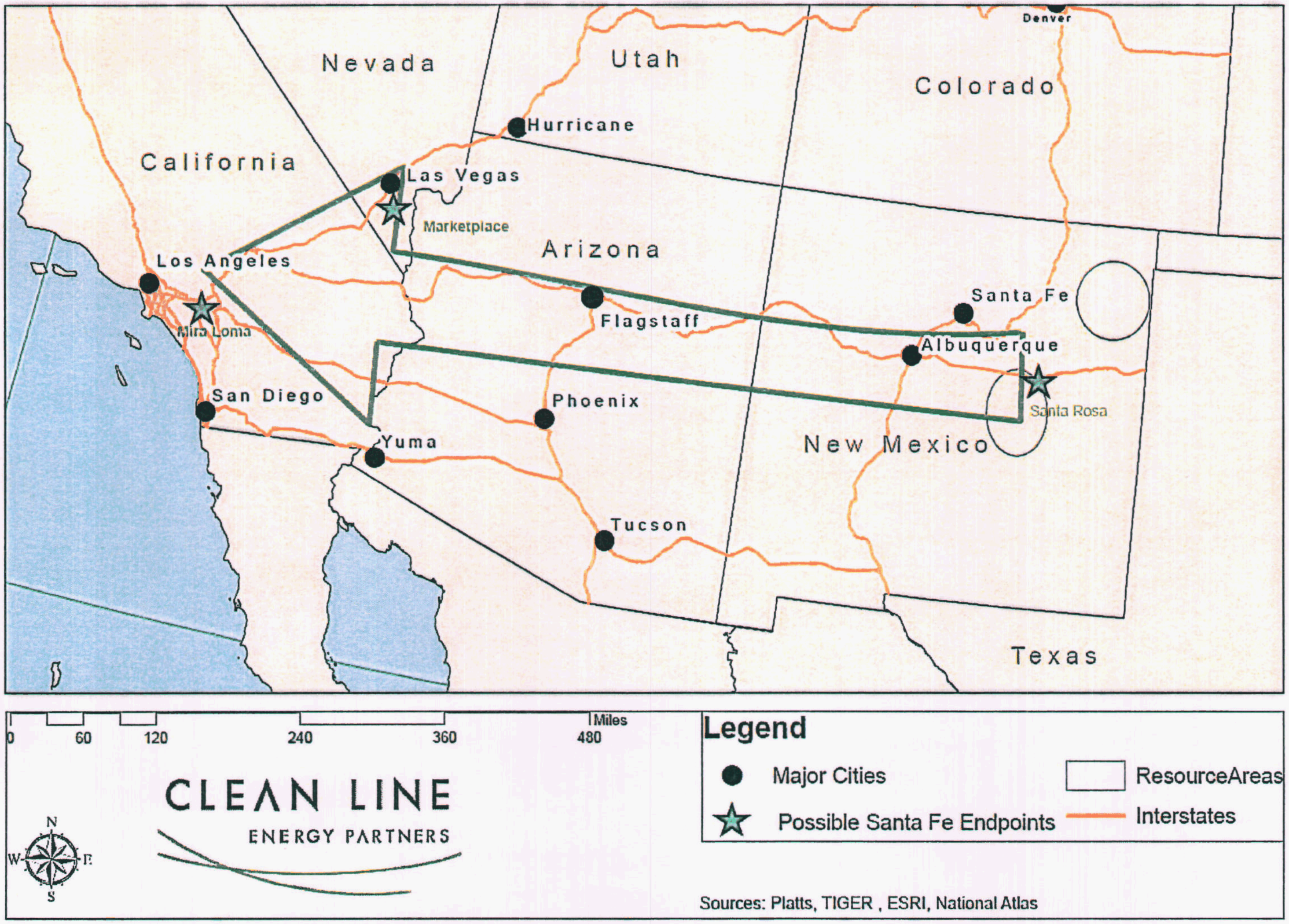


Exhibit 31 – Eldorado Valley Study Group

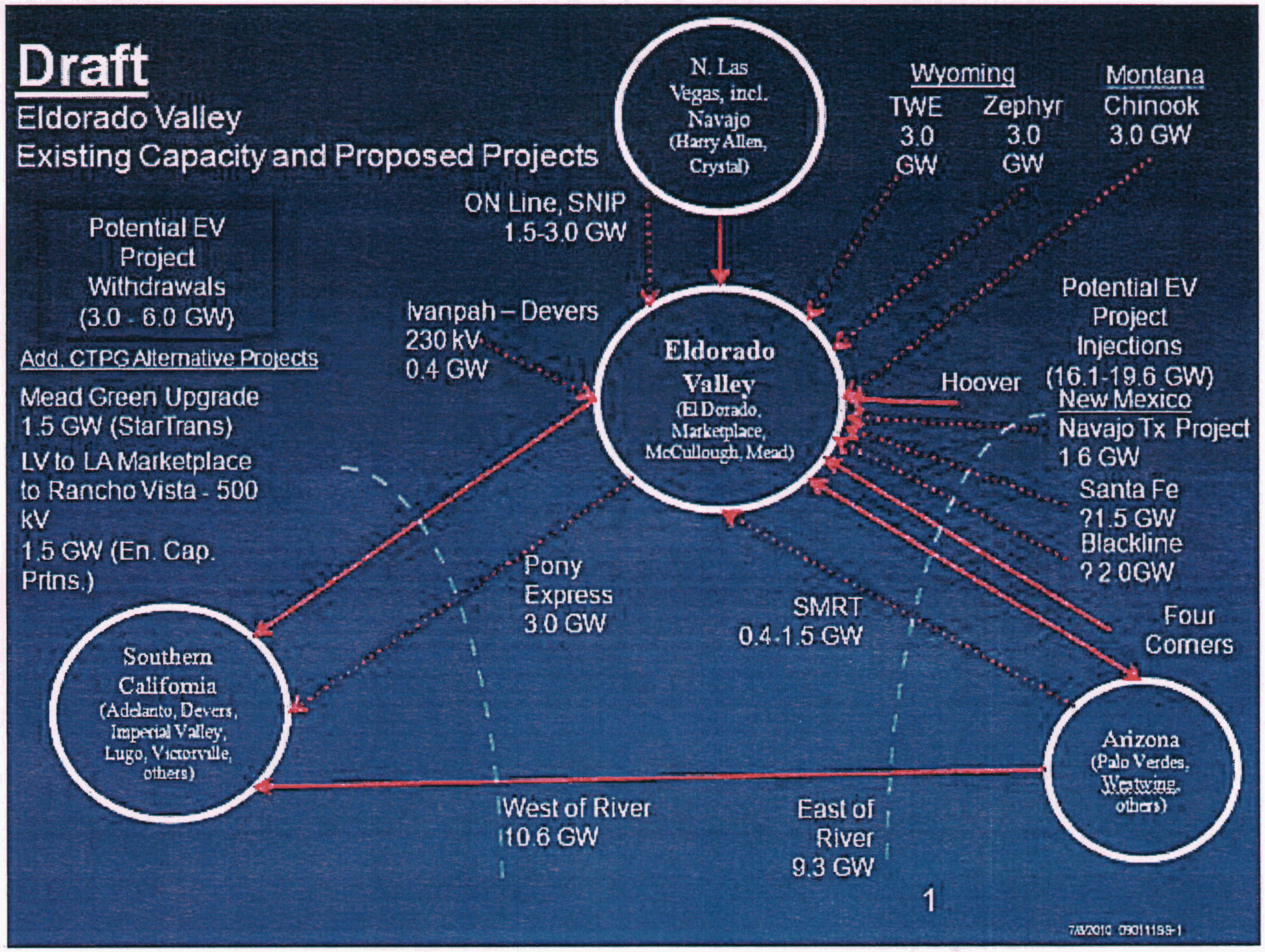


