FINAL DRAFT

Ninth Biennial Transmission Assessment 2016-2025

Staff Report

Docket No. E-00000D-15-0001

July 22, 2016

Prepared by Arizona Corporation Commission Staff

And

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Foreword

The Arizona Corporation Commission ("ACC" or "Commission") performs a biennial review of the ten-year transmission plans filed by parties who are responsible for transmission facilities in Arizona and issues a written decision regarding the adequacy of the existing and planned transmission facilities to reliably meet the present and future transmission system needs of Arizona.[1] This report by the Staff of the Commission's Utilities Division ("ACC Staff" or "Staff") is the Ninth Biennial Transmission Assessment ("BTA" or "Ninth BTA") and has been prepared in accordance with a contract agreement between K.R. Saline and Associates, PLC ("KRSA") and the Commission. It is considered a public document. Use of the report by other parties shall be at their own risk. Neither KRSA nor the Commission accepts any duty of care to such third parties.

Arizona's Ninth BTA is based upon the Ten-Year Plans filed with the Commission by parties in January 2016. It also incorporates information and comments provided by participants and attendees in the BTA workshops and report review process. The ACC Staff and KRSA appreciate the contributions, cooperation, and support of industry participants throughout the Ninth BTA process.

[1] Arizona Revised Statute §40-360.02

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Executive Summary

Staff, with the aid of KRSA, scrutinized the Ten-Year Plans and related filings submitted to the Commission[2], held open and transparent workshops on June 1, 2016 ("Workshop I") and August 3, 2016, ("Workshop II") to solicit industry participation, and drafted this Ninth BTA based solely on the results of these activities. Although Staff and KRSA did examine and question study work, they stopped short of independently verifying the study results.

The Ten-Year Plans and related filings that were reviewed by Staff and KRSA included utility transmission plans with supporting technical study work, merchant developer plans for transmission projects and generator interconnection tie-lines, and Commission-ordered technical studies, including the Ten Year Snapshot and Extreme Contingency study. In preparing the first draft of the Ninth BTA, Staff and KRSA also examined the Workshop I presentations and reviewed the recordings.[3] Two successive drafts of this Ninth BTA were made available for industry and stakeholder comments; the comments were considered in preparing the final report.

This Ninth BTA assesses the adequacy of Arizona's transmission system to reliably meet the existing and planned transmission needs of the state by addressing four fundamental public policy questions during the course of this BTA:

1. <u>Adequacy of the existing and planned transmission system to reliably serve local load</u> - Does the existing and planned transmission system meet the load serving needs of the state during the 2016-2025 timeframe in a reliable manner?

2. <u>Efficacy of the Commission-ordered studies</u> - Do the Simultaneous Import Limit ("SIL"), Maximum Load Serving Capability ("MLSC"), Reliability Must Run[5] ("RMR"), Ten Year Snapshot, Distributed Generation ("DG") and Energy Efficiency ("EE") and Extreme Contingency studies filed as part of the Ninth BTA

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[2] Docket No. E-00000D-15-0001
[3] Video of June 1, 2016 Workshop I are available at the ACC Public Meeting Archive http://media-07.granicus.com:443/OnDemand/azcc/azcc_159b3f75-264b-4636-95f1-4e3c488eba70.mp4
[4] This BTA does not establish Commission policy and is not final unless and until approved by a written decision of the Commission.
[5] RMR Studies were not required for the Ninth BTA based upon criteria set by the Commission in the Seventh BTA

provide useful and sufficient information in determining adequacy of the state's transmission system over the next 10 years?

3. Adequacy of the system to reliably support the wholesale market - Are the transmission planning efforts effectively addressing concerns raised in previous BTAs about the adequacy of the state's transmission system to reliably support the competitive wholesale market in Arizona?
4. Suitability of the 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") and Western Electricity Coordinating Council ("WECC")?

Conclusions

The information provided by the utilities and other transmission developers for the Ninth BTA was comprehensive and responsive to the statutory and Commission-ordered requirements. The information provided was used to develop the conclusions of the Ninth BTA; where applicable, the conclusions were organized to answer the four key policy questions described above.

General Conclusions

1. The aggregate of the filed Ten-Year Plans ("Arizona Plan") is a comprehensive summary of filed ten year transmission expansion plans from a holistic perspective. The Arizona Plan includes nineteen filing entities and consists of thirty-six transmission projects of approximately 707 miles in length. Forty-nine projects are beyond the ten year horizon or have in-service dates that are yet to be determined and account for an additional 939 miles of new transmission. Additionally, utilities have seven transmission lines, totaling approximately 82 miles in length, which they plan to reconductor.

2. As active members of the WestConnect Planning Management Committee, Arizona Utilities have increased situational awareness, cooperation, and coordination with neighboring utilities, sub-regional, and regional planning groups to address potential reliability issues that could affect Arizona, the desert southwest region, and other regions throughout the WECC. While the

individual plans lean heavily towards addressing local load-serving needs, as they must, they also reflect a high level of coordination that addresses state and regional needs in a cohesive manner.

3. There are no definitive answers at this time to the question of reliability issues regarding coal plant retirements, especially when considered in combination with increased reliance on renewable generation that will have significant impact throughout the western interconnection. The opportunity to coordinate within the scope and timeline of the 2016 WestConnect Regional Study Plan, to include interregional coordination, will enhance the credibility of the Arizona reliability study by allowing broader geographic coverage. The WestConnect study plan includes development of regional base transmission plan models plus four scenarios[6] aimed at addressing the potential impact on bulk electric system ("BES") stability of actual and proposed coal plant retirements, as well as the increased use of solar photovoltaic and wind generation, which do not provide inertia benefits. More detail on the WestConnect study scope is available in Section 5.4.1 of this report.

   Since this potential issue is still unfolding, it will require continued monitoring of and participation in states' compliance activities along with WECC and regional modeling and study efforts going forward.

4. The "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" ("Guiding Principles") that Staff relies on to aid in determining the adequacy and reliability of both transmission and generation systems are presented in Appendix A. No revisions to the Guiding Principles are necessary in this Ninth BTA.

Adequacy of the Existing and Planned Transmission System to Reliably Serve Local Load

The adequacy of the transmission system to reliably serve load is central to the BTA. Based upon the technical study work examined by Staff and KRSA, the existing and proposed transmission system meets the load serving requirements of Arizona in a reliable manner for the 2016-2025 timeframe.

[6] Section 3.2 of the WestConnect Regional Study Plan states, "WestConnect regional assessments are centered on base cases and scenarios, which when taken together provide a robust platform that is used to identify the potential for regional transmission needs and emerging regional opportunities".

1. The 2016 level of summer preparedness of the utilities in Arizona, as presented in the April 28, 2016 workshop, demonstrated that sufficient preparedness measures are being taken. The current transmission system in Arizona is judged to be adequate to reliably support the energy needs of the state in 2016.
2. The statewide demand forecast has continued to be lowered since the Fifth BTA. During the Ninth BTA the Arizona utilities reported a Ten-Year Forecast that was, on average, 4.3% lower than was reported during the Eighth BTA. Over the past four BTAs load forecasts have changed substantially, and the deferment of several growth-related transmission projects has followed. In the Eighth BTA, Staff recommended, and the Commission agreed that for reliability or load growth driven transmission projects a system load level range at which a transmission project is needed should be reported along with the projected in-service year beginning with ten year transmission plans filed in January 2016. Compliance with this requirement produced mixed results and, in general, did not provide additional insight into project construction timelines. Staff has reviewed this aspect of the filings and concludes that future inclusion of specific load level ranges is not warranted in future Ten-Year Plans.
3. All SIL and MLSC studies, which measure local transmission systems' ability to serve load reliably in load pockets, indicate that the local transmission systems are adequate to meet the ten year local load forecasts.

Efficacy of Commission-Ordered Studies

The Commission has ordered the following studies to be performed as part of the BTA: SIL, MLSC, RMR if certain triggers are met, Ten Year Snapshot, and Extreme Contingency Analysis. The principal purpose of the Commission-ordered studies is to assure the certainty of the conclusions and recommendations within the BTA. Each Commission-ordered study required for the Ninth BTA is filed with the Commission. Staff and KRSA conclude the Commission-ordered studies demonstrate that the Arizona transmission system is reasonably prepared to reliably serve local load in the ten year timeframe.

1. As indicated previously, the SIL and MLSC studies indicate that the local transmission systems are adequate to meet ten year local load forecasts.

2. In the Seventh BTA, Staff suspended the RMR studies and implemented requirement criteria for restarting such studies based on a biennial review of specific triggering factors. None of the triggering factors occurred for the Ninth BTA which would require RMR study work in any of the RMR areas.
3. The Ten Year Snapshot study indicates Arizona's transmission plan is robust and supports the statewide load forecast through 2025. The Ten Year Snapshot has also been adjusted to monitor system elements down to and including the 115kV level, addressing potential lower voltage concerns.
4. The Extreme Contingency study satisfies the Commission's requirement to address and document extreme contingency outage studies for Arizona's major generation hubs and major transmission stations. Arizona Public Service ("APS") and Tucson Electric Power ("TEP") performed the Extreme Contingency studies for 2016 and projected 2025 APS and projected 2024 TEP system conditions. APS study results indicated that the transmission system can withstand the extreme contingencies that were evaluated; TEP results indicated potential extreme contingency issues that will need to be evaluated and mitigated in future internal planning studies. Staff and KRSA concur that the Extreme Contingency studies performed by APS and TEP satisfy the requirements of Commission Decision No. 67457.
5. The EE/DG studies satisfy the Commission's requirement to conduct a fifth-year technical study, down to the 115kV level, on the impacts of DG and EE. The studies indicate that EE/DG have properly been studied in system planning and EE/DG do not impact the reliability of the transmission system belonging to Arizona's load-serving utilities.

Adequacy of System to Reliably Support Wholesale Market

Regional and sub-regional planning studies have effectively addressed the interconnected extra high voltage ("EHV") transmission that is critical to a functional interstate wholesale market. Based upon the technical study work filed with the Commission and industry presentations, the existing and planned Arizona EHV system is adequate to support a robust wholesale market.

1. Six major interstate EHV transmission projects are proposed and have been addressed in this BTA. Individually and collectively these projects will improve the opportunity for interstate commerce.

2. Staff and KRSA conclude that the Arizona utilities are taking sufficient action with respect to transmission planning impacts related to the integration of renewable generation resources.
3. The Fifth BTA ordered the utilities to provide their top three renewable transmission projects ("RTP"). Since the Eighth BTA, APS completed the Palo Verde-North Gila 500 kV line in May 2015 and the Delaney-Palo Verde 500kV line in May 2016. One other APS RTP, the Palo Verde to Liberty/ Gila Bend to Liberty project, is on hold due to the previous downturn in the economy and a slowdown of renewable energy development in the area. In June of 2014, SRP completed the following components of the Southeast Valley Project: Pinal Central 500kV and 230kV substations, Duke 500kV substation, Pinal West – Duke - Pinal Central 500kV line, Pinal Central – Browning 500 kV line, Pinal Central – Randolph 230kV line and the Pinal Central 500 kV shunt reactor. TEP followed up by completing the Pinal Central - Tortolita 500kV line in October of 2015. Additionally, one RTP is no longer being pursued but is instead being worked on jointly as part of the Southline Project. Finally, one RTP has moved outside of the Ten-Year Plan window because the line was successfully re-rated without new transmission development. Remaining RTPs are being monitored for development as reliability and resource needs arise.
4. FERC Order No. 1000 requires FERC jurisdictional transmission providers and encourages non-jurisdictional transmission providers to work collaboratively with stakeholders on a regional and interregional basis to improve regional transmission planning processes and cost allocation mechanisms in a cost-effective manner. The WestConnect Planning Management Committee is tasked with ensuring compliance with FERC Order No. 1000 requirements; WestConnect released its first regional transmission plan on December 16, 2015 and has begun work on the 2016-2017 planning cycle. This process offers a readily accessible forum for stakeholders to be involved in the planning of transmission systems that will support a robust wholesale market.

Suitability of Utilized Planning Processes

Based upon information provided by the utilities, the Arizona utilities utilize significant and well defined transmission planning processes.

1. The results of NERC/WECC reliability standard audits over the past two years, as provided by the utilities in the Ninth BTA proceeding, indicate there were no concerns of Arizona's BES failing to comply with the applicable planning standards established by NERC/WECC.

2. Technical studies filed in the Ninth BTA indicate a robust study process for assessing transmission system performance for the 2016-2025 planning period.
3. Arizona utilities communicate their transmission plans in an open and transparent manner at local, state, sub-regional, and regional transmission planning forums using public processes.

Recommendations

Based upon the conclusions, Staff offers the following recommendations for Commission consideration and action:

1. Staff recommends that the Commission support:
   a. The continued use of the "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" as revised in the Eighth BTA.
   b. The use of collaborative transmission planning processes such as those that currently exist in Arizona, which help to facilitate competitive wholesale markets and broad stakeholder participation in grid expansion plans.
   c. The continued suspension of the requirement for performing RMR studies in every BTA and use of criteria for restarting such studies based on a biennial review of factors as outlined in the Seventh BTA.
   d. The suspension of the requirement that Arizona utilities, for each load growth or reliability driven transmission project, include the load level range at which each transmission project is anticipated to be needed, as directed in Decision No. 74785. Utilities shall continue to describe, in general terms, the driving factor(s) for each transmission project in the Ten-Year Plan
   e. The suspension of the requirement for TEP to file the SWAT CRATF report on behalf of the Arizona utilities within 30 days of completion as directed in Decision No. 74785. Utilities shall participate in WestConnect Regional Planning process and coordinate the Arizona reliability study with WestConnect study and scenario results, and TEP will report relevant findings on behalf of the utilities in future BTA Proceedings.
   f. That any requirement established in a prior BTA will continue in force unless the Commission suspends such requirement in a succeeding BTA. Nevertheless, Staff

recommends that the Commission emphasize the importance of these continuing requirements for Arizona utilities:

i. Advise each interconnection applicant at the time the applicant files for interconnection of the need to contact the Commission for appropriate ACC filing requirements related to the Power Plant and Transmission Line Siting Committee.

ii. Report relevant findings in future BTAs regarding compliance with transmission planning standards from NERC/WECC reliability audits that have been finalized and filed with FERC.

iii. Address the effects of DG and EE on future transmission needs in their Ten-Year Plan filings.

iv. Ensure that the Commission-ordered Ten Year Snapshot study monitors transmission elements down to and including the 115 kV level for thermal loading and voltage violations.

v. Include planned transmission reconductor projects, transformer capacity upgrade projects, and reactive power compensation facility additions at 115 kV and above in future Ten-Year Plan filings.

g. The policy that the LSE in Cochise and Santa Cruz Counties continue to monitor the reliability in Cochise and Santa Cruz Counties, respectively, and propose any modifications that they deem to be appropriate in future Ten-Year Plans. Staff also recommends that the Commission continue to collect applicable outage data from the respective utilities in order to monitor any changes in Cochise County and Santa Cruz County system reliability in future BTA proceedings.

h. The acceptance of the results of the following Commission-ordered studies provided as part of the Ninth BTA filings:

i. The SIL and MLSC are adequate to meet ten year local load forecasts.

ii. The RMR studies were not required because none of the triggering factors occurred for the Ninth BTA that would require RMR study work in any of the RMR areas.

iii. The Extreme Contingency analysis for Arizona's major transmission corridors and substations and the associated risks and consequences of such overlapping contingencies.

iv. Ten Year Snapshot study results documenting the performance of Arizona's statewide transmission system in 2025 for a comprehensive set of single ("n-1") contingencies, each tested with the absence of different major planned transmission projects.

v. The EE/DG study results containing the fifth-year contingency analysis with and without disaggregated DG and EE loads.

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1 Overview

1.1 Assessment Authority

Arizona statutes require every entity considering construction of any transmission line equal to or greater than 115 kilovolt ("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 31st of each year.[7] Every entity considering construction of a new power plant of 100 Megawatts ("MW") or greater, as defined in the Arizona Revised Statute § 40-360,[8] within Arizona is required to file a plan with the ACC ninety days before filing an application for a Certificate of Environmental Compatibility ("CEC").[9] 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.[10] 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 this State to meet the present and future energy needs of this State in a reliable manner".[11]

1.2 Purpose and Framework

The purpose of this report is to inform the Commission of currently planned transmission facilities and to offer an assessment of the adequacy of the existing and planned Arizona electric transmission system. This Ninth Biennial Transmission Assessment ("Ninth BTA" or "BTA") evaluates the ten year transmission plans filed with the Commission in January 2016.[12] 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.

[7] Arizona Revised Statute § 40-360.02.A
[8] Per Arizona Revised Statute § 40-360 Definitions a power "plant" means "each separate thermal electric, nuclear or hydroelectric generating unit with a nameplate rating of one hundred megawatts or more for which expenditures or financial commitments for land acquisition, materials, construction or engineering in excess of fifty thousand dollars have not been made prior to August 13, 1971."
[9] Arizona Revised Statute § 40-360.02.B
[10] Arizona Revised Statute § 40-360.02.C.7
[11] Arizona Revised Statute § 40-360.02.G
[12] Docket No. E-00000D-15-0001

In the Arizona BTA process, entities conduct their own technical studies, participate in collaborative and open regional planning processes, and present the study results in their Ten-Year Plan reports at public workshops. Staff of the Commission's Utilities Division ("Staff") and KR Saline & Associates, PLC ("KRSA") relied on the technical reports and documents filed with the Commission and other publicly available industry reports rather than performing independent technical study work.

In addition to the ten year filings, the Commission ordered supplemental studies to be performed as a portion of this Ninth BTA.[13] These studies include; a study on effects of DG and EE installations on future transmission needs, System Import Limit ("SIL")/Maximum Load Serving Capability ("MLSC"), Reliability Must Run ("RMR") if certain triggers are met, the Ten Year Snapshot study, and Extreme Contingency studies required from prior ACC BTAs.[14] Each Commission-ordered study was filed with the Commission.

Staff relies on the "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" ("Guiding Principles") for aid in determining the adequacy and reliability of both transmission and generation systems. These Guiding Principles were adopted in the First BTA and have been re-adopted through the Seventh BTA. In the Eighth BTA, Staff updated the guiding principles to reflect the current state of the industry within Arizona and nationally. The update specifically addressed mandatory, enforceable, updated reliability standards put in place following the Energy Policy Act of 2005. The Commission accepted the updated Guiding Principles in Decision No. 74785.

Staff retained KRSA to assist with this Ninth BTA. Together, Staff and KRSA critically reviewed the Ten-Year Plans that were filed and addressed the following four key public policy questions:

1. <u>Adequacy of the existing and planned transmission system to reliably serve local load</u>
   - Does the existing and planned transmission system meet the load serving needs of the state during the 2016-2025 timeframe in a reliable manner?

[13] Decision No. 74785, Docket No. E-00000D-13-0002
[14] A complete history of Commission-ordered Studies is found in Appendix B.

2. Efficacy of the Commission-ordered studies - Do the Simultaneous Import Limit ("SIL"), Maximum Load Serving Capability ("MLSC"), Reliability Must Run[15] ("RMR") if certain triggers are met, Ten Year Snapshot, Distributed Generation ("DG") and Energy Efficiency ("EE"), and Extreme Contingency studies filed as part of the Ninth BTA provide useful and sufficient information in determining adequacy of the state's transmission system over the next 10 years?
3. Adequacy of the system to reliably support the wholesale market - Are the transmission planning efforts effectively addressing concerns raised in previous BTAs about the adequacy of the state's transmission system to reliably support the competitive wholesale market in Arizona?
4. Suitability of the 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 North American Electricity Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC")?

1.3 Assessment Process

A four-step approach was used in the preparation of this Ninth BTA report. The first step was to conduct the Ninth BTA Workshop I ("Workshop I"), during which each entity was provided an opportunity to present their Ten Year Plan filings and address questions from stakeholders. The second step included the review of industry filings submitted for the Ninth BTA. The third step was the development, distribution, and posting of the first draft report for public comment.[16] Revisions were then made and a second draft of the report was posted for public comment. The final step included conducting the Ninth BTA Workshop II ("Workshop II") during which Staff and KRSA presented the second draft of the report.[17] A summary of each step of the BTA process is described in the following sections.

