Regional Transmission Plan Report

WestConnect 2024-25 Regional Transmission Planning Cycle

Approved by the WestConnect Planning Management Committee
December 17, 2025

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1. Executive Summary

The WestConnect 2024-25 Regional Transmission Plan Report ("Regional Plan Report") is based on an evaluation of the transmission network in the WestConnect region for the 10-year timeframe. This report summarizes the processes, assumptions, and technical methods used to develop the WestConnect 2024-25 Regional Transmission Plan ("Regional Transmission Plan"); this involves the evaluation of the transmission network across the WestConnect region to determine regional reliability, economic, and public policy driven transmission needs and seeks to identify the more efficient or cost-effective solutions for the needs.

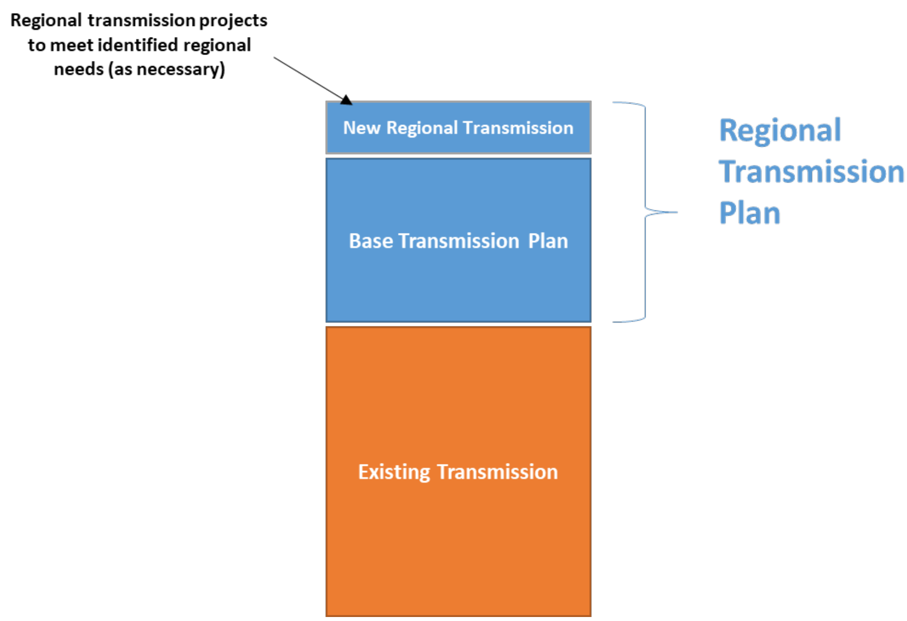
This Regional Plan Report is the final step of the WestConnect biennial Regional Transmission Planning Process ("Planning Process") and is intended to provide the reader with an overview of the core elements of the 2024-25 Planning Process. During the two-year planning cycle, the WestConnect Planning Management Committee ("PMC") produces detailed interim reports at the conclusion of each phase of the Planning Process, which are drawn from to create this Regional Plan Report. The interim reports contain significantly more detail than this Regional Plan Report and are made available on the WestConnect website. Their contents are summarized in **Table 1**.

Table 1. Summary of Interim Planning Documents for 2024-25 Planning Process

Interim Report	PMC Approval Date	Hyperlink	Contents
2024-25 Study Plan	March 20, 2024	Link	• Summary of study methods, models, tools, and analyses • Base Transmission Plan identified • Process schedule
2024-25 Model Development Report	December 18, 2024	Link	• Detailed assumptions and processes used to create models used to perform regional assessment • Analysis of Base Transmission Plan contents
2024-25 Regional Transmission Needs Assessment Report	January 15, 2025	Link	• Study results and findings from regional needs assessment

The Regional Transmission Plan reflects the planned transmission that is necessary to meet the region's needs. The Regional Transmission Plan consists of the Base Transmission Plan, which is created at the beginning of each planning cycle to establish the assumed transmission network reflected in planning models for the 10-year timeframe, along with any regional transmission projects selected as the more efficient or cost-effective alternative to a regional need identified during the WestConnect regional assessments, as illustrated in **Figure 1**.

Figure 1. Regional Transmission Plan



The 2024-25 Base Transmission Plan includes 209 planned transmission projects, spanning 2,360 miles, with a total estimated capital investment of $5,800 Million. 82% of these projects involve facilities below 230 kV. Since the 2022-23 WestConnect Regional Transmission Plan, the WestConnect region has seen 123 new planned projects, 32 previously planned projects go into service, 25 previously planned projects begin construction, and 48 previously planned projects which are no longer planned. As defined by WestConnect, "planned" facilities include projects that are expected to be in-service during the approaching 10 years and are required to meet enacted Public Policy Requirements, have a sponsor, and are incorporated in an entity's regulatory filings or capital budget, or have an agreement committing entities to participate and construct.

In evaluating the need for new regional transmission projects in the Regional Transmission Plan, WestConnect first determines the system's needs. WestConnect uses three types of assessments to identify regional needs: reliability, economic, and public policy. These assessments were respectively dependent on powerflow ("PF") models, a production cost model ("PCM"), and confirmation from each Transmission Owner with Load Serving Obligation ("TOLSO") member that these models reflect plans to meet enacted public policies impacting the region.

The TOLSO membership format did exist at the time of the modeling and assessments for this 2024-2025 WestConnect Regional Planning cycle; however, on April 24, 2025, FERC issued an approval for Planning Participation Agreement ("PPA") revisions effective December 17, 2024, that removed the TOLSO Member Sector and Coordinating Transmission Owner subsector of the TOLSO Member Sector and left only the Enrolled Transmission Owner Member Sector. As such, this Regional Transmission Plan Report will be effective for the current WestConnect members. See Section 2.2 for more membership specifics.

Table 2 summarizes the WestConnect Planning Models developed and analyzed in the 2024-25 Planning Process, which include "Base Case" models used to identify regional needs, and "Sensitivity Cases" used to evaluate the impact of uncertainty in load, hydro, gas price, and carbon emission assumptions on the economic model results.

Table 2. WestConnect Planning Models for Regional Assessment

Case Name	Case Description and Scope
2034 Heavy Summer Base Case	Summer peak load conditions, with typical flows throughout the Western Interconnection.
2034 Light Spring Base Case	Light load conditions during spring months of March, April, or May with solar and wind serving a significant portion of the Western Interconnection total load.
2034 Base Case PCM	Business-as-usual, expected-future case with (1) median load, (2) median hydro conditions and (3) representation of resources consistent with member-approved resource plans as of March 2024.

The reliability assessment for regional needs was based on reliability standards adopted by the North American Electric Reliability Corporation ("NERC") and the Western Electricity Coordinating Council ("WECC"), and supplemented with any more stringent TOLSO planning criteria based on TOLSO member feedback. Regional issues subject to deeper investigation were defined as system performance issues impacting more than one Transmission Owner ("TO") Member system. The results of the reliability analyses identified three branch overloads within single-TO systems, which WestConnect determined to be local issues and not regional.

The economic assessment for regional needs involved reviewing the 2034 Base Case simulation results for regional congestion (i.e., number of hours) and congestion cost (i.e., the cost to re-dispatch more expensive generation because of transmission constraints) in order to determine a set of congested elements that warranted testing for the economic potential for a regional project solution, while also recognizing that the presence of congestion does not always equate to a regional need for congestion relief at a particular location. Similar to the reliability assessment, the review focused on the congestion issues impacting more than one TO Member system. The 2034 Base Case results identified two congested elements or paths in multi-TO systems, which WestConnect determined to be minor congestion which does not warrant a regional need determination.

The public policy assessment was intended to identify any regional issues driven by enacted Public Policy Requirements. As part of the model development phase of the Planning Process, each TOLSO member provided express confirmation that the developed WestConnect 2034 economic and powerflow models included all local planning assumptions driven by enacted Public Policy Requirements for study year 2034, to the extent a plan for compliance with the Public Policy Requirement was completed prior to the model development phase of the planning cycle.[1] WestConnect started this effort during the 2020-21 Planning Process to determine whether the WestConnect economic models indicated a renewable energy penetration trajectory consistent with enacted public policies. This additional work was driven by stakeholder interest and continues to be performed by comparing the region's modeled load and renewable energy in the regional Base Cases to prior planning cycle cases. WestConnect continues to find a reasonable trend towards WestConnect members meeting enacted Public Policy Requirements. During the regional reliability and economic assessments for this cycle, no regional issues were identified. If regional issues were identified in the assessments, WestConnect would then take the second

[1] *In the context of FERC Order 1000, enacted Public Policy Requirements are state or federal laws or regulations, meaning enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level.*

step of evaluating if those issues were driven by actions needed to comply with Public Policy Requirements. No stakeholders suggested or recommended the identification of a regional public policy-driven transmission need following the WestConnect presentation to stakeholders of enacted public policies and local transmission solutions to Public Policy Requirements. As a result, there were no public policy-driven needs identified in the WestConnect 2024-25 Regional Planning Process.

Based on the findings from the 2024-25 planning cycle analyses performed for reliability, economic, and public policy transmission needs, **no regional transmission needs were identified in the 2024-25 assessment**. As a result, the PMC did not collect transmission or non-transmission alternatives for evaluation since there were no regional needs to evaluate the alternatives against, and the 2024-25 Regional Transmission Plan is identical to the 2024-25 Base Transmission Plan. The evaluations of multi-TO economic issues identified in the regional assessments are summarized in **Table 3.** There were no multi-TO reliability issues.

Table 3. Evaluation of Multi-TO Economic Issues

Multi-TO Economic Issue	Rationale provided for why this should not be a regional need
1. Path 36 TOT 3 Interface	BEPC, PSCO, TSGT, WAPA- RMR: TOT3/Path 36 congestion is relatively low and there are many adjacent system changes presently occurring that are predicted to improve congestion. Although the amount has increased from previous cycle results this limited amount does not warrant a regional need at this time.
2. Dave Johnston – Laramie River 230 kV	BEPC, PSCO, TSGT, WAPA- RMR: Dave Johnston – Laramie River 230 kV congestion is relatively low but is attributed to increased neighboring Planning Region wind resources. This seams congestion is managed by inclusion of Phase Shifters at Anticline and buildout of the Gateway transmission project by PacifiCorp.
3. Craig Yampa Valley – Craig 230 kV line	BEPC, PSCO, TSGT, WAPA- RMR: The observed congestion on this line does not warrant establishing this as a regional need as it is limited in duration, cost, and impact. The congestion is a direct result of serving local load and forecasted BTM generation. Additionally, the line and Craig YV terminal equipment are owned by PSCo. While the Craig substation equipment has mixed ownership, PSCo has full ownership of the terminal equipment for this line. This makes the congestion on this facility more similar to a single TO facility in nature.
4. Pinnacle Peak (APS) – Pinnacle Peak 230 kV line	APS, WAPA-DSW: The observed congestion on this line does not justify designating it as a regional need. Both the congestion hours and cost of the congestion are minimal and do not warrant a capital investment. Historically, the line's flows have remained well below the capacity. Additionally, reliance on a single data point for one WestConnect cycle results raises concerns about the analysis's reliability. WAPA recommends using multiple scenarios and years to provide a more robust reliable evaluation.
5. Path 15 Midway – Los Banos	WAPA-SNR: Not a regional issue – Path 15 and related facilities are part of the CAISO Planning Region. Possible topology issue in the PCM which originated from the WECC ADS. Unable to get a correction from WECC/CAISO prior to finalizing models.

The 2024-25 Planning Process also included scenario studies, which were used for information only, and considered as alternate but plausible futures. The scenario studies are not required under FERC Order 1000 member tariffs, were not used to identify regional needs, and did not impact the Regional Transmission Plan. The scenario studies are shown in **Table 4,** and are also described in the 2024-25 Study Plan and in Section 9 and Appendix D of this report.[2]

Table 4. WestConnect Scenario Studies

Scenario	Description and Scope
Decreased Facility Rating Scenario	Evaluate the impacts of an overall decrease in facility ratings by a given percentage. Transmission facility ratings can be adversely impacted by several factors, including higher ambient temperatures. The purpose of this study was to provide a relative view of how decreased facility ratings might impact reliability.
Extreme Cold Weather Scenario	Evaluate the reliability of the WestConnect footprint for a 10-year, heavy winter condition, with higher-than-expected loads and reduced resource availability that would be the result of extremely cold weather throughout the region. An extreme cold weather event would result in higher loads than expected, combined with shortages of resources, and as a result, impact the reliability of the system. The purpose of this scenario was to provide information into system import or export capabilities, and potential reliability issues, including how to serve load, that could result in the need for transmission or resource enhancements.
20-Year Increased Renewable Scenario	Perform regional reliability and economic assessments using models that represent a 20-year timeframe with aggressive renewable energy penetration. The purpose of this scenario was to help WestConnect members understand transmission-related issues associated with a 20-year future that attempts to capture current policy requirements throughout the Planning Region, as well as public policy requirements that are likely to change in the 20-year planning horizon and are expected to trend towards more aggressive objectives for carbon reduction.

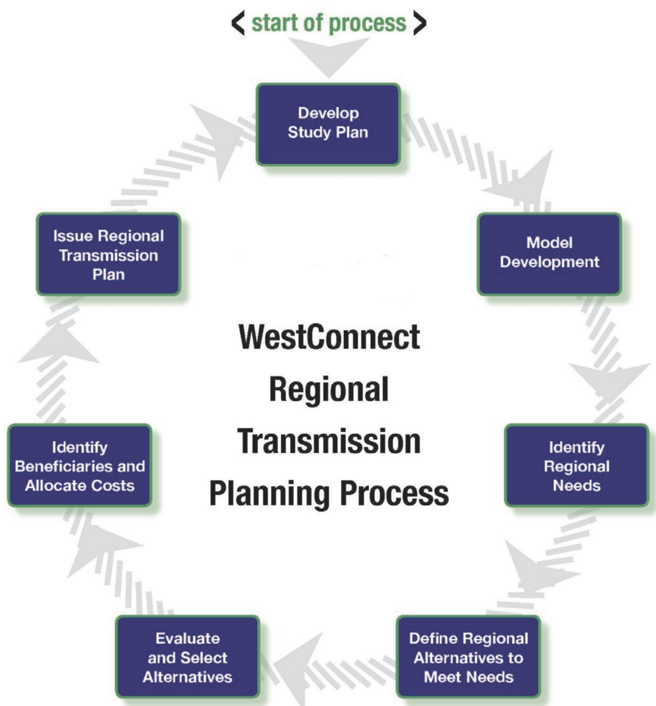
[2] *The Decreased Facility Rating and Extreme Cold Weather scenarios were completed, but the work on the 20-Year Renewable Scenario was stopped prior to any modeling and assessment being performed.*

2. Planning Management and Process

This WestConnect 2024-25 Regional Transmission Plan Report ("Regional Plan Report") is the final step of the WestConnect 2024-25 biennial Regional Transmission Planning Process ("Planning Process") and summarizes the processes, assumptions, and technical methods used to develop the WestConnect 2024-25 Regional Transmission Plan ("Regional Transmission Plan"), which identifies the more efficient or cost-effective transmission solutions for the region. The document also explains why projects were either included or not included in the Regional Transmission Plan.

The WestConnect Planning Process was developed for compliance with Federal Energy Regulatory Commission (FERC) Order Number 1000 ("Order No. 1000"), Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities. The Planning Process consists of seven primary steps as shown in **Figure 2**.

Figure 2. WestConnect Regional Transmission Planning Process



The Planning Process commences in even numbered years, resulting in the development of a Regional Transmission Plan every odd-numbered year. During the Planning Process, WestConnect seeks to identify regional reliability, economic, and public policy transmission needs. If regional transmission needs are identified, WestConnect solicits alternatives (transmission or non-transmission alternatives) from WestConnect members and stakeholders to meet the regional needs. WestConnect then evaluates the alternatives to determine which meet the region's needs more efficiently or cost-effectively. The selected alternatives are then identified in the Regional Plan Report. Identified alternatives submitted for the purposes of cost allocation may go through the cost allocation process if they are eligible and pass the cost/benefit thresholds established for the relevant category of project (reliability, economic, or public policy).

Additional details of the WestConnect Regional Transmission Planning Process can be reviewed in the WestConnect Regional Business Practice Manual ("BPM").

2.1 Planning Management

The WestConnect PMC has overall responsibility for all WestConnect regional planning activities. The Planning Process activities are conducted under the direction of the PMC by the WestConnect Planning Subcommittee ("PS") and WestConnect Cost Allocation Subcommittee (CAS), and with input from PMC members and stakeholders, as described in greater detail in subsequent sections of this document.

2.2 Planning Region

The WestConnect planning process evaluates regional transmission needs of the WestConnect planning region, which is defined as the combined footprints of signatories to the PPA within the TOLSO Member Sector[3]. TOLSO Members participating in the WestConnect 2024-25 planning process, and the systems considered in the regional assessment included:

- Arizona Electric Power Cooperative, Inc.[4]
- Arizona Public Service
- Basin Electric[5]
- Black Hills Energy
- Colorado Springs Utilities[4]
- Deseret Generation and Transmission Co-operative
- El Paso Electric
- Imperial Irrigation District[4]
- Los Angeles Department of Water and Power[4]
- Platte River Power Authority[4]
- Public Service Company of New Mexico
- Sacramento Municipal Utility District[4]
- Salt River Project[4]
- Tucson Electric Power Company
- Transmission Agency of Northern California[4]
- Tri-State Generation and Transmission
- Western Area Power Administration (Desert Southwest, Rocky Mountain, Sierra Nevada)[4]
- Public Service Company of Colorado (Xcel Energy)

WestConnect conducted FERC Order No. 1000 regional transmission needs assessments for the 2024-25 planning cycle for the Transmission Owner (TO) entities listed above.[6] The approximate footprint of those TOs (for 2024) is shown in **Figure 3**.

In addition to the TOLSO members, the following PMC members from the Independent Transmission Developer Member Sector and Key Interest Group Sector also participated in the planning effort:

- Black Forest Partners
- Southwestern Power Group
- TransCanyon, LLC
- Interwest Energy Alliance
- GridLiance Southwest, LLC
- Western Energy Connection, LLC
- Xcel Energy West Transmission Company, LLC

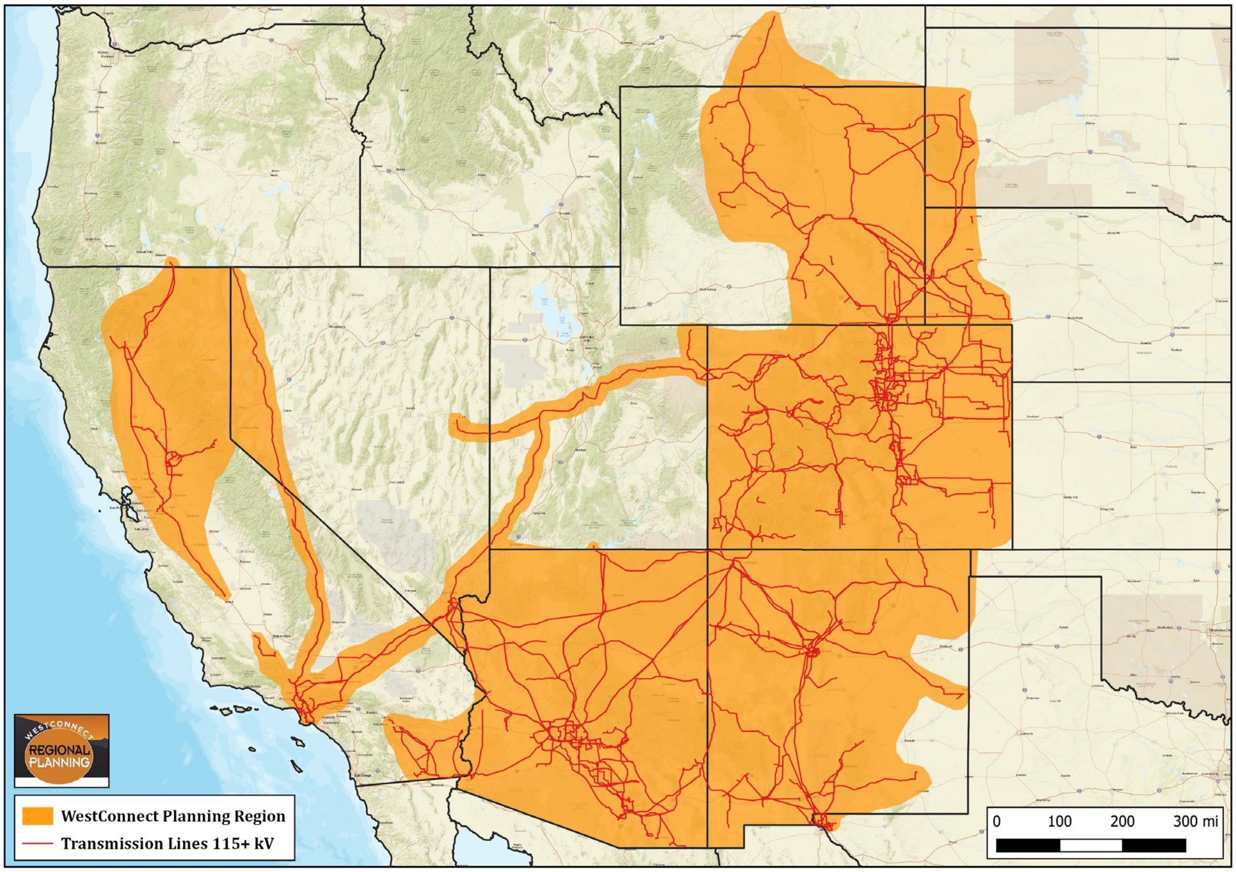
[3] *On April 24, 2025, FERC issued an approval for PPA revisions effective December 17, 2024, that removed the TOLSO Member Sector and Coordinating Transmission Owner subsector of the TOLSO Member Sector and left only the Enrolled Transmission Owner Member Sector.*

[4] *Non-member after 2024.*

[5] *Basin Electric withdrew from the WestConnect PPA on October 16, 2025.*

[6] *All references to Order No. 1000 include any subsequent orders (see [Order No. 1000 Regional Compliance Orders](#)).*

Figure 3. Approximate Footprint of 2024 WestConnect Member TOLSO Members and Participating TOs



2.3 WestConnect 2024-25 Membership Changes

At the beginning of the 2024-25 Planning Cycle the TOLSO membership consisted of:

- Enrolled Transmission Owners (ETOs) composed of entities that enroll in the WestConnect Planning Region for purposes of Cost Allocation pursuant to Order No. 1000 and that (1) provide transmission service and own a minimum of one hundred (100) circuit miles or $100 million of original installed cost of transmission plant rated at 115 kV and higher within the Western Interconnection; and (2) serve a minimum of 150 MW of retail and/or wholesale network load within the Western Interconnection, and

- Coordinating Transmission Owners (CTOs) comprised of entities that joined the TOLSO Member Sector to participate in the WestConnect Regional Planning Process without enrolling for Order No. 1000 Cost Allocation purposes.

