FINAL DRAFT

Tenth Biennial Transmission Assessment 2018-2027

Staff Report

Docket No. E-00000D-17-0001

December 31, 2018

Prepared by Arizona Corporation Commission Staff

And

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Decision No. 76975

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 Tenth Biennial Transmission Assessment ("BTA" or "Tenth BTA") and has been prepared in accordance with a contract agreement between ESTA International, LLC ("ESTA") and the Commission. It is considered a public document. Use of the report by other parties shall be at their own risk. Neither ESTA nor the Commission accept any duty of care to such third parties.

Arizona's Tenth BTA is based upon the Ten-Year Plans filed with the Commission by parties in January 2018. It also incorporates information and comments provided by participants and attendees in the BTA workshops and report review process. ACC Staff and ESTA appreciate the contributions, cooperation, and support of industry participants throughout the Tenth BTA process.

[1] Arizona Revised Statute §40-360.02

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Decision No. 76975

Executive Summary

Staff, with the aid of ESTA, examined the Ten-Year Plans and related filings submitted to the Commission[2], held open and transparent workshops on June 25, 2018 ("Workshop I") and September 28, 2018, ("Workshop II") to solicit industry participation, and drafted this Tenth BTA report based solely on the results of these activities. Although Staff and ESTA reviewed and questioned study work, they stopped short of independently verifying the study results. The Ten-Year Plans and related filings that were reviewed by Staff and ESTA 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 Tenth BTA report, Staff and ESTA also reviewed the Workshop I presentations and recordings.[3] Two successive drafts of this Tenth BTA were made available for industry and stakeholder comments; the comments were considered in preparing the final report. This Tenth BTA process 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 asked during this BTA:[4]

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 2018-2027 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[5] ("RMR"), Ten-Year Snapshot, Distributed Generation ("DG") and Energy Efficiency ("EE"), and Extreme Contingency studies filed as part of the Tenth BTA provide useful and sufficient information in determining adequacy of the State's transmission system over the next ten 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?

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[2] Docket No. E-00000D-17-0001
[3] Video of June 25, 2018 Workshop I is available at the ACC Public Meeting Archive http://azcc.granicus.com/MediaPlayer.php?view_id=3&clip_id=3124
[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 Tenth BTA based upon criteria set by the Commission in the Seventh BTA

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 Tenth BTA was comprehensive and responsive to the statutory and Commission-ordered requirements. The information provided was used to develop the conclusions of the Tenth 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 fifty-seven transmission projects of approximately 923 miles in length. Forty-five additional projects are beyond the ten-year horizon or have in-service dates that are yet to be determined and account for 881 miles of new transmission. Additionally, there are eleven transmission lines, totaling approximately 103 miles in length, which utilities plan to reconductor.

2. As active members of the WestConnect Planning Management Committee, Arizona Utilities have increased their 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 should, the plans 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 questions of reliability that would accompany accelerated coal plant retirements especially when considered in combination with increased reliance on renewable generation that will have significant impacts throughout the western interconnection. Regardless, Tucson Electric Power ("TEP") filed the relevant portion of the WestConnect Clean Power Plan ("CPP") Utility Plans Scenario study on April 27, 2018 on behalf of the Arizona Utilities, as required by Decision No. 75817. The report was prepared from the WestConnect Planning Study 2016-2017 Cycle Regional Transmission

Plan. The results of the study show there are no regionally significant issues but there were local issues under the originally proposed CPP. The retirement of significant amounts of coal generation with replacement by natural gas and renewable resources did not appear to compromise the reliability of the system. As more coal resources are retired throughout the West, this is an issue that should continue to be monitored by the utilities and the utilities should provide any relevant updates in future BTAs.

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 recommended by this Tenth 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 process. Based upon the technical study work examined by Staff and ESTA, the existing and proposed transmission system meets the load-serving requirements of Arizona in a reliable manner for the 2018-2027 timeframe.

1. The 2018 summer level of preparedness of the utilities in Arizona, as presented in the April 24, 2018 workshop, demonstrated that sufficient preparedness measures were being taken to reliably supply Arizona's energy needs in 2018.[6]

2. The statewide demand forecast has continued to be lowered since the Fifth BTA. During the Tenth BTA, the Arizona utilities reported a Ten-Year Forecast that was, on average, 0.65 percent lower than what was reported during the Ninth BTA.

3. All SIL and MLSC studies, which measure planned local transmission systems' ability to serve load reliably in load pockets[7], indicate that the local transmission systems are adequate to meet the ten-year local load forecasts.

[6] Video of the April 24, 2018 Summer Preparedness workshop is available at the ACC public meeting archive: http://azcc.granicus.com/MediaPlayer.php?view_id=3&clip_id=3030

[7] A load pocket is a geographic area where existing transmission capacity is not capable of serving the entire electric load of the area without relying on generation capacity that is physically located in that area.

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 occur), Ten-Year Snapshot, and Extreme Contingency Analysis. The principal purpose of the Commission-ordered studies is to assure compliance with the conclusions and recommendations within the BTA. Each Commission-ordered study required for the Tenth BTA is filed with the Commission.

Staff and ESTA 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. The SIL and MLSC studies demonstrate that the planned local transmission systems are adequate to meet ten-year local load forecasts.

2. In the Seventh BTA, Staff suspended the RMR studies and established criteria for restarting such studies based on a biennial review of specific triggering factors. None of these triggering factors occurred in the Tenth BTA studies in any of the RMR areas.

3. The Ten-Year Snapshot study indicates Arizona's transmission plan is robust and supports the statewide loads forecasted through 2027.

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/corridors. Arizona Public Service ("APS") and TEP performed the Extreme Contingency studies for projected 2019 and 2027 system conditions. APS's extreme contingency analyses indicate overall system and local Phoenix reserve requirements can be met. TEP's extreme contingency analysis resulted in power flow "no-solve" cases for two specific contingency events in 2019 and one specific contingency event in 2027.[8] However, the extreme contingency analysis results also show that all of the 2019 and 2027 no-solve scenarios would be mitigated by the addition of the Southline Transmission Project which is expected to go into service in the 2020 timeframe. In the meantime, TEP stated both 2019 no-solve scenarios are being managed through physical security hardening measures and operational measures. TEP also intends to continue to monitor the exposure to and impacts on the system due to these outages, and additional mitigation options will be evaluated in future internal studies if needed.

[8] A non-solving power flow case means that computer model was not able to find a solution to the equations used in the model. This usually indicates either a basic model-data problem or some sort of a voltage problem.

Staff and ESTA concur that the Extreme Contingency studies performed by APS and TEP satisfy the requirements of Commission Decision No. 67457.

5. Staff and ESTA conclude the EE/DG studies satisfy the Commission's requirement to conduct a fifth-year technical study, down to the 115 kV level, on the impacts of DG and EE. The studies indicate that EE/DG were properly studied in system planning and found that 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. Four major interstate EHV transmission projects were filed and addressed in this BTA. Individually and collectively, these projects will improve the opportunity for interstate commerce.

2. Staff and ESTA conclude that the Arizona utilities are taking sufficient action with respect to transmission planning impacts related to integrating renewable generation resources.

3. The Fifth BTA ordered the utilities to provide their top three Renewable Transmission Projects ("RTP"). APS completed the Palo Verde-North Gila 500 kV line in May 2015 and the Delaney-Palo Verde 500 kV line in May 2016. One other APS RTP, the Palo Verde to Liberty/Gila Bend to Liberty project, is on hold due to the downturn in the economy and a slowdown of renewable energy development in the area. In June 2014, Salt River Project ("SRP"), completed the following components of the Southeast Valley Project: Pinal Central 500 kV and 230 kV substations, Duke 500 kV substation, Pinal West – Duke - Pinal Central 500 kV line, Pinal Central – Browning 500 kV line, Pinal Central – Randolph 230 kV line and the Pinal Central 500 kV shunt reactor. TEP followed up by completing the Pinal Central - Tortolita 500 kV line in October of 2015. In addition, one RTP is no longer being pursued but is instead being worked on jointly as part of the Southline Project. Finally, two RTPs have moved outside of the Ten-Year Plan window.

4. Federal Energy Regulatory Commission ("FERC") Order 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 the 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 1000 requirements. WestConnect's 2018-2019 Regional Planning Cycle is currently underway, and its Final Regional Study Plan for the 2018-2019 Planning Cycle was published on March 14, 2018. This process offers a readily accessible forum for stakeholders to be involved planning 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 a significant and well-defined transmission planning processes:

1. The results of NERC/WECC Reliability Standard audits over the past two years indicate there were fourteen possible Critical Infrastructure Protection ("CIP") violations and one possible Operation and Planning violation. All possible violations have since been mitigated. There is no concern of Arizona's Bulk Electric System ("BES") failing to comply with the applicable planning standards established by NERC/WECC.

2. Technical studies filed in the Tenth BTA indicate a robust study process for assessing transmission system performance for the 2018-2027 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 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 continued 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. With the filing of the appropriate sections of the WestConnect Regional Plan, the requirement for completion of a coal reduction scenario evaluation to be coordinated among the Arizona utilities should be considered complete.

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 by evaluating the fifth year.

    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 Load Serving Entity ("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 Tenth 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 Tenth 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 2027 for a comprehensive set of single contingencies ("n-1"), 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.

Decision No. 76975

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Decision No. 76975

Contents

Figures

Tables

Exhibits

Decision No. 76975

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.[9] Every entity considering construction of a new power plant of 100 Megawatts ("MW") or greater, as defined in the Arizona Revised Statute ("A.R.S.") § 40-360,[10] within Arizona is required to file a plan with the ACC ninety days before filing an application for a Certificate of Environmental Compatibility ("CEC").[11] 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.[12] 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".[13]

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 Tenth Biennial Transmission Assessment ("BTA" or "Tenth BTA") evaluates the ten-year transmission plans filed with the Commission in January 2018.[14] This report fulfills the statutory obligation to review these transmission plans and assess whether the Arizona transmission system is, and will likely remain, adequate throughout the ten-year timeframe.

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 ESTA relied on the technical reports and documents filed with the Commission and other publicly available industry reports rather than performing independent technical study work.

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[9] A.R.S. § 40-360.02.A

[10] Per A.R.S. § 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."

[11] A.R.S. § 40-360.02.B

[12] A.R.S. § 40-360.02.C.7

[13] A.R.S. § 40-360.02.G

[14] Docket No. E-00000D-17-0001. http://edocket.azcc.gov/Docket/DocketDetailSearch?docketId=19839#docket-detail-container1

In addition to the ten-year filings, the Commission ordered supplemental studies to be performed as a portion of this Tenth BTA.[15] These studies include: a study on effects of Distributed Generation ("DG") and Energy Efficiency ("EE") installations on future transmission needs, Simultaneous 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.[16] 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 ESTA to assist with this Tenth BTA. Together, Staff and ESTA critically reviewed the Ten-Year Plans that were filed and addressed the following four key public policy questions:

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 2018-2027 timeframe in a reliable manner?

2. **Efficacy of the Commission-ordered studies** - Do the SIL, MLSC, RMR[17] (if certain triggers are met), Ten-Year Snapshot, DG and EE, and Extreme Contingency studies filed as part of the Tenth BTA provide useful and sufficient information in determining adequacy of the State's transmission system over the next ten 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** – Are the plans and planning activities consistent with transmission planning principles and good utility

[15] Decision No. 74785, Docket No. E-00000D-13-0002
[16] A complete history of Commission-ordered Studies is found in Appendix B.
[17] RMR Studies were not required for the Tenth BTA based upon criteria set by the Commission in the Seventh BTA

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 Tenth BTA report. The first step was to conduct the Tenth 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 Tenth BTA. The third step was the development, distribution, and posting of the first draft report for public comment. Revisions were then made, and a second draft of the report was posted for public comment. The final step included conducting the Tenth BTA Workshop II ("Workshop II") during which Staff (with assistance from ESTA) presented the second draft of the report. A summary of each step of the BTA process is described in the following sections.

1.3.1 Workshop I: Industry Presentations

Staff conducted a public workshop on June 25, 2018, at the Commission's Hearing Room No. 1 in Phoenix, Arizona[18]. A complete listing of the Workshop I attendees and presenters is given in Appendix C. The Tenth BTA Workshop I provided an informal setting for entities that filed Ten-Year 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] Video of the June 25, 2018 Workshop I is available at the ACC public meeting archive: http://azcc.granicus.com/MediaPlayer.php?view_id=3&clip_id=3124

Workshop I – Agenda Items	Presenters
Utility Ten-Year Transmission Plans	Arizona Public Service ("APS"), Salt River Project ("SRP"), Tucson Electric Power ("TEP")/UNS Electric ("UNSE"), Arizona Electric Power Cooperative ("AEPCO")
Interstate and Merchant Transmission Projects	SunZia, North Gila-Imperial Valley, Big Chino, Ten West Link, Southline
Market and Generation Interconnection Driven Transmission Projects	Bowie Power Plant
Commission Ordered BTA Requirements	Ten Year Snapshot and Extreme Contingency Studies, EE and DG Studies presented by APS, SRP, TEP/UNSE
National and Regional Transmission Issues	WestConnect and Southwest Area Transmission ("SWAT")
Other Transmission Related Topics of Interest	Coal Reduction Assessment Task Force ("CRATF") Study Report update provided by Staff

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: Utility Ten-Year Transmission Plans, Interstate and Merchant Transmission Projects, Market and Generation Interconnection Driven Transmission Projects, Commission-ordered BTA Requirements, National and Regional Transmission Issues, 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, and audience. Staff concluded Workshop I with an 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 Tenth BTA

Staff and ESTA reviewed all filings made to date by utilities in the Tenth BTA to ensure required data was filed. When deficiencies were identified, data requests were issued 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 Tenth BTA.[19]

Utility	Ten-Year Plan	2018-2027 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 10th BTA	X	X	Extreme Contingency Study
SRP	X	X	Not Required in 10th 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 10th BTA	X	N/A	N/A
TEP	X	X	Not Required in 10th BTA	X	X	Extreme Contingency Study
UNSE	X	N/A	Not Required in 10th BTA	N/A	X	N/A

TABLE 2: SUMMARY OF UTILITY DATA

1.3.3 Preparation of Draft Report and Industry Comment

Staff and ESTA prepared an initial draft of the Tenth BTA report for industry review and comment on August 24, 2018. The first draft report was developed from data contained in the Ten-Year Plan submittals, information gathered at Workshop I, a review of industry reports and presentations and subsequent replies to data requests from the utilities.[20] 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 ESTA received, reviewed, and considered industry comments. The comments were collected, categorized, and posted for stakeholder review. After reflecting upon and addressing comments received from the industry, a second draft of the report was then prepared by Staff and ESTA. The docketed comments and the second draft of the report were the subject of Workshop II.