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[15] RMR Studies were not required for the Ninth BTA based upon criteria set by the Commission in the Seventh BTA
[16] The first draft was posted to the Commission's website on July 5, 2016
[17] The Workshop II agenda and presentations are located at http://www.azcc.gov/Divisions/Utilities/Electric/BTA-Index.ASP

1.3.1 Workshop I: Industry Presentations

KRSA assisted Staff in conducting a public workshop on June 1, 2016, at the Commission's Hearing Room #1 in Phoenix, Arizona. A complete listing of the Workshop I attendees and presenters is given in Appendix C. The Ninth BTA Workshop I provided an informal setting for entities that filed ten years plans to share their transmission plans with interested stakeholders and the Commission. Further, Workshop I provided an opportunity to discuss transmission related topics of interest for inclusion in this BTA report. A summary listing of presentations made during Workshop I is provided in Table 1.[18]

Workshop I – Agenda Items	Presenters
Ten-Year Plan Presentations	Arizona Public Service ("APS"), Salt River Project ("SRP"), Arizona G&T Cooperatives ("AZG&T"), Tucson Electric Power ("TEP")/UniSource Electric ("UNSE"), Sun Zia, Southline, Bowie Power Plant
Unfiled Merchant Transmission Projects	Centennial West Clean Line Project[19]
Commission Ordered BTA Requirements	Ten Year Snapshot and Extreme Contingency Studies, EE/DG Study
National and Regional Transmission Issues	WestConnect and Southwest Area Transmission ("SWAT")
Other Transmission Related Topics of Interest	Coal Reduction Impact Assessment, Western Area Power Administration Transmission Infrastructure Program ("TIP")

Table 1 - Summary of Workshop I Presentations

Prior to Workshop I, each presenter was provided a set of questions, as outlined in Appendix D, to address within their Workshop I presentation. Each presentation was grouped into its respective panel: Ten-Year Plan Presentations, Unfiled Merchant Transmission Projects, Commission-ordered BTA Requirements, and Other Transmission Related Topics of Interest. At the conclusion of each panel's presentations an open period of discussion was held for questions and comments from Commissioners, Staff, KRSA, and audience. Staff and KRSA concluded Workshop I with an

[18] The Workshop I agenda presentations are located at http://www.azcc.gov/Divisions/Utilities/Electric/BTA-Index.ASP

[19] During Workshop I, Clean Line Energy Partners shared a presentation on the Centennial West and Western Spirit Clean Line transmission projects. While these projects are described in this report, they were not considered as elements of the Ten-Year Plans for which this BTA makes an adequacy determination.

overview of the remaining steps in the BTA process and Presenters were requested to file a copy of their presentations in the BTA docket.

1.3.2 Review of Industry Filings in Ninth BTA

Staff and KRSA reviewed all of the filings that had been made to date by utilities in the Ninth BTA to ensure required data was filed. When deficiencies were identified, data requests were utilized to obtain required data.

Table 2 shows a matrix of the various categories of Ten-Year Planning information filed by utilities or Sub-Regional Transmission Planning Groups and received from data requests during the Ninth BTA.[20]

Utility	Ten-Year Plan	2016-2025 Utility Technical Study Report	RMR Study Report	Planning Criteria & Ratings	DG & EE Study	Filings of Joint Study Report(s)
APS	X	X	Not Required in 9th BTA	X	X	Extreme Contingency Study
SRP	X	X	Not Required in 9th BTA	X	X	N/A
SWAT-AZ	N/A	N/A	N/A	N/A	N/A	Ten Year Snapshot
AZG&T	X	X	Not Required in 9th BTA	X	N/A	N/A
TEP	X	X	Not Required in 9th BTA	X	X	Extreme Contingency Study
UNS Electric	X	N/A	Not Required in 9th BTA	N/A	X	N/A

Table 2 - Summary of Utility Data

1.3.3 Preparation of Draft Report and Industry Comment

Staff and KRSA provided an initial draft of the Ninth BTA report for industry review and comment on July 5, 2016. The first draft report was developed from data contained in the Ten-Year

[20] The Extreme Contingency Study was performed by APS and coordinated through SWAT

Plan submittals, information gathered at Workshop I, a review of industry reports and presentations and subsequent replies to data requests from the utilities.[21] The draft report was posted on the Commission's website and public notices sent out through various stakeholder distribution lists as part of the review process. During the two week review period, Staff and KRSA received, reviewed and considered industry comments. The comments were collected, categorized, and posted for stakeholder review. Reflecting and addressing comments received from the industry, a second draft of the report was then prepared by Staff and KRSA. The docketed comments and the second draft of the report were the subject of Workshop II.

1.3.4 Workshop II: Staff/KRSA Presentation of Final Report

The 2016 BTA Workshop II was held at the Commission's Hearing Room #1 on August 3, 2016. The purpose of Workshop II was to present the final draft of the Ninth BTA. Questions, comments, and clarification resulting from this workshop were incorporated in the final report for presentation to the Commission.

[Additional details to be added after Workshop II]

1.4 Terminology and Acronyms

Staff and KRSA have strived to define all industry acronyms and provide clarifying footnotes to industry language used throughout the report. Appendix F includes a listing of additional terminology and acronyms that supplement our clarifying efforts.

1.5 Additional Resources

When additional information was required that was not included in the filing, Staff and KRSA used external resources. The additional information resources used in the BTA assessment are listed in Appendix G.

[21] Video of June 1, 2016 Workshop I is available at the ACC Public Meeting Archive - http://media-07.granicus.com:443/OnDemand/azcc/azcc_0e21c628-a065-40a0-9053-ded5de4b5197.mp4

2 Ten-Year Plans

Nineteen entities formally filed Ten-Year Plans with the Commission. The Ten-Year Plans for WestConnect and the Western Area Power Administration ("WAPA") were also considered while preparing this assessment. Table 3 includes the parties that filed ten year transmission plans and the location of additional information on their filings in the Exhibits section of this report.

Entity	Reference Location
Ajo Improvement Company	Exhibit 19
Arizona Public Service	Exhibit 14
Bowie Power Station	Exhibit 19
Buckeye Generation Center	Exhibit 19
Crossroads Solar	Exhibit 19
El Paso Electric ("EPE")	Exhibit 19
Gila Bend Power Partners	Exhibit 19
Mohave County Wind Farm	Exhibit 19
Public Service Company of New Mexico ("PNM")	NA
Southline Transmission Project	Exhibit 19
Salt River Project	Exhibit 15
Sun Streams Solar Project	Exhibit 19
SunZia Southwest Transmission Project	Exhibit 19
Arizona G&T Cooperatives	Exhibit 16
Ten West Link	Exhibit 19
Tucson Electric Power	Exhibit 17
Tribal Solar, LLC	Exhibit 19
Unisource Electric	Exhibit 18
White Wing Ranch North	Exhibit 19

Table 3 - List of Parties Filing Ten-Year Plans 2016 Tabular Reference Table[22]

In addition to new construction projects, the Commission has previously determined that plans to reconductor existing transmission lines, upgrade bulk power transformer capacity, and expand reactive power compensation to support transmission capacity upgrades should be filed in the BTA allowing the Commission to perform a more comprehensive assessment of transmission adequacy and reliability.[23] As directed, the projects filed in the Ninth BTA include planned transmission lines at 115 kV and above, including major reconfigurations and upgrades from a lower design voltage to a higher design voltage, reconductoring of existing transmission lines, bulk power substation transformer bank replacements and additions, and reactive power compensation facility additions at 115 kV and above. The Ninth BTA examines the aggregate of these Ten-Year Plans.

Arizona Utilities perform technical analysis in accordance with NERC Transmission Planning ("TPL") and Transmission Operations ("TOP") standards, and their own internal planning criteria, guidelines and methods. These planning practices are utilized to ensure that their respective systems are planned to provide reliable service to customers under various system conditions.

2.1 Summary of Arizona Plan

The aggregate of the filed Ten-Year Plans ("Arizona Plan") is a comprehensive summary of filed ten year transmission expansion plans from a holistic perspective. The Arizona Plan includes nineteen filing entities and consists of thirty-six transmission projects of approximately 707 miles in length. Forty-nine projects are beyond the ten year horizon or have in-service dates that are yet to be determined and account for an additional 939 miles of new transmission. Additionally, utilities have seven transmission lines, totaling approximately 82 miles in length, which they plan to reconductor.[25]

In-Service Date[24]	# of Projects	Mileage
2017	6	37
2018	8	318
2019	3	1
2020	8	64
2021	7	230
2022	1	4
2023	1	1
2024	2	52
2025	0	0
Subtotal	36	707
2026 & Beyond	49	939
Total	85	1,646

Table 4 - Summary of Arizona Plan by In-Service Date

Table 4 depicts the number of new transmission projects and associated mileage for each year of the Ten-Year Plan. Projects with an in-service date to-be-determined ("TBD") or beyond the ten

[23] Decision No. 72031

[24] Table 4 represents new transmission projects only. Planned reconductor projects, transformer capacity upgrade projects, and reactive power compensation facility additions at 115 kV and above have been excluded.

[25] Unfiled projects are excluded from this adequacy analysis for the BTA, but are depicted with all other projects on maps provided as Exhibits 1-6.

year 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. As is typical in transmission planning, a majority of the Arizona Plan projects fall into the first five years of the planning horizon as years six through ten are less scrutinized or definitive than the first five years of the plan.

Table 5 depicts the number of Arizona Plan projects by voltage class. Projects with multiple voltages or for which the voltage class has not been resolved are reported at the highest voltage class identified for the project.[26]

Voltage Class	Number of Projects 2016-2025	Number of Projects Post 2025-TBD	Mileage
500 KV	6	7	628
345 kV	3	9	604
230 kV	15	25	300
138 kV	10	2	82
115 kV	2	6	32
Total	36	49	1,646

Table 5 - Summary of Arizona Plan by Voltage Class

As indicated in Table 5, the Arizona Plan includes a significant number of 345 & 500 kV transmission miles. Most of the 500 kV total transmission miles are attributable to three transmission projects: SunZia Southwest Transmission Project; Palo Verde – Saguaro 500 kV; and the Ten West Link Transmission Project. Collectively, these projects account for 444 of the 628 500 kV miles shown in Table 5 above. Similarly, the proposed 345 kV system increase is primarily being driven by the Southline Transmission Project and the Westwing Substation to South Substation. The Southline and Westwing projects represent 424 miles out of the total 604 miles planned. The Arizona Plan is listed in tabular form in Exhibit 12 and Exhibit 13 by in-service date and voltage class, respectively.

The Arizona Plan includes eight merchant generators and one utility generator totaling 4,083 MW and requiring approximately 43 miles of generator tie-lines in Arizona, summarized in Table 6. The utility generator being reported is the Ocotillo Modernization Project, which was included in the APS Ten-Year Plan and is discussed in Section 4.1.12.

[26] Projects proposing more than one route (i.e. alternative routes) and/or more than one voltage will be counted once and assume the highest mileage/voltage for the summary tables.

Description	Maximum Output (MW)	Gen-Tie Length (Mi)
Bowie Power Station	1,000	15
Buckeye Generation Center	630	1
Crossroads Solar Energy Project	150	12
Fort Mojave Solar Project	332	< 1
Gila Bend Power Project	833	6
Mohave County Wind Farm	500	6
Sun Streams Solar Project	150	< 1
White Wing Ranch North	200	3

Table 6 - Summary of Merchant Generation and Tie-Lines

Maps depicting all facilities included in the Arizona Plan are shown in Exhibits 1-5 with the Project Look-up table included as Exhibit 6.

2.2 Plan Changes Since the Eighth BTA

Transmission plans predictably change over time. 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 interconnections and delivery requests, and changes in the economic or financial climate faced by a project sponsor. Since the Eighth BTA, numerous projects have been completed and expected in-service dates for others have been adjusted to correspond with changing planning assumptions and reliability needs. Further, the scope or the name of an original project might have been changed. A list of name changes is provided in Table 7.

Current Name	Formerly Known As
Komatke 230/69kV	Jojoba 230/69kV substation
Price Road Corridor	East Valley Industrial Expansion
Ocotillo Modernization Project	Ocotillo 230kV Generation Interconnections
Mohave County Wind Farm	BP Wind Power Plant
Ten West Link	Delaney-Colorado River 500 kV Transmission Project

Table 7 - Project Name Changes or Aliases

A list of all changes between the Eighth and Ninth BTAs for transmission projects 115 kV and above is provided in Exhibit 10. Table 8 is a list of changes that have occurred at Extra High Voltage ("EHV") levels of 345 kV and above.

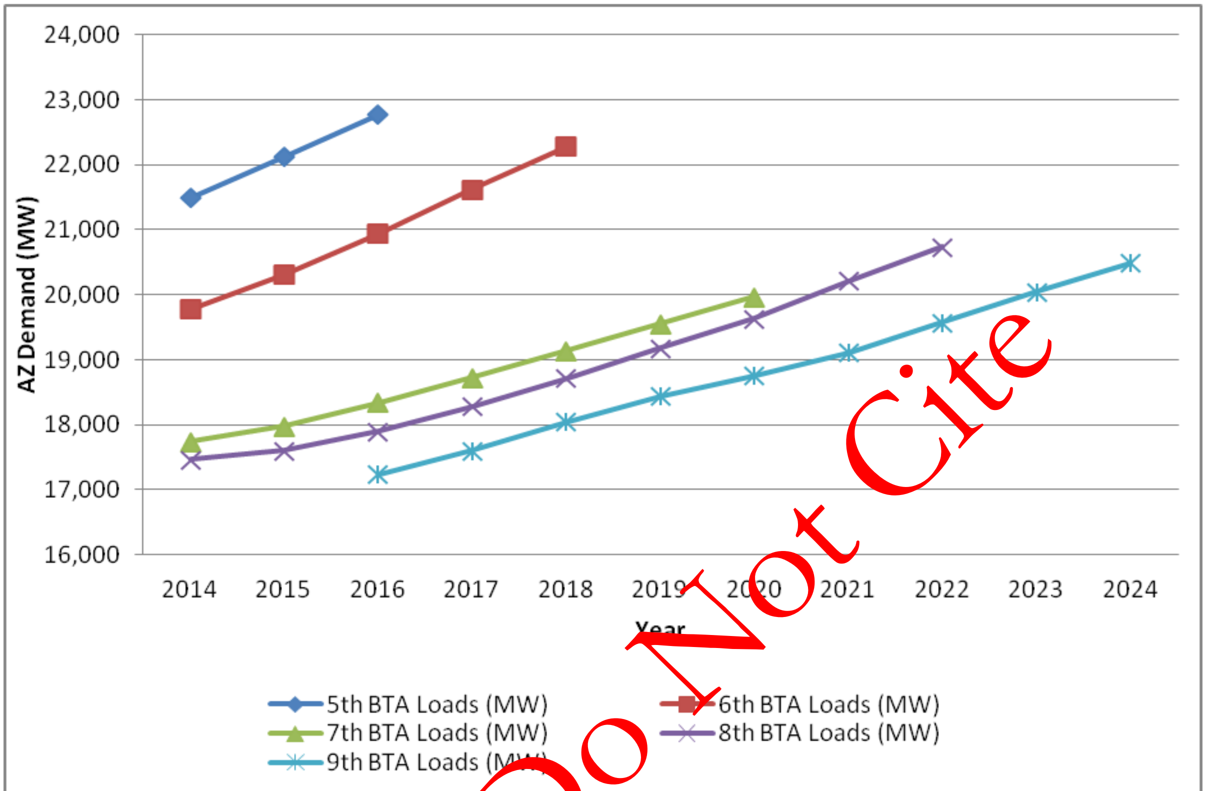
In-Service Date	Project Description	Utility	Voltage Class (kV)	Status
2014	Pinal West – Duke – Pinal Central 500kV line	SRP	500	Completed
2014	Pinal Central – Browning 500kV line	SRP	500	Completed
2014	Pinal Central Substation and Shunt Reactor	SRP	500	Completed
2015	Hassayampa – North Gila #2	APS	500	Completed
2015	Pinal Central - Tortolita	TEP	500	Completed
2016	Delaney - Palo Verde 500kV Line	APS	500	Completed
2016	Delaney - Sun Valley 500kV Line	APS	500	Completed
2015	Series Capacitor Replacement at Vail 345kV Substation (Springerville-Vail)	TEP	345	Completed
2015	Series Capacitor Replacement at Vail 345kV Substation (Winchester-Vail)	TEP	345	Completed
2015	Series Capacitor Replacement at Greenlee 345kV Substation (Springerville-Greenlee)	TEP	345	Completed
2017	Four Comers 500/345kV Transformer	APS	500	New
2017	Hassayampa - Pinal West 500kV Line Loop-in to Jojoba Switchyard	TEP	500	Deferred 2015 to 2017
2018	Bowie 1,000MW Power Station	Bowie	345	Deferred 2016-2018
2021	SunZia Southwest Transmission 500kV Project	SRP	500	Deferred 2017 to 2021
TBD	Abel 500kV Substation	SRP	500	Deferred From 2020 to TBD
TBD	Greenlee Switching Station through Hidalgo to Luna (Deming area)	EPE	345	Deferred Indefinitely

Table 8 – Significant EHV Project Changes since the Eighth BTA

2.3 Driving Factors Affecting the Ten-Year Plan – Load Forecast

In reviewing the filings, the chief determinant for the ten year transmission plans in Arizona was found to be the projected future load growth. Figure 1 shows the change in statewide demand forecasts between previous BTAs and the current Ninth BTA.

Figure 1 - Change in Arizona Demand Forecast



The statewide demand forecast has continued to be lowered since the Fifth BTA. During the Ninth BTA the Arizona utilities reported a Ten-Year Forecast that was, on average, 4.3% lower than was reported during the Eighth BTA. Although the statewide forecast has been lowered overall, the demand forecast shows a projected growth rate of approximately 2.18% per year for the Ten-Year forecast period. APS has reduced their forecast by approximately 4.75% per year in this BTA. In their 2017 Preliminary IRP, APS forecast results point to reduced natural and net population migrations and high penetrations of DG and EE occurring in recent years, which may explain the significant drop since the Eighth BTA. APS also reported the delay of North Gila – Orchard 230 kV project due to slower anticipated growth. SRP has reduced their forecast by approximately 5.11% over the planning period and is experiencing similar trends as APS. SRP has also reported the delay of two significant load-growth related projects: the Price Road Corridor and the Eastern Mining Expansion projects. The detailed forecast data for APS, SRP, AZG&T, and TEP/UNSE has been included in Exhibit 9.[27]

In its Sixth BTA Order the Commission directed Arizona utilities to "include the effects of distributed renewable generation and energy efficiency programs on future transmission expansion needs in future Ten-Year Plan filings."[28] Supplemental to the requirements of the Sixth BTA, in the Eighth BTA the Commission directed Arizona utilities with retail load to report the effects of DG and EE on future transmission needs. The study is to include a technical analysis performed on the fifth year transmission plan and including a contingency analysis depicting the planned transmission system with and without disaggregated DG and EE load. The filed Ten-Year Plans for APS, SRP, and TEP/UNSE included the results of the technical study work and discussed the factors that were taken into account in developing the demand forecasts used in studies performed for the current Ten-Year Plans. The DG and EE technical study results are discussed in more detail in section 3.3.5. Overall, Arizona Utilities reported a projected fifth-year DG and EE load reduction of 1,394 MW throughout Arizona. The DG and EE combined with a slow economic recovery have aided in keeping the current state-wide load forecasts lower than previously anticipated.

[27] Studies performed by AZG&T for the 2012-2021 ACC Ten Year Plan were stressed using non-coincident load values for worst case scenario analysis.
[28] Decision No. 72031 (December 10, 2010)

2.4 Driving Factors Affecting the Ten-Year Plan – Generator Interconnections

Under FERC regulations, generation developers seeking to interconnect to a transmission provider's system must file an interconnection application.[29] The rules and procedures for such applications are defined in the transmission provider's Open Access Transmission Tariff ("OATT"). As part of the BTA process, Staff and KRSA detailed each utility's generation interconnection queues from the Eighth and Ninth BTA. These are summarized in Table 9 and detailed in Exhibit 11, along with the difference between the two. In parallel with the FERC's interconnection process, any party contemplating construction of transmission in Arizona, including generator tie-lines, must file a Ten-Year Plan with the Commission.[30]

Utility	Approximate Capacity (MW) of Generators in Utility Queue		Interconnection Queues from Eighth to Ninth
	Eighth BTA	Ninth BTA	
APS	4,774	3,960	(814)
SRP	3,824	1,945	(1,879)
TEP/ UNS ELECTRIC	851	761	(90)
WAPA	2,660	1,704	(956)
AZG&T	0	0	0
Total	12,109	8,370	(3,739)

Table 9 - Summary of Arizona Generator Interconnection Queues

Arizona combined interconnection queues have continued to fall since the Seventh BTA. During the Seventh BTA, 18,453 MW of capacity was placed in the queues. Since the Seventh BTA several large projects have come online, including the Agua Caliente, Arlington Valley II, Mesquite, and Solana Generating stations, which have a combined capacity of 1,127 MW which would represent a portion of the capacity reported in the Seventh BTA. However, it is clear that the interconnection queues have seen a significant amount of projects withdraw from the queue. Still, at the time of the Ninth BTA, as shown in Table 9, over 8.3 GW of generation capacity is still contemplated for development. Almost half of the interconnection queue generation is in APS' queue. As shown in section 2.2, Arizona's load forecast does not support the need for this much

[29] Generators over 20 MW are interconnected pursuant to a Large Generator Interconnection Agreement ("LGIA"); generators 20 MW or less are interconnected pursuant to a Small Generator Interconnection Agreement.
[30] ARS § 40-360.02.A

additional merchant generation. Therefore, it is presumed that anticipated exports to California continue to be a driving factor in generation development. Confirming this, the WECC 2016 State of the Interconnection[31] report illustrated that, in 2014, there was a net export of 39,000 GWh out of the Southwest area into California.

