Ashley Kelly
Manager, State Regulatory
Strategy and Compliance

Mail Station 9708
PO Box 53999
Phoenix, Arizona 85072-3999
Tel 602-371-7182
Ashley.Kelly@aps.com

January 31, 2024

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

RE: Arizona Public Service Company (APS or Company)
Ten-Year Transmission System Plan
Docket No. E-99999A-23-0016

In compliance with A.R.S. § 40-360.02, enclosed please find Arizona Public Service Company's (APS) 2024-2033 Ten-Year Transmission System Plan (Ten-Year Plan) for major transmission facilities. These new transmission projects, coupled with additional distribution and sub-transmission investment, will support reliable power delivery in APS's service area, Arizona, and in the western United States.

In this filing, APS includes: (1) Ten-Year Plan, marked as Attachment A; (2) Renewable Transmission Action Plan, marked as Attachment B; (3) Technical Study on the Effects of DG/EE on Future Transmission Needs, marked as Attachment C; (4) Reliability Must-Run Analysis marked as Attachment D; and (5) Transmission Planning Process and Guidelines, marked as Attachment E.

The technical study report is deemed confidential Critical Energy/Electric Infrastructure Information (CEII). This confidential information can be made available upon request under separate cover pursuant to a protective agreement.

Please let me know if you have any questions.

Sincerely,

/s/ Ashley Kelly

Ashley Kelly

AK/ks
Attachments

Attachment A

2024-2033 Ten-Year Transmission System Plan

Arizona Public Service Company 2024 to 2033 Ten-Year Transmission System Plan

Prepared for the Arizona Corporation Commission

January 2024

Table of Contents

Overview

General Information

Pursuant to A.R.S. § 40-360.02, Arizona Public Service Company (APS) submits its 2024-2033 Ten-Year Transmission System Plan (Ten-Year Plan), attached as Attachment A. Also included in this filing are the Renewable Transmission Action Plan (RTAP; Attachment B) as required by Arizona Corporation Commission (ACC or Commission) Decision No. 70635 (December 11, 2008), the Technical Study on the Effects of DG/EE (Attachment C) as required by Decision No. 74785 (October 24, 2014), and the Reliability Must Run (RMR) report for the Phoenix Metropolitan load pocket (Attachment D) as required by Decision No. 65476 (December 19, 2002). The Internal Planning Criteria, required by Decision No. 63876 (July 25, 2001), are included as Attachment E. The technical study report and system ratings are deemed Confidential Critical Energy/Electric Infrastructure Information (CEII). This confidential information can be made available upon request under separate cover pursuant to a Protective Agreement.

This Ten-Year Plan describes planned transmission lines of 115kV or higher voltage that APS may construct or participate in over the next ten-year period. Pursuant to A.R.S. § 40-360(10), underground facilities are not subject to line siting. However, APS lists underground facilities in the Ten-Year Plan as they are an important part of the transmission system and transmission planning process.

To prioritize reliability and meet substantial growth in residential and commercial energy needs, APS has developed a future-focused, strategic transmission plan. This Ten-Year Plan includes five critical transmission projects that comprise the APS strategic transmission portfolio, which represent a significant upgrade to our transmission system. These five projects, along with other projects included in this Plan, will support growing energy needs, strengthen reliability, and allow for the connection of new resources.

Included in this plan are approximately 32 miles of new 500kV transmission lines, 1 mile of new 345kV transmission lines, 578 miles of 345kV transmission line upgrades, 76 miles of new 230kV transmission lines, 12 miles of underground 230kV upgrades, and 140 miles of 230kV transmission overhead line rebuilds described as planned projects in this Ten-Year Plan. In addition, the following equipment is included in the Ten-Year Plan: 43 new transformers, 3 new shunt reactors, 19 new shunt capacitors, 1 new STATCOM, 4 transformer replacements, 1 shunt reactor replacement, and 2 series capacitor replacements. The total investment for the APS projects and the anticipated APS portion of the participation projects as they are modeled in this filing is estimated to be $5.656 billion.[1] Table 1 provides an overview of the projects included in the Ten-Year Plan.

Table 1: Ten-Year Transmission Project Overview

Lines and Equipment	Total Included in Ten-Year Plan
500kV New Transmission Lines	Approximately 32 miles
345kV New Transmission Lines	Approximately 1 mile
345kV Transmission Line Rebuilds	Approximately 578 miles
230kV New Transmission Lines	Approximately 76 miles
230kV Transmission Overhead Line Rebuilds	Approximately 140 miles
230kV Transmission Underground Line Rebuilds	Approximately 12 miles
New Transformers	38 transformers
Transformer Replacements	4 transformers
New Shunt Reactors	3 reactors
Shunt Reactor Replacements	1 reactor
New Shunt Capacitors	19 capacitors
Series Capacitor Replacements	2 capacitors
New STATCOM	1 STATCOM
Total Investment	$5.656 billion[2]

1 This value is not comparable to the Capital Expenditures table presented in the "Liquidity and Capital Resources" section of APS's 10-K filing, which also includes other transmission costs for new subtransmission projects (69kV) and transmission upgrades and replacements. This value also does not include the allowance for funds used during construction.
[2] See footnote 1

Consistent with the Commission's Sixth Biennial Transmission Assessment[3] (BTA), this Ten-Year Plan includes information regarding planned transmission reconductor projects, substation transformer replacements, and reactive power compensation projects. At this time, APS does not plan to reconductor any transmission lines, but does have plans to upgrade approximately 12 miles of underground 230kV and rebuild approximately 140 miles of 230kV overhead transmission and 578 miles of 345kV overhead transmission.

These types of plans often change as they typically are in direct response to load growth, generator interconnections, and many other factors influencing the interconnected transmission grid. Therefore, in-service dates for projects such as transformer replacements or additions, reconductoring transmission lines, and reactive power support may change to reflect the load changes in the local system. Additionally, there may be projects added throughout the course of the planning year to adapt to changes in system topology, serve new large-load customers, mitigate the impacts of generation retirement, or accommodate new generator interconnections. For example, new projects may be identified or planned projects may be advanced to serve customers, either single large customers such as new data centers or large master-planned communities, or to support rapid customer electrification and technology advancement. Table 2: Equipment Additions and Replacements, is a list, by estimated year of in-service, of the planned substation transformer additions and replacements, reactive devices being installed or replaced, new transmission lines, and transmission line upgrades.

Table 2: Equipment Additions and Replacements

Equipment	Year
Three Rivers 230/69kV Transformer Additions (3 units) Saguaro 500/115kV Transformer Replacements (2 units) Three Rivers 230kV Shunt Capacitor Addition (1 unit) Cholla 345kV Shunt Reactor Additions (2 units) Country Club to Lincoln Street 230kV Underground Upgrade (3.5mi)	2024

[3] Decision No. 72031, December 10, 2010.

Equipment	Year
Goodyear 230/69kV Transformer Additions (3 units) Runway 230/69kV Transformer Addition (1 unit) Stratus 230/69kV Transformer Addition (1 unit) Broadway 230/69kV Transformer Additions (2 units) Contrail 230/69kV Transformer Additions (3 units) Dromedary 230kV Shunt Capacitor Additions (4 units) Goodyear 230kV Shunt Capacitor Addition (1 unit) Runway 230kV Shunt Capacitor Addition (1 unit) Sabre 230kV Shunt Capacitor Additions (2 units) Stratus 230kV Shunt Capacitor Addition (1 unit) Contrail 230kV Shunt Capacitor Addition (1 unit)	2025
Runway 230/69kV Transformer Additions (3 units) Rudd 500/230kV Transformer Addition (1 unit) Willow Lake 230kV Shunt Capacitor Additions (2 units) Cholla 500kV Shunt Reactor Replacement (1 unit)	2026
Diamond 230/69kV Transformer Additions (3 units) Freedom 230/69kV Transformer Addition (1 unit) Mead Phoenix Project Q01 500/230kV Transformer Addition (1 unit) Ocotillo 230/69kV Transformer Addition (1 unit) Outer Circle 230/69kV Transformer Addition (1 unit) Runway 230/69kV Transformer Addition (1 units) Scatter Wash 230/69kV Transformer Addition (1 unit) Sun Valley 500/230kV Transformer Addition (1 unit) TS31 230/69kV Transformer Additions (2 units) Verde 230/69kV Transformer Replacements (2 units) Diamond 230kV Shunt Capacitor Addition (1 unit) Runway 230kV Shunt Capacitor Addition (1 unit) TS31 230kV STATCOM Addition (1 unit) Country Club to Meadowbrook 230kV Underground Upgrade (3mi)	2027

Equipment	Year
Bianco 230/69kV Transformer Additions (2 units) Yavapai 230/69kV Transformer Addition (1 unit)	2028
Rudd 500/230kV Transformer Addition (1 unit) TS22 500/230kV Transformer Additions (2 units) TS22 500kV Shunt Reactor Addition (1 unit) Meadowbrook to Sunnyslope 230kV Underground Upgrade (5mi)	2029
TS21 500/230KV Transformer Additions (2 units) TS21 230kV Shunt Capacitor Additions (2 units)	2032
TS22 500/230KV Transformer Addition (1 unit) TS22 230kV Shunt Capacitor Addition (2 units)	2033
Cholla 345kV Series Capacitor Replacements (2 units)	2035
Avery 230/69kV Transformer Additions (2 units) Broadway 230/69kV Transformer Addition (1 unit) Raceway 230/69kV Transformer Addition (1 unit) TS17 230/69kV Transformer Additions (2 units) Sun Valley 230/69kV Transformer Addition (1 unit) Trilby Wash 230/69kV Transformer Addition (1 unit) Lone Peak 230/69kV Transformer Addition (1 unit) Palm Valley 230/69kV Transformer Addition (1 unit) West Phoenix 230/69kV Transformer Addition (1 unit) TS22 230/69kV Transformer Addition (1 unit) TS25 230/69kV Transformer Additions (2 units) TS29 230/69kV Transformer Additions (2 units) Parkway 230/69kV Transformer Addition (1 unit) Avery 230kV Shunt Capacitor Additions (2 units) Broadway 230kV Shunt Capacitor Addition (1 unit) TS29 230kV Shunt Capacitor Addition (1 unit) Country Club to Grand Terminal 230kV Underground Upgrade	TBD

Some of the facilities reported in prior Ten-Year Plan filings have been completed. Others have been canceled or deferred beyond the upcoming ten-year period and therefore are not included in this plan. The projects that have "To Be Determined" (TBD) in-service dates are projects that have been identified but are either still outside of the ten-year planning window or the in-service date has not yet been established. They are included in this filing for informational purposes. A summary of changes from last year's Ten-Year Plan is provided on pg. 13.

APS has included planned transmission maps showing the electrical connections and in-service dates for all overhead transmission projects planned by APS for Arizona Extra High Voltage (EHV) and Outer Divisions (pg. 17), the Phoenix metropolitan area (pg. 18), and the Yuma area (pg. 19). Written descriptions of each proposed transmission project are provided on subsequent pages in the expected chronological order of each project. The line routings shown on the system maps and the descriptions of each transmission line are intended to be general, showing electrical connections and not specific routings and are subject to revision. Specific routings are recommended by the Arizona Power Plant and Transmission Line Siting Committee and approved by the Commission when issuing a Certificate of Environmental Compatibility (CEC) and through subsequent right-of-way acquisition.

APS participates in numerous regional planning organizations, which provide an opportunity for other entities to participate in future planned projects. Through membership and participation in these organizations, the needs of multiple entities and the region as a whole can be identified and studied, which maximizes the effectiveness and use of new projects. Regional organizations in which APS is a member include the Western Electricity Coordinating Council (WECC), the WestConnect regional planning group, and the Southwest Area Transmission (SWAT) subregional planning group. The plans included in this filing are the result of these coordinated planning efforts.

The Commission's Sixth BTA ordered utilities to include the effects of distributed generation (DG) and energy efficiency (EE) programs on future transmission needs. APS's modeled load, as described in the Technical Study Report, addresses the requirements of the Commission's Sixth BTA. Additionally, in the Eighth BTA Decision[4], the Commission directed utilities to conduct or procure a study that would more directly evaluate the effects of DG and EE installations and programs on their future transmission needs. This study is included in this filing as Attachment C.

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

The Commission's decision in the Seventh BTA[5] remains in effect. This decision suspended the requirement for performing Reliability Must Run (RMR) studies in every BTA and instead only requires that an RMR study be performed if certain criteria are met. For the 2024 BTA, APS determined that criteria were triggered to perform an RMR study for the Phoenix load pocket, which is one of the two areas in the APS service territory where load cannot entirely be served by imports over transmission lines. The RMR study is attached to this filing as Exhibit D. The RMR study performed in 2022 identified that the Yuma load pocket no longer had any RMR hours; however, APS continued to monitor relative to triggering criteria. For the 2024 BTA, APS determined that criteria were not triggered to perform an RMR study for the Yuma load pocket, and as a result, the 2024 RMR study is limited to the Phoenix metropolitan area.

Also, consistent with the Commission's Decision in the Seventh BTA, APS continues to monitor reliability in Cochise County. To improve reliability in Cochise County, APS, Arizona Electric Power Cooperative (AEPCO), and Sulphur Springs Valley Electric Cooperative (SSVEC) have executed agreements[6] to coordinate and jointly participate in a number of projects and upgrades within the Cochise County area. These agreements incorporate, among other things, new and upgraded transmission lines and substations, new transformers, and reconfigurations on the 230kV, 115kV, and 69kV systems to sustain reliable operation in the area. In 2023 APS, AEPCO, and SSVEC completed the final remaining upgrades contained in the Cochise County agreement.[7]

The Commission's Ninth BTA Decision[8] ordered utilities to describe, in general terms, the driving factor(s) for each transmission project in the Ten-Year Plan. This information is included in the project descriptions.

Power flow analysis was conducted to identify thermal overloads under normal and contingency conditions in compliance with North American Electric Reliability Corporation (NERC) Reliability Standards and WECC System Performance Criteria. The projects identified in this Ten-Year Plan, with their anticipated in-service dates, will ensure that APS's transmission system meets all applicable reliability criteria for Category P0 and P1 conditions, as defined in NERC Reliability Standard TPL-001-5.1. Changes in regulatory requirements, regulatory approvals, or underlying assumptions such as load forecasts, generation or transmission expansions, economic issues, retirement of generation, changes in the system topology, and other utilities' plans may substantially impact this

[5] Decision No. 73625, December 12, 2012.
[6] See Cochise County Mutual Standby Transmission Service Agreement, APS Service Agreement No. 372, filed with the Federal Energy Regulatory Commission (FERC) on May 21, 2019, in FERC Docket No. ER19-1915-000.
[7] Work on the Adams-Boothill and Boothill-Mural 115kV lines was completed in 2023.
[8] Decision No. 75817, November 21, 2016.

Ten-Year Plan and could result in changes to anticipated in-service dates or project scopes. Additionally, future federal and regional mandates may impact this Ten-Year Plan specifically and the transmission planning process in general. This Ten-Year Plan contains tentative information only and is subject to change without notice at the discretion of APS in accordance with A.R.S. § 40-360.02(F).

Project Changes From the 2023 to 2032 Ten-Year Plan

The following projects were removed, changed, or completed since the January 2023 filing of APS's 2023 to 2032 Ten-Year Plan:

- The upgrades to the Adams-Boothill and Boothill-Mural 115kV lines were placed in service in 2023.
- The McFarland Solar Project Generation Tie Line was placed in service in 2023.
- The Chevelon Butte Wind Generation Tie Line Project was placed in service in 2023.
- The AES Energy Storage Project Interconnection at Westwing 230kV Substation was placed in service in 2023.
- The in-service date for the Serrano Solar and Storage Project Generation Tie Line was updated from 2023 to 2024.
- The construction start date for the Contrail 230kV Lines was updated from 2023 to 2024. The length of the lines was updated from 7 miles to 9 miles.
- The construction start date for the Three Rivers 230kV Transmission Line Project was updated from 2023 to 2024.
- The in-service date for Goodyear substation, which is an intermediate point on the Three Rivers 230kV Transmission Line Project, was updated from 2024 to 2025.
- TS26 switchyard is now called Dromedary. The in-service date for Dromedary switchyard has been updated to 2025.
- The Palm Valley-Parkway Switchyards project from the 2023 to 2032 Ten-Year Plan has been split into two separate projects to track the completion of the Dromedary and TS27 switchyards separately. The Dromedary switchyard in-service date is now 2025. The TS27 in-service date has been updated to TBD.
- The construction start date for the Broadway 230kV lines was updated from 2023 to 2025.
- The construction start date for the Proving Ground Solar and Storage 500kV Interconnection was updated from 2023 to 2025, and the in-service date for the project was updated from 2025 to 2026.
- The construction start date for the Hashknife Energy Center Generation Tie Line Project was updated from 2024 to 2026, and the in-service date for the project was updated from 2025 to 2026.
- The in-service date for the Runway Additional 230kV Lines Project has been updated from 2025 to 2026.
- The in-service date for Diamond substation, which is an intermediate point on the Runway Additional 230kV Lines Project, was updated from 2025 to 2027.
- The in-service date for the Sundance to Pinal Central 230kV line has been updated from TBD to 2027.

- The name for the Mead – Perkins Line Interconnection Project has been updated to the Bagdad 230kV Transmission Line project and the in-service date has been updated from TBD to 2027.
- TS23 Substation is now called Outer Circle Substation.
- TS24 Substation is now called Bianco Substation. The in-service date for the substation and 230kV lines has been moved from 2026 to 2028.
- The in-service date for the TS22 Project was updated from 2027 to 2029.
- The in-service date for the Panda to Freedom 230kV line rebuild has been updated from 2027 to 2031.
- The in-service date for the Pinnacle Peak to Ocotillo 230kV line rebuilds has been updated from TBD to 2031.
- The in-service date for the Jojoba-Rudd 500kV Line has been updated from 2028 to 2032.
- The in-service date for the TS21 substation, listed as an intermediate point on the Jojoba-Rudd 500kV Line has been updated from TBD to 2032.
- The in-service date for the Four Corners to Cholla to Pinnacle Peak 345kV Line Rebuilds has been updated from TBD to 2035.
- The in-service date for the TS27 Switchyard and Lines has been updated from 2027 to TBD.