On October 17, 2024, FERC issued an order directing the ETOs to remove the CTO framework from the regional planning provisions of their Open Access Transmission Tariffs (OATTs) and to make corresponding changes to the PPA. These changes were made as directed, and on April 24, 2025, FERC issued an approval for the OATT and PPA revisions, effective December 17, 2024, that removed the TOLSO Member Sector and Coordinating Transmission Owner subsector of the TOLSO Member Sector and left only the Enrolled Transmission Owner Member Sector. As a result, the WestConnect Order No. 1000 regional transmission planning process will only plan for the needs of ETOs and may only allocate costs to ETOs.

2.4 Local versus Regional Transmission Issues

For the purposes of the regional transmission needs assessment, a single-TO transmission issue is when a single-TO need impacts only the TO footprint in which it resides. Single-TO transmission issues and non-member issues are not within the scope of the WestConnect regional transmission planning process and are not considered regional transmission needs. However, for the sake of completeness and study transparency, the PS reviews all identified single-TO transmission system issues to ensure that in combination, none of the issues are regional in nature. Single-TO system issues are the responsibility of the affected TO to resolve, if necessary.

Regional needs are generally defined by impacts to more than one TO. However, the PMC may determine that in some instances, transmission issues that impact more than one TO are still local, rather than regional, in nature. In such cases, WestConnect will provide an explanation as to how impacts are classified.

2.5 Documentation of the 2024-25 Planning Process

This Regional Plan Report is intended to stand on its own, providing an overview of the core elements of the 2024-25 Planning Process. However, this report does not include all details pertaining to the Planning Process. The PMC produces interim reports at the conclusion of each phase of the Planning Process. These interim reports are drawn from to create this Regional Plan Report. The interim reports contain significantly more detail than this Regional Plan Report and are made available on the WestConnect website. Specifically, the interim reports contain technical appendices that are referenced to but are not repeated in this document.

2.5.1 Study Plan

The scope of work for the 2024-25 Planning Process is documented in the 2024-25 Regional Study Plan ("Study Plan"), which was approved by the PMC on March 20, 2024. The Study Plan describes the Base Transmission Plan as well as the reliability, economic, and public policy assessments to be performed in the planning cycle. It covers the scope of work for model development and provides technical guidance regarding the identification of regional needs.

2.5.2 Model Development Report

The Base Case models were approved by the PMC on October 16, 2024, and the regional model development process and the input assumptions for the regional planning models is documented in the 2024-25 Model Development Report ("Model Development Report"), which was approved by the PMC on December 18, 2024. The report describes the development process of the regional base models and details key model assumptions and parameters, such as study timeframe, study horizon, study area, the Base Transmission Plan, and how enacted public policies were considered. Along with the Model Development Report, the PMC approved the regional base models for use in regional assessments.

2.5.3 Regional Transmission Needs Assessment Report

The methods used to identify regional needs are documented in the 2024-25 Regional Transmission Needs Assessment Report ("Needs Assessment Report"), which was approved by the PMC on January 15, 2025. The Needs Assessment Report details the methods, assumptions, and results of the three types of regional needs assessments: reliability, economic, and public policy.

3. 2024-25 Base Transmission Plan

WestConnect created the regional Base Transmission Plan at the beginning of the 2024-25 Planning Process to establish the transmission network topology that is reflected in the regional planning models for the 10-year timeframe and evaluated in the regional needs assessments. The Base Transmission Plan consists of the "planned" incremental transmission facilities included by TOs in local transmission plans,[7] as well as regional transmission facilities identified in previous regional transmission plans that are not subject to reevaluation.[8] It also includes any assumptions member TOs may have made with regard to other incremental regional transmission facilities in the development of their local transmission plans. "Conceptual" transmission projects are not included in the Base Transmission Plan. As defined by WestConnect, "planned" facilities include projects that are expected to be in-service during the approaching 10 years and are required to meet Public Policy Requirements, have a sponsor, and are incorporated in an entity's regulatory filings or capital budget, or have an agreement committing entities to participate and construct.

The Base Transmission Plan may also include projects under development by independent transmission developer (ITD) entities in the WestConnect planning region, to the extent there is sufficient likelihood of completion associated with these projects to warrant their inclusion in the Base Transmission Plan.[9] For the 2024-25 Regional Process, WestConnect received five ITP submittals for the 2024-25 Planning Process:

- SunZia 500 kV DC Transmission Project
- Rio Sol 500 kV AC Transmission Project
- North Gila – Imperial Valley #2 (NGIV2) 500 kV line
- Southline Project: Afton – Apache 345 kV line
- Southline Project: Apache – Vail 345 kV line

The SunZia and NGIV2 projects were found to meet the criteria and were included in the base models.

The Base Transmission Plan was developed using project information collected via the WestConnect Transmission Plan Project List (TPPL), which serves as a project repository for TO member and TO participant local transmission plans as well as ITD projects. The TPPL data used for the 2024-25 Planning Process was based on updates submitted between December 7, 2023, and February 2, 2024. The full list of approved regional Base Transmission Plan projects – prior to updates made during model development – can be found in **Appendix A**.

3.1 2024-25 Regional Base Transmission Plan Projects

The 2024-25 Base Transmission Plan project list includes 260 planned transmission projects that consist of 116 new or upgraded transmission lines, 116 substations, and 28 other planned projects. From the data reported in the TPPL, these projects span a reported total of 3,105 miles and add up to a total capital investment of about $8,500 Million. **Table 5** and **Table 6** summarize the Base Transmission projects by project type and voltage.

[7] *Developed in accordance with Order No. 890 local planning processes. The Base Transmission Plan also includes any non-Bulk Electric System (non-BES) assumptions TO members may have made with regard to other incremental regional transmission facilities in the development of their local transmission plans.*

[8] *There were no regional transmission projects identified to meet regional need(s) in the 2022-23 planning cycle.*

[9] *A description of the criteria used to identify projects for inclusion in the Base Transmission Plan is in the BPM.*

Table 5. Regional Base Transmission Plan Projects by Type, Mileage, and Investment ($K), based on TPPL data

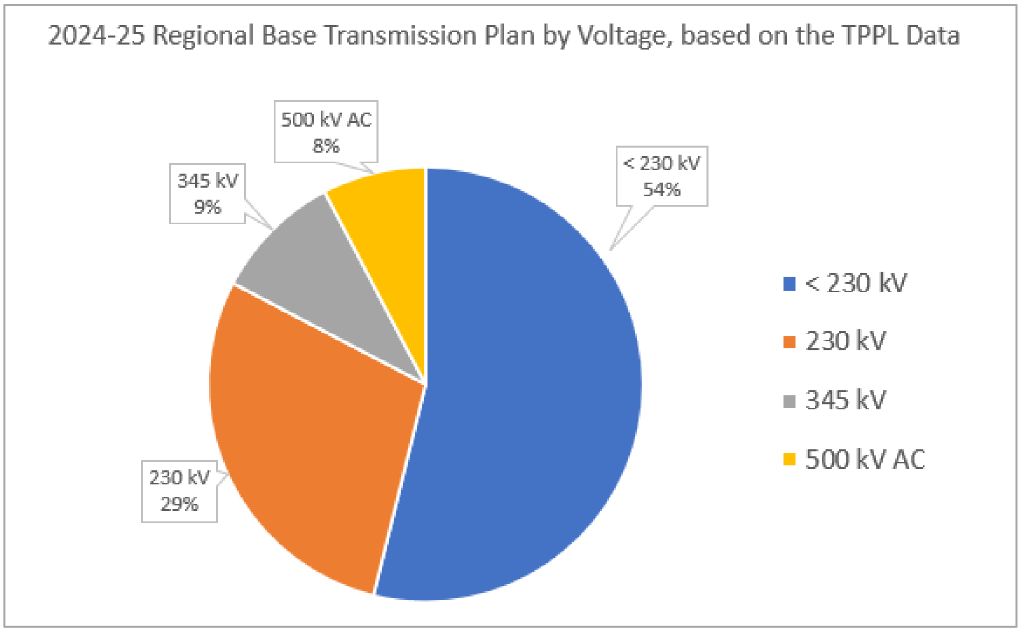
Type of Project	Number of Projects	Length (Miles)	Planned Investment ($K)
Substation	116	-	$2,133,581
Transmission Line	116	3,105	$5,363,210
Other	28	-	$1,001,975
Total	260	3,105	$8,498,766

Table 6. Number of TOLSO Base Transmission Plan Projects by Voltage and TOLSO, based on TPPL data

TOLSO (ETO)	< 230 kV	230 kV	345 kV	500 kV AC	TBD	Total
Arizona Public Service	-	13	2	5	-	20
Black Hills Energy	5	-	-	-	-	5
Black Hills Power	-	-	-	-	-	0
Cheyenne Light Fuel and Power	10	6	-	-	-	16
Deseret Power	-	-	-	-	-	0
El Paso Electric Company	56	-	14	-	-	70
Public Service Company of Colorado/ Xcel Energy	3	4	2	-	-	9
Public Service Company of New Mexico	-	-	2	-	-	2
Tri-State Generation and Transmission Association	8	4	1	-	-	13
Tucson Electric Power	31	7	2	1	-	41
Total ETO (member) Projects	**113**	**34**	**23**	**6**	**0**	**176**
TOLSO (CTO)	**< 230 kV**	**230 kV**	**345 kV**	**500 kV AC**	**TBD**	**Total**
Arizona Electric Power Cooperative	1	1	1	-	-	3
Colorado Springs Utility	8	3	-	-	-	11
Imperial Irrigation District	2	2	-	-	-	4
Los Angeles Department of Water and Power	3	14	1	5	-	23
Platte River Power Authority	1	2	-	-	-	3
Sacramento Municipal Utility District	1	4	-	-	-	5
Salt River Project	1	9	-	9	-	19
Transmission Agency of Northern California	-	-	-	-	-	0
Western Area Power Administration - DSW	3	2	-	-	-	5
Western Area Power Administration - RMR	7	4	-	-	-	11
Western Area Power Administration - SNR	-	-	-	-	-	0
Total CTO (member) Projects	**27**	**41**	**2**	**14**	**0**	**84**
Total Projects for Modeling	**140**	**75**	**25**	**20**	**0**	**260**

Review of the of the 2024-25 regional Base Transmission Plan projects showed that 54% were classified as below 230 kV, 29% were classified as 230 kV, 9% were classified as 345 kV; and 8% were classified as the 500 kV. **Figure** 4 illustrates the percentage breakout for the 2024-25 regional Base Transmission Plan projects by voltage.

Figure 4. 2024-25 Regional Base Transmission Plan Transmission Line by Voltage, based on the TPPL data



3.2 Updates to the 2022-2023 Regional Transmission Plan Projects

Review of the 2022-23 Regional Study plan base transmission projects showed several projects have gone into service, started construction, or have had other updates to their development status. The full list of 2022-23 regional Base Transmission Plan projects can be found in the [2022-23 Regional Transmission Plan], Appendix B. Updated information provided to the TPPL showed that 32 projects were placed in service, 25 projects were updated to under construction development status, 10 projects were updated to conceptual development status and 14 projects were withdrawn from the 2022-23 Regional Transmission Plan. The remaining 2022-23 regional Base Transmission Plan projects continued as planned projects in the 2024-25 regional Base Transmission Plan. Additionally, 116 new planned projects were added to the TPPL and included in the 2024-25 regional Base Transmission Plan. **Table 7** and **Table 8** summarize the updates to the 2022-23 regional Base Transmission Plan projects, which include both ETO and CTO projects.

Table 7. 2022-23 Transmission Plan Projects In-Service, Mileage, and Investment ($K)

Type of Project	Number of Projects	Length (Miles)	Planned Investment ($K)
Substation	8	-	$42,057
Transmission Line	10	145	$160,630
Transmission Line & Substation	9	92	$213,172
Transformer	3	-	$5,500
Other	2	-	$10,500
Total ETO &CTO Projects	**32**	**237**	**$431,859**

Table 8. 2022-23 Planned Projects Withdrawn or Changed to Conceptual by Voltage, based on TPPL data

New Status	Type	< 230 kV	230 kV	345 kV	Total
Conceptual	Substation	4	-	1	5
	Transmission Line	3	-	-	3
	Trans Line and Sub	1	-	1	2
	Other	-	-	-	0
	Subtotal	8	0	2	10
Withdrawn	Substation	3	-	-	3
	Transmission Line	4	1	-	5
	Trans Line and Sub	-	-	-	0
	Transformer	2	-	1	3
	Other	3	-	-	3
	Subtotal	12	1	1	14
	Total ETO & CTO	**20**	**1**	**3**	**24**

3.2.1 Regional Base Transmission Plan Projects by State

The 2024-25 regional Base Transmission Plan has projects in multiple states in the WestConnect footprint and in some instances, projects span multiple states. **Table 9** summarizes the number of projects by states with aggregated capital investment.

Table 9. 2024-25 Base Transmission Plan Projects by State, Mileage, and Investment ($K), based on TPPL data

State	Number of Projects	Length (Miles)	Planned Investment ($K)
Arizona	87	745	$1,724,868
California	29	394	$2,011,180
Colorado	47	861	$2,449,321
Nebraska	2	-	$10,883
Nevada	1	13	$82,000
New Mexico	22	57	$492,165
Texas	47	144	$879,488
Wyoming	18	281	$360,299
Multiple	7	611	$488,563
Total ETO & CTO Projects	**260**	**3,105**	**$8,498,766**

Review of the 2024-25 regional Base Transmission Plan projects by state showed that many (33%) of the projects are located in Arizona, 18% of the projects are located in Colorado, 11% are located in California, and 3% span multiple states. The remaining projects are located in in Nebraska, Nevada, New Mexico, Texas, and Wyoming.

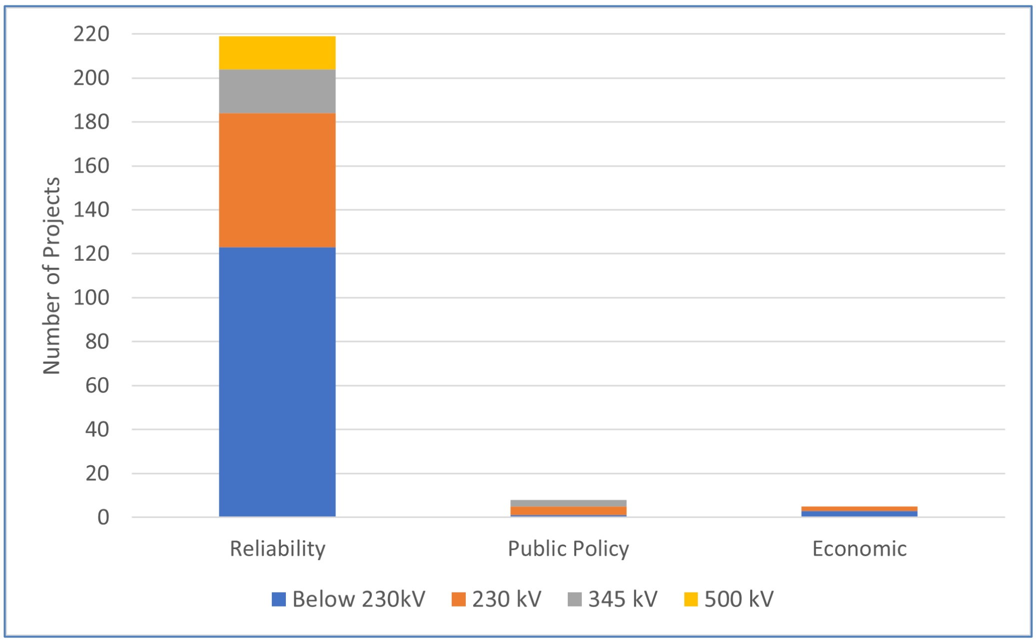
3.2.2 Regional Base Transmission Plan Projects by Driver

Review of the 2024-25 regional Base Transmission Plan planned projects showed that nearly all of projects (90%) are primarily driven by reliability needs, 3% are primarily driven by public policy, and only 1% are primarily economic driven. **Table 10** and **Figure 5** below break out the projects by voltage, and primary driver.

Table 10. 2024-25 Regional Base Transmission Plan Projects by Driver and Voltage based on TPPL data

Driver (Primary/Secondary)	< 230 kV	230 kV	345 kV	500 kV	TBD	Total
Reliability	116	55	19	11	-	201
Reliability/Public Policy	6	6	1	4	-	17
Public Policy	1	3	4	-	-	8
Public Policy/Reliability	-	2	-	-	-	2
Other	13	7	1	5	-	26
Economic	3	1	-	-	-	4
Economic/Reliability	-	1	-	-	-	1
Reliability/Economic	1	-	-	-	-	1
Total ETO & CTO Projects	**140**	**75**	**25**	**20**	**0**	**260**

Figure 5. 2024-25 Regional Base Transmission Plan Number of Projects by Primary Driver and Voltage, based on the TPPL data



4. Reliability Assessment

The purpose of the reliability assessment is to identify regional transmission needs in the 10-year timeframe. WestConnect conducted the 2024-25 regional reliability assessment with two Base Cases: a 2034 Heavy Summer case and a 2034 Light Spring case. The reliability assessment for regional needs was based on reliability standards adopted by the NERC TPL-001-5.1 Table 1 (P0 and P1) and TPL-001-WECC-CRT-3.2 (Transmission System Planning Performance WECC Regional Criterion, which has been replaced with TPL-001-WECC-CRT-4), and supplemented with any more stringent TOLSO planning criteria based on TOLSO Member feedback. Regional issues subject to deeper investigation were defined as system performance issues impacting, or between, more than one TO Member system.

4.1 Case Development

The information in this section summarizes each reliability model and provides details about the major assumptions incorporated into the reliability cases. The quality of the Base Cases and contingency definitions were improved by iteratively developing draft cases with contingency definitions and performing test simulations. After each draft and test simulation, data owners had the opportunity to examine the input and output data and submit corrections. This procedure resulted in seven review drafts of the base reliability models.

4.1.1 2034 Heavy Summer Base Case

Description: The case is designed to evaluate the Base Transmission Plan under peak summer loading conditions. The seed case was the WECC 2034 Heavy Summer 1 Planning Base Case (34HS1), which was approved October 25, 2023. The 34HS1 case was updated with the latest topology (i.e. generator, load, and transmission) information from WestConnect participants while still representing typical heavy summer load conditions and generator dispatch.

Generation: Within WestConnect, the case features a dispatch of 37,143 MW of thermal, 6,034 MW of hydro, 8,645 MW of wind, 15,564 MW of solar, and 3,606 MW of Battery Storage resources.

Load: The aggregate coincident peak load level for the WestConnect footprint is 65,928 MW. The original WECC case represented the system coincident peak for a heavy summer condition between the hours of 1500 to 1700 MDT during the months of June – August. The intent was to continue these assumptions during its case development.

Transmission: No major planned transmission additions beyond the Base Transmission Plan were included in the case.

4.1.2 2034 Light Spring Base Case

Description: The purpose of the case is to assess performance under light-load conditions with solar and wind serving a significant but realistic portion of the WestConnect total load. The seed case was intended to be the WECC 2034 Light Spring 1 Specialized Case (34LSP1-S). However, since the case was delayed, the WestConnect 2034 Heavy Summer powerflow case was used to create the Light Spring model.

Generation: Within WestConnect, the case features a dispatch of 20,995 MW of thermal, 3,423 MW of hydro, 6,678 MW of wind, 12,794 MW of solar, and 506 MW of Battery Storage resources.

Load: The total WestConnect load in the case is 39,357 MW, which is 55% of the WestConnect peak conforming load in the WestConnect 2034 Heavy Summer Base Case. The load levels represent the system from 1200 to 1400 hours MDT during spring months of March, April, and May.

Transmission: Identical transmission assumptions as the 2034 Heavy Summer Base Case – see above for details.

4.1.3 Contingency Other Data

The PS also considered the following when developing the reliability cases:

- **Operating Procedures** – Any special operating procedures required for compliance with NERC reliability standards were considered and included in the powerflow cases.
- **Protection Systems** – The impact of protection systems including Remedial Action Scheme (RAS) required for compliance with NERC reliability standards were included in the powerflow cases.
- **Control Devices** – Any special control devices required were included in the powerflow cases.

4.2 Study Method

The assessment for regional needs was based on reliability standards adopted by the North American Electric Reliability Corporation (NERC), WECC regional criteria, and supplemented with any more stringent TO planning criteria. Initial identification of regional issues for further review was defined as system performance issues impacting or between more than one TO Member system.

The reliability assessment included extensive testing and multiple iterations of model refinements, simulations, participant review of results, and incorporation of modifications and comments into the subsequent round of simulations. The base case contingency and transient stability analysis became the final regional reliability assessment.

4.2.1 Steady State Contingency Analysis

Contingency definitions for the steady-state contingency analysis were limited to N-1 contingencies for elements 230 kV and above, generator step-up transformers for generation with at least 200 MW capacity, and member-requested N-2 contingencies. All bulk electric system (BES) branches and buses – i.e., elements above 100 kV – in the reliability models were monitored.

4.2.2 Transient Stability Analysis

The PMC agreed that the transient stability simulations studied in the 2022-23 study cycle would be repeated for this cycle. One disturbance from the 2022-23 study cycle was determined to be no longer viable due to changes in system topology, so nine transient stability simulations were performed.