A number of proposed and conceptual intra- and inter-state projects are considered in this Ninth BTA between Arizona and California that if built will increase transfer capacity. With California recently increasing the state's renewable portfolio standards to 50% by 2030, several stakeholders expressed renewed activity and interest in generation projects that have previously filed Ten-Year Plans.

[31] WECC 2016 State of the Interconnection. Pg. 31.

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3 Adequacy of the System

State statutes require that the Commission determine the adequacy of existing and planned facilities to meet the present and future energy needs of Arizona in a reliable manner.[32] Adequacy is defined as the ability of the electric systems to supply the aggregate electrical demand and energy requirements at all times, accounting for scheduled and reasonably expected unscheduled outages of system elements. Adequacy is generally considered a planning issue related to the capability and amount of facilities installed. The adequacy of the transmission system in the BTA process is determined through a critical review of the utility Ten-Year Plan study work, results of NERC/WECC reliability audits, findings from Commission-ordered BTA study work, review of information presented at the "Summer 2016 Energy Preparedness" meeting[33], and consideration of information provided on physical security of the transmission system.

3.1 Utility Study Work

Individual utilities within the state of Arizona plan and design their bulk transmission systems in accordance with the NERC/WECC Planning Standards, guidelines established at the state level, and their own internal planning criteria, guidelines and methods. These planning practices are utilized to ensure that their respective systems are planned to provide reliable service to customers under various system conditions. These requirements are also intended to ensure that neighboring utilities and neighboring states plan their systems in a coordinated manner by following a consistent set of standards, criteria and guidelines.

In terms of Ninth BTA utility study work filings, "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."[34] The required technical study work is in compliance with NERC Transmission Planning ("TPL") Standards. On October 17, 2013 FERC issued Order No. 786, adopting TPL standard TPL-001-4.

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[32] Arizona Revised Statute § 40-360.02.G

[33] Summer 2016 Energy Preparedness April 28, 2016 at the ACC in Phoenix hearing room #1. http://www.azcc.gov/Divisions/Utilities/Electric/SummerPreparedness.asp

[34] ARS § 40-36.02.C.7

The new standard included significant changes from the previous standard by, among other changes, requiring annual assessments addressing near-term and long-term planning horizons for steady state, short circuit and stability conditions[35]. TPL-001-4 includes updated Steady State & Stability Performance Planning Events, expanding the number of event categories to seven. The changes to the planning events are depicted below in Table 10.

New Planning Event Categories	Previous Planning Event Categories	Description
P0	A	System Intact
P1	B	Single Contingency (Fault of a shunt device- fixed, switched or SVC/STATCOM is new)
P2	C1, C2	Single event may result in multiple element outages. Open line w/o fault, bus section fault, internal breaker fault
P3	C3	Loss of generator unit followed by system adjustments + P1. No load shed is allowed
P4	C	Fault + stuck breaker events
P5	NA	Fault + relay failure to operate (new)
P6	C3	Two overlapping singles (not generator)
P7	C4, C5	Common tower outages; loss of bipolar DC

Table 10 – Updated Steady State & Stability Performance Planning Events

There are eight Transmission System Planning Performance Requirements that are subject to NERC audits. WECC is currently in the progress of updating the System Performance Criteria, TPL-001-WECC-CRT, to correspond with the new NERC standard.

Staff and KRSA have received and reviewed the required ten year study work from each Arizona utility. Table 11 summarizes the findings from Staff and KRSA's review of the utility provided Ten-Year Planning efforts.

[35] FERC ORDER No. 786. October 17, 2013. http://www.ferc.gov/whats-new/comm-meet/2013/101713/E-2.pdf

Utility	System Configuration Utilized	Category P0 and P1 Steady State and Stability Performed	Category P0 Issues – No Contingency	Category P1 Issues – Single Contingency	Plans Developed to Resolve Problem
APS	2015 HS Case for years 2016-2019. 2023 HS SWAT-AZ Case for 2020-2023. 2024 HS SWAT-AZ for 2024-2025	Yes	None	None	N/A
SRP	2015 HS4 for 2016-2019. 2020 WECC HS2 for 2020-2023. WECC HS1 2024-2025, and WECC 2025 HS1	Yes[36]	None	None	N/A
AZG&T	SWAT-AZ 2016 HS/LW, 2020 HS, 2025 HS/LW	Yes	None	Yes	Yes
TEP	2016 HS for 2017-2018, 2020 HS for 2019-2021, 2024 HS for 2022-2026	Yes	None	None	N/A

Table 11 – Summary Table of Utility Study Work

Additionally, over the past four BTAs load forecasts have changed substantially along with the associated transmission projects. In order to provide the Commission with additional information on the impact of load forecasts on transmission projects, Staff concluded in the Eighth BTA that, for reliability or load growth driven transmission projects, a system load level range at which a transmission project is needed should be reported along with the projected in-service year. The Commission directed that the load level range should be reported beginning with ten year transmission plans filed on January 31, 2016.

A review of the Ten-Year Plans showed that compliance with the load level range reporting requirement varied. APS generally did not provide a load level but made the statement that "in-

[36] SRP's technical study work was performed under the previous TPL-001-02 NERC criterion. Steady State and Stability results contained in Table 11 refer to the equivalent Category A and Category B criteria.

service need date for this line will be continuously evaluated in planning studies to keep pace with system needs." SRP did identify a load level range for the Price Road Corridor project; however, reliability driven projects were reported as "not triggered by rising system load levels." TEP included the load level range only for load-driven projects and AZG&T referred to a May 2014 optimization study as the justification for the installation of reactive resources needed for reliability purposes.

Based on the above responses, Staff and KRSA believe that the load level range may be an impractical metric for inclusion in future Ten-Year Plans. Load growth and reliability needs will change year-to-year and will be continuously monitored in the utilities' annual planning processes which will identify the needed investments. To the extent that load growth or reliability needs change, and the utilities have an instinctive desire to avoid unnecessary investment, the timing of future transmission projects or improvements will be determined and updated in subsequent Ten-Year Plans.

Based on the results, the 2016 technical studies filed in the Ninth BTA indicate a robust study process for assessing transmission system performance, both steady-state and transient,[37] for the 2016-2025 planning period.

3.2 NERC/WECC Reliability Audit

The Commission directed the Arizona utilities to "report relevant findings in future BTAs regarding compliance with transmission planning standards from NERC/WECC reliability audits that have been finalized and filed with FERC."[38] Table 12 summarizes the related information filed in the Ninth BTA.

[37] "Steady State" refers to the time periods before a system disturbance occurs and after the system has fully recovered from a disturbance. "Transient" or "Transient Stability" refers to the time period after a system disturbance occurs, when the system is responding to the disturbance.
[38] Decision No. 72031

Utility	Reliability Audit Finalized and filed with FERC Since Eighth BTA	Comments Related to Transmission Planning Standards
APS	NO	Audit performed in November 2013 and received a report of "no findings". The next NERC/WECC reliability audit is scheduled to occur November 2016.
SRP	NO	Audit performed in August 2013 and received a report of "no findings". The next NERC/WECC reliability audit is scheduled to occur October 2016.
TEP	YES	Audit performed in August 2014 and included a review of 33 Operation & Planning and 23 Critical Infrastructure ("CIP") requirements. One possible CIP violation identified and has since mitigated. Next audit is scheduled for October 2017.
AZG&T	YES	Audit performed in February 2015 and received a report of "in 100% compliance with all NERC and WECC standards"

Table 12 – WECC Audit Results

Based on the results of NERC/WECC reliability standards audits over the past two years, there was only one possible CIP violation that has since been mitigated. In general, there are no concerns of Arizona's BES failing to comply with the applicable planning standards established by NERC/WECC.

3.3 Commission-Ordered Studies

Previous BTA processes identified the need for supplemental studies to be performed by Arizona utilities. The purpose of the Commission-ordered studies is to assure the certainty of the conclusions and recommendations within the BTA and to draw attention to potential transmission system concerns which necessitate closer Commission scrutiny.

The Commission-ordered studies falls into five categories: transmission load serving capability, RMR, Ten Year Snapshot, Extreme Contingency, and Energy Efficiency and Distributed Generation. Table 13 summarizes the history and purpose of Commission-ordered BTA studies. The subsequent sections discuss the results of Commission-ordered BTA studies.

Commission Ordered Study Work	Purpose	Required Since
Transmission Load Serving Capability	Determine the maximum amount of load which can be served within the transmission constrained import areas	First BTA
Reliability Must Run	Determine constrained transmission import areas with local generation operation requirements	Second BTA
Ten Year Snapshot	Determine transmission system's robustness against delays of major projects	Third BTA
Extreme Contingency	Determine transmission system's stoutness against extreme outage events	Third BTA
Energy Efficiency and Distributed Generation	Determine the impact of EE/DG on transmission system performance	Eighth BTA

Table 13 - Summary of Commission-Ordered BTA Studies[39]

3.3.1 2016 Transmission Load Serving Capability Assessment

Load serving capability is assessed by the ability of the electric system to serve load within a constrained area known as a load pocket. The load pocket constraints generally occur during limited hours of the year. During these limited operating hours each year, there is a requirement for generation located within the load pocket to serve the portion of the load that cannot be served by transmission. This type of generation is often referred to as RMR generation and is required to operate out of merit order. The combination of transmission and generation facilities establishes what is referred to as the load serving capability of an area. The Commission expects utilities to assure that adequate import capability is available to meet the load requirements of all distribution customers within their service areas. The Commission has adopted the use of two terms as indicators of the load serving capability of local load pockets: SIL and MLSC.[40]

In the First BTA, Staff identified three load pockets in Arizona to be monitored for transmission import constraints: Phoenix, Tucson and Yuma. The Second BTA added fourth and fifth load

[39] In the Seventh BTA, Staff suspended the requirement for performing RMR studies in every BTA and implemented criteria for restarting such studies on a biennial review of specific system factors.
[40] See Appendix E, RMR Conditions and Study Methodology

pockets: Mohave County and Santa Cruz County. Prior BTAs examined import constraints in Pinal County and identified it as a local area that also needed to be monitored. In the Fifth BTA, Cochise County was also identified as needing import assessments to address continuity of service concerns.

3.3.1.1 Cochise County Import Assessment

Although the Commission did not order an RMR study for Cochise County, it directed that studies be filed for Cochise County addressing "continuity of service" issues.[41] However, in the Seventh BTA, Staff recommended suspension of efforts to upgrade reliability to a continuity of service definition for Cochise County due to the high cost of capital upgrades for new transmission required to achieve such a level of reliability and the low customer density in these service areas. This included the suspension of filing of two more Cochise County Study Group ("CCSG") progress reports in 2012.

Further, Staff recommended that the CCSG participants continue to monitor the reliability in Cochise County and propose any modifications that each deemed to be appropriate in future Ten-Year Plans. Staff also recommended that the Commission continue to collect applicable outage data from the respective utilities in order to monitor any changes in Cochise County system reliability in future BTA proceedings.

AZG&T is continuing its efforts with APS and Sulphur Springs Valley Electric Cooperative ("SSVEC") to develop the joint Tombstone Junction Project in Cochise County to effect reliability improvements in the area. Various configurations have been studied by AZG&T and APS and the two parties, along with SSVEC, continue to discuss joint participation on the project. AZG&T is current reporting an in-service date of 2021 for the Tombstone Junction Project.

Through a data request Staff and KRSA received Cochise County outage data for APS, TEP and AZG&T. In APS's service territory in Cochise County there have been two sustained outages of five minutes or longer in the past two years and four momentary interruptions. TEP reported one sustained outage and one momentary interruption. The cause of the sustained outage is unknown; however, only one customer was impacted. AZG&T reported two sustained outages in

[41] Decision No. 70635

2015 affecting their transmission system and nine momentary interruptions. Table 14 summarizes the sustained outages reported by APS, AZG&T and TEP.

System	Year	Number of Sustained Outages	Average Outage Time (Minutes)	Average Number of Customers Affected
APS	2014	0	0	0
	2015	2	79	13,887
	2016 (through June 1)	0	0	0
TEP	2014	1	586	1
	2015	0	0	0
	2016 (through June 1)	0	0	0
AZG&T	2014	0	0	0
	2015	2	23	16,192
	2016 (through June 1)	0	0	0

Table 14 - Cochise County Sustained Outages Data Summary

After reviewing the 2014-2016 outage data reported for Cochise County, Staff and KRSA do not find any significant cause for concern. Staff and KRSA find that Cochise County outage data should continue to be collected and monitored in future BTA. Further, Staff and KRSA find the Cochise County import assessment requirement is satisfied for this Ninth BTA.

3.3.1.2 Santa Cruz Import Assessment

Santa Cruz County, similar to Cochise County, is served by a radial transmission system. UNS Electric is the load serving entity ("LSE") in Santa Cruz County. With the completion of the radial 115 kV line to 138 kV, the area load serving capability increased to 159 MW under normal conditions, through a combination of the radial transmission delivery capability and 61 MW of local combustion turbine generation at Valencia Substation in Nogales. The Ninth BTA load forecast for Santa Cruz is 82 MW in 2023, 2 MW less than the Eighth BTA forecast of 84 MW for 2023.

In addition to the import assessment, the Commission directed studies be filed for Santa Cruz County addressing "continuity of service" issues.[42] However, in the Seventh BTA, Staff recommended suspension of efforts to upgrade reliability to a continuity of service definition for Santa Cruz County due to the high cost of capital upgrades for new transmission required to achieve such a level of reliability, and the low customer density in these service areas.

[42] Decision No. 70635

In addition, Staff recommended that UNS Electric continue to monitor the reliability in Santa Cruz County and propose any modifications that were deemed to be appropriate in future Ten-Year Plans. Staff also recommended that the Commission continue to collect applicable outage data from UNS Electric in order to monitor any changes in Santa Cruz County system reliability in future BTA proceedings.

Through a data request, Staff and KRSA received Santa Cruz County outage data from UNS Electric. Table 15 summarizes UNS's response. The outage data shows there were 4 momentary interruptions in service and no sustained outages reported from 2014-2016 in Santa Cruz County.

Year	Number of Sustained Outages / Interruptions	Average Outage Time (Minutes)	Average Number of Customers Affected
2014	1	2	20,000
2015	2	< 1 Minute	10,000
2016 (through June 1)	1	< 1 Minute	20,000

Table 15 - Santa Cruz Sustained Outages and Momentary Interruptions Data Summary

Staff and KRSA find that Santa Cruz County outage data should continue to be collected and monitored in future BTA. Further, Staff and KRSA find the Santa Cruz County import assessment requirement is satisfied for this Ninth BTA.

3.3.2 Import Assessments Requiring RMR Studies

During some portions of the year, generation units within a load pocket might be required to operate out of merit order[43] to serve a portion of the local load; this is referred to as RMR generation. The 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.

[43] Merit order is a way of ranking available sources of energy, especially electrical generation, in ascending order of their short-run marginal costs of production, so that those with the lowest marginal costs are the first ones to be brought online to meet demand, and the plants with the highest marginal costs are the last to be brought on line. Dispatching generation in this way minimizes the cost of production of electricity. Sometimes generating units must be started out of merit order due to transmission congestion, system reliability or other reasons.

The past few BTA studies have shown decreasing RMR costs in most of the areas as transmission system upgrades have been made, local generation has developed, and load growth has stagnated. In the Seventh BTA, Staff suspended the requirement for performing RMR studies in every BTA and implemented criteria for restarting such studies based on a biennial review of factors such as: [44]

- An increase of more than 2.5% in an RMR pocket load forecast since the previous BTA.[45]
- Planned retirement or an expected long-term outage during the summer months of June, July, or August of a key transmission or substation facility supplying an RMR load pocket, unless a facility being retired will be replaced with a comparable facility before the next summer season.
- Planned retirement or an expected long term outage during the summer months of June, July, or August of a generating unit in an RMR load pocket that has been utilized in the past for RMR purposes, unless a generator being retired will be replaced with a comparable unit before the next summer season.
- A significant customer outage in an RMR load pocket defined as a sustained outage of more than one hour exceeding the greater of 100 MW or 10% of the peak demand in the pocket.

Each Arizona utility reported that none of the criteria for triggering RMR studies occurred during the Ninth BTA; therefore updated RMR studies were not filed for the five RMR areas.

3.3.2.1 Phoenix Metropolitan Area RMR Assessment

The interconnected transmission system serving the metropolitan Phoenix area is owned and operated by APS, SRP and WAPA. A majority of the Phoenix area ("Phoenix Valley") load is served by transmission imports. Load growth occurring in the north and west segment of the

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[44] Decision No. 73625

[45] For example, the final RMR study year filed in the Seventh BTA was 2021 and the Eighth BTA load forecast for 2021 was compared to the Seventh BTA forecast amount for this year to determine the percent increase. Using the data for the Phoenix RMR area, the peak demand forecast for 2021 was 14,209 MW in 2012 so the need for restarting RMR analysis would have been considered if 2014 BTA 2021 forecast had exceeded 14,209 x 1.025 = 14,564 MW.

Phoenix Valley is served by APS and the load growth in the east and south is served by SRP. An RMR condition exists for the Phoenix Valley because the peak load for the area exceeds the SIL of the existing and planned transmission system serving the area. APS has included four transmission projects in their Ten-Year Plan that will add import capability into Phoenix. However, APS reported that no triggering criteria for restarting the Phoenix Valley RMR studies have occurred since the Seventh BTA, therefore there are no updated results to report for the Ninth BTA.

3.3.2.2 Tucson Area RMR Assessment

The Tucson area is interconnected to the EHV transmission system at Tortolita, South, and Vail Substations. These three stations interconnect and supply energy to the local TEP 138 kV system. In December 2015, TEP completed the Pinal Central to Tortolita 500 kV transmission line, providing additional capacity from Palo Verde into TEP's northern service territory. 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. TEP reported that no triggering criteria for restarting the Tucson Area RMR studies have occurred since the Eighth BTA.

3.3.2.3 Yuma Area RMR 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. APS also completed a second 500 kV line from North Gila to the Palo Verde Hub[46] in May 2015, further increasing the import capability into the Yuma load pocket. Additionally, APS plans to construct the North Gila to Orchard 230kV transmission line to add additional import capability in 2021. APS has reported that no triggering criteria for restarting the Yuma Area RMR studies have occurred since the Eighth BTA.

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[46] Hassayampa to North Gila #2 (HANG2) 500kV Transmission Line project.

3.3.2.4 *Santa Cruz County RMR Assessment*

Santa Cruz County is served by a radial transmission system. UNS Electric is the LSE in Santa Cruz County. UNS Electric reported that no triggering criteria for restarting the Santa Cruz County RMR studies have occurred since the Eighth BTA.

3.3.2.5 *Mohave County RMR Assessment*

Mohave County is the only Arizona load pocket with local generation that has a peak load that does not exceed its reported SIL rating. UNS Electric is a LSE in Mohave County.[47] UNS Electric reported no triggering criteria for restarting the Mohave County RMR studies have occurred since the Eighth BTA.

3.3.3 Ten Year Snapshot Study

The SWAT subcommittee, Arizona Transmission System ("SWAT-AZ"), performed and filed a report documenting results of its Ten Year Snapshot study. This study provides an assessment of the Ten-Year Plans proposed by Arizona transmission owners.[48] The Ten Year Snapshot study consists of conducting normal and single contingency ("n-0" and "n-1" respectively) power flow analyses that determine the adequacy of the planned transmission system in the tenth year of the planning period. The Ten Year Snapshot study also assesses the effect of omitting individually planned transmission projects.[49]

Whereas some of the Arizona transmission owners have filed technical study reports for their respective areas of the system as part of the Ninth BTA, the SWAT-Arizona Ten Year Snapshot study represents the only comprehensive assessment of 2025 Arizona transmission plans. Furthermore, the Ten Year Snapshot study done in 2016 includes all transmission and generation projects statewide, making the report uniquely valuable for assessing the overall adequacy of Arizona transmission plans in 2025.