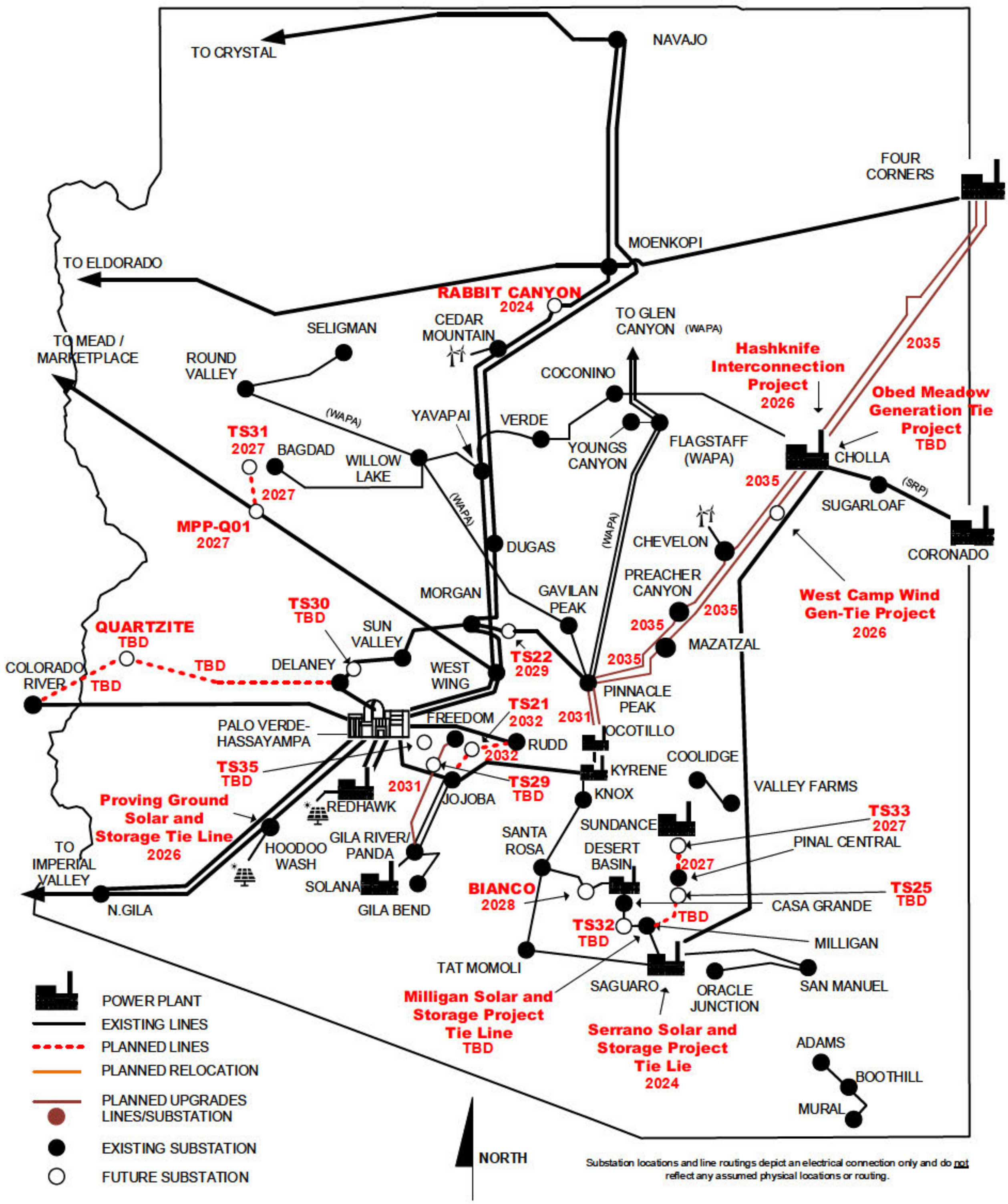
New Projects in the 2024 to 2033 Ten-Year Plan

The following new transmission projects were included in the APS 2024 to 2033 Ten-Year Plan:

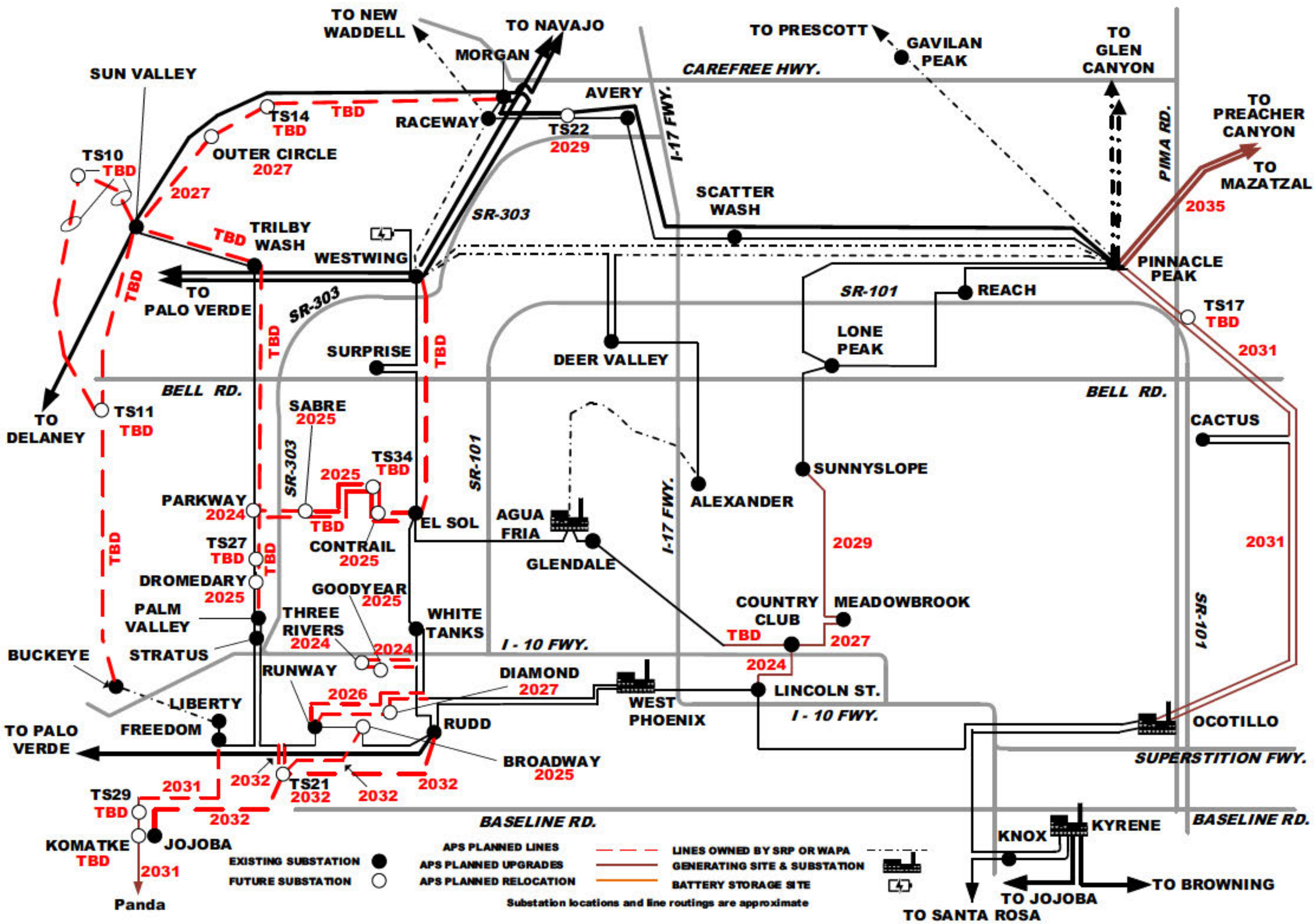
- The Rabbit Canyon 500kV Switchyard and Lines project with an in-service date of 2024.
- The Sabre switchyard, included as an intermediate point on the Contrail 230kV lines with an in-service date of 2025.
- The West Camp Wind Gen-Tie Project with an in-service date of 2026.
- The TS33 switchyard, included as an intermediate point on the Sundance to Pinal Central 230kV line with an in-service date of 2027.
- The Runway-Stratus 230kV Line Cut-In to TS21 substation with an in-service date of 2032.
- The TS21-Broadway 230kV Line project with an in-service date of 2032.
- The TS34 switchyard, included as an intermediate point on the Contrail 230kV lines, with an in-service date of TBD.

Planned Transmission Maps

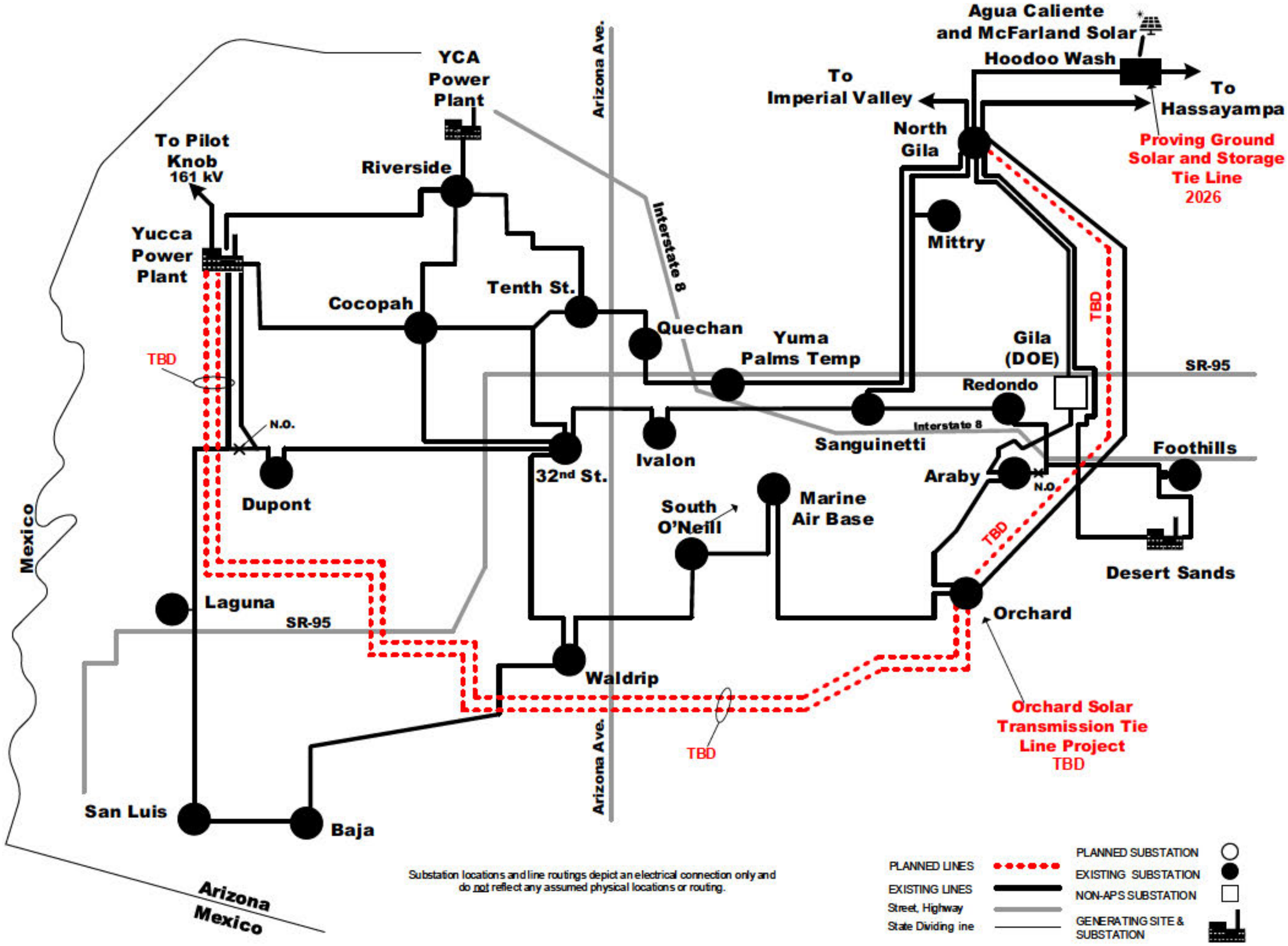
Arizona EHV and Outer Division Transmission Plans



Phoenix Metropolitan Area Transmission Plans



Yuma Area Transmission Plans



Project Descriptions

Serrano Solar and Storage Project Generation Tie Line

Project Sponsor

Solar Pepper Power, LLC

Other Participants

Arizona Public Service Company

Construction Start

2023

Projected In-service Date

2024

Facility Details

Voltage Class	230kV AC
Facility Rating	TBD
Point of Origin	Serrano Solar and Storage Project substation
Intermediate Points of Interconnection	None
Point of Termination	Saguaro Substation
Length	Less than 1 mile

Routing

The APS-owned portion of the route will begin where the line crosses the west side of the Saguaro generation plant controlled access boundary, east of Interstate 10. From there, the line will travel an additional 0.75 miles to the point of interconnection at Saguaro substation.

Purpose

To connect the Serrano Solar and Storage Project substation to the Saguaro substation. The APS portion of the project is due to the tie line sharing structures with existing APS lines and traversing through controlled access areas within the Saguaro Power Plant property.

Permitting and Siting Status

On 1/31/2022 the Commission granted CEC-1 and CEC-2, respectively, to Solar Pepper Power, LLC (Case No. 196). CEC-1 is for the portion of the project that originates at the Solar and Storage Project substation up to the Point of Change of Ownership (POCO) near the Saguaro generation plant-controlled access boundary. CEC-2 is for the portion of the project from the POCO to the point of interconnection at Saguaro substation. At a future date, prior to construction, the Interconnection Customer will transfer CEC-2 to APS.

Rabbit Canyon 500kV Switchyard and Lines

Project Sponsor

RWE Renewable Development, LLC

Other Participants

Arizona Public Service Company

Construction Start

2023

Projected In-service Date

2024

Facility Details

Voltage Class	500kV AC
Facility Rating	TBD
Point of Origin	Moenkopi-Cedar Mountain 500kV line
Intermediate Points of Interconnection	None
Point of Termination	Rabbit Canyon switchyard (in service 2024)
Length	Less than 1 mile

Routing

Lines will be extended from the Moenkopi-Cedar Mountain 500kV line to the new Rabbit Canyon 500kV switchyard located within Township 26N, Range 5E, Section 21 and north of the southern limit of the Moenkopi-Cedar Mountain 500kV right of way.

Purpose

To interconnect multiple generation interconnection projects to the Moenkopi-Cedar Mountain 500kV line.

Permitting and Siting Status

On 11/3/2023, the Commission granted CEC 225-A (Case No. 225, Decision No. 79167) and CEC-225-B (Case No. 225, Decision No. 79168) to RWE Renewables Development, LLC. CEC 225-A is for a 5-mile generation tie line from the Wind Project to the planned APS switchyard. The companion CEC 225-B is for the APS switchyard, now called Rabbit Canyon. At a future date, prior to construction, the Interconnection Customer will transfer CEC 225-B to APS.

Three Rivers 230kV Transmission Line Project

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2024

Projected In-service Date

2024

Facility Details

Voltage Class	230kV AC
Facility Rating	3000 A
Point of Origin	Rudd-White Tanks 230kV line
Intermediate Points of Interconnection	Goodyear substation (in service 2025)
Point of Termination	Three Rivers substation (in service 2024)
Length	Approximately 8 miles

Routing

The Three Rivers substation will be located approximately three and a half miles to the west of the Rudd-White Tanks 230kV line on the southwest corner of Van Buren Street and Bullard Avenue. The project consists of a single 230kV transmission line connecting the Rudd-White Tanks 230kV line to the Three Rivers substation and a second independent 230kV single-circuit transmission line connecting Three Rivers substation to the Goodyear substation and then back to the Rudd-White Tanks line.

Purpose

To provide electric energy to a new high load customer in the area. In-service date is predicated on ramp rate of customer load.

Permitting and Siting Status

CEC issued 12/3/2021 (Case No. 193, Decision No. 78318).

Parkway 230kV Lines

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2023

Projected In-service Date

2024

Facility Details

Voltage Class	230kV AC
Facility Rating	3000 A
Point of Origin	Palm Valley-Trilby Wash 230kV line
Intermediate Points of Interconnection	None
Point of Termination	Parkway substation (in service 2024)
Length	Less than 1 mile

Routing

The Parkway substation will be located adjacent to the Palm Valley-Trilby Wash 230kV line, north of Olive Avenue and between the Loop 303 and Cotton Lane.

Purpose

To provide a switchyard to connect the Contrail 230kV lines into the existing Palm Valley-Trilby Wash 230kV line.

Permitting and Siting Status

CEC issued on 12/22/2003 (Case No. 122, Decision No. 66646, West Valley-South Project). On 6/27/2013, Decision No. 73937 amended the CEC authorizing a term extension to 12/23/2018 for the first circuit of the Project and to 12/23/2028 for the second circuit and other facilities. On 10/2/2020, Decision No. 77761 amended the CEC authorizing an additional substation for a large-load customer. On 1/9/2024, Decision No. 79248 further amended the CEC authorizing the addition of Dromedary switchyard to serve a large-load customer.

Contrail 230kV Lines

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2024

Projected In-service Date

2025

Facility Details

Voltage Class	230kV AC
Facility Rating	3000 A
Point of Origin	El Sol substation
Intermediate Points of Interconnection	Contrail substation, TS34 switchyard (in service TBD), and Sabre switchyard (in service 2024)
Point of Termination	Parkway substation (in service 2024)
Length	Approximately 9 miles

Routing

A single circuit line will originate at the El Sol substation and will head generally west and connect into the Contrail substation, located on the southeast corner of Olive Avenue and Dysart Road. From Contrail substation, the line will head north to Peoria Ave along the 127th Avenue alignment. The future TS34 switchyard will connect into the line along this alignment. The line will head west on Peoria Avenue to Litchfield Road and then generally south and west until it terminates at the future Parkway substation. The future Sabre switchyard will tie into the line along Olive Avenue near the 147th Avenue alignment. All structures are planned to be double circuit capable.

Purpose

To provide electric energy to new high load customers in the area. In-service date is predicated on ramp rate of customer load.

Permitting and Siting Status

CEC issued 4/28/2022 (Case No. 198, Decision No. 78543). APS anticipates filing an application to amend CEC 198 in 2024 to request authorization for construction of the TS34 switchyard and the Sabre switchyard.

Broadway 230kV Lines

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2025

Projected In-service Date

2025

Facility Details

Voltage Class	230kV AC
Facility Rating	3000 A
Point of Origin	Runway-Rudd 230kV line
Intermediate Points of Interconnection	None
Point of Termination	Broadway substation
Length	Less than 1 mile

Routing

The Broadway substation will be cut into the Runway-Rudd 230kV line. The substation is located on the north side of Broadway Road and adjacent to the Runway-Rudd 230kV line.

Purpose

To provide electric energy to a new high-load customer in the area. In-service date is predicated on ramp rate of customer load.

Permitting and Siting Status

CEC issued 11/7/2019 (Case No. 183, Decision No. 77469).

Dromedary 230kV Switchyard and Lines

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2024

Projected In-service Date

2025

Facility Details

Voltage Class	230kV AC
Facility Rating	3000 A
Point of Origin	Palm Valley-Parkway 230kV line
Intermediate Points of Interconnection	None
Point of Termination	Dromedary 230kV switchyard (in service 2025)
Length	Less than 1 mile

Routing

The existing Palm Valley-Trilby Wash 230kV line will be cut into the planned Dromedary switchyard, located at the northwest corner of Camelback Road and Cotton Lane in Glendale, using two double circuit monopole structures. The Palm Valley-Trilby Wash 230kV line will become the Palm Valley-Parkway 230kV line in 2024, following the completion of Parkway 230kV Lines project and prior to the completion of the Dromedary 230kV switchyard. The monopoles used for the cut-in of Dromedary switchyard will be capable of carrying both the existing 230kV line and the planned second circuit between Palm Valley and Parkway substations.