4.3 Study Results and Findings

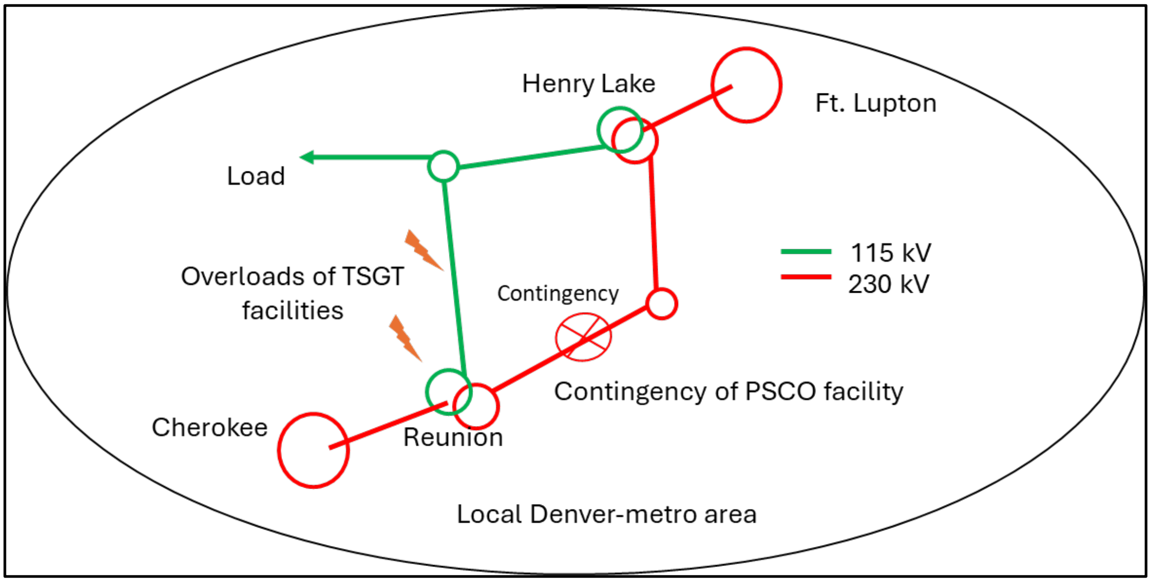
The 2024-25 WestConnect Regional Needs Assessment indicated the potential for a single regional reliability need. The issue was flagged for further discussion because of the involvement of multiple entities.

A summary of the issue is as follows:

- A contingency of a 230 kV line in the vicinity of the Denver-metro load area was found to result in overloads of two transmission facilities, also within the Denver-metro load area.
- The contingency is a 230 kV line owned by Public Service Company of Colorado (PSCO).
- The overloaded transmission facilities are owned by Tri-State Generation & Transmission (TSGT).
- PSCO and TSGT are members of WestConnect.

Figure 6 shows a basic description of the issue.

Figure 6. Simple drawing of potential regional reliability issue



Upon a comprehensive review of the regional reliability assessment results, the PS concluded that although the issue involved multiple entities, with a contingency on one entity's system causing an overload on another entity's transmission facilities, the overloaded facilities are owned by a single entity. Therefore, any mitigation would likely only benefit that single entity (TSGT). As a result, the PS recommended to the PMC at the November 13, 2024, meeting that the single reliability issue not be considered a regional reliability need. This conclusion was reached because neither the Heavy Summer nor Light Spring assessments identified reliability issues that were between two or more WestConnect members that impacted two or more WestConnect members. The reliability issues were presented to the PMC on October 16, 2024 (link) and November 13, 2024 (link).

5. Economic Assessment

The regional economic assessment identifies congestion within the WestConnect planning region in the 10-year timeframe. WestConnect performed the 2024-25 regional economic assessment by conducting a PCM study on a 2034 Base Case along with four sensitivity cases. The goal of the assessment was to test the Base Case and the Base Transmission Plan for economic congestion impacting more than one ETO member.

WestConnect reviews metrics such as congested hours and congestion costs for regional transmission elements greater than 100-kV and WECC transfer paths (or other defined interfaces in the WestConnect footprint) along with any member-specified lower voltage BES elements. Regional transmission facilities or paths/interfaces with congestion impacting more than one ETO member are identified and verified through member review, historical benchmarking, and follow-up studies. Given the regional focus of the process, analysis is limited to transmission (or paths/interfaces) between multiple member systems, transmission (or paths/interfaces) owned by multiple members; and congestion occurring within the footprint of multiple members.

If the production cost modeling identifies congestion that impacts more than one TO, that congestion could result in the identification of a regional economic-driven transmission need. However, not all congestion or economic-related issues identified during the production cost modeling analysis will result in the identification of regional economic needs. Members make a determination of what congestion identified in the PCM is considered significant enough to constitute a regional economic need. If a regional need is identified, then members will identify more efficient or cost-effective regional transmission projects to meet any identified economic-driven transmission needs but will not modify local transmission plans.

5.1 Case Development

As with the reliability assessment, the economic assessment included testing and model refinements, simulations, participant review of results, and incorporation of modifications and comments into the subsequent round of simulations. After each draft and test simulation, data owners had the opportunity to examine the input and output data and submit corrections.

5.1.1 2034 Base Case

Description: The case is a production cost model (PCM) dataset designed to represent a likely, median 2034 future. The WECC 2034 ADS Version 1 (V1), released on July 5, 2024, PCM served as the seed case for the WestConnect economic model 2034 Base Case. That case was then reconciled with the WestConnect 2032 PCM and the case updated as needed during Quarters 2 and 3 of the 2024-25 planning cycle. The WestConnect PCM was then compared with the WECC 2034 ADS PCM Version 2 (V2), which was released on July 29, 2024. These updates were consistent with the process described below, which focuses on what updates were completed with the WECC 2034 ADS PCM V2 dataset as the reference.

Generation:

- The latest WestConnect generator-specific modeling was developed and used to update the dataset. This included but was not limited to: generator type, commission and retirement date, forced outage rate, outage duration, minimum and maximum capability with applicable de-rates for plant load or seasonal ambient temperature, minimum up and down times, fuel assignments, variable operations and maintenance and start-up costs, linkage to reserve modeling and regional/remote scheduling, linkage to operational nomograms, hydro fixed shape or load/price-driven scheduling, and hourly shapes. **Table 11** provides a summary by fuel category of the generation updates made to the WECC 2034 ADS PCM V2. The positive (or negative) values represent the capacity (in MWs) and resulting generated energy (in GWh) added to (or removed from) the WECC 2034 ADS PCM V2 in order to create the WestConnect 2034 Base Case PCM.

Table 11. Generation Differences from WECC 2034 ADS PCM V2
Percentages are in reference to the totals in the WECC 2034 ADS PCM V2

Fuel Category	Differences, WestConnect less WECC PCM				Annual Generation (GWh)		Capacity (MW)	
	Annual Generation		Capacity					
	GWh	%	MW	%	WestConnect	WECC	WestConnect	WECC
Coal	18,776	38.73%	290	2.62%	48,486	29,709	8,004	7,714
Gas	53,244	20.52%	-1,654	-1.55%	259,434	206,190	106,585	108,239
Water	-889	-0.33%	134	0.16%	266,416	267,305	84,257	84,123
Uranium	-4,735	-10.56%	-1,013	-19.57%	44,825	49,560	5,177	6,190
Solar PV	30,131	10.93%	1,890	1.52%	275,713	245,581	124,008	122,118
Solar Thermal	80	2.56%	0	0.00%	3,128	3,047	1,167	1,167
Wind	-29,625	-15.10%	-16,996	-25.04%	196,172	225,797	67,886	84,882
Bio	1,547	12.22%	-3	-0.14%	12,654	11,108	2,239	2,242
Geothermal	129,	0.53%	-142	-4.19%	24,434	24,305	3,395	3,537
BESS	-22,819	-31.38%	2,968	3.97%	72,725	95,543	74,778	71,809
Other	3,728	47.02%	1	0.01%	7,928	4,200	6,375	6,374
Overall	**49,568**		**-14,527**		**1,211,915**	**1,162,347**	**483,869**	**498,396**

- The behind-the-meter distributed generation (BTM-DG) assumptions were retained from the WECC 2034 ADS PCM V2 which modeled them on the resource-side. **Table 12** summarizes the amount of BTM-DG by area represented in the WestConnect 2034 Base Case PCM.

Table 12. Behind-the-Meter Distributed Generation

Area Name	Capacity (MW)	Generation (GWh)	Capacity Factor (%)	Dispatch at Area Peak Load (% of Capacity)
AZPS	2,888	5,483	20%	31%
BANC	915	1,600	20%	47%
EPE	332	645	22%	45%
IID	109	208	22%	55%
LDWP	800	1,455	21%	61%
PNM	409	781	22%	33%
PSCO	1,721	2,896	20%	46%
SRP	264	501	22%	68%
TEPC	682	1,325	22%	29%
WACM	28	50	19%	60%
WALC	47	92	20%	84%

Load: WestConnect Members carefully reviewed the load forecasts provided with the WECC 2034 ADS PCM V2 (derived from the WECC 2024 Loads and Resources Data Collection Process) and made no modifications internal to WestConnect. No changes were made to the load forecasts for areas outside of WestConnect. **Figure 7** and **Figure 8** provide the annual load energy, various load snapshots (peak load and load during system/WECC peak), and the average load on a "PCM Area" basis. The PCM Areas are generally analogous to Balancing Areas (BAs) rather than specific utilities. The "PF Load" – load in the WestConnect 2034 Heavy

Summer Base Case – is provided for a frame of reference, though, some difference between the PCM and PF load snapshots is typical given the below-listed considerations.

- The PF model focuses on an extreme or more-stressed-than-normal system condition whereas the economic model load shapes do not contain extremely high or low load values since they are developed to support a median year-long simulation.
- The economic model load shapes do not include the impact of BTM-DG whereas the PF model loads may or may not contain BTM-DG.

Figure 7. WestConnect PCM Areas' Annual Demand (GWh) in WestConnect 2034 Base Case (PCM)

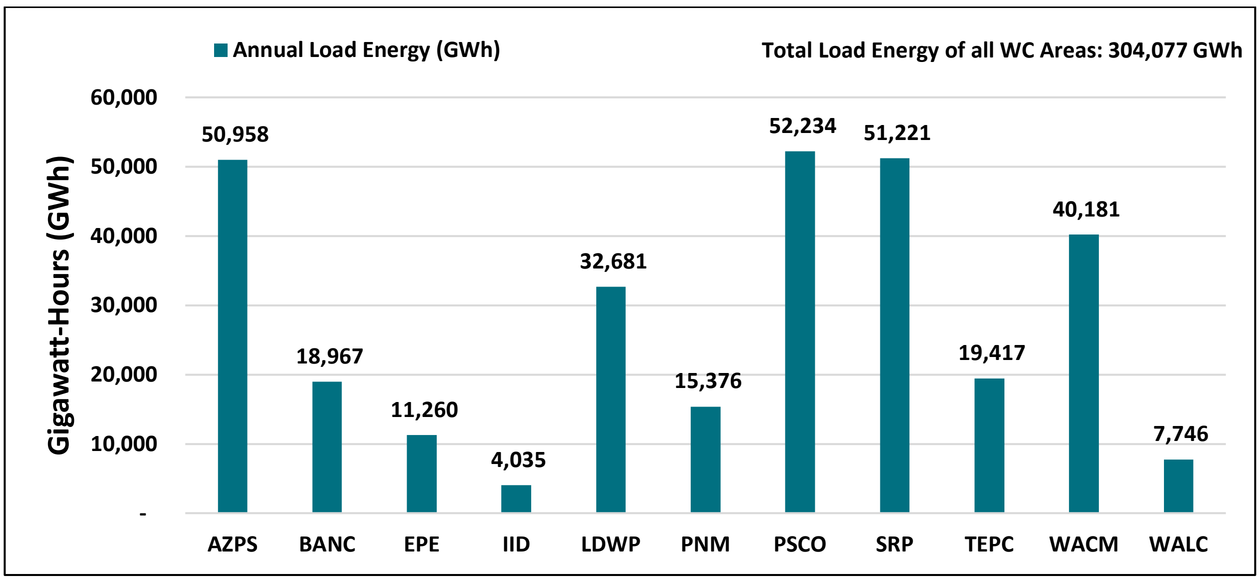
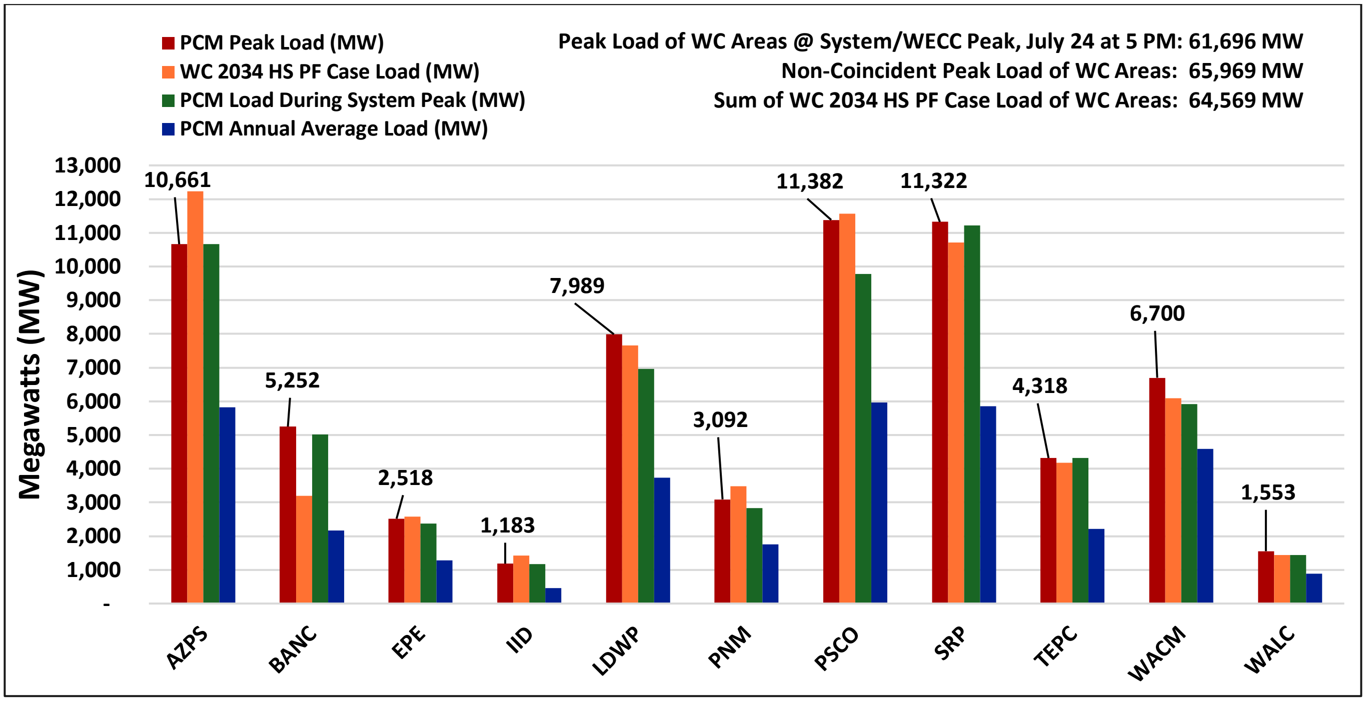


Figure 8. WestConnect PCM Areas' Peak Demand, Demand During System Peak, and Average Demand (MW) in WestConnect 2034 Base Case (PCM), shown with the Demand of the 2034 Heavy Summer Base Case



Transmission: The WECC 2034 ADS PCM V2 was updated with the WestConnect member topology to be consistent with the WestConnect Base Transmission Plan and the reliability model topology. WestConnect also reviewed the case for seasonal branch ratings, interfaces, and nomograms – making the below listed changes in each of these categories. The transmission topology outside of WestConnect, including the Common Case Transmission Assumptions, was not modified.

- Branch monitoring in the WestConnect footprint: Monitored transmission elements greater than 100 kV in WestConnect, greater than 200 kV outside of WestConnect, and all phase shifting transformers (PST) (phase angle regulators, or PAR).
- Updated interface definitions and ratings.

Other Assumptions:

- Any opportunity to more closely align the economic base case model with the reliability base case model was taken. For example, the summer and winter branch ratings and load distribution factors were aligned with the 2034 Heavy Summer Base Case.
- Fuel price forecasts and emission rate assumptions were pulled from the WECC 2034 ADS PCM V1 and subsequently updated with new fuel prices approved by the WECC PCDS and included in the WECC 2034 ADS PCM V2. These assumptions are included in the 2024-25 Model Development Report.
- Reserve requirements modeling was updated from what was represented in the WECC 2034 ADS PCM V2. These assumptions are summarized below:
  - The reserves included in the production cost modeling include spinning reserves, regulation and load following reserves, and frequency response reserves. In modeling these reserve requirements, GridView sets aside generating capacity within a given footprint sufficient to meet the hourly reserve requirement, subject to eligible unit's ramping rates, which vary by technology type.

- Contingency Reserves (Spinning Reserves):
  - Modeling spinning reserves in the production cost model is typically done in tiers to best capture the sharing of reserves across the system. The total hourly reserve requirement is carried at the Reserve Sharing Group level, as applicable to a given BA, with sub-constraints layered on at the BA-level to ensure that a portion of the total reserves are carried locally at the participating BA-level.
  - Consistent with BAL-002-WECC-2, the spinning reserve requirement is set to 3% of hourly load for a given reserve sharing group area. Assumed that NW and SW BA's locally meet 25% and 90% (respectively) of their contingency reserve requirement based on previous WECC models citing WECC EDT Phase 2 Benefits Analysis Methodology (October 2011 Revision).
  - The Northwest Reserve Sharing Group (Western Power Pool – formerly Northwest Power Pool) was modified to include new entrants that joined in Q4 2023.
  - Assumed a 50/50 split between spinning and non-spinning reserves, leading to 1.5% load and 1.5% generation requirement at the RSG-level and a 0.375% load and 0.375% generation requirement at the underlying BA-level
- Flexibility Reserves:
  - Regulation Ancillary Service (AS) assumptions shown in **Table 13** were based on the CPUC Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies, February 20, 2019 (link).
  - Load Following AS assumptions shown were based on the CPUC SERVM model for their 2018-19 IRP.
- The model did not include modeling for non-spinning requirements since neither dataset currently has quick-start generator designations.

Table 13. Reserve Requirement and Ancillary Service Assumptions in WestConnect 2034 Base Case

Reserve Requirement/AS	Ramping Response Requirement (minutes)	Requirement (at RSG level)	What it represents	What can contribute
Contingency/Spinning	10	1.5% of load and generation	Actions that can be taken to maintain system balance during an unexpected loss of generation or transmission	• Dispatchable thermals (excludes biomass/geothermal/nuclear/co-gen) generators subject to available headroom and ramp rate • Storage and hydro resources as constrained by headroom
Regulation Up	10	1.0% of load, 0.5% of generation	Security against unexpected loss of generation.	• Dispatchable thermals (excludes biomass/geothermal/nuclear/co-gen) generators subject to available headroom and ramp rate • Storage and hydro resources as constrained by headroom
Regulation Down				***Same as Reg Up contributors*** **+** ***Wind & Solar (no more than 20% of Maximum Capacity)***
Load Following Up	20	1.5% of load and generation	Capacity reserved to accommodate load and/or renewable forecast error and sub-hourly deviations in forecasts. Not an actual product in most areas – proxy product to maintain reliability.	***Same as Reg Up contributors***
Load Following Down	20	1.5% of load and generation		***Same as Reg Down contributors***

- Frequency Response AS assumptions were based on system-wide values from the CAISO SB350 Study Assumptions. This and the related assumptions are summarized in **Table 14**.

Table 14. Frequency Response Ancillary Service Assumptions in WestConnect 2034 Base Case

AS	Ramping Response Requirement (minutes)	Requirement (at RSG level)	What it represents	What can contribute
Frequency Response	1	385/1,753	• Response to frequency changes within one minute • 50% of constraint assumed to be met by hydro and renewable resources (full constraint is 2505 MW)	• Storage, coal, and gas only • Limit gas-fired contribution to 8% of their capacity/headroom (via Ancillary Max Contribution)

- The below listed thermal generation modeling assumptions were taken from the WECC Intertek report dated May 12, 2020, "Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council."
  - Cost per start: used the warm, median values
  - Ramping limits
  - Minimum up and down times
  - Variable Operations and Maintenance (VOM) cost

- Wheeling charges, which represent the transmission service charges associated with transferring power between areas, were revised from the original WECC 2034 ADS PCM V2 values to peak and off-peak wheeling charges based on the latest OATT rate. These assumptions are provided in the 2024-25 Model Development Report. The WECC 2034 ADS PCM V2 also contained additional wheeling charges associated with modeling carbon emission charges applicable to California, Oregon, and Washington, and these rates were updated. PS members reviewed these updates through draft model releases. Additional details for the wheeling charge modeling assumptions are included below:
  - The regular, inter-area wheeling charges were based upon the OATT on-peak and off-peak non-firm point-to-point transmission service charges (Schedule 8) as well as Schedule 1 (Scheduling System Control and Dispatch Service) and Schedule 2 (Reactive Supply and Voltage Control) charge components of transmission providers in the Western Interconnection.

  - Emission-related wheeling charges: The carbon emission charges applicable to California representing the California Global Solutions Act (AB 32) modeling and supplemental updates to the WECC 2034 ADS PCM V2 by the WECC Production Cost Data Subcommittee (PCDS) were implemented. Refer to the "Carbon emission charges updates" topic below for more details.

  - The WECC 2034 ADS PCM V2 included tiered wheeling constraints – zero wheeling charges up to a MW threshold and non-zero wheeling charges thereafter – on the Nevada, Idaho, Montana, and Canadian borders of the NW footprint as well as the PACE/APS border, and these wheeling charges were retained.

- Nomograms and transmission interfaces were modeled by starting with the WestConnect 2032 PCM, pulling in updates based on the WECC 2034 ADS PCM V2, and then enhanced with additional nomograms and conditional constraints provided by WestConnect members. These input conditions aim to address the operational needs of individual member systems, such as voltage support and other factors, including must run and must take conditions, that drive the need for certain generation resources to be committed in a particular way, consistent with the existing operational practices of the WestConnect member systems. The names of monitored interfaces are included in the 2024-25 Model Development Report. The

"SMUD Op Nomogram", "EPE Balance", and "TEP Local Gen" were nomograms added to the model to commit local generation. In addition, other nomograms were added for generating plants containing a combination of solar PV and battery storage to ensure their combined output did not exceed their contractual limits, and others were added to ensure the battery storage only charged via the solar PV output for certain plants.

- Carbon emission charges updates: Details are below, in 2024 dollars.
    - California: Updated to $64/MT based on the WECC PCDS recommendation (Final 2023 CEC IEPR GHG Allowance Price Projections) (California Carbon Price Assumption)
        - In addition, the reduced emission factor for NW imports was also updated to 0.0174 MT CO_2e/MWh based on CARB Mandatory GHG Reporting - Asset Controlling Supplier. This affected the above-mentioned updates to the emission-related wheeling charges.
    - Oregon: Added emissions allowance per WECC PCDS recommendation at $64/MT (same as California) with updates planned following WECC stakeholder feedback.
    - Washington: Added emissions allowance per WECC PCDS recommendation at $64/MT (same as California) with updates planned following WECC stakeholder feedback.
    - Alberta: Updated to $37/MT based on WECC PCDS recommendation.
    - British Columbia: Updated to $37/MT based on WECC PCDS recommendation.

