WestConnect 2020-21 Regional Transmission Planning Cycle

Regional Transmission Plan Report

Approved by the WestConnect Planning Management Committee
December 15, 2021

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1 Executive Summary

The WestConnect 2020-21 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 2020-21 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.

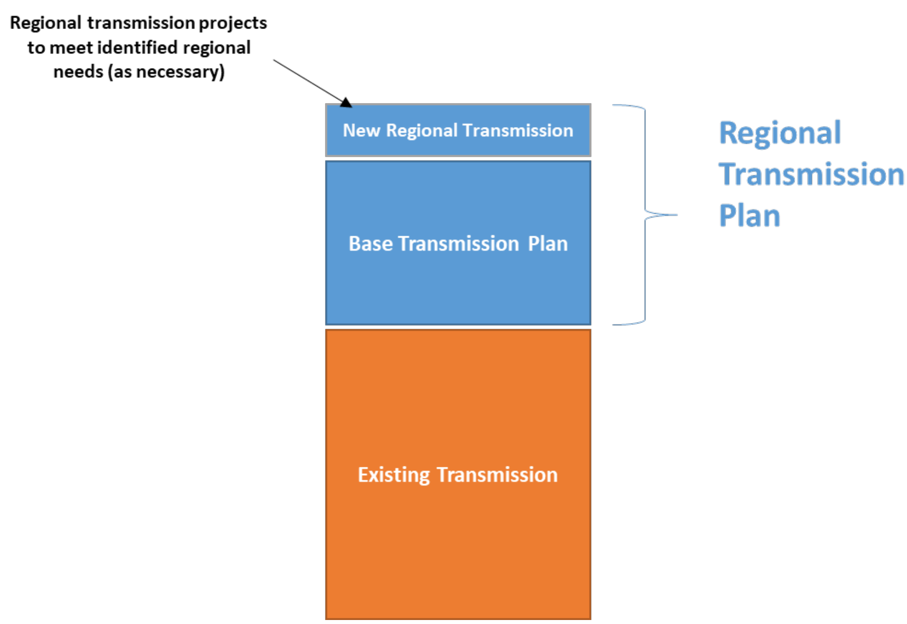
This Regional Plan Report is the final step of the WestConnect biennial Regional Transmission Planning Process ("Planning Process") and is intended to provide the reader with an overview of the core elements of the 2020-21 Planning Process. During the two-year planning cycle, the WestConnect Planning 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 2020-21 Planning Process

Interim Report	PMC Approval Date	Hyperlink	Contents
2020-21 Study Plan	March 18, 2020	Link	• Summary of study methods, models, tools, and analyses • Base Transmission Plan identified • Process schedule
2020-21 Model Development Report	February 17, 2021	Link	• Detailed assumptions and processes used to create models used to perform regional assessment • Analysis of Base Transmission Plan contents
2020-21 Regional Transmission Needs Assessment Report	February 17, 2021	Link	• Study results and findings from regional needs assessment
2020-21 Scenario Assessment Report	September 15, 2021	Link	• Study results and findings from scenario studies

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 WestConnect's regional assessments, as illustrated in **Figure 1**.

Figure 1: Regional Transmission Plan



The 2020-21 Base Transmission Plan includes 212 planned transmission projects, spanning 821 miles with a total estimated capital investment of $799.3 Million. 61% of these projects involve facilities below 230 kV. Since the 2018-19 WestConnect Regional Transmission Plan, the WestConnect region has seen 99 new planned projects, 35 previously planned projects go into service, 14 previously planned projects began construction, and 28 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 power flow 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. **Table 2** summarizes the WestConnect Planning Models developed and analyzed in the 2020-21 Planning Process, which include "Base Case" models used to identify regional needs, and a "Sensitivity Case" used to evaluate the impact of wheeling charge modeling assumptions on the economic model results.

Table 2: WestConnect Planning Models for Regional Assessment

Case Name	Case Description and Scope
2030 Heavy Summer Base Case	Summer peak load conditions during 1500 to 1700 MDT, with typical flows throughout the Western Interconnection.
2030 Light Spring Base Case	Light load conditions during 1000 to 1400 MDT in spring months of March, April, and May with solar and wind serving a significant but realistic portion of the Western Interconnection total load. Case includes renewable resource capacity consistent with any applicable and enacted Public Policy Requirements.
2030 Base Case PCM	Business-as-usual, expected-future case with median load and hydro conditions and representation of resources consistent with enacted public policies.

The reliability assessment for regional needs was based on reliability standards adopted by the North American Electric Reliability Corporation ("NERC") TPL-001-4 Table 1 (P0 and P1) and TPL-001-WECC-CRT-3.2 (Transmission System Planning Performance WECC Regional Criterion), 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 2030 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 2030 Base Case results identified 9 congested elements or paths in multi-TO systems and 44 congested elements or paths in single-TO systems, all of which WestConnect determined to be either local issues or 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 2030 economic and power flow models included all local planning assumptions driven by enacted Public Policy Requirements for study year 2030, 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 took an additional step 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

[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*

additional work was driven by stakeholder interest and was performed by comparing the region's modeled load and renewable energy in the 2030 Base Case to that of the 2028 Base Case and 2026 Base Case from the 2018-19 and 2016-17 planning cycles (respectively). WestConnect found a reasonable trend towards WestConnect members meeting enacted Public Policy Requirements. During the regional reliability and economic assessments, no regional issues were identified.[2] No stakeholders suggested or recommended the identification of a regional public policy-driven transmission need following WestConnect's presentation to stakeholders of enacted public policies and local transmission solutions to Public Policy Requirements. As a result, there are no identified public policy-driven needs in the WestConnect 2020-21 Regional Planning Process.