Purpose

To provide electric energy to a new high-load customer.

Permitting and Siting Status

CEC issued on 12/22/2003 (Case No. 122, Decision No. 66646, West Valley-South Project). On 6/27/2013, Decision No. 73937 amended the CEC authorizing a term extension to 12/23/2018 for the first circuit of the Project and to 12/23/2028 for the second circuit and other facilities. On 10/2/2020, Decision No. 77761 amended the CEC authorizing an additional substation for a large-load customer. On 1/9/2024, Decision No.79248 further amended the CEC authorizing the addition of Dromedary switchyard to serve a large-load customer.

Runway Additional 230kV Lines

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2026

Projected In-service Date

2026

Facility Details

Voltage Class	230kV AC
Facility Rating	3000 A
Point of Origin	White Tanks-West Phoenix 230kV line
Intermediate Points of Interconnection	Diamond substation (in service 2027)
Point of Termination	Runway substation
Length	Approximately 4.2 miles

Routing

The new double circuit 230kV line to Runway substation will cut into the existing White Tanks-West Phoenix 230kV line, just north of West Buckeye Road. It will generally head southwest along an existing transmission corridor and then west to the Diamond 230kV substation, spanning approximately 2.5 miles. From Diamond substation it will head north along Litchfield Road to Lower Buckeye Road, then west on Lower Buckeye Road to MC 85. The line will head southwest along MC 85 before turning south to Runway substation. Diamond substation will be cut into the future Runway-West Phoenix 230kV line, which will be located on the south side of the new double circuit structures.

Purpose

To provide electric energy to new high-load customers. The in-service date is predicated on the ramp rate of customer load.

Permitting and Siting Status

CEC issued 1/23/2023 (Case No. 209, Decision No.78834).

Hashknife Energy Center Generation Tie Line Project

Project Sponsor

Hashknife Energy Center LLC

Other Participants

Arizona Public Service Company

Construction Start

2026

Projected In-service Date

2026

Facility Details

Voltage Class	500kV AC
Facility Rating	TBD
Point of Origin	Hashknife Energy Center substation (in service 2025)
Intermediate Points of Interconnection	None
Point of Termination	Cholla substation
Length	Less than 1 mile

Routing

The APS-owned portion of the line commences at the Cholla generation plant-controlled access boundary. From there, the line heads southeast for approximately 0.3 miles to the point of interconnection at the Cholla substation. The final few structures carrying the line will be collocated with the APS Coconino-Cholla 230kV line.

Purpose

To connect the Hashknife Energy Center Project to the Cholla substation.

Permitting and Siting Status

On 1/22/2021, in Decision Nos. 77888 and 77889 (Case No. 187), the Commission granted CEC-1 and CEC-2, respectively, to Hashknife Energy Center LLC. CEC-1 is for the portion of the Project that originates at the Hashknife Energy Center substation to the point of future ownership change, the Point of Physical Demarcation (POPD), near the Cholla generation plant-controlled access boundary. The companion CEC-2 is for the portion of the Project from the POPD to the point of interconnection at the Cholla substation. At a future date, prior to construction, the Interconnection Customer will transfer CEC-2 to APS.

Proving Ground Solar and Storage 500kV Interconnection

Project Sponsor

Arizona Public Service Company

Other Participants

Imperial Irrigation District

Construction Start

2025

Projected In-service Date

2026

Facility Details

Voltage Class	500kV AC
Facility Rating	TBD
Point of Origin	Proving Ground Solar and Storage Project Step-Up substation (in service 2025)
Intermediate Points of Interconnection	None
Point of Termination	Hoodoo Wash switchyard
Length	Less than 1 mile

Routing

The generation tie line will exit the step-up substation at 500kV. The 500kV generation tie line will route along the north side of Palomas Road for approximately 3,000 feet terminating in the Hoodoo Wash switchyard. Approximately 1,000 feet will be collocated on Hassayampa-North Gila 500kV line as it enters the Hoodoo Wash switchyard.

Purpose

To connect the Proving Ground Solar and Battery Storage project to the Hoodoo Wash switchyard.

Permitting and Siting Status

CEC was issued 4/17/2023 (Case No. 214, Decision No. 78914). CEC 214 authorized a 0.6 mile 500kV transmission line to connect the Proving Grounds Solar and Storage Project to Hoodoo Wash 500kV switchyard. The decision also amended CEC 135 (Case No. 135, Decision No. 70127, Palo Verde to North Gila) to authorize a new structure on the Hassayampa-North Gila 500kV line to facilitate the interconnection of the new Proving Grounds Solar and Storage Project 500kV line into Hoodoo Wash.

West Camp Wind Gen-Tie Project

Project Sponsor

West Camp Wind Farm, LLC

Other Participants

Arizona Public Service Company

Construction Start

2025

Projected In-service Date

2026

Facility Details

Voltage Class	345kV AC
Facility Rating	TBD
Point of Origin	West Camp Wind collector substations
Intermediate Points of Interconnection	West Camp Wind switchyard (in service 2026)
Point of Termination	Cholla-Mazatzal 345kV line
Length	Less than 1 mile

Routing

The line will extend from the West Camp Wind collector substations generally north to the Point of Change of Ownership (POCO) between West Camp Wind and APS, located on the first structure outside of a new APS switchyard located south of the Cholla-Mazatzal 345kV line. Lines will be extended from the switchyard to the Cholla-Mazatzal line to cut the line in and out of the new switchyard.

Purpose

To connect the West Camp Wind Farm generation project to the Cholla-Mazatzal 345kV line.

Permitting and Siting Status

On 12/15/2022, the Commission granted CEC-206-1 (Case No. 206, Decision No. 78810) and CEC-206-2 (Case No. 206, Decision No. 78811) to West Camp Wind Farm, LLC. CEC-206-1 is for the lines from the collector substations to Point of Change of Ownership (POCO) outside the planned APS switchyard. CEC-206-2 is for the new APS 345kV interconnection switchyard and ties to the Cholla-Mazatzal 345kV line and will be transferred to APS in the future.

Sun Valley to Outer Circle 230kV Line

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2026

Projected In-service Date

2027

Facility Details

Voltage Class	230kV AC
Facility Rating	3000 A
Point of Origin	Sun Valley substation
Intermediate Points of Interconnection	None
Point of Termination	Outer Circle substation (in service 2027)
Length	Approximately 17 miles

Routing

The line would originate at the Sun Valley Substation and head north to the existing Sun Valley-Morgan 500kV alignment. From there, the line will head generally north and east, utilizing the open circuit position on the existing Sun Valley-Morgan 500kV line structures. The line will terminate at the Outer Circle substation, located on the southeast corner of the 235th Avenue alignment and Grand Avenue, northwest of the City of Surprise.

Purpose

To provide electric energy to growing load demands in the northwest Surprise and Wittmann areas, including proposed new logistics and industrial loads. In addition, this new 230/69kV source substation will reduce loading constraints and provide greater reliability for the Wickenburg, Morristown, Wittmann and Surprise areas.

Permitting and Siting Status

CEC issued (Case No. 138, Decision No. 70850, amended by Decision Nos. 71645 and 75092, TS5-TS9 500/230kV Project). This CEC allows for the construction of the 230kV line along the Sun Valley-Morgan corridor.

Sundance to Pinal Central 230kV Line

Project Sponsor

Arizona Public Service Company

Other Participants

Electrical District #2

Construction Start

2025

Projected In-service Date

2027

Facility Details

Voltage Class	230kV AC
Facility Rating	TBD
Point of Origin	Sundance to Faul 230kV line
Intermediate Points of Interconnection	TS33 substation (in service 2027)
Point of Termination	Pinal Central substation
Length	Approximately 6.25 miles

Routing

Approximately one quarter mile of the Sundance to Pinal Central 230kV has been constructed from Sundance switchyard to the Electrical District #2 Faul 69kV Substation. A new APS substation, TS33, will be cut into this line within the Sundance Generation Plant property and along the approved alignment of the project. From TS33, a single circuit line will be extended south to Randolph Road. From Randolph Road, the line will head west to the Curry Road alignment. The line will then head south on the Curry Road alignment to the south side of the Duke-Pinal Central 500kV line right of way. From that point, the line will head east to Pinal Central, paralleling the Duke-Pinal Central 500kV line. Single circuit lines will be constructed to be capable of a future second circuit.

Purpose

To provide an alternative route for Sundance area generation to reach the Phoenix Metropolitan load pocket and to increase operational flexibility and support future growth in Pinal County.

Permitting and Siting Status

CEC issued 4/29/2008 (Case No. 136, Decision No. 70325, Sundance to Pinal South 230kV Transmission Line project). APS anticipates filing an amendment in 2024 to request an extension of the CEC.

Bagdad 230kV Transmission Line

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2025

Projected In-service Date

2027

Facility Details

Voltage Class	230kV AC
Facility Rating	3000 A
Point of Origin	Mead Phoenix Project Q01 substation (in service 2027)
Intermediate Points of Interconnection	None
Point of Termination	TS31 substation (in service 2027)
Length	Approximately 15 miles

Routing

The Mead Phoenix Project Q01 substation will tap the Mead-Perkins 500kV line approximately 4 miles southeast of the intersection of US 93 and SR 97. From Mead Phoenix Q01, a new 230kV line will head generally north for approximately 15 miles to the new TS31 substation. At TS31, voltage will be stepped down to 69kV to serve a new high load customer.

Purpose

To provide electric energy to a new high-load customer. The in-service date is predicated on the date required by the customer to energize new load.

Permitting and Siting Status

APS anticipates filing an application for a CEC in 2024.

Bianco 230kV Lines

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2027

Projected In-service Date

2028

Facility Details

Voltage Class	230kV AC
Facility Rating	TBD
Point of Origin	Santa Rosa-Desert Basin 230kV line
Intermediate Points of Interconnection	None
Point of Termination	Bianco substation (in service 2028)
Length	Approximately 4 miles

Routing

The future Bianco substation, located east of Bianco Road and between Clayton Road and SR84 in Casa Grande, will be cut in and out of the of existing Santa Rosa-Desert Basin 230kV line. The new section of the Santa Rosa-Bianco 230kV line will head generally south from the existing line to Bianco substation paralleling Bianco Road. The new section of the Desert Basin-Bianco 230kV line will head generally south from the existing line in a new alignment between Bianco Road and Ethington Road. The new line sections will be constructed with capability to add a future second circuit.

Purpose

To support continued load growth in Pinal County, especially new manufacturing and industrial customers in the Casa Grande area. Significant load increases in the Pinal County area over the past several years, coupled with anticipated continued growth are leading to projected thermal overloads on Pinal County 69kV lines. The projected overloads can be resolved through the addition of Bianco substation. The Bianco project will also fix existing paired element limitations at the Casa Grande substation.

Permitting and Siting Status

An application for a CEC has not yet been filed.

TS22 Project

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2028

Projected In-service Date

2029

Facility Details

Voltage Class	230kV AC and 500kV AC
Facility Rating	TBD
Point of Origin	Raceway-Avery 230kV line and Morgan-Pinnacle Peak 500kV line
Intermediate Points of Interconnection	None
Point of Termination	TS22 substation (in service 2029)
Length	Less than 1 mile

Routing

The TS22 substation is planned to be located generally northwest of the intersection of 51st Avenue and Dove Valley Road and will be adjacent to the double circuit transmission poles carrying the Raceway-Avery 230kV line and the Morgan-Pinnacle Peak 500kV line. The project will cut the new substation in and out of the existing 230kV and 500kV lines.

Purpose

To provide electric energy to a new high-load customer and ultimately additional future high-load customers.

Permitting and Siting Status

CEC issued 2/20/2007 (Case No. 131, Decision No. 69343, Morgan-Pinnacle Peak 500kV/230kV Transmission Line Project). Decision No. 78251, on 9/29/2021, amended the CEC authorizing the cut-in and construction of a third substation (TS22).

Panda to Freedom 230kV Line Rebuild

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2029

Projected In-service Date

2031

Facility Details

Voltage Class	230kV AC
Facility Rating	3000 A
Point of Origin	Panda 230kV substation
Intermediate Points of Interconnection	Komatke substation (in service TBD) and TS29 substation (in service TBD)
Point of Termination	Freedom 230kV substation
Length	Approximately 40 miles

Routing

Heading north from Panda substation to Jojoba substation, the line will be rebuilt generally using a new alignment west of the existing Gila River-Jojoba 500kV lines. The rebuilt line will be constructed using monopoles capable of supporting a second future 500kV line. From Jojoba to the Gila River, the line will be rebuilt in a new alignment adjacent to the existing line. In this section the new line will share structures with the planned Jojoba-TS21 500kV line. North of the Gila River, the Panda-Freedom 230kV line and Jojoba-TS21 500kV line will head east on shared structures in a new alignment generally paralleling the Gila River. From a point generally south of Freedom substation, the new Panda-Freedom 230kV line will head generally north in a new alignment, terminating at Freedom and separate from the Jojoba-TS21 500kV line route. This final section will utilize monopole structures capable of carrying a future second 230kV circuit.

Purpose

To alleviate projected loading constraints on the existing Panda-Freedom line due to new high-load customers in Metro Phoenix and generation additions in the vicinity of the Gila River and Panda substations. The rebuilt line will also support continued customer growth in the Buckeye area and increase access to diverse generation resources.

Permitting and Siting Status

An application for a CEC has not yet been filed. The CEC for the existing Panda-Freedom 230kV line was authorized in Case No. 26, Decision No. 46865. During the development of the project APS will determine if a CEC amendment or a new CEC application is most appropriate.

Pinnacle Peak to Ocotillo 230kV Line Rebuilds

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2029

Projected In-service Date

2031

Facility Details

Voltage Class	230kV AC
Facility Rating	3000 A
Point of Origin	Pinnacle Peak substation
Intermediate Points of Interconnection	TS17 substation (in service TBD), Cactus substation, Brandow substation (SRP), and Ward substation (SRP)
Point of Termination	Ocotillo substation
Length	Approximately 25 miles per line (4 lines)

Routing

Rebuild the two sets of double circuit lines on existing structures between Pinnacle Peak and Ocotillo substations. The APS Pinnacle Peak-Ocotillo 230kV line, Pinnacle Peak-Cactus 230kV line, and Cactus-Ocotillo 230kV line will be rebuilt along with the SRP lines sharing the structures (the SRP Pinnacle Peak-Brandow and Brandow-Ward 230kV lines). The lines will likely be rebuilt in the existing alignment. APS is evaluating a possibility of using 500kV construction for at least one future circuit to increase future capacity in the corridor.

Purpose

To replace the existing structures between Pinnacle Peak and Ocotillo. This rebuild will replace aging towers to ensure continued reliability and safety and increase capacity in the Metro Phoenix load pocket.

Permitting and Siting Status

An application for a CEC has not yet been filed. There is no existing CEC as the lines were constructed in the early 1960s, prior to the requirements for a CEC.

Jojoba-Rudd 500kV Line

Project Sponsor

Arizona Public Service Company

Other Participants

Salt River Project

Construction Start

2029

Projected In-service Date

2032

Facility Details

Voltage Class	500kV AC
Facility Rating	TBD
Point of Origin	Jojoba switchyard
Intermediate Points of Interconnection	TS21 substation (in service 2032)
Point of Termination	Rudd substation
Length	Approximately 28 miles

Routing

The Jojoba-Rudd 500kV line will exit Jojoba substation and join with the Panda- Freedom 230kV line, sharing double-circuit structures with that line. Both lines will head generally north, paralleling the existing Panda-Freedom 230kV alignment until they reach the area north of the Gila River. From there, the lines will head generally east, staying north of the Gila River until a point south of Freedom substation, where the lines will split. From this point, the Jojoba-Rudd line will head generally northeast to the future TS21 substation, targeted in an area south of the Palo Verde-Rudd 500kV line corridor and west of Cotton Lane. Between the split with the Panda-Freedom 230kV line and TS21, the new line will be constructed using structures capable of a future second 230kV circuit. From TS21, the line will head generally east to Rudd, paralleling the Palo Verde-Rudd corridor. Circuit arrangement in the corridor from TS21 to Rudd has not yet been determined.

Purpose

To provide an additional EHV source to the Phoenix Metropolitan area, which is experiencing rapid economic development. This line helps maintain compliance with NERC Reliability Standards and support load growth. In addition, this new source will provide customers greater access to a diverse mix of resources from around the region.

Permitting and Siting Status

An application for a CEC has not yet been filed.

Runway-Stratus 230kV Line Cut-In to TS21

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2029

Projected In-service Date

2032

Facility Details

Voltage Class	230kV AC
Facility Rating	3000 A
Point of Origin	Runway-Stratus 230kV line
Intermediate Points of Interconnection	None
Point of Termination	TS21 substation (in service 2032)
Length	Approximately 1 mile

Routing

New 230kV lines will be extended south from the Runway-Stratus 230kV line to the TS21 substation to cut the line in and out of TS21. The location of TS21 is targeted in an area south of corridor containing the Runway-Stratus 230kV line and Palo Verde-Rudd 500kV line and west of Cotton Lane.

Purpose

To support the growing demand from high-load data center customers in the West Valley by connecting the TS21 substation into the 230kV network. The TS21 500/230kV substation and 230kV lines will relieve loading constraints on the Rudd substation and other 230kV lines in the West Valley.

Permitting and Siting Status

An application for a CEC has not yet been filed.

TS21 to Broadway 230kV Line

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2029

Projected In-service Date

2032

Facility Details

Voltage Class	230kV AC
Facility Rating	3000 A
Point of Origin	TS21 substation (in service 2032)
Intermediate Points of Interconnection	None
Point of Termination	Broadway substation
Length	Approximately 6 miles

Routing

A new 230kV line will be extended generally northeast from the future TS21 substation to Broadway Road. From Broadway Road, the line will head east to Broadway substation, paralleling the WAPA 230kV line corridor. The line will be capable of a future second 230kV circuit and 69kV underbuild.

Purpose

To support the growing demand from high-load data center customers in the West Valley by connecting the TS21 substation into the 230kV network. The TS21 500/230kV substation and 230kV lines will relieve loading constraints on the Rudd substation and other 230kV lines in the West Valley.

Permitting and Siting Status

An application for a CEC has not yet been filed.

Four Corners to Cholla to Pinnacle Peak 345kV Line Rebuilds

Project Sponsor

Arizona Public Service Company

Other Participants

None

Construction Start

2030

Projected In-service Date

2035

Facility Details

Voltage Class	345kV AC
Facility Rating	3000 A
Point of Origin	Four Corners substation
Intermediate Points of Interconnection	Cholla substation, West Camp Wind switchyard (in service 2026), Chevelon switchyard, Preacher Canyon substation, and Mazatzal substation
Point of Termination	Pinnacle Peak substation
Length	Approximately 289 miles per line (2 lines)

Routing

Rebuild the two existing circuits between Four Corners substation and Pinnacle Peak substation. For most of the route, lines will be rebuilt out of lead to avoid extended system outages.

Purpose

To replace existing lattice towers along the entire route. This rebuild will replace aging towers to ensure continued reliability and safety, improve deliverability into the Metro Phoenix area, and increase import capability to the Metro Phoenix area from the Cholla substation and the Four Corners region. The increase in capacity of the rebuilt lines will improve access to a diverse mix of resources from the Four Corners region and the southwest. The lines will be constructed to accommodate potential conversion to 500kV operation in the future.