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

[20] Video of June 25, 2018 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

1.3.4 Workshop II: Staff Presentation of Final Report

The 2018 BTA Workshop II was held at the Commission's Hearing Room No. 1 on September 28, 2018.[21] The purpose of Workshop II was to discuss comments received regarding the first draft of the Tenth BTA. Questions, comments, and clarification resulting from this workshop were incorporated in the final report for presentation to the Commission.

During Workshop II, Staff presented all comments received in response to the first draft of the Tenth BTA and also informed stakeholders of planned changes to the Tenth BTA. In addition, Staff requested feedback regarding the planned changes. There were two additional presentations made by TEP and WECC. The WECC presentation provided an update on current planning activities and changes. TEP's presentation focused on the results of the WestConnect Clean Power Plan Utility Plans Scenario study (see Section 5.4.1 for further detail).

1.4 Terminology and Acronyms

Staff and ESTA 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 the clarifying efforts.

1.5 Additional Resources

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

[21] Video of the September 28, 2018 Workshop II is available at the ACC Public Meeting Archive - http://azcc.granicus.com/MediaPlayer.php?view_id=3&clip_id=3277

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2 Ten-Year Plans

Nineteen entities formally filed Ten-Year Plans with the Commission. The Ten-Year Plans for WestConnect and 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.[22]

Entity	Reference Location
Arizona Electric Power Cooperative Inc.	Exhibit 16
Ajo Improvement Company	Exhibit 19
Arizona Public Service	Exhibit 14
Big Chino Valley Pumped Storage, LLC	Exhibit 19
Bowie Power Station	Exhibit 19
Crossroads Solar	Exhibit 19
Gila Bend Power Partners	Exhibit 19
Mohave County Wind Farm	Exhibit 19
North Gila Imperial Valley	Exhibit 19
Pinal Central Energy Center, LLC	Exhibit 19
Public Service Company of New Mexico ("PNM")	N/A
Southline Transmission Project	Exhibit 19
Southwest Transmission Partners, LLC	Exhibit 19
Salt River Project	Exhibit 15
SunZia Southwest Transmission Project	Exhibit 19
Ten West Link	Exhibit 19
Tucson Electric Power	Exhibit 17
UNS Electric, Inc.	Exhibit 18
Wilmot Properties, LLC	Exhibit 19

TABLE 3: LIST OF PARTIES FILING TEN-YEAR PLANS 2018 TABULAR REFERENCE TABLE

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 Tenth 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 Tenth BTA examines the aggregate of these Ten-Year Plans.

[22] Decision No. 72031
[23] Decision No. 72031

Arizona Utilities perform technical analyses 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 fifty-seven transmission projects of approximately 923 miles in length. Forty-five projects are beyond the ten-year horizon or have in-service dates that are yet to be determined and account for an additional 881 miles of new transmission. Additionally, utilities have eleven transmission lines, totaling approximately 103 miles in length, which they plan to reconductor.[24]

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-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.

[24] 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.

In-Service Date[25]	# of Projects	Mileage
2018	9	73
2019	7	56
2020	15	324
2021	8	257
2022	4	33
2023	2	-
2024	5	73
2025	3	91
2026	3	14
2027	1	1
Subtotal	57	923
TBD	45	881
Total	102	1,804

TABLE 4: TRANSMISSION PROJECTS WITH MILEAGE BY YEAR

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]

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 760 total 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 366 miles out of the total 502 miles planned. The Arizona Plan is listed in tabular form in Exhibit 12 and Exhibit 13 by in-service date and voltage class, respectively.

[25] 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.
[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.

Voltage Class	Number of Projects		Mileage
	2018-2027	Post 2027-TBD	
500 KV	7	5	760
345 kV	2	6	502
230 kV	11	19	196
138 kV	31	8	335
115 kV	5	7	11
Total	57	45	1,804

TABLE 5: PLANNED TRANSMISSION PROJECTS BY VOLTAGE

The Arizona Plan includes eight merchant generators and one utility generator totaling 5,355 MW and requiring approximately 99 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.

Description	Maximum Output (MW)	Gen-Tie Length (Mi)
Bowie Power Station	1,000	15
Crossroads Solar Energy Project	150	12
Big Chino Pumped Storage Project	2,000	50
Gila Bend Power Plant	833	6
Mohave county wind farm project	500	6
Ocotillo Modernization Project	290	1
Wilmot project - Natural gas	450	4.5
Wilmot project - solar plus battery	102	4.5
Pinal Central Energy Center	30	0.4
Total	5,355	99.4

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 Ninth 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 Ninth 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.

Table 7 is a list of changes that have occurred at EHV levels of 345 kV and above.

In-Service Date	Project Description	Developer	Voltage Class (kV)	Status
2018	Mazatzal 345/69kV Substation	APS	345	In-Service
2018	Morgan – Sun Valley 500kV Line	APS	500	In-Service
2018	Bowie 1,000MW Power Station	Bowie	345	Deferred 2016-2018
2020	Hassayampa - Pinal West 500kV Line Loop-in to Jojoba Switchyard	TEP	500	Deferred 2017 to 2020
2021	SunZia Southwest Transmission 500kV Project	Private[27]	500	Deferred 2017 to 2021
TBD	Palo Verde – Saguaro 500kV Line	APS	500	New
TBD	Pinal Central – Abel – RS-20 500kV	SRP	500	New
TBD	Gila River – Pinal West 500kV	TEP	500	New
TBD	Springerville Substation - Greenlee Substation - 3nd Circuit	TEP	345	New

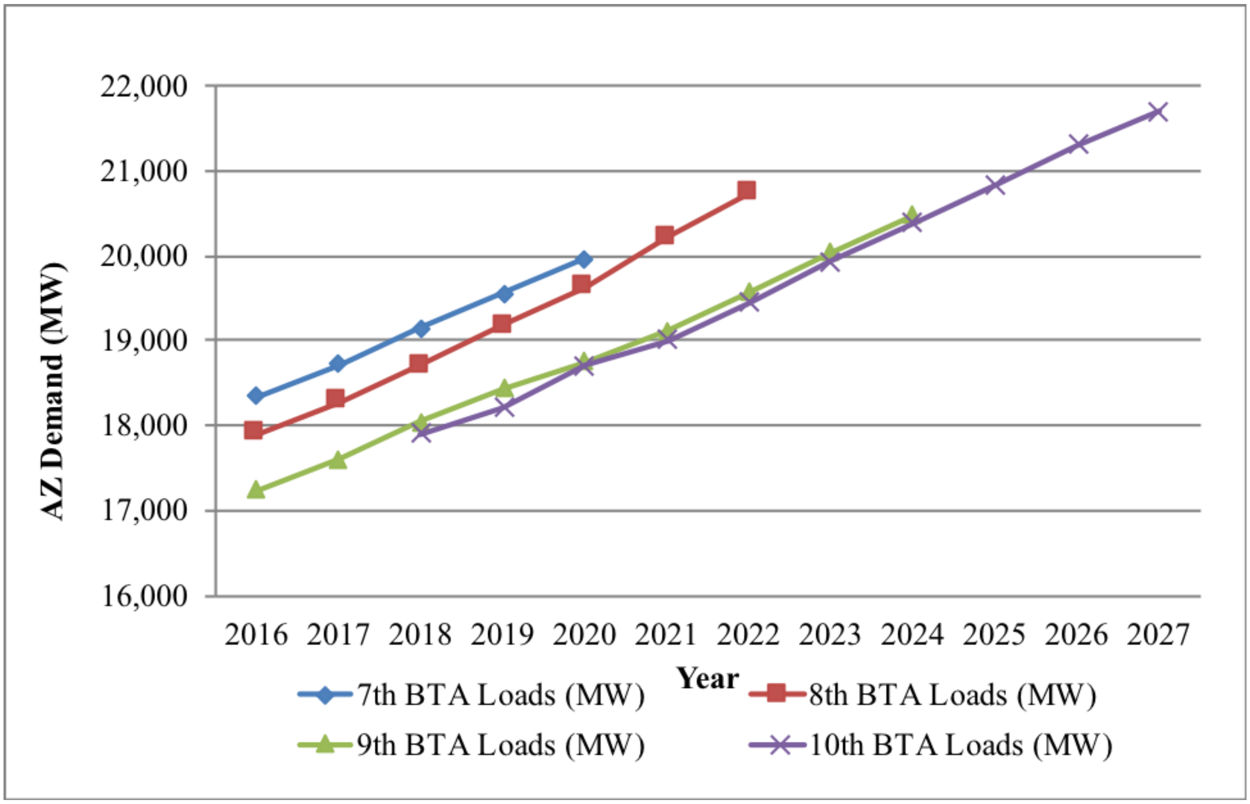
TABLE 7- SIGNIFICANT EHV PROJECT CHANGES SINCE THE NINTH BTA

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 Tenth BTA.

[27] SRP is a part owner for the SunZia Soutwest Transmission 500kV Project

FIGURE 1: CHANGE IN ARIZONA DEMAND FORECAST



The statewide demand forecast has continued to be lowered since the Fifth BTA. During the Tenth BTA, the Arizona utilities reported a Ten-Year Forecast that was, on average, 0.65 percent lower than was reported during the Ninth BTA. Although the statewide forecast has been lowered overall, the demand forecast shows a projected growth rate of approximately 2.16 percent per year for the Ten-Year forecast period. APS and SRP have reduced their yearly forecast, on average, by approximately 1.05 percent per year in this BTA. The detailed forecast data for APS, SRP, Arizona G&T Cooperatives ("AZG&T"), and TEP/UNSE has been included in Exhibit 9.[28]

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."[29] 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

[28] 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.
[29] Decision No. 72031 (December 10, 2010)

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 1,452 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.

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

Under Federal Energy Regulatory Commission ("FERC") regulations, generation developers seeking to interconnect to a transmission provider's system must file an interconnection application.[30] 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 detailed each utility's generation interconnection queues from the Ninth and Tenth BTA. These are summarized in Table 9 and detailed in Exhibit 11, along with the difference between the two. In parallel with 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.[31]

Utility	Approximate Capacity (MW) of Generators in Utility Queue		Interconnection Queues from Ninth to Tenth
	Ninth BTA	Tenth BTA	
APS	3,960	14,162	10,202
SRP	1,945	2,706	761
TEP/ UNSE	761	634	(127)
WAPA	1,704	1,435	(269)
AZG&T	0	200	200
Total	8,370	19,137	10,767

TABLE 8 - UTILITY GENERATION INTERCONNECTION QUEUES

Arizona combined interconnection queues have increased significantly since the Ninth BTA. At the time of the Tenth BTA, 19.1 GW of generation capacity is being 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 additional merchant generation. With California recently increasing the State's renewable portfolio standards to 50 percent by 2030, it is presumed that anticipated exports to California continue to be a driving factor in generation development. A number of proposed and conceptual intra- and inter-state projects

[30] 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.
[31] ARS § 40-360.02C7

between Arizona and California are considered in this Tenth BTA that, if built, will increase transfer capacity.

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 2018 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 Tenth 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 complies with NERC TPL Standards. On October 17, 2013 FERC issued Order No. 786, adopting TPL standard TPL-001-4. 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,

[32] A.R.S. § 40-360.02.G

[33] Summer 2018 Energy Preparedness April 24, 2018 at the ACC in Phoenix hearing room #1. https://tucson.com/news/local/arizona-utility-puts-m-in-election-races-mostly-to-defeat/article_bd6258db-d678-534b-aa8d-ec505f19f0ff.html

[34] ARS § 40-36.02.C.7

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

expanding the number of event categories to eight. The changes to the planning events are depicted below in Table 9. The TPL-001-4 standard also clarified and expanded extreme events that must be evaluated.

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 9 - UPDATED STEADY STATE & STABILITY PERFORMANCE PLANNING EVENTS

There are eight Transmission System Planning Performance Requirements that are subject to NERC audits. In 2016, WECC updated the System Performance Criteria, TPL-001-WECC-CRT, to correspond with the new NERC standard.

Staff and ESTA have received and reviewed the required ten-year study work from each Arizona utility. Table 10 summarizes the findings from Staff and ESTA's review of the utility provided Ten-Year Planning materials.

Utility	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	Yes	None	None	N/A
SRP	Yes	None	None	N/A
AZG&T	Yes	None	Yes	Yes
TEP	Yes	None	None	N/A

TABLE 10 - SUMMARY TABLE OF UTILITY STUDY WORK

Based on the results, the 2018 technical studies filed in the Tenth BTA indicate a robust study process for assessing transmission system performance, both steady-state and transient, for the 2018-2027 planning period.[36]

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."[37] Table 11 summarizes the related information filed in the Tenth BTA.

[36] "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.
[37] Decision No. 72031

Utility	Reliability Audit Finalized and filed with FERC Since Ninth BTA	Comments Related to Transmission Planning Standards
APS	YES	Audit performed in November 2016 and report received by APS on June 26, 2017. Audit confirmed four potential CIP violations that had been self-identified by APS. All potential violations have since been resolved.
SRP	YES	Audit performed in October 2016 and included a review of 21 Operations & Planning and 19 CIP requirements. One possible CIP violation was identified, which has since been categorized as a Compliance Exception[38]. The next NERC/WECC reliability audit is scheduled to occur February 2019.
TEP	YES	Audit performed in August 2017 and included a review of 27 Operation & Planning and 28 CIP requirements. Four possible CIP violations were identified and have since been mitigated.
AZG&T	YES	Audit performed in January and February 2018 and included a review of 15 Operation & Planning and 19 CIP requirements. With respect to the 15 O&P reliability standards, the WECC audit team made a "No Finding" determination for 14 reliability standards and a "Potential Noncompliance" determination for one reliability standard, which has since been categorized as a Compliance Exception. With respect to the 19 CIP reliability standards, the WECC audit team made a "No Finding" determination for 13 reliability standards and a "Potential Noncompliance" determination for five reliability standards, which have seen been mitigated.

TABLE 11 - WECC AUDIT RESULTS

[38] A "Compliance Exception" is an instance of noncompliance which poses a minimal risk to the reliability of the bulk power system that does not warrant a penalty and which is recorded and mitigated without triggering an enforcement action. For more information: https://www.nerc.com/pa/comp/Reliability%20Assurance%20Initiative/Compliance%20Exception%20Overview.pdf

The results of NERC/WECC reliability standard audits over the past two years indicate there were fourteen possible CIP violations and one possible Operation and Planning violation. All possible violations have since been mitigated. There is no concern 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 Arizona utilities to perform supplemental studies. The purpose of the Commission-ordered studies is to assure compliance with 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 fall into five categories:

1. Transmission load-serving capability,
2. RMR,
3. Ten-Year Snapshot,
4. Extreme Contingency, and
5. Energy Efficiency and Distributed Generation.