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[47] Other entities serving load in Mohave County include Aha-Macov, Central Arizona Project, Mohave Electric Cooperative, and the City of Needles

[48] The SWAT-Arizona Subcommittee is partially comprised of the following transmission participants: APS, SRP, AZG&T, TEP, UNS Electric and Western.

[49] It should be noted that removal of an individual project in some cases involved the removal of multiple transmission lines and/or bulk power transformers.

The 2025 case modeled a statewide load of 22,430 MW which is 1,105 MW or 4.7% lower than the statewide load modeled in the previous Ten year Snapshot study completed for the year 2023. The 2025 base case model used for the study was based on the complete list of projects that were planned to be in service by 2025 at the time of base case development, which took place from January to April 2015.

In all, a total of four base case project deferral scenarios, including four projects, two from APS and two from SRP , 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 Ten Year Snapshot study reached the following major conclusions:

- Arizona's 2025 transmission plan is robust and supports the statewide load forecast.
- The 2025 Heavy Summer base case included a single bus voltage issue and no thermal violations with all lines in service, as well as voltage, thermal, and no-solve concerns under simulated contingency conditions. Single contingency outage analysis on the base case showed two different overloaded 115 kV elements that can be mitigated through increased output at the Apache Generating Station.
- The 2025 Heavy Summer base case included a single N-1 outage that resulted in a no-solve, or no solution at the Marana - Saguaro 115 kV (Breaker to Breaker) sub-station. The no-solve has been discussed with the affected utility and will be considered in future planning studies.
- Since the Ten-Year Snapshot was performed, WAPA and AZG&T have completed the Saguaro Bypass Project which may provide a mitigation strategy to both the overloaded elements and the N-1 outage discussed above; however, these changes have not yet been since studied for 2025.
- Study results remained unchanged from the 2025 Heavy Summer base case under single contingency (N-1-1) project analysis.
- Planned projects support the loads estimated for the 2025 timeframe.

- Delaying any one of the projects beyond 2025 did not have a significant negative impact on system performance.

Staff and KRSA conclude the Ten Year Snapshot study documents the performance of Arizona's statewide transmission system in 2025 for a comprehensive set of N-1 contingencies, each tested with the absence of different major planned transmission projects. Potential mitigation strategies have been discussed for the 115 kV elements projected to be overloaded and the identified outage; however, the study work remains to be completed. Should the identified issues continue to be reported in the Tenth BTA, Staff may make requests for additional analysis or comments. Finally, Staff and KRSA have concluded that the Ten Year Snapshot does include the monitoring of transmission elements down to and including 115 kV as required by the Eighth BTA.

3.3.4 Extreme Contingency Study Work

The Commission directed that, as part of the Ninth BTA, 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, if mitigating infrastructure improvements are not planned.[50] Studies have been filed in response to the Commission requirement. Two extreme contingency studies were performed: one by APS and the other by TEP. Each was coordinated through the SWAT-Arizona subcommittee.

The APS and TEP analyses were performed using 2016 and 2025 summer peak load models which reflected the filed ten year project plans. This analysis generally corresponds to NERC Category P2 through P7 events, but did not include an assessment of transient stability performance.[51] EHV transmission line corridors were chosen for study based upon exposure to forest fires and other extreme events. APS performed studies for corridor outages involving five sets of lines/transformers. TEP performed studies for corridor outages involving three sets of lines/transformers.[52]

[50] Decision No. 67457
[51] NERC Reliability Standards TPL-001-4
[52] The details of the extreme contingencies performed by APS and TEP are considered sensitive information and therefore removed from this report.

APS's extreme contingency analyses indicate all load and local Phoenix reserve requirements can be met. The extreme contingency analyses do show that specific outages will require post-contingency operator response including generation re-dispatching and system reconfiguration to alleviate overloads. These APS results are for both the 2016 and 2025 system conditions.

TEP's extreme contingency analysis were studied for both the 2016 and 2024 heavy summer power flow and included an analysis of a single transmission corridor as well as two substations susceptible to multiple transformer outages. The extreme contingency study resulted in power flow no-solve results for both 2016 and 2024. The transmission corridor and one of the substation locations exhibited potential issues in 2024, while only one of the substation locations exhibited potential issues in 2016. TEP intends to continue to monitor the impacts of the system due to these outages and mitigation needs will be evaluated in future internal studies.

Staff and KRSA found the Extreme Contingency Analysis studies satisfy the requirements of Commission Decision No. 67457.

3.3.5 Distributed Generation and Energy Efficiency

In the Eighth BTA, the Commission ordered[53] jurisdictional utilities to study the effects of distributed generation and renewable efficiency programs on future transmission needs in their Ten-Year Plan filings. The directives in the order were as follows:

> *The technical study should be performed on the fifth year transmission plan by disaggregating the utilities' load forecasts from effects of DG and EE and performing contingency analysis with and without the disaggregate DG and EE. The technical study should at a minimum discuss DG and EE forecasting methodologies and transmission loading impacts. The study should monitor transmission down to and including the 115 kV level.*

APS's 2020 system peak forecast excluding the effects of DG and EE is 8,064 MW; the 703 MW difference is comprised of 79% EE and 21% DG. The EE impacts were forecasted based on continued compliance with EE Rules and Commission Orders and in accordance with APS's 2015 Demand Side Management Implementation Plan. DG was forecast using the average monthly volume of applications that APS received in 2015 and projected forward to the study year. APS

[53] Decision No. 74785, October 24, 2014

assumed all of the DG and EE were located in the metro Phoenix load area where they are most prevalent. These forecasts were incorporated into a 2020 heavy summer case coordination through the SWAT-AZ subcommittee and examined using the All Lines in Service and Single Contingency criterion. The results indicate that projected DG and EE have no effect on APS's BES as currently planned for 2020. However, if planning and predictions in local growth and customer behaviors are met, the analysis did show some impact at the subtransmission level with delayed or non-implemented DG and EE. This impact could require advancing the in-service date of one 230/69kV substation an unknown number of years to alleviate overloads on existing 230/69kV transformers.

SRP's DG and EE forecasting methodology included an assessment of historical EE and DG impacts for determining future effects based on forecasted loads within SRP's six-year fiscal planning period. For out years, SRP relied on EPRI's long-run forecast models. SRP developed three power flow cases for their BTA study work. The cases were developed from the WECC 2020 HS2 case and were reflective of system peak with and without DG/EE and a near-peak case with EE/DG removed and no utility solar generation online. The load forecast studied included a peak load of 8,204 MW and 597 MW of DG and EE with a resulting net peak load of 7,607MW. The near-peak load was forecasted to be 7,453 MW. Using the All Lines in Service and Single Contingency as the criteria, SRP's power flow analysis found no overloads for N-1 outages, and no voltage violations were observed. The results showed that SRP's transmission system meets all of SRP's internal criteria, and satisfies applicable WECC and NERC criteria regardless of the future EE and DG.

TEP's analysis incorporated loads approved by TEP management in December of 2014, which took into account DG and EE loads as of February 2014. TEP performed power flow analysis, with and without the DG and EE loads, to identify thermal overloads under normal and contingency conditions. Analysis was done in compliance with NERC Reliability Standards and WECC System Performance Criteria. Results of the analysis concluded that no additional projects were required as a result of DG and EE effects. TEP's reported DG and EE loads contribute to the systems load profile to a much lesser degree than they do for APS and SRP load profiles. KRSA concludes that this is likely due to differing economic and rate design factors that lead to wider adoption of distributed generation in the Phoenix Metropolitan area compared to Tucson.

Staff and KRSA conclude the fifth-year technical study on the impacts of DG and EE was properly conducted and reported by the Arizona Utilities. The utilities should continue to report the considerations being made for and the impact of DG and EE on future transmission reliability in their Ten-Year Plans.

3.4 2016 Summer Energy Preparedness

The 2016 Summer Energy Preparedness meeting occurred on April 28, 2016, at the ACC offices. The 2016 Summer Energy Preparedness meeting is an open meeting where electric and natural gas utilities inform the Commission of their level of preparedness to deal with the ensuing summer peak season. The 2016 Summer Energy Preparedness meeting included presentations and comments by the following electric utilities: APS, SRP, TEP/UNS Electric, and Arizona's G&T Cooperatives. APS, SRP, TEP/UNS Electric, and the AZG&T each indicated preparedness for the 2016 summer peak demand. This preparedness included a declaration of adequate generation and reserves and sufficient transmission capacity to withstand normal outage contingencies. Emergency plans are also in place to respond to extreme outage events, extreme system conditions, and events of natural disaster including storms or fires.

Staff and KRSA were in attendance at the Summer Preparedness open meeting. APS indicated it is well prepared for the up-coming 2016 summer demand. APS discussed a need to add more dispatch flexibility to integrate increasing levels of renewable energy. An All-source RFP was issued March 11, 2016 seeking flexible capacity for post-2020 needs. APS identified several reliability activities including the installation of stopper poles, storm hardening of the 69kV system, deployment of smart grid devices and physical and cyber security substation upgrades. APS also identified several west valley transmission projects that will be completed and energized by June 1, 2016. APS stated adequate generation resources are in place to meet customer load and meet reserve requirements, line maintenance efforts are on track, on-going coordination and integration with emergency planners is occurring, and strong customer communication channels are in place.[54]

SRP indicated that SRP transmission, distribution, generation and planned energy purchases are adequate to serve the forecasted year 2016 demand. Peak demand is forecasted to be lower than last

[54] APS, *Arizona Public Service Company 2016 Summer Readiness,* given on April 28, 2016, slide 24, http://www.azcc.gov/Divisions/Utilities/Electric/summer%20preparedness/2014%20Summer%20Prep%20-%20APS.pdf

year's actual peak and is supported by a robust transmission system. SRP's presentation outlined transmission improvements made, system preparations and an overview of outage response and reporting mechanisms in place. .[55]

TEP summarized its presentation noting that sufficient generation and transmission resources are available to meet both TEP's and UNSE's load. TEP made several system reliability enhancements including the completion of the Pinal Central to Tortolita 500 kV project, an upgrade to their Emergency Management System ("EMS") to meet version 5 of the NERC Critical Infrastructure Protection ("CIP") compliance requirements, and 138kV re-conductor and series capacitor replacement projects. TEP stated reliable transmission and distribution systems with capacity to meet peak demand are in place. TEP stated operational testing has been conducted and summer operations plans are in place. TEP stated equipment and plans are available to respond quickly and efficiently to emergencies.[56]

In addition to participating in the Southwest Reserve Sharing Group, The AZG&T maintain transmission capacity to cover the largest unit outage and have additional arrangements with transmission counterparties for emergency market access for extended outages. The AZG&T completed capacitor bank installations, breaker and relay upgrades and Remote Terminal Unit ("RTU") installations at several substations and rebuilt a grounding transformer at the Greenlee substation. The AZG&T participated in WECC Reliability Coordinator restoration training in March 2016, updated the joint generation contingency reserve plan for an Apache generating station outage, added System State Estimator to their EMS system and upgraded RTUs at substations. The AZG&T reported sufficient resources, fuel supply and transmission, and that they are operationally well prepared to meet the forecasted demand and energy needs.[57]

Staff and KRSA conclude that the 2016 level of summer preparedness of the utilities in Arizona, as presented in the April 28, 2016 workshop, demonstrated sufficient preparedness measures are

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55 SRP, *SRP Summer Preparedness 2016* Presentation, given on April 28, 2016, slide 17, http://www.azcc.gov/Divisions/Utilities/Electric/summer%20preparedness/2016%20Summer/SRP%20Summer%20Prep%204-28-16.pdf

56 TEP, *2016 Summer Preparedness,* given on April 28, 2016, slide 15, http://www.azcc.gov/Divisions/Utilities/Electric/summer%20preparedness/2014%20Summer%20Prep%20-%20TEP%20UNSE.pdf

57 Arizona's G&T Cooperatives, *Arizona's Cooperatives Summer Preparedness Report to ACC 2016, given on April 28, 2016,silde20,* http://www.azcc.gov/Divisions/Utilities/Electric/summer%20preparedness/2016%20Summer/Arizona%20G&T%20Cooperatives%20Summer%20Prep%204-28-16.pdf

being taken. The current transmission system in Arizona is judged to be adequate to reliably support the energy needs of the state in 2016.

3.5 Physical Security

FERC directed NERC to submit for approval reliability standards that will require transmission owners and operators to take action or demonstrate that they have taken action to address physical security risks and vulnerabilities related to the reliable operation of the BES. The proposed reliability standards should require owners or operators of the BES to:

1. Identify facilities on the bulk-power system that are critical to reliable system operation, and
2. Validate and implement plans to protect against physical attacks that may compromise the operability or recovery of such facilities.

In response to the FERC directive, NERC developed the CIP-014-1 "Physical Security" standard which was formally adopted by NERC on May 13, 2014. On November 20, 2014 FERC issued an order approving CIP-014-01[58]; however, subsequent comments led to a revision of the standard. The final standard, CIP-014-2 Revision 2, was issued by NERC and approved by FERC on July 14, 2015[59].

The standard includes six requirements and applies to substations operating at greater than 500 kV and selected substations operating between 200 kV and 499 kV that meet a specified criterion. Under the standard, transmission owners are required to conduct risk assessments, including verification by a third party, conduct an evaluation of potential threats and vulnerabilities of a physical attack at sites identified in the assessment, and prepare and implement a physical security plan for applicable sites.

At the request of Staff and KRSA Arizona utilities provided information and details on their plans and efforts to ensure physical security and resiliency in the planning and operation of the Arizona electric system, the details of which are considered confidential. Based on this information,

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58 FERC Ruling approving Reliability Standard CIP-014-1 - https://www.ferc.gov/whats-new/comm-meet/2014/112014/E-4.pdf

59 CIP-014-1 – Physical Security Standard - http://www.nerc.com/pa/Stand/Prjct201404PhsclScrty/CIP-014-2_Physical_Security_2015Jan30_clean.pdf

Staff and KRSA conclude the Arizona utilities are taking actions to address the physical security risks to reasonably ensure the reliable operation of the Arizona transmission system.

4 Interstate, Merchant and Generation Transmission Projects

Wholesale market power purchases and sales rely on available interstate transmission. These interstate and merchant transmission projects make possible a competitive and healthy wholesale market while complementing the states' utilities electric infrastructures by providing additional import/export points. Several market access projects and merchant transmission projects are discussed in this BTA. This section of the BTA report highlights the status of eighteen such planned projects that affect Arizona. Exhibit 19 provides a tabular listing of the interstate, merchant and generation transmission projects.

4.1 Projects Filed or Presented in the Ninth BTA

4.1.1 Ten West Link 500 kV Transmission Line

The Ten West Link, formerly referred to as the Delaney – Colorado River Transmission Project, would provide an additional interstate 500 kV interconnection between Arizona and California.[60] DCR Transmission, LLC filed a Ten-Year Plan for this project. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included as Exhibit 21.

The Ten West Link 500 kV line is conceptualized as a 114 mile, 500 kV single circuit structure between the APS Delaney 500 kV substation located in Arizona and the Southern California Edison's ("SCE") Colorado River 500 kV substation.

The Ten West Link project was recently studied as an economic project in the California Independent System Operator ("CAISO") 2013-2014 Transmission Plan. The project demonstrated sufficient benefits when compared to the cost and was recommended for approval by the CAISO Board.[61] At the March 20, 2014 Independent System Operator ("ISO") Board of Governors meeting, the ISO Board of Governors failed to approve the line and CAISO staff was directed to perform further assessments and report the results back to the Board. Subsequently, the ISO Board

[60] The Arizona portion of the previously planned Palo Verde – Devers #2 Project of which SCE has already built the California portion.

[61] http://www.caiso.com/Documents/Board-Approved2013-2014TransmissionPlan.pdf

of Governors approved the Delaney – Colorado River 500 kV transmission line project at the July 16, 2014 meeting.[62] Following the approval, the CAISO conducted a Competitive Solicitation under FERC 1000 rules to select a Project Sponsor. On July 10, 2015, CAISO selected DCR Transmission as the preferred Project Sponsor, and the Approved Project Sponsor Agreement was executed on December 1, 2015.

The Bureau of Land Management ("BLM") will be acting as the lead agency overseeing the Environmental Impact Study ("EIS") required under the National Environmental Policy Act ("NEPA"). DCR Transmission intends to file an Application for a Certificate of Environmental Compatibility with the ACC after the EIS is completed. Estimated filing date is October 2016. DCR Transmission will be working closely with both Arizona and California line siting authorities and will be participating in the WECC Comprehensive Progress Report process.

4.1.2 SunZia Southwest Transmission Project

The SunZia 500 kV transmission line project would provide an interstate 500 kV interconnection between Arizona and New Mexico. A Ten-Year Plan was received and this project was presented and discussed at Workshop I. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for this BTA. Overview maps showing the general routing and interconnection points of this project are included within Exhibits 1, 3, 5 and 24.

The SunZia project is currently planned to consist of approximately 515 miles of two new single-circuit 500 kV transmission lines, either two alternating current ("AC") or one AC and one direct current ("DC"), and associated substations beginning at a new substation in central New Mexico and terminating at Pinal Central substation near Coolidge, Arizona. Approximately 200 miles of the proposed route are within Arizona, with 132 miles on state trust land, 50 miles on BLM land, and 17 miles on private land.

The sponsors of the SunZia Southwest Transmission Project include Salt River Project, Shell Wind Energy, Southwestern Power Group, Tri-State Generation and Transmission Association, and Tucson Electric Power. SunZia is anticipated to deliver primarily renewable energy from sources yet

[62] http://www.caiso.com/Documents/DecisionDelaney-ColoradoRiverTransmissionProject-Motion-July2014.pdf

to be determined to markets in Arizona and California. The first phase of commercial operation is expected to commence in 2021.

Milestones achieved since the Eighth BTA include the Record of Decision ("ROD") issued by the Bureau of Land Management (BLM) on January 23rd 2015. During 2016, SunZia will conclude negotiations for right-of-way across federal land along BLM's selected route documented in the ROD. On September 2, 2015 SunZia applied for a Certificate of Environmental Compatibility from the Arizona Corporation Commission. Thirteen days of hearings, including two field tours, were conducted by the Arizona Power Plant and Line Siting Committee ("LSC"). The LSC voted unanimously to approve the CEC application and the ACC accepted the CEC, without changes, on February 3rd 2016[63]. SunZia now has federal and Arizona state approval. Future plans are to apply for a location Control Permit from the state of New Mexico's Public Regulation Commission in the summer of 2016. As of March 2016, SunZia has an agreement in place with the Department of Defense and the Department of Army resolving all military related conflicts. On January 27, 2015, WECC re-confirmed SunZia's accepted path rating of 3,000 MW. In addition, a Letter of Intent was signed in August 2013 with the project's first anchor tenant, First Wind Energy, LLC, for up to 1,500 MW of capacity.

4.1.3 Centennial West Clean Line Project

The Centennial West Clean Line Project ("Clean Line") is planned to be a ±600 kV High Voltage Direct Current ("HVDC") transmission line that would provide an interstate interconnection between New Mexico and California with routing through, and the potential for an interconnection point in, Arizona. No Ten-Year Plan was filed with the Commission in 2016 for this project. Therefore, this project was not considered for the adequacy assessment nor included in the Ten-Year Plan statistics compiled for this BTA. This project was presented and discussed at Workshop I. An overview map showing the general routing and interconnection points of this project is included as Exhibit 22.

The Centennial West Clean Line project is currently planned to consist of approximately 900 miles of HVDC beginning in northeastern New Mexico and terminating in southern California.

[63] ACC Decision No. 75464, February 3, 2016. http://images.edocket.azcc.gov/docketpdf/0000168504.pdf

Approximately 300 miles of the total project would be in northern Arizona. Clean Line filed an application for right-of-way across Federal lands[64] and a preliminary Plan of Development with the Bureau of Land Management in 2011, and has completed the Project Coordination Review portion of the WECC path rating process[65]. Additionally, Centennial West Clean Line executed a Memorandum of Understanding ("MOU") with the New Mexico Renewable Energy Transmission Authority which is authorized by statute to acquire land for the project and own transmission facilities. Eighteen community leader workshops in four states and two tribal nations have been held to gather information about local routing opportunities and constraints.