5.2 Study Methodology & Criteria

WestConnect conducted the study and reviewed the 2034 Base Case results for regional congestion (number of hours) and congestion cost (the cost to re-dispatch more expensive generation because of transmission constraints). Given the regional focus of the WestConnect process, the PS limited its congestion analysis to:

- Transmission elements (or paths/interfaces) between multiple WestConnect member TOs.
- Transmission elements (or paths/interfaces) owned by multiple WestConnect member TOs; and
- Congestion occurring within the footprints of multiple TOs that has potential to be addressed by a regional transmission project or non-transmission alternative.[10]

Congestion hours are the number of binding hours where the PCM determines there is a constraint on a transmission element or path/interface. The congestion cost is calculated by the Shadow Price multiplied by the MW flow at the constraint for a specific hour. The Shadow Price is a decrease in production cost if the constraint has one MW of relief. It is an indication of the marginal value of the line or path/interface. A higher value indicates the higher production cost benefits when line capacity is expanded. The number of binding hours is also an important indicator for transmission upgrades.

5.3 Study Results and Findings

The objective of the economic needs assessment was to arrive at a set of congested elements that warranted testing for the economic potential for a regional project solution, recognizing that the presence of congestion does not always equate to a regional need for congestion relief at a particular location.

The base economic regional Needs Assessments revealed two instances of congestion shown in Table 15.

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[10] Congestion within a single TO's footprint (and not reasonably related or tied to other TO footprints) is out of scope of the regional planning effort and is alternatively subject to Order 890 economic planning requirements.

Table 15 Economic Assessment Results

Entities Involved	Branch or Path Name	Avg Flow (MW)	Flow Direction	Annual (2034) Congestion Hours (% Hrs) / Cost (K$)
TSGT|PSCo	P36 TOT 3	919	N>S	138 (2%) / 10,032
PSCO|TSGT	CRAIG_YV - CRAIG 230 kV Line	73	W>E	723 (8%) / 1,005

The highest congestion was on the TOT 3 path, with congestion occurring 2% of hours and an associated congestion cost of about $10 million as determined by the PCM. PMC agreed with affected members that congestion is low enough to not be considered a regional need.

Members that were affected by the economic issues were requested to assist the PS by providing narrative perspectives on the specific issues that affected them. Every affected member provided a narrative response to the PS. The economic issues were presented to the PMC on October 16, 2024 (link) and November 13, 2024 (link).

The PS addressed the congestion issues individually. Upon a comprehensive review of the regional reliability assessment results, the PS determined the base economic congestion results did not result in the identification of any regional economic needs. The PS recommended to the PMC at the November 13, 2024, PMC meeting that the five economic congestion issues not be considered as regional economic needs. The congestion results for the base case PCM and detailed explanations are provided in Appendix B.

5.4 Sensitivity Studies

5.4.1 Economic Sensitivity Models

Models were developed for sensitivity studies on the 2034 Base Case economic model to better understand whether regional transmission congestion may be impacted by adjusting certain input assumptions subject to significant uncertainty. The sensitivity analysis is intended to make relatively minor adjustments that would still remain within the expected future framework of the base models. The PS determined four sensitivities of interest, and their assumptions are described below.

2034 High Load Sensitivity Case

Description: Scaled up the hourly load shape of BAs within WestConnect so their annual peak and energy is a 100%+ percentage of their value in the 2034 Base Case:

- All WestConnect Areas: 120% of both peak and energy

2034 Low Hydro Sensitivity Case

Description: Replaced hydro modeling with WECC 2001-based hydro modeling data developed by WECC in conjunction with their 2034 Common Case PCM dataset.

2034 High Gas Price Sensitivity Case

Description: Increased all the natural gas prices to 140% of their value in the 2034 Base Case.

2034 System-Wide Carbon Emission Cost Sensitivity Case

Description: Applied CO_2 emission charges to all generators in WECC via the below updates to the 2034 Base Case:

- Applied a reduced carbon emission price of $20/MT ($9/MWh) for all generation in California, Oregon, and Washington so the net change for units internally to these States remains the same ($20/MT + $44/MT = $64/MT)
- Kept the Alberta and British Columbia carbon emission prices unchanged at $37/MT
- Removed the carbon emission wheeling charges from all California borders except with Baja California (CFE)

5.4.2 Sensitivity Results

WestConnect concluded that there was no significant congestion to identify a regional need in the Base Case economic assessment. For completeness, the PS conducted the sensitivity studies described above and confirmed that the different assumptions were not hiding potential regional congestion. The detailed results of the sensitivity cases are provided in **Appendix C**.

6. Public Policy Assessment

WestConnect administered the process for identifying regional transmission needs driven by enacted Public Policy Requirements. Enacted Public Policy Requirements are state or federal laws or regulations, meaning enacted statutes (i.e., passed by the legislature and signed by the executive) and regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level and including those enacted by local governmental entities, such as a municipality or county. Given this, regional public policy-driven needs are evaluated in the following ways:

1) New regional economic or reliability needs driven by enacted Public Policy Requirements; or
2) Stakeholder review of local TO Public Policy Requirements-driven transmission projects and associated suggestions as to whether one or more TO projects may constitute a public policy-driven regional transmission need.

6.1 Study Method

WestConnect began the evaluation of regional transmission needs driven by Public Policy Requirements for the 2024-25 planning cycle by soliciting TO members to identify enacted Public Policy Requirements in the region and to identify if any of the enacted Public Policy Requirements were driving local projects in the local TO's transmission plan that were incorporated in the base case models used in the WestConnect planning process. A list of enacted Public Policy Requirements in the region was documented in the Study Plan and this list was further refined by the PS in public meetings and posted in meeting materials. This list was provided to stakeholders to help evaluate if any Public Policy Requirement may result in a regional transmission need. WestConnect also described the local transmission projects that were driven by Public Policy Requirements and that were incorporated in the WestConnect base case models.

Table 16 lists all enacted public policies applicable to the WestConnect footprint, including Public Policy Requirements. A portion of the enacted public policies are driving planned local transmission projects reflected in the regional base economic and reliability models, whereas others are not currently driving planned local transmission projects. Each TOLSO member provided confirmation that, to the extent a plan for compliance with the Public Policy Requirements was completed prior to the model development phase of the WestConnect 2024-25 planning cycle, the WestConnect 2034 economic and reliability models reflect these public policies' conditions for the study year 2034. Company goals, although not Public Policy Requirements, such as the PNM Commitment to Carbon Free by 2040[11], were also considered in the development of the base models.

Table 16. Public Policies Considered and/or Incorporated into 2034 WestConnect Planning Models

Public Policy Requirement	Description
Arizona Renewable Energy Standard	Requires IOUs and retail suppliers to supply 15% of electricity from renewable resources by 2025, with a minimum of 30% of the renewable resources provided by distributed generation
California AB398/SB32	Requires the California State Air Resources Board to approve a statewide greenhouse gas emissions limit equivalent to the statewide greenhouse gas emissions level in 1990 to be achieved by 2020 and to ensure that statewide greenhouse gas emissions are reduced to at least 40% below the 1990 level by 2030

[11] *Public Service of New Mexico plans to produce 100% carbon free energy by 2040. Source: https://www.pnm.com/our-commitment*

Public Policy Requirement	Description
California SB100	Requires Investor-owned utilities (IOUs) and municipal utilities to meet a 60% renewable portfolio standard ("RPS") by 2030
California SB350	Requires IOUs and municipal utilities to meet a 50% RPS by 2030 and requires the establishment of annual targets for energy efficiency savings
Colorado HB 18-1270 ("Energy Storage Procurement Act")	Directs the Commission to develop a framework to incorporate energy storage systems in utility procurement and planning processes. See C.R.S. § 40-2-201, et seq. The legislation broadly addresses resource acquisition and resource planning, and transmission and distribution system planning functions of electric utilities. Energy storage systems may be owned by an electric utility or any other person. Benefits include increased integration of energy into the grid; improved reliability of the grid; a reduction in the need for increased generation during periods of peak demand; and, the avoidance, reduction, or deferral of investment by the electric utility
Colorado HB 19-1261 and SB 1261 ("GHG Reduction Bills")	HB 19-1261 requires the Air Quality Control Commission ("AQCC") to promulgate rules and regulations for statewide greenhouse gas ("GHG") pollution abatement. Section 1 of SB 1261 states that Colorado shall have statewide goals to reduce 2025 greenhouse gas emissions by at least 26%, 2030 greenhouse gas emissions by at least 50%, and 2050 greenhouse gas emissions by at least 90% of the levels of statewide greenhouse gas emissions that existed in 2005. A clean energy plan filed by a utility is deemed approved if the plan demonstrates an 80% reduction by 2030.
Colorado HB10-1001	Established Colorado Renewable Energy Standard ("RES") to 30% by 2020 for IOUs (Xcel & Black Hills)
Colorado SB 07-100	Requires IOUs to identify Energy Resource Zones, plan transmission to alleviate constraints from those zones, and pursue projects according to the timing of resource development in those zones
Colorado SB 18-009 ("Energy Storage Rights Bill")	Protects the rights of Colorado electricity consumers to install, interconnect, and use energy storage systems on their property without the burden of unnecessary restrictions or regulations and without unfair or discriminatory rates or fees.
Colorado SB 19-077 ("Electric Vehicles Bill")	The bill enables a regulatory approval process for electric utilities to invest in charging facilities and provide incentive rebates; thus, the investments and rebates may earn a return at the utility's authorized weighted-average cost of capital. Where approved, the costs for the investments and rebates may be recovered from all customers of the electric utility similar to recovery of distribution system investments. Natural gas public utilities may provide fueling stations for alternative fuel vehicles as non-regulated services only.
Colorado SB 19-236 ("PUC Sunset Bill")	The primary purpose of this bill is to reauthorize the CPUC, by appropriations, for a seven-year period to September 1, 2026. Reauthorization is required by the sunset process. Additionally, the bill carries numerous requirements for utilities and the CPUC to achieve an affordable, reliable, clean electric system. Included in the bill are requirements to reduce the qualifying retail utility's carbon dioxide emissions associated with electricity sales to the qualifying retail utility's electricity customers by eighty percent from 2005 levels by 2030, and that seeks to achieve providing its customers with energy generated from one-hundred-percent clean energy resources by 2050. The bill also subjects co-ops to Colorado Public Utility Commission rulemaking.
Colorado SB13-252	Requires cooperative utilities to generate 20% of their electricity from renewables by 2020

Public Policy Requirement	Description
Colorado SB21-072	This bill requires electric transmission utilities in Colorado to join an organized wholesale market ("OWM") by January 1, 2030, provided that the OWM meets certain criteria set forth in the statute. This bill also creates the Colorado Electric Transmission Authority, a governmental entity that is authorized to independently develop and finance transmission projects.
Colorado HB21-1266	This bill is a broad policy measure to promote environmental justice in disproportionately impacted communities through the creation of an Environmental Justice Task Force. The bill requires wholesale generation and transmission cooperatives to file with the Public Utilities Commission a Clean Energy Plan to achieve 80% emissions reductions by 2030.
Colorado SB 21-246	The primary purpose of this bill is to direct the approval of plans for the electrification of buildings that use fossil fuel-based systems through existing demand side management programs.
Colorado HB21-1238	The primary purpose of this bill is to update the PUC's rules and decision-making process with respect to natural gas demand-side management programs including the use of the Social Cost of Carbon and Social Cost of Methane.
Colorado SB21-272	The primary purpose of this bill is to update the PUC's rules and decision-making process to better incorporate the impacts and benefits to underserved or disproportionately impacted communities and groups including workforces impacted by generation acquisition and retirement. Other requirements include how utilities finance resources or investments, the retirement of renewable energy credits, and the inclusion of the Social Cost of Carbon in resource planning decisions.
Colorado SB23-016	This legislation updates the State of Colorado's statutory greenhouse gas emissions goals (HB19-1261) to add a 65% reduction goal for 2035, an 80% reduction goal for 2040, and a 90% reduction goal for 2045, as well as amending the state's 2050 goal from a 90% reduction goal to 100%.
Public Policy Requirement: California SB 1020	• Description: Under SB 1020, at least 90% of all retail sales of electricity in California must be supplied by eligible renewable and zero-carbon energy resources by December 31, 2035. By December 31, 2040, 95% of all retail electricity sales must be supplied by eligible renewable and zero-carbon energy resources. Additionally, all electricity resources by the end of 2035.
Executive Order 14057 (EO 14057), Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability (Dec. 8, 2021)	The President's executive order directs the federal government to use its scale and procurement power to achieve five ambitious goals: • 100 percent carbon pollution-free electricity ("CFE") by 2030, at least half of which will be locally supplied clean energy to meet 24/7 demand; • 100 percent zero-emission vehicle ("ZEV") acquisitions by 2035, including 100 percent zero-emission light-duty vehicle acquisitions by 2027; • Net-zero emissions from federal procurement no later than 2050, including a Buy Clean policy to promote use of construction materials with lower embodied emissions; • A net-zero emissions building portfolio by 2045, including a 50 percent emissions reduction by 2032; and Net-zero emissions from overall federal operations by 2050, including a 65 percent emissions reduction by 2030.

Public Policy Requirement	Description
New Mexico Efficient Use of Energy Act	Require utilities to include cost-effective energy efficiency (EE) and demand response (“DR”) programs in their resource portfolios and establish cost-effectiveness as a mandatory criterion for all programs
New Mexico Energy Transition Act (2019 SB 489)	Subject to the Reasonable Cost Threshold (“RCT”), the Energy Transition Act defines renewable energy requirements that are a percentage of a utility’s retail energy sales and the type of utility: • By 2020, 20% for public utilities and 10% for cooperatives • By 2025, 40% for public utilities and cooperatives • By 2030, 50% for public utilities and cooperatives • By 2040, 80% for public utilities with provisions associated with carbon free generation • 100% carbon-free by 2045 for public utilities and by 2050 for cooperatives
New Mexico Title 17-Public Utilities and Utility Services Part 574 Applications to Expand Transportation Electrification	"The purpose of this rule is to implement Section 62-8-12 NMSA 1978, applications to expand transportation electrification, and to bring to New Mexico the economic development and environmental benefits of expanded electrification of the State’s transportation modalities and transportation infrastructure. Three-year plan with a planning outlook for two-years beyond the proposed three-year plan"
New Mexico Title 17-Public Utilities and Utility Services Part 588 Grid Modernization Grant Program	Grid modernization roadmap and grant program is focused on improvements to electric distribution or transmission infrastructure, including related data analytics equipment, that are designed to accommodate or facilitate the integration of renewable electric generation resources with the electric distribution grid or to otherwise enhance electric distribution or transmission grid reliability, grid security, demand response capability, customer service or energy efficiency or conservation and includes:(a) advanced metering infrastructure that facilitates metering and providing related price signals to users to incentivize shifting demand;(b) intelligent grid devices for real time system and asset information at key substations and large industrial customers;(c) automated control systems for electric distribution circuits and substations;(d) communications networks for service meters;(e) distribution system hardening projects for circuits and substations designed to reduce service outages or service restoration times;(f) physical security measures at key distribution substations; (g) cybersecurity measures;(h) energy storage systems and microgrids that support circuit-level grid stability, power quality, reliability or resiliency or provide temporary backup energy supply;(i) electrical facilities and infrastructure necessary to support electric vehicle charging systems;(j) new customer information platforms designed to provide improved customer access, greater service options and expanded access to energy usage information; and (k) other new technologies that may be developed regarding the electric grid.
New Mexico Advanced Clean Car Rule	Starting in calendar year 2026, 43% of all new passenger cars and light-duty trucks shipped to New Mexico auto dealerships by national auto manufacturers must be zero emission vehicles. Similarly, beginning in calendar year 2026, 15% of all new commercial heavy-duty trucks shipped to New Mexico auto dealerships by national auto manufacturers must be zero emission vehicles. These percentages gradually increase over time.
SRP Sustainable Energy Goal	Reduce the amount of CO_2 emitted per megawatt-hour (MWh) by 65% from 2005 levels by 2035 and by 90% by fiscal year 2050.

Public Policy Requirement	Description
Texas RPS	Texas RPS requires a total renewable capacity of 5,880 MW (which has already been achieved) by 2025 be installed in the state which is in turn converted into a renewable energy requirement. The renewable energy requirements are allocated to load serving entities based on their amount of retail energy sales as a percent of the total Texas energy served
Texas Substantive Rule 25.181 (Energy Efficiency Rule)	Require utilities to meet certain energy efficiency targets

In an effort to engage stakeholders, the list of enacted Public Policy Requirements in the region and local projects in the TOs' local transmission plans that were driven by Public Policy Requirements was presented to stakeholders at the November 13, 2024, WestConnect Stakeholder meeting, as well as at the open PMC meeting held the same day. Stakeholders were asked to review the information and suggest to WestConnect possible regional public policy-driven transmission needs. An open stakeholder comment window was announced via posting on the WestConnect website and through an email to the WestConnect stakeholder distribution list for the purpose of collecting suggestions of possible regional public policy-driven transmission needs. The stakeholder comment window was open from November 13, 2024, through December 4, 2024, and invited comments on the WestConnect reliability and economic needs assessment results in addition to suggestions of possible regional public policy-driven transmission needs. WestConnect received one set of comments from a stakeholder regarding the regional assessment, but the comments did not suggest or recommend the identification of a regional public policy-driven transmission need.

6.2 Evaluating Progress

As with prior cycles, WestConnect conducted a high-level accounting and comparison of each PCM Area energy sales and renewable energy to observe if the energy penetration trajectory, based on data provided by members for the economic models, tracks with enacted public policies. The process is outlined below.

1. Annual generation consisting of Bio, Geothermal, Solar PV, Solar Thermal, & Wind were summed for each PCM Load Area as Renewable Energy ("RE"). The Reserve Capacity Distribution settings in the 2034 Base Case PCM were used to allocate resources to their appropriate remote load area.
2. Each PCM Load Area's "Energy Sales" was determined by taking the "Served Load Includes Losses", subtracting losses, adding the magnitude of negative generation (e.g., pumping loads with hourly profiles), and subtracting behind-the-meter generation (e.g., distributed generator or DG-BTM, energy efficiency or EE, demand response or DR).
3. The "Renewable Energy" was divided by the "Energy Sales" as the "RE as % of Energy Sales" for the 2034 Base Case PCM and compared with these same values from the previous three planning cycles (to allow for comparison between planning cycles).

Only the single year results from each study year were used in the RE check and no banking of renewable energy from other years was assumed. **Figure 9** shows the results of the renewable energy check, which the PS determined show a reasonable trend towards WestConnect members meeting enacted public policies.

Table 17 shows the losses and load including losses used to calculate the WestConnect Energy Sales. The results of the renewable energy check were also presented to stakeholders on November 13, 2024.

Figure 9. Sum of Energy Sales, Renewable Generation, and Overall RE as % of Energy Sales Based on Single-Year Results from the 2034 Base Case PCM and the Base Case PCM's from previous planning cycles

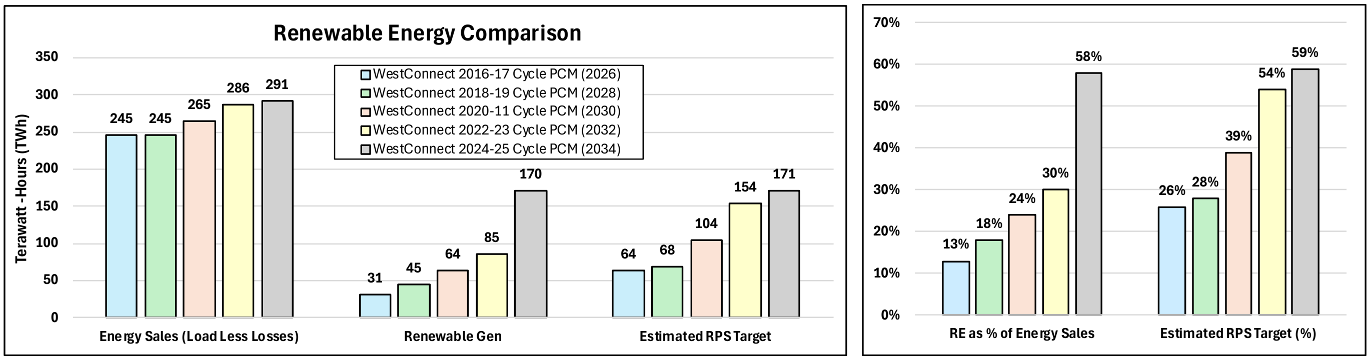

Table 17. BA Losses and Served Load Including Losses used to calculate the WestConnect Energy Sales in the Renewable Energy Check

BA	Losses (MWh)	Served Load Includes Losses (MWh)
AZPS	1,619,310	44,564,312
BANC	771,891	21,846,017
EPE	374,876	11,975,682
IID	199,304	4,791,888
LDWP	1,332,424	46,582,375
PNM	500,485	17,269,592
PSCO	1,839,963	55,987,612
SRP	1,687,780	48,656,614
TEPC	579,376	19,768,885
WACM	699,336	28,461,260
WALC	386,111	10,081,379
Total	**9,990,856**	**309,985,617**

6.3 Results and Findings

In conducting the regional reliability and economic assessments the PS did not find any regional issues, and as such, no further investigation of regional issues was done to determine if there were regional reliability and/or economic needs driven by enacted Public Policy Requirements. Furthermore, stakeholders did not suggest or recommend the identification of a regional public policy-driven transmission need based on the information shared at the November 13, 2024, stakeholder meeting, which included the results of the regional reliability and economic needs assessments, and the list of Public Policy Requirements impacting the WestConnect region and local transmission projects driven by Public Policy Requirements. Based on these two findings, there are no identified public policy-driven needs in the WestConnect 2024-25 Regional Planning Process. The WestConnect PMC approved the 2024-25 WestConnect Regional Transmission Needs Assessment Report on January 15, 2025, which did not identify any regional transmission needs driven by Public Policy Requirements.

7. Regional Transmission Plan Summary

Based on the findings from the 2024-25 planning cycle analysis performed for reliability, economic, and public policy transmission needs as described in this report, no regional transmission needs were identified in the 2024-25 assessment.

Since no regional transmission needs were identified, the PMC did not collect transmission or non-transmission alternatives for evaluation since there were no regional transmission needs to evaluate the alternatives against.