Table 12 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 12 - SUMMARY OF COMMISSION-ORDERED BTA STUDIES[39]

[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.

3.3.1 2018 Transmission Load Serving Capability Assessment

Load-serving capability is 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, generation located within the load pocket must serve the portion of the load that cannot be served via transmission from generation outside the load pocket. This type of generation is often referred to as RMR (reliability must run) generation that is required to operate out of merit order. The combined ability of transmission and generation facilities to serve a local area's load is 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 (2000), Staff identified three load pockets in Arizona to be monitored for transmission import constraints: Phoenix, Tucson and Yuma. The Second BTA (2002) added the Mohave County and Santa Cruz County load pockets. Subsequent BTAs examined import constraints in Pinal County and identified it as a local area that also needed to be monitored. In the Fifth BTA (2008), Cochise County was also identified as needing import assessments to address continuity of service concerns.

While the Phoenix, Tucson, Yuma and Mohave County load pockets' focus has been and continues to be on load-serving capability during peak-load times, Cochise and Santa Cruz counties are different. The Commission's focus for Cochise County and Santa Cruz County load pockets has shifted to monitoring the continuity of service (e.g., year-round reliability performance).

3.3.1.1 Cochise County Import Assessment

In the Fifth BTA (2008), Decision No. 70635, the Commission directed that studies be filed for Cochise County addressing "continuity of service" issues.[41] However, in the Seventh BTA (2012), Staff recommended suspending efforts to upgrade reliability to a continuity-of-service standard 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 suspending the filing of two more Cochise County Study Group ("CCSG") progress reports in 2012.

Staff further recommended that the CCSG participants continue monitoring the reliability in Cochise County and propose any appropriate modifications in future Ten-Year Plans. Staff also

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[40]. See Appendix E, RMR Conditions and Study Methodology
[41]. Decision No. 70635. http://docket.images.azcc.gov/0000091783.pdf

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.

Cochise County loads are served by radial transmission sources operated by AZG&T, APS and TEP. The 2019 forecasted peak customer demand in the county is 266 MW.

Through a data request Staff and ESTA received Cochise County outage data for APS, TEP and AZG&T for 2016 through early 2018 as shown in. In APS's service territory in Cochise County during this period no sustained outages of five minutes or longer were reported. TEP reported two sustained transmission outages in 2017 and one sustained interruption year-to-date (through May 11, 2018). AZG&T reported an average of two sustained outages per year in 2016-2017 affecting their transmission system, and no sustained outages to date in 2018.

System	Year	Number of sustained outages	Average outage time (minutes)[42]	Average number of customers affected
APS	2014	0	0	0
	2015	2	79	13,887
	2016	0	0	0
	2017	0	0	0
	2018 (through June 1)	0	0	0
TEP	2014	1	586	1
	2015	0	0	0
	2016	0	0	0
	2017	2	0.25	1
	2018 (through June 1)	1	47	1
AZG&T	2014	0	0	0
	2015	2	23	16,192
	2016	3	42	9,121
	2017	1	47.5	16,620
	2018 (through June 1)	0	0	0

TABLE 13 - COCHISE COUNTY SUSTAINED OUTAGES DATA SUMMARY

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

[42] In this context "average outage time" is calculated from the time to restore the last customer during each outage event in a given system and given year, divided by the number of outages in that system and year. If multiple customers were out of service, an individual customer's outage time might actually have been shorter.

and APS and the two parties, along with SSVEC, continue to discuss joint participation on the project. AZG&T now estimates a 2021 in-service date for the Tombstone Junction Project.

After reviewing the 2014-2018 outage data reported for Cochise County and the Ten-Year transmission expansion plans in the load area, Staff and ESTA did not find any significant cause for concern in the outage trend. Staff and ESTA find that Cochise County outage data should continue to be collected and monitored in future BTAs. Further, Staff and ESTA find the Cochise County import assessment requirement is satisfied for this Tenth BTA.

3.3.1.2 Santa Cruz Import Assessment

Santa Cruz County, similar to Cochise County, is served by radial transmission. UNSE is the LSE in Santa Cruz County. The Tenth BTA load forecast for Santa Cruz is 76 MW in 2018 and 91 MW in 2027. In the Fifth BTA, the Commission directed studies be filed for Santa Cruz County addressing "continuity of service" issues.[43] However, as with Cochise County, in the Seventh BTA (2012), Staff recommended suspending efforts to upgrade reliability to a continuity-of-service standard 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.

In addition, Staff recommended that UNSE 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 collecting applicable outage data from UNSE in order to monitor any changes in Santa Cruz County system reliability in future BTA proceedings.

Through data requests, Staff and ESTA received Santa Cruz County outage data from UNSE. Table 14 - Santa Cruz Sustained Outages and Momentary Interruptions Data Summary summarizes UNSE's responses. The outage data shows there was one momentary interruption in service and no sustained outages reported from 2014, increasing to six momentary interruptions and two sustained interruptions in 2017. In addition, there were two planned interruptions for construction work in in 2016 each affecting 10,183 customers with and average duration of 3.1 hours and also two planned outages in 2017 also affecting 10,183 customers with an average duration of 4.25 hours per outage. These statistics indicate an increase in Santa Cruz County outage events in 2015-2017.

[43] Decision No. 70635. http://docket.images.azcc.gov/0000091783.pdf

Year	Number of sustained outages interruptions	Number momentary outages interruptions	Average outage time (minutes)44	Average number of customers affected
2014	0	1	n/a	n/a
2015	0	2	n/a	n/a
2016	0	4	n/a	n/a
2017	2	6	30	10,183
2018 (thru May)	0	0	0	0

TABLE 14 - SANTA CRUZ SUSTAINED OUTAGES AND MOMENTARY INTERRUPTIONS DATA SUMMARY

UNSE has one planned EHV transmission project listed in its Ten Year-Plan for Santa Cruz County. This project is the Nogales Transmission, LLC owned Nogales Interconnection project, a 230 kV transmission line providing interconnection between the Western interconnection in the US and the Mexican grid. The remaining projects, including planned transmission and substation installations, are to facilitate this interconnection and reduce any system impacts. These projects also have the potential of reinforcing the reliability of the existing transmission grid in the Santa Cruz region.

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

3.3.2 Import Assessments Requiring RMR Studies

During some portions of the year, generating units within a load pocket might be required to operate out of merit order to serve a portion of the local load; RMR generation.[45] The power generated from local generation may be more expensive than the power from outside resources and may be less environmentally desirable. During RMR conditions, transmission providers must dispatch RMR generation to relieve the congestion on transmission lines.

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:[46]

[44] Excludes momentary outages (<5 min.) and planned outage events.
[45] Merit order is the sequence of available energy sources, especially generation, in ascending order of their short-run marginal production costs. This merit order is used to minimize production cost by using those with the lowest marginal costs first and those with the highest cost last. Sometimes generating units must be started out of merit order due to transmission congestion, system reliability or other reasons.
[46] Decision No. 73625.

- An increase of more than 2.5 percent in an RMR pocket load forecast since the previous BTA.[47]

- 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 percent of the peak demand in the pocket.

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

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 in the north and west segment of the Phoenix Valley is served by APS and the load 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 reported that no triggering criteria for restarting the Phoenix Valley RMR studies have occurred since the Ninth BTA, therefore there are no updated results to report for the Tenth BTA.

3.3.2.2 Tucson Area RMR Assessment

The Tucson area is interconnected to the EHV transmission system at the Tortolita, South, and Vail Substations. These three substations interconnect and supply energy to the local TEP

[47] 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.

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 Ninth 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 the Gila Substation and to the Imperial Irrigation District (IID) at the 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. 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 Ninth BTA.

3.3.2.4 3.3.2.4 Santa Cruz County RMR Assessment

Santa Cruz County is served by a radial transmission system. UNSE is the LSE in Santa Cruz County. UNSE reported that no triggering criteria for restarting the Santa Cruz County RMR studies have occurred since the Ninth 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. UNSE is the predominant LSE in Mohave County.[48] UNSE reported that no triggering criteria for Mohave County RMR studies have occurred since the Ninth 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.[49] NERC Standard TPL-001-4 steady state criteria and WECC Criterion TPL-001-WECC-CRT-3.1 were used to evaluate thermal and voltage performance. The Ten-Year Snapshot study consists of conducting normal and single contingency (NERC "P0" and "P1" events) power flow analyses that determine

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

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

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 selected individually planned transmission projects.[50]

Whereas some of the Arizona transmission owners have filed technical study reports for their respective areas of the system as part of the Tenth BTA, the SWAT-AZ Ten-Year Snapshot study represents the only comprehensive assessment of 2027 Arizona transmission plans. Furthermore, the Ten-Year Snapshot study done in 2018 includes all transmission and generation projects statewide, making the report uniquely valuable for assessing the overall adequacy of Arizona transmission plans in 2027.

The 2027 case modeled a statewide load of 24,097 MW (excluding losses) which is 776 MW or 3.3 percent higher than the statewide load modeled in the previous Ten-year Snapshot study completed for the year 2025. Arizona system losses in the case were 808 MW. Arizona generation was dispatched at 28,393 MW which included 3,488 MW of generation (in excess of Arizona loads and losses) scheduled as exports to areas outside of Arizona. [51] The 2027 base case model used for the study was based on the complete list of projects that were planned to be in service by 2027 at the time of base-case development, which took place from January to April 2017.

In all, a total of three base-case project-deferral scenarios were analyzed under both P0 and P1 conditions, including one project from APS and two from SRP, to assess the impact of such deferrals on system performance. Each of the deferral scenarios involved planned projects at 230 kV. The two SRP BES projects were selected because they're driven by requests from third parties for service to new customer load(s) and SRP has no control over the timing of these new load additions. The APS project was selected because even though it has a specific proposed in-service date it is not currently under construction, thus the completion date is uncertain.[52]

All Arizona transmission system facilities with nominal voltages of 115 kV or greater were monitored for compliance with steady-state thermal loading and voltage criteria for all contingencies tested.[53]

The Ten-Year Snapshot study reached the following major conclusions:

- Arizona's 2027 transmission plan is robust and supports the statewide load forecast.

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[50] 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.
[51] Load, generation and loss data for the 2027 case was updated pursuant to a 7-30-18 email from SRP Planning.
[52] Refers to APS's Orchard Project status per APS's comments on draft BTA report filed on 9-7-18
[53] Stability analysis was not run because it is not required by the Commission for the Ten-Year Snapshot Study.

- No steady-state BES violations were identified with all lines in service in either the base case or deferral scenarios.

- Single contingency (P1) analysis showed no voltage violations occurring in the BES, other than high voltages on several busses that can be mitigated by adjusting voltage schedules of nearby generators. The 2027 Heavy-summer base case also included a single P1 event that resulted in a loading of 100.7 percent of contingency (emergency) rating of the Liberty – Rudd 230 kV line in one of the delayed expansion project scenarios. However, the report concludes that this potential problem will be eliminated by an upgrade of the line planned for 2019.

- No reliability issues were found with the delay of any one of the three deferral projects beyond 2027.

Staff and ESTA conclude the Ten-Year Snapshot study documents reliable performance of Arizona's planned statewide transmission system in 2027 for a comprehensive set of Pl contingencies, in both the base-case expansion scenario and in each of the three selected transmission project-deferral scenarios. Finally, Staff and ESTA have concluded that the Ten-Year Snapshot monitors transmission elements down to and including 115 kV as required by the Eighth BTA.

Extreme Contingency Study Work

3.3.4 Arizona Commission-ordered extreme contingencies

In the Tenth BTA the Commission directed the parties to continue addressing and documenting selected extreme contingency outages for key BES transmission corridors that deliver power from Arizona's major generation hubs, as well as extreme outage events at selected major transmission stations, and identify any associated risks or consequences (taking into account planned infrastructure improvements that may provide mitigation).[54] Studies have been filed in the Tenth BTA in response to this Commission requirement. Two extreme contingency studies were performed: one by APS and the other by TEP. Each was coordinated through the SWAT-AZ subcommittee. Both the APS and TEP analyses were performed using 2019 and 2027 summer peak load models, and each included the filed Ten-Year Plan projects at the time the study was made. This analysis generally corresponds to an extreme contingency, loss of a corridor, and then a P0 through P1 event, excluding an assessment of transient stability performance.

EHV transmission line corridors outages chosen for study were based upon the corridors with the highest exposure to extreme events such as forest fires. APS performed studies for corridor outages along four major transmission paths bringing remote generation into the Phoenix

[54] Decision No. 67457

metro region. In APS's prior study done for the Ninth BTA, loss of all 500/230kV transformer banks at one BES substation was also examined, but due to the recent addition of fire walls between the transformer banks at that station this severe contingency was deleted in the Tenth BTA. However, the TEP extreme contingency study examined both a major corridor outage involving several BES lines as well as transmission station outages involving multiple BES transformers.[55] In its extreme contingency scenarios, APS also modelled operational adjustments following each initial common corridor outage event and then ran a comprehensive set of subsequent P1 outage events (on top of the initial corridor outage) to examine any associated risks and consequences.

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 generation redispatch and/or the operation of BES switchgear at specific locations to alleviate overloads for both the 2019 and 2027 system conditions. For extreme contingencies that require generation redispatch, one of three methods may be applied: 1. generation redispatch by an automatic remedial action scheme, 2. Grid-operator-directed redispatch based on established procedures for specific contingency conditions, or 3. grid operator response to real-time contingency analysis indicating a reliability need for generation redispatch. Load shedding was not required for any of the extreme contingencies studied in either 2019 or 2027.[56]

TEP's extreme contingency analysis was studied for both the 2019 and 2027 heavy summer load conditions and included an analysis of a single transmission corridor with high fire exposure as well as two substations susceptible to multiple transformer outages.[57] The extreme-contingency study resulted in power flow "no-solve" results for two specific contingency events in 2019 and one specific contingency event in 2027.[58] Specifically, the transmission corridor outage and one of the substation outages exhibited potential no-solve issues in 2019, while only one of the substation outages exhibited potential no-solve issue in 2027. TEP advised that the cause of these specific power flow no-solve results is a shortage of local load-area dynamic reactive power to support the local voltages that would occur if one of these contingency events occurred. However, the extreme contingency analysis results also show that all of the 2019 and 2027 no-solve scenarios would be mitigated by the addition of the Southline Transmission Project which is currently expected to go into service in the 2020 timeframe.[59] Therefore, whatever risk there may be in 2019 for these no-solve events should be resolved within the next two years. In the meantime,

[55] The details of the extreme contingencies performed by APS and TEP are confidential energy infrastructure information and therefore removed from this report.
[56] NERC transmission planning standard TPL-001-4 allows non-consequential (i.e., controlled) load shedding to take place for a simultaneous outage of adjacent transmission circuits on a common structure.
[57] TEP already includes loss of any two lines on a common corridor (including those that fall within the NERC TPL-001-4 level extreme contingency category) as part of its baseline contingency set in TEP's ten-year expansion planning studies.
[58] A non-solving power flow case means that computer model was not able to find a solution to the equations used in the model. This usually indicates either a basic model-data problem or some sort of a voltage problem.
[59] TEP did not model the SunZia Southwest line in its Extreme Contingency study and does not believe it would impact its study findings.