Clean Line last filed a Ten-Year Plan in January 2012. The Clean Line Project is sponsored by Clean Line Energy Partners, LLC. The project is expected to deliver 3,500 MW of renewable energy to markets in California and the West. Commercial operation is currently planned to begin in 2020.

4.1.4 Bowie Power Station

Bowie Power Station is a proposed 1,000 MW natural gas generating station consisting of two combustion turbines and one steam turbine which will be located in Southeastern Arizona and will serve the load requirements of that area. A Ten-Year Plan was received and this project was presented and discussed at Workshop I. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for the Ninth BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The project is owned by Southwestern Power Group II, LLC ("SWPG"). During December 2014, SWPG became a member of WestConnect and plans to stay involved in the transmission planning activities in the region. A fifteen mile double-circuit 345 kV transmission line will interconnect the generating facilities to the transmission grid, and will run between Bowie Plant Switchyard and the proposed Willow Switchyard on TEP's Greenlee-Winchester-Vail 345 kV line. CECs for the generating station and transmission facilities were originally granted in March 2002, and were subsequently extended by the Commission through December 2010 and again through

64 Application Form SF-299, "Application for Transportation and Utility Systems and Facilities on Federal Lands".

65 The purpose of the Path Rating Process is to provide a formal process for project sponsors to attain an -Accepted Rating and demonstrate how their Project will meet NERC Reliability Standards and WECC Criteria. This three-phase process addresses planned new facility additions and upgrades, or the re-rating of existing facilities. It requires coordination through a review group comprised of the project sponsors and representatives of other systems that may be affected by the project

December 2020.[66] The proposed alignment of the transmission line was also revised in 2008 to comply with the requirements of the Arizona State Land Department.[67] In September 2013, Bowie submitted a new Class I air quality application to the Arizona Department of Environmental Quality ("ADEQ") and the final five-year permit was issued on October 16, 2014.

SWPG and TEP entered into an interconnection facilities study agreement on October 12, 2013, and the facilities study was provided by TEP on October 29, 2013. Bowie and TEP completed a large generator interconnection agreement ("LGIA") on January 30, 2015. The Bowie Generator Interconnection Study Report and Facility Study were provided to Docket Control of the ACC on February 23, 2015. Currently, initial energizing of the interconnection facilities is estimated to occur by December 31, 2018, with commercial operation of the initial 500 MW power block occurring by December 2020. SWPG continues to participate in regional planning forums and is a Class 3 member in good standing in the Western Electricity Coordinating Council.

4.1.5 Mohave County Wind Farm Project

The Mohave County Wind Farm Project, formerly known as the BP Wind Energy North America Project, is comprised of a proposed 500 MW wind energy power plant and associated transmission interconnection tie-line and other facilities, either at 345 kV or at 500 kV. In March of 2015, BP Wind sold the project to Orion Energy Group, LLC. A Ten-Year Plan was received for this project, and the project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The project's original design intended to construct up to 243 wind turbines on Federal lands located in Mohave County, Arizona, near the city of Kingman, to deliver to load-serving entities yet to be determined. The project would interconnect with either the 345 kV Mead-Peacock-Liberty line or the 500 kV Mead-Phoenix line via a gen-tie line approximately 5 miles in length, the final route of which has not yet been determined. A Record of Decision for the project was signed on

[66] Decision No. 71951, dated 11/1/2010, the ACC granted Bowie a second extension on the durations of the CECs through 12/31/2020.

[67] Decision No. 70588, dated 11/6/2008, approved adjustment to Bowie's approximately 15-mile, double-circuit 345 kV generator tie-line on Arizona State Land Department ("ASLD") property. This line interconnects the Willow Substation to TEP's existing Greenlee-Winchester-Vail 345 kV line.

June 28, 2013, approving the use of 35,329 acres of BLM-managed land and 2,781 acres of Reclamation-managed land for the development of the project. A CEC for the transmission line was granted by the Commission in November 2012; commercial operation is expected to begin in 2017 or 2018. Appropriate feasibility and system impact studies will be filed in the Ten-Year Plan docket once the interconnection point has been finalized.

4.1.6 Gila Bend Power Partners

Gila Bend Power Partners proposes to build a 500 kV transmission line from the planned 833 MW combined cycle Gila Bend Power Project to a new switchyard interconnecting with APS's Gila River Line and the Jojoba Switchyard, and ultimately the Hassayampa Switchyard. A Ten-Year Plan was received for this project. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibits 1 and 2.

The line would run parallel to the existing Palo Verde to Kyrene 500 kV transmission line. Three CECs have been granted for the project and are approved through February 2018. The project is currently on hold due to unfavorable market conditions. However, Gila Bend Power Partners has filed Ten-Year Plans in the Ninth BTA.

4.1.7 SolarReserve

SolarReserve, LLC proposes to construct the Crossroads Solar Energy Project, a new 150 MW concentrating solar power plant and transmission line, to be located near the intersection of Interstate 8 and Paloma Road in southwestern Maricopa County, to the Panda – Gila River substation. A Ten-Year Plan was received for this project. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The new 230 kV gen tie line will be approximately 12 miles in length but its exact route has not yet been determined. However, it is expected to largely follow the Abengoa Solana power project generation tie-line. A CEC for the project was granted in February 2011. In 2011, SolarReserve submitted a copy of the System Impact Study as part of their 2011 Ten-Year Plan filing. In 2013, the Crossroads project withdrew from the APS interconnection study process and expects to re-enter that process at a future time; therefore, this project was not considered for the adequacy assessment being made in the Ninth BTA. Current forecasts are for a commercial operation date by the end of 2017.

4.1.8 Southline Transmission Project

The Southline Transmission Project ("Southline") is a 345 kV line that would provide an interstate 345 kV interconnection between Arizona and New Mexico. A Ten-Year Plan has been filed with the Commission for this project by Southline Transmission, LLC, a subsidiary of Hunt Power L.P.; this project was also presented and discussed at Workshop I. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for the Ninth BTA. An overview map showing the general routing and interconnection points of this project is included as Exhibit 23.

Southline Transmission LLC is sponsoring the Southline Project to improve reliability and help facilitate the development and delivery of renewable energy in the region. Black Forest Partners, L.P. is the project manager. The Southline Project proposes to build a 360-mile line from Las Cruces, New Mexico to Tucson, Arizona, across federal, state, and private land. Consisting of two segments, the first segment of the project proposes construction of a 240 mile double-circuit 345-kV line that would link an existing substation at Afton, near Las Cruces, to the existing Apache substation near Wilcox, Arizona. The second segment would upgrade and rebuild 130 miles of existing WAPA and TEP transmission lines from 115 kV to double-circuit 230 kV between the Apache substation and the Saguaro substation near Tucson. Overall the project may interconnect with the existing transmission system at up to fourteen substation locations.

On November 6, 2015, the BLM and WAPA, serving as joint lead agencies, released the Final Environmental Impact Statement for the project. The ROD was signed in April 2016. More than 85% of the preferred route will parallel or upgrade existing transmission corridors. Southline expects to initiate the AZ state permitting process in the second quarter of 2016. The capacity rights to the project are being allocated to customers by SU FERC LLC ("SU FERC"), an affiliate of Sharyland Utilities. SU FERC was granted negotiated rate authority by FERC and has initiated an open solicitation process on March 31, 2016. A final version of the WECC Phase 2 report has been issued. Commercial operations are anticipated to begin in 2018. When completed, the Southline Project will add 1,000 MW of bidirectional transfer capability to the grid.

4.1.9 Buckeye Generation Center

The Buckeye Generation Center is a 650 MW natural-gas peaking facility to be located on a site within Maricopa County. A Ten-Year Plan was received for this project; and, the project has received the requisite Maricopa County Comprehensive Plan Amendment and Air Permit. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for this BTA. Overview maps showing the general routing and interconnection points of this project are included within Exhibits 1 and 2.

The Buckeye Generation Center would include the development of a 1-mile, 230 kV gen-tie line to connect the project site to a proposed 69/230 kV substation to be constructed, owned and operated by APS. The location of the 230 kV gen-tie line has been determined, subject to final design. In addition, the project site will be connected to a 230/500 kV transformer to be located within the 69/230 kV substation, which will provide access to the ANPP 500 kV Jojoba substation.

The Buckeye Generation Center is sponsored by Buckeye Generation Center, LLC and is intended to add peaking power for Arizona electric utilities and to the interstate electrical grid. The currently estimated in-service date is 2020.

4.1.10 Sun Streams

Sun Streams, LLC, a wholly-owned subsidiary of Element Power, is sponsoring the Sun Streams Solar Project substation and gen-tie line to interconnect a proposed 150 MW photovoltaic solar facility. A Ten-Year Plan was received for this project. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included within Exhibit 1.

The Sun Streams project includes the development of a 500/34.5 kV step up transformer and 1,600 feet of 500 kV AC single circuit line to be interconnected at 500 kV at the Hassayampa Switchyard. A System Impact Study was prepared by WHenergy Consulting, Inc. and filed previously. The ACC approved the CEC for the project on August 12, 2014, Decision No 74688. The project is expected to be in-service in the first quarter of 2020.

4.1.11 Tribal Solar

Tribal Solar, LLC, a wholly-owned subsidiary of First Solar, is sponsoring the substation and gen-tie line associated with the proposed Fort Mojave Solar Project. The estimated 332 MW project is planned to include the construction of a 34.5/230 kV substation at the Fort Mojave project site located on the Fort Mojave Indian reservation in Mohave County, Arizona and San Bernardino County, California. A Ten-Year Plan was received for this project. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included within Exhibit 1.

The gen-tie line will generally run from the new Fort Mojave Solar Project substation, west 1,250 feet across the Colorado River into Nevada, then approximately 18 miles to the Mojave 500kV switchyard. On April 11, 2016, the Bureau of Indian affairs, as lead cooperating agency, filed a notice of intent to prepare an Environmental Impact Statement for the project[68]. A System Impact Study was prepared by the CAISO and filed previously with the ACC on March 27, 2013. All new project related transmission facilities to be built in Arizona will be constructed entirely within the Fort Mojave Indian Reservation and will not be subject to ACC/CEC jurisdiction. Southern California Edison has agreed to a twenty-year purchase power agreement with the project. Currently, the project's in-service date is uncertain.

4.1.12 Ocotillo Modernization Project

The Ocotillo Modernization Project ("OMP") involves the planned retirement of existing generators and subsequent addition of generation at the existing Ocotillo generating facility in Tempe, Arizona. The project is included as part of the APS Ten-Year Plan filing and was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for this BTA. An overview map showing the interconnection points of this project is within Exhibit 1.

The existing Ocotillo generating facility is comprised of two steam generators (110 MW net each) and two gas generators (55 MW net each) which have a total net output of 330 MW. The proposed project will retire the two steam generators and replace them with five new General

[68] Notice of Intent to Prepare EIS, FRN, April 11, 2016. https://federalregister.gov/a/2016-08264

Electric LMS100 gas turbines each with a 102 MW nominal summer rating, resulting in a net increase of 290 MW of capacity at the station. A Certificate of Environmental Compatibility was issued on November 13, 2014 and the project is anticipated to be in-service in 2019.

4.1.13 White Wing Ranch North

White Wing Ranch North, LLC, a wholly-owned subsidiary of First Solar, is sponsoring the substation and gen-tie line associated with the proposed White Wing Ranch North Solar Project. The estimated 200 MW project is planned to include the construction of a 34.5/230 kV substation at the project site located in Yuma County. A Ten-Year Plan was received for this project. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included within Exhibit 1.

The gen-tie line will be a 3 mile 500kV AC gen-tie line originating at the project substation and terminating at the existing Hoodoo Wash Substation. The line would cross about 3 miles of BLM land. The proposed location of the line was determined in coordination with the BLM. It would be located entirely within either the Agua Caliente Solar Energy Zone (SEZ) or a BLM-designated utility corridor. A special use permit was issued at the March 7 Yuma County Board of Supervisors meeting allowing the project to move forward. A System Impact Study was prepared by APS and included in the Ten-Year Plan filing. The project is planning to file for their Arizona CEC in July 2016. Currently, the project's in-service date may be as early as Q4 2018.

4.2 Significant Projects Filed in Previous BTAs

Significant projects that have previously filed Ten-Year Plans, and having in-service dates that fall within the planning period, continue to be monitored as part of the BTA process. The projects that have been selected to be included in this section represent sizable projects that may have material impacts on existing transmission paths and are included for informational purposes only. Inclusion of the selected projects does not equate to a judgment by Staff or KRSA on the likelihood of a project being developed.

Staff would strongly support a recommendation that projects, that have previously filed a Ten-Year Plan, provide an annual status report in the Ten-Year Planning docket highlighting the ongoing activity and efforts being made. Staff believes this would provide benefit to the BTA process.

4.2.1 TransWest Express

The TransWest Express Transmission project is a HVDC line planned for the cost-effective delivery of wind energy to Arizona, California, and Nevada. No Ten-Year Plan has been filed with the Commission for this project nor was this project specifically discussed at Workshop I. Therefore, this project was not considered for the adequacy assessment nor included in the Ten-Year Plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

If developed, the 600 kV HVDC transmission line would include 730 miles of transmission lines. The transmission is proposed to originate near Sinclair, WY near the Platte substation and to terminate in Southern Nevada in the Eldorado Valley near the Marketplace substation complex. TransWest Express plans call for the construction of a 3,000 MW line with 1,500 MW of terminal capacity initially; an additional 1,500MW of terminal equipment, in parallel, is proposed to be added at a later date. Alternative configurations include the potential to build a third terminal to connect to the 345 kV bus at the Intermountain Power Project in Utah and to use 500kV AC technology in lieu of HVDC[69].

The project is jointly being developed between TransWest Express, LLC, a wholly owned subsidiary of the Anschutz Corporation, and WAPA. The two entities released a draft Environmental Impact Statement ("EIS") in July 2013. The final EIS was published on May 1, 2015 with the Record of Decision expected in 2016. The project has made an Economic Planning Study request with the CAISO to be included with the ISO's 50% Renewable Energy Goals for 2030 Special Study. The revised study plan is currently undergoing phase 2b[70] WECC path rating process for a north to south rating of 1,500MW. PacifiCorp is performing studies for the northern

[69] https://www.caiso.com/Documents/TransWestExpressProjectOverview.pdf

[70] Phase 2B is used to identify those Phase 2 proposed projects that have completed and obtained approval by the Project Review Group of a study plan and the first base case needed to perform simultaneous studies. At any point in time, if any two Projects are together in Phase 2B of the Path Rating Process, they are Similarly Situated and have a responsibility to mitigate interaction they have with each other until both become operational.

interconnection and TransWest is performing studies for southern interconnections. A three-year construction schedule is planned with commercial operation to begin as early as December 2020 or later as needed.

4.2.2 EnviroMission

EnviroMission Inc. is sponsoring the development of a 200 MW Solar Tower located in La Paz County, south of Parker, Arizona. No Ten-Year Plan was received for this project. This project was not considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The La Paz Solar Tower project would include the development of a single 2,600 foot tall solar electric generation facility and associated gen-tie line. The site selected also has room to potentially accommodate additional solar towers in the future. The project would provide clean renewable energy with dynamic scheduling capabilities and contends to be a base-load resource.

Currently the project has not selected a location for interconnection(s) to the transmission system. A possible interconnection that has been identified includes developing facilities in cooperation with Central Arizona Water and Conservation District ("CAWCD") to jointly serve the Central Arizona Project ("CAP") pumping plants and the project site. These facilities in all likelihood would include a 500 kV interconnection at Salome substation to access the Delaney – Colorado River 500 kV line. The project currently has a targeted in-service date of spring 2020.

4.2.3 Longview Transmission Project

In January 2014, Longview Energy Exchange, LLC ("Longview") submitted a ten-year transmission plan consisting of three potential transmission corridors that are being considered for interconnecting a 2,000 MW adjustable speed hydro-electric pump storage project by 2021. No Ten-Year Plan has been filed with the Commission for this project nor was this project specifically discussed at Workshop I. Therefore, this project was not considered for the adequacy assessment nor included in the Ten-Year Plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project is included within Exhibit 1.

Longview includes the development of a new 500 kV switchyard at the project site. The 500 kV lines being considered include a 50 mile line from the Longview switchyard and terminating at a new

500 kV switchyard in the vicinity of the existing Peacock Substation to interconnect with the Mead-Perkins 500 kV line, and either a 40 mile line from the Longview switchyard interconnecting at the Navajo transmission system at the Yavapai substation, or a 30 mile line terminating at a new 500 kV switchyard to interconnect with the Moenkopi-Eldorado 500 kV line. Construction is expected to begin in 2018 with an estimated in-service date of 2021.

Feasibility, market assessment, and WECC firmed resource studies have been completed for the project. A FERC preliminary permit application was filed[71] and the FERC Order was issued April 26, 2012. A CEC application with the ACC is pending an environmental study of each route.

4.2.4 Harcuvar Transmission Project

The Harcuvar Transmission Project ("HTP") is sponsored by the CAWCD. The project is intended to increase system reliability, permit interconnection of potential solar and thermal generation to the grid, and provide access to the Palo Verde hub, California ISO, and WAPA's Parker-Davis transmission system. No Ten-Year Plan has been filed with the Commission for this project nor was this project specifically discussed at Workshop I. Therefore, this project was not considered for the adequacy assessment nor included in the Ten-Year Plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

A Ten-Year Plan was last filed on April 2, 2015. In that plan, HTP is proposed to be developed in two distinct phases in close coordination with the EnviroMission La Paz Solar Tower Project. Phase 1 of the HTP would connect a new 230 kV substation to the Bouse 161 kV substation via a phase shifting transformer and transformation to WAPA's 161 kV service voltage. A new double circuit 230 kV line would connect the new substation to the 500/230 Delaney-Colorado River substation. In Phase 2 of the HTP, the 115 kV ties will be added at Bouse Hills Pumping Plant and Little Harquahala Pumping plant along with a 30 mile line underbuild on the 230 kV structures. The HTP was submitted to the CAISO process for analysis in its 2015-2016 Transmission Planning Cycle. The last reported in-service date is in the spring of 2020.

[71] Preliminary permit application was filed as project 14341-000

4.2.5 High Plains Express

The High Plains Express project intends to enhance reliability and increase access to generation resources across the transmission grid throughout Wyoming, Colorado, New Mexico, and Arizona. A Ten-Year Plan was not filed with the Commission for this project nor was this project specifically discussed at Workshop I. Therefore, this project was not considered for the adequacy assessment nor included in the Ten-Year Plan statistics compiled for this BTA.

The project includes the planned development of a high-voltage, 2500 mile, 500 kV AC transmission backbone which will add 4,000 MW of capacity import and export capability. The list of parties participating in the development of the High Plains Express includes Black Hills Corporation, Colorado Springs Utilities, Public Service Company of New Mexico, Public Service Company of Colorado ("Xcel Energy"), SRP, Tri-State Generation & Transmission ("Tri-State"), LS Power, NextEra Energy, WAPA, and Wyoming Infrastructure Authority ("WIA").

Participants completed a preliminary feasibility study in 2008. The High Plains Express Initiative finished Stage 2 in 2011 and issued a Stage 2 Report; however, the project is currently suspended. The most recent anticipated in-service date is 2030.

4.2.6 North Gila – Imperial Valley #2

The North Gila – Imperial Valley # 2 Project, sponsored by Southwest Transmission Partners, LLC, in participation with IID, would be a 500 kV transmission line, single or potentially double-circuit, interconnecting the existing North Gila Substation near Yuma, Arizona with the existing Imperial Valley Substation in the vicinity of El Centro, California. A Ten-Year Plan has not been filed with the Commission for this project. Therefore, this project was not considered for the adequacy assessment nor included in the Ten-Year Plan statistics compiled for this BTA. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The line would be approximately eighty five miles in length, and parallel the Southwest Power Link ("SWPL") 500 kV line for much of its length. Depending on the final configuration, the project in all likelihood would increase total transfer capability ("TTC") up to 2,400 MW for Path 46 ("West of River") and up to 1,200 MW for Path 49 ("East of River"). To date, the project participants have submitted the right of way ("ROW") application to BLM and initiated the WECC

Three Phase Rating process and received Phase 1 status, as well as participated in regional planning efforts. The anticipated date of operation is the fourth quarter of 2020.