Given this, the Regional Transmission Plan produced at the conclusion of the 2024-25 planning cycle is the same as the Base Transmission Plan developed at the start of the planning cycle, with the exception that certain non-public utilities were represented in the Base Transmission Plan but are no longer part of the region at this time. The Regional Transmission Plan is to represent the regional plan of those entities enrolled in the WestConnect region.

The transmission projects of enrolled transmission owners in the WestConnect region at the time this regional plan is being posted are those projects shown in **Appendix A**.

8. Stakeholder Involvement and Interregional Coordination

8.1 Stakeholder Process

The WestConnect regional planning process is performed in an open and transparent manner to attain objective analysis and results. WestConnect invites and encourages interested parties or entities to participate in and provide input to the regional transmission planning process at all planning process stages. Stakeholders have opportunities to participate in and provide input to local transmission plans as provided for in each TO Member's OATT. Further, stakeholders have opportunities to participate in and provide input into subregional planning efforts within Colorado Coordinated Planning Group ("CCPG"), Sierra Subregional Planning Group ("SSPG"), and Southwest Area Transmission ("SWAT"). Finally, all WestConnect planning meetings are open to stakeholders.[12] Stakeholders' opportunities for timely input and meaningful participation are available throughout the WestConnect planning process. More specifically, the PS and PMC meetings held to support the regional transmission planning process were open to the public, and each meeting provided an opportunity for stakeholder comment. Notice of all meetings and stakeholder comment periods were posted to the WestConnect Calendar webpage and distributed via email. In addition, WestConnect accepted stakeholder comments on the interim reports created throughout the 2024-25 planning cycle. Further, open stakeholder meetings to discuss the WestConnect regional Planning Process were conducted on February 21, 2024, November 13, 2024, February 11, 2025, and November 13, 2025. The meetings were announced through the WestConnect website and stakeholder distribution lists, and all stakeholders were invited to attend.

During the 2024-25 planning cycle, stakeholder comments were submitted following the November 13, 2024, stakeholder meeting. The comments received requested that the PMC clarify the process used to determine regional economic needs, consider developing objective methods or thresholds to use in determining regional needs, and consider whether the PCM adequately addresses extreme grid conditions. In response, the PMC agreed to include a written description of the PCM methods for quantifying economic congestion values and an

[12] At times, the PS and PMC convene closed sessions for the purpose of addressing matters not appropriate for public meetings. Closed sessions typically address administrative, legal, and/or contractual matters, and include, from time to time, matters involving the handling and protections of non-public information."

explanation of how the PMC considers grid congestion during the planning horizon in the Regional Plan Report[13], and discussed the possibility of forming a task force to address the requests related to production cost modeling. The Economic Assessment section of this report (Section 5) explains how WestConnect evaluates economic modeling results. However, in June 2025, the ETOs requested that all activities not required under FERC Order 1000 tariffs discontinue for the remainder of the 2024-25 planning cycle, which included the potential formation of a PCM metrics task force[14].

The full comments, as well as the PMC responses to the comments, are posted on the Stakeholder Comments webpage, which the PMC uses to collect, track, and resolve stakeholder comments and concerns. On occasion, stakeholders have also offered verbal or written comments to specific topics discussed in WestConnect planning meetings. In those cases, the stakeholder comments have been captured in the meeting notes or posted to the respective calendar meeting pages.

8.2 Interregional Coordination

WestConnect coordinates its planning data and information with the two other established Planning Regions in the Western Interconnection (California Independent System Operator and NorthernGrid) by:

- Participating in annual interregional coordination meetings.
    - During the 2024-25 planning cycle, NorthernGrid hosted the interregional coordination meeting on March 24, 2024, in Portland Oregon. The California ISO hosted the interregional coordination meeting on March 26, 2025, in Folsom, California.
- Distributing regional planning data or information such as:
    - Draft and Final Regional Study Plan
    - Regional Transmission Needs Assessment Report
    - List of Interregional Transmission Projects ("ITP") submitted to WestConnect
    - Assessments and selection of ITPs into Regional Transmission Plan
    - Draft and Final Regional Transmission Plan
- Sharing planning assumptions if and when requested and subject to applicable confidentiality requirements; and
- Participating in a coordinated ITP evaluation process, as necessary, when an ITP is submitted to WestConnect as an alternative to meet an identified regional need. [15]

To the extent WestConnect received updated modeling data from TOs outside of the WestConnect planning region during the development of the regional models, it was considered, and if appropriate, incorporated into the regional models. The goal in seeking input from neighboring planning regions and TOs outside of the WestConnect planning footprint is to maintain external model consistency and align planning assumptions as closely as possible.

The process WestConnect utilizes to conduct its interregional coordination activities is described in the WestConnect Regional Planning Process BPM which is posted on the WestConnect website.

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[13] *2024_25 stakeholder comments and PMC responses*

[14] *June 13, 2025, ETO letter to PMC is here.*

[15] *Additional details regarding the ITP submittal and evaluation process can be found in the BPM.*

8.3 Interregional Project Submittals

An ITP is defined in the common tariff language developed for the Order No. 1000 interregional compliance filings as "a proposed new transmission project that would directly interconnect electrically to existing or planned transmission facilities in two or more planning regions and that is submitted into the regional transmission planning processes of all such planning regions." ITP proponents seeking to have their project included in the WestConnect Base Transmission Plan had the opportunity to do so at the beginning of the planning cycle. ITP proponents that wanted their ITP considered for cost allocation and/or to have their project evaluated to meet an identified regional need needed to submit their project to WestConnect via the WestConnect Regional Project Submittal Form no later than March 31, 2024, so that WestConnect could coordinate the ITP evaluation process with all other Relevant Planning Regions.

Three submittals were made in 2024:

- Mead – Mohave 500 kV line
- Sloan – Mead 230 kV #2
- Western Bounty multi-segment HVDC project

Details for each ITP submittal can be found on the Interregional Coordination webpage. WestConnect does not evaluate ITP submittals until regional transmission needs are identified. If regional needs are identified, then the ITPs have an opportunity to indicate which need they would seek to address, and the ITP would be studied alongside any other regional project submittals. However, since there were no regional transmission needs identified by WestConnect in the 2024-25 Planning Process, the submitted ITPs were not studied in this planning cycle.

9. Scenario Studies

In addition to the regional needs assessment, WestConnect also conducts information-only scenario studies that look at alternate but plausible futures. They represent futures with resource, load, and public policy assumptions that are different in one or more ways than what is assumed in the Base Cases. Scenario studies do not inform the identification of regional needs under the FERC Order 1000 member tariff, and do not affect the contents of the regional plan produced through the member tariff's biennial planning process. Members or stakeholders propose scenarios for consideration in the WestConnect planning process through an open submittal window, as outlined in the WestConnect Business Practice Manual. WestConnect held the open window from December 1, 2023, through January 10, 2024. Three requests were submitted during the open window as shown in **Table 18** below.

Table 18. Scenarios Received During Open Window for the 2024-25 Study Plan

Requestor	Description/Name
Ron Belval, Rob Kondziolka	Renewable Resource Adequacy Feasibility/Gap Analysis
TransCanyon, LLC	Decreased line ratings from increased ambient temperatures
Xcel Energy	Extreme Cold Weather

These scenario requests were reviewed by the PS on January 16, 2024. A representative for each scenario request provided a presentation to the PS to summarize the request and answer questions. Following the meeting the WestConnect representatives worked with the requestors for the Renewable Resource Adequacy Feasibility /Gap Analysis scenario to gain clarity and discuss potential modifications. During an interim PS meeting on February 8, 2024, the PS agreed to recommend to the PMC that three scenarios be included in the 2024-25 Study Plan. The 2024-25 Study Plan included those three scenarios, and was approved by the PMC on March 30, 2024. The Decreased Facility Rating and Extreme Cold Weather scenarios were completed, but the work on the 20-Year Renewable Scenario was stopped prior to any modeling and assessment being performed. On June 13, 2025, the ETOs notified the PMC to not move forward with any non-tariff activities for the remainder of the 2024-25 planning cycle. The ETO Letter is posted to the WestConnect website at Documents.aspx

Details of the scenario assessments and results are in **Appendix D**.

Appendix A – Transmission Plan Project List

Table 19 below includes the planned projects in the 2024-25 regional planning cycle that are part of the Regional Transmission Plan.

Table 19 - Regional Transmission Plan Projects

Sponsor	Project Name	Status	Voltage	In 2022-23 RTP?	ISD
Arizona Public Service	Pinal Central - Sundance 230kV Line	Planned	230 kV	No	2027
Arizona Public Service	TS21 500/230kV Substation	Planned	500 kV AC	No	2032
Arizona Public Service	Three Rivers 230kV Transmission Line Project	Planned	230 kV	Yes	2024
Arizona Public Service	Contrail 230kV Lines	Planned	230 kV	Yes	2025
Arizona Public Service	Broadway 230kV Lines	Planned	230 kV	Yes	2025
Arizona Public Service	Runway Additional 230kV Lines	Planned	230 kV	Yes	2026
Arizona Public Service	TS22 Project	Planned	500 kV AC	Yes	2029
Arizona Public Service	Jojoba to Rudd 500kV line	Planned	500 kV AC	Yes	2032
Arizona Public Service	Bagdad 230kV Transmission Line	Planned	230 kV	No	2027
Arizona Public Service	Dromedary 230kV Switchyard and Lines	Planned	230 kV	No	2025
Arizona Public Service	Hashknife Energy Center Generation Tie Line Project	Planned	500 kV AC	No	2026
Arizona Public Service	Proving Ground Solar and Storage 500kV Interconnection	Planned	500 kV AC	No	2026
Arizona Public Service	West Camp Wind Gen Tie Project	Planned	345 kV	No	2026
Arizona Public Service	Sun Valley to Outer Circle 230kV line	Planned	230 kV	No	2027
Arizona Public Service	Bianco 230kV Lines	Planned	230 kV	No	2028
Arizona Public Service	Panda - Freedom 230kV Line Rebuild	Planned	230 kV	No	2031
Arizona Public Service	Pinnacle Peak to Ocotillo 230kV Line Rebuilds	Planned	230 kV	No	2031
Arizona Public Service	Runway - Stratus 230kV Cut-In to TS21	Planned	230 kV	No	2032
Arizona Public Service	TS21 to Broadway 230kV Line	Planned	230 kV	No	2032
Arizona Public Service	Four Corners to Cholla to Pinnacle Peak 345kV Line Rebuilds	Planned	345 kV	No	2035
Black Hills Energy	BHCT-G29 Substation	Planned	115 kV	No	2025
Black Hills Energy	Skala - Cañon City 115 kV Rebuild	Planned	115 kV	No	2024
Black Hills Energy	Cañon City - Hogback 115 kV Rebuild	Planned	115 kV	No	2024
Black Hills Energy	Hogback - Cañon West 115 kV Rebuild	Planned	115 kV	No	2024
Black Hills Energy	West Station - Portland 115 kV Rebuild	Planned	115 kV	No	2025
Cheyenne Light Fuel and Power	Orchard Valley 115 kV Substation	Planned	115 kV	Yes	2024
Cheyenne Light Fuel and Power	Allison Draw 115 kV Substation	Planned	115 kV	Yes	2024
Cheyenne Light Fuel and Power	Bison - Orchard Valley 115 kV Line	Planned	115 kV	Yes	2024
Cheyenne Light Fuel and Power	Orchard Valley - King Ranch 115 kV Line	Planned	115 kV	Yes	2024
Cheyenne Light Fuel and Power	Bison - West Cheyenne 115 kV Line	Planned	115 kV	Yes	2024
Cheyenne Light Fuel and Power	Happy Jack - North Range #2 115 kV Line	Planned	115 kV	No	2024
Cheyenne Light Fuel and Power	Allison Draw - Campstool 115 kV Line	Planned	115 kV	Yes	2024
Cheyenne Light Fuel and Power	Allison Draw - CPGS 115 kV Line	Planned	115 kV	Yes	2024
Cheyenne Light Fuel and Power	Bluffs 230 kV Substation	Planned	230 kV	Yes	2026
Cheyenne Light Fuel and Power	Sweetgrass 230 kV Substation	Planned	230 kV	Yes	2026
Cheyenne Light Fuel and Power	Sweetgrass - Bluffs 230 kV Line	Planned	230 kV	Yes	2026
Cheyenne Light Fuel and Power	West Cheyenne 230 kV Substation	Planned	230 kV	Yes	2026
Cheyenne Light Fuel and Power	West Cheyenne - Sweetgrass 230 kV Line	Planned	230 kV	Yes	2026

Appendix A – Transmission Plan Project List

Cheyenne Light Fuel and Power	West Cheyenne - Windstar 230 kV Line	Planned	230 kV	Yes	2026
Cheyenne Light Fuel and Power	Wallick 115 kV Substation	Planned	115 kV	No	2025
Cheyenne Light Fuel and Power	Sweetgrass - Bison 115 kV #3 & #4	Planned	115 kV	No	2025
El Paso Electric Company	Verde 115 kV Substation (Load Serving Station Portion Added), 115/24kV 50 MVA Transformer Addition	Planned	115 kV	Yes	2027
El Paso Electric Company	Afton-Newman 345kV Line Reconfiguration, In and Out in Vado 345 kV Substation	Planned	345 kV	Yes	2028
El Paso Electric Company	McCombs Substation (New) and Related 115 kV Line Reconfiguration	Planned	115 kV	Yes	2027
El Paso Electric Company	Jornada-Arroyo 115 kV Line (Reconductor/Rebuild)	Planned	115 kV	Yes	2027
El Paso Electric Company	Apollo-Cox Line 69 kV to 115 kV (Moongate-Apollo Portion - Rebuild)	Planned	115 kV	Yes	2027
El Paso Electric Company	Afton North 345 kV Substation (New)	Planned	345 kV	No	2028
El Paso Electric Company	Afton-Afton North 345 kV Double Bundled Line (New)	Planned	345 kV	Yes	2028
El Paso Electric Company	Vado Substation 345/115 kV (New)	Planned	345 kV	Yes	2028
El Paso Electric Company	Seabeck Switching Station 115 kV (New)	Planned	115 kV	Yes	2029
El Paso Electric Company	Seabeck-Horizon 115 kV Line (Rebuild, Upgrade)	Planned	115 kV	Yes	2029
El Paso Electric Company	Seabeck-San Felipe 115 kV Line (Reconfiguration)	Planned	115 kV	Yes	2029
El Paso Electric Company	San Felipe Substation 115/69 kV (New) & 1 X 115/69 kV Autotransformer	Planned	115 kV	Yes	2025
El Paso Electric Company	Sparks-San Felipe Line (Voltage Conversion, Rebuild, Reconductor) 69 kV to 115 kV	Planned	115 kV	Yes	2027
El Paso Electric Company	San Felipe (New) 115 kV Capacitors (2 x 15.9 MVAR)	Planned	115 kV	Yes	2026
El Paso Electric Company	Pine Switching Station 115 kV (New)	Planned	115 kV	Yes	2027
El Paso Electric Company	Pine-Seabeck 115 kV Line (New)	Planned	115 kV	Yes	2029
El Paso Electric Company	Marvin-Pine 115kV Line (Reconductor)	Planned	115 kV	Yes	2028
El Paso Electric Company	Rio Grande-Sunset 69 kV Lines (5500/5600) (Rebuild, Reconductor)	Planned	Below 115 kV	No	2024
El Paso Electric Company	CE-2 Substation (New) and Related 115 kV West Loop Line Reconfiguration	Planned	115 kV	Yes	2027
El Paso Electric Company	Vado-Salopek 115 kV Line (Rebuild, Reconductor)	Planned	115 kV	Yes	2028
El Paso Electric Company	New Amrad SVC device connecting on high-voltage side to Amrad 345 kV side using its own dedicated step-up transformer to a dedicated bay.	Planned	345 kV	Yes	2027
El Paso Electric Company	CE3 Substation (New) and Related 115 kV West Loop Line Reconfiguration	Planned	115 kV	Yes	2029
El Paso Electric Company	Anthony-Vado 115 kV Line (Rebuild, Reconductor)	Planned	115 kV	Yes	2028
El Paso Electric Company	CE-4 Substation (New) and Related 115 kV West Loop Line Reconfiguration	Planned	115 kV	Yes	2030
El Paso Electric Company	In-and-Out into Vado 345 kV Substation from Afton North-Newman 345 kV Line	Planned	345 kV	Yes	2028
El Paso Electric Company	Vado 224 MVA Vado 345/115 kV Autotransformer (New)	Planned	345 kV	Yes	2028
El Paso Electric Company	Leasburg Substation 115 kV (New)	Planned	115 kV	Yes	2028
El Paso Electric Company	Arroyo-Cox 69 kV to 115 kV (Arroyo-Moongate 115 kV line - Reconductor, Reconfiguration and Moongate-Apollo 115 kV line - Reconfiguration)	Planned	115 kV	Yes	2027
El Paso Electric Company	Eastlake Temporary Substation (New) and Related 115 kV line reconfiguration	Planned	115 kV	No	2024
El Paso Electric Company	Verde 115 kV Switching Station (New) and Related 115 kV Line Reconfiguration	Planned	115 kV	No	2024
El Paso Electric Company	Austin-Marlow 115 kV Line (Rebuild, Reconductor)	Planned	115 kV	No	2024
El Paso Electric Company	Clint-Valley 69 kV Line (Rebuild, Reconductor)	Planned	Below 115 kV	No	2024
El Paso Electric Company	Lane-Americas 69 kV Line (Reconductor)	Planned	Below 115 kV	No	2024
El Paso Electric Company	Lane-Wrangler 115 kV Line (Rebuild, Reconductor)	Planned	115 kV	No	2024
El Paso Electric Company	Rio Bosque-Ascarate 69 kV Line (Reconductor)	Planned	Below 115 kV	No	2024
El Paso Electric Company	Sparks-Felipe 69 kV Line (Rebuild, Reconductor)	Planned	Below 115 kV	No	2024

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El Paso Electric Company	Westside Temporary Substation (New) and Related 115 kV Line Reconfiguration	Planned	115 kV	No	2024
El Paso Electric Company	Ascarate-Trowbridge 115 kV Line (Reconductor)	Planned	115 kV	No	2025
El Paso Electric Company	Hawkins Substation 69 kV (New) and Line Reconfiguration	Planned	Below 115 kV	No	2025
El Paso Electric Company	Horizon-San Felipe 115 kV Line (New)	Planned	115 kV	No	2025
El Paso Electric Company	Pellicano-Montwood 115 kV Line (Reconductor)	Planned	115 kV	No	2025
El Paso Electric Company	WS2 Substation (New) and Related 115 kV Line Reconfiguration	Planned	115 kV	No	2025
El Paso Electric Company	Americas-Passmore 69 kV Line (Reconductor)	Planned	Below 115 kV	No	2026
El Paso Electric Company	Eastlake Substation (New) and Related 115 kV Line Reconductor and Reconfiguration	Planned	115 kV	No	2026
El Paso Electric Company	Passmore Substation (New) and Related 69 kV Line Reconductor and Reconfiguration	Planned	Below 115 kV	No	2026
El Paso Electric Company	Wrangler-Eastlake 115 kV Line (Rebuild, Reconductor)	Planned	115 kV	No	2027
El Paso Electric Company	Arroyo Variable Line Shunt Reactor (50-100 MVAR) on the Arroyo end of the West Mesa-Arroyo 345 kV Line	Planned	345 kV	No	2027
El Paso Electric Company	Newman 2 Thermal Generation Conversion to Synchronous Condenser	Planned	115 kV	No	2027
El Paso Electric Company	Afton North-Airport 345 kV Line (New)	Planned	345 kV	No	2028
El Paso Electric Company	Afton-Newman 345kV Line Reconfiguration	Planned	345 kV	No	2028
El Paso Electric Company	Airport 345/115 kV Autotransformer (New)	Planned	345 kV	No	2028
El Paso Electric Company	Airport 345/115/24 kV Substation	Planned	345 kV	No	2028
El Paso Electric Company	Marvin (FE6) 115 kV New Full Substation	Planned	115 kV	No	2028
El Paso Electric Company	Artesia/Eddy HVDC Tie Replacement (New)	Planned	345 kV	No	2028
El Paso Electric Company	WS1 Substation (New) and Related 115 kV Line Reconfiguration	Planned	115 kV	No	2028
El Paso Electric Company	McNutt Substation (New) and Related 115 kV Line Reconfiguration	Planned	115 kV	No	2028
El Paso Electric Company	EA1 Substation (New) and Related 115 kV Line Reconfiguration	Planned	115 kV	No	2029
El Paso Electric Company	FE7 115 kV Substation (New) and Related 115 kV Line Reconfiguration	Planned	115 kV	No	2029
El Paso Electric Company	Caliente 345/115 kV Autotransformer T3 (New)	Planned	345 kV	No	2030
El Paso Electric Company	CE4-Executive 115 kV Line (New)	Planned	115 kV	No	2030
El Paso Electric Company	Marlow-Trowbridge 115 kV Line (Rebuild, Reconductor)	Planned	115 kV	No	2030
El Paso Electric Company	Newman-McCombs 115 kV Line Circuit 1 (Reconductor)	Planned	115 kV	No	2030
El Paso Electric Company	Newman-McCombs 115 kV Line Circuit 2 (Reconductor)	Planned	115 kV	No	2030
El Paso Electric Company	Copper Thermal Generation Conversion to Synchronous Condenser	Planned	115 kV	No	2030
El Paso Electric Company	NE3 Substation (New) and Related 115 kV Line Reconfiguration	Planned	115 kV	No	2031
El Paso Electric Company	Newman 3 Thermal Generation Conversion to Synchronous Condenser	Planned	115 kV	No	2032
El Paso Electric Company	Newman 4 ST Thermal Generation Conversion to Synchronous Condenser	Planned	115 kV	No	2032
El Paso Electric Company	Dyer 115/69 kV Autotransformer T1 (Upgrade)	Planned	115 kV	No	2032
El Paso Electric Company	Newman-Roberts 115 kV Line Circuit 1 (Reconductor)	Planned	115 kV	No	2032
El Paso Electric Company	CE2-Rio Grande 115 kV Line (Rebuild)	Planned	115 kV	No	2033
Public Service Company of Colorado/ Xcel Energy	Gilman-Avon 115 kV Transmission Line	Planned	115 kV	Yes	2027
Public Service Company of Colorado/ Xcel Energy	Colorado's Power Pathway	Planned	345 kV	Yes	2027
Public Service Company of Colorado/ Xcel Energy	Stagecoach Switching Station	Planned	230 kV	Yes	2024
Public Service Company of Colorado/ Xcel Energy	Daniels Park to Prairie Reconductor 230kV	Planned	230 kV	Yes	2026
Public Service Company of Colorado/ Xcel Energy	Midway Transformer Upgrade	Planned	230 kV	Yes	2023
Public Service Company of Colorado/ Xcel Energy	Metro Water Recovery Trans Service, Sub	Planned	115 kV	No	2024
Public Service Company of Colorado/ Xcel Energy	Kestrel Substation	Planned	230 kV	No	2024
Public Service Company of Colorado/ Xcel Energy	Poder (Formerly Stock Show) Distribution Substation	Planned	115 kV	No	2026
Public Service Company of Colorado/ Xcel Energy	Sandstone Switching Station	Planned	345 kV	No	2027
Public Service Company of New Mexico	Quail Ranch Switching Station	Planned	345 kV	Yes	2023