TEP stated that its exposure to the one substation no-solve scenario is being managed through physical security hardening measures pursuant to a NERC CIP-014 vulnerability assessment. And, the one transmission corridor no-solve scenario exposure is being managed by operational measures to implement rotating load shedding for overland fire conditions that might require tripping of all lines on the corridor. TEP also intends to continue to monitor the exposure to and impacts on the system due of these outages and additional mitigation options will be evaluated in future internal studies if needed.

It should be noted that the set of 'extreme contingencies' analyzed in the Commission ordered study were developed over successive BTA's based on certain planning risks within the Arizona transmission system independent of NERC's definition of extreme events. While some overlap exists between the ACC and NERC extreme event sets, they are not intended to match. Staff and ESTA found the Extreme Contingency Analysis studies satisfy the requirements of Commission Decision No. 67457.

3.3.5 NERC Extreme Events

Circa 2011, NERC made significant revisions to the NERC transmission standards, especially "Table 1" of TPL-001 through TPL-004. The previous versions of Table 1 described contingencies in categories 'A' through 'D' describing contingencies and their acceptable performance. Category D was classified as 'extreme'. The new version of the standards consolidated TPL-001 through TPL-004 into a new TPL-001-4 that included a revised Table 1.

The most significant change was to clarify and expand the various contingencies that must be evaluated. The new standards fall into two major groups, those that must be planned for and extreme events. The old categories were changed from A through D into a set of events defined as 'P0' to 'P7' that clarified and expanded the standards. The new 'P' standards describe events that utilities must plan for in their expansion planning studies. The NERC Table 1 also clarifies and expands the extreme events that utilities must assess. The standards state:

> *"Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2* [Studies shall be performed to assess the impact of the extreme events]. *The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted."* NERC Standard TPL001-4, requirement 3.5, 3 July 2018.

Some examples of these extreme events include:

- Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.

- Local area events affecting the Transmission System such as:

  - Loss of a tower line with three or more circuits.

  - Loss of all Transmission lines on a common right-of-way.

  - Loss of a switching station or substation (loss of one voltage level plus transformers).

  - Loss of all generating units at a generating station.

  - Loss of a large Load or major load center.

These extreme events are more extensive than, and supplement, those required by the Arizona Commission. The Arizona utilities comply with the NERC Standards.

3.3.6 Distributed Generation and Energy Efficiency

In the Eighth BTA, the Commission ordered jurisdictional utilities to study the effects of distributed generation and renewable efficiency programs on future transmission needs in their Ten-Year Plan filings.[60] 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.*

In its Tenth BTA filing on DG and EE impacts, APS used the 2022 heavy-summer base-case from its 2018-2027 Ten-Year Plan that was updated in coordination with SWAT for use in the study. APS reported that the combined total DG and EE impact on its 2022 system-peak forecast is 455 MW comprised of 86 percent EE and 14 percent DG (as compared to 79 percent

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

EE and 21 percent DG in its Ninth BTA filing).[61] In addition to the 2022 base case with DG/EE impacts modeled, a second case was created with the 455 MW of DG/EE removed and other generation within Arizona redispatched to offset this difference. The EE impacts were forecasted by assuming levels associated with APS's 2017 Integrated Resource Plan ("IRP"). DG was forecast using the average monthly volume of installations on the APS system in 2017 and projected forward to the study year. APS assumed 76 percent of both the DG capacity and the EE capacity were located in the metro Phoenix load area where they are most prevalent, and the reminder located outside the metro area. These forecasts were incorporated into the 2022 heavy-summer case and system performance was examined in both scenarios (with and without DG/EE) for both NERC P0 and P1 conditions. All internal APS bulk power single-contingencies were studied as well as external BES contingencies within Arizona that were expected to produce significant system impacts. The results show that with the projected 2022 DG and EE levels no APS BES project advancements or new projects would be required to reliably meet the increased load.[62] The report adds that the study "only addressed APS's BES and there may be some impacts at the sub-transmission level due to variations in timing and quantity of implemented DG and EE."

SRP submitted a filing on its DG and EE impacts based on analysis using a 2022 summer peak model derived from WECC's 2022 HS2 (high summer load) base case. The analysis included base-case conditions and all BES single-contingencies within Arizona. SRP's DG and EE forecasting methodology included an assessment of historical DG/EE impacts on system energy usage to determine the effect of DG/EE on future energy and demand forecasts. The cases reflected system peak-load conditions with and without DG/EE. The 2022 load forecast included a peak load of 8,697 MW (excluding the impact of 744 MW of DG/EE) with a resulting net peak load of 7,953 MW (including the impact of DG/EE). Both scenarios were modelled. In the no-DG/EE scenario the missing generation was made up from other SRP system generation mostly located in northern Arizona. For both NERC P0 and P1 conditions, SRP's power flow analysis found no overloads or voltage violations. The report concludes that SRP's planned 2022 transmission system meets all of SRP's internal criteria and satisfies applicable WECC and NERC criteria regardless of the presence or absence of forecasted EE and DG.

TEP and UNSE's DG and EE impact analysis was performed using a 2022 study year model and included DG and EE load forecasts as of March 2017. For 2022 summer peak, TEP and UNSE forecasts a 64 MW combined contribution from DG and EE.[63] A power flow analysis was performed with and without the DG and EE loads to identify thermal overloads under P0 and P1 conditions. Contingencies included each BES element within the TEP and UNSE system plus each BES tie from the system to neighboring systems. Analysis was done in compliance with

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[61] This increment was calculated as the difference between the pre-2017 level of EE / DG and the 2021 level.
[62] "APS Technical Study Effects of Distributed Generation and Energy Efficiency on Future Transmission Need", January 2018, p4.
[63] For study purposes TEP adds an additional 5 percent to load pocket demand as a 'stability margin". After this adjustment, TEP modeled 3178.5 MW of system load in its 2021 case with DG / EE and 3055.5 MW of load in its case without DG / EE.

NERC Reliability Standards and WECC System Performance Criteria.[64] The analysis concluded that no additional transmission projects or system needs were identified for 2022.

Staff and ESTA conclude that the fifth-year technical studies on the impacts of DG and EE by APS, SRP and TEP, were properly conducted and reported by the Arizona Utilities. Although each utility used slightly different criteria for selecting their respective sets of P1 events for use in the DG/EE analysis, Staff and ESTA conclude that the BES contingencies used are sufficiently robust to flag any significant DG/EE impacts on the individual utility transmission system expansion plans. 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 2018 Summer Energy Preparedness

The 2018 Summer Energy Preparedness meeting occurred on April 24, 2018, at the ACC Phoenix offices. The 2018 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 2018 Summer Energy Preparedness meeting included presentations and comments by the following electric utilities: APS, SRP, TEP, UNSE, and AZG&T. APS, SRP, TEP/UNSE, and the AZG&T each indicated preparedness for the 2018 summer peak demand. This preparedness included a declaration of adequate generation and reserves and sufficient transmission capacity to withstand normal 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 attended the Summer Preparedness open meeting. APS indicated it is well prepared for the up-coming 2018 summer demand. In its presentation to the Commission, APS provided an update on the completion of the Sun Valley – Morgan 500 kV Line, which effectively completed a high voltage loop around the Phoenix load pocket, providing more robust system. APS identified several reliability activities including line patrols and tower inspections, transmission peak-load studies, operations preparation and response to elevated fire conditions, vegetation management, and external and internal emergency preparedness and response drills. It also stated it has adequate generation resources, fuel supplies, and transmission capacity in place to meet customer demand for the summer.

SRP stated that peak demand is forecasted to be higher than last year's actual peak and adequate resources have been secured to meet anticipated demand. In its presentation to the Commission, SRP provided detail regarding purchased power, stating that regional market conditions suggest that there will be sufficient capacity to meet the demand and that a purchased-power portfolio is in place to meet demand. In addition, SRP stated it has adequate fuel to meet

[64] At the time of the study TEP's stability margin was based on NERC Reliability Standard TPL-001-WECC-CRT-2.1 system performance regional criteria, which has since been superseded by TPL-001-WECC-CRT-3.

demand and discussed the acquisition of Blocks 1 & 2 (550 MW each) at Gila River Power Station and the Pinal Central Energy Center (20 MW of solar PV with 10 MW of battery storage expected to be operational in May 2018). Stating that transmission and distribution systems are prepared for summer operations, SRP also discussed transmission improvements made, system preparations, and an overview of outage response and reporting mechanisms in place.

TEP presented on behalf of both TEP and UNSE at the Workshop. TEP stated it has made 237 MW of transformer capacity replacements, 270 MW of transmission line capacity upgrades, and also communication/automation upgrades. In its presentation to the Commission, TEP discussed on-hand emergency equipment, which includes emergency towers, mobile transformers, and spare substation transformers. TEP also discussed a recent outage in Nogales and provided information on its response and corrective actions, which included the use of a mobile transformer. In addition, information was provided regarding emergency preparation activities such as; black start drills, calls with reliability Coordinator and Balancing Authority operators, and storm preparation meetings. TEP stated it has a real-time outage map ready for customer notification and discussed automated customer notifications. The presentation was summarized noting that sufficient generation and transmission resources are available to meet both TEP's and UNSE's load.

AEPCO, also referred to as AZG&T, stated it has secured sufficient resources to meet the coincident peak demand for its all requirements members and its allocated capacity obligation to each of its partial requirements members. During its presentation, AEPCO also provided a resource portfolio update, stating that most of the peak demand will be served by AEPCO resources while the remaining demand will be met with market purchases. In addition, AEPCO stated it maintains an annually updated plan in case of the loss of its single largest generator under peak load conditions. AEPCO continues membership in the Southwest Reserve Sharing Group and also maintains transmission capacity to cover the largest unit outage and has additional arrangements with transmission counterparties for emergency market access for extended outages. In addition, AEPCO provided a fuel supply update and summary, generation maintenance & testing activities, and transmission & distribution maintenance activities, and also provided a summary of recent transmission system upgrades and discussed operational preparedness for emergency situations. AEPCO reported sufficient resources, fuel supply and transmission, and that it is operationally well prepared to meet the forecasted demand and energy needs.

Staff concludes that the 2018 level of summer preparedness of the utilities in Arizona, as presented in the April 24, 2018 workshop, demonstrated 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 2018.

3.5 Physical Security & Cybersecurity

FERC directed NERC to submit for approval reliability standards that will require transmission owners and operators to act or demonstrate that they have acted 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[65]; 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[66].

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

There are ten NERC CIP standards related to cyber security. FERC Order No. 822[67], issued January 21, 2016, approved seven CIP Reliability Standards: CIP-003-6 (Security Management Controls), CIP-004-6 (Personnel and Training), CIP-006-6 (Physical Security of BES Cyber Systems), CIP-007-6 (Systems Security Management), CIP-009-6 (Recovery Plans for BES Cyber Systems), CIP-010-2 (Configuration Change Management and Vulnerability Assessments), and CIP-011-2 (Information Protection) which supersede previous versions of each respective standard. These reliability standards were designed to mitigate the cybersecurity risks to bulk

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

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

[67] https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order%20Approving%20Revised%20CIP%20Reliability%20Standards.pdf

electric system facilities, systems, and equipment, which, if destroyed, degraded, or otherwise rendered unavailable as a result of a cybersecurity incident, would affect the reliable operation of the Bulk-Power System.

Accordingly, Staff requested information from the Arizona utilities related to actions taken by the utilities to ensure transmission system reliability in the event of a cyber-attack, the details of which are considered confidential. Based on this information, Staff concludes the Arizona utilities are taking actions to address cybersecurity 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 intrastate and 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 capability. Several market access projects and merchant transmission projects are discussed in this BTA. This section of the BTA report highlights the status of twenty-one 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 Tenth 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.[68] 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. A Ten-Year Plan was received and this project was presented and discussed at Workshop I. The Project has been previously reviewed by the ACC as part of its 2014 8th and 2016 9th Biennial Transmission Assessments. 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.

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

The Ten West Link project was 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.[69] 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 of Governors approved the Delaney – Colorado River 500 kV transmission line project at the July 16, 2014 meeting.[70] 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.

DCR Transmission intends on closely coordinating with siting authorities in both Arizona and California as the Project progresses. The Project will be regularly reviewed and discussed at regional planning forums such as West Connect, SWAT, and SWAT's various subcommittees. 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 CECwith the ACC after draft EIS becomes available. BLM is on schedule to issue the Draft EIS for Ten West Link in summer 2018 and DCR Transmission anticipates filing its CEC Application thereafter in the fall of 2018.

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 520 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 134 miles on state trust land, 50 miles on BLM land, and 16 miles on private land. SunZia is anticipated to deliver primarily renewable energy from sources yet to be determined to markets in Arizona and California. The first phase of commercial operation is expected to commence in 2020.

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[69] http://www.caiso.com/Documents/Board-Approved2013-2014TransmissionPlan.pdf
[70] http://www.caiso.com/Documents/DecisionDelaney-ColoradoRiverTransmissionProject-Motion-July2014.pdf

Milestones achieved over the course of this project include the Record of Decision ("ROD") issued by the Bureau of Land Management ("BLM") on January 23, 2015. On September 2, 2015 SunZia applied for a CEC from the ACC. 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[71]. SunZia now has federal and Arizona state approval. In March 2016, contracts were executed with the Department of Defense and Department of Army to mitigate all impacts. In March 2018, SunZia applied for location control permit and ROW width approval from the New Mexico Regulation Commission and expect the permits by September 2018. 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. SunZia continues to obtain agreements with private landowners in Arizona whose property is needed for construction operation and maintenance of the Project. During 2018, SunZia will continue to coordinate with the Arizona State Land Department as the agency processes SunZia's right-of-way application.