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5 Regional and National Transmission Issues

Significant increases in distributed generation and energy efficiency penetration, and the integration of large renewable projects and shuttering of traditional generation sources is testing the reliability of the regional and national transmission grid system. Arizona Utilities are facing the need to invest in advanced technology and make improvements in communication and automation to enable the transmission and distribution system to be more flexible and responsive to accommodate the variability of renewable resources. Arizona utilities must also make generation resource decisions that seek to balance the shift towards greater renewable generation integration while maintaining system inertia and voltage support. Natural gas generation resources are becoming the energy source of choice to provide this quick-starting, flexible generation and the Ocotillo Modernization Project is cited by APS as an example of the type of balance needed to maintain grid reliability and operational flexibility. To accommodate the growth of renewable generation, several Arizona utilities are currently evaluating their participation in the Energy Imbalance Market, which is operated by the CAISO, as an option to add increased resource flexibility through market-based solutions.

This section describes select regulatory and industry activities which occur on the national and regional stage, where Arizona Utilities are coordinating on transmission reliability issues related to the changing resource landscape. Only those activities related to transmission infrastructure, regional and subregional transmission grid expansion, transmission reliability, and integration of renewable generation resources are described herein.

5.1 Regional Transmission Planning – WestConnect

WestConnect was established in 2001 as an organization of electric utility companies working to assess both stakeholder and market needs in a collaborative manner, with the end goal of developing cost-effective enhancements to the wholesale electricity market in the western United States. In addition, since 2007, and in response to FERC Order 890, WestConnect members have collaborated formally with regard to regional transmission planning efforts[72]. With the issuance of FERC Order 1000 WestConnect's regional transmission planning activities conducted under the Planning Management Committee have expanded significantly and are described in greater detail in the subsequent sections. The members of WestConnect include utility companies which provide transmission services within the western interconnection, particularly Arizona, New Mexico, Colorado, Wyoming, Nevada, California, and South Dakota.[73] Initiatives that have been undertaken or are under way by the WestConnect Steering and Planning Management Committees include:[74]

- FERC Order No. 890 OATT transmission planning through the WestConnect Project Agreement for Subregional Transmission Planning ("STP") effective May 23, 2007;[75]
- FERC Order No. 1000 implementation;
- Flow-based market investigations;
- Large generator interconnection process ("LGIP") refinements;
- Streamlining the large generator interconnection process;
- Non-pancaked hourly non-firm transmission service;
- An energy imbalance service ("EIS") investigation;
- TTC/available transfer capability ("ATC") group; and
- Virtual control area investigation.

APS, SRP, TEP, AZG&T, and WAPA actively participate and coordinate on planning activities through the WestConnect Planning Management Committee as well as through the Southwest Area Transmission Subregional Planning Group ("SWAT").

[72] The WestConnect Project Agreement for Subregional Transmission Planning ("STP"), effective May 23, 2007, was signed by 15 regional utilities, including APS, TEP, SRP, and AZG&T, formalizing regional planning activities and facilitated compliance with FERC Order No. 890.

[73] More information on the WestConnect membership can be found at http://www.westconnect.com/about_steeringcomm.php.

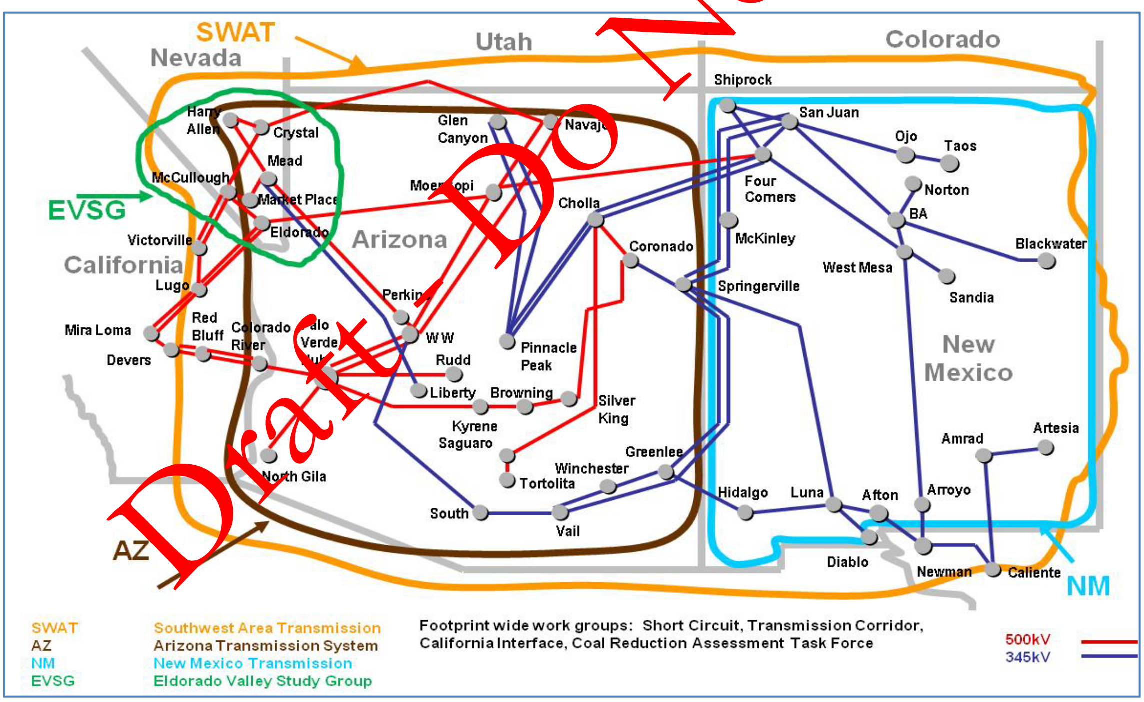
[74] WestConnect Initiatives - http://www.westconnect.com/initiatives.php

[75] WestConnect Project Agreement for STP - http://www.westconnect.com/filestorage/wc_regional_planning_project_agmt_exec_copy_052307_amended_obj_proc_011409.pdf

5.1.1 SWAT Subregional Planning Group

SWAT is a subregional transmission planning group that started in 2004 from the expansion of the Central Arizona Transmission Study ("CATS") Group. Located within the WestConnect footprint, SWAT provides a forum for discussion of planning, coordination, and implementation of a robust transmission system in Arizona, New Mexico, and portions of Colorado, Texas, Nevada, and California. The process is open to interested stakeholders throughout the Desert Southwest and is intended to develop transmission expansion plans with a broad basis of support. SWAT participants include transmission users, environmental entities, transmission owners, transmission operators, transmission regulators and governmental entities. SWAT includes several subcommittees and workgroups under the overarching umbrella of the SWAT Oversight Committee. The planning area of SWAT and its subcommittees is depicted in Figure 2.

Figure 2 - SWAT and Subcommittees Footprints



Since the Eighth BTA, SWAT has discussed FERC Order No. 1000 ("Order No. 1000") implementation, hosted educational webinars and maintained maps and project listings. SWAT also provided a forum for the discussion of both new and existing transmission projects, coordinated on seams issues as defined in Section 6.7 with other planning regions, and coordinated on State and Federal issues related to transmission development. - In the spring of 2015, the SWAT Steering Committee sought to streamline its broader efforts towards a more manageable process. Many of the SWAT subcommittees are focused on geography-specific work groups and in an effort to consolidate the meetings, most of the geographic updates are now shared in the SWAT Oversight Forum. The activities of SWAT's subcommittees and workgroups are described below; more information on each is available through the WestConnect website.[76]

5.1.1.1 Arizona Subcommittee

SWAT-AZ was formed in February 2013 by the merger of the Central Arizona Transmission System ("CATS"), Southeast Arizona Transmission Study ("SATS"), and Colorado River Transmission ("CRT") subcommittees. The objective of SWAT-AZ is to study the high voltage ("HV") and EHV systems throughout Arizona and on both sides of the Colorado River between Yuma and southern Nevada. Major transmission owning utilities in Arizona have been active in SWAT-AZ regardless of jurisdictional status to the ACC. Additionally, SWAT-AZ receives significant participation from Transmission Owners in or adjacent to Arizona.

SWAT-AZ shares project updates, other technical updates, and hosts educational presentations on such topics as NERC planning standards, transmission planning tools, and environmental permitting resources. Since its inception, SWAT-AZ has coordinated the study plan and technical study work to support the BTA, specifically assisting with the 10th Year Snapshot Study (N-1-1), the Extreme Contingency Study, the EE/DG studies, and the load forecasts for Reliability Must Run Studies. SWAT-AZ has also coordinated on the NERC TPL Standards implementation and assisted in the WestConnect Order No. 1000 planning processes. SWAT-AZ now reports as part of the SWAT Oversight Forum.

5.1.1.2 Short Circuit Working Group

The Short-Circuit Working Group ("SCWG") includes representatives of transmission owners, transmission operators, and other interested stakeholders. The objective of the SCWG is to promote regional short circuit studies and common methodologies for individually and jointly

[76] See http://www.westconnect.com/planning_swat.php.

owned/operated transmission systems in the Desert Southwest. The Short-Circuit Working Group has merged the SRP, WAPA, and APS models into one ASPEN[77] case. The group has reached out to TEP, PNM, and IID to begin standardizing the modeling and naming conventions to merge those models. The group hopes to have a new short-circuit model for SWAT by the end of this year.

5.1.1.3 El Dorado Valley Study Group

The Eldorado Valley Study Group ("EVSG") serves as a forum for communication and coordination between the owners of the electric system in Nevada's Eldorado Valley and nearby areas, and parties interested in interconnecting with the region's system. The El Dorado Valley system is interconnected with the Arizona transmission system and is located on the export path between Arizona and California. EVSG's recent activities include providing data and modeling support for FERC Order 1000 regional planning studies encompassing the EVSG area, facilitating interregional coordination between CAISO and WestConnect, providing a forum for visibility of technical studies of projects pursuing interconnecting within the EVSG footprint, coordination with local land use jurisdictions for transmission corridors, future projects, and potential physical congestion or constraints. The last time the EVSG met independently was in January 2015 and since then has coordinated its efforts via the SWAT Oversight forum.

5.1.1.4 California Interface Work Group

The California Interface Work Group ("CIWG") was formed in May 2013 with the objective of addressing seams issues between SWAT and California entities such as the now-dissolved California Transmission Planning Group ("CTPG"), CAISO, and California Public Utility Commission ("CPUC"). The work group has focused on interregional coordination and monitoring of the development of the CAISO 2016-2017 Transmission Plan. The work group primarily focuses on interregional transmission projects such as the Colorado River-Delaney 500kV and Harry Allen-Eldorado 500 kV transmission projects. The CIWG now reports as part of the SWAT Oversight forum.

[77] ASPEN is a short circuit program used in system analysis.

5.1.1.5 Transmission Corridor Work Group

The Transmission Corridor Work Group ("TCWG") interacts with State, Federal, and Tribal entities to facilitate awareness and cooperation among stakeholders affected by potential transmission projects, particularly from the perspective of improving siting and permitting processes. The TCWG's recent efforts have concentrated on the maintenance of general information for outreach and educational activities. During the past two years, the TCWG has continued to have discussions on conceptual opportunities for a transmission corridor along the proposed interstate I-11 that would stretch from the Arizona-Mexico border and head north east to Nevada. The Arizona Department of Transportation is holding monthly meetings on the topic of the proposed interstate and the TCWG will continue to monitor and seek opportunities for the development of potential new transmission corridors.

5.1.1.6 Coal Reduction Assessment Task Force

The Coal Reduction Assessment Task Force ("CRATF") was formed in February 2013 at the initiative of the SWAT stakeholders for the purpose of assessing the reliability impacts of anticipated as well as hypothetical coal retirements in the southwest. In the Eighth BTA, the CRATF reported on the first phase of a reliability study and was ordered in Decision 74785 to file the results of the study within 30 days of completion. Currently being led by Tucson Electric Power, the ultimate goal is to evaluate the impacts from reduced availability of coal generation within the scope and timeline of the WestConnect Regional Study Plan. Progress on the CRATF study is discussed in Section 5.4.1. of this report.

5.2 FERC Order 1000

On July 21, 2011, FERC issued Order No. 1000, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities".[78] Order No. 1000 amended the transmission planning and cost allocation requirements established in FERC Order No. 890 to ensure Commission-jurisdictional services are provided at just and reasonable rates and without unduly discriminatory or preferential treatment. Order No. 1000 established criteria for transmission

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[78] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), available at- https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf

planning processes and required public utility transmission providers to participate in a regional coordinated transmission planning process, to consider transmission needs driven by public policy requirements, and to improve coordination between neighboring transmission planning regions to seek efficient interregional solutions. Order No. 1000 compliance has varied in its implementation across the U.S. and continues to be evaluated.

5.2.1 Role of WestConnect

In a March 22, 2013 Order on Compliance, FERC found that the proposed WestConnect planning region met the geographic scope requirements of Order No. 1000.[79] WestConnect since has worked to align its planning and organizational operations with the principles and guidelines as outlined by Order No. 1000 and the March 22, 2013 Order on Compliance.

Under the Order No. 1000 planning process the existing WestConnect planning efforts are expanded to include regional reliability assessments, production cost modeling to identify economic needs, analysis of proposed regional projects that meet reliability, economic and/or public policy-driven needs, and application of binding cost allocation methodologies for eligible projects. The WestConnect Planning Participation Agreement[80] established a Planning Management Committee ("PMC") made up of one representative of each of the signatory parties. Under the Order 1000 planning process proposed in the compliance filings, the PMC is tasked with ensuring that the WestConnect planning processes are in compliance with Order No. 1000 and overseeing the development and approval of a regional transmission plan that includes application of cost allocation methodologies. The PMC is comprised of 5 Member Sectors including, transmission owners, transmission customers, independent transmission developers, state regulatory commissions, and key interest groups. All entities who become members of the WestConnect PMC will have voting rights as defined in the transmission providers' OATTs and in the Planning Participation Agreement.

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[79] *Order on Compliance Filings*, 142 FERC ¶ 61,206 (2013).
[80] The WestConnect Planning Participation, effective January 1, 2015, was signed by 7 public utility transmission providers, including APS and TEP, and was later signed by an additional 11 regional utilities including SRP and AZG&T, formalizing regional planning activities conducted in compliance with FERC Order 1000.

5.2.1.1 2015 Abbreviated Cycle - Regional Transmission Plan

On January 6, 2015 WestConnect outlined their planning process[81] for an abbreviated one-year regional planning cycle in the 2015 Regional Study Plan. The study plan laid out the seven primary steps of the planning process being developed to comply with the Order No. 1000 requirements. WestConnect worked with Subregional Planning Groups, Transmission Owners, PMC members and stakeholders to develop a 10-year, 2024 heavy summer power flow base case that was used to conduct a reliability assessment to identify transmission needs based on the NERC TPL standards for N-1 outages. The model was updated to reflect all enacted public policies, primarily being the renewable portfolio standards. On December 16, 2015, WestConnect published the 2015 abbreviated cycle regional transmission plan[82]. Based on the abbreviated cycle analysis, the report concluded there were no regional transmission needs identified in the 2015 assessment.

5.2.1.2 2016 Regional Transmission Plan

The WestConnect Regional Transmission Planning Cycle is biennial and with exception for the abbreviated 2015 plan, the biennial cycle will commence in even-numbered years to align with its interregional neighboring planning regions and each region's planning process, with 2016 being the first full Planning Cycle. On February 17, 2016 WestConnect published an updated Business Practice Manual[83] outlining the criterion for project inclusion in the WestConnect base transmission plan and procedures for executing the planning process.

Assessments will be conducted to identify reliability, economic, and public policy-driven needs using power flow and production cost models. WestConnect is currently focusing their efforts on the development of the 10-year, 2026 Heavy Summer Base Case using WECC models as the starting point for its 2016-17 Regional Transmission Plan. Additional scenario models being developed will include light load with high wind generation, individual member utility plans for Clean Power Plan compliance, and a heavy renewable energy and energy efficiency build out model. The 2026 base

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[81] WestConnect Regional Transmission Planning Process – 2015 Regional Study Plan, Approved by WestConnect Planning Management Committee and published January 6, 2015. http://westconnect.com/filestorage/wc_2015_regional_study_plan_010615.pdf

[82] WestConnect Regional Transmission Planning – 2015 Abbreviated Cycle. December 16, 2015. http://westconnect.com/filestorage/12_16_15_wc_2015_regional_transmission_plan.pdf

[83] WestConnect Regional Planning Process Business Practice Manual, February 17, 2016. http://westconnect.com/filestorage/02_17_16_regional_planning_process_business_practice_manual.pdf

transmission plan will also include the Delany-Colorado River 500kV and Harry Allen-Eldora 500kV transmission projects to align with CAISO planning models. The Planning Cycle will focus on model development and identifying regional needs during 2016, followed by the evaluation and identification of alternatives, cost allocation, and the drafting of the Regional Plan in 2017. The first WestConnect Biennial Regional Plan is anticipated to be released in early 2018.

5.2.2 Interregional Coordination

The CAISO, ColumbiaGrid, Northern Tier Transmission Group ("NTTG"), and WestConnect developed a multi-regional process to comply with Order No. 1000's requirements for interregional coordination. Interregional Coordination meetings are being held annually with the most recent one being held in Tempe, Arizona on February 25, 2016. The annual interregional coordination meetings provide the entities with the opportunity to share and coordinate each region's current planning efforts. WestConnect's input included base cases and assumptions used in study plans, planning models, and identification of regional needs.

5.2.3 Relationship to the BTA Process

The WestConnect transmission planning process, with the enhancement of Order No. 1000 planning requirements, provides additional coverage of regional transmission planning activities not currently covered under the ACC BTA process. FERC Order No. 1000 requires regional and interregional agencies to work collaboratively to improve regional transmission planning processes and cost allocation mechanisms. Where the ACC BTA focuses on intrastate impacts of planned transmission projects, Order No. 1000 will also help ensure the state's transmission owners consider regional and interregional transmission projects in assessing the most efficient and cost effective means to meet transmission needs of their customers.

5.3 Western Area Power Administration Transmission Infrastructure Program

WAPA established the Transmission Infrastructure Program ("TIP") in February 2009 to implement Title III, Section 301 of the Hoover Power Plant Act of 1984, as amended by the American Recovery and Reinvestment Act of 2009 ("ARRA"). In April 7, 2014, Western published a Federal Register notice ("FRN") announcing a revised TIP and made a request for new project proposals and implemented program revisions to revise project evaluation criteria, clarify the role of the DOE and Loan Programs Office, and establish distinct project development and project finance phases.[84]

The latest FRN keeps the principles of TIP fundamentally the same as the original May 14, 2009 FRN that established TIP. TIP projects must meet the following criteria:

1. Facilitate the delivery of renewable energy;
2. Have at least one terminus within Western service territory;
3. Have a reasonable expectation the project will generate revenue to repay;
4. Demonstrate that it will not adversely impact system reliability; and
5. Be in the public interest.

Four transmission projects, having passed the evaluation criteria, are currently being developed under the Western TIP program. During Workshop I, Western provided an update on TIP and discussed the evolving role of TIP as performing a financial function rather than a transmission planning function. The presentation included an overview of the loan financing process, various loan types, and recent financing activity.

5.3.1 TIP Impacts on Arizona

A number of TIP projects will have a significant impact on Arizona. These projects include recently energized and planned facilities as summarized below:

- The Electrical District 5-Palo Verde Hub ("ED5-PVH") Project is a TIP financed project that connects Western's Parker-Davis Project transmission system to the Palo Verde market hub. TIP provided a $191 million construction and term loan facility for the project which was energized in January 2015. The project includes a 500/230 kV interconnection between the SEV Duke substation and Western's Test-Track substation and a new 230 kV circuit from Western's Test-Track substation to Western's ED5 substation located south of Eloy in Pinal County.
- The Southline Project, as discussed in section 4.1.8 of this report, is in the development phase. Western is participating in this project as current plans are to rebuild and upgrade approximately

[84] FRN 79 FR 19065

130 miles of Western transmission lines between Apache and Saguaro Substations. The anticipated completion of the Southline Project is 2018. Western is evaluating to what extent it will participate in the ownership of the proposed project and is currently seeking input from transmission customers to define if and how Western participates in this project.

- The TransWest Express Project, as discussed in section 4.2.1, is currently in the development phase with an anticipated completion date of 2020. Western and TransWest Express, LLC entered into a Development Agreement with Western in September 2011 and are each contributing $25M in funding during the development phase.
- The Centennial West Clean Line Project, as discussed in section 4.1.3, is currently in the development phase with an anticipated completion date of 2020. In June 2012 Western and Centennial West Clean Line LLC entered into an advance funding agreement. Centennial West will fund all costs related to the project, including environmental compliance work and Western's review and due diligence of the proposed project. The agreement covers the development period of the proposed project, during which Western and Clean Line will evaluate the project and determine next steps after completion of the development phase.