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Public Service Company of New Mexico	Hidden Mountain Switching Station	Planned	345 kV	No	2026
Tri-State Generation and Transmission Association	Frontier Reactor Addition	Planned	115 kV	Yes	2026
Tri-State Generation and Transmission Association	Rolling Meadows Substation	Planned	115 kV	Yes	2026
Tri-State Generation and Transmission Association	Milk Creek Switchyard on Craig-Meeker 345kV line	Planned	345 kV	Yes	2024
Tri-State Generation and Transmission Association	Slater Double Circuit Project	Planned	115 kV	Yes	2025
Tri-State Generation and Transmission Association	Boone - Huckleberry 230 kV	Planned	230 kV	Yes	2026
Tri-State Generation and Transmission Association	Badger Creek - Big Sandy 230 kV	Planned	230 kV	Yes	2028
Tri-State Generation and Transmission Association	Big Sandy - Burlington 230 kV Uprate	Planned	230 kV	Yes	2028
Tri-State Generation and Transmission Association	Archer - Stegall Sectionalization Project	Planned	115 kV	Yes	2024
Tri-State Generation and Transmission Association	Crosspoint Substation	Planned	230 kV	No	2025
Tri-State Generation and Transmission Association	Sulfur Creek Tap	Planned	138 kV	No	2026
Tri-State Generation and Transmission Association	Breaker Addition at Sidney Substation	Planned	115 kV	No	2024
Tri-State Generation and Transmission Association	Breaker Addition at Garnet Mesa	Planned	115 kV	No	2024
Tri-State Generation and Transmission Association	Breaker Addition at Hesperus Substation	Planned	115 kV	No	2024
Tucson Electric Power	Grier 138/13.8 kV Substation	Planned	138 kV	Yes	2028
Tucson Electric Power	Lago Del Oro 138/13.8 kV Substation	Planned	138 kV	Yes	2031
Tucson Electric Power	Corona 138/13.8 kV Substation	Planned	138 kV	Yes	2033
Tucson Electric Power	Craycroft-Barril 138/13.8 kV Substation	Planned	138 kV	Yes	2031
Tucson Electric Power	Golden Valley 230kV Transmission Line	Planned	230 kV	Yes	2031
Tucson Electric Power	Hartt 138/13.8 kV Substation	Planned	138 kV	Yes	2028
Tucson Electric Power	Grier 138-kV Transmission Line	Planned	138 kV	Yes	2028
Tucson Electric Power	Rancho Vistoso - Lago Del Oro 138kV Line	Planned	138 kV	Yes	2032
Tucson Electric Power	Naranja 138/13.8 kV Substation	Planned	138 kV	Yes	2029
Tucson Electric Power	Vine 138/13.8 kV Substation (was UA North)	Planned	138 kV	Yes	2027
Tucson Electric Power	New 138kV line North Loop to Naranja to La Canada	Planned	138 kV	Yes	2029
Tucson Electric Power	Re-Conductor Vail to Kantor 138-kV Transmission Line, south of Nogales Tap	Planned	138 kV	No	2031
Tucson Electric Power	Kantor Capacitor Bank Addition	Planned	138 kV	No	2028
Tucson Electric Power	Sears Wilmot 138/13.8 kV Substation	Planned	138 kV	Yes	2031
Tucson Electric Power	Rio Rico 138kV Switchyard	Planned	138 kV	Yes	2027
Tucson Electric Power	Greenlee Capacitor Additions	Planned	345 kV	Yes	2025
Tucson Electric Power	Rio Rico Capacitor Bank Addition	Planned	138 kV	Yes	2027
Tucson Electric Power	Rillito 138kV Conversion to breaker-and-a-half substation	Planned	138 kV	Yes	2027
Tucson Electric Power	Orange Grove Capacitor Bank Addition	Planned	138 kV	Yes	2025
Tucson Electric Power	New 230kV Yard at Tortolita Substation	Planned	230 kV	Yes	2026
Tucson Electric Power	New 230kV Yard at DMP Substation	Planned	230 kV	Yes	2026
Tucson Electric Power	New 230kV Yard at Vail Substation	Planned	230 kV	Yes	2027
Tucson Electric Power	Tortolita to DMP 230kV line	Planned	230 kV	Yes	2026
Tucson Electric Power	DMP to Vail 230kV line	Planned	230 kV	Yes	2027
Tucson Electric Power	Tortolita 500/230kV Transformers	Planned	500 kV AC	Yes	2026
Tucson Electric Power	DMP 230/138kV Transformers	Planned	230 kV	Yes	2026
Tucson Electric Power	Vail 345/230kV Transformers	Planned	345 kV	Yes	2027
Tucson Electric Power	Bopp-Donald 138/13.8kV Substation	Planned	138 kV	Yes	2031
Tucson Electric Power	Cottonwood to Bopp-Donald 138kV line	Planned	138 kV	Yes	2031
Tucson Electric Power	Bopp-Donald to Midvale 138kV line	Planned	138 kV	Yes	2032
Tucson Electric Power	TEPTDA 138kV Substation	Planned	138 kV	Yes	2032
Tucson Electric Power	Whetstone 138kV Substation	Planned	138 kV	Yes	2025
Tucson Electric Power	Harshaw 138kV Substation	Planned	138 kV	No	2027
Tucson Electric Power	Rio Rico - Harshaw 138kV Transmission Line	Planned	138 kV	No	2027

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Tucson Electric Power	Kipper 138kV Substation	Planned	138 kV	No	2026
Tucson Electric Power	Canoa Ranch to Kantor 138kV Transmission Line	Planned	138 kV	No	2028
Tucson Electric Power	Gateway 138kV Substation	Planned	138 kV	No	2030
Tucson Electric Power	Kantor to Gateway 138kV Line	Planned	138 kV	No	2030
Tucson Electric Power	Gateway to Valencia 138kV Transmission Line	Planned	138 kV	No	2030
Tucson Electric Power	Port 138kV Substation	Planned	138 kV	No	2029
Tucson Electric Power	Aerospace Research Campus Transmission Project	Planned	138 kV	No	2026

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Table 20 below includes the planned projects in the 2024-25 regional planning cycle that were included in the study models but are not part of the Regional Transmission Plan. These projects were submitted by non-public utilities that are no longer part of the region at this time.

Table 20 - Projects Submitted by Non-WestConnect Entities

Sponsor	Project Name	Status	Voltage	In 2022-23 RTP?	ISD
Arizona Electric Power Cooperative	Marana Substation Rebuild	Planned	115 kV	Yes	2024
Arizona Electric Power Cooperative	Greenlee Transformer Upgrade	Planned	115 kV	No	2024
Arizona Electric Power Cooperative	Pantano Transformer Upgrade	Planned	230 kV	No	2024
Colorado Springs Utility	Flying Horse Flow Mitigation	Planned	115 kV	Yes	2024
Colorado Springs Utility	South System Improvement - Midway to Kelker 230kV Line	Planned	230 kV	No	2027
Colorado Springs Utility	Central System Improvement - Kelker Substation Rebuild - New Kelker-Southplant 115kV Line	Planned	115 kV	Yes	2026
Colorado Springs Utility	Flying Horse Power Transformer	Planned	115 kV	Yes	2026
Colorado Springs Utility	Claremont Transformer	Planned	230 kV	Yes	2026
Colorado Springs Utility	Horizon Transformer	Planned	230 kV	No	2026
Colorado Springs Utility	Central Bluffs Substation	Planned	115 kV	No	2026
Colorado Springs Utility	Kelker-Central Bluff Line Uprate	Planned	115 kV	No	2027
Colorado Springs Utility	Kelker-Rock Island Line Uprate	Planned	115 kV	No	2027
Colorado Springs Utility	North Plant-Central Bluff Line Uprate	Planned	115 kV	No	2026
Colorado Springs Utility	Cottonwood-Kettle Creek Line Uprate	Planned	115 kV	No	2027
Imperial Irrigation District	Grapefruit Switching Station Upgrade	Planned	Below 115 kV	No	2025-26
Imperial Irrigation District	92kV "R" Line Network Upgrades	Planned	Below 115 kV	Yes	2025
Imperial Irrigation District	Ramon-Mirage ck #2	Planned	230 kV	No	2025
Imperial Irrigation District	Path 42 RAS Revision and Rating Increase	Planned	230 kV	Yes	2024
Los Angeles Department of Water and Power	New Valley - Rinaldi Line 3 and upgrade Valley - Rinaldi Lines 1 and 2	Planned	230 kV	No	2028
Los Angeles Department of Water and Power	New Valley - Toluca Line 3 and upgrade Valley - Toluca Lines 1 and 2	Planned	230 kV	No	2026
Los Angeles Department of Water and Power	Upgrade Lugo-Victorville Line 1 & terminal equipment	Planned	500 kV AC	No	2027
Los Angeles Department of Water and Power	New Rosamond Station	Planned	230 kV	No	2025
Los Angeles Department of Water and Power	Apex-Crystal Transmission Line	Planned	500 kV AC	No	2027
Los Angeles Department of Water and Power	Re-conductor Rinaldi-Tarzana 230kV Line 1 & 2	Planned	230 kV	No	2025
Los Angeles Department of Water and Power	New Receiving Station X (LAX)	Planned	230 kV	No	2026
Los Angeles Department of Water and Power	Reconductor Barren Ridge - Haskell Canyon 230 kV Line 1	Planned	230 kV	No	2025
Los Angeles Department of Water and Power	McCullough-Victorville series cap upgrade	Planned	500 kV AC	No	2025
Los Angeles Department of Water and Power	Tarzana-Olympic 1A & 1B 138 kV conversion to 230 kV	Planned	230 kV	No	2026
Los Angeles Department of Water and Power	Upgrade Scattergood Auto and Phase Shifting Transformer	Planned	230 kV	No	2026
Los Angeles Department of Water and Power	Upgrade Toluca-Hollywood Line 1 Underground Cable	Planned	230 kV	No	2027
Los Angeles Department of Water and Power	Upgrade Rinaldi - Airway Lines 1 and 2	Planned	230 kV	No	2029
Los Angeles Department of Water and Power	Clearance Mitigation Upgrade for Adelanto-Toluca Line 1	Planned	500 kV AC	No	2026

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Los Angeles Department of Water and Power	Adelanto-Rinaldi Line 1 Clearance Mitigation	Planned	500 kV AC	No	2026
Los Angeles Department of Water and Power	Add voltage support in the LA Basin	Planned	138 kV	No	2025
Los Angeles Department of Water and Power	Upgrade Hollywood - Fairfax 138kV Series Reactor	Planned	138 kV	No	2027
Los Angeles Department of Water and Power	Upgrade Fairfax - Olympic 138kV Series Reactor	Planned	138 kV	No	2030
Los Angeles Department of Water and Power	Sylmar Bank E	Planned	230 kV	No	2026
Los Angeles Department of Water and Power	Sylmar Bank F	Planned	230 kV	No	2026
Los Angeles Department of Water and Power	Sylmar Bank G	Planned	230 kV	No	2028
Los Angeles Department of Water and Power	New IPP Synchronous Condensers (2 x 375 MVA and 1 spare 375 MVA)	Planned	345 kV	No	2026
Los Angeles Department of Water and Power	New Toluca - Atwater Line 2 and upgrade Toluca -Atwater Line 1	Planned	230 kV	No	2029
Platte River Power Authority	Timberline 230/115kV Transformer T3 Replacement	Planned	230 kV	Yes	2024
Platte River Power Authority	Longs Peak 230/115kV T1 Transformer Replacement	Planned	230 kV	Yes	2025
Platte River Power Authority	Drake - Timberline 115kV Line Rebuild	Planned	115 kV	Yes	2027
Sacramento Municipal Utility District	Coyote Creek 230 kV Switching Station	Planned	230 kV	No	2027
Sacramento Municipal Utility District	El Rio 230 kV Substation Conversion	Planned	230 kV	No	2026
Sacramento Municipal Utility District	El Rio 230/115 kV Transformer	Planned	230 kV	No	2026
Sacramento Municipal Utility District	Station J 115 kV Substation	Planned	115 kV	No	2030
Sacramento Municipal Utility District	Country Acres 230 kV Switching Station	Planned	230 kV	No	2026
Salt River Project	Hassayampa - Pinal West 500kV #2	Planned	500 kV AC	No	2028
Salt River Project	Coolidge Expansion Project	Planned	500 kV AC	Yes	2026
Salt River Project	Browning 500/230 kV Transformer 3	Planned	500 kV AC	Yes	2024
Salt River Project	Browning 500/230 kV Transformer 4	Planned	500 kV AC	Yes	2025
Salt River Project	Reconductor Anderson - Kyrene 230 kV	Planned	230 kV	Yes	2028
Salt River Project	Reconductor Orme - Rudd 230 kV #1	Planned	230 kV	Yes	2024
Salt River Project	Reconductor Orme - Rudd 230 kV #2	Planned	230 kV	Yes	2024
Salt River Project	Laveen 500/230 kV Project 230 kV Lines	Planned	230 kV	No	2027
Salt River Project	Laveen 500/230 kV Project Substation Portion	Planned	230 kV	No	2027
Salt River Project	Rudd 500/230 kV Transformer #5	Planned	500 kV AC	No	2026
Salt River Project	Duke 500/230 kV Transformer #2	Planned	500 kV AC	No	2028
Salt River Project	Reconductor Miami - Pinto Valley 115 kV	Planned	115 kV	No	2026
Salt River Project	Nate 230 kV	Planned	230 kV	No	2027
Salt River Project	Pinnacle Peak SRP - WAPA Series Reactors	Planned	230 kV	No	2026
Salt River Project	Henshaw - Knox Series Reactors	Planned	230 kV	No	2028
Salt River Project	Kyrene East - West Series Reactors	Planned	230 kV	No	2028
Salt River Project	Pinal Central 500/230 kV Transformer #3	Planned	500 kV AC	No	2024
Salt River Project	Pinal Central 500/230 kV Transformer #4	Planned	500 kV AC	No	2024
Salt River Project	Rudd 500/230 kV Transformer #6	Planned	500 kV AC	No	2029
Western Area Power Administration - DSW	Bouse – Kofa	Planned	161 kV	Yes	2025
Western Area Power Administration - DSW	Parker – Blythe	Planned	161 kV	Yes	2027
Western Area Power Administration - DSW	Tucson - Oracle	Planned	115 kV	No	2026
Western Area Power Administration - DSW	Bouse upgrade	Planned	230 kV	No	2027
Western Area Power Administration - DSW	Pinal Central - ED5 Transmission Line	Planned	230 kV	No	2025
Western Area Power Administration - RMR	Sand Creek Tap	Planned	115 kV	Yes	2025
Western Area Power Administration - RMR	Stegall Bus Sectionalization	Planned	230 kV	Yes	2025

Appendix A – Transmission Plan Project List

Western Area Power Administration - RMR	Blue Mesa	Planned	115 kV	Yes	2026
Western Area Power Administration - RMR	Glendo Podolak upgrade	Planned	115 kV	Yes	2024
Western Area Power Administration - RMR	Brush KY1A	Planned	115 kV	Yes	2025
Western Area Power Administration - RMR	Weld KV1A	Planned	230 kV	Yes	2023
Western Area Power Administration - RMR	Wiggins KY1A	Planned	115 kV	Yes	2025
Western Area Power Administration - RMR	Weld Substation Upgrade - 230kV Breaker and a Half	Planned	230 kV	No	2032
Western Area Power Administration - RMR	Lyman 5-Breaker ring bus (34.5kv) and new control building	Planned	115 kV	No	2032
Western Area Power Administration - RMR	Nunn KY1A Replacement	Planned	115 kV	No	2033
Western Area Power Administration - RMR	Yellowtail Phase-2, replace KV2A, 13.8kv CB 128, 528	Planned	230 kV	No	2030

Appendix B Economic Assessment Results

Appendix B – Economic Assessment Results

Tables 21 and 22 show the economic assessment results for this cycle.

Table 21 Multiple WestConnect Entities

Entities Involved	Branch or Path Name	Avg Flow (MW)	Flow Direction	Annual (2034) Congestion Hours (% Hrs) / Cost (K$)
TSGT|PSCo	P36 TOT 3	919	N>S	138 (2%) / 10,032
PSCO|TSGT	CRAIG_YV - CRAIG 230 kV Line	73	W>E	723 (8%) / 1,005

Table 22 Information Gathered from Members When the Assessment was Performed:

Branch or Path Name	Entities Involved	Member Response
P36 TOT 3	PSCO, TSGT	TOT3/Path 36 congestion is relatively low and there are many adjacent system changes presently occurring that are predicted to improve congestion. Although the amount has increased from previous cycle results this limited amount does not warrant a regional need at this time.
CRAIG_YV – CRAIG 230 kV Line	PSCO, TSGT	The observed congestion on this line does not warrant establishing this as a regional need as it is limited in duration, cost, and impact. The congestion is a direct result of serving local load and forecasted BTM generation. Additionally, the line and Craig YV terminal equipment are owned by PSCo. While the Craig substation equipment has mixed ownership, PSCo has full ownership of the terminal equipment for this line. This makes the congestion on this facility more similar to a single TO facility in nature.

Appendix B Economic Assessment Results

Potential Regional Economic Need Decision

Potential Economic Needs

- Regional Assessment Results
  - The regional assessment resulted in a single potential regional reliability need
  - The regional economic assessment resulted in four occurrences of congestion involving multiple WestConnect entities at the time of the assessment in 2024.[16]

- PS recommendation to PMC on November 13, 2024
  - *The PS recommended that the issues from the Regional Assessment not be considered regional needs.*

- PS decision on December 17, 2024
  - Additional information was presented and discussed
  - PS addressed some of the stakeholder comments
  - *Consensus: The PS had no changes to their November 13, 2024, recommendation:*
    - *None of the potential issues should be considered a regional need.*

- PMC Decision on December 18, 2024
  - *The Planning Management Committee agreed with the Planning Subcommittee that the potential regional reliability issue identified in the 2024-25 Regional Assessment should not be considered a regional need.*

[16] *Only two of those four occurrences involve members enrolled in the WestConnect region*

Appendix C Economic Sensitivities

Appendix C - Economic Sensitivities

The information found in Appendix C of this document retains information from both ETO and CTO as a result that the simulations were calculated before December 17, 2024, removal of the CTOs from the TOLSO member sector of WestConnect. For the year 2025, the former CTOs are not accounted as part of the Regional Plan but are kept for completeness and clarity of the report as the bi-annual cycle was mid-way through.

Low Hydro

- The 2034 WCPCM Base Case uses a median year hydro condition. Hydro conditions from 2001 provide the best representation of hydro operations for a low water year. Low hydro shapes were derived from data developed by WECC for the 2024 TEPPC Common Case

Figure 10 2034 Hydro Generation Summary (GWh)

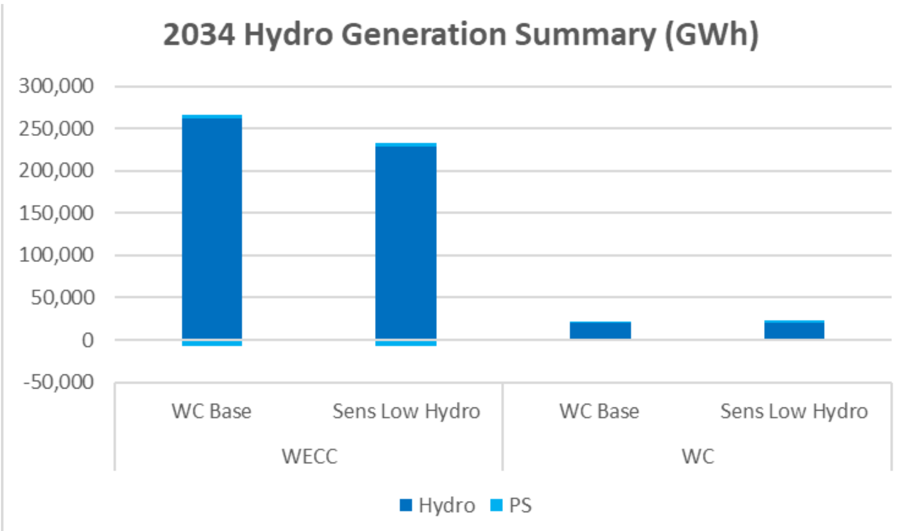


Figure 11 Hydro generation levels in WestConnect and WECC

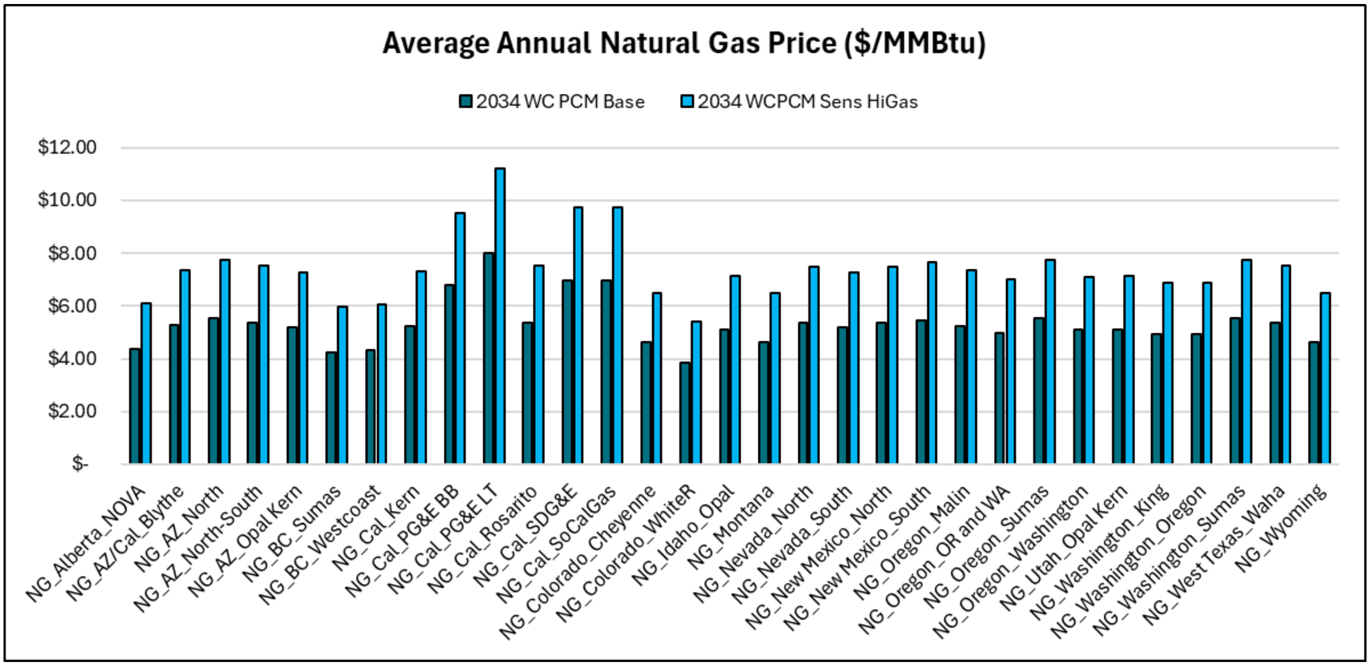
Metric	Region	Fuel Type	Hydro	PS	PS Pump
Generation (GWh)	WECC	WC Base	261,892	4,524	-7,037
		Sens Low Hydro	228,314	4,825	-7,485
	WC	WC Base	19,944	1,630	-1,946
		Sens Low Hydro	20,900	1,742	-2,120
Capacity (MW)	WECC	WC Base	72,278	6,046	6,046
		Sens Low Hydro	72,278	6,046	6,046
	WC	WC Base	7,129	3,351	3,351
		Sens Low Hydro	7,129	3,351	3,351
Capacity Factor	WECC	WC Base	41.3%	8.5%	-13.3%
		Sens Low Hydro	36.0%	9.1%	-14.1%
	WC	WC Base	31.8%	5.5%	-6.6%
		Sens Low Hydro	33.4%	5.9%	-7.2%