Permitting and Siting Status

An application for a CEC has not yet been filed.

To Be Determined Projects

List of To Be Determined Projects

Table 3: To Be Determined Projects

Project Name	Permitting and Siting Status
El Sol to Westwing 230kV Line	CEC issued (Case No. 9, Docket No. U-1345).
Palo Verde to Saguaro 500kV Line	CEC issued (Case No. 24, Decision No. 46802).
Komatke 230/69kV Substation	CEC issued (Case No. 102, Decision No. 62960).
Palm Valley-Dromedary-TS27-Parkway 230kV Line Circuit #2	CEC issued (Case No. 122, Decision No. 66646, amended by Decision Nos. 73937, 77761 and 79248 West Valley-South 230kV Transmission Line Project).
Sun Valley to Trilby Wash 230kV Line Circuit #2	CEC issued (Case No. 127, Decision No. 67828, amended by Decision Nos. 74955 and 75045, West Valley North 230kV Transmission Line project).
Trilby Wash to Parkway 230kV Line Circuit #2	The Trilby Wash-TS2 segment CEC issued (Case No. 127, Decision No. 67828, amended by Decision Nos. 74955 and 75045, West Valley North 230kV Transmission Line project).
El Sol-Contrail-TS34-Sabre-Parkway 230kV Line Circuit #2	CEC issued 11/7/2019 (Case No. 183, Decision No. 77469, West Valley Central CEC).
Morgan to Outer Circle 230kV Line	CEC issued (Case No. 138, Decision No. 70850, amended by Decision Nos. 71645 and 75092, TS5-TS9 500/230kV Project).
Orchard to Yucca 230kV Lines	CEC issued (Case No. 163, Decision No. 72801, North Gila to TS8 to Yucca 230kV Transmission Line Project).
North Gila-Orchard 230kV Line Circuit #2	CEC issued (Case No. 163, Decision No. 72801, North Gila to TS8 to Yucca 230kV Transmission Line Project).
Buckeye-TS11-Sun Valley 230kV Line	An application for a CEC has not yet been filed.
Sun Valley-TS10-TS11 230kV Line	An application for a CEC has not yet been filed.
Delaney to Quartzsite 500kV and 230kV Lines	An application for a CEC has not yet been filed.

Project Name	Permitting and Siting Status
Quartzsite to Colorado River 500kV Line	An application for a CEC has not yet been filed.
Milligan to Pinal Central 230kV Line	An application for a CEC has not yet been filed.
TS14 230KV Lines	An application for a CEC has not yet been filed.
TS17 230kV Lines	An application for a CEC has not yet been filed.
TS27 230kV Switchyard and Lines	CEC issued (Case No. 122, Decision No. 66646, amended by Decision Nos. 73937, 77761, and 79248, West Valley-South Project).
TS30 500/230kV Substation and Lines	An application for a CEC has not yet been filed.
TS32 230kV Lines	An application for a CEC has not yet been filed.
TS35 Substation and Lines	An application for a CEC has not yet been filed.
Milligan Solar and Storage Project Generator Tie Line	An application for a CEC has not yet been filed.
Obed Meadow 230kV Generation Tie Line Project	CEC issued 12/12/2023 (Case No. 222, Decisions No. 79187 and 79188). CEC 222-B will be transferred to APS at a future date.
Orchard Solar 230kV Transmission Line Project	CEC issued 3/23/2023 (Case No. 213, Decisions No. 78893 and 78894). CEC-2 for the generation tie line may be transferred to APS in the future.

Attachment B

Renewable Transmission Action Plan

Arizona Public Service Company
Renewable Transmission Action Plan
January 2024

In the Fifth Biennial Transmission Assessment (BTA) Decision, (Decision No. 70635, December 11, 2008), the Arizona Corporation Commission (ACC or Commission) ordered Arizona Public Service Company (APS or Company) to file a document identifying their top potential Renewable Transmission Projects (RTPs) that would support the growth of renewable resources in Arizona. As such, on January 29, 2010, APS filed with the Commission its top potential RTPs, which were identified in collaboration with the Southwest Area Transmission planning group (SWAT) and its subgroups, other utilities and stakeholders. In its filing, APS included a Renewable Transmission Action Plan (RTAP), which included the method used to identify RTPs, project approval and financing of the RTPs.

On January 6, 2011, the Commission approved APS's first RTAP (Decision No. 72057, January 6, 2011[1]), which allows APS to pursue the development steps indicated in the APS RTAP. The Decision, in part, ordered:

> *IT IS FURTHER ORDERED that the timing of the next Renewable Transmission Action Plan filing shall be in parallel with the 2012 Biennial Transmission Assessment process.*
>
> *IT IS FURTHER ORDERED that Arizona Public Service Company shall, in any future Renewable Transmission Action Plans filed with the Commission, identify Renewable Transmission Projects, which include the acquisition of transmission capacity, such as, but not limited to, (i) new transmission line(s), (ii) upgrade(s) of existing line(s), or (iii) the development of transmission project(s) previously identified by the utility (whether conceptual, planned, committed and/or existing), all of which provide either:*
>
> 1. *Additional direct transmission infrastructure providing access to areas within the state of Arizona that have renewable energy resources, as defined by the Commission's Renewable Energy Standard Rules (A.A.C. R14-2-1801, et seq.), or are likely to have renewable energy resources; or*
> 2. *Additional transmission facilities that enable renewable resources to be delivered to load centers.*

Over the last decade across the country, and specifically within APS's generation interconnection queue, there is significant activity to interconnect renewable energy projects. These projects have ranged from large scale projects connecting into the Bulk Electric System, down to smaller scale projects connecting into the local sub-transmission and distribution systems. The development of renewable energy projects is now the overwhelming majority of interconnection requests that are received and are an important source of energy to meet future resource needs.

Two of the three RTPs that APS filed in its original RTAP have been completed.
The remaining RTP that APS filed in its original RTAP continues to be viable and are being developed as reliability and resource needs have been identified within the planning horizon. Described below is the current status of the proposed development

---

[1] *Commission Decision No. 72057 found that APS's 2010 RTAP process and Plan is appropriate and consistent with the Commission's Fifth Biennial Transmission Assessment final order.*

plan for a Palo Verde to Liberty and Gila Bend to Liberty projects (approved by the Commission in Decision No. 72057).

> The Palo Verde to Liberty and Gila Bend to Liberty projects were conceptual in nature when they were proposed. APS's 2024-2033 Ten-Year Transmission System Plan contains projects that closely resemble those proposed projects, but in an updated and more appropriate form for the existing transmission system. These projects include the Jojoba to Rudd 500kV project and the Panda to Freedom 230kV rebuild project.
>
> The Jojoba to Rudd project accomplishes the goals of the conceptual Palo Verde hub to Liberty project. While Jojoba is not within the Palo Verde hub it does connect directly to the Palo Verde hub and will help to increase the deliverability of resources from the Palo Verde hub into Phoenix.
>
> The second project is the Panda to Freedom 230kV rebuild project. The rebuild of the existing line will provide a significant increase in the capability to deliver resources from the Gila Bend area.
>
> Both of these projects are in the planning phase.

The APS 2024-2033 Ten-Year Transmission System Plan does not show a need for additional RTPs beyond what the Commission approved in Decision No. 72057. As a result, in this RTAP APS is not proposing new RTPs. APS will explore new renewable transmission opportunities when appropriate.

Attachment C

Technical Study on the Effects of Distributed Generation/Energy Efficiency on Fifth Year Transmission Plan

Technical Study

Effects of Energy Efficiency and Distributed Generation on Future Transmission Needs

FINAL

SALT RIVER PROJECT

ARIZONA PUBLIC SERVICE COMPANY

January 2024

Executive Summary

In Decision No. 74785 (October 24, 2014), the Eighth Biennial Transmission Assessment (Eighth BTA), the Commission ordered Arizona utilities with retail load to study the effects of Energy Efficiency (EE) and Distributed Generation (DG) on their future planned transmission systems in their fifth planning year (the Study).

To perform the Study, Salt River Project (SRP) and Arizona Public Service Company (APS) used the 2028 Heavy Summer base case, which was reviewed and updated by APS, SRP, Tucson Electric Power (TEP), UNS Electric (UNSE), Arizona Electric Power Cooperative (AEPCO), and Western Area Power Administration (WAPA) (Arizona entities).

- The first case is the base case or typical system peak planning load, which includes the effects of EE/DG offset to peak load.
- The second case is the base case with the projected increases in EE/DG over the next five (5) years backed out of the load forecast.
- The projected increases of EE/DG in APS's footprint for 2024 to 2028 that are backed out of the forecast for this case total 739 MW, which includes 591 MW for EE and 148 MW for DG.
- The projected increases of EE/DG in SRP's footprint for 2024 to 2028 that are backed out of the forecast for this case total 280 MW, which includes 143 MW for EE and 137 MW for DG.

The Study indicated that the delayed or non-implemented EE/DG over APS and SRP's combined footprint causes no thermal overloads on 100kV and above transmission facilities.

Table of Contents

1. Introduction

In Decision No. 74785 (October 24, 2014), the Eighth Biennial Transmission Assessment (Eighth BTA), the Commission ordered Arizona utilities with retail load to study the effects of Distributed Generation (DG) and Energy Efficiency (EE) installations and/or programs on their future planned transmission systems. The Decision states:

> The technical study should be performed on the fifth year transmission plan by disaggregating the utilities' load forecasts from effects of EE/DG and performing contingency analysis with and without the disaggregate EE/DG. The technical study should at a minimum discuss EE/DG forecasting methodologies and transmission loading impacts. The study should monitor transmission down to and including the 115 kV level. Alternative methodologies or study approaches will be acceptable on condition that the study results satisfy the minimum requirements [above].[1]

2. Study Requirements and Assumptions

2.1.Study Requirements

To fulfill this requirement in the Eighth BTA, the Study looks at two load scenarios outlined in Table 1 below. The first case uses the forecasted load including the effects of EE/DG per the typical planning process. The second case uses the forecasted load excluding the effects of projected increases in EE/DG between 2024 and 2028 This scenario is equivalent to "disaggregating the utilities load forecasts from effects of EE/DG.[2]"

Table 1 - Summary of Cases

Case	Scenario	Load	EE	DG	Utility Solar
1	Base	Peak	On	On	On
2	EE/DG	Peak	Pre 2024 only	Pre 2024 only	On

The Study monitored the loading impacts to the transmission system and performed reliability analysis similar to how SRP and APS analyzes it in the ten-year planning process. For the two cases, transmission facilities greater than 100kV are examined to ensure there are no thermal or voltage criteria violations. These facilities are examined with all lines in-service and for all single contingencies.

[1] Decision No. 74785 at 9:22-27 and 10:1-2.
[2] *Id.* at 9:22-24.

2.2.Studied Cases Assumptions

This Study used the 2028 power flow case, consistent with the planned projects in SRP's and APS's 2024-2033 Ten-Year Plans. The 2028 heavy summer case was a "seed case" created by Arizona entities for use in planning studies during 2023. For the EE/DG scenario case the APS and SRP loads in the 2028 planning case were increased to reflect the absence of EE/DG installations after 2023, as described below.

- Within the APS service territory, the estimated increase in EE and DG from 2024 to 2028 is 739 MW. This total includes 591 MW for EE and 148 MW for DG. Of these amounts, 77% of the MW contributions of DG were estimated to be from metro Phoenix load areas, while 23% of the MW contributions of DG were estimated to be from areas outside the metro area. Similarly, 75% of the MW contributions of EE were estimated to be from metro Phoenix load areas, while 25% of the MW contributions of EE were estimated to be from areas outside the metro area. Identified large industrial loads were not scaled during the process of creating the scenario cases. Available generation within Arizona was increased to account for the increased load.
- SRP's forecasting group estimated EE and DG would contribute an additional 280 MW in 2028, compared to 2024, all of which occurred within the Phoenix metro load pocket. For the EE/DG scenario case the SRP load in the 2028 planning case was increased by this value to study its delayed/non-implemented impact. Available generation within Arizona was increased to account for the increased load.

3. Energy Efficiency and Distributed Generation Forecasting Methodology Description

EE/DG estimates were developed to determine what each program's role was at the time of the system peak in 2028. The combined total EE/DG impacts at peak on APS's transmission system in 2028 are estimated to be an additional 739 MW, compared to 2024. SRP's forecasting group estimated EE and DG would contribute 280 MW in 2028. The details of the EE and DG estimates are described below.

3.1.Energy Efficiency Impact

To forecast the EE program impact (net of demand response curtailment) on APS's system peak in 2028, several steps were taken. First, efficiency measures in 2024-2028 were forecasted by assuming levels associated with APS's 2020 IRP. Then, when the EE amounts were determined, as defined above, they were assessed to establish the EE programs overall impact coincident to APS's system peak. SRP's EE forecasting included expected impacts through 2028 during system peak. Table 2 provides the projected EE for APS and SRP at peak hour for 2028.

Table 2: APS and SRP Energy Efficiency Forecast 2024-2028

	2028
APS EE impact to peak	591 MW
SRP EE impact to peak	143 MW

3.2. Distributed Generation Impact

The impact to APS and SRP load from DG systems in 2028 was based on projections of new DG system installations. The projection of installations was then applied to each month of the forecast period until 2028 to forecast the total amount of DG on the network. From this, the impacts to the 2028 APS and SRP system coincident peaks from DG were determined. The forecasted incremental DG at peak hour for 2028 is provided in Table 3.

Table 3: APS and SRP Distributed Generation Forecast 2024-2028

	2028
APS DG impact at peak load	148 MW
SRP DG impact at peak load	137 MW

4. Study Results

The 2028 base case and the case with delayed or non-implemented EE and DG showed no APS or SRP thermal violations on the monitored elements for all lines in-service condition. Also, under this condition no APS or SRP voltage violations were noted.

The results for the case with delayed or non-implemented EE and DG over the entire APS and SRP combined footprint show no overloads on SRP's BES. No thermal violations were noted on APS's 100kV and above transmission system with the single contingency power flow analysis. Additionally, no new or significantly exasperated existing voltage violations on the 100kV and above transmission system were observed in this analysis.

5. Conclusion

The Study indicates that delayed or non-implemented EE/DG has no effect on the reliability of the APS or SRP 100kV and above transmission systems as currently planned in 2028. It should be noted that this study only addresses the impacts to the APS and SRP 100kV and above transmission system and there may be some impacts at the sub-transmission level due to changes in the quantity and timing of EE/DG implementation.

Attachment D

Reliability Must-Run Analysis 2024-2033

Reliability Must-Run Analysis

2024-2033

January 2024
APS Transmission Planning

TABLE OF CONTENTS

PAGE

List of Tables

Page

LIST OF FIGURES

Page

APS Reliability Must-Run Analysis 2024-2033

I. EXECUTIVE SUMMARY

This report documents the study methodology, results, and conclusions of Arizona Public Service Company's (APS or Company) Reliability Must-Run (RMR) Analysis for the ten years from 2024 to 2033 (2024 RMR Analysis). This analysis was conducted in response to the Arizona Corporation Commission's (ACC) Second Biennial Transmission Assessment (BTA) and Decision No. 65476 (December 19, 2002). The 2024 RMR Analysis covers a ten-year period and includes detailed analysis for the years 2028 and 2033.

APS has performed and filed with the ACC numerous RMR studies since 2003. After reviewing the 2012 RMR study, the ACC Seventh BTA suspended the requirement for performing RMR studies in every BTA and implemented criteria for restarting such studies based on a biennial review. In the next 10 years, none of the triggering events have occurred that would require performing a RMR study.

APS performed the 2022 RMR analysis to evaluate RMR conditions for the ten years following 2021, which was the last year studied in the 2012 RMR. The 2022 RMR evaluation results were similar to prior RMR studies and indicated that the cost for any transmission alternative would significantly exceed the costs associated with any RMR conditions that currently exist. Additionally, the analysis showed that Yuma is no longer import-limited and is not identified as a load pocket.

This 2024 RMR study has been performed for the Phoenix metro load pocket to comply with the requirement to file based on increased projected load forecast.[1] Load forecasts since the last RMR reflect higher demand, especially in Maricopa County, primarily driven by three major factors: data center growth, large industrial customer growth, and electric vehicle adoption.

A. Study Overview

The existence of transmission import limited areas is not uncommon in the United States, and particularly in the West where load centers are generally separated by long distances. An import area is transmission limited when all load cannot be served solely by importing resources over local transmission lines, thus requiring some use of local generating units to reliably meet peak load.

The transmission import-limited Phoenix metro area in APS's system was studied to determine:

- The system simultaneous import limit (SIL), which is the maximum amount of capacity that can be reliably imported into an area with no local generation;
- The maximum load serving capability (MLSC), which is the total load that can be served from imports and from local generation;

[1] An increase of more than 2.5% in the load forecast since the previous BTA (e.g. relative to the final RMR study year for which RMR studies were last filed.)

- The load serving capability and local generation reserves, at the peak forecasted load; and
- Annual RMR conditions, including magnitude of load in excess of the import capability and number of hours the load exceeds the SIL.

The Phoenix area is a tight network of APS and SRP load, resources, and transmission facilities. Because the Phoenix system is highly integrated, the import limits must be determined for the combined area. This analysis was coordinated with SRP personnel, who had significant involvement in the study and overall analysis.

After the combined import limits for the Phoenix area were determined, RMR conditions were evaluated based on the import limits, the Phoenix area load, and local generation, which includes generation owned by APS, SRP, and others.

B. Summary of Results

Results of the analysis for the two years of the study, 2028 and 2033, assumed that present plans for system improvements, in place when the study was conducted, are completed on schedule.

The following table summarizes the estimated RMR conditions for the Phoenix area.

Table ES1
Phoenix Area RMR Conditions

Year	SIL[1] (MW)	Peak Demand (MW)	Import at Peak (MW)	RMR[2] at Peak (MW)	RMR[3] Hours	RMR Energy[4] (GWH)	RMR Energy (% of total)	RMR Cost[5] ($M)
2028	**11,979**	**15,641**	**12,279**	**3,362**	**1,057**	**1,422**	**1.8**	**0**
2033	**9,922**	**17,841**	**12,227**	**5,614**	**4,800**	**7,372**	**7.8**	**0**

Table Key:
[1]**SIL** – System Simultaneous Import Limit is the maximum amount of capacity that can be reliably imported into the area with no local generation operating.
[2]**RMR** at Peak – The amount of local generation required to meet the area peak demand (Peak Demand minus Import Capability at peak load – See figures 3 and 4).
[3]**RMR Hours** – The number of hours that the area's demand exceeds the SIL, thus requiring the use of local generation to meet load.
[4]**RMR Energy** – The annual energy required to be met by local generation (even if otherwise economically dispatched).
[5]**RMR Cost** – The difference in annual generation cost with and without the transmission limitation (this accounts for generation economically dispatched).

APS determined the reserve requirement for Phoenix based on its system Loss of Load Expectation (LOLE) reliability target of one event in ten years. The APS system reserve margin, described below in Section IV (see E. Reserves) is a reasonable approximation of reserve required to meet reliability requirements for the Phoenix load pocket given the changes to the load pocket generation and transmission system upgrades. This criteria would result in not being able to meet Phoenix load once in ten years.