4.1.3 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 Cochise County, 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 Tenth 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 December 2020.[72] The proposed alignment of the transmission line was also revised in

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

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

2008 to comply with the requirements of the Arizona State Land Department.[73] 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 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, 2019, with commercial operation of the initial 500 MW power block occurring by December 2020. SWPG continues to participate in regional planning forums, Southwest Area Transmission Group and WestConnect, and is a Class 3 member in good standing in the Western Electricity Coordinating Council.

4.1.4 Mohave County Wind Farm Gen-Tie 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 at 345 kV. The gen-tie Project consists of approximately six miles of 345 kV generation inter-tie line and two new 34.5 kV to 345 kV step up substations, located in the White Hills of Mohave County, approximately 40 miles northwest of Kingman, Arizona. A Ten-Year Plan was received for this gen-tie 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 will connect a new wind power facility ("Wind Plant") to a new switch yard that will connect to the existing 345 kV Liberty-Mead transmission line. The Wind Plant'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. A Record of Decision for the project was signed on 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; and in October 2018 the CEC was extended by the Commission to November 2024. An interconnection request was filed with WAPA in March 2007 and WAPA finalized the facility study in November 2017. Appropriate feasibility and system impact studies will be filed in the Ten-Year Plan docket once the interconnection point has been finalized.

[73] 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.

4.1.5 Gila Bend Power Partners

Gila Bend Power Partners ("GBPP") 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 and 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. The various elements of the Project have been approved through three CECs, namely Case 106, Case 109 and Case 119 have been granted for the project and are approved through February 2025. The project is currently on hold due to unfavorable market conditions. However, Gila Bend Power Partners has filed Ten-Year Plans in the Tenth BTA. The Ten year filing also included a System Impact Study report which demonstrates the flow and stability at the Watermelon switchyard point of interconnection for the GBPP line.

4.1.6 SolarReserve Project

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 Tenth BTA. Current forecasts are for a commercial operation date by the end of 2021.

4.1.7 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 Tenth 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 an approximately 370-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 249-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 121 miles of existing WAPA 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. The ACC approved a CEC for the Project on February 24, 2017 in Decision No. 75978, and Southline is progressing with its Interconnection activities in Arizona. 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 3 report has been issued. Southline currently anticipates construction to begin in 2018 with operations phased into service starting in 2020. When completed, the Southline Project will add 1,000 MW of bidirectional transfer capability to the grid. Southline continues to actively participate in Arizona and regional transmission planning groups including WestConnect SWAT, SWAT-AZ, Planning Management Committee.

4.1.8 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 been filed with the Commission for this project by NGIV2, LLC a subsidiary of ITC Grid Developments.; 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 Tenth BTA. The ten-year filing included a report (North Gila - Imperial Valley #2 WECC Comprehensive Progress Report) to demonstrate power flow and transient stability analysis including the NG-IV#2 transmission line.

Development Team is comprised of ITC Grid Development, LLC and Southwest Transmission Partners, LLC. An overview map showing the general routing and interconnection points of this project are included within Exhibit 1.

The line would be approximately 90 miles in length, and parallel the Southwest Power Link ("SWPL") 500 kV line for much of its length and approximately 7 miles located in Arizona. The portion of the line in Arizona would parallel existing/approved lines. 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 is currently in Phase 2 of its WECC Path Rating Study projected to wrap up in Q1 2019. The NG-IV#2 Project has been actively involved with SWAT, WestConnect and CAISO transmission planning forums. The EIS/EIR process will be initiated in Q3 2018. The anticipated date of operation is the fourth quarter of 2022.

4.1.9 NextEra Energy Resources

The Pinal Central Energy Center Generation Tie-In Line project includes the construction and operation of an approximately 0.40-mile 230 kV generation transmission tie-in line ("Gen-Tie") and associated substation facilities. The proposed Gen-Tie Project is intended to deliver power from the Pinal Central Energy Center ("PCEC"), a proposed innovative clean energy facility that will combine 20 MW of solar photovoltaic generating capacity with a 10 MW/40 MWh advanced battery storage system to the existing Pinal Central 230/500kV Substation. A Ten-Year Plan has been filed with the Commission for this project by NextEra Energy Resources. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for the Tenth BTA.

The Gen-Tie Project will be located in Pinal County, Arizona. On April 3, 2014, PCEC submitted to SRP, the managing agent for the Pinal Central Substation, an application for interconnection from SRP to the Pinal Central Energy Center. SRP prepared a generator interconnection study to study the impact to the system and identify any needed reinforcements to mitigate the impacts. The study concluded that the Gen-Tie Project will have no significant impact on the existing Arizona transmission system. The Project was granted a CEC by the ACC on June 22, 2017 in Decision No. 76160. The Project is expected to achieve commercial operation around May 31, 2018.

4.1.10 Wilmot Project

Wilmot Properties LLC., through its affiliates, is planning the construction of natural gas-fired 420-450 MW electric generation peaking facility (the "Proposed Facility") and/or a 42 MW alternating current solar facility with 60 MW/360MWh of battery storage (the "Solar Plus Battery Facility"). A Ten-Year Plan has been filed with the Commission for this project by Crockett Law Group on behalf of Wilmot Properties. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for the Tenth BTA.

The Project will be located in an unincorporated portion of Pinal County, Arizona. Wilmot may build both the gas- fired 420-450 MW power plant and the Solar Plus Utility-Scale Battery

Facility. Alternatively, Wilmot may build only one facility or the other. The Project facility(s) will utilize a 230 kV gen-tie line of approximately 4.5 miles in length to interconnect with the existing 230 kV Santa Rosa substation. Wilmot intends to apply for a CEC with the ACC and is currently working to obtain right-of-way and determine the precise location and alignment of the gen-tie. The Natural Gas aspect of the Project is currently contemplated as a 2-unit F-class peaking simple cycle combustion turbine plant capable of generating approximately 420-450 megawatts of electricity on a hot summer day. Wilmot has submitted an interconnection request and is awaiting preliminary power flow and stability results which should be tentatively available in the first quarter of 2018. The currently estimated in-service date for the Proposed Facility and the Gen Tie Line is April 2022.

4.1.11 Big Chino Valley Pumped Storage Project

The Big Chino Valley Pumped Storage Project consists of three potential 500 kV transmission corridors that are being considered for interconnecting the 2,000 MW adjustable speed hydroelectric generation, otherwise known as “pumped storage hydro”. The project is being developed by Big Chino Valley Pumped Storage LLC ("Big Chino Valley") a subsidiary of ITC Holdings Corp. ("ITC"), which is majority owned by Fortis Inc. and minority owned by GIC Private Limited. A Ten-Year Plan has been filed with the Commission for this project by Big Chino Valley Pumped Storage LLC. This project was considered for the adequacy assessment and included in the Ten-Year Plan statistics compiled for the Tenth BTA.

This project was originally submitted in a ten-year transmission plan filing by Longview Energy Exchange, LLC in January 2014. Big Chino Valley purchased the rights to the Big Chino Valley Pumped Storage Project through an acquisition process in 2017. Feasibility, market assessment, and WECC firm resource studies were completed for the project by the previous owner. A new analysis of the project is underway by Big Chino Valley with results expected in 2018. A preliminary permit for the Big Chino Valley Project was approved by FERC on December 28, 2017. As part of the planning process, power flow analysis, short circuit and stability analysis are underway to determine the impacts to the network and determine any required upgrades to the network to maintain safe and reliable operation of the grid.

Big Chino Valley is currently in the planning and permitting process. It intends to initiate Phase 1 of the WECC path rating process in Q3 2018 and conclude the FERC license process by 2021, with construction to begin in 2022. Estimated in-service dates will vary depending upon changes in regulatory requirements, underlying assumptions, other utilities' plans and general economic conditions.

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 ESTA on the likelihood of a project being developed.

Staff recommends that entities with ongoing projects who have previously filed a Ten-Year Plan should continue to do so annually, as required by A.R.S. § 40-360, until the successful completion of their project.

4.2.1 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 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 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. Approximately 300 miles of the total project would be in northern Arizona. Clean Line filed an application for right-of-way across Federal lands[74] 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[75]. 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. According to the Project website, construction is currently planned to begin in 2020.

[74] Application Form SF-299, "Application for Transportation and Utility Systems and Facilities on Federal Lands".
[75] 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

4.2.2 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 not received 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 is included within Exhibit 1.

The gen-tie line will be a 3.5-mile 500kV AC 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 a previous Ten-Year Plan filing. The project was granted a CEC by the ACC on November 21, 2017 in Decision No. 75816. According to the Project website, it is currently in the permitting phase and a tentative in-service date is not mentioned.

4.2.3 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 not received 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 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. According to the Project website, it is currently in the permitting phase and a tentative in-service date is not mentioned. No significant progress was observed in the Project since conclusion of the previous BTA process.

4.2.4 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 not received 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. The project has received the requisite Maricopa County Comprehensive Plan Amendment and Air Permit. 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 2019.

4.2.5 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 1,500 MW 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[76].

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, and the final EIS was published on May 1,

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

2015. The Record of Decision ("ROD") from BLM was issued in December 2016 and the ROD from WAPA was issued in January 2017. The project has made an Economic Planning Study request with the CAISO to be included with the ISO's 50 percent Renewable Energy Goals for 2030 Special Study. In November 2017, WECC granted an Accepted Rating for the first stage of the TransWest Express Transmission Project, further advancing the 600 kV project in the regional planning and rating process. PacifiCorp is performing studies for the northern interconnection and TransWest is performing studies for southern interconnections. The project is estimated to be constructed in during the period of 2020-2022.

4.2.6 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 nor was it 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. According to a press release in April 2018, EnviroMission Limited has executed a financial advisory agreement with Atkins Acuity, a member of the SNC-Lavalin Group, to raise the development and project capital necessary to commercialize the first EnviroMission Solar Tower power station.

4.2.7 Longview Transmission Project

In 2017, the rights to this project were acquired by Big Chino Valley Pumped Storage LLC a subsidiary of ITC Holdings Corp, who is currently developing this project. This project is discussed in Section 4.1.11 of this report.

4.2.8 Harcuvar Transmission Project

The Harcuvar Transmission Project ("HTP") is sponsored by the CAWCD. 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. No significant progress was observed in the Project since conclusion of the previous BTA process. The last reported in-service date is in the spring of 2020.

4.2.9 High Plains Express

The High Plains Express 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. 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 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, and no significant progress was observed since the conclusion of the previous BTA process. The most recent anticipated in-service date is 2030.

5 Regional and National Transmission Issues

Significant increases in distributed generation and energy efficiency penetration, and the integration of large renewable projects combined with the shuttering of conventional generation sources are challenging traditional transmission system planning and operation procedures. Arizona utilities may need to invest in advanced technology and improved communication and automation to enable the necessary flexibility and responsiveness in transmission and distribution systems to accommodate the variability of renewable wind and solar resources. Arizona utilities must also make generation resource decisions that balance increased wind and solar generation penetration with the need for adequate system inertia and voltage support. Natural gas generation resources are becoming the energy source of choice to provide the needed quick-starting, flexible generation. 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 incorporate the growth of renewable generation, several Arizona utilities are currently evaluating their participation in the CAISO Energy Imbalance Market as an option to add increased resource flexibility through market-based solutions.

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

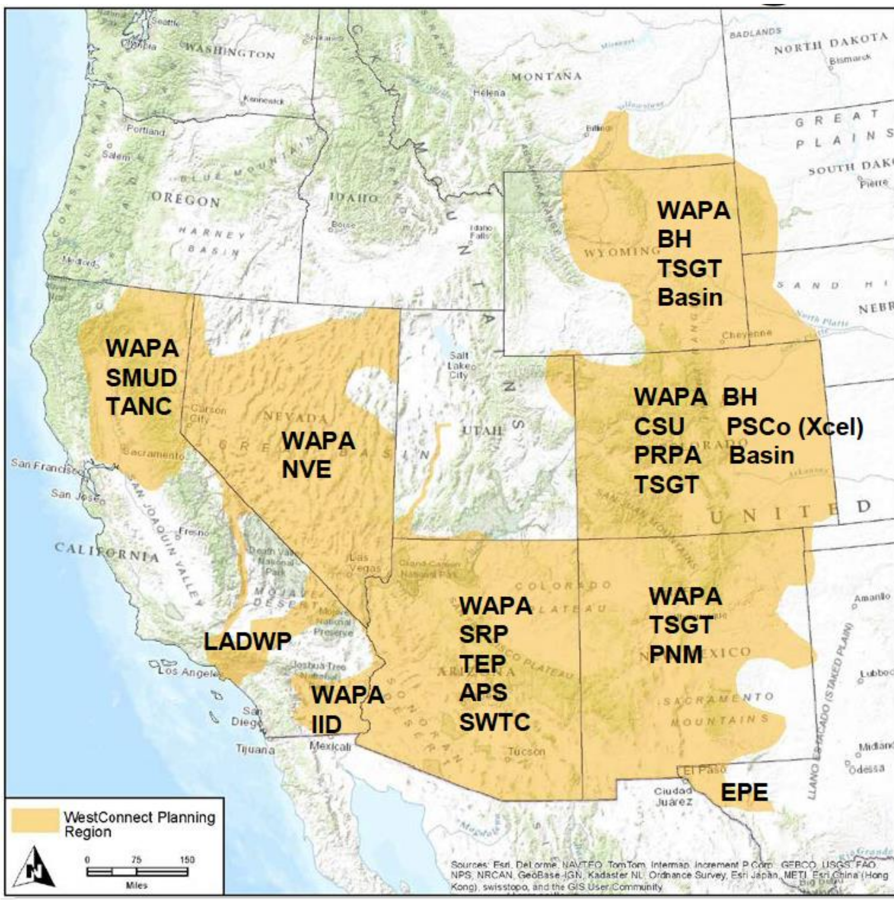
5.1 Regional Transmission Planning – WestConnect

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 regarding regional transmission planning efforts.[77] 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 as shown in Figure 2.[78]

[77] The WestConnect Project Agreement for Subregional Transmission Planning, 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.
[78] Regional planning figure from WestConnect's presentation at Workshop I of the Tenth BTA More information on the WestConnect membership can be found at http://www.westconnect.com/aboutsteeringcomm.php.