Appendix C Economic Sensitivities

High Gas Prices

- Assumed natural gas prices are 40% higher than the base case
  - Base Case annual average gas price: $5.30/MMBtu
  - Sensitivity Case annual average gas price: $7.43/MMBtu

Figure 12 Average Annual Natural Gas Price



High Load Forecast

- Sensitivity case assumed peak loads and energy 20% higher than the Base Case

Table 23 Peak Loads & Energy

		2034 WCPCM Base		2034 WCPCM sens High Load			
Area	Region	Peak (MW)	Energy (GWh)	Peak Inc %	Energy Inc %	Peak (MW)	Energy (GWh)
AZPS	SW_AZPS	10,661	50,958	120%	120%	12,853	61,379
EPE	SW_EPE	2,518	11,260	120%	120%	3,030	13,571
PNM	SW_PNM	3,092	15,376	120%	120%	3,721	18,550
PSCO	RM_PSCO	11,382	52,234	120%	120%	13,716	63,050
TEPC	SW_TEPC	4,318	19,417	120%	120%	5,182	23,300

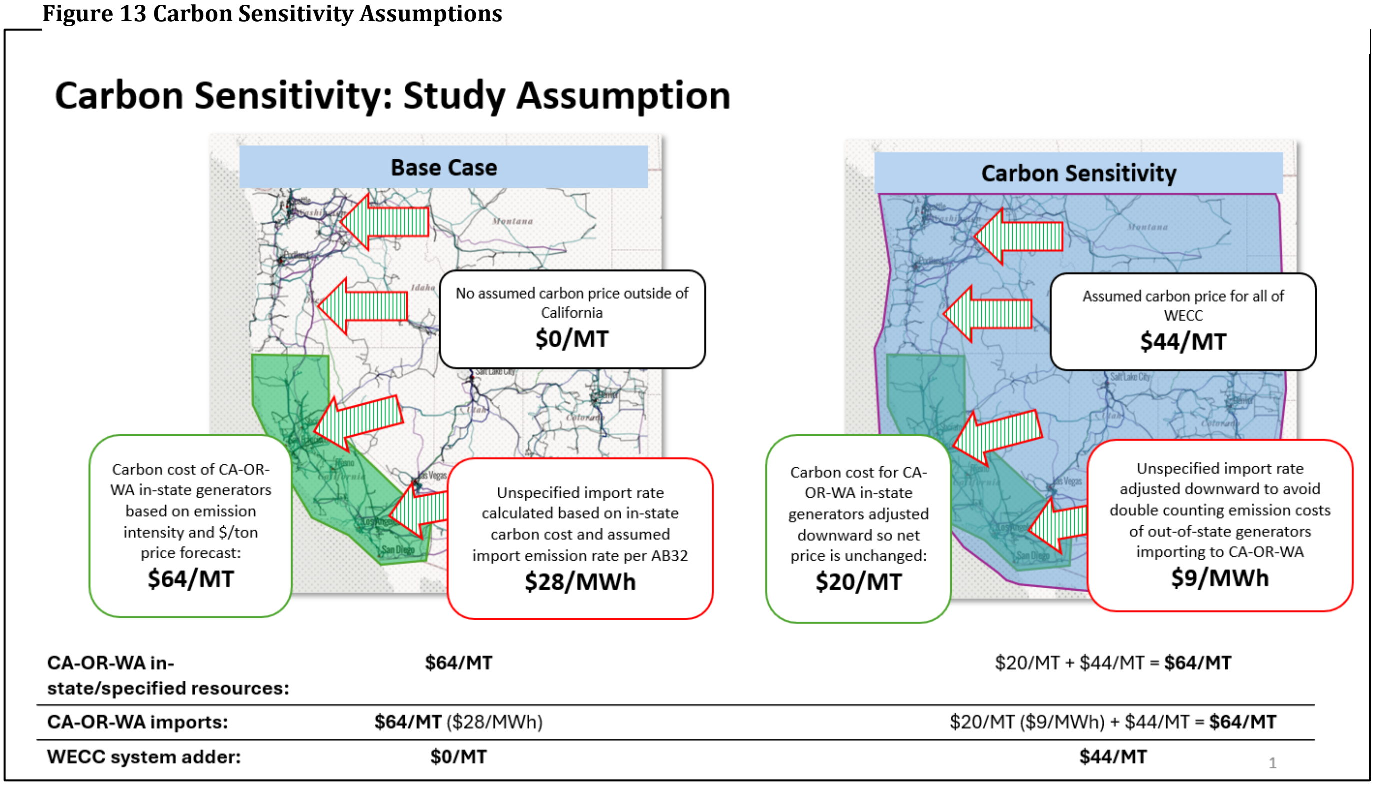
Appendix C Economic Sensitivities

System Carbon Emission Cost

Description: Applied CO2 emission charges to all generators in WECC via the below updates to the 2034 Base Case:

- Applied a reduced carbon emission price of $20/MT ($9/MWh) for all generation in California, Oregon, and Washington so the net change for units internally to these States remain the same ($20/MT + $44/MT = $64/MT)
- Kept the Alberta and British Columbia carbon emission prices unchanged at $37/MT
- Removed the carbon emission wheeling charges from all California borders except with Baja California (CFE)

Figure 13 Carbon Sensitivity Assumptions



Appendix C Economic Sensitivities

Congestion Summary

The tables below summarize congestion hours, costs, average flows and unserved load.

Table 24 - Congestion Hours / Cost

			Congestion Hours (% hrs)/Cost(K$)				
Assumed Grouping	Branch or Path Name	Entities Involved	Base	Low Hydro	High Gas	High Load	System Carbon Price
Multiple WC Entities	P36 TOT 3	PSCO|TSGT	138 (2%) / 10,032	82 (1%) / 1,542	128 (1%) / 3,423	600 (7%) / 557,608	131 (1%) / 3,620
	CRAIG_YV - CRAIG 230 kV Line #1	PSCO|TSGT	723 (8%) / 1,005	735 (8%) / 0,969	742 (8%) / 1,128	637 (7%) / 1,184	715 (8%) / 1,162
	LAMAR_SWYD - LAMAR_C2 230 kV Line #1	PSCO|TSGT	0	136 (2%) / 0,252	133 (2%) / 0,203	0	0
	BONANZA - CRAIG 345 kV Line #1	DG&T|TSGT	0	0	0	331 (4%) / 216,219	0
Total Multi-TO Congestion ($)			**$11,037,000**	**$2,763,000**	**$4,754,000**	**$775,011,000**	**$4,782,000**
Total Multi-TO Congestion (% Change)				**-75%**	**-57%**	**6922%**	**-57%**

Congestion Summary

Table 25 - Average Flows (MW)

			Average Flow (MW)				
Assumed Grouping	Branch or Path Name	Entities Involved	Base	Low Hydro	High Gas	High Load	System Carbon Price
Multiple WC Entities	P36 TOT 3	PSCO|TSGT	919	836	931	1120	900
	CRAIG_YV - CRAIG 230 kV Line #1	PSCO|TSGT	73	73	73	69	73
	LAMAR_SWYD - LAMAR_C2 230 kV Line #1	PSCO|TSGT	0	50	47	0	0
	BONANZA - CRAIG 345 kV Line #1	DG&T|TSGT	0	0	0	364	0

Table 26 Unserved Load (MWh)

Total Unserved Load (MWh)					
Region	Base	Low Hydro	High Gas	High Load	System Carbon Price
AZPS	0	0	0	0	0
EPE	0	0	0	0	0
PNM	0	0	0	0	0
PSCO	0	0	0	92,982	0
TEPC	0	0	0	0	0

Appendix C Economic Sensitivities

Generation Fleet[17]

Table 27 Generation Fleet Values

Metric	Case	Nuclear	Coal	Gas	Hydro	PS	Geothermal	Biomass	Other	BESS	Solar	Wind
Capacity (MW)	Base	3,500	3,080	30,587	7,129	3,351	602	0	4,167	24,749	34,404	15,039
	LowHydro	3,500	3,080	30,587	7,129	3,351	602	0	4,167	24,749	34,404	15,039
	HiGas	3,500	3,080	30,587	7,129	3,351	602	0	4,167	24,749	34,404	15,039
	HiLoad	3,500	3,080	30,587	7,129	3,351	602	0	4,167	24,749	34,404	15,039
	SysCarbPrice	3,500	3,080	30,587	7,129	3,351	602	0	4,167	24,749	34,404	15,039
Generation (GWh)	Base	28,950	17,884	70,830	19,944	1,630	3,634	0	4,316	26,638	84,414	47,067
	LowHydro	28,948	17,670	72,873	20,900	1,742	3,654	0	4,693	27,654	84,044	46,950
	HiGas	28,948	18,610	69,698	19,943	1,572	3,543	0	4,177	27,209	84,385	46,982
	HiLoad	28,948	19,607	104,960	19,945	1,406	3,859	0	7,474	25,887	86,197	47,655
	SysCarbPrice	28,948	18,119	67,426	19,941	1,592	3,356	0	4,520	26,805	85,253	47,274
Spillage (MWh)	Base	0	0	0	5,392	0	0	0	0	0	6,693,602	3,535,523
	LowHydro	0	0	0	5,722	0	0	0	0	0	7,064,115	3,651,816
	HiGas	0	0	0	5,865	0	0	0	0	0	6,723,158	3,620,396
	HiLoad	0	0	0	4,096	0	0	0	0	0	4,910,535	2,947,609
	SysCarbPrice	0	0	0	8,066	0	0	0	0	0	5,854,568	3,328,580
CO2e (Short Tons)	Base	0	5,725,547	23,437,480	0	0	489,421	0	1,697,372	0	0	0
	LowHydro	0	5,654,738	24,626,081	0	0	507,702	0	1,888,989	0	0	0
	HiGas	0	5,664,659	22,903,380	0	0	436,314	0	1,375,048	0	0	0
	HiLoad	0	6,260,835	39,645,865	0	0	571,338	0	4,231,195	0	0	0
	SysCarbPrice	0	5,771,760	22,096,575	0	0	396,044	0	1,535,054	0	0	0
CO2e Cost (M$)	Base	0	0	421	0	0	11	0	43	0	0	0
	LowHydro	0	0	463	0	0	12	0	49	0	0	0
	HiGas	0	0	401	0	0	9	0	36	0	0	0
	HiLoad	0	0	605	0	0	14	0	103	0	0	0
	SysCarbPrice	0	335	1,016	0	0	8	0	72	0	0	0
LMP ($/MWh)	Base	19.87	25.00	32.28	33.59	40.94	37.85		37.04	20.56	26.86	28.15
	LowHydro	22.03	24.41	34.57	29.88	42.25	39.63		39.00	22.44	28.80	29.18
	HiGas	28.97	32.89	42.13	43.29	51.36	46.36		47.50	29.48	36.21	37.24
	HiLoad	31.77	51.75	57.52	60.13	78.56	44.24		79.37	37.20	53.67	70.05
	SysCarbPrice	33.96	36.36	41.21	41.40	47.78	35.26		46.82	32.40	37.05	38.22
MCC ($/MWh)	Base	-21.69	-15.90	-11.21	-9.60	-3.94	-1.83		-7.16	-22.22	-16.26	-14.07
	LowHydro	-22.06	-19.85	-11.68	-16.12	-5.58	-2.48		-8.06	-23.03	-17.08	-15.90
	HiGas	-22.37	-17.39	-11.63	-9.98	-4.12	-2.63		-7.15	-23.34	-17.05	-14.83
	HiLoad	-20.38	-0.66	2.19	5.06	20.75	-5.43		22.37	-17.34	-1.67	14.97
	SysCarbPrice	-11.11	-8.55	-6.16	-5.55	-1.17	-7.85		-1.45	-14.10	-9.87	-7.80

[17] *The Generation Fleet table shown above represents the combined generation fleet of those entities that were WestConnect members at the time the economic assessment was performed in year 2024. The table is not representative of the generation fleet of the WestConnect region in year 2025.*

Appendix C Economic Sensitivities

Generation Fleet (GWh)[18]

Table 28 Generation Fleet (GWh)

AZPS	LowHydro	10,131	0	7,067	0	0	89	0	59	12,871	24,211	4,831
	HiGas	10,131	0	6,860	0	0	89	0	69	12,577	24,384	4,810
	HiLoad	10,131	0	11,587	0	0	92	0	335	11,957	25,223	4,961
	SysCarbPrice	10,131	0	6,980	0	0	86	0	60	12,204	24,814	4,920
BANC	Base	0	0	8,305	5,023	0	0	0	189	49	1,740	1,843
	LowHydro	0	0	9,173	5,554	0	0	0	253	108	1,740	1,872
	HiGas	0	0	7,905	5,023	0	0	0	116	52	1,740	1,854
	HiLoad	0	0	10,162	5,023	0	0	0	373	64	1,740	1,849
	SysCarbPrice	0	0	7,897	5,022	0	0	0	122	53	1,740	1,853
EPE	Base	5,501	0	2,270	0	0	0	0	0	2,093	6,314	209
	LowHydro	5,501	0	2,241	0	0	0	0	0	2,119	6,362	217
	HiGas	5,501	0	1,950	0	0	0	0	0	2,148	6,313	211
	HiLoad	5,501	0	3,438	0	0	0	0	0	2,012	6,597	222
	SysCarbPrice	5,501	0	1,848	0	0	0	0	0	2,140	6,368	213
IID	Base	132	0	664	1,488	0	3,054	0	11	357	1,123	0
	LowHydro	132	0	713	1,488	0	3,065	0	17	367	1,123	0
	HiGas	132	0	672	1,488	0	2,966	0	15	364	1,123	0
	HiLoad	132	0	852	1,489	0	3,230	0	50	361	1,123	0
	SysCarbPrice	132	0	515	1,486	0	2,814	0	15	372	1,123	0
LDWP	Base	3,544	0	14,674	1,417	620	19	0	1,050	1,209	4,582	2,404
	LowHydro	3,544	0	15,493	2,249	693	28	0	1,155	1,411	4,582	2,405
	HiGas	3,544	0	14,058	1,416	622	14	0	781	1,340	4,582	2,404
	HiLoad	3,544	0	18,762	1,417	556	48	0	1,641	1,203	4,582	2,404
	SysCarbPrice	3,544	0	12,412	1,417	716	0	0	1,053	1,479	4,582	2,404
PNM	Base	3,551	0	1,205	800	0	77	0	0	3,042	7,423	9,792
	LowHydro	3,551	0	1,124	862	0	77	0	0	3,106	7,592	9,639
	HiGas	3,551	0	1,502	800	0	78	0	0	3,113	7,383	9,691
	HiLoad	3,551	0	2,010	800	0	83	0	0	3,118	7,517	9,993
	SysCarbPrice	3,551	0	1,517	800	0	79	0	0	3,132	7,429	9,824
PSCO	Base	0	0	18,798	380	159	0	0	15	1,715	11,381	19,998
	LowHydro	0	0	19,165	381	164	0	0	15	1,739	11,444	19,991
	HiGas	0	0	18,670	380	147	0	0	16	1,747	11,381	20,015
	HiLoad	0	0	27,272	381	169	0	0	73	1,770	11,530	20,183
	SysCarbPrice	0	0	18,674	381	139	0	0	15	1,692	11,385	20,029
SRP	Base	6,089	0	6,132	94	757	395	0	77	1,430	8,689	1,898
	LowHydro	6,089	0	6,020	94	782	395	0	82	1,478	8,698	1,907
	HiGas	6,089	0	5,989	94	714	396	0	60	1,625	8,693	1,905
	HiLoad	6,089	0	11,955	94	577	407	0	630	1,254	8,734	1,916
	SysCarbPrice	6,089	0	5,615	94	648	377	0	71	1,561	8,716	1,912
TEPC	Base	0	4,907	4,424	0	0	0	0	2,733	2,613	7,830	1,150
	LowHydro	0	4,778	4,329	0	0	0	0	2,879	2,668	7,817	1,149
	HiGas	0	5,220	4,898	0	0	0	0	425	2,455	7,837	1,149
	HiLoad	0	5,437	8,402	0	0	0	0	1,145	2,355	7,996	1,175
	SysCarbPrice	0	5,299	4,738	0	0	0	0	377	2,437	7,912	1,166
WACM	Base	0	12,146	5,916	4,770	94	0	0	165	1,072	2,941	3,370
	LowHydro	0	12,134	6,175	3,754	103	0	0	196	1,099	2,939	3,368
	HiGas	0	12,369	5,813	4,770	89	0	0	155	1,118	2,942	3,370
	HiLoad	0	13,172	8,569	4,770	104	0	0	435	1,164	2,945	3,370
	SysCarbPrice	0	12,566	5,877	4,770	89	0	0	140	1,074	2,942	3,370
WALC	Base	0	831	1,267	5,971	0	0	0	26	665	8,049	1,574
	LowHydro	0	758	1,375	6,517	0	0	0	37	688	7,534	1,572
	HiGas	0	1,021	1,381	5,971	0	0	0	66	670	8,006	1,574
	HiLoad	0	998	1,952	5,971	0	0	0	142	629	8,210	1,582
	SysCarbPrice	0	254	1,353	5,971	0	0	0	67	661	8,242	1,583

[18] The Generation Fleet table shown above represents the combined generation fleet of those entities that were WestConnect members at the time the economic assessment was performed in year 2024. The table is not representative of the generation fleet of the WestConnect region in year 2025.

Appendix D Scenario Studies

Appendix D - Scenario Studies

Decreased Facility Rating Scenario

The purpose of the Decreased Facility Rating Scenario was to evaluate the impacts of an overall decrease in facility ratings. The original thought behind the scenario was that transmission facility ratings could be reduced if future climate conditions result in a rise in ambient temperatures. Also, facility rating methodologies differ by owners and operators, and can also vary along the length of transmission lines. The purpose of this study was to provide a relative view of how a decrease in region-wide facility ratings might impact reliability performance.

Decreased Facility Rating Methodology

The PS discussed several approaches to performing the scenario assessment including:

a. Region-wide reduction in the level of loading monitored for facilities.
b. Region-wide or subregional reduction in the modeled rating for each facility by an agreed-to percentage
c. Member-specific reduced ratings for their facilities, based on agreed-to temperature increases.

The PS agreed that the most efficient approach would be a region-wide reduction in the level of loading monitored by 5%.

Decreased Facility Rating Assessment

The scenario reliability assessment was performed using the same methodology as for the base reliability assessment. However, facility contingency loadings were monitored for 95% instead of 100%.

Decreased Facility Rating Study Results

The scenario resulted in 14 unique overloaded elements, compared to the base reliability results. Three of those issues are considered local in that they only impact a single facility. The remaining 11 could be considered potential regional issues, where contingencies resulted in overloads on elements owned by more than one entity. Those issues were similar to the potential regional issues from the Base assessment, which were ultimately deemed to not be regional needs.

Appendix D Scenario Studies

Extreme Cold Weather Scenario

The purpose of the Extreme Cold Weather Scenario was to evaluate the reliability of the WestConnect footprint for an extreme cold weather event, by modeling a 10-year, heavy winter condition, with higher-than-expected loads, and reduced resource availability.

For example, historical extremely cold weather conditions have led to shortages in natural gas and renewable resource availability in addition to increased loads, resulting in reliability issues. The purpose of this scenario was to provide valuable information about potential reliability issues, regional system imports and export capabilities, and the need for transmission or resource enhancements.

Extreme Cold Weather Methodology

For reliability modeling, the PS agreed to utilize the 2033-34 WECC Heavy Winter Case (34HW1B1) as the starting (seed) case. A first phase of modifications was made to ensure the WestConnect transmission topology matched the 10-year base (heavy summer and light spring) models. Load and resource adjustments were then made to model the extreme weather conditions.

The approach for modeling the loads and resources for the scenario began by collecting historical load and resource data from the Energy Information Administration (EIA)-930 database, which includes hourly and daily BA data from 2016-2024. The data was evaluated to identify the most extreme conditions in terms of highest loads with low resource availability resulting in anomalously high net loads. Each week of load for the WestConnect footprint was compared to the average, expected load week across the 2016-2024 data history. Historical winter weeks that exhibited the greatest deviation from the average load week, measured as mean absolute error (MAE), were identified as extreme load weeks. That process identified the most extreme week, highest MAE, as the week of January 8, 2024, which aligned with a winter arctic blast that came down from Western Canada **Figure 14**. That event not only broke low temperature records across the Pacific Northwest, but also significantly impacted the WestConnect footprint with both higher peak loads and higher sustained loading, not just mid-day, but into the evenings. A comparison of the actual extreme event load to the average week load is depicted in **Figure 15** below.