The SIL and MLSC are determined by performing power flow studies. The SIL and MLSC results are utilized to develop the Phoenix area Load Serving Capability (LSC) graphs, determining the amount of local Phoenix generation that is required to serve the projected peak demand, and determining the import capability at the projected peak demand. The Phoenix area projected reserves are calculated from the total local Phoenix generation less the amount of local generation required at peak demand. The following table shows the projected Phoenix area reserve capacity.

Table ES2
Phoenix Area Reserve Capacity

Year	Local Generation	Peak Demand (MW)	Import at Peak (MW)	RMR at Peak (MW)	Projected Reserves[1]	Required Reserves[2]
2028	**6,322**	**15,641**	**12,279**	**3,362**	**2,960**	**232**
2033	**6,560**	**17,841**	**12,227**	**5,614**	**946**	**387**

Table Key:
[1]**Projected Reserves** – The amount of local generation plus import at peak minus peak demand.
[2]**Required Reserves** – The amount of local generation required to be held in reserve at Peak.

The cost of using must-run units can be measured by the difference between generation costs with the transmission limit and costs without the limit. This report looks at and compares the cost of serving the RMR area with and without the identified transmission constraints. This report concludes that for the Phoenix metropolitan area, there is no cost of RMR due to all the internal generation being economically dispatched for all RMR hours.

Table ES3
Phoenix Area RMR Outside Economic Dispatch

Year	Hours outside economic dispatch	Energy outside economic dispatch (GWH)	RMR cost ($M)
2028	**0**	**0**	**0**
2033	**0**	**0**	**0**

C. Report Conclusions

Phoenix Area Conclusions

1. Phoenix area existing and planned transmission and local generation are adequate to reliably serve Phoenix area peak load in 2028 and 2033. Additionally, the projected generation reserve margin maintains local reliability requirements in both years.
2. Phoenix area load is expected to exceed the available transmission import capability for 1,057 hours in 2028 and 4,800 hours in 2033. In 2028, these hours represent less than two

percent of the annual energy requirements for the Phoenix area. By 2033, these hours represent less than eight percent of the annual energy requirements for the Phoenix area.

3. The study results indicate that there is no out-of-merit dispatch of units in the load pocket in 2028 and 2033. Despite more RMR plant hours in 2033, because there is no out-of-merit dispatch there is no RMR cost.

D. Report Organization

This report is organized in six sections. Section I provides an executive summary of the report. Section II provides general background information of the study requirements, an overview of RMR, and describes the study methodology. Section III describes the Phoenix area, the nature of the import limit, the resulting import limits for 2028 and 2033, and the impact of various generators in and around the Phoenix area on the import limit. Section IV describes the RMR conditions such as number of hours, maximum capacity, and annual energy for the Phoenix area. Finally, Section V lists the conclusions of the analysis.

II. Introduction

A. Background of Study Requirement

Like all large electric utilities, to reliably serve their customers Arizona utilities have historically relied on transmission to deliver remote generation into its load centers as well as local generation. Due in part to environmental, economic, and fuel availability considerations, large base-load thermal generators have typically been located away from the load centers while smaller but less efficient intermediate and peaking units, with lower capacity factors, were located within the load centers. Although this local generation is relied on for a relatively small amount of energy, this local generation is critically important for the reliability of the local power system. The November 2003 U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada pointed out the importance of the reactive capability of voltage support from local generation. Local generation can provide critical support for transmission contingencies and other power system disturbances and can prevent customer outages including blackout conditions such as those experienced in the Northeast on August 14, 2003. Local generation also results in lower power system losses and lower capital expenses for transmission infrastructure.

Historically, vertically-integrated utilities, such as APS, managed the siting and construction of both generation and transmission resources needed to serve their customers. Electric systems were designed based on a detailed integrated resource planning process used to evaluate the appropriate balance of generation, transmission, and demand-side resources. Interconnections with neighboring systems were primarily intended to improve system reliability and lower the costs of reserves by allowing for sharing of capacity reserves by multiple systems. Each utility's system was primarily designed to accommodate that utility's resources and that utility's load.

The Commission's Second Biennial Transmission Assessment (BTA) required "any [Utility Distribution Company] that currently relies on local generation, or foresees a future time period when utilization of local generation may be required to assure reliable service for a local area, [to] perform and report the findings of an RMR study as a feature of their ten year plan filing with the Commission in January 2003 and 2004." The Assessment required that the RMR study filed in January 2003 evaluate RMR conditions through the 2005 summer peak. The January 2004 RMR study covers the 10-year period from 2004 to 2013. The Commission's Third BTA determined that RMR studies must be performed on a biennial basis, with the next report being filed with the ten year plan filed in January 2006. The Commission's Fourth BTA reaffirmed that RMR studies will continue to be performed on a biennial basis, with two representative years being studied and publicly available data being utilized.[2] The ACC Seventh BTA suspended the requirement for performing RMR studies in every BTA and implemented criteria for restarting such studies based on a biennial review of the following factors:

1) An increase of more than 2.5% in the load forecast since the previous BTA (e.g. relative to the final RMR study year for which RMR studies were last filed.)[3]
2) Planned retirement (or an expected long-term outage during the summer months of June, July or August) of a transmission or substation facility required to serve an RMR load pocket, unless a facility being retired will be replaced with a comparable facility before the next summer season.
3) 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.
4) A significant customer outage[4] in an RMR load pocket during summer months.

B. Overview of RMR

Local "load pockets" are areas that do not have enough transmission import capability to serve all load in the area solely by importing remote generation over local transmission facilities. For these areas, during peak hours of the year, local generation is required to serve that portion of the load that cannot reliably be served by transmission imports. This local generation requirement is often referred to as Reliability Must-Run or RMR generation. In these areas, during peak conditions, load is served by a combination of importing remote generation over transmission lines and operating local generation. The Phoenix metropolitan area load, which is served by a combination of APS and Salt River Project (SRP) facilities, cannot be served completely by power imported over transmission lines in the APS service territory.

[2] The years 2028 and 2033 were selected because Arizona entities coordinated the power flow base case development for these years.
[3] For example, the final RMR study year filed in this BTA is 2033 and future BTA load forecasts for 2033 would be compared to this BTA forecast amount for this year to determine the percent increase. Using the data for the Phoenix RMR area, the peak demand forecast for 2033 is equal to 17,841 MW, so the need for restarting RMR analysis would be considered if and when a revised 2033 forecast exceeds 17,841 x 1.025 = 18,287 MW.
[4] Defined as a sustained outage that exceeds the greater of 100 MW or 10% of the peak demand in an RMR pocket.

The maximum load that can be served in a load pocket with all local generation operating – in other words, the maximum load that can be served by importing remote generation and local generation – is referred to as the system MLSC. The MLSC is established through technical studies by ensuring that:

- With all local generation operating and maximum imports of remote generation on the transmission system there are no transmission system normal operating (N-0/P0) limit violations of thermal loading or voltages, and
- Thermal loading remains below equipment emergency ratings, voltages remain within emergency operating limits, and a positive reactive power margin is maintained.

The maximum load that can be served in a load pocket with no local generation operating — in other words, the maximum load that can be served solely by importing remote generation — is referred to as the system SIL. The SIL is established through technical studies by ensuring that:

- With no local generation operating there are no transmission system normal operating (N-0/P0) limit violations of thermal loading or voltages, and
- Under all single contingency outage events (N-1/P1) there are no emergency operating limit violations of thermal loading or voltages, and no system voltage instability.

C. Study Methodology

Import limit analysis was performed for the Phoenix area. The import limit area or load pocket is defined as that load which, when increased, would increase the severity of the limiting contingency. For example, load in Flagstaff has no impact on the severity of the limiting contingency for the Phoenix import limited area, and therefore Flagstaff is not included in the Phoenix load pocket. In contrast, downtown Phoenix load does impact the severity of the limiting contingency and therefore is included in the load pocket. All area contingencies known to result in system stress were evaluated to determine the critical contingency for the area. Import limits were determined by contingency conditions of thermal loading at the emergency rating of a facility, steady state voltages at the emergency voltage limit, and system instability, specifically voltage instability.

Import limits were determined for the Phoenix area with no local generation operating, with maximum local generation operating, and sufficient points in between to determine curves which define import limits at all load levels. This methodology was applied to studies of the Phoenix area, which for 2028 and 2033 is constrained by thermal loadings.

From each year's forecasted peak load and historical daily load cycles, the annual RMR conditions were determined, including magnitude of local load that is expected to exceed the SIL and the annual hours for which local load is expected to exceed the SIL.

Additional transmission alternatives to mitigate the import limits of the Phoenix area in 2028 were not studied due to the minimal amounts of RMR conditions that were identified in the study. The cost for any transmission alternative would significantly exceed the costs associated with any RMR conditions that currently exist.

D. Determination of SIL and RMR Conditions

In this analysis, assessment of the SIL and RMR conditions for the Phoenix area was performed for the years 2028 and 2033. Base case and contingency power flow, and voltage stability analyses were performed to determine import limitations. The initial starting cases were based on the Western Energy Coordinating Council (WECC) heavy summer full loop base cases in GE Power Flow format for the corresponding year. Those base cases model the entire Western Interconnection's transmission system and were reviewed and then updated to represent expected loads and system configuration for 2028 and 2033. Both cases were coordinated between APS, SRP, Tucson Electric Power Company (TEP), Arizona Electric Power Cooperative (AEPCO), and WAPA to capture the most accurate expected operating conditions for the Arizona transmission system.

III. PHOENIX LOAD POCKET

A. Description of Phoenix Area

During summers of 2028 and 2033, the Phoenix area — which consists of both APS's and SRP's integrated network — will be served from the following major Extra High Voltage (EHV) substations: Westwing, Pinnacle Peak, Kyrene, Rudd, Browning, Silverking, Abel, Sun Valley, Morgan, and the future TS22 substation. These EHV stations form the foundation of an extensive internal network of 230kV transmission lines that constitute the high voltage energy delivery system within the Phoenix load area.

Because the City of Mesa load is served by dedicated resources external to Phoenix, the RMR analysis is performed with this load excluded.

Energy flows into the EHV delivery points from the EHV transmission lines and then is stepped down to 230kV and transmitted into the load center via the 230kV transmission lines. These loads, with area losses, are measured by determining the flows from the EHV substations into the load area to include all of these load stations. The specific loads to be included in the Phoenix area load for each of the years was determined by sensitivity analysis performed in a previous RMR study effort which determined the impact of various loads on the severity of the critical contingencies. Figure 1 shows all of the loads included for the 2028 study. Figure 2 shows all of the loads included for the 2033 study.

Figure 1

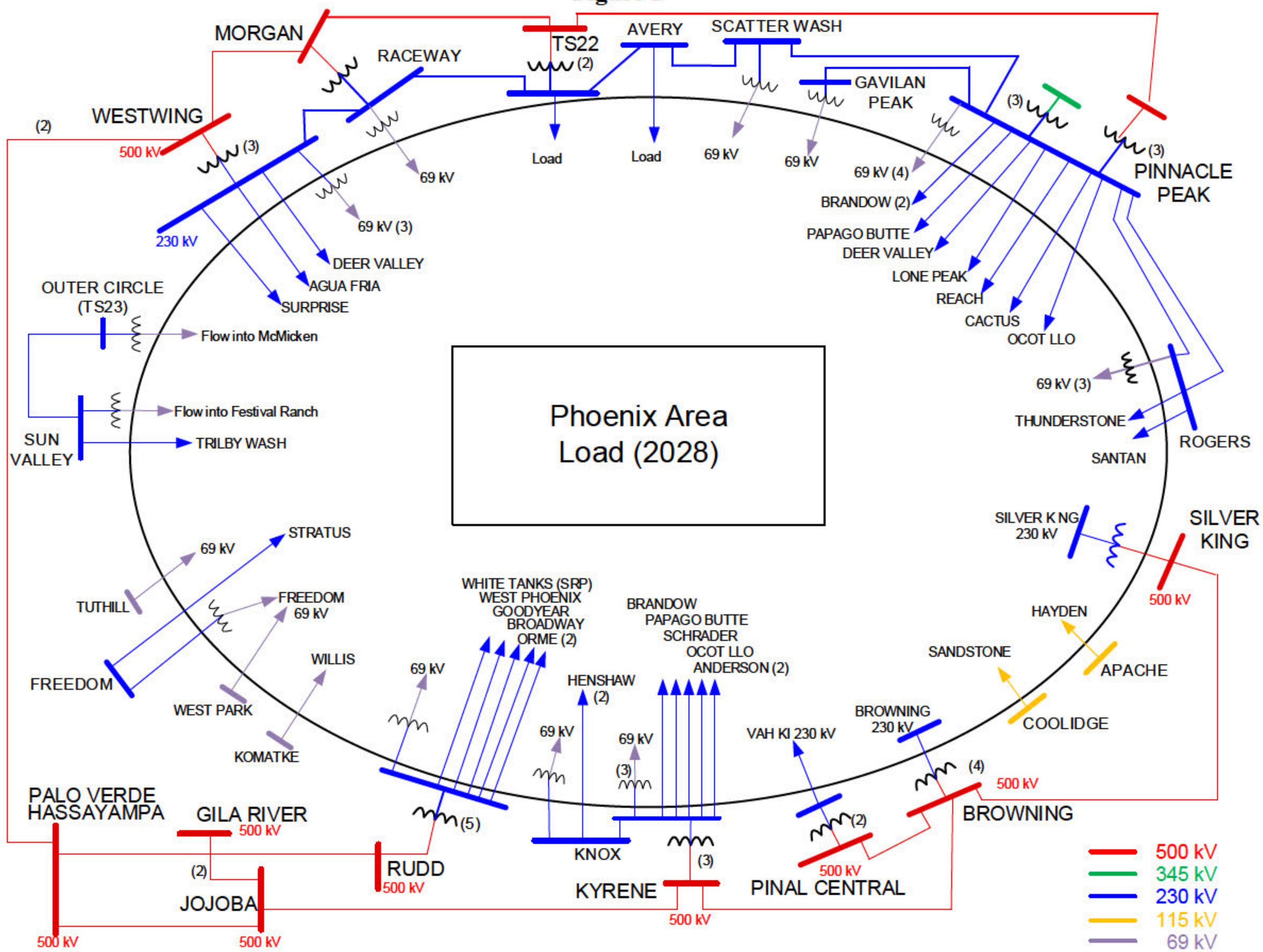
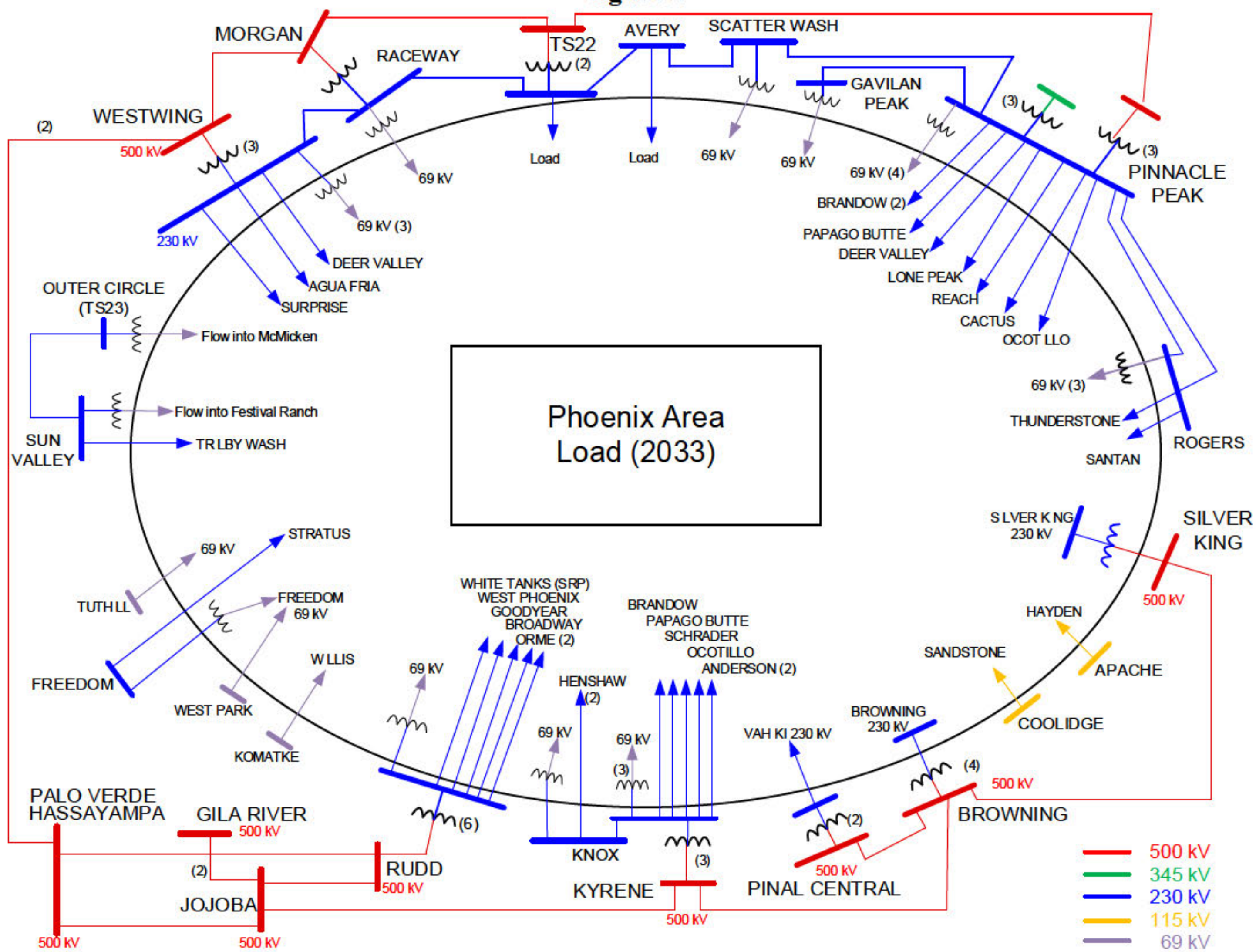

MORGAN
TS22
AVERY
SCATTER WASH
RACEWAY
GAVILAN PEAK
WESTWING
500 kV
230 kV
69 kV
Load
69 kV (3)
69 kV (4)
BRANDOW (2)
PAPAGO BUTTE
DEER VALLEY
LONE PEAK
REACH
CACTUS
OCOT LLO
PINNACLE PEAK
DEER VALLEY
AGUA FRIA
SURPRISE
OUTER CIRCLE (TS23)
Flow into McMicken
Flow into Festival Ranch
TRILBY WASH
SUN VALLEY
Phoenix Area Load (2028)
THUNDERSTONE
SANTAN
ROGERS
SILVER KING 230 kV
SILVER KING
STRATUS
TUTHILL
FREEDOM 69 kV
FREEDOM
WILLIS
WEST PARK
KOMATKE
WHITE TANKS (SRP)
WEST PHOENIX
GOODYEAR
BROADWAY
ORME (2)
HENSHAW (2)
BRANDOW
PAPAGO BUTTE
SCHRADER
OCOT LLO
ANDERSON (2)
HAYDEN
SANDSTONE
APACHE
COOLIDGE
BROWNING 230 kV
VAH KI 230 kV
BROWNING
PALO VERDE HASSAYAMPA
GILA RIVER
RUDD
JOJOBA
KNOX
KYRENE
PINAL CENTRAL
500 kV
345 kV
230 kV
115 kV
69 kV