Based on the findings from the 2020-21 planning cycle analyses performed for reliability, economic, and public policy transmission needs, **no regional transmission needs were identified in the 2020-21 assessment**. As a result, the PMC did not collect transmission or non-transmission alternatives for evaluation since there were no regional transmission needs to evaluate the alternatives against and the 2020-21 Regional Transmission Plan is identical to the 2020-21 Base Transmission Plan.

The evaluations of multi-TO issues identified in the regional assessments are summarized in **Table 3** (there were no multi-TO reliability issues).

Table 3. Evaluation of Economic Multi-TO Issues

Economic Multi-TO Issue	Rationale provided for why this should not identify a regional need
1. Story – Pawnee 230kV Line #1 was congested for 434 hours in the 2030 Base Case, amounting to $5,997K in congestion cost.	Xcel/PSCO and TSGT: Observed congestion on this line does not warrant establishing this as a regional need. The total congestion hours are low and historic flow for this line on Balancing Authority (BA) Peak day has been well below line capacity. Further, there are concerns with the confidence level of having a singular data point. PSCo would encourage multiple futures and years to allow for averaging of results. Additionally, the line itself and the Pawnee terminal are fully owned by PSCo. The Story terminal equipment has mixed ownership, with PSCo having full ownership of some equipment. This makes the congestion on this facility more similar to a single TO facility in nature.
2. Gila River Panda 500/230kV Transformer #1 was congested for 154 hours in the 2030 Base Case, amounting to $5,164K in congestion cost.	APS and SRP: Minimal hours of congestion. Further, this specific transformer is unique in that APS has no ownership, however APS has 100% rights for the entire transformer capacity. Further, the congestion manifesting itself here is a result of market energy sales since APS has no ownership in Gila River generation.

[2] *If regional reliability or economic issues were identified in the economic or reliability assessments, WestConnect would then take the second step of evaluating if those issues were driven by actions needed to comply with Public Policy Requirements.*

Economic Multi-TO Issue	Rationale provided for why this should not identify a regional need
3. WECC Transfer Path 29 (Intermountain – Gonder 230kV) was congested for 139 hours in the 2030 Base Case, amounting to $894K in congestion cost.	LADWP and NVE: The observed congestion is insignificant both by hours and by cost. PACE's generation is one of the contributors and WECC Transfer Path 29 shares transfer capacity with WECC Transfer Path 32 (Pavant – Gonder 230kV and Intermountain – Gonder 230kV).
4. Dave Johnston – Laramie River 230kV Line #1 was congested for 24 hours in the 2030 Base Case, amounting to $795K in congestion cost.	TSGT: Only 24 hours of congestion is very minor (<1% of the year) and can be considered noise
5. WECC Transfer Path 30 (TOT 1A) was congested for 33 hours in the 2030 Base Case, amounting to $499K in congestion cost.	TSGT: Only 33 hours of congestion is very minor (<1% of the year) and can be considered noise
6. WECC Transfer Path 36 (TOT 3) was congested for 4 hours in the 2030 Base Case, amounting to $295K in congestion cost.	TSGT: Only 4 hours of congestion is very minor (<1% of the year) and can be considered noise and does not warrant a regional need. Cost and hours are insignificant and would not justify capital investment.
7. Uvas – Alta Luna 115kV Line #1 was congested for 14 hours in the 2030 Base Case, amounting to $108K in congestion cost.	TSGT and EPE: Only 14 hours of congestion is very minor (<1% of the year) and can be considered noise. Furthermore, the 115 kV UVAS substation interconnection proposed in EPE's future transmission plans will be constructed under the auspices of the EPE/Tri-State Interconnection Agreement. Therefore, any mitigations on the EPE and/or Tri-State systems required for this 115 kV interconnection will be evaluated and constructed under that Agreement.
8. WECC Transfer Path 32 (Pavant – Gonder 230kV and Intermountain – Gonder 230kV) was congested for 12 hours in the 2030 Base Case, amounting to $79K in congestion cost.	LADWP and NVE: The observed congestion is insignificant both by hours and by cost. Also, there's a potential for rating increase of WECC Transfer Path 32 in the west-to-east direction if needed. The Pavant – Gonder 230kV line is between NVE & PacifiCorp.
9. Midway PS – Midway BR 230kV Line #1 was congested for 1 hour in the 2030 Base Case, amounting to $2K in congestion cost.	Xcel/PSCO: This level of congestion does not warrant a regional need. Cost and hours are insignificant and would not justify capital investment.

The 2020-21 Planning Process also included "Scenario Case" models, which are used for information-only scenario studies that considered alternate, but plausible futures. The Scenario Cases are not used to identify regional needs and they do not impact the Regional Transmission Plan. The Scenario Cases, shown in **Table 4,** include Committed Uses (CU) and New Mexico Export Stress (NME) scenario assessments. These studies were performed for informational purposes and did not impact the Regional Transmission Plan.

Table 4: WestConnect Planning Models for Scenario Studies

Case Name	Case Description and Scope
2030 Committed Uses With EIM Scenario Case	Using Open Access Same-Time Information System ("OASIS") and Energy Imbalance Market ("EIM") Energy Transfer System Resources ("ETSRs") data[3], assumptions were developed to represent firm transmission capacity reservations, firm available transfer capability ("FATC"), total transfer capability ("TTC"), and additional inter-BA transfer flexibility provided by the EIM. These assumptions were used to enhance the wheeling path modeling of the 2030 Base Case PCM. The Planning Subcommittee acknowledged that this EIM capacity representation does not represent all of the nuances of participation in the EIM and decided to evaluate two PCM cases, one with and one without the EIM capacity assumptions.
2030 Committed Uses Without EIM Scenario Case	
2030 New Mexico Export Stress Scenario Case	Hour 12 on April 2nd (1200 Mountain Standard Time) in the 2030 Base Case simulation, which was a system condition representative of high New Mexico export to the rest of the Western Interconnection. The New Mexico export amounted to 2,046 MW during that hour.[4]

The CU scenario cases were focused on testing a potential enhancement to the wheeling charge assumptions for future economic assessments and concluded with result comparisons between the CU scenario cases and 2030 Base Case PCM in order to determine whether one or both CU scenario cases produced more reasonable results. The results compared included generator commitment hours, inter-BA interchange flow, local BA generation and load, generator production cost, wind and solar curtailment, branch/path congestion cost, and branch/path number of congested hours. The Planning Subcommittee concluded that both CU PCM simulations ("with EIM" and "without EIM") produced improved results compared to the WestConnect 2030 Base Case PCM and the results of the "without EIM" CU PCM were most reasonable.