Exhibit 32 – Cochise County Transmission Plan

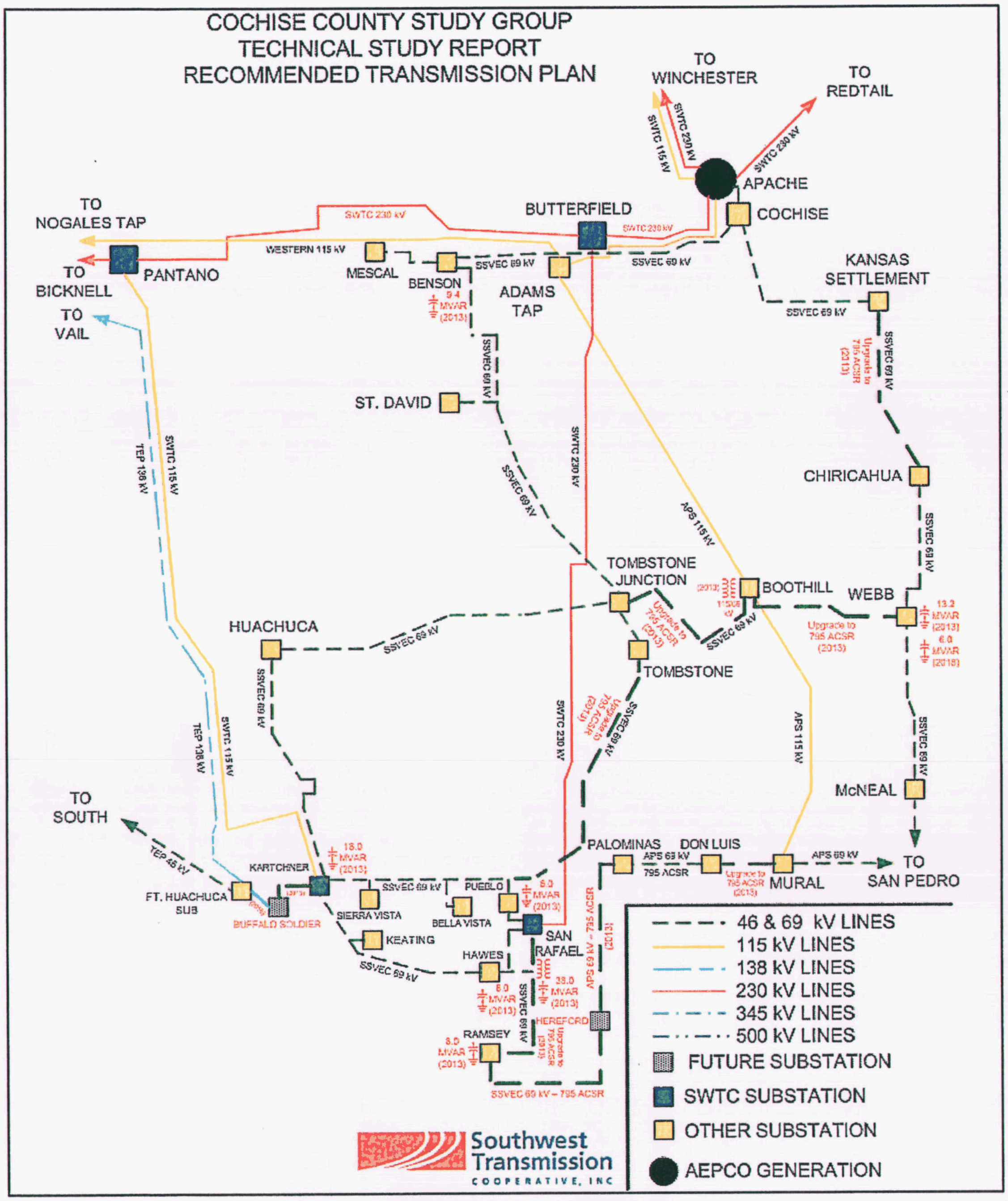


Exhibit 33 – SMRT Project and Study Area

SMRT PROJECT AND STUDY AREA