FIGURE 2: WESTCONNECT PLANNING REGION



Initiatives that have been undertaken or are under way by the WestConnect Steering and Planning Management Committees include:[79]

- FERC Order No. 890 OATT transmission planning through the WestConnect Project Agreement for Subregional Transmission Planning ("STP") effective May 23, 2007;[80]

- FERC Order No. 1000 implementation;

- Flow-based market investigations;

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[79] WestConnect Initiatives - http://www.westconnect.com/initiatives.php
[80] WestConnect Project Agreement for STP - http://www.westconnect.com/filestorage/wcregionalplanningprojectagmtexeccopy052307amendedobjproc011409.pdf

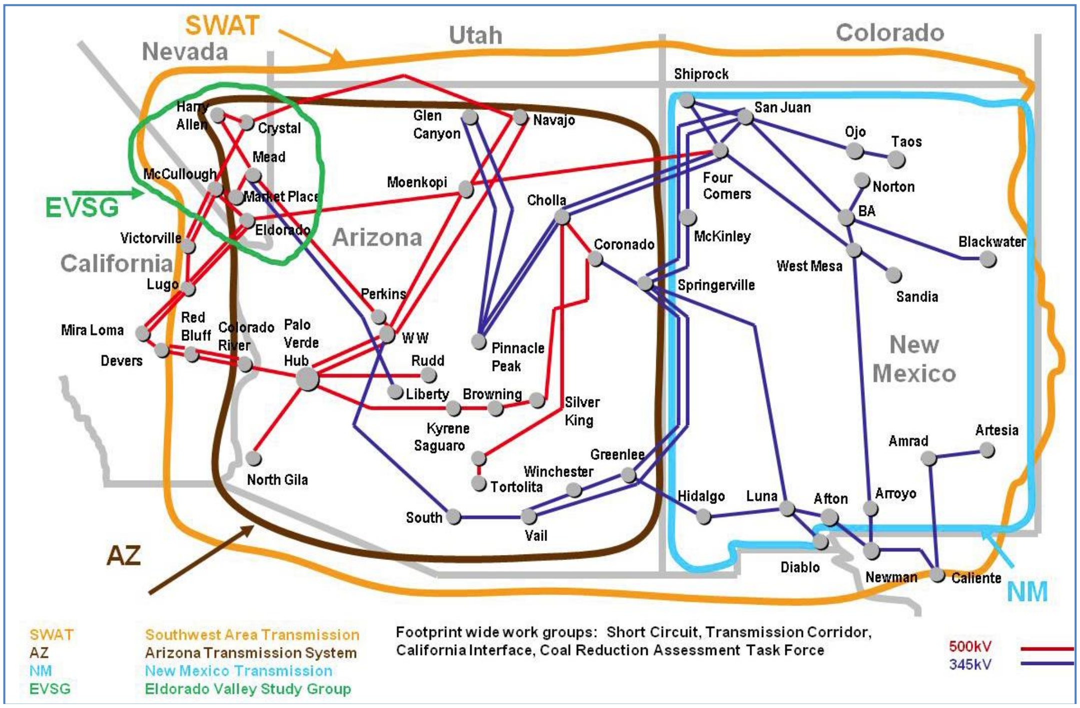
- Large generator interconnection process refinements;
- Streamlining the large generator interconnection process;
- Non-pancaked hourly non-firm transmission service;
- An energy imbalance service investigation;
- TTC/available transfer capability group; and
- Virtual control area investigation.

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").

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 discussing planning, coordinating, and implementing 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 3.

FIGURE 3: SWAT AND SUBCOMMITTEES FOOTPRINTS



Since the 2014 SWAT has discussed FERC Order No. 1000 implementation, hosted educational webinars and maintained maps and project listings. SWAT also provided a forum for discussing both new and existing transmission projects, coordinated on seams issues as defined in Section 5.6 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, with more information on each available on the WestConnect website.[81]

5.1.1.1 Arizona Subcommittee

SWAT-AZ was formed in February 2013 by the merger of the CATS, Southeast Arizona Transmission Study, and Colorado River Transmission subcommittees. The objective of SWAT-AZ is to study the high voltage 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 with the ACC.

[81] See http://regplanning.westconnect.com/swat_az_transmission.htm.

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 Ten-Year Snapshot Study (n-l-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 owned/operated transmission systems in the Desert Southwest. The Short-Circuit Working Group has merged the SRP, WAPA, and APS models into one ASPEN case.[82] The group has reached out to TEP, PNM, and IID to begin standardizing the modeling and naming conventions to merge those models.

5.1.1.3 El Dorado Valley Study Group

The El Dorado Valley Study Group ("EVSG") serves as a forum for communication and coordination among 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-

[82] ASPEN is a short circuit software package used in system analysis.

dissolved California Transmission Planning Group, CAISO, and California Public Utility Commission. 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.

5.1.1.5 Transmission Corridor Work Group

The Transmission Corridor Work Group ("TCWG") interacts with State, Federal, and Tribal entities facilitating 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 maintaining general information for outreach and educational activities. 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.

5.2 FERC Order 1000

On July 21, 2011, FERC issued Order 1000, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities".[83] Order 1000 amended the transmission planning and cost allocation requirements established in FERC Order 890 to ensure Commission-jurisdictional services are provided at just and reasonable rates and without unduly discriminatory or preferential treatment. Order 1000 established criteria for transmission 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 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 1000.[84] WestConnect since has

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[83] *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 ZE-6.pdf
[84] Order on Compliance Filings, 142 FERC ¶61,206 (2013).

worked to align its planning and organizational operations with the principles and guidelines as outlined by Order 1000 and the March 22, 2013 Order on Compliance.

At Workshop No. 1 of the Tenth BTA, WestConnect presented the following regulatory update:

> "All tariff revisions related to the regional planning requirements of Order 1000 were fully accepted by FERC on January 21, 2016. On August 8, 2016 the 5th Circuit Court of Appeals vacated FERC's compliance orders related to mandates regarding the role of the non-jurisdictional utilities in cost allocation. On November 16, 2017 FERC upheld its previous compliance orders and provided further explanation as to why its mandates will ensure just and reasonable rates between public and non-public utility transmission providers in the WestConnect region. Numerous requests for review have been filed with FERC."

Under the Order 1000 planning process, the existing WestConnect planning efforts have 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 established a Planning Management Committee ("PMC") made up of one representative of each of the signatory parties.[85] Under the Order 1000 planning process proposed in the compliance filings, the PMC is tasked with ensuring that the WestConnect planning processes comply with Order 1000 and overseeing the development and approval of a regional transmission plan that includes application of cost allocation methodologies. The PMC is comprised of five 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' Open-Access Transmission Tariffs and in the Planning Participation Agreement.

5.2.1.1 2016-2017 Regional Transmission Plan

The 2016-17 regional transmission plan was the first full biennial Order 1000 regional planning process for WestConnect. On December 20, 2017 WestConnect approved it's 2016-17 Regional Transmission Plan. All Arizona utilities and many other stakeholders participated in this regional study process intended to comply with FERC Order 1000 requirements. With the participation of stakeholders, WestConnect took WECC 2026 seed cases and modified them to

[85] The WestConnect Planning Participation, effective January 1, 2015, was signed by 7 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.

serve as 2026 HS (Heavy Summer) and 2026 LS (Light Spring) base cases. The study scope included three distinct tranches of analysis: 1. a Regional Reliability Assessment; 2. a Regional Economic Assessment; and 3. a Regional Public Policy Assessment. For each assessment a set of additional base cases and sensitivity cases was developed. Unlike the other two tranches which used power flow and transient-stability models, the Regional Economic Assessment used a production-costing model capable of estimating annual energy cost and grid congestion levels for the WestConnect region including Arizona.

The overarching goal of a regional planning process that is FERC Order 1000 compliant is to identify any additional regional transmission projects that may be needed in addition to those already proposed by utilities and other developers. WestConnect defines "regional projects" as projects that are required between two states or two sub-regions, as opposed to local or intrastate projects. When a need for such a regional project is identified, FERC Order 1000 requires that a bid process be conducted for sponsors who propose such projects. However, after studying the 2026 base cases, scenario cases and sensitivity cases covered in its 2016-17 regional study plan, WestConnect concluded that: "Based on the analysis performed for reliability, economic and public policy requirement-driven transmission needs, no regional transmission needs were identified in the 2016-17 cycle."[86] Targeted 2026 sensitivity cases in WestConnect's economic analysis identified a slight congestion exposure on APS's Lincoln Street-Country Club 230 kV line as a "local" (non-regional) issue. APS has an operational mitigation plan for this exposure and "is currently finalizing a plan to address this thermal overload issue for the long term."[87]

In addition to the planning scenarios addressed by its 2016-17 planning cycle, WestConnect also included selected additional scenarios within its study scope for informational purposes only. Two of the informational scenarios included in the 2016-17 cycle addressed possible "futures" that might result under the Federal CPP. The results of this portion of the 2016-17 WestConnect report are addressed in Section 5.5.1, below.

5.2.1.2 2018-2019 Regional Planning Cycle

The 2018-2019 Regional Planning Cycle is currently underway. WestConnect published the Final Regional Study Plan for the 2018-2019 Planning Cycle on March 14, 2018.[88] The Study Plan identifies the scope and schedule of the study work that is to be performed during the planning cycle. However, the Study Plan does not explain the entire process, and the Business Practice Manual should be used as a reference for additional details.[89]

[86] WestConnect 2016-17 Regional Transmission Plan, Dec. 20, 2017, p 1.
[87]. APS response to Staff Data Request 2.2 dated May 8, 2018.
[88] WestConnect 2018-2019 Final Regional Study Plan.
https://doc.westconnect.com/Documents.aspx?NID=18068&dl=1
[89] WestConnect Regional Planning Process Business Practice Manual, February 17, 2016.
http://westconnect.com/filestorage/02_17_16_regional_planning_process_business_practice_manual.pdf

The Planning Management Committee approved two scenarios to be included in the 2018-2019 study plan, which include a Load Stress Study (Heavy Summer) and a CAISO Export Express Study. Currently, the regional planning models are being developed and scoping for the scenario studies has begun. WestConnect reported at the Tenth BTA Workshop No. 1 that it is currently in the model/scenario building phase of its next biennial regional planning process (2018-19). Per WestConnect's presentation at Workshop I, the following two scenarios are currently envisioned:

1. **Load Stress Study—**Reliability study based on 2028 Heavy Summer case where regional peak load is increased 10 percent and the load/gen imbalanced is filled with renewable capacity not dispatched in the Base Case, or incremental renewable capacity if no headroom is available. Details of dispatch are TBD. The analysis is designed to test robustness of the Base Transmission Plan against potential changes in load and incremental dispatch of renewable resources. WestConnect will consider performing a congestion/economic study if deemed useful.

2. **CAISO Export Stress Study**—Reliability study based on a regional model that will be adjusted based on CAISO export conditions observed in a regional production-cost model. Alternatively, WestConnect will seek guidance from CAISO on assumptions appropriate for export study. The analysis is designed to evaluate reliability of the regional system of power flows from the CAISO to WestConnect during CAISO overgeneration conditions.

In addition, the 2018-19 biennial study will include selected inter-regional transmission projects ("ITP's"). According to WestConnect's presentation the pending assessment of ITP's to be included "first depends on a need being identified in the current planning cycle. Needs assessment will be conducted in Q4 2018. If needs are identified, an ITP will need to be resubmitted during the project submittal window (approximately Q5)."

5.2.2 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; the meetings provide the entities with the opportunity to share and coordinate each region's current planning efforts.[90] WestConnect's input included base cases and assumptions used in planning studies, planning models, and in identifying regional needs.

[90] The most recent meeting was held in Folsom, California on February 22, 2018. https://www.columbiagrid.org/O1000Inter-overview.cfm

5.2.3 Relationship to the BTA Process

The WestConnect transmission planning process, with the enhanced FERC Order 1000 planning requirements, provides additional coverage of regional transmission planning activities not currently covered under the ACC BTA process. FERC Order 1000 requires regional and interregional agencies to work collaboratively to improve regional transmission planning processes and cost-allocation mechanisms. Where the ACC BTA emphasizes intrastate impacts of planned transmission projects, the FERC Order 1000 wider regional approach also helps 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"). On April 7, 2014, WAPA 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.[91]

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.

Three transmission projects, having passed the evaluation criteria, are currently being developed under the WAPA TIP program and have the potential to significantly impact Arizona. These projects are summarized below:

- The Southline Project, as discussed in section 4.1.7 of this report, is in the development phase. Western is participating in this project as current plans are to rebuild and upgrade approximately 130 miles of Western transmission lines between Apache and Saguaro Substations. The ACC approved a CEC on February 24, 2017 (Decision No. 75978). Construction is anticipated to begin in 2018 with

[91] FRN 79 FR 19065

operations phased into service starting in 2020. WAPA 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 WAPA participates in this project.

- The TransWest Express Project, as discussed in section 4.2.5, is currently in the development phase with an anticipated completion date of 2020-2022. 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. In November 2017, WECC granted an Accepted Rating for the first stage of the TransWest Express Transmission Project, further advancing the 600 kV project in the regional planning and rating process.

- The Centennial West Clean Line Project, as discussed in section 4.2.1, 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.

5.3.1 WECC Regional Transmission Expansion Planning

The Western Electricity Coordinating Council ("WECC") is a FERC approved regional reliability entity with authority delegated to it by NERC for compliance monitoring and enforcement of BES reliability standards in the Western Interconnection.[92] In addition, WECC provides an environment for developing regional Reliability Standards and coordinating the operating and planning activities of its members as set forth in the WECC Bylaws.[93]

5.3.2 WECC and the BTA Process

At the time of the Commission's Ninth BTA decision, it was anticipated that WECC would continue utilizing the then existing Transmission Expansion Planning Policy Committee ("TEPPC") to oversee its ten to twenty-year expansion-planning study process. However, the

[92] The Western Interconnection encompasses all of the states within the U.S. mountain and pacific time zones, the corresponding provinces in Canada and the state of Baja California Norte in Mexico. The BES encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected Bulk-Power System, and basically includes all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. For further details see the NERC document *Bulk Electric System Definition Reference Document Version 2*, April 2014.

[93] The WECC Bylaws and other governing documents at www.wecc.biz/Pages/GovernanceDocuments.aspx.