Figure 2


MORGAN
TS22
AVERY
SCATTER WASH
RACEWAY
WESTWING
GAVILAN PEAK
PINNACLE PEAK
(2)
500 kV
230 kV
Load
Load
69 kV
69 kV (3)
69 kV (4)
BRANDOW (2)
PAPAGO BUTTE
DEER VALLEY
LONE PEAK
REACH
CACTUS
OCOT LLO
DEER VALLEY
AGUA FRIA
SURPRISE
OUTER CIRCLE (TS23)
Flow into McMicken
Flow into Festival Ranch
TR LBY WASH
SUN VALLEY
Phoenix Area Load (2033)
THUNDERSTONE
SANTAN
ROGERS
S LVER K NG 230 kV
SILVER KING
STRATUS
TUTH LL
FREEDOM
FREEDOM 69 kV
WEST PARK
W LLIS
KOMATKE
WHITE TANKS (SRP)
WEST PHOENIX
GOODYEAR
BROADWAY
ORME (2)
HENSHAW (2)
BRANDOW
PAPAGO BUTTE
SCHRADER
OCOTILLO
ANDERSON (2)
HAYDEN
APACHE
SANDSTONE
COOLIDGE
BROWNING 230 kV
VAH KI 230 kV
(4)
(6)
PALO VERDE HASSAYAMPA
GILA RIVER
RUDD
JOJOBA
KNOX
KYRENE
PINAL CENTRAL
BROWNING
500 kV
345 kV
230 kV
115 kV
69 kV

In performing the Phoenix area studies several planned projects were added to reflect transmission system upgrades, in the Phoenix area High Voltage (HV) system and the Arizona EHV system, for the next ten years. They are listed below; under one of the two study years they will first appear:

Projects in service by 2028

- McFarland Solar Project Generation and Tie Line
- Chevelon Butte Wind Generation and Tie Line Project
- Serrano Solar and Storage Project Generation Tie Line
- AES Interconnection at Westwing 230kV
- Hashknife Generation and Tie Line Project
- TS22 500 and 230kV lines
- Three Rivers 230kV Lines
- Contrail 230kV Lines
- Parkway (TS2) 230kV Lines
- Runway additional 230kV Lines
- Broadway 230kV Lines
- Proving Ground Solar and Storage Generation and 500kV Interconnection
- Bianco (TS24) 230kV Lines
- Sun Valley – Outer Circle (TS23) 230kV Line Project
- Rudd 500/230kV transformer #5
- Browning 500/230kV transformer #4
- Orme – Rudd 230kV #1 and #2 reconductor

Additional Projects in service by 2033

- Rudd 500/230kV transformer #6
- Jojoba – Rudd 500kV Line
- Panda – Freedom 230kV Line Rebuild

B. Phoenix Area Critical Outages

1. 2028

For the 2028 year, the primary critical outage is the Palo Verde – Rudd 500kV line overloading the Liberty – Rudd 230kV line for MLSC and the Pinnacle Peak – Rogers 230kV #1 line overloading the Pinnacle Peak – Rogers 230kV #2 line for SIL.

2. <u>2033</u>

In 2033, the critical outage is the Pinnacle Peak – Rogers 230kV #1 line overloading the Pinnacle Peak – Rogers 230kV #2 line for both the MLSC and SIL.

3. <u>Criteria</u>

A thermal overload occurs when more power flows through an element than the continuous or emergency rating of that element. The voltage stability analysis was also performed to identify voltage stability limits. The analysis increased the load levels within the load pocket until voltage collapse occurred. The reported voltage stability limit is then assumed as 95% of the load level just prior to the voltage collapse and reduced again by the Phoenix area reserve margin. The 5% margin is consistent with WECC voltage stability reactive power margin requirements for single contingency conditions.

C. Phoenix Area – SIL and MLSC for 2028 and 2033

Analysis of the Phoenix area transmission network resulted in area import limits based on the limits discussed in the previous section (B. Phoenix Area Critical Outages). Operation of the Phoenix system within these limits ensures that the area does not experience voltage instability or thermal overloading of a system element. The Phoenix area SIL and MLSC for the years 2028 and 2033 are outlined in Table 1.

Table 1
2028 and 2033 Phoenix area SIL and MLSC

Year	SIL (MW)	MLSC (MW)
2028	11,979	18,865
2033	9,922	19,176

The maximum Phoenix area load-serving capability for various generation levels is shown in Figures 3 and 4.

Figure 3

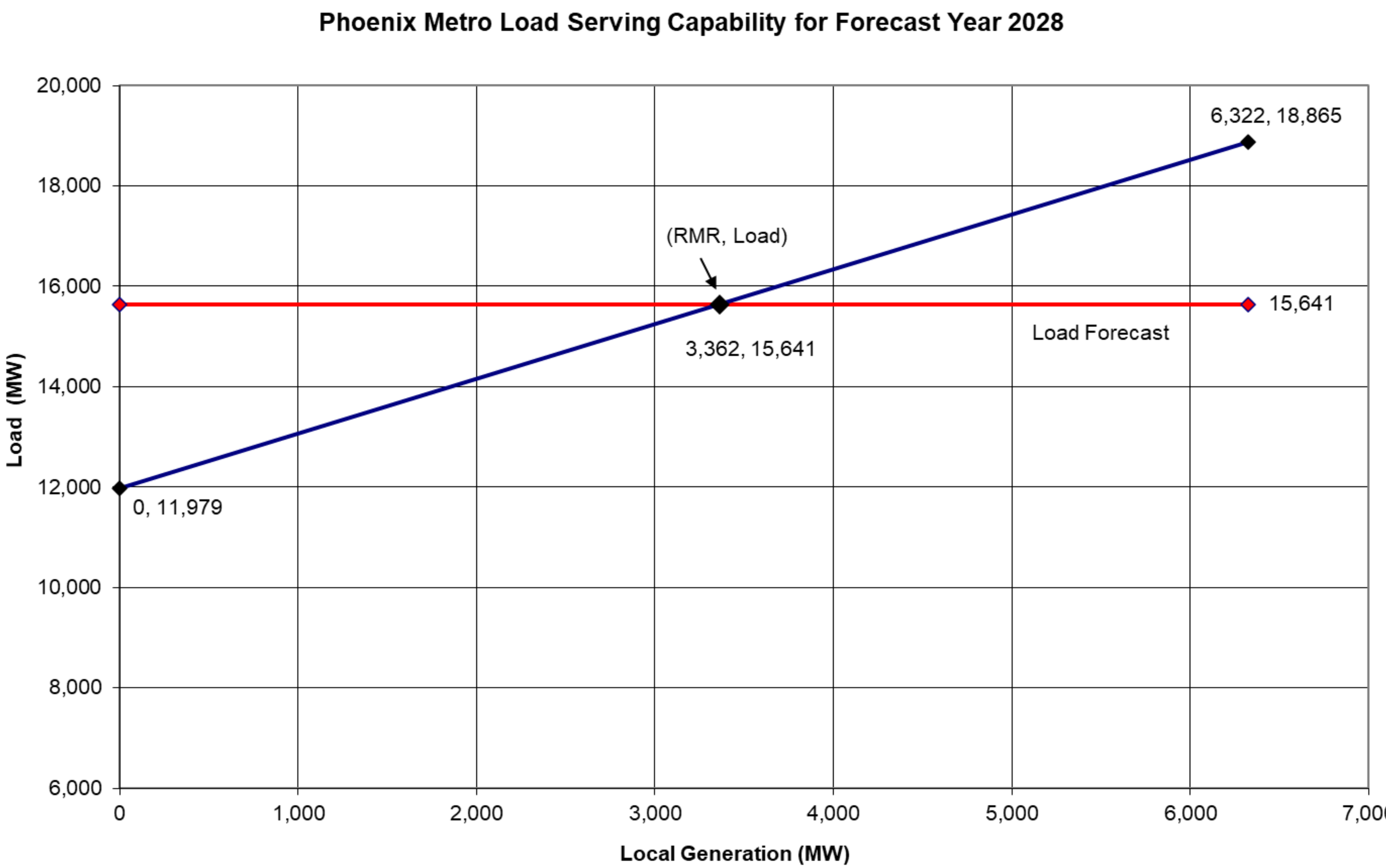
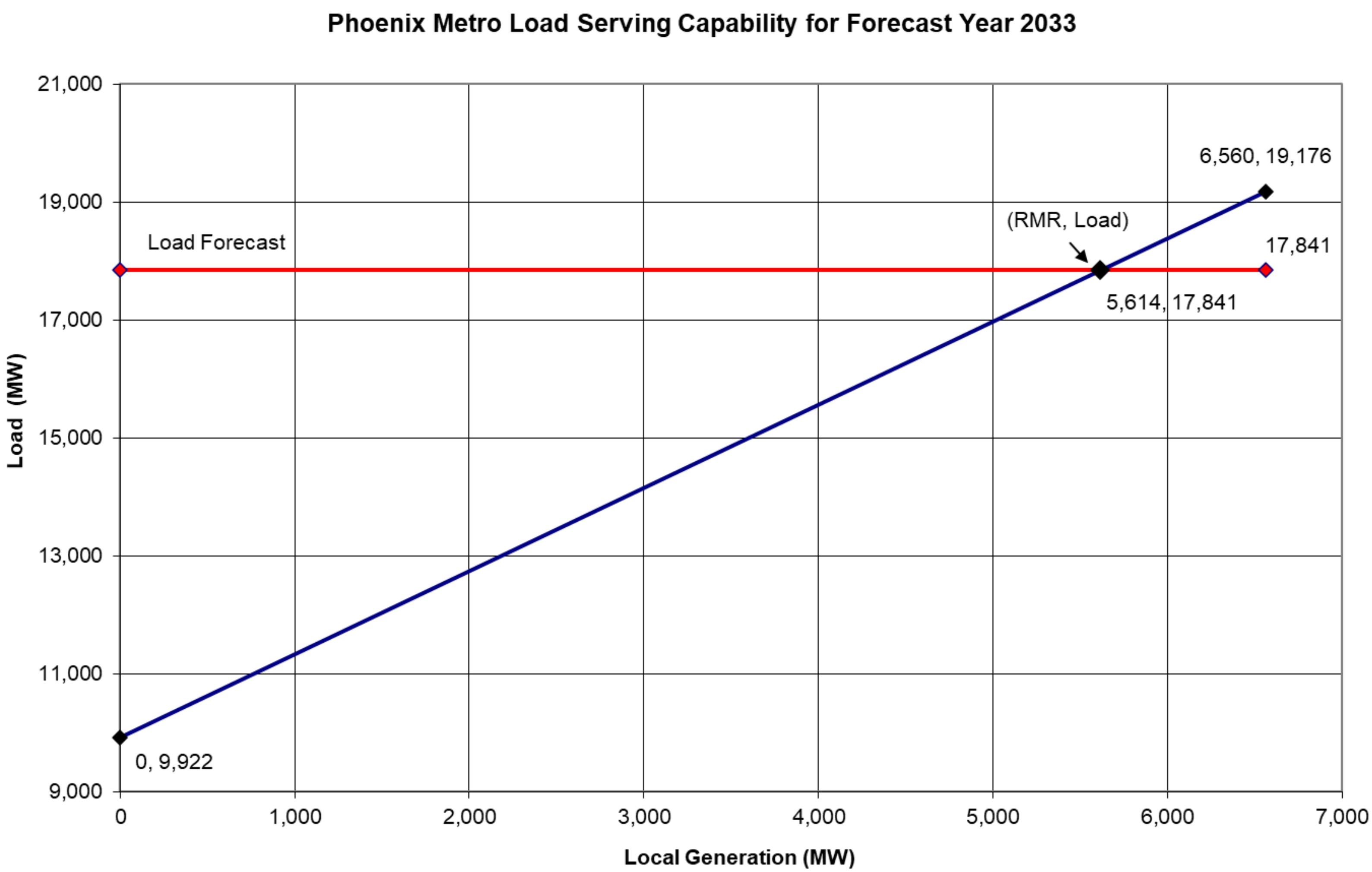

Phoenix Metro Load Serving Capability for Forecast Year 2028
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
Load (MW)
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
Local Generation (MW)
6,322, 18,865
(RMR, Load)
15,641
Load Forecast
3,362, 15,641
0, 11,979

Figure 4


Phoenix Metro Load Serving Capability for Forecast Year 2033
21,000
19,000
17,000
15,000
13,000
11,000
9,000
Load (MW)
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
Local Generation (MW)
Load Forecast
6,560, 19,176
(RMR, Load)
17,841
5,614, 17,841
0, 9,922

IV. Phoenix Area Analysis of RMR Conditions

A. Annual RMR Conditions

An RMR condition exists when the local load is greater than the SIL. In such cases, the RMR condition is the amount of generation that must be located inside of the constrained load area to meet the utility's peak load. RMR conditions for the Phoenix area are shown in Table 2 and are represented in the load-duration curves in Figures 5 and 6.

Table 2
Phoenix RMR Conditions (MW)

	2028	2033
Peak Load	15,641	17,841
Import Capability at Peak	12,279	12,227
Must-Run Generation at Peak	3,362	5,614
Hours Load Exceeds SIL	1,057	4,800
Energy - GWH	1,422	7,372
Energy Percent of Valley Load	1.8%	7.8%

Figure 5

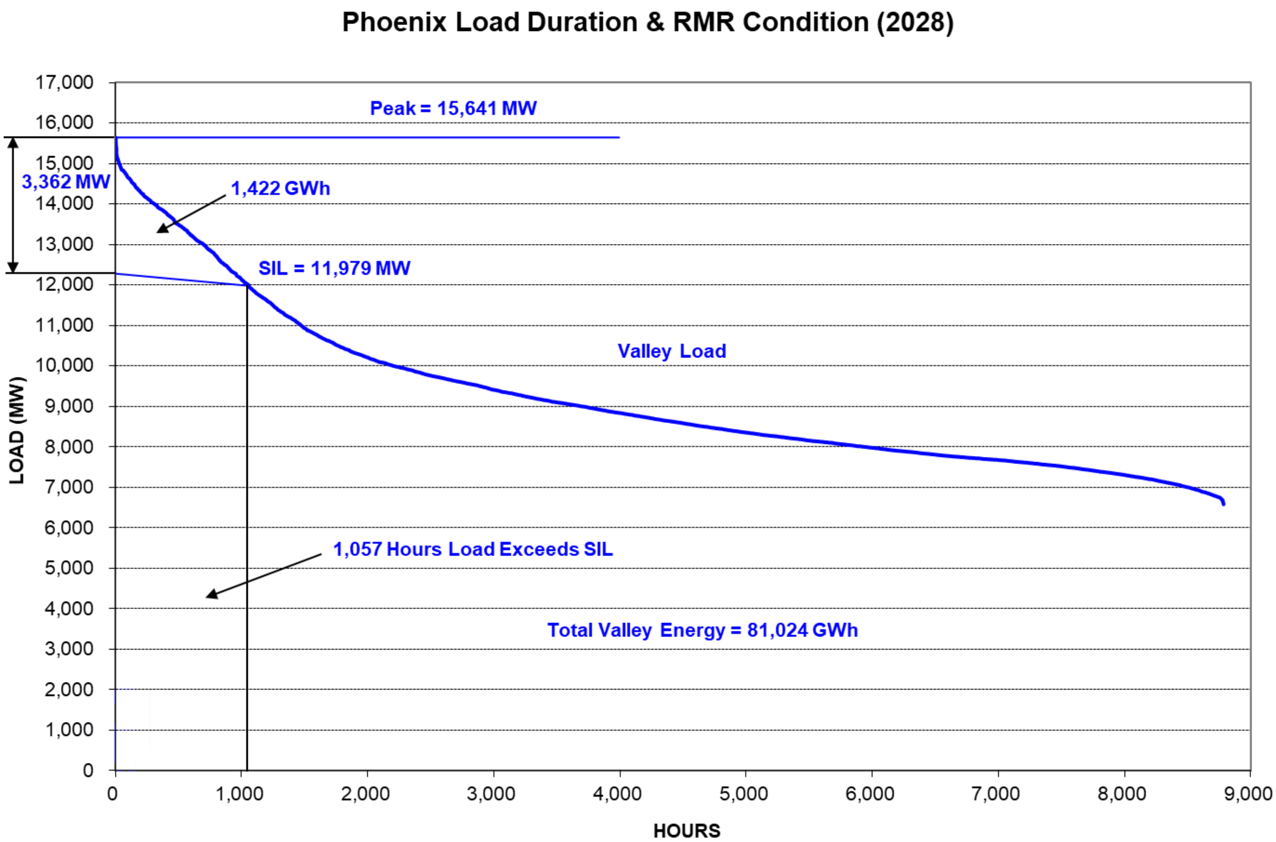

Phoenix Load Duration & RMR Condition (2028)
Peak = 15,641 MW
3,362 MW
1,422 GWh
SIL = 11,979 MW
Valley Load
1,057 Hours Load Exceeds SIL
Total Valley Energy = 81,024 GWh
LOAD (MW)
HOURS
17,000
16,000
15,000
14,000
13,000
12,000
11,000
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
9,000

Figure 6

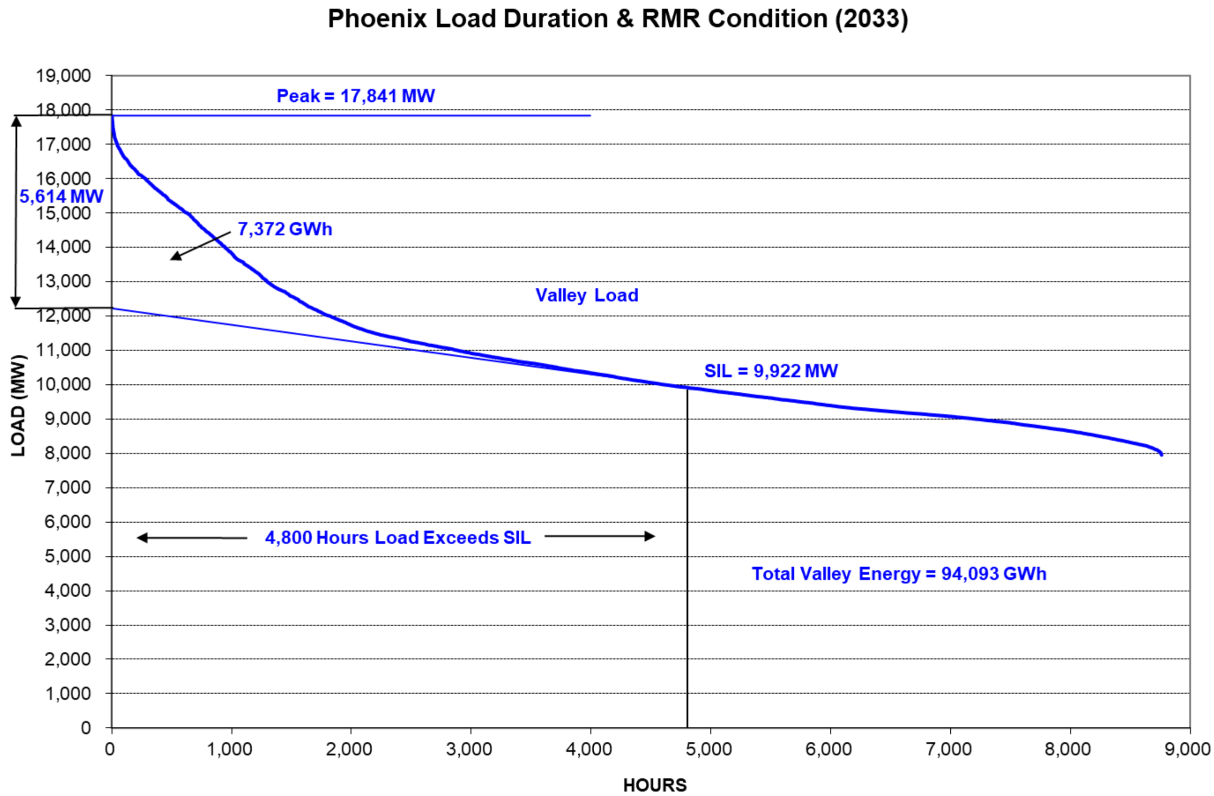


Table 2 shows that Phoenix is expected to require 3,362 MW of local generation resources over and above its import capability to meet peak load in 2028 and 5,614 MW in 2033. For Phoenix, generation is estimated to be in a must-run condition for 1,057 hours in 2028 and 4,800 hours in 2033. However, because RMR occurs only at peak, the amount of associated energy is less than two percent in 2028 and less than eight percent in 2033 of the total Phoenix area energy requirements, as shown in Figures 5 and 6.