OVERLAPS SOLAR POTENTIAL

4 Elements and 1 Sensitivity

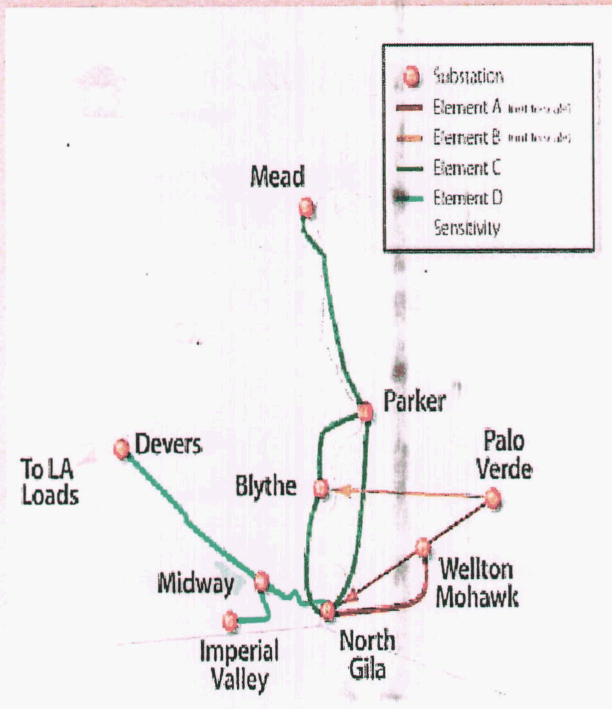
A—Palo Verde-North Gila
- 500-kV, 100 miles