The NME scenario case was subjected to the same analysis as the reliability needs assessment and focused on evaluating the reliability of the WestConnect regional transmission system during high export conditions from New Mexico to the rest of the Western Interconnection. NME scenario case development leveraged the condition with the highest New Mexico export flow observed in the WestConnect 2030 Base Case economic model. This scenario assessment indicated several multi-owner issues and indicated that the system. However, the resource mix in New Mexico is constantly evolving

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[3] *The OASIS data included data from the Open Access Technology International (OATI) OASIS website (http://www.oasis.oati.com/) and the California ISO OASIS website (http://oasis.caiso.com/).*

[4] *The New Mexico export was originally calculated from PNM Exports less those going to EPE and was 2,054 MW in Hour 12 on April 2nd; however, the New Mexico export calculation was later refined to include the collective flow exiting New Mexico from the PNM and EPE areas, resulting in the 2,046 MW of New Mexico export in Hour 12 on April 2nd.*

and these reliability issues don't necessarily show up with different resource assumptions and future studies in this regard are deferred the PNM local planning process.

During the NME scenario study, the WestConnect 2030 Light Spring Base Case's dynamic data required many updates outside of the WestConnect footprint to achieve a flat no disturbance transient simulation, which indicates there are issues in the dynamic data of the WECC 2030 Light Spring 1-S Base Case (30LSP1S) and – by extension – these issues may still exist in the WECC master dynamics file (MDF) and, if so, will adversely impact WestConnect's next planning cycle. To help resolve these and similar issues in future WECC Base Cases, WestConnect has developed the below recommendations for WECC's consideration and will provide WECC, upon request by WECC, with the details of the dynamic data updates implemented outside of WestConnect during this assessment so WECC can coordinate with the associated data submitters to resolve similar issues in future WECC Base Cases. Acting on these recommendations will not only benefit WestConnect's future assessments, but will undoubtedly benefit WECC's own Round Trip.

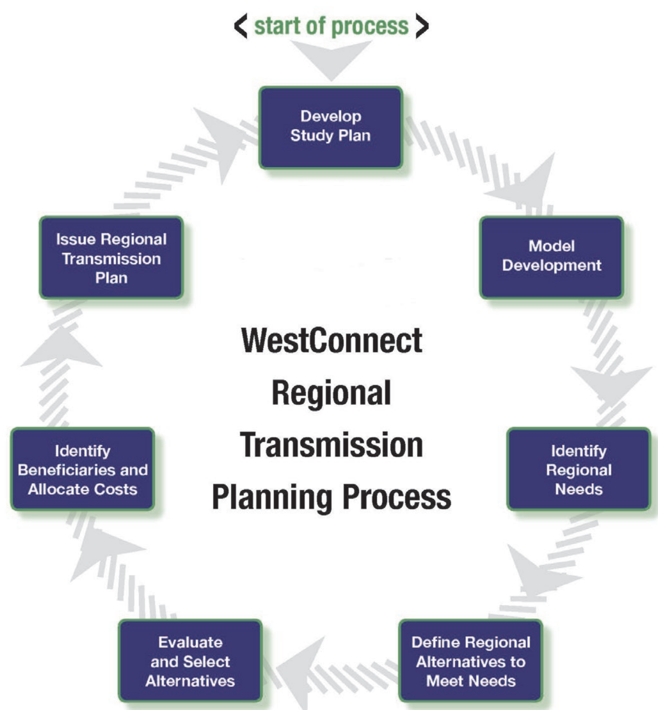
1. The issues flagged in the "Steady-State and Dynamics Dashboard" and "Annual Base Case Compilation and Data Check Log" reports provided with each WECC Base Case should be resolved prior to finalizing the case.
2. For generators capable of negative dispatch (e.g., batteries, pumped-storage hydro, motor loads), the WECC MDF should include dynamic data that works with both positive and negative dispatch and associated comments indicating which set of models is appropriate for each mode of operation.
3. The MVA base of the models in the WECC MDF data should match the MVA base of the models in the WECC Base Cases.
4. As part of finalizing a WECC Base Case, the dynamic data should be tested and validated for all generators in the case that are not retired prior to the represented snapshot, including the generators that may be turned off in the particular snapshot (i.e., it could be dispatched in a sensitivity of the system condition).
5. The MDF should indicate any known operational limitations of the dynamic data being used. For instance, the WECC Wind Power Plant Dynamic Modeling Guide indicates that Phase I wind models only provide reasonable representation of the generator when its dispatch is within 25% to 100% of its rated power and this limitation should accompany the use of any these models in the MDF.