WECC Board subsequently performed a comprehensive review of its committee structures and responsibilities. As a result of this review, WECC reorganized the committee structure for interconnection-wide grid expansion planning by placing all related activities under a newly formed Reliability Assessment Committee ("RAC"). The RAC was created by the WECC Board of Directors on December 7, 2016. WECC describes the RAC role as follows:

> *"The Reliability Assessment Committee (RAC) provides overall guidance for WECC's reliability assessment activities, consistent with the business plan and budget approved by the WECC Board of Directors. The RAC's focus question is, 'What reliability risks might the Western Interconnection face in the next 20 years and do we have the data and tools required to make reliability assessments?' Its primary functions are to coordinate the activities of the RAC subcommittees to ensure that work completed in each subcommittee is consistent across functions and that study results and data be shared consistently across the Western Interconnection and to oversee development of the Anchor Data Set (ADS). The RAC works closely with WECC's Reliability Planning staff to coordinate work plans, prioritize analytical work, ensure stakeholder participation, and vetting and collaborate with federal, state/provincial, and regional planning organizations."*[94]

The RAS reports directly to WECC's Board of Directors. WECC's Reliability Planning manager recently stated that: "[the] transition from the previous TEPPC/TAS/SPSG structure to the new RAC and Subcommittee structure has been a significant change to the way we develop, complete and report on reliability assessments."[95] During calendar year 2017 RAC efforts focused on developing its membership and organization, plus initiating the transition for responsibility for products previously produced by the WECC Planning Coordination Committee ("PCC") and TEPPC.

In parallel with this transition process the TEPPC conducted its previously approved 2016-17 study plan focused on facilitating economic transmission planning in the Western Interconnection over the next ten to twenty-year period. Those results, as summarized below, are currently being reviewed by the new RAC. During the 2016-17 study program TEPPC continued its four main functions, including:

1. Develop and maintain a public database for production-cost and related analysis;

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94 https://www.wecc.biz/RAC/Pages/Default.aspx

95 Byron B. Woertz, Jr., Manager, WECC System Adequacy Planning to ACC Staff/Consultant, emailed dated 5-14-18.

2. Develop and implement the interconnection-wide expansion planning processes in coordination with the WECC Planning Coordination Committee, as well as other WECC committees, Regional Planning Groups, and other stakeholders;

3. Guide and improve the economic analysis and modeling of the generating resources and grid within 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.

Responsibility for finalizing and approving ten to twenty-year interconnection-wide transmission plans based on the 2016-17 study program, as described in the last bullet above, has now been assumed by the WECC RAC. Results of the TEPPC 2016-17 study program are discussed below.

5.3.2.1 2016-2017 TEPPC Study Plan

The 2016-17 TEPPC study plan covered both ten-year study cases and twenty-year study cases, including a 2034 Reference Case along with several scenario alternatives and special interest sensitivities. The 2016 study program analyzed the "most likely future" 2026 (ten-year) "reference case" along with sensitivities for changes in loads, hydro levels, natural gas price, and CO_2 price. The 2017 study program built on the 2016 work and analyzed selected 2026 transmission expansion cases (East-to-West, NE-to-SW and "Transmission Backbone") as well as the twenty-year (i.e., 2034) studies. TEPPC's ten-year regional transmission planning continued to utilize a nodal production-cost model to evaluate the performance of the Western Interconnection on an economic (e.g., production cost) basis.

Criteria for determining new transmission lines to incorporate in the Common Case Transmission Assumptions included determining 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, which reserved the right to exclude projects on an individual basis.[96]

[96] 2024 Common Case Transmission Assumptions. WECC Regional Planning Coordination Group. June 2, 2014.

Results from the 2016-17 TEPPC Study Program were presented via a webinar at Workshop II of the Tenth BTA proceeding by Byron Woertz, manager of WECC System Adequacy Planning. Key findings from the ten-year analysis were as follows:

- Across all cases studied the planned WECC grid appears to be adequate;
- Resources in all WECC sub-regions meet planning reserve margin level ("RML") criteria in the ten-year timeframe and expected generation retirements are not currently a major concern;
- The Western Interconnection appears to be able to function reliably with the projected levels of renewables;
- Energy storage improved use of wind in the WECC ten-year study cases

Key observations from the twenty-year analysis reported by WECC at the workshop were as follows:

- Additional resources will be needed above the 2026 common case resource portfolio in order to meet firm capacity requirements and seasonal variations in the twenty-year moderate-to-high renewable growth scenarios;
- Gas-fired resources will still be needed for reliability goals but may not be economically competitive based solely on energy production needs, inferring a potential need for market-based incentives;
- Wind is the most economical incremental renewable resource in the twenty-year timeframe based on energy production;
- West-wide the levels of coal-fired generation, water consumption and CO_2 production will be significantly reduced

In addition, based on the 2016-17 results consideration may be given in future WECC studies to refining valuation models in order to enable generation and transmission co-optimization, and identifying potential future reliability risks as well as study methodologies/analytical models for reliability assessment.

5.3.2.2 RAC Status and Study Plans

As a result of the WECC Board's decision in December 2016 to revamp the region's expansion planning committee structure, the following subcommittees now report directly to the newly formed RAC (i.e., board-level committee):[97]

- **Scenario Development Subcommittee** (recommends future ten to twenty-year west-wide planning horizon scenarios for consideration by the RAC);
- **Studies Subcommittee** (develops the integrated study program needed to address the defined future scenarios and associated assessment of potential future reliability risks)
- **Modeling Subcommittee** (oversees work groups that develop and maintain the detailed simulation models of the west-wide BES such as electrical network, loads, resources and production costing models)
- **Data Subcommittee** (defines what data is needed by WECC in order to support its portfolio of reliability and economic assessment models)

Participation in these WECC subcommittees and work groups is open to all interested stakeholders including the Arizona utilities.

5.3.2.3 Recent FERC Orders

FERC issued three Orders since the Ninth BTA that apply to the Arizona utilities: Orders 827, 828, and 842. FERC also issued Order 841 that applies to markets but this Order makes clear FERC's interest in how electric storage should be integrated into markets, and therefore, not directly to Arizona utilities. And, the Arizona utilities participate in the CA market where all three Orders apply.

5.3.2.4 FERC Order 827

FERC Order 827 (June 2016) revised the *pro-forma* Large Generator Interconnection Agreement ("LGIA") and the *pro-forma* Small Generator Interconnection Agreement. The revisions require wind generators to provide reactive power. As a result, all newly interconnecting non-synchronous generators will be required to provide reactive power at the high-side of the generator substation as a condition of interconnection.

[97] Per webinar presentation by Byron Woertz of WECC at Tenth BTA Workshop II on September 28, 2018.

5.3.2.5 FERC Order 828

FERC Order 828 (July 2016) changed the *pro-forma* Small Generator Interconnection Agreement ("SGIA") for small generating facilities no larger than 20 MW. The change requires newly interconnecting small generating facilities to ride-through abnormal frequency and voltage events and not disconnect during such events. The specific ride-through settings must be consistent with Good Utility Practice and any standards and guidelines applied by the transmission provider to other generating facilities on a comparable basis. FERC concluded that newly interconnecting small generating facilities should meet ride-through requirements comparable to large generating facilities.

5.3.2.6 FERC Order 842

FERC Order 842 (February 2018) revises its regulations to require newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. To implement these requirements, the Commission modified the *pro-forma* LGIA and the *pro-forma* SGIA to address the potential reliability impact of the evolving generation resource mix, and to ensure that the relevant provisions of the *pro-forma* LGIA and *pro-forma* SGIA are just, reasonable, and not unduly discriminatory or preferential.

5.3.2.7 FERC Order 841

FERC Order 841 (February 2018) removed barriers to participation of electric storage resources in the capacity, energy, and ancillary service markets. The issues addressed by the Order may not apply to the Arizona utilities because they do not operate in a market environment. However, the Order presents important issues that FERC is clearly interested in addressing. And, the Order would apply for any Arizona energy storage that might want to participate in the CAISO market.

FERC Order 841 removed barriers to participation of electric storage resources in the capacity, energy, and ancillary service markets. The Order requires tariffs be revised to establish a participation model with market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the markets. The participation model must:

1. Ensure that a resource using the participation model is eligible to provide all capacity, energy, and ancillary services that the resource is technically capable of providing in the markets;

2. Ensure that a resource using the participation model can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer

consistent with existing market rules that govern when a resource can set the wholesale price;

3. Account for the physical and operating characteristics of electric storage resources through bidding parameters or other means; and

4. Establish a minimum size requirement for participation in the markets that does not exceed 100 kW.

Additionally, each RTO/ISO must specify that the sale of electric energy from the markets to an electric storage resource, that the resource then resells back to those markets, must be at the wholesale locational marginal price.

In April 2018, FERC held two-day conference regarding their concerns about integrating aggregated distributed energy resources ("DERs") into wholesale electricity markets. The conference addressed issues that must be solved before DERs can become a significant player in the largest electricity markets. The original proposed rule on energy storage—that became Order 841—included a section on how to address aggregated DERs, but FERC opted to postpone the decision until it gathered more information from stakeholders.

5.4 The 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* ("Clean Power Plan" or "CPP"), on August 3, 2015.[98] 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: steam electric and natural gas power plants. The goals are expressed 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 percent reduction in the CO_2 emissions rate (in lbs CO_2/MWh) or a 25 percent reduction in total annual emissions (in short tons CO_2) by 2030, based on a 2012 historic year. Twenty-seven states petitioned the District of Colombia 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 EPA proposed to repeal the CPP on October 10, 2017. At the same time, the EPA requested information from the public on possible amendments to the plan which was announced in an Advanced Notice of Proposed Rulemaking, issued on December 28, 2017.

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

Beginning in 2014, the State of Arizona coordinated the development of a State plan through the ADEQ. ADEQ established a Technical Working Group ("TWG") that included 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 have complied 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. ADEQ also worked on compliance analyses with several other entities to determine reliability and economic impacts under various scenarios. At that time, ADEQ decided to slow, but not stop, work on the CPP.

On March 28, 2017, President Donald Trump signed the Executive Order on Energy Independence (E.O. 13783), which called for a review of the CPP and on October 10, 2017, EPA proposed to repeal the CPP. On October 9, 2018, the United States Supreme Court issued a 5-4 ruling blocking any attempt to appeal the Trump Administration's decision to overturn the CPP.

On August 21, 2018, the EPA announced the Affordable Clean Energy ("ACE") Rule which is planned to replace the Clean Power Plan.[99] The ACE Rule aims to reduced greenhouse gas emissions from existing coal-fired electric utility generating units and power plants across the country. This would be accomplished through four main actions:

i. Defines the "best system of emission reduction" for GHG emissions from existing power plants as on-site, heat-rate efficiency improvements;

ii. Provides state with a list of "candidate technologies" that can be used to establish standards of performance and incorporated into their state plans;

iii. Updates EPA's New Source Review Permitting program to incentivize efficiency improvements at existing power plants; and

iv. Aligns Clean Air act section 111(d) general implementing regulations to give states adequate time and flexibility to develop their state plans.

EPA held a public hearing on the ACE Rule on Monday October 1, 2018. The public comment period on the proposed ACE Rule will end on October 31, 2018.

The development of the ACE Rule will be closely followed by Staff and further updates, as related to transmission planning, will be provided in future BTAs.

[99] https://www.epa.gov/sites/production/files/2018-08/documents/ace_overview_0.pdf

5.4.1 CRATF

The 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 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[100]. 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.

In Decision No. 74785, the Commission directed TEP to file the 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 Ninth BTA docket and presented at the Ninth BTA Workshop I on the status of the final Study Report and efforts made since the Eighth BTA. The CRATF report presentation at the Ninth BTA Workshop I 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 the Ninth BTA, Decision No. 75817, the Commission suspended 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. Rather, the Commission ordered the Utilities to participate in the WestConnect Regional Planning process and coordinate Arizona reliability studies with WestConnect study and scenario results. In addition, the Commission ordered TEP to report the findings on behalf of the utilities in future BTA Proceedings.

On April 27, 2018 TEP filed the relevant portion of the WestConnect CPP Utility Plans Scenario study on behalf of the Arizona Utilities. The report was prepared from the WestConnect Planning Study 2016-2017 Cycle Regional Transmission Plan. The Arizona utilities originally submitted to WestConnect an "Arizona Utilities CPP Compliance" scenario during the December 2015 submittal window. That scenario was broadened to include all WestConnect participating

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

utilities. In this scenario, approximately 1300 MW of coal resources and 400 MW of natural gas resources were replaced with approximately 600 MW of renewable resources and 1100 MW of natural gas resources. The results of the study show there are no regionally significant issues but there were local voltage issues and thermal overloads under the CPP compliance scenarios. There were no regional transmission overloads identified in the reliability assessment. Despite the increase in renewable penetration detailed in the study, the system was able to recover frequency appropriately and within WECC criteria. The retirement of significant amounts of coal generation did not appear to compromise the reliability of the system.

On September 28, 2018, TEP presented the results of the WestConnect CPP Utility Plans Scenario study on behalf of the Arizona utilities at Workshop II in Hearing Room 1 at the Commission's Phoenix Office.

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 3 report on low levels of 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, low voltage and thermal problems will inevitably require some transmission improvements, the dynamic behavior of distributed photovoltaic has the potential to significantly impact the BES, and there is a limit to how much coal reduction can take place.

NERC has published Phase I and Phase II of their national study: Potential Reliability Impacts of EPA's Clean Power Plan[101]. 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 BES. Dynamic Reactive Resources may be needed to maintain voltage stability and dynamic stability, which may be more pronounced where generation is farther away from load centers. Overall, the change in power flows called for extensive power system studies and planning and 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.

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

5.4.3 Arizona CPP Impacts

On March 28, 2017, President Donald Trump signed the Executive Order on Energy Independence (E.O. 13783), which called for a review of the CPP and on October 10, 2017, EPA proposed to repeal the CPP. With the increased frequency of coal plants being retired and the uptake in natural gas procurement, 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 as being directly related to coal plant retirements.

Over the fifteen-year planning period, presented in the IRPs of APS and TEP, the utilities indicated plans for a major reduction in coal generation resources. According to the 2017 APS IRP, APS plans on reducing approximately 702 MW of coal by 2032.[102] In the 2017 TEP IRP, TEP states it will reduce coal-fired capacity by 508 MW over the next five years and a total of 678 MW by 2031.[103] Generally, natural gas resources will largely supplement these reductions in coal resources as well as some renewable resource additions.