B. Phoenix Economic Analysis of RMR

To consider potential economic effects resulting from using local generation or arising from RMR conditions, an analysis was performed using a dispatch model. To determine if there was any additional expense due to RMR generation, the cost of the marginal internal generation online was compared to the forecasted market price. If any generation was priced higher than the forecasted market price it would indicate uneconomic dispatch and hence an RMR cost.

The analysis shows that no internal generation was dispatched with a higher marginal cost then forecasted market prices in 2028 and 2033. Therefore, there was no cost associated with any transmission limitations and hence no RMR costs.

C. Phoenix Area Reserve Capacity

MLSC is the maximum load that can be served in the load pocket. It is the import capability plus the generation capability located inside the load pocket. Based on the load forecast and SIL presented in this analysis, along with existing local generation, the MLSCs for Phoenix were developed. The SIL and MLSC were utilized to develop the Phoenix Area Load Serving Capability graphs; Figures 3 and 4. The import capability and the amount of local generation required, at the forecasted peak load, were determined. Valley generation and import capability at peak less peak load is equal to the projected reserves for that year. The approach used shows how much generation or transmission may be needed to reliably meet load.

The generation and transmission assumptions are depicted in Table 3. As shown on this table, additional resources, beyond those projects in APS's Ten-Year Plan, are not required in years 2028 and 2033 to reliably serve the peak load and maintain the required reserves margin.

Table 3
Phoenix Area Reserve Capacity (MW)

	2028	2033
Peak Load	15,641	17,841
Import Capability @ Peak	12,279	12,227
Valley Generation	6,322	6,560
Valley Gen + Import	18,601	18,787
Reserves	2,960	946
Required Reserves	232	387

C. Area Load Forecast

The historical peak load and annual energy within the Phoenix area constraint is shown in Table 4 for 2018-2022, along with forecasted peak load for 2028 and 2033. Forecasted peak load is based on the same assumptions embodied in APS's total system load forecast used for budgeting and planning. This peak load is the load measured within the defined Phoenix area constraint.

Table 4
Phoenix Load and Energy
(MW / GWh)

	Historical					Forecast	
	2018	**2019**	**2020**	**2021**	**2022**	**2028**	**2033**
Phoenix							
Load	12,696	12,562	13,279	13,115	13,054	15,641	17,841
Energy	51,264	51,824	53,566	52,768	54,231	81,024	94,093
Load Factor	46%	47%	46%	46%	47%	59%	60%

Phoenix area APS load forecasts were developed through the use of a multiple regression model using historic hourly load data, weather, and number of customers. These historic relationships (correlations) were combined with the metro area customer forecast and normal Phoenix weather to produce the APS Phoenix area load. The SRP forecast was then added to the APS forecast to obtain a total valley load forecast.

D. Generation

APS owns/purchases 2,435 MW or 31% of the total 7,766 MW of generation electrically located inside the Phoenix area (793 MW of which are future resources under development). SRP owns/purchases 5,332 MW, of which 588 MW are future resources under development. Table 5 shows summer on-peak and nameplate capacities associated with each unit.

Table 5
Phoenix Area Generation

Owner	Plant	Type	Capacity (MW) Summer On-Peak 2028	Capacity (MW) Summer On-Peak 2033	Nameplate Capability (MW)	Fuel Type
APS	Ocotillo GT1	GT	47	47	55	NG
APS	Ocotillo GT2	GT	47	47	55	NG
APS	Future GT1 @ Ocotillo	GT	-	40	41	NG
APS	Future GT2 @ Ocotillo	GT	-	40	41	NG
APS	Ocotillo GT 3-7	GT	444	444	520	NG
APS	Aligned Microgrid	IC	9	9	11	FO2
APS	City of Phoenix Microgrid	IC	5	5	6	FO2
APS	Future Microgrid: Avery	IC	42	42	49	FO2
APS	West Phoenix GT1	GT	47	47	55	NG
APS	West Phoenix GT2	GT	47	47	55	NG
APS	Future GT1 @ West Phoenix	GT	-	40	41	NG
APS	Future GT2 @ West Phoenix	GT	-	40	41	NG
APS	West Phoenix CC1	CC	73	73	85	NG
APS	West Phoenix CC2	CC	73	73	85	NG
APS	West Phoenix CC3	CC	73	73	85	NG
APS	West Phoenix CC4	CC	96	96	112	NG
APS	West Phoenix CC5	CC	430	430	504	NG
APS	Luke AFB	PV	3	3	11	SUN
APS	NW Regional Landfill	IC	3	3	3	BIO
APS	Future ESS: El Sol	BA	40	44	50	MWH
APS	Future ESS: Estrella Grid	BA	60	66	75	MWH
APS	Future ESS: Scatter Wash 1 & 2	BA	204	223	255	MWH
APS	Future ESS: Westwing I & II	BA	160	175	200	MWH

SRP	Agua Fria 1	ST	96	96	113	NG
SRP	Agua Fria 2	ST	96	96	113	NG
SRP	Agua Fria 3	ST	154	154	181	NG
SRP	Agua Fria 4	GT	62	62	73	NG
SRP	Agua Fria 5	GT	62	62	73	NG
SRP	Agua Fria 6	GT	62	62	73	NG
SRP	Agua Fria 7	GT	39	39	46	NG
SRP	Agua Fria 8	GT	39	39	46	NG
SRP	Coolidge GT 1-12	GT	473	473	554	NG
SRP	Coolidge Expansion GT 1-12	GT	572	572	588	NG
SRP	Horse Mesa 1	HY	10	10	10	WAT
SRP	Horse Mesa 2	HY	10	10	10	WAT
SRP	Horse Mesa 3	HY	10	10	10	WAT
SRP	Horse Mesa 4	HY	96	96	96	WAT
SRP	Kyrene GT4	GT	50	50	59	NG
SRP	Kyrene GT5	GT	45	45	53	NG
SRP	Kyrene GT6	GT	45	45	53	NG
SRP	Kyrene CC1	CC	217	217	254	NG
SRP	Mormon Flat 1	HY	12	12	12	WAT
SRP	Mormon Flat 2	HY	57	57	57	WAT
SRP	Roosevelt	HY	36	36	36	WAT
SRP	Santan 1	CC	78	78	92	NG
SRP	Santan 2	CC	78	78	92	NG
SRP	Santan 3	CC	78	78	92	NG
SRP	Santan 4	CC	78	78	92	NG
SRP	Santan 5	CC	594	594	696	NG
SRP	Santan 6	CC	288	288	338	NG
SRP	Stewart Mt	HY	13	13	13	WAT
SRP	Box Canyon	PVS	360	360	360	SUN
SRP	Copper Crossing Solar Ranch	PV	6	6	20	SUN

SRP	Queen Creek Solar	PV	3	3	10	SUN
SRP	Randolph Solar Park	PV	59	59	202	SUN
SRP	Sandstone Solar Facility	PV	13	13	45	SUN
SRP	Valley Farms Solar	PV	61	61	209	SUN
SRP	Bolster Substation ESS @ Agua Fria	BA	20	22	25	MWH
SRP	Browning Battery	BA	72	78	90	MWH
SRP	Corbell Battery	BA	73	80	92	MWH
SRP	Rudd Battery	BA	204	223	255	MWH
SRP	Copper Crossing Energy & Research GT1	GT	48	48	50	NG
SRP	Copper Crossing Energy & Research GT2	GT	48	48	50	NG
Phoenix Total			**6,322**	**6,560**	**7,766**	

APS owns West Phoenix CC 1-2-3-4-5, West Phoenix CT 1-2, Ocotillo CT 1-2, and Ocotillo CT 3-7. As part of the 2019 Ocotillo Modernization Project, APS replaced the two existing 1960s-era Ocotillo steam units with five new quick-start combustion turbines (CT 3-7). APS microgrid resources include Aligned and City of Phoenix. Renewable resources include Luke AFB Solar Plant and Northwest Regional landfill biogas plant.

APS planned future resources within the Phoenix area include the Avery microgrid and four planned BESS (Battery Energy Storage System) facilities; 1) Westwing I and II, 2) Scatter Wash 1 and 2, 3) El Sol, and 4) Estrella Grid. APS also included opportunities to add four future CTs, two each at Ocotillo and West Phoenix generating stations.

SRP owns the Agua Fria, Kyrene and Santan generating stations inside the Phoenix area. These units were built in the late 1950s to the mid-1970s, with three exceptions - a new Kyrene CC unit went into service in 2002, a new Santan 5 unit went into service in 2005, and a new Santan 6 unit went into service in 2006. SRP plans to add twelve new CTs at Coolidge generating station, which went into service in 2011. Copper Crossing Energy and Research CT 1-2 are expected to be online by the summer of 2024.

SRP operates four dams along the Salt River System: Roosevelt, Horse Mesa, Mormon Flat, and Stewart Mountain.

SRP solar (PV) and solar with storage (PVS) resources include Box Canyon (PVS), Queen Creek, Sandstone, Valley Farms, Copper Crossing Solar Ranch, and Randolph Solar Park. SRP operates four BESS facilities; Browning, Corbell, Rudd, and Bolster.

E. Reserves

APS determined the reserve requirement for Phoenix based on its system Loss of Load Expectation (LOLE) reliability target of one event in ten years. LOLE is widely used across the electric utility industry as a core reliability metric. APS leveraged Astrapé Consulting and their industry leading SERVM software platform to conduct a rigorous resource adequacy study to establish the required Planning Reserve Margin (PRM) needed to meet this targeted reliability metric. The study used modes of analysis based on randomly determined data sets to capture the intermittent nature of variable energy resources and inherent variability of demand, as well as the operational performance uncertainty of conventional resources. The suite of factors considered include asymmetry, variability, and correlation of conventional resource outages; interaction between various renewable and energy-limited resources; energy market liquidity; and weather-impacted stochastically treated load patterns. The resource adequacy study resulted in a recommended Installed Capacity (ICAP) PRM of 20.2 %, which is an increase of about 5% from APS's current ICAP PRM of 15%.

Additionally, the Astrapé study helped inform and establish a PRM using the superior Perfect Capacity (PCAP) accounting methodology, which is more efficient, equitable in its treatment of different resources, and unaffected by changes in resource mix for a given load pattern. In comparison, the traditional ICAP and Unforced Capacity (UCAP) methodologies only use proxies for conventional resource perfect capacity. For these reasons, beginning in 2026, APS is adopting a PCAP PRM of 6.9%, which is equivalent to the ICAP PRM of 20.2%. The 6.9% PCAP PRM applied to the RMR generation at peak is a reasonable approximation of reserve required to meet reliability requirements for the Phoenix load pocket given the changes to the load pocket generation and transmission system upgrades. This criteria would result in not being able to meet Phoenix load once in ten years.

V. CONCLUSIONS

Phoenix Area Conclusions

1. Phoenix area existing and planned transmission and local generation are adequate to reliably serve Phoenix area peak load in 2028 and 2033. Additionally, the projected generation reserve margin maintains local reliability requirements in both years.
2. Phoenix area load is expected to exceed the available transmission import capability for 1,057 hours in 2028 and 4,800 hours in 2033. In 2028, these hours represent less than two percent of the annual energy requirements for the Phoenix area. In 2033, these hours represent less than eight percent of the annual energy requirements for the Phoenix area.
3. The study results indicate that there is no out-of-merit dispatch of units in the load pocket in 2028 and 2033. Despite more RMR plant hours in 2033, because there is no out-of-merit dispatch there is no RMR cost.

Attachment E

APS’s Transmission Planning Process and Guidelines

TRANSMISSION PLANNING PROCESS AND GUIDELINES

APS Transmission Planning
January 25, 2019

Table of Contents

I. INTRODUCTION AND PURPOSE

The Transmission Planning Process and Guidelines (Guidelines) are used by Arizona Public Service Company (APS) to assist in planning its Extra High Voltage (EHV) transmission system (345 kV and 500 kV) and High Voltage (HV) transmission system (230 kV and 115 kV). In addition to these Guidelines, APS follows the Western Electricity Coordinating Council's (WECC) System Performance Criteria (TPL-001-WECC-CRT-3) in addition to NERC Table 1 in the TPL-001-4 standard.

II. PLANNING METHODOLOGY

A. General

APS uses a deterministic approach for transmission system planning. Under this approach, system performance should meet certain specific criteria under normal conditions (all lines in-service), for any single contingency condition and for selected double contingency conditions as defined under TPL-001-WECC-CRT-3. In general, an adequately planned transmission system will:

- Provide an acceptable level of service that is cost-effective for normal, single and selected double contingency conditions.
- Maintain service to all firm loads for any single or selected double contingency outages; except for radial loads.
- Not result in overloaded equipment or unacceptable voltage conditions for single or selected double contingency outages.
- Not result in cascading for single or selected double contingency outages.
- Provide for the proper balance between the transmission import capability and local generation requirements for an import limited load area.

Although APS uses a deterministic approach for transmission system planning, the WECC reliability planning criteria provides for exceptions based on methodologies provided by the WECC RPEWG. Historical system reliability performance is analyzed on a periodic basis and the results are used in the design of planned facilities.

These planning methodologies, assumptions, and guidelines are used as the basis for the development of future transmission facilities. Additionally, consideration of potential alternatives to transmission facilities (such as distributed generation or new technologies) is evaluated on a case-specific basis.

As new planning tools and/or information become available revisions or additions to these guidelines will be made as appropriate.

B. Transmission Planning Process

APS's transmission planning process consists of an assessment of the following needs:

- Provide adequate transmission to access designated network resources in-order to reliably and economically serve all network loads.
- Support APS's and other network customers' local transmission and sub-transmission systems.
- Provide for interconnection to new resources.
- Accommodate requests for long-term transmission access.

During this process, consideration is given to load growth patterns, other system changes affected by right-of-way, facilities siting constraints, routing of future transportation corridors, and joint planning with neighboring utilities, governmental entities, and other interested stakeholders (*see* APS Open Access Transmission Tariff (OATT) Attachment (E)). Finally, all EHV and HV substations will be CIP substations.

1. EHV Transmission Planning Process

APS's EHV transmission system, which consists of 500 kV and 345 kV, has primarily been developed to provide transmission to bring the output of large base-loaded generators to load centers, such as Phoenix. Need for new EHV facilities may result from any of the bullet items described above. APS's annual planning process includes an assessment of APS's transmission capability to ensure that designated network resources can be accessed to reliably and economically serve all network loads. In addition, Reliability Must-Run (RMR) studies are selectively performed to ensure that proper balance between the transmission import capability and local generation requirements for an import limited load area are maintained.

2. 230 kV Transmission Planning Process

APS's 230 kV transmission system has primarily been developed to provide transmission to distribute power from the EHV bulk power substations and local generators to the distribution system and loads throughout the load areas.

Planning for the 230 kV system assesses the need for new 230/69 kV substations to support local sub-transmission and distribution system growth and the reliability performance of the existing 230 kV system. This process takes into account the future land use plans that were developed by government agencies, Landis aerial photo maps, master plans that were provided by private developers, and APS's long-range forecasted load densities per square mile for residential, commercial, and industrial loads.

3. Transmission Facilities Required for Generation/Resource Additions

New transmission facilities may also be required in conjunction with generation resources due to (1) a "merchant" request by an Independent Power Producer (IPP) for generator interconnection to the APS system, (2) a "merchant" request for point-to-point transmission service from the generator (receipt point) to the designated delivery point, or (3) designation of new resources or re-designation of existing units to serve APS network load (including removal of an older units' native load designation). These studies/processes are performed pursuant to the APS OATT.

C. Ten Year Transmission System Plans

Each year APS uses the planning process described in section B to update the Ten Year Transmission System Plan. The APS Ten Year Transmission System Plan identifies all new transmission facilities, 115 kV and above, and all facility replacements/upgrades required over the next ten years to reliably and economically serve the load.

D. Regional Coordinated Planning

1. Western Electric Coordinating Council (WECC)

APS is a member of the WECC. The focus of the WECC is promoting the reliability of the interconnected bulk electric system. The WECC provides the means for:

- Developing regional planning and operating criteria.
- Coordinating future plans.
- Establishing new or modifying existing WECC Path Ratings through procedures.
- Compiling regional data banks, including the BCCS, for use by the member systems and the WECC in conducting technical studies.
- Assessing and coordinating operating procedures and solutions to regional problems.
- Establishing an open forum with interested non-project participants to review the plan of service for a project.
- Through the WECC Transmission Expansion Policy Committee, performing economic transmission congestion analysis.

APS works with WECC to adhere to these planning practices.

2. Technical Task Force and ad-hoc Work Groups

Many joint participant projects in the Desert Southwest rely on technical study groups for evaluating issues associated with their respective projects. These evaluations often include studies to address various types of issues associated with transfer capability, interconnections, reliability and security. APS actively participates in many of these groups such as the Western Arizona Transmission System Task Force and the Four Corners Technical Task Force.

3. Sub-Regional Planning Groups

Southwest Area Transmission (SWAT) and other sub-regional planning groups provide a forum for entities within a region, and any other interested parties, to determine and study the needs of the region as a whole. It also provides a forum for specific projects to be exposed to potential partners and allows for joint studies and participation from interested parties.