B—Palo Verde-Blythe
- 500-kV, 110 miles

C— North of Parker
- 230/500-kV 190 miles

South of Parker
- 230/500-kV, 330 miles

D- Imperial Valley Segment
- Details TBD



Western AREA POWER ADMINISTRATION

Exhibit 34 – SWTC Renewable Transmission Projects

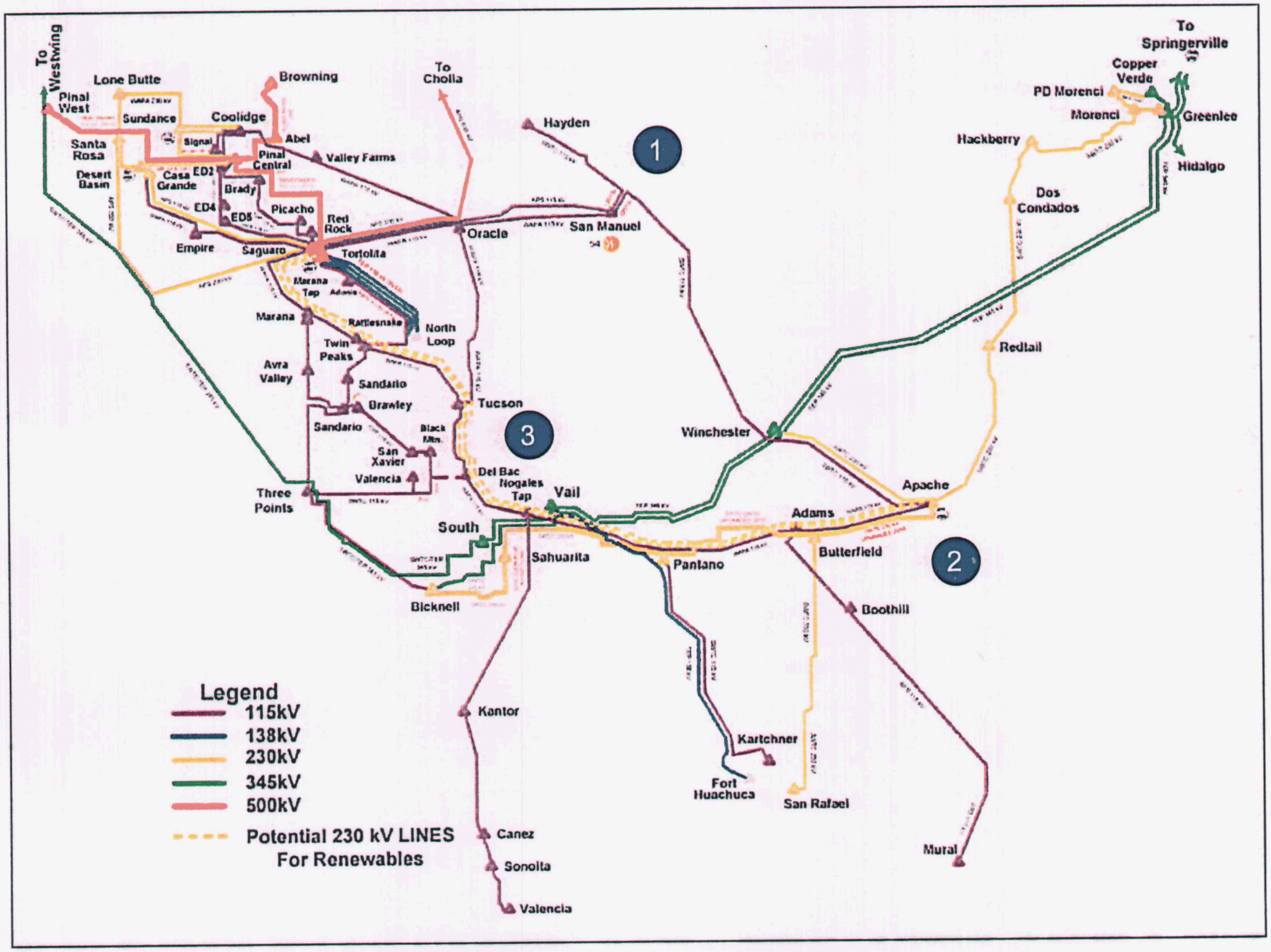
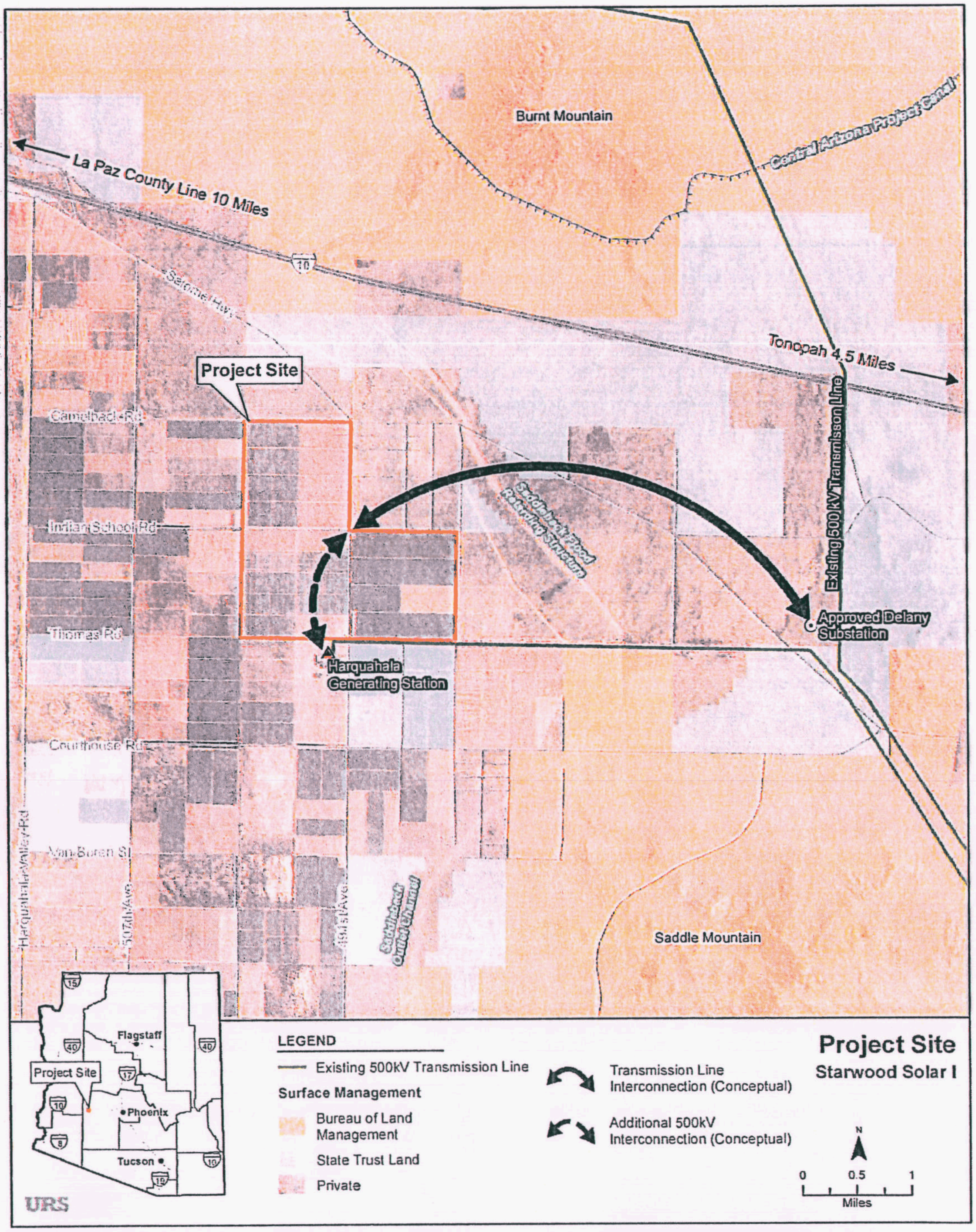