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 potential 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 ESTA feel that the work that WestConnect and the Arizona utilities are investigating, as well as other industry planning activities, are critical to transmission system reliability. This is an issue that the Commission and Staff should follow closely and which the utilities should report any relevant 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 or other operational boundaries. Increased regional and interregional coordination has been conducted as a result of FERC Order 1000, transmission planning requirements, and WECC Transmission Expansion Planning. Existing Seams transmission paths affecting Arizona are detailed on Exhibit 7 and illustrated in Exhibit 8. As the Western Interconnection transitions to multiple Reliability Coordinators following the announced wind-down of Peak RC, additional seams may emerge across Reliability Coordinator boundaries for planning in the operational horizon. Current efforts to mitigate seams issues within

[102] APS 2017 Integrated Resource Plan http://docket.images.azcc.gov/0000178832.pdf
[103] TEP 2017 Integrated Resource Plan http://docket.images.azcc.gov/0000178618.pdf

Arizona occur within the context of WestConnect meetings and as required by NERC Reliability Standard TPL-001-4.

5.5.1 WECC Seams Activity

The WECC Planning Coordinating 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.[104] The PCFTF identified several issues surrounding the role of the Planning Coordinator, including the lack of formal arrangements among 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 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 making several recommendations including forming the Planning Coordinator Gap Resolution Team ("PC-GRT").[105] The PC-GRT is now 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 to the WECC Planning Coordination Committee and Board of Directors.

In the WestConnect 2015 Regional Transmission Plan, WestConnect coordinated with the CAISO on including the Delaney-Colorado River 500 kV and the Harry Allen-Eldorado 500 kV transmission lines in WestConnect's 2024 Regional Base Transmission Plan.[106] 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 ESTA 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.

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

[105]. 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

[106] WestConnect 2015 Abbreviate Cycle Regional Transmission Plan, pgs 8-9.
http://westconnect.com/filestorage/12%2016%2015%20wc%202015%20regional%20transmission%20plan.pdf

5.5.2 Western Interconnection Reliability Coordinator

A potentially significant seams issue for Arizona surfaced on July 18, 2018 with an announcement by "Peak Reliability, Inc.", the current NERC approved Reliability Coordinator ("RC") for the Western Interconnection, that it intends to ramp down its RC role as soon as December 31, 2019.[107] Peak Reliability currently serves under contract as the RC for all balancing authorities and transmission operators in the Western Interconnection. In this role Peak Reliability is responsible to ensure that real-time conditions on the Western Interconnection remain in compliance with NERC operating reliability standards and that the aggregate impact of day to day and hour to hour operational actions/market actions by individual transmission operators/balancing authorities are consistent with these standards.

The transition plan to a new RC entity is currently unclear. However, Peak Reliability's announcement follows news from the CAISO in May 2018 of its intent to withdraw from Peak Reliability and become its own RC entity. A major industry publication has reported that in addition to the plan to serve as its own RC entity, the CAISO has now signed non-binding letters of intent with most of the entities in the Western Interconnection to replace Peak Reliability as a new RC service provider "at rates dramatically undercutting Peaks."[108] The article also reports that at least one Western Interconnection entity has considered obtaining its RC services from the Southwest Power Pool ("SPP") RC entity.[109] In response to Peak Reliability's latest announcement the CAISO released a statement that it "is committed to working with Peak and others in the West on a transition that focuses on reliability, as balancing authorities, and transmission operators make their selection of a [new] RC service provider."[110]

Even though an RC entity doesn't have a direct role in expansion planning for the regional transmission grid, the transition from Peak Reliability to another Westwide RC entity or possibly to multiple RC's covering different portions of the Western Interconnection could have future reliability implications to the Arizona system.

This seams issue should continue to be monitored by the ACC in conjunction with the Utilities and other stakeholders.

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

[107] Robert Mullin, *Peak Reliability to Wind Down Operations*, RTO Insider, 18 July 2018.
[108] *RTO Insider*, 7-18-18.
[109] Ibid.
[110] Ibid.

related to the Renewable Portfolio Standards ("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 they have received multiple Transmission Service Requests for use of the existing Four Corners transmission system in order to deliver power to the West. In addition, TEP stated that it is evaluating RFPs from out of state wind resources to complement its solar portfolio, meet Arizona RPS requirements, and meet TEP's 30 percent renewables by 2030 goal. As a result, TEP stated additional transmission development may be necessary to deliver these resources to TEP.

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 twenty years. SVERI participants include 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[111]. 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 three-hour ramp challenge in March of 2020, to the Southwest's worst-case month of December 2027 where a 5,250 MW three-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.[112]

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

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[111] http://sveri.net/wp-content/uploads/2014/09/SVERI-Load-Shape-Analysis-Final-Report-Jan-2015.pdf

[112] 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

5.7 Renewable Transmission Action Plans

In the Fifth BTA the Commission ordered the Arizona utilities to each provide their top three Renewable Transmission Projects ("RTPs"). In addition, SRP identified a fourth project. None of the utilities identified any new RTPs in their Tenth BTA filings. The list of identified RTPs since the Fifth BTA and progress towards the development of these RTPs through this time is summarized below.

Project name	APS	SRP	TEP	AZ G&T	Current status
Palo Verde-North Gila 500 kV	X				Completed / In-Service in May 2015
Palo Verde-Liberty & Gila Bend-Liberty 500 kV	X				Delayed Indefinitely; will be developed as reliability and resource needs arise
Delaney-Palo Verde 500 kV	X				Energized May 2016
Pinal West-Pinal Central 500 kV		X			Completed in June 2014
Pinal West – Duke – Pinal Central 500 kV		X			Completed in June 2014
Pinal Central – Browning 500 kV		X			Completed in June 2014
Pinal Central – Randolph 230 kV		X			Completed in June 2014
Palo Verde-Pinal West-Pinal Central		X	X		Completed in June 2014
Pinal Central-Tortolita 500 kV			X		Completed in October 2015
Western Apache-Tortolita 115 kV-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 230 kV Line Upgrade				X	Line re-rated; upgrade need moved outside of Ten-Year Plan
Western Saguaro-Apache 115 kV Line Upgrade				X	No longer being pursued, instead working with Western on Southline rebuild to 230 kV

TABLE 15 - SUMMARY OF RTP DEVELOPMENT STATUS

In its Tenth BTA filing, APS advised that renewable resource expansion in their service territory, which is primarily solar, has been trending toward smaller projects which interconnect at lower voltage levels on their system (69 kV or below) rather than on the BES. As a result, APS doesn't see a need for any new RTPs at this time. Nevertheless, APS states that the one RTP from its original RTAP that hasn't yet been built (Palo Verde-Liberty and Liberty-Gila Bend 500 kV) "continues to be viable and will be developed as reliability and resource needs arise."

5.7.1 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 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 First Quarter 2018 Western EIM Benefits Report, the benefits quantified from EIM activities include the following:[113]

- More efficient dispatch, both inter-and intra-regional, in the Fifteen-Minute Market (FMM) and Real-Time Dispatch (RTD). Q1 estimated savings = $42.08 million.
- Reduced renewable energy curtailment. Q1 estimated reduction = 65,860 MWh displacing approximately 28,188 metric tons of CO_2.
- Reduced flexibility ramping reserves needed in all balancing authority areas. Q1 reduction = 387 MW – 492 MW in the upward direction and 490 MW – 542 MW in the downward direction.

According to the report, "the estimated gross benefits for January, February and March 2018 are $42.08 million, bringing the total benefits of EIM to $330.52 million since the California Independent System Operator (ISO) expanded its real-time market to balancing authority areas outside the ISO in November 2014. The report also shows that EIM is helping to displace less-clean energy supplies with surplus renewable energy that otherwise may have been curtailed."

APS joined the EIM on October 1, 2016. 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. In it's 2017-2018 IRP[114], SRP states that it will be joining the EIM in April 2020 and that the EIM will improve

[113] https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ1_2018.pdf
[114] SRP 2017-2018 Integrated Resource Plan Report https://www.srpnet.com/about/stations/pdfx/2018irp.pdf

integration of renewable energy. The EIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Utah, Washington, and Wyoming.

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, it appears the EIM has helped facilitate renewable resource integration by reducing curtailment and may increase reliability by sharing information between balancing authorities on electricity delivery conditions across the EIM region.

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

6 Conclusions

This Tenth 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:[115]

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 2018-2027 timeframe in a reliable manner?

2. **Efficacy of the Commission-ordered studies** - Do the SIL, MLSC, RMR, Ten-Year Snapshot, DG and EE, and Extreme Contingency studies filed as part of the Tenth BTA provide useful and sufficient information in determining adequacy of the State's transmission system over the next ten 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?

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

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 ESTA, the existing and proposed transmission system meets the load serving requirements of Arizona in a reliable manner for the 2018-2027 period from these eight findings:

1. The aggregate of the filed Ten-Year Plans is a comprehensive summary of 2018-2027 transmission expansion plans from a holistic perspective. The Arizona Plan includes nineteen filing entities and consists of fifty-seven transmission projects of approximately 923 miles in length. Forty-five projects are beyond the ten-year horizon or have in-service dates that are yet to be determined and account for an additional 881 miles of new transmission. Additionally, utilities have eleven transmission lines, totaling approximately 103 miles in length, which they plan to reconductor.

2. The 2018 level of summer preparedness of the utilities in Arizona, as presented in the April 24, 2018 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 2018.

3. The statewide demand forecast has continued to be lowered since the Fifth BTA. During the Tenth BTA, the Arizona utilities reported a Ten-Year Forecast that was, on average, 0.65 percent lower than what was reported during the Ninth BTA. Over the past four BTAs load forecasts have changed substantially, and the deferment of several growth-related transmission projects has followed. The overall Arizona load growth rate is projected to average approximately 2.16 percent 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 85 MW is less than the load serving capability of 159 MW.

   b. The CCSG participants monitored the reliability in Cochise County. AZG&T, APS, and Sulphur Springs Valley Electric Cooperative are developing the joint Tombstone Junction Project in Cochise County to improve reliability in the area, with an estimated in-service date of 2021. The LSEs 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 concludes 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 and ESTA conclude the fifth-year technical studies on the impacts of DG and EE by APS, SRP, TEP and UNSE, were properly conducted and reported by the Arizona Utilities. 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 may 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 Tenth BTA is filed with the Commission. Staff and ESTA conclude the Commission-ordered studies demonstrate that the Arizona transmission system is reasonably prepared to reliably serve local load in the ten-year timeframe from these five findings:

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 Tenth 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 2027. The Ten-Year Snapshot has also been adjusted to monitor system elements down to and including the 115 kV level, addressing any potential low voltage concerns. Major findings of the Ten-Year Snapshot include:

    a. Arizona's 2027 transmission plan is robust and supports the statewide load forecast.

    b. No steady state BES violations were identified with all lines in service in either the base case or deferral scenarios.

    c. Single contingency (P1) analysis showed no voltage violations occurring in the BES, other than high voltages on several busses that can be mitigated by adjusting voltage schedules of nearby generators. The 2025 Heavy-summer base case also included a single P1 event that resulted in a loading of 100.7 percent of contingency (emergency) rating of the Liberty – Rudd 230 kV line in one of the delayed expansion project scenarios. However, the report concludes that this potential problem will be eliminated by an upgrade of the line planned for 2019.

    d. No reliability issues were found with the delay of any one of the three deferral projects beyond 2027.

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 2019 and 2027 system conditions.

    b. TEP's extreme contingency analysis resulted in power flow "no-solve" results for two specific contingency events in both 2019 and one specific contingency event in 2027.[116] However, the extreme contingency analysis results also show that all of the 2019 and 2027 no-solve scenarios would be

[116] A non-solving power flow case means that computer model was not able to find a solution to the equations used in the model. This usually indicates either a basic model-data problem or some sort of a voltage problem.

mitigated by the addition of the Southline Transmission Project which is currently expected to go into service in the 2020 timeframe. In the meantime, TEP stated both 2019 no-solve scenarios are being managed through physical security hardening measures and operational measures. TEP also intends to continue to monitor the exposure to and impacts on the system due to these outages and additional mitigation options will be evaluated in future internal studies if needed.

5. The EE/DG studies satisfy the Commission's requirement to conduct a fifth-year technical study, down to the 115 kV 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 2022 system peak forecast includes 455 MW of EE and DG. APS has assumed 76 percent of both the DG capacity and EE capacity were located within the metro Phoenix load area where they are most prevalent, and the remainder located outside the metro area. Projected EE/DG have no effect on APS's BES as currently planned for 2022.

   b. SRP's 2022 system peak forecast includes 774 MW of EE and DG. For both NERC P0 and P1 conditions, SRP's power flow analysis found no overloads or voltage violations. 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 presence or absence of forecasted EE and DG.

   c. TEP and UNSE's 2022 system peak forecast includes 64 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 from these five findings:

1. Four 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 SunZia 500 kV Project and the 345 kV Southline Transmission Project will provide additional transmission capacity between Arizona and New Mexico.

b. The planned Ten West Link 500 kV project and the conceptual North Gila – Imperial Valley No. 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 concludes 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 twenty 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 five of the RTPs, 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, two RTPs have moved outside of the Ten-Year Plan window.

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's 2018-2019 Regional Planning Cycle is currently underway, and its Final Regional Study Plan for the 2018-2019 Planning Cycle was published on March 14, 2018.

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 from these three findings:

1. The results of NERC/WECC reliability standard audits over the past two years indicate there were fourteen possible CIP violations and one possible Operation and Planning violation. All possible violations have since been mitigated. There is no concern of Arizona's BES failing to comply with the applicable planning standards established by NERC/WECC.

    a. APS and SRP had audits performed in 2016. Four possible CIP violations were noted in the APS audit, which have since been resolved. One possible CIP violation was noted in SRP's audit, which has since been categorized as a Compliance Exception.

    b. TEP had an audit performed in August 2017 which identified four possible CIP violations which have since been mitigated.

    c. AZG&T had an audit performed in February 2018 which identified potential non-compliance with one Operation & Planning requirement and five CIP requirements. All non-compliance issues have since been mitigated.

2. Technical studies filed in the Tenth BTA indicate a robust study process for assessing transmission system performance for the 2018-2027 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 have actively participated in and are members of the WestConnect PMC, a regional transmission planning group.

   d. Arizona utilities have actively participated in WECC TEPPC and will continue to participate in the new WECC RAC planning process (which replaces the TEPPC process) as the regional approach to examine long-term, public transmission expansion planning in the Western Interconnection. Major EHV Arizona transmission plans are incorporated into the TEPPC transmission planning processes to facilitate and coordinate interconnection-wide, ten and twenty-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 continued 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. With the filing of the appropriate sections of the WestConnect Regional Plan, the requirement for completion of a coal reduction scenario evaluation to be coordinated among the Arizona utilities should be considered complete.

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 by evaluating the fifth year.

   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 Tenth 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 Tenth 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 2027 for a comprehensive set of single contingencies (n-1), 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.