Figure 14. January 2024 Winter Arctic Blast Temperatures

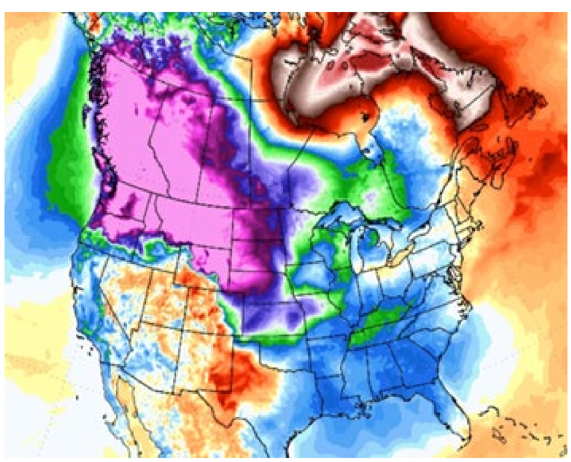
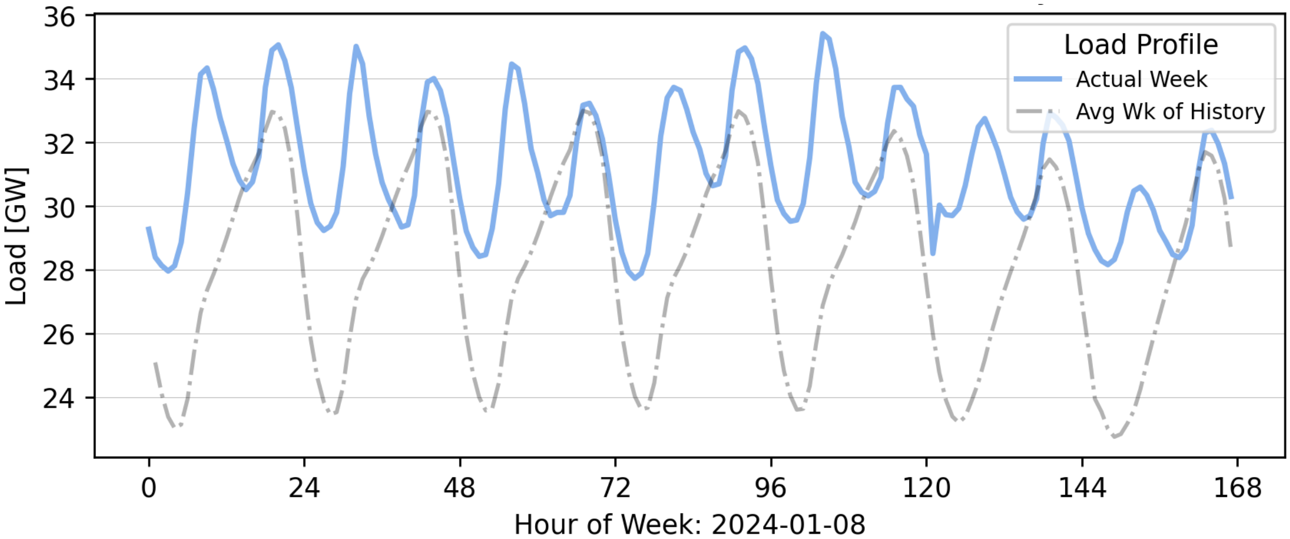


Figure 15. Most Extreme Winter Week from Load History



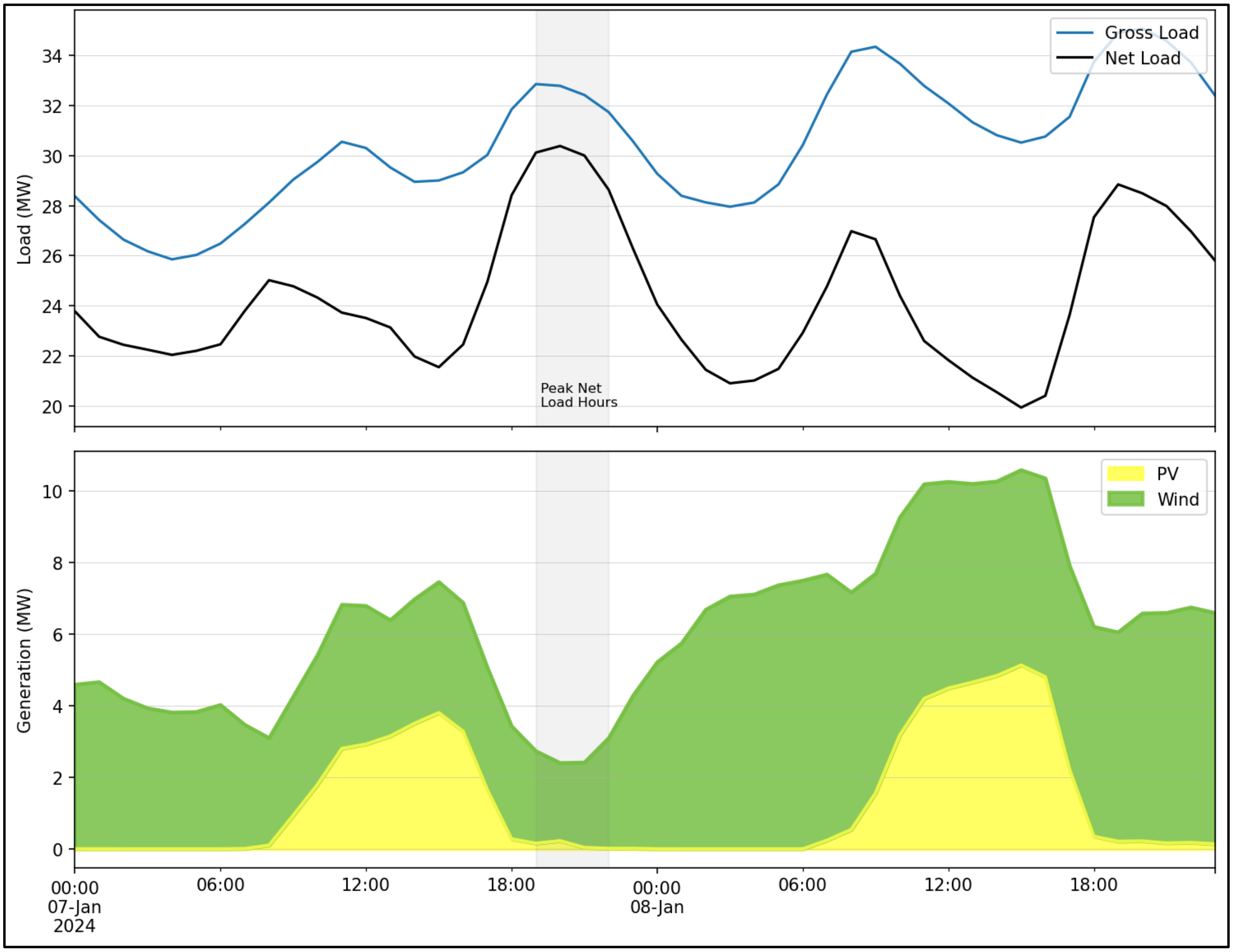
Appendix D Scenario Studies

The next step consisted of reviewing net loads, which are calculated by subtracting solar and wind generation from gross hourly load. In addition to historical hourly load data, the EIA-930 also provides generation data by resource type. The peak net loads during this extreme event week occurred during the hours of 19:00 p.m. – 21:00 on January 7, **Figure 16**. These hours exhibited below average wind generation and near zero solar generation as the sun set. To create a 2034 load forecast that captures this extreme weather event, the 2024 historical load shape was normalized and scaled by the peak hourly load forecast from the WECC 2034 ADS). It was further modified to account for increased energy consumption during the extreme weather event by applying the following scalar, $\beta_{Extreme\ Event}$, to the new 2034 January hourly load forecast:

$$\beta_{Extreme\ Event} = \frac{E_{Jan\ 2024}}{\boldsymbol{Avg}(E_{Dec\ 2023}, E_{Feb\ 2024})}$$

where $E_{Jan\ 2024}$ represents the total energy consumed during the extreme event month of January 2024 is divided by the average energy consumption of the previous month, $E_{Dec\ 2023}$, and following month, $E_{Feb\ 2024}$. The extreme event scalar $\beta_{Extreme\ Event}$ reflects the increase in total energy caused by the extreme event, $E_{Jan\ 2024}$, above the expected energy demand, taken as the average of previous and following months.

Figure 16: Peak net load period in WestConnect footprint

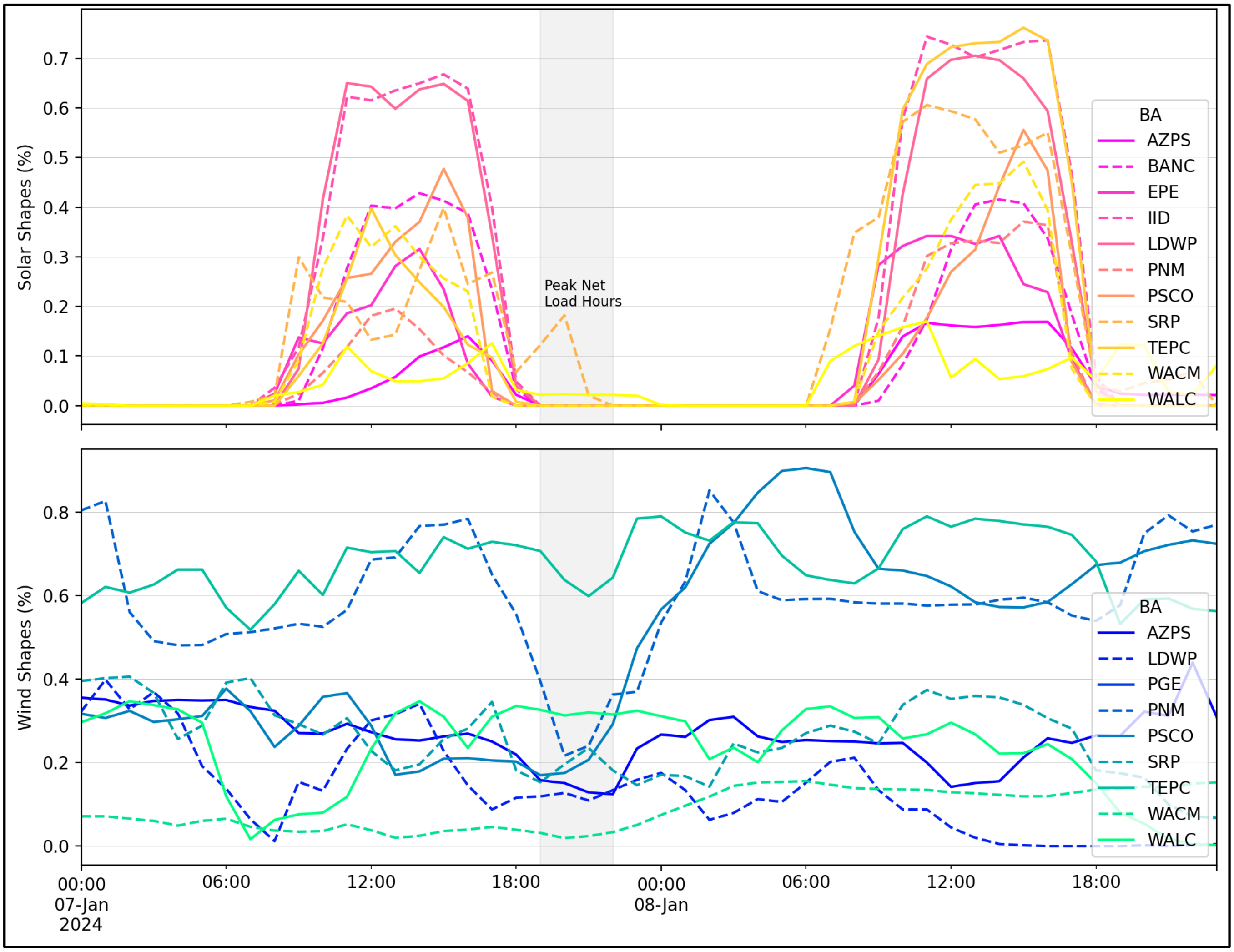


Since hourly load forecast in the WECC ADS PCM model is based on a "1 in 2" load forecast, but WECC powerflow cases usually represent a "1 in 10" load forecast, the 2034 hourly extreme weather load forecast was increased by a ratio of the load in the WECC 2034 Heavy Winter power flow case to the corresponding winter peak hourly load from the 2034 WECC ADS.

Historical capacity factor shapes for wind, solar, and natural gas resources in the WestConnect footprint from the EIA-930 data, as reported by individual BAs, were used to develop generation dispatch assumptions for each Balancing Area in the WestConnect footprint as shown in **Figure 17** below.

Appendix D Scenario Studies

Figure 17 VER capacity factor adjustments during extreme event period.



The forecasted 2034 load and generation dispatch information from EIA-930 was broken out by WestConnect powerflow areas to include in the scenario powerflow model.

The WECC Extreme Winter Weather Study, which was performed in 2022, was also reviewed to determine if any assumptions from that study could be adopted for the WestConnect sensitivity. However, the load assumptions in that study were not as extreme as what was found in the historical event data. It appeared that WECC relied on the 2032 Anchor Data Set modeling data, and only increased loads by 10%, which was not as extreme as the historical events evaluated, which showed loads up to 40% higher than those modeled in the WECC study. The final load modifications are shown in **Table 29**.

Table 29. Load Modifications to 2033-2034 Heavy Winter PF Model

Powerflow Owner	BA	34HW Base Case Load (MW)	Proposed Extreme Cold Weather Load (MW)	Load Change from 34HW Base Case
AEPCO	WALC	767	767	0
APS	AZPS	7,252	7,252	0
Basin	WACM	296	335	39
Black Hills	WACM	1,280	1,446	166
Black Hills	PSCO	370	418	48
CSU	WACM	906	1,024	118
DG&T	PACE	410	410	0
EPE	EPE	1,703	1,703	0
IID	IID	589	589	0
LADWP	LDWP	3,888	4,619	731
PRPA	PSCO	719	813	94
PSCO/Xcel	PSCO	7,838	8,857	1,019
PNM	PNM	2,259	2,259	0
SMUD	BANC	1,922	2,287	365
SRP	SRP	5,483	5,483	0
TSGT	PNM	402	402	0
TSGT	PSCO	272	307	35
TSGT	WACM	1,798	2,032	234
TEP	TEPC	2,509	2,509	0
WAPA - DSW	WALC	1,040	1,040	0
WAPA - RMR	WACM	738	834	96
WAPA- SNR	BANC	199	237	38
Total		**42,640**	**45,623**	**2,983**

PS agreed that no changes should be made to the Desert Southwest loads, since they felt they were already at extreme levels in the WECC case. Final generation modifications are shown in **Table 30**.

Table 30. Generation Modifications to 2033-2034 Heavy Winter PF Model

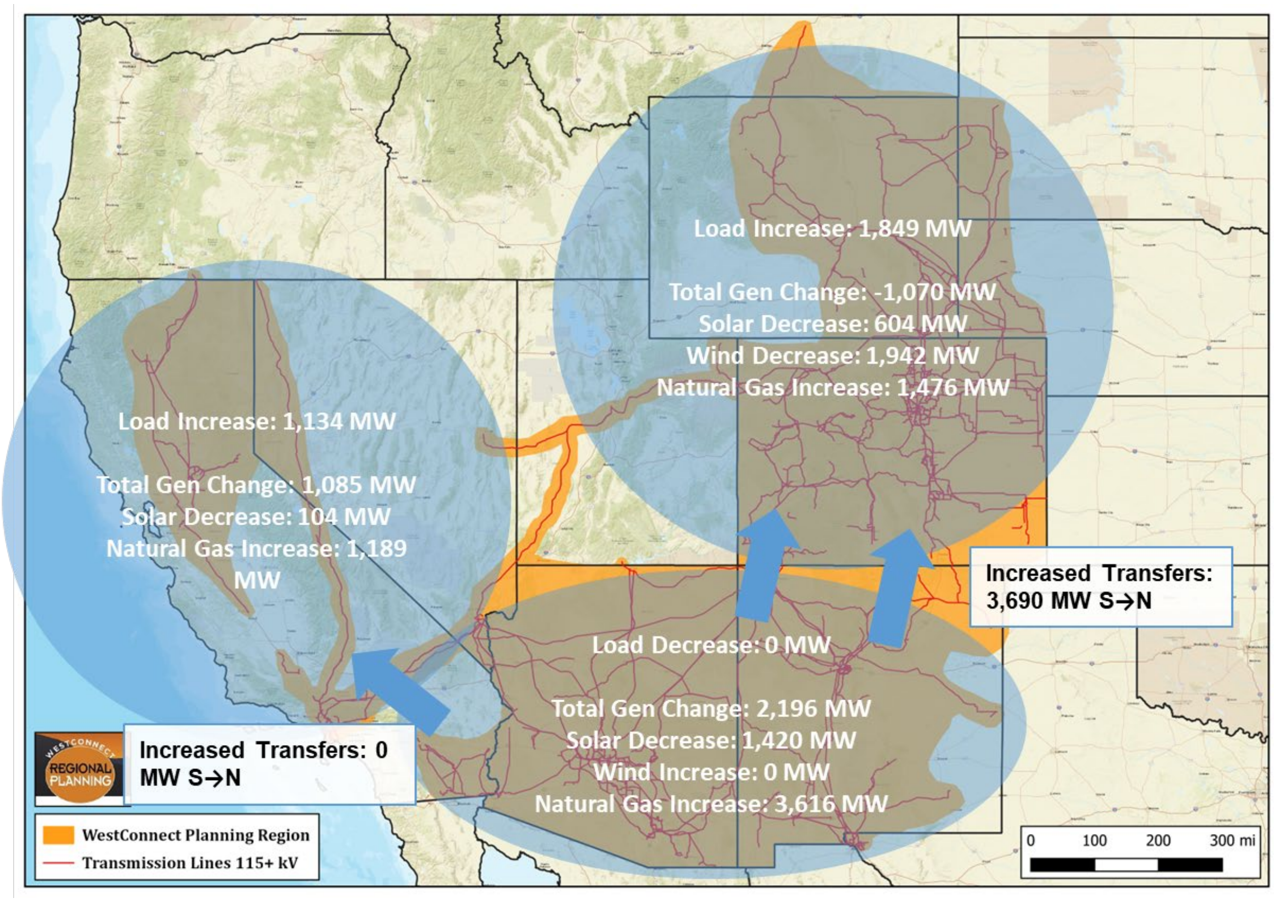
Powerflow Area	34HW PV CF	Proposed PV CF	MW Change to 34HW - PV	34HW Wind CF	Proposed Wind CF	MW Change to 34HW – Wind	34HW Gas CF	Proposed Gas CF	MW Change to 34HW –Gas
NEW MEXICO	19%	0%	-364	36%	36%	0	58%	92%	402
EL PASO	18%	0%	-269	0%	0%	0	42%	66%	442
APS	0%	0%	-6	45%	45%	0	17%	53%	1,213
SRP	11%	0%	-445	0%	0%	0	49%	67%	1,240
TEP	37%	0%	-324	44%	44%	0	67%	87%	319
AEPCO	6%	0%	-13	0%	0%	0	51%	51%	0
WAPA L.C.	0%	0%	0	57%	57%	0	99%	99%	0
IID	0%	0%	0	0%	0%	0	62%	62%	0
LADWP	0%	0%	0	43%	43%	0	40%	52%	761
PG AND E	1%	0%	-104	47%	47%	0	45%	47%	428
PACE	0%	0%	0	72%	72%	0	59%	68%	949
PSCOLORADO	5%	0%	-108	50%	30%	-1,202	89%	97%	418
WAPA R.M.	54%	0%	-496	80%	19%	-740	89%	93%	109
Total			**-2,128**			**-1,942**			**6,281**

The resulting subregional transfers from the changes in loads and resources are shown in **Figure 18**. The bulk of the load increase and the resource decrease was in the Colorado/Wyoming and California subregions.

Appendix D Scenario Studies

For the Desert Southwest subregion, there were enough natural gas resources to provide for the resource deficiency in the other two other subregions.

Figure 18 WestConnect Planning Region Updates for Extreme Cold Assessment



Extreme Cold Weather Assessment

The scenario reliability assessment was performed using the same methodology as for the base reliability assessment.

Extreme Cold Weather Results

The scenario resulted in three contingencies with failed solutions: N-1 outage of San Juan-San Juan PS (to Waterflow) 345kV line, G-1 Laramie River Unit 2 and N-1 outage of Walsenburg-Valent 230kV line. The San Juan-San Juan PS unsolved contingency is a result of the high transfers from Arizona and New Mexico into Colorado. The Walsenburg-Valent 230kV unsolved contingency is a known issue. The Laramie River Unit 2 is likely due to that generator being the swing machine for the WAPA-RMR powerflow area.

There were five local issues, and nine regional-type issues. Of the nine regional-type issues, two were overloads on a single-owner line or transformer with one or both terminals having a different single-owner. The other seven issues were instances of a single contingency causing multiple overloads, where overloaded elements have different single owners.

Appendix D Scenario Studies

20-Year Increased Renewable Scenario

The purpose of this scenario, as originally contemplated, was to perform regional reliability and economic assessments using models that represent a 20-year timeframe with aggressive renewable energy penetration. There was interest in a 20-year scenario to explore public policies that may change in the years beyond the 10-year planning horizon under a future in which carbon reduction may become even more aggressively pursued.

Due to the FERC Order on Remand effective December 16, 2024, the ETOs requested that all non-Order 1000 required work be paused for the remainder of the 2024-25 planning cycle beginning in May 2025. Other membership and stakeholder support was voiced for continuing work on the 20-year scenario, resulting in a PMC motion to continue work on the study at the May 21, 2025, PMC open meeting. The vote did not pass. Then in June 2025, ETOs requested that all activities not directly related to FERC Order 1000 stop[19]. Due to the request from the ETOs and the May 21st PMC vote, work on the 20-Year Renewable Scenario was stopped prior to any modeling and assessments being performed, and the study of this 20-year scenario did not advance beyond preliminary discussions. Study assumptions were not finalized, and no modeling or assessment was performed.

[19] *The ETOs submitted a letter to the PMC on June 13, 2025, detailing their decision not to move forward with the 20-year Increased Renewable Scenario. The letter is available on the WestConnect website here: Documents.aspx*