4. WestConnect

APS and the other WestConnect members executed the WestConnect Project Agreement for Subregional Transmission Planning in May 2007. This agreement promotes coordination of regional transmission planning for the WestConnect planning area by formalizing a relationship among the WestConnect members and the WestConnect area sub-regional planning groups including SWAT. The agreement provides for resources and funding for the development of a ten year integrated regional transmission plan for the WestConnect planning area. The agreement also ensures that the WestConnect transmission planning process will be coordinated and integrated with other planning processes within the Western Interconnection and with the WECC planning process.

5. Joint Studies

In many instances, transmission projects can serve the needs of several utilities and/or IPPs. To this end, joint study efforts may be undertaken. Such joint study efforts endeavor to develop a plan that will meet the needs and desires of all individual companies involved.

E. Generation Schedules

For planning purposes, economic dispatches of network resources are determined for APS's system peak load in the following manner:

- Determine base generation available and schedule these units at maximum output.
- Determine resources purchased from other utilities, IPPs, or power marketing agencies.
- Determine APS's spinning reserve requirements.

- Schedule intermediate generation (oil/gas steam units) such that the spinning reserve requirements, in section (c) above, are met.
- Determine the amount of peaking generation (combustion turbine units) required to supply the remaining system peak load.

Phoenix area network resources are dispatched based on economics and any existing import limitations. When possible, spinning reserve will be carried on higher cost Phoenix area network generating units.

Generation output schedules for interconnected utilities and IPPs are based upon consultation with the neighboring utilities and IPPs or as modeled in the latest data in WECC coordinated study cases.

F. Load Projections

APS substation load projections are based on the APS Corporate Load Forecast. Substation load projections for neighboring interconnected utilities or power agencies operating in the WECC area are based on the latest data in WECC coordinated study cases. Heavy summer loads are used for the Ten Year Transmission System Plans.

G. Alternative Evaluations

1. General

In evaluating several alternative plans, comparisons of power flows, transient stability tests, and fault levels are made first. After the alternatives are found that meet the system performance criteria in each of these three areas comparisons may be made of the losses, transfer capability, impact on system operations, and reliability of each of the plans. Finally, the costs of facility additions (capital cost items), costs of losses, and relative costs of transfer capabilities are determined. A brief discussion of each of these considerations follows.

2. Power Flow Analyses

Power flows of base case (all lines in-service) and single contingency conditions are tested and should conform to the system performance criteria set forth in Section IV of these Guidelines. Double or multiple contingencies are also examined in the context of common mode and common corridor outages. Normal system voltages, voltage deviations, and voltage extreme limitations are based upon operating experience resulting in acceptable voltage levels to the customer. Power flow limits are based upon the thermal ratings and/or sag limitations of conductors or equipment, as applicable.

3. Transient Stability Studies

Stability guidelines are established to maintain system stability for single contingency, three-phase fault conditions. Double or multiple contingencies are also examined in the context of common mode and common corridor outages.

4. Short Circuit Studies

Three-phase and single-phase-to-ground fault studies are performed to ensure the adequacy of system protection equipment to clear and isolate faults.

5. Reactive Power Margin Analyses

Reactive Power Margin analyses are performed when steady-state analyses indicate possible insufficient voltage stability margins. V-Q curve analyses are used to determine post-transient voltage stability.

6. Losses Analyses

A comparison of individual element and overall transmission system losses are made for each alternative plan being studied. The losses computed in the power flow program consist of the I^2R losses of lines and transformers and the core losses in transformers, where represented.

7. Transfer Capability Studies

In evaluating the relative merits of one or more EHV transmission plans, non-simultaneous ratings are determined using methodologies consistent with WECC Path Rating Procedures as defined in the *WECC Project Coordination and Path Rating Processes* manual and NERC Standard MOD-029. In addition, simultaneous relationships are identified that can either be mitigated through use of nomograms, operating procedures or other methods.

8. Subsynchronous Resonance (SSR)

SSR phenomenon result from the use of series capacitors in the network where the tuned electrical network exchanges energy with a turbine generator at one or more of the natural frequencies of the mechanical system. SSR countermeasures are applied to prevent damage to machines as a result of transient current or sustained oscillations following a system disturbance. SSR studies are not used directly in the planning process. SSR countermeasures are determined after the transmission plans are finalized.

9. Flexible AC Transmission System (FACTS)

FACTS devices are a recent application of Power Electronics to the transmission system. These devices make it possible to use circuit reactance, voltage magnitude and phase angle as control parameters to redistribute power flows and regulate bus voltages, thereby improving power system operation.

FACTS devices can provide series or shunt compensation. These devices can be used as a controllable voltage source in series or as a controllable current source in shunt mode to improve the power transmission system operations.

FACTS will be evaluated as a means of power flow control and/or to provide damping to dynamic oscillations where a need is identified and it is economically justified. Examples include DSTATCOM for powerfactor correction and the DVR for dynamic voltage regulation for distribution loads.

10. Economic Evaluation

In general, an economic evaluation of alternative plans consists of a cumulative net present worth or equivalent annual cost comparison of capital costs.

III. PLANNING ASSUMPTIONS

A. General

1. Loads

Loads used for the APS system originate from the latest APS Corporate Load Forecast. In most cases, the corrected power factor of APS loads is 99.5% at 69 kV substations.

2. Generation and Other Resources

Generation dispatch is based on firm power and/or transmission wheeling contracts including network resources designations.

3. Normal Voltage Levels

Nominal EHV design voltages are 500 kV, 345 kV, 230 kV, and 115 kV. Nominal EHV operating voltages are 535 kV, 348 kV, 239 kV, and 119 kV, with exceptions at certain buses.

4. Sources of Databases

APS currently relies on WECC cases and internal data listings as their depository of EHV and HV system data and models.

5. Voltage Control Devices

Devices which can control voltages are shunt capacitors, shunt reactors, tap-changing-under-load (TCUL) and fixed-tap transformers, static Volt Ampere Reactive (VAR) compensators, and machine VAR capabilities. If future voltage control devices are necessary, these devices will be evaluated based upon economics and the equipment's ability to obtain an adequate voltage profile on the EHV and HV systems. Currently, APS has TCULs on only its 500 kV autotransformers except for a few transformers. Other than operator control, the TCUL transformers do not automatically regulate voltages.

6. Phase Shifters

For pre-disturbances scenarios, phase shifters may be used to hold flows depending on the objectives of the study. For post-disturbance scenarios, the phase shifters are assumed to not hold flows and are not automatically regulated.

7. Conductor Sizes

APS uses several types of standard phase conductors depending on the design, voltage class and application for new transmission lines. Table 1 lists the current standard conductor sizes for the various voltage levels used for new facilities.

Table 1. Standard conductor sizes.

Class	Conductor
525 kV	3x1780 kcm ACSR Chukar 2x2156 kcm ACSR Bluebird
345 kV	2x795 kcm ACSR Tern
230 kV	1x2156 kcm ACSS Bluebird 1x1272 kcm ACSR Bittern 1x795 kcm ACSR Tern
115 kV	(same as 230 kV construction)
69 kV	1x795 kcm ACSS Tern 1x795 kcm AA Arbutus 1x336 kcm ACSR Linnet

8. 69 kV System Modeling

230 kV facility outages may impact the underlying 69 kV system due to the interconnection of those systems. For this reason, power flow cases may include a detailed 69 kV system representation. Solutions to any problems encountered on the 69 kV system are coordinated with the subtransmission planning engineers.

9. Substation Transformers

- 500 kV and 345 kV Substations

  Bulk substation transformer banks may be made up of one three-phase or three single-phase transformers, depending upon bank size and economics. For larger banks where single-phase transformers are used, a fourth (spare) single-phase transformer will be used in a jack-bus arrangement to improve reliability and facilitate connection of the spare in the event of an outage of one of the single-phase transformers.

TCULs are typically used on the 525 kV transformers generally with a range of plus or minus 10% of nominal voltage. Primary voltages will be 525 kV or 345 kV, and secondary voltages will be 230 kV or 69 kV and tertiary voltages will be 34.5 kV, 14.4 kV or 12.47 kV.

- 230 kV Substations

For high-density load areas, both 230/69 kV and 69/12.5 kV transformers can be utilized. 230/69 kV transformers will be rated at 113/150/188 MVA with a 65^{o}C temperature rise, unless otherwise specified. 69/12.5 kV transformers will be rated at 25/33/41 MVA with a 65^{o}C temperature rise, unless otherwise specified.

With all elements in service, a transformer may be loaded up to its top Forced Air (ONAF) rating without sustaining any loss of service life. For a single contingency outage (loss of one transformer) the remaining new transformer or transformers may be loaded up to 25% above their top ONAF rating, unless heat test data indicate a different overload capability. The loss of service life sustained will depend on the transformer pre-loading and the outage duration. No-load tap setting adjustment capabilities on 230/69 kV transformers will be ±5% from the nominal voltage setting (230/69 kV) at 2½% increments.

10. Switchyard Arrangements

- 500 kV and 345 kV Substations

Existing 345 kV switchyard arrangements use breaker-and-one-half, main-and-transfer, or modified paired-element circuit breaker switching schemes. Because of the large amounts of power transferred via 500 kV switchyards and the necessity of having adequate reliability, all 500 kV circuit breaker arrangements are planned for an ultimate breaker-and-one-half scheme. If only three or four elements are initially required, the circuit breakers are connected in a ring bus arrangement, but physically positioned for a breaker-and-one-half scheme. The maximum desired number of elements to be connected in the ring bus arrangement is four. System elements such as generators, transformers, and lines will be arranged in breaker-and-one-half schemes such that a failure of a center breaker will not result in the loss of two lines routed in the same general direction and will minimize the impact of losing two elements.

- 230 kV Substations

  Future 230/69 kV substations should be capable of serving up to 452 Megavolt-Amps (MVA) of load. 400 MVA has historically been the most common substation load level in the Phoenix Metropolitan area. Future, typical 230/69 kV substations should accommodate up to four 230 kV line terminations and up to three 230/69 kV transformer bays. Based upon costs, as well as reliability and operating flexibility considerations, a breaker-and-one-half layout should be utilized for all future 230/69 kV Metropolitan Phoenix Area substations, with provision for initial development to be a ring bus. Any two 230/69 kV transformers are to be separated by two breakers, whenever feasible, so that a stuck breaker will not result in an outage of both transformers.

11. Series Capacitor Application

Series capacitors are planned according to the needs of their associated transmission projects and are typically a customized design. Benefits resulting from the installation of series capacitors include but are not limited to improved transient stability, voltage regulating capability and reactive capability. A new series capacitor installation will currently include MOV protection that mitigates fault current levels through the series capacitor for internal faults. A bank will typically bypass for internal faults because there is no benefit to requiring that the bank remain in service when the line is tripped. Depending on the required impedances and ampacity level, new series capacitor banks may be either one to three segment units. The bank ratings should be based upon line's ultimate uses. At a minimum bank should be upgradable to higher ampacity needs in the future. Most 500 kV banks in APS system have a continuous rating of either 1750 A or 2200 A. ANSI standard require that the 30 minutes emergency rating be 135% of the continuous.

12. Shunt and Tertiary Reactor Application

Shunt and/or tertiary reactors may be installed to prevent open end line voltages from being excessive, in addition to voltage control. The open end line voltage must not be more than 0.05 per unit voltage greater than the sending end voltage. Tertiary reactors may also be used for voltage and VAR control as discussed above. EHV reactors are used to adjust pre-disturbance voltages if controlled through a breaker, circuit switcher or motor operated disconnect switch. APS currently does not automatically control its EHV or HV reactors or capacitors.

B. Power Flow Studies

1. System Stressing

Realistic generation capabilities and schedules should be used to stress the transmission system in order to maximize the transfer of resources during the maximum load condition or path rating studies. Existing WECC or regional path ratings and facilities ratings will not be violated pre- or facility ratings post-disturbance.

2. Displacement

In cases where displacements (due to power flow opposite normal generation schedules) may have an appreciable effect on transmission line loading, a reasonable amount of displacement (Generation Units) may be removed in-order to stress a given transmission path. Alternately, no fictitious generation sources may be used to stress paths.

C. Transient Stability Studies

1. Fault Simulation

When studying system disturbances caused by faults, two conditions will be simulated:

- Three-phase-to-ground faults with normal clearing.
- Single-line-to-ground faults with a stuck circuit breaker in one phase with delayed clearing.

2. Margin

- Generation margin may be applied for the contingencies primarily affected by generation.
- Power flow margin may be applied for the contingencies primarily affected by power flow

3. Unit Tripping

Generator unit tripping may be allowed in-order to increase system stability performance if part of a proposed or existing remedial action scheme.

4. Machine Reactance Representation

For transient stability studies, the unsaturated transient reactance of machines with full representation will be used.

5. Fault Damping

Fault damping will be applied to the generating units adjacent to three phase faults. Fault damping levels will be determined from studies that account for the effect of generator amortisseur windings and the SSR filters. Fault damping will be applied on the buses listed in Table 2 for three phase faults on the nearest EHV or HV bus. If the model does not provide the ancillary signals for applying and removing damping values then a brake can be applied to the terminal bus of the affected generator.

Table 2. Damping levels for three phase faults.

Fault location	Affected units	Percent Damping
Palo Verde 500 kV	1-3	7.25%
Four Corners 500 & 345 kV	4&5	10%
Coronado 500 kV	1&2	12.5%
Cholla 500 kV	2-4	10%

6. Series Capacitor Switching

For APS designed banks, a MOV/by-pass model is employed in transient stability analysis.

D. Short Circuit Studies

Three-phase and single-phase-to-ground faults will be evaluated.

1. Generation Representation

All generation will be represented.

2. Machine Reactance Representation

The saturated subtransient reactance (X''_d) values will be used.

3. Line Representation

Unless previously calculated as part of APSs requirement for MOD-032, the transmission line zero sequence impedance (Z_0) is assumed to be equal to three times the positive sequence impedance (Z_1). If a new transmission impedance is required, APS utilizes the CAPE line constant program for determining sequence values.

4. Transformer Representation

The transformer zero sequence impedance (X_0) is assumed to be equal to the positive sequence impedance (X_1). Bulk substation transformers are modeled as auto-transformers. The two-winding model is that of a grounded-wye transformer. The three-winding model is that of a wye-delta-wye with a solid ground.

5. Series Capacitor Switching

Series capacitors, locations to be determined from short circuit studies, will be flashed and reinserted as appropriate.

E. Reactive Power Margin Studies

Using Q-V curve analyses, APS assesses the interconnected transmission system to ensure there are sufficient reactive resources located throughout the electric system to maintain post-transient voltage stability for system normal conditions and certain contingencies.

IV. SYSTEM PERFORMANCE

A. Power Flow Studies

1. Normal (Base Case Conditions)

- Voltage Levels

  a. General

Nominal Voltage Level	Continuous Voltage Limits
525 kV	+/- 5%
345 kV	+/- 5%
230 kV	+/- 5%
115 kV	+/- 5%
69 kV	+/- 5%
Palo Verde	525-525 kV

- Facility Loading Limits

  a. Transmission Lines

  EHV transmission line loading cannot exceed 100% of the continuous rating, which is based upon established conductor temperature limit or sag limitation as defined by APS latest estimates for NERC Standard FAC-008-3.

  b. Underground Cable

  Underground cable loading should not exceed 100% of the continuous rating with all elements in service. This rating is based on a cable temperature of 85°C with no loss of cable life.

  c. Transformers

  For all transformers pre-disturbance flows cannot exceed APS established continuous ratings using methodologies used in reporting ratings under NERC Standard FAC-008-3.

  d. Series Capacitors

  Series Capacitors cannot exceed 100% of continuous rating as determined using methodologies used in reporting ratings under NERC Standard FAC-008-3.

- Interchange of VARS

Interchange of VARs between companies at interconnections will be reduced to a minimum and maintained near zero.

- Distribution of Flow

Schedules on a new project will be compared to simulated power flows to ensure a reasonable level of flowability.

2. Single and selected Double Contingency Outages

- Voltage Levels

Maximum voltage deviation on APS's major buses cannot exceed an 8% voltage dip for single contingencies. APS uses the following formulae to calculate voltage deviations for post-disturbance conditions.

$$\%Deviation = 100x(\frac{Vpre - Vpost}{Vpre})$$

- Facilities Loading Limits

  a. Transmission Lines

  Transmission line loading cannot exceed 100% of the lesser of the sag limit or the emergency rating (30-minute rating) which is based upon established conductor temperature limits.

  b. Underground Cable

  Underground cable loading should not exceed the emergency rating during a single-contingency outage. This rating is based on a cable temperature of 105°C for two hours of emergency operation with no loss of cable life.

  c. Transformers

  For all transformers post-disturbance flows cannot exceed APS established emergency ratings using methodologies used in reporting ratings under NERC Standard FAC-008-3.

  d. Series Capacitors

  Series Capacitors cannot exceed 100% of emergency rating as determined using methodologies used in reporting ratings under NERC Standard FAC-008-3.

- Generator Units

Generator units used for controlling remote voltages will be modified to hold their base case terminal voltages.

- Impact on Interconnected System

  Single and selected double contingency outages will not cause overloads upon any neighboring transmission system.

B. Transient Stability Studies

Transient stability studies are performed on the 500 kV, 345 kV, and 230 kV systems but may be performed on lower voltage systems depending on the study objectives.

1. Fault Simulation

Three-phase and single-line-to-ground faults initiated disturbances will be simulated according to the guidelines described in NERC TPL-001-4 Table 1 as well as WECC Regional Criteria TPL-001-WECC-CRT-3. Normal clearing times for different voltage levels are given in Table 3 for new facilities. Fault damping will be applied when applicable at fault inception. Breaker failure operation on the 500 kV system has a minimum clearing time of 10 cycles.

Table 3. Normal clearing times for new facilities.

Voltage level	Normal clearing times
500 & 345 kV	4 cycle
230 kV	5 cycle
115 kV	5 cycle
≤69 kV	7 cycle

2. Series Capacitor Switching

All of APS's designed and installed series capacitor units are protected from internal faults using MOV and by-pass elements. For transient stability analysis, models are used to represent the mitigation provided by the MOV components or through by-passing of the series capacitors.

3. System Stability

The system performance will be considered acceptable if the following conditions are met:

- All machines in the system remain synchronized as demonstrated by the relative rotor angles.
- Positive system damping exists as demonstrated by the damping of relative rotor angles and the damping of voltage magnitude swings. For N-1 and N-2 disturbances, APS follows the voltage and frequency performance guidelines as

described in NERC's TPL-001-4 Table 1 and WECC Regional Criteria TPL-001-WECC-CRT-3.

- Cascading does not occur for any category contingency.

4. Re-closing

Automatic re-closing of circuit breakers controlling EHV facilities is not utilized.

5. Short Circuit Studies

Fault current shall not exceed 100% of the applicable breaker fault current interruption capability for three-phase or single-line-to-ground faults.

6. Reactive Power Margin Studies

For system normal conditions or single contingency conditions, post-transient voltage stability is required with a path or load area modeled at a minimum of 105% of the path rating or maximum planned load limit for the area under study, whichever is applicable. For multiple contingencies, post-transient voltage stability is required with a path or load area modeled at a minimum of 102.5% of the path rating or maximum planned load limit for the area under study, whichever is applicable.