5.3.2 WECC Regional Transmission Expansion Planning

WECC is the regional entity responsible for coordinating and promoting BES reliability in the Western Interconnection. In carrying out this responsibility, WECC performs compliance monitoring and enforcement, standards development, operation of the Western Renewable Energy Generation Information System ("WREGIS"), reliability planning, and performance analysis.

TEPPC, a WECC board-level committee, is responsible for conducting and facilitating economic transmission planning in the Western Interconnection. TEPPC has four main functions, including:

1) Develop and maintain a public database for production cost and related analysis;
2) Develop and implement interconnection-wide expansion planning processes in coordination with the Planning Coordination Committee, other WECC committees, Regional Planning Groups ("RPGs"), and other stakeholders;

3) Guide and improve the economic analysis and modeling of the Western Interconnection and conduct related transmission utilization and expansion studies; and
4) Based on the above, prepare interconnection-wide transmission plans consistent with applicable NERC and WECC reliability standards.

The TEPPC 10-year regional transmission plan relies on a nodal production cost model to evaluate the transmission grid on an economic basis.

5.3.2.1 2015 TEPPC Study Plan

The 2015 TEPPC study plan included eighteen 10-year study cases, enhancement to the Long-Term Planning Tool and the capital expansion model used for 20-year planning studies, and six 20-year study cases. The plan was based the on 2024 Common Case Transmission Assumptions ("CCTA") and additional scenarios which included an Energy-Water-Climate Change Scenario, Clean Power Plan Analysis, Planning for Uncertainty, and a Flexibility Study. The 2024 CCTA, serving as the "expected future" for planning, is built from information provided by WECC's stakeholders, including state and sub-regional representatives such as SWAT, and vetted thoroughly through WECC's stakeholder processes.

Criteria for determining new transmission lines to incorporate in the CCTA included a determination of whether the transmission line was regionally significant, whether the transmission was currently under construction and was expected to be in-service, whether there were strong financial indicators that provided enough evidence that the transmission project would be financially sound enough to come to fruition, whether the project had sufficiently progressed through local or federal permitting processes, and whether the project was dependent on another transmission project. All projects passing the selection criterion were reviewed by the Regional Planning Coordination Group (RPCG), which reserved the right to exclude projects on an individual basis[85].

The Draft 2015 Integrated Transmission and Reliability Assessment, a product of the TEPPC approved "hybrid" approach to reporting approved in February 2015, was presented at the WECC Technical Advisory Subcommittee (TAS) meeting in February of 2016 summarizing the findings of

[85] 2024 Common Case Transmission Assumptions (CCTA). WECC Regional Planning Coordination Group. June 2, 2014.

the 2015 Study Plan efforts. Major observations of the 10-year study cases reported in the assessment include:

- Under the various configurations for loads, resources, and transmission expansion, there were no studies that resulted in unserved load.
- Path flows in the Western Interconnection varied from case-to-case; however, while some paths were heavily utilized it is likely that Balancing Areas would maintain reliable operations without exceeding path ratings.
- Large additions of renewable energy often included significant amounts of dump energy. Other accommodations may be needed to fully utilize renewable generation expansion.
- Based on WECC's economic dispatch model, incremental load is served primarily by coal and gas resources.
- The price assumed for carbon makes a significant impact on resource selection due to its impact on resources' Levelized Cost of Energy (LCOE).
- Selection of coal resource retirements required extensive discussions and resulting CO_2 reductions fell short of the target for the interim goal identified in the EPA's Clean Power Plan.

5.3.2.2 2016 TEPPC Study Plan

On December 2, 2015, the WECC Board of Directors approved an Interim Planning Protocol[86] for the 2016 work plan. During 2016, TEPPC plans to undertake a comprehensive review of the existing Charter and Planning Protocol and submit recommendations to the WECC Board of Directors for consideration in a future Planning Protocol. The 2016 study program will continue to focus on the use and development of unified, foundational datasets and tools and will, at a minimum, include an annual summary report[87]. Key topics for the study program will include increasing levels of distributed generation, increasing levels of renewable generation and evolving policy objectives, and potential increase in coal plant retirements or displacements. Additionally, the

[86] Interim TEPPC Planning Protocol. Approved by WECC Board of Directors. December 2, 2015. https://www.wecc.biz/Corporate/TEPPC-Interim-Planning-Protocol-2015-Final.pdf

[87] Defined in the interim planning protocol, the annual report contrasts with the existing Planning Protocol which calls for a 10- and 20-year "plan"

study program will include an analysis of Section 368[88] energy corridors for potential high transmission utilization. The study program will rely on 2026 CCTA, being developed through the same bottom-up activities as regional study groups.

5.4 Clean Power Plan

Since the Eighth BTA, the Environmental Protection Agency has issued its final rule, titled *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* ("CPP"), on August 3, 2015[89]. The CPP ruling, under the authority of section 111(d) of the Clean Air Act, establishes state-specific interim and final CO_2 emission goals for two types of Electricity Generating Units (EGUs): steam electric and natural gas power plants. The goals are expressed either as rate-based or mass-based, either of which can be used by a state in its compliance plan. For the state of Arizona, this translates to a 34% reduction in the CO_2 emissions rate (in lbs CO_2 /MWh) or a 25% reduction in total annual emissions (in short tons CO_2) by 2030, based on a 2012 historic year. Twenty-seven states petitioned the Columbia Circuit of the United States Court of Appeals for an emergency stay arguing that the EPA was overstepping its legal authority and on February 9, 2016, the Supreme Court stepped in and ordered the EPA to halt enforcement of the plan. The full U.S. Court of Appeals for the D.C. Circuit will hear oral arguments beginning on September 27, 2016.

The State of Arizona is coordinating the development of the State plan through the Arizona Department of Environmental Quality ("ADEQ"). ADEQ has established a Technical Working Group (TWG) that includes representatives of utilities as well as other stakeholders to analyze the impacts of the CPP. The Arizona Utilities Group ("AUG") hired PACE Global to determine the impacts of the mass- versus rate-based compliance pathways. The results were reported to the TWG and indicate that, without any additional measures, and factoring-in scheduled retirements of coal facilities, the state of Arizona would be in compliance under a rate-based rather than a mass-based compliance pathway. The results were based on models conducted for all Electricity Generating Units ("EGUs") in the state, rather than a utility-by-utility comparison.

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[88] Section 368 corridors as identified in the Energy Policy Act of 2005 (EPAct)

[89] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (CPP), 80 Fed. Reg.64662 (Oct. 23, 2015).

ADEQ is also working on compliance analyses with several other entities to determine reliability and economic impacts under myriad scenarios. Reliability assessment will be modeled by Arizona State University (ASU) in collaboration with Northern Arizona University (NAU). Macro- economic analysis will be conducted by U.C. Berkeley and Dallas Burtraw (W.P. Carey School of Business).

Preliminary results of the ASU-NAU compliance analysis[90] of both mass- and rate-based pathways indicate compliance under both pathways. Compliance under the mass-based pathway was met through banked allowances from Renewable Energy (RE), Energy Efficiency (EE), and Gas Shift ERCs (GS) without additional measures.

Furthermore, Energy Strategies and Fovea, LLC, partnering with the Center for the New Energy Economy (CNEE) at Colorado State University, created and are maintaining a Clean Power Plan Evaluation Model for twelve Western States and two tribal jurisdictions. The twelve states and tribal jurisdictions included in the model are: Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming and Ute and Navajo tribal jurisdictions.

CNEE's analytical tool evaluates the six available compliance pathways using data sets derived from public sources to estimate the expected business-as-usual CO_2 emissions and emissions rate from affected sources from 2013 through 2030; quantify the CO_2 reductions required to meet EPA's interim and final targets (compliance gap); and evaluate combinations of measures, including opportunities to trade compliance instruments between states.

Regardless of the emergency stay in place on the CPP, Arizona continues to move forward on the State Plan, and Arizona Utilities continue to evaluate the impacts of various coal reduction scenarios.

5.4.1 Coal Reduction Assessment Task Force

The Coal Reduction Assessment Task Force ("CRATF") was established in February 2013 to facilitate a study process for the proposed CPP rulemaking. Key issues to be addressed were concerns over the loss of "inertia" associated with coal plant retirements, what was believed to be an

[90] Analysis is based on the EPA's proposed model rules and allowances. It assumes no new source complement under the mass-based compliance pathway

accelerated timeline for compliance, the impact on Path Ratings, and the retirement of other significant generation resources, such as the San Onofre Nuclear Generating Station ("SONGS") and several once-through-cooled natural gas fuel generators along the California coast. Phase I of the study work was completed and a summary of the findings was included in the Eighth BTA[91]. The results indicated that high coal reduction with high renewable penetration would significantly increase the risk of system instability. Overall, there is a limit to the number of coal plants that can be retired unless some portion of that capacity is replaced with gas fired capacity or other resources that compensate for loss of inertia and dynamic reactive capability.

The CRATF report presentation at the 9th BTA Workshop No. 1 recommended greater consideration of intra- and inter-regional power transfers, additional coordination among the regional planning groups and state processes, coordinating the Arizona reliability study with the WestConnect 2016-17 Regional Planning Process and formal inclusion of a utilities CPP compliance plan scenario in the WestConnect Study plan.

In Decision No. 74785, the Commission directed TEP to file the SWAT Coal Reduction Assessment Task Force ("CRATF") study report on behalf of the Arizona Utilities within 30 days of completion of the study. If the CRATF study is not finalized or if it does not include specific recommendations on maintaining Arizona transmission system reliability, Arizona utilities were directed to jointly produce or procure an informational report to identify minimum transmission requirements to maintain adequate system reliability in a fifth year coal reduction scenario. On behalf of Arizona Utilities, TEP made an information filing in the current docket and presented at Workshop I on the status of the final Study Report and efforts made since the Eighth BTA.

Since the Eighth BTA, the Arizona utilities have taken the opportunity to coordinate within the scope and timeline of the WestConnect Regional Study Plan, beginning with submittal of an "Arizona Utilities CPP Compliance" scenario during the December 2015 submittal window. That scenario was broadened to include all WestConnect participating utilities. The title was therefore changed to the "CPP – WestConnect Utility Plans" scenario. Two base transmission plan and two CPP compliant scenario power flow models are being included in the current study plan. Two

[91] Eighth Biennial Transmission Assessment, §5.5.2, *Technical Study Work*.

additional scenario production cost models will also be developed and analyzed. The power flow and production cost scenarios are respectively shown in Tables 16 and 17.

Table 16 - CPP scenarios included in WestConnect evaluation

Case Name	Case Description and Scope
2026 Heavy Summer Base Case	Summer peak load conditions during 15:00 to 17:00 MDT, with typical flows throughout the Western Interconnection – traditional case build
2026 Light Spring Base Case	Light load conditions with high wind generation – traditional case build
CPP – WestConnect Utility Plans	Reflect individual WestConnect member utility plans for CPP compliance
CPP – Heavy RE/EE Build Out	Additional coal retirements, additional RE/EE, minimal new natural gas generation – include transient study for frequency response check

Table 17 - CPP power flow scenario cases included in WestConnect study plan

Case Name	Case Description and Scope
2026 Base Case	Business-as-usual case based on WECC 2026 Common Case with additional regional updates from WestConnect members.
High Renewables	California 50% RPS with regional resources (Wyoming wind and New Mexico wind) and increase WestConnect state RPS requirement beyond enacted with other resources
CPP – WestConnect Utility Plans	Reflect individual WestConnect member utility plans for CPP compliance
CPP – Market-Based Compliance	Model CO_2 price in WestConnect to achieve mass-based regional CPP compliance
CPP – Heavy RE/EE Build Out	Additional coal retirements, additional RE/EE, minimal new natural gas generation

The WestConnect Utility Plan scenario became the template for other WestConnect subregional planning groups and states to use for their inclusion in the WestConnect Study Plan. The Study Plan is currently in the Model Development phase of the WestConnect 2016-2017 planning cycle and the data, base cases, and initial study results are expected to be available by mid-2017. Once the study results are completed, CRATF will reconvene to outline next steps and deliverables pending WestConnect evaluation of alternatives to identify transmission needs and will report relevant findings in future BTA proceedings.

5.4.2 Other Study Work

Alongside the WestConnect planning efforts, other entities have been conducting study work that is becoming instrumental in the CPP discussion and state planning efforts. The National Renewable Energy Laboratory ("NREL") set out to study impacts of integrating large amounts of wind and solar into the electric system in the west. With a focus on renewable integration, study efforts began in 2008 and Phase 3 of the Western Wind and Solar Integration Study ("WWSIS") was published following the Eighth BTA in December 2014, a Phase 3a report on low levels on synchronous generation was subsequently released in November 2015. Conclusions from the Phase 3 report, which focused on transient stability and frequency response, included that at a minimum, load voltage and thermal problems will inevitably require some transmission improvements, the dynamic behavior of distributed photovoltaic has the potential to significantly impact the Bulk Power System ("BPS"), and there is a limit to how much coal reduction can take place.

The North American Electric Reliability Corporation ("NERC") has published Phase I and Phase II of their national study: Potential Reliability Impacts of EPA's Clean Power Plan[92]. Phase I included a transmission adequacy analysis to determine a comparable range of transmission needs along with lead times required to build that transmission. NERC found that the change in the power flow, both in direction and magnitude, could present challenges in planning and operation of the BPS. Dynamic Reactive Resources may be needed to maintain voltage stability and dynamic stability also needed to be taken into consideration where generation is farther away from load centers. Overall, the change in power flows called for extensive power system studies and planning and

[92]The NERC Phase I report incorporated the results from the WECC Phase I Preliminary Technical Report published in September 2014.

additional transmission lines would be necessary to optimize trading capabilities among regions. Additionally, consideration must be made for the lead time needed for development of transmission facilities.

5.4.3 Arizona CPP Impacts

As part of the presentations for Workshop I, Arizona Utilities were asked to describe the extent to which potential coal replacement generation was being considered in their transmission planning process and to identify any transmission projects that are directly related to actual, planned, or potential coal retirements. The utilities did not identify any transmission projects and stated that known resource changes are generally already being included in their planning processes. Although there are not any transmission additions being reported at this time, the impact of the CPP on the utility's coal fleet is seen in the 2016 preliminary Integrated Resource Plans that have been submitted.

APS continues to follow its coal strategy that was outlined in a September 2014 IRP Supplement. APS has ended operations of Units 1-3 at the Four Corners Generating Station as a mitigation strategy to making a $586 million capital investment for environmental upgrades. As proposed in the supplement, APS shut down Unit 2 at the Cholla Power Plant in October 2015 and has no plans to operate units 1 and 3 beyond 2025; however, APS reserves the right to convert units 1 and 3 to natural gas, rather than retire them, depending upon future needs and the economics of a coal to gas conversion at that time. APS anticipates that it will be in a position to meet CPP compliance, based on the assumption that ADEQ will select a rate-base compliance plan. Additional coal reductions may be needed if ADEQ selects a mass-based compliance plan, or if additional EPA requirements are implemented on the Navajo Nation where APS has a 14% stake in the Navajo Generating Station ("NGS"). Between Cholla and Four Corners, APS retired 560 MW of its coal resources.

In TEP's 2017 Preliminary IRP, TEP aims to balance CO_2 reductions against their need for reliable, cost-effective generating resources, such as the Springerville Generating Station. ("SGS"). In 2015, TEP has successfully transitioned the H. Wilson Sundt Generating Station Unit 4 from coal to natural gas. TEP has reduced their ownership in San Juan Generating Station Unit 1 to 49.5% and has the right to exit its remaining interest when the coal contract expires in 2022. An October 2014 plan approved by the EPA to bring the San Juan Generating Station in compliance with the Regional Haze Rule, calls for the closure of Units 2 and 3 by December 2017. Additionally, TEP is evaluating the long term viability of its coal operations at the Four Corners Power Plant beyond 2031, and beyond 2030 for its ownership in the NGS. TEP has stated that these moves would put it in a strong position to comply with CPP requirements.

The Arizona transmission system was designed to accommodate the large coal generation fleet that is geographically distant from the load centers. The integration of renewable energy projects and the simultaneous reduction of coal resources is likely to have an impact on the operation of the transmission grid. The loss of system inertia and dynamic reactive capability as well as changes in power flows, pose significant risks and updates should continue to be filed in the BTA process. Overall, Staff and KRSA feel that the work, that WestConnect and CRATF are investigating as well as other industry planning activities, are critical to transmission system reliability. This is an issue that the Commission and Commission Staff should follow closely and which the utilities should report their findings to the Commission.

5.5 Seams Issues

Seams issues include differences in the electric energy market models, scheduling and congestion management protocols, planning, licensing, ownership and operational control of transmission facilities that cross state boundaries. Increased regional and interregional coordination has been conducted as a result of FERC Order No. 1000 transmission planning requirements and WECC Transmission Expansion Planning. Seams transmission paths affecting Arizona are detailed on Exhibit 7 and illustrated in Exhibit 8.

The WECC Planning Committee established a Planning Coordinator Function Task Force ("PCFTF") to consider and address potential gap issues that were identified from the September 8, 2011 outage[93]. The PCFTF identified several issues surrounding the role of the Planning Coordinator including the lack of formal acknowledgement between Planning Coordinators and area entities, proper inclusion of all facilities effecting the planning area, and differing definitions of the role between the NERC Rules of Procedure and NERC Function Model and its crossover with the

[93] The September 8, 2011 was discussed in section 5.7.1 of the Eighth BTA.

Transmission Planner function that has led to inconsistency and confusion over the role and expectations of the Planning Coordinator. On September 14, 2015, the PCFTF issued a whitepaper[94] making several recommendations including the formation of the Planning Coordinator Gap Resolution Team ("PC-GRT"). Presently the PC-GRT is actively engaged in modifying the NERC Functional Model clarifying roles and responsibilities of the Planning Coordinator and Transmission Planner. The PC-GRT seeks to resolve gaps between the Planning Coordinator and Transmission Planner, requiring that every BES asset needs to be accounted for in their respective planning areas. The PC-GRT continues to work towards the recommendations of the PCFTF and reports back the WECC Planning Coordination Committee and Board of Directors.

In the WestConnect 2015 Regional Transmission Plan[95], WestConnect coordinated with the CAISO on the inclusion of the Delaney-Colorado River 500 kV and the Harry Allen-Eldorado 500 kV transmission lines in WestConnect's 2024 Regional Base Transmission Plan. Both projects were included in the CAISO Ten-Year Planning Studies and were incorporated into WestConnect models to align the WestConnect Ten-Year Planning Studies with those of the CAISO.

Staff and KRSA have concluded that the utilities are properly coordinating with neighboring utilities to address seams related issues. Increased regional and subregional coordination activities, including the PC-GRT and the SWAT CIWG, are important for coordinating transmission expansion projects and inter- and intra-regional transmission reliability concerns.

5.6 Additional Renewables Integration Efforts

During Workshop I, utilities were asked to describe the extent to which renewable generation being added to comply with renewable portfolio standards in neighboring states was being considered in their transmission planning processes and to identify specific projects directly related to the RPS of neighboring states. The utilities did not identify any specific transmission projects related to RPS of neighboring states and generally rely and participate on the WECC common case development that includes resource decisions being made in the Southwest. APS did comment that

[94] Planning Coordinator Function Task Force, *Methodology for Defining Planning Coordinator Areas in the WECC Region,* whitepaper, September 14, 2015. https://www.wecc.biz/Reliability/PCFTF%20White%20Paper_final_9-14-15.pdf
[95] WestConnect 2015 Abbreviate Cycle Regional Transmission Plan, pgs 8-9. http://westconnect.com/filestorage/12_16_15_wc_2015_regional_transmission_plan.pdf

they have received multiple Transmission Service Requests for use of the existing transmission Four Corners transmission system in order to deliver power to the west.

5.6.1 Southwest Variable Energy Resource Initiative ("SVERI")

SVERI was organized in the fall of 2012 to be forward thinking on how increased renewable generation can be economically managed across the combined footprint of the group and to evaluate likely penetration, location, and operational characteristics of variable energy resources within the Southwest over the next 20 years. SVERI participants include Arizona Electric Power Cooperative ("AEPCO"), APS, EPE, Imperial Irrigation District ("IID"), PNM, SRP, TEP and the Western DSW.

SVERI seeks to evaluate and develop tools that may facilitate variable energy resources. In May of 2014, in collaboration with the University of Arizona, SVERI launched a data access website that collects, displays, and analyzes generator output and real-time load data for all renewable generation from across the Desert Southwest. As of January 2016, SVERI members decided not to do any further development of the website, but to continue to gather and monitor data.