Exhibit 35 – Starwood Solar I Project



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Sixth Biennial Transmission Assessment 2010-2019

Table of Appendices

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

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[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

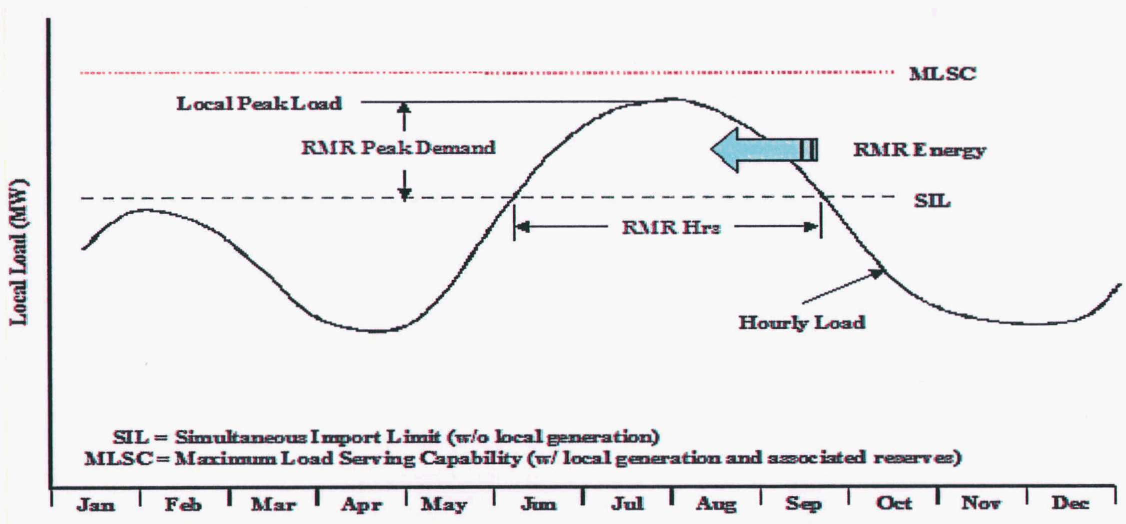
APPENDIX C - RMR CONDITIONS AND STUDY METHODOLOGY

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
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Haunty	Jim		EC Source		jhaunty@forcecap.com	X	
Held	Matt	VP, Projects	Solar Reserve LLC	310-315-2275	mheld@solarreserve.com	X	
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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	
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McMinn	Barbra	Manger	APS	602-371-6383	barbara.mcminn@aps.com		X
Miller	Dean		Husk Partners	602-451-2729	dean@huskpartners.com	X	
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Reinhold	Charles		West Connect	208-253-6916	reinhold@ctcweb.net	X	
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Williamson	Ray	Engineer	ACC			X	X
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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	UniSource Energy Services
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 10th 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 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. 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.