2 Planning Management and Process

This WestConnect 2020-21 Regional Transmission Plan Report ("Regional Plan Report") is the final step of the WestConnect 2020-21 biennial Regional Transmission Planning Process ("Planning Process") and summarizes the processes, assumptions, and technical methods used to develop the WestConnect 2020-21 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 outlined 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 Planning Management Committee ("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

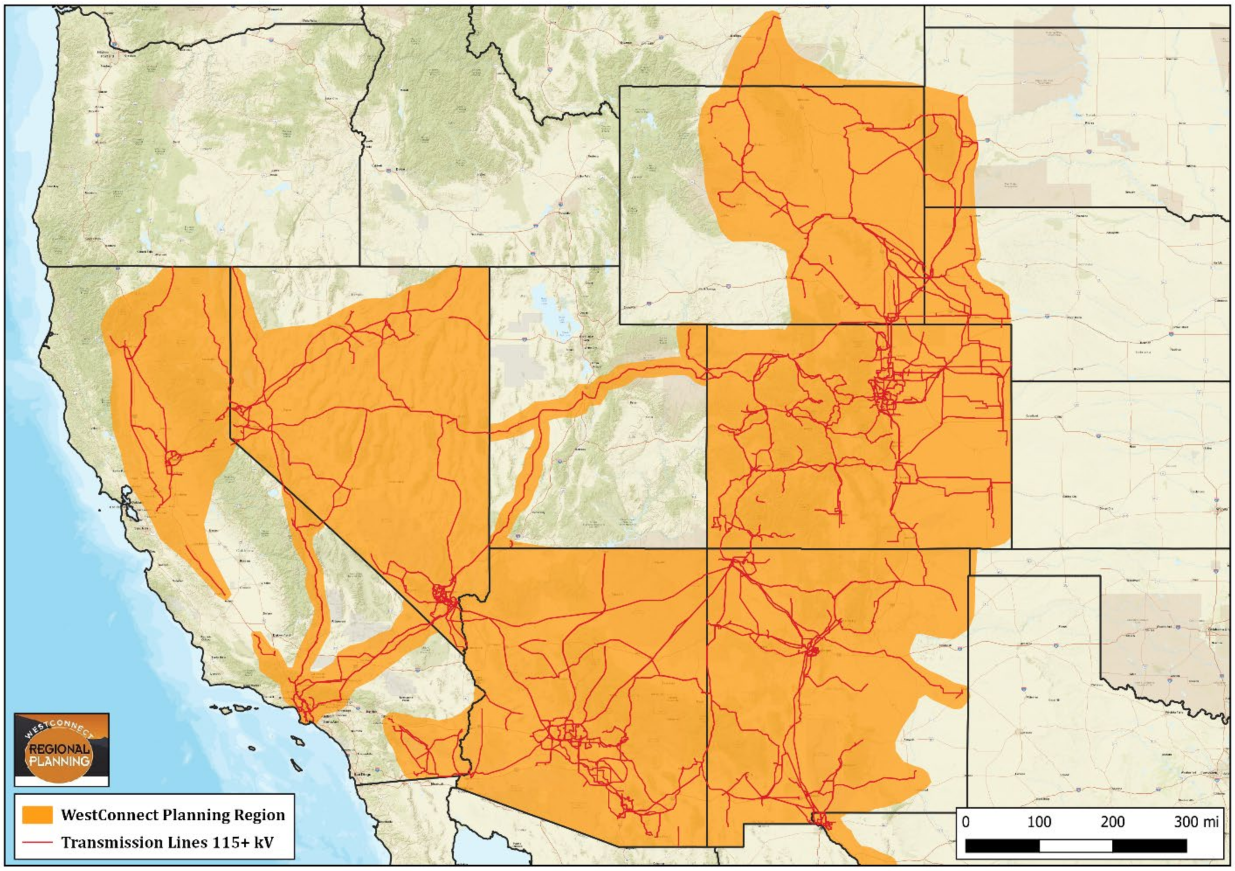
The WestConnect planning process evaluates regional transmission needs of the WestConnect planning region, which is defined as the combined footprints of signatories to the Planning Participation Agreement within the Transmission Owner with Load Serving Obligation ("TOLSO") Members. TOLSO Members participating in the WestConnect 2020-21 planning process and the systems considered in the regional assessment included:

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

WestConnect conducts FERC Order No. 1000 regional transmission needs assessments for Transmission Owner ("TO") entities that are WestConnect members.[5] The approximate footprint of both member and participating TOs is shown in **Figure 3**.

[5] *All references to Order No. 1000 include any subsequent orders. (see http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf)*

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



In addition to the TOLSO members, the following PMC members from the Independent Transmission Developer Member Sector and Key Interest Group Sector[6] also participate in the planning effort:

- American Transmission Company
- Black Forest Partners
- Southwestern Power Group
- TransCanyon
- Western Energy Connection, LLC
- Xcel Western Transmission Company

2.3 Local versus Regional Transmission Issues

For the purposes of the regional transmission needs assessment, 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 system transmission 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.

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[6] *Natural Resources Defense Council began the 2020-21 planning cycle as an active member from the Key Interest Group Sector, but became an inactive member on November 18, 2020 due to their inability to regularly attend WestConnect meetings.*

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.

2.4 Documentation of the 2020-21 Planning Process

This Regional Plan Report is intended to stand on its own, providing an overview of the core elements of the 2020-21 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.

2.4.1 Study Plan

The scope of work for the 2020-21 Planning Process is documented in the 2020-21 Regional Study Plan ("Study Plan"), which was approved by the PMC on March 18, 2020. 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.

2.4.2 Model Development Report

The regional model development process and the input assumptions for the regional planning models is documented in the 2020-21 Model Development Report ("Model Development Report"), which was approved by the PMC on February 17, 2021. 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.

2.4.3 Regional Assessment Report

The methods used to identify regional needs are documented in the 2020-21 Regional Transmission Needs Assessment Report ("Needs Assessment Report"), which was approved by the PMC on February 17, 2021. The Needs Assessment Report details the methods, assumptions, and results of the three types of regional needs assessments: reliability, economic, and public policy.

2.4.4 Scenario Assessment Report

In addition to describing the Base Case planning assessments used to identify regional transmission needs, the Study Plan also describes information-only scenario studies that consider alternate but plausible futures. Scenarios represent futures or system conditions with resource, load, and public policy assumptions that are different in one or more ways than what is assumed in the regional base models. The 2020-21 Scenario Assessment Report ("Scenario Assessment Report"), which was approved by the PMC on September 15, 2021, details the development process, study method, and results of the scenarios identified in the Study Plan.

3 2020-21 Base Transmission Plan

WestConnect created the regional base transmission plan at the beginning of the 2020-21 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 2020-21 Regional Process, no ITD projects met the criteria for inclusion.

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 2020-21 Planning Process was based on updates submitted as of January 2020, with subsequent updates to the data made by members as of November 13, 2020.

The full list of approved regional base transmission plan projects – prior to updates made during model development – can be found in Appendix A of the Study Plan.

3.1 2020-21 Regional Base Transmission Plan Projects

The 2020-21 Base Transmission Plan project list includes 212 planned transmission projects that consist of 74 new or upgraded transmission lines, 66 substations, 29 transmission line and substations, 24 transformers, and 19 other planned projects. From the data reported in the TPPL, these projects span a reported total of 821 miles and add up to a total capital investment of $799.3 Million.[10] **Table 5**, **Table 6**, and **Table 7** summarize the Base Transmission Plan 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 2018-19 planning cycle.

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

[10] 45% of the transmission line projects listed in the 2020-21 Base Transmission Plan did not report line mileage in the TPPL data and 70% of the projects did not report cost information in the TPPL data.

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

Type of Project	Number of Projects	Length (Miles)	Planned Investment ($K)
Substation	66	-	$201,399
Transmission Line	74	586	$288,644
Transmission Line and Substation	29	235	$287,532
Transformer	24	-	$14,580
Other	19	-	$7,095
Total	212	821	$799,250

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

TOLSO	< 230 kV	230 kV	345 kV	500 kV AC	TBD	Total
Arizona Electric Power Cooperative	2	1	-	-	-	**3**
Arizona Public Service	-	7	-	-	-	**7**
Black Hills Energy	8	-	-	-	-	**8**
Black Hills Power	-	5	-	-	-	**5**
Cheyenne Light Fuel and Power	4	-	-	-	-	**4**
Colorado Springs Utility	-	-	-	-	-	**-**
Deseret Power	-	-	-	-	-	**-**
El Paso Electric Company	24	-	3	-	-	**27**
Imperial Irrigation District	1	1	-	-	-	**2**
Los Angeles Department of Water and Power	1	16	-	5	1	**23**
NV Energy	11	6	4	-	-	**21**
Platte River Power Authority	-	2	-	-	-	**2**
Public Service Company of Colorado/ Xcel Energy	4	3	1	-	-	**8**
Public Service Company of New Mexico	1	-	2	-	-	**3**
Sacramento Municipal Utility District	-	2	-	-	-	**2**
Salt River Project	2	1	-	1	-	**4**
Transmission Agency of Northern California	-	-	-	-	-	**-**
Tri-State Generation and Transmission Association	16	7	2	-	-	**25**
Tucson Electric Power	46	2	7	1	-	**56**

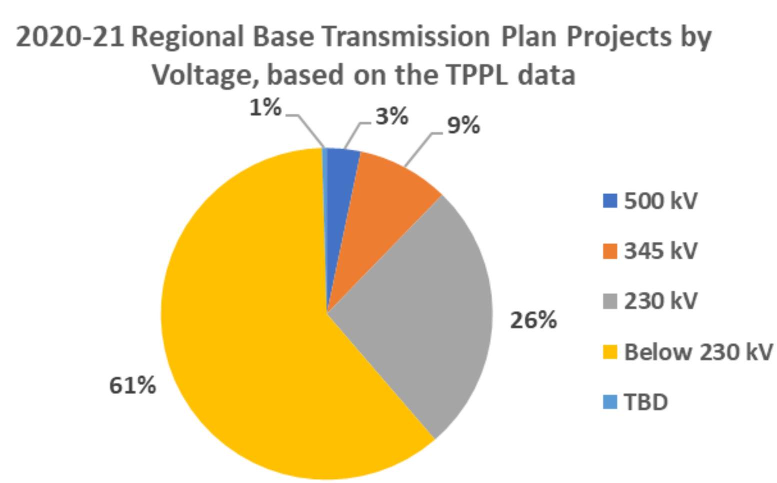
TOLSO	< 230 kV	230 kV	345 kV	500 kV AC	TBD	Total
Western Area Power Administration - DSW	5	-	-	-	-	**5**
Western Area Power Administration - RMR	4	3	-	-	-	**7**
Western Area Power Administration - SNR	-	-	-	-	-	**-**
Total Projects	**129**	**56**	**19**	**7**	**1**	**212**

Table 7. Regional Base Transmission Plan Projects by Voltage, Reported Mileage, and Reported Investment ($K), based on the TPPL data

Type of Project	Number of Projects	Length (Miles)	Planned Investment ($K)
500 kV	7	0.1	-
345 kV	19	73	$93,427
230 kV	56	268	$271,453
Below 230kV	129	480	$434,370
TBD	1	-	-
Total Projects	**212**	**821**	**$799,250**

Review of the of the 2020-21 regional base transmission plan projects showed that 61% were classified as below 230 kV, 26% were classified as 230 kV, 9% were classified as 345 kV; 3% were classified as the 500 kV; and 1% was classified as TBD. **Figure 4** illustrates the percentage breakout for the 2020-21 regional base transmission plan projects by voltage.

Figure 4. 2020-21 Regional Base Transmission Plan Projects by Voltage, based on the TPPL data



3.2 Updates to the 2018-19 Regional Transmission Plan Projects

Review of the 2018-19 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 2018-19 regional base transmission plan projects can be found in the 2018-19 Regional Transmission Plan Appendix A[11]. Updated information provided to the TPPL showed that 35 projects were placed in service, 14 projects were updated to under construction development status, 4 projects were updated to conceptual development status and 24 projects were withdrawn from the 2018-19 Regional Transmission Plan. The remaining 2018-19 regional base transmission plan projects continued as planned projects in the 2020-21 regional base transmission plan. Additionally, 99 new planned projects were added to the TPPL and included in the 2020-21 regional base transmission plan. **Table 8**, **Table 9**, and **Table 10** summarize the updates to the 2018-19 regional base transmission plan projects.

Table 8. 2018-19 Regional Base Transmission Plan Projects In-Service, Reported Mileage, and Reported Investment ($K), based on the TPPL data

Type of Project	Number of Projects	Length (Miles)	Planned Investment ($K)
Substation	10	-	$31,700
Transmission Line	16	248	$124,558
Transmission Line and Substation	3	-	-
Transformer	3	-	$6,700
Other	3	-	$63,909
Total Projects	**35**	**248**	**$226,867**

Table 9. 2018-19 Regional Transmission Plan Projects Under Construction, Reported Mileage, and Reported Investment ($K), based on the TPPL data

Type of Project	Number of Projects	Length (Miles)	Planned Investment ($K)
Substation	5	1	$8,000
Transmission Line	5	30	$17,500
Transmission Line and Substation	2	45	$85,000
Transformer	1	-	$7,800
Other	1	-	$3,700
Total Projects	**14**	**76**	**$122,000**

[11] *https://doc.westconnect.com/Documents.aspx?NID=18530&dl=1#page=41*

Table 10. 2018-19 Planned Regional Transmission Plan Projects Withdrawn or Changed to Conceptual by Voltage, based on the TPPL data

New Status	Type	< 230 kV	230 kV	345 kV	Total
Conceptual	Transmission Line	3	-	-	3
	Transmission Line and Substation	-	1	-	1
Withdrawn	Substation	14	-	-	14
	Transmission Line	7	-	-	7
	Transmission Line and Substation	1	-	-	1
	Transformer	-	-	1	1
	Other	1	-	-	1
	Total	**26**	**1**	**1**	**28**

3.3 Regional Base Transmission Plan Projects by State

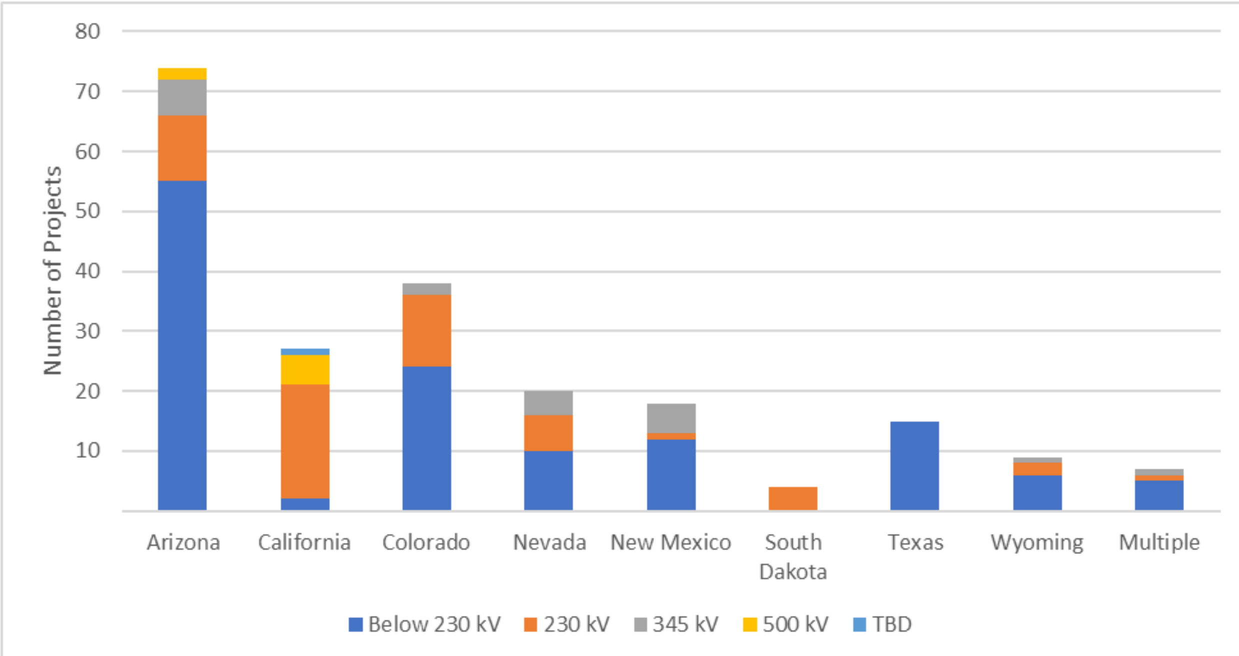
The 2020-21 regional base transmission plan has projects in multiple states in the WestConnect footprint and in some instances, projects span multiple states. **Table 11** summarizes the number of projects by states with aggregated capital investment.

Table 11. 2020-21 Regional Base Transmission Plan Projects by State, Reported Mileage, and Reported Investment ($K), based on the TPPL data

State	Number of Projects	Length (Miles)	Planned Investment ($K)
Arizona	74	275	$270,869
California	27	7	$0
Colorado	38	321	$373,402
Nevada	20	1	$0
New Mexico	18	21	$2,872
South Dakota	4	148	$62,530
Texas	15	21	$0
Wyoming	9	17	$53,177
Multiple	7	11	$36,400
Total Projects	**212**	**821**	**$799,250**

Review of the 2020-21 regional base transmission plan projects by state showed that many (35%) of the projects are located in Arizona, 18% of the projects are located in Colorado, 13% are located in California, and 3% span multiple states. The remaining projects are located in in Nevada, New Mexico, South Dakota, Texas, and Wyoming. **Figure 5** illustrates the breakout of projects by voltage and state.

Figure 5. 2020-21 Regional Base Transmission Plan Projects by Voltage and State, based on the TPPL data



3.4 Regional Base Transmission Plan Projects by Driver

Review of the 2020-21 regional base transmission planned projects showed that nearly all of projects (94%) are primarily driven by reliability needs, 4% are primarily driven by public policy, and the remaining 2% are primarily economic driven. Further review showed that the majority are primarily reliability driven projects below 230 kV (59%). **Table 12**, **Table 13**, and **Figure 6** below breakout the projects by length, planned investment costs, voltage, and primary driver.

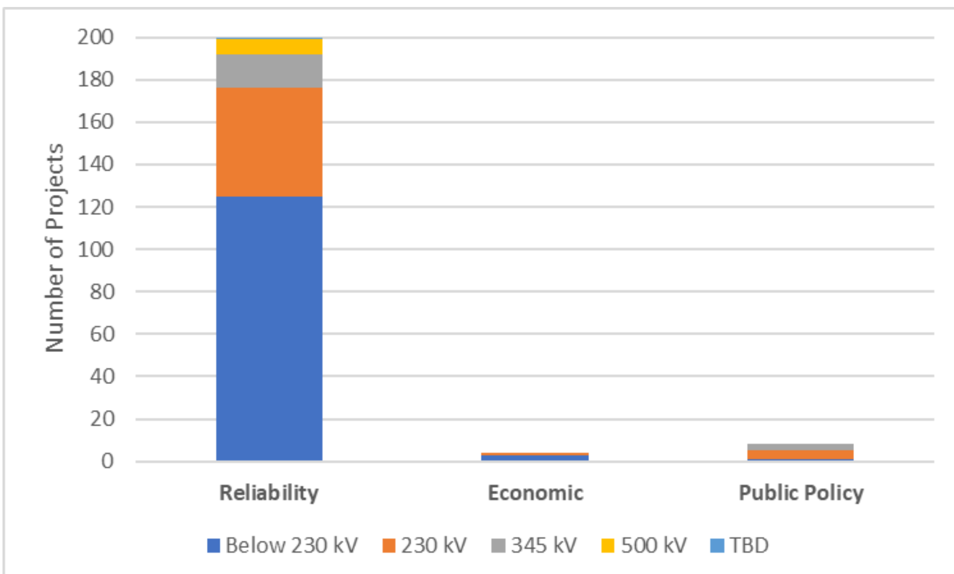
Table 12. 2020-21 Regional Base Transmission Plan Projects by Driver, Reported Mileage, and Reported Investment ($K), based on the TPPL data

Driver (Primary/Secondary)	Number of Projects	Length (Miles)	Planned Investment ($K)
Reliability	183	708	$694,775
Economic	4	13	$28,250
Public Policy	6	-	-
Reliability/Economic	7	100	$64,226
Reliability/Public Policy	10	-	$12,000
Economic/Reliability	-	-	-
Economic/Public Policy	-	-	-
Public Policy/Reliability	2	-	-
Public Policy/Economic	-	-	-
Total Projects	**212**	**821**	**$799,250**

Table 13. 2020-21 Regional Base Transmission Plan Projects by Driver and Voltage, Reported Mileage, and Reported Investment ($K), based on the TPPL data

Driver (Primary/Secondary)	< 230kV	230 kV	345 kV	500 kV	TBD	Total
Reliability	117	45	14	6	1	183
Economic	3	1	-	-	-	4
Public Policy	1	4	1	-	-	6
Reliability/Economic	5	1	1	-	-	7
Reliability/Public Policy	3	5	1	1	-	10
Economic/Reliability	-	-	-	-	-	
Economic/Public Policy	-	-	-	-	-	
Public Policy/Reliability	-	-	2	-	-	2
Public Policy/Economic	-	-	-	-	-	0
Total Projects	**129**	**56**	**19**	**7**	**1**	**212**

Figure 6. 2020-21 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 2020-21 regional reliability assessment on two Base Cases: a 2030 Heavy Summer case and a 2030 Light Spring case. The reliability assessment for regional needs was based on reliability standards adopted by the North American Electric Reliability Corporation ("NERC") TPL-001-4 Table 1 (P0 and P1) and TPL-001-WECC-CRT-3.2 (Transmission System Planning Performance WECC Regional Criterion), 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 2030 Heavy Summer Base Case

Description: The case is designed to evaluate the Base Transmission Plan under heavy summer conditions. The seed case was the WECC 2030 Heavy Summer 1 ADS Planning Base Case dated October 28, 2019 (30HS1), which was updated with the latest topology (i.e., generator, load, and transmission) information from WestConnect participants. The load level and generator dispatch were updated to account for these updates while still representing typical heavy summer load conditions and generator dispatch.

Generation: Within WestConnect, the case features a dispatch of 48,194 MW of thermal, 8,416 MW of hydro, 3,621 MW of wind, and 10,992 MW of solar resources.

Load: The aggregate coincident peak load level for the WestConnect footprint is 67,257 MW. The original WECC case represented the system coincident peak for a heavy summer conditions between the hours of 1500 to 1700 MDT during the months of June – August. WestConnect's 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.

Other assumptions: WestConnect coordinated with the California Independent System Operator (California ISO) and NorthernGrid on certain assumptions during model development. A summary of the changes is below.

- Updates in the California ISO footprint: The planned solar generation in the Valley Electric Association (VEA) footprint was revised to a total capacity of 700 MW (from the 1,098.4 MW modeled in the WECC 30HS1 Base Case) based on coordination between WestConnect, NV Energy, and the California ISO.

- Updates in the NorthernGrid footprint: The Boardman to Hemingway 500-kV Line (B2H) (a.k.a. Longhorn to Hemingway) was added for consistency with WECC and NorthernGrid transmission assumptions.

4.1.2 2030 Light Spring Base Case

Description: The purpose of the case is to assess Base Transmission Plan performance under light-load conditions with solar and wind serving a significant but realistic portion of WestConnect's total load. The seed case was the WECC 2030 Light Spring 1 Scenario Case dated December 9, 2019 (30LSP1-S).

Generation: Within WestConnect, the case features a dispatch of 27,442 MW of thermal, 5,471 MW of hydro, 3,887 MW of wind, and 7,601 MW of solar resources. The case description of the WECC 30LSP1-S included wind and solar dispatch targets shown in **Figure 7**.

Figure 7: Wind and Solar Dispatch Targets from the WECC 30LSP1-S Case Description

Area	Average Dispatch (% of Cap), Weighted by Cap, Type and Area		
	Wind Turbine	Solar PV	Solar Thermal
Alberta	40%		
Arizona	41%	84%	99%[2]
B.C.Hydro	20%		
El Paso		82%	
Idaho	62%	64%	
IID		97%	
LADWP	45%	94%	
Mexico-CFE	42%	80%	
Montana	47%	47%	
Nevada		86%	79%
New Mexico	46%	80%	
Northwest	57%	50%	
PACE	48%	63%	
PG&E	61%	90%	
PSCo	37%	72%	
San Diego	48%	91%	
Sierra	52%	91%	79%
SCE	41%	91%	100%[2]
WAPA R.M.	49%	47%	
WAPA U.W.		47%	

[2] For percent values near or at 100% of nameplate capacity, Data Submitters should provide the maximum recorded output of any existing Wind Turbine, Solar PV and Solar Thermal resources in their area if 100% of nameplate capacity is not feasible. Future resources should be modeled with the expected maximum dispatch value.

Load: The total WestConnect load in the case is 40,701 MW, which is 61% of the WestConnect peak load in the WestConnect 2030 Heavy Summer Base Case. The load levels represent the system during 1000 to 1400 hours MDT during spring.

Transmission: Identical transmission assumptions as the 2030 Heavy Summer Base Case – see above for details.

Other assumptions: Identical other assumptions as the 2030 Heavy Summer Base Case – see above for details.

4.1.3 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 power flow cases.
- **Protection Systems** – The impact of protection systems including Remedial Action Scheme (RAS) required for compliance with NERC reliability standards were included in the power flow cases.
- **Control Devices** – Any special control devices required were included in the power flow cases.

4.2 Study Method

The scope of the reliability assessment was based on a list of comprehensive N-1 contingencies, plus TOLSO additions, in order to identify a regional need, as determined by the PS.[12] The intent was to minimize flagging and processing, local or "non-regional" issues. Contingency definitions for the steady-state contingency analysis were limited to N-1 contingencies for elements 230 kV and above, generator step-up ("GSU") transformers for generation with at least 200 MW capacity, and member-requested N-2 contingencies. Monitoring and violation reporting was performed for elements above 90-kV outside of the WestConnect footprint and member-identified elements within WestConnect footprint.

WestConnect also performed transient stability simulations. The PS surveyed the membership to develop the list of transient stability outages performed, which resulted in selecting ten disturbances across the WestConnect footprint.

System performance issues impacting, or between, more than one TO Member system were identified for further review by the PS. Local issues were reported for informational purposes. The local issues were not the focus of this assessment and were deferred to the applicable TOLSO Member.

4.3 Study Results and Findings

Upon a comprehensive review of the regional reliability assessment results in public meetings, no regional needs were identified. This conclusion was reached because neither the Heavy Summer nor the Light Spring assessments identified reliability issues that were between two or more WestConnect members or impacted two or more WestConnect members. More details, including the local/single-system issues and results of the transient stability simulations, are provided in the slides of the PMC meeting on December 16, 2020.

[12] *An initial list of automatically generated single branch ("N-1") outages for 230 kV and higher elements was created, and participants submitted any revisions to ensure the outages represented actual N-1 disturbances as well as any multi-element contingency definitions not automatically created.*

5 Economic Assessment

WestConnect performed the 2020-21 regional economic assessment by conducting a production cost model ("PCM") study on a 2030 Base Case along with one sensitivity case. The goal of the assessment was to test the Base Case and the Base Transmission Plan for economic congestion between more than one TO Member's area.

5.1 Case Development

The economic Base Case originated from the WestConnect 2028 Base Case economic model from the 2018-19 planning cycle, and was reviewed and updated by WestConnect members during Quarters 2, 3, and 4 of the 2020-21 planning cycle. The Quarter 3 updates included assumptions pulled from the WECC 2030 Anchor Dataset (ADS) interconnection-wide 10-year PCM ("2030 ADS PCM V1.0"), dated June 30, 2020. The reliability base models and economic base models had consistent electric topologies (e.g., matching load, generator, and branch models). What follows is a description of the key assumptions used to form the 2030 Base Case used to evaluate regional economic needs.

As with the reliability assessment, the economic 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. 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 economic models.

5.1.1 2030 Base Case

Description: The case is a production cost model (PCM) dataset designed to represent a likely, median 2030 future. The WestConnect 2028 PCM from the 2018-19 planning cycle served as the seed case for the WestConnect economic