In January 2015, SVERI reported a Load Shape Analysis using 2014 forecasts[96]. The analysis was a study on the cumulative impacts of increasing variable energy resources in the southwest region. The results of the data show that SVERI participants, in aggregate, do not experience the same load shape challenges that are comparable to California, the Pacific Northwest or the Inland Rocky Mountain regions of the Western Grid. This is illustrated in the example provided in the study comparing CAISO's anticipated 13,000 MW 3-hour ramp challenge in March of 2020, to the Southwest's worst-case month of December 2027 where a 5,250 MW 3-hour ramp is projected to occur. Additionally, SVERI has completed an internal report on regional initiatives including Area Control Error (ACE), Diversity Interchange (ADI), Dynamic System Scheduling, and the Intra-hour Transaction Accelerator Platform (ITAP) which can leverage the flexibility and diversity of the transmission system.[97]

[96] http://sveri.net/wp-content/uploads/2014/09/SVERI-Load-Shape-Analysis-Final-Report-Jan-2015.pdf
[97] Grid Integration in the West: Bulk Electric System Reliability, Clean Energy, Integration, and Economic Efficiency. 2015. http://americaspowerplan.com/wp-content/uploads/2015/08/Grid-Integration-in-the-West-07-19-15-Updated.pdf

SVERI members continue to monitor trends in the region and share updates; however, no additional study work is planned at this time.

5.6.2 Renewable Transmission Action Plans ("RTPs")

In the Fifth BTA the Commission ordered the Arizona utilities to provide their top three RTPs. Progress towards the development of the RTPs is summarized below.

Project Name	APS	SRP	TEP	AZG&T	Current Status
Palo Verde-North Gila 500kV	X				Completed/ In-Service in May 2015
Palo Verde-Liberty & Gila Bend-Liberty 500kV	X				Delayed Indefinitely
Delaney-Palo Verde 500kV[98]	X				Energized May 2016
Pinal West-Pinal Central 500kV		X			Completed in June 2014
Palo Verde-Pinal West-Pinal Central			X		Completed in June 2014
Pinal Central-Tortolita 500kV			X		Completed in October 2015
Western Apache-Tortolita 115kV-230kV Upgrade			X		No longer being pursued, instead working with Western on Southline rebuild to 230 kV
San Manuel Interconnect Project				X	Being considered outside of Ten-Year Plan
Apache-Bicknell 230kV Line Upgrade				X	Line re-rated; upgrade need moved outside of Ten-Year Plan
Western Saguaro-Apache 115kV Line Upgrade				X	No longer being pursued, instead working with Western on Southline rebuild to 230 kV

Table 18 - Summary of RTP Development Status

5.6.3 Energy Imbalance Market ("EIM")

On November 1, 2014 the CAISO and PacifiCorp launched the first western real-time energy balancing market as a way to balance load and generation in a more efficient manner and to share reserves and integrate renewable resources across a larger geographic region. An EIM creates a

[98] The Delaney-Palo Verde 500 kV is an important component of the Delaney to Colorado River (DCR) transmission project as the project establishes the Delaney substation. The substation has been identified as the starting point of the DCR transmission project, which would provide a connection to the Southern California markets.

much shorter window market opportunity for balancing loads and resources and proposes to expand system-wide dispatch which can help with the variability and intermittency of renewable resources.

In the 2016 Q1 Quantifying EIM Benefits Report, the benefits quantified from EIM activities include the following:

- More efficient dispatch, both inter- and intra-regional, in the Fifteen-Minute Market and Real-Time Dispatch,
- Reduced renewable energy curtailment, and
- Reduced flexibility reserves needed in all balancing authority areas.

APS has signed up to join the CAISO EIM beginning in October 2016 and expects to benefit from access to a large and diverse pool of resources that can quickly respond to the variability of renewable energy resources.[99] TEP has contracted with the energy consulting firm E3 to perform a study to evaluate the economic benefits of participating in the EIM. TEP will then evaluate the relevant costs and benefits of joining the Western EIM.

There are no definitive answers at this time to the question of transmission reliability issues that may arise from the adoption of the EIM as a tool to improve renewable energy integration. However, although the EIM is a market-based solution to resource needs, there is potential for change in how traditional thermal generation resources are operated in the Southwest.

Based upon the information reviewed, Staff and KRSA conclude the Arizona utilities are taking sufficient action with respect to transmission planning impacts related to the integration of renewable generation resources.

[99] APS Preliminary 2017 Integrated Resource Plan. March 1, 2016

6 Conclusions

This Ninth BTA assesses the adequacy of Arizona's transmission system to reliably meet the existing and planned energy needs of the state by addressing four fundamental public policy questions during the course of this BTA:[100]

1. Adequacy of the existing and planned transmission system to reliably serve local load - Does the existing and planned transmission system meet the load serving needs of the state during the 2016-2025 timeframe in a reliable manner?

2. Efficacy of the Commission-ordered studies - Do the Simultaneous Import Limit ("SIL"), Maximum Load Serving Capability ("MLSC"), Reliability Must Run ("RMR"), Ten Year Snapshot, Distributed Generation and Energy Efficiency, and Extreme Contingency studies filed as part of the Ninth BTA provide useful and sufficient information in determining adequacy of the state's transmission system over the next 10 years?
3. Adequacy of the system to reliably support the wholesale market - Did 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?
4. Suitability of the transmission planning processes utilized - Did 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 and WECC?

6.1 Adequacy of the Existing and Planned Transmission System to Reliably Serve Local Load

The adequacy of the transmission system to reliably serve load is central to the BTA. Based upon the technical study work examined by Staff and KRSA, the existing and proposed transmission

100 This BTA does not establish Commission policy and is not final unless and until approved by a written decision of the Commission.

system meets the load serving requirements of Arizona in a reliable manner for the 2016-2025 timeframe.

1. The aggregate of the filed Ten-Year Plans is a comprehensive summary of filed ten year transmission expansion plans from a holistic perspective. The Arizona Plan includes nineteen filing entities and consists of thirty-six transmission projects of approximately 707 miles in length. Forty-nine projects are beyond the ten year horizon or have in-service dates that are yet to be determined and account for an additional 939 miles of new transmission. Additionally, utilities have seven transmission lines, totaling approximately 82 miles in length, which they plan to reconductor.
2. The 2016 level of summer preparedness of the utilities in Arizona, as presented in the April 28, 2016 workshop, demonstrated that sufficient preparedness measures are being taken. The current transmission system in Arizona is judged to be adequate to reliably support the energy needs of the state in 2016.
3. The statewide demand forecast has continued to be lowered since the Fifth BTA. During the Ninth BTA the Arizona utilities reported a Ten-Year Forecast that was, on average, 4.3% lower than what was reported during the Eighth BTA. Over the past four BTAs load forecasts have changed substantially, and the deferment of several growth-related transmission projects has followed.
    a. The utilities indicated that DG and EE impacts were taken into account in demand forecasts. DG and EE alone do not account for the continued decline in the statewide demand forecast, the main factor behind the drop in the forecast from 2014 to 2016 is the impact of the continuing economic recession.
    b. The overall Arizona load growth rate is projected to average approximately 2.18% per year.
4. The SIL and MLSC, measures of the transmission system ability to serve load reliably in load pockets, are adequate to meet ten year local load forecasts.
    a. Santa Cruz County load forecast of 82 MW is less than the load serving capability of 159 MW.

b. The CCSG participants monitored the reliability in Cochise County, but did not offer any new future Ten-Year Plans. The Load Serving Entities ("LSE") in Cochise County continue to monitor the reliability in Cochise County and will propose any modifications that they deem to be appropriate in future Ten-Year Plans.

5. Arizona Utilities are taking steps to increase situational awareness, cooperation, and coordination with neighboring utilities, regional and subregional planning groups to address potential interregional reliability issues. Specific improvements include developing a wider view of the system; providing additional detail to ensure the system is being modeled appropriately; the addition of next-day studies, bi-weekly outage coordination calls, coordinated seasonal studies; and increasing their staff to accommodate the increased operational planning requirements.
6. Each Arizona utility provided information and details on their plans to ensure physical security and resiliency of the Arizona electric system. Staff and KRSA conclude the Arizona utilities are taking actions to address the physical security risks to reasonably ensure the reliable operation of the Arizona transmission system.
7. Staff concludes that while the utilities have included the effect of DG and EE standards, the impact of these standards and related uncertainty on specific transmission needs has not been specifically identified.
8. Utilities, through the SWAT subregional planning group and WestConnect, continue to examine the potential impact on BES stability of actual and proposed coal plant retirements and their associated inertia coupled with increased use of solar photovoltaic and wind generation, which do not currently provide inertia benefits. This is an issue that the Commission and Staff should follow closely and on which the utilities should report their findings to the Commission as directed in the Recommendations section below.

6.2 Efficacy of Commission-Ordered Studies

The Commission has ordered the following studies to be performed as part of the BTA: SIL, MLSC, RMR, Ten Year Snapshot, and Extreme Contingency Analysis. The principal purpose of the Commission-ordered studies is to assure the certainty of the conclusions and recommendations within the BTA. Each Commission-ordered study required for the Ninth BTA is filed with the Commission. Staff and KRSA conclude the Commission-ordered studies demonstrate that the

Arizona transmission system is reasonably prepared to reliably serve local load in the ten year timeframe.

1. As indicated previously, the SIL and MLSC are adequate to meet ten year local load forecasts.
2. In the Seventh BTA, Staff suspended the RMR studies and implemented requirement criteria for restarting such studies based on a biennial review of specific triggering factors. None of the triggering factors occurred for the Ninth BTA which would require RMR study work in any of the RMR areas.
3. The Ten Year Snapshot study indicates Arizona's transmission plan is robust and supports the statewide load forecast through 2025. The Ten Year Snapshot has also been adjusted to monitor system elements down to and including the 115kV level, addressing any potential low voltage concerns. Major findings of the Ten Year Snapshot include:
    a. The 2025 Heavy Summer base case included a single bus voltage issue and no thermal violations with all lines in service, as well as voltage, thermal, and no-solve concerns under simulated contingency conditions. Single contingency outage analysis on the base case showed two different overloaded 115 kV elements that can be mitigated through increased output at the Apache Generating Station.
    b. The 2025 Heavy Summer base case included a single N-1 outage that resulted in a no-solve, or no solution at the Marana - Saguaro 115 kV (Breaker to Breaker) sub-station. The no-solve has been discussed with the affected utility and will be considered in future planning studies.
    c. Since the Ten-Year Snapshot was performed, WAPA and AZG&T have completed the Saguaro Bypass Project which may provide a mitigation strategy to both the overloaded elements and the N-1 outage; however, these changes have yet not been since studied for 2025. Delaying any one of the projects beyond 2025 did not have a significant negative impact on system performance.
    d. Potential mitigation strategies have been discussed for the 115 kV elements projected to be overloaded and the identified outage; however, the study work remains to be completed. Should the identified issues continue to be reported in the Tenth BTA, Staff may make requests for additional analysis or comments

4. The Extreme Contingency study satisfies the Commission's requirement to address and document extreme contingency outage studies for Arizona's major generation hubs and major transmission stations.
   a. APS's extreme contingency analyses indicate all load and local Phoenix reserve requirements can be met. These APS results are for both the 2016 and 2025 system conditions.
   b. TEP's extreme contingency analysis indicates TEP can withstand each extreme contingency outage. Study results show that TEP can withstand these extreme contingencies under the 2016 and 2024 system conditions.
5. The EE/DG studies satisfy the Commission's requirement to conduct a fifth-year technical study, down to the 115kV level, on the impacts of DG and EE. The studies indicate that EE/DG have properly been studied in system planning and EE/DG do not impact the reliability of the transmission system belonging to Arizona's load-serving utilities.
   a. APS's 2020 system peak forecast includes 703 MW of EE and DG. APS has assumed all of the EE/DG is located within the metro Phoenix load area where they are most prevalent. Projected EE/DG have no effect on APS's BES as currently planned for 2020; however, some impact at the subtransmission level may occur.
   b. SRP's 2020 system peak forecast includes 597 MW of EE and DG. SRP's power flow analysis found no overloads for N-1 outages, and no voltage violations were observed. The results show that SRP's transmission system meets all of SRP's internal criteria, and satisfies applicable WECC and NERC criteria regardless of the future EE and DG.
   c. TEP's 2020 system peak forecast includes 94 MW of EE and DG. Analysis was done in compliance with NERC Reliability standards and WECC System Performance Criteria. Results of the analysis concluded that no additional projects were required as a result of DG and EE effects.

6.3 Adequacy of System to Reliably Support Wholesale Market

Regional and sub-regional planning studies have effectively addressed the interconnected EHV transmission that is critical to a functional interstate wholesale market. Based upon the technical study work filed with the Commission and industry presentations, the existing and planned Arizona EHV system is adequate to support a robust wholesale market.

1. Six major interstate EHV transmission projects are proposed and have been addressed in this BTA. Individually and collectively these projects will improve the opportunity for interstate commerce.
   a. The 500 kV DC TransWest Express Project and High Plains Express Project conceptually interconnect the Desert Southwest with Wyoming.
   b. The SunZia 500 kV Project and Southline Transmission Project will provide additional transmission capacity between Arizona and New Mexico.
   c. The planned Ten West Link 500 kV project and the conceptual North Gila – Imperial Valley #2 500 kV project provide additional transmission capacity between Arizona and California.
2. Western's TIP is involved in a number of the interstate transmission projects that will have a significant impact on Arizona's transmission system in the ten year time frame.
3. Staff and KRSA conclude the Arizona utilities are taking sufficient action with respect to transmission planning impacts related to the integration of renewable generation resources.
   a. Arizona Utilities are sufficiently participating in intra- and inter-regional planning efforts to coordinate on the integration of new renewable generation resources. Issues related to renewable integration are being identified and incorporated into future study plans.
   b. Arizona utilities developed and participate in SVERI. SVERI evaluates likely penetration, locations and operation characteristics of variable energy resources within the Southwest over the next 20 years.
   c. Arizona Utilities are evaluating a market-based approach through Energy Imbalance Markets to aid in maximizing the renewable generation resources already constructed.
   d. Arizona Utilities are evaluating the extent to which coal retirements may impact or limit the amount of renewable generation that the Arizona transmission grid can support.
4. The Fifth BTA ordered the utilities to provide their top three RTPs. The Arizona utilities have completed four of the RTPs with a fifth project recently energized in 2016, one RTP is being actively pursued for development and three RTPs are being monitored for development as

reliability and resource needs arise. Additionally, one RTP is no longer being pursued, but is instead being worked on jointly as part of the Southline Project. Finally, one RTP has moved outside of the Ten-Year Plan window because the line was successfully re-rated without new transmission development.

5. FERC Order No. 1000 requires FERC jurisdictional transmission providers and encourages non-jurisdictional transmission providers to work collaboratively with stakeholders on a regional and interregional basis to improve regional transmission planning processes and cost allocation mechanisms in a cost-effective manner. All Arizona FERC jurisdictional transmission providers have made their compliance filings with the FERC to implement Order 1000 through the WestConnect Regional Transmission Planning process. WestConnect has published the results of the 2015 Abbreviated Cycle Regional Transmission Plan and the first full biennial transmission plan is underway.

6.4 Suitability of Utilized Planning Processes

Based upon information provided by the utilities, the Arizona utilities utilize significant and well defined transmission planning processes.

1. The results of NERC/WECC reliability standard audits over the past two years, as provided by the utilities in the Ninth BTA proceeding, indicate there were no concerns of Arizona's BES failing to comply with the applicable planning standards established by NERC/WECC.
    a. APS and SRP had audits performed in 2013 which received a report of "no findings". APS' next NERC/WECC reliability audit is scheduled to occur in November 2016. SRP's next audit is scheduled to occur in October 2016.
    b. TEP had an audit performed in August 2014 which identified one possible CIP violation which has since mitigated. Next audit is scheduled for October 2017.
    c. AZG&T had an audit performed in February 2015 which received a report of "no findings".
2. Technical studies filed in the Ninth BTA indicate a robust study process for assessing transmission system performance for the 2016-2025 planning period.
    a. Transmission planning criteria and methodologies provided to the Commission meet or exceed industry accepted performance standards.

b. When reliability concerns were identified in the utility study work, effective mitigations were developed to address these concerns.

3. Utilities communicate their transmission plans in robust local, state, subregional and regional, open and transparent transmission planning forums using public processes.

   a. Arizona utilities hold semi-annual FERC Order 890 stakeholder meetings to discuss their current transmission plans, provide an opportunity for stakeholder input and alternatives and to provide updates on their transmission projects.

   b. Arizona utilities actively participate in SWAT to discuss transmission plans in a subregional transmission planning forum. The SWAT meetings include discussions on utility transmission plans and are open to stakeholder participation and input. Arizona utilities also actively participate and often take leadership positions in SWAT subgroups and task forces designed to address specific, localized transmission concerns.

   c. Arizona utilities actively participate in and are members of the WestConnect PMC, a regional transmission planning group.

   d. Arizona utilities actively participate in WECC TEPPC to examine long-term, public transmission expansion planning. Major EHV Arizona transmission plans are incorporated into the TEPPC transmission planning processes to facilitate and coordinate interconnection-wide, 10 and 20 year expansion studies.

7 Recommendations

Based upon the conclusions, Staff offers the following recommendations for Commission consideration and action:

1. Staff recommends that the Commission support:
   a. The continued use of the "Guiding Principles for ACC Staff Determination of Electric System Adequacy and Reliability" as revised in the Eighth BTA.
   b. The use of collaborative transmission planning processes such as those that currently exist in Arizona, which help to facilitate competitive wholesale markets and broad stakeholder participation in grid expansion plans.
   c. The continued suspension of the requirement for performing RMR studies in every BTA and use of criteria for restarting such studies based on a biennial review of factors as outlined in the Seventh BTA.
   d. The suspension of the requirement that Arizona utilities, for each load growth or reliability driven transmission project, include the load level range at which each transmission project is anticipated to be needed, as directed in Decision No. 74785. Utilities shall continue to describe, in general terms, the driving factor(s) for each transmission project in the Ten-Year Plan
   e. The suspension of the requirement for TEP to file the SWAT CRATF report on behalf of the Arizona utilities within 30 days of completion as directed in Decision No. 74785. Utilities shall participate in WestConnect Regional Planning process and coordinate the Arizona reliability study with WestConnect study and scenario results, and TEP will report relevant findings on behalf of the utilities in future BTA Proceedings.
   f. That any requirement established in a prior BTA will continue in force unless the Commission suspends such requirement in a succeeding BTA. Nevertheless, Staff recommends that the Commission emphasize the importance of these continuing requirements for Arizona utilities:
      i. Advise each interconnection applicant at the time the applicant files for interconnection of the need to contact the Commission for appropriate ACC

filing requirements related to the Power Plant and Transmission Line Siting Committee.

ii. Report relevant findings in future BTAs regarding compliance with transmission planning standards from NERC/WECC reliability audits that have been finalized and filed with FERC.

iii. Address the effects of DG and EE on future transmission needs in their Ten-Year Plan filings.

iv. Ensure that the Commission-ordered Ten Year Snapshot study monitors transmission elements down to and including the 115 kV level for thermal loading and voltage violations.

v. Include planned transmission reconductor projects, transformer capacity upgrade projects, and reactive power compensation facility additions at 115 kV and above in future Ten-Year Plan filings.

g. The policy that the LSE in Cochise and Santa Cruz Counties continue to monitor the reliability in Cochise and Santa Cruz Counties, respectively, and propose any modifications that they deem to be appropriate in future Ten-Year Plans. Staff also recommends that the Commission continue to collect applicable outage data from the respective utilities in order to monitor any changes in Cochise County and Santa Cruz County system reliability in future BTA proceedings.

h. The acceptance of the results of the following Commission-ordered studies provided as part of the Ninth BTA filings:

i. The SIL and MLSC are adequate to meet ten year local load forecasts.

ii. The RMR studies were not required because none of the triggering factors occurred for the Ninth BTA that would require RMR study work in any of the RMR areas.

iii. The Extreme Contingency analysis for Arizona's major transmission corridors and substations and the associated risks and consequences of such overlapping contingencies.

iv. Ten Year Snapshot study results documenting the performance of Arizona's statewide transmission system in 2025 for a comprehensive set of single ("n-1") contingencies, each tested with the absence of different major planned transmission projects.

v. The EE/DG study results containing the fifth-year contingency analysis with and without disaggregated DG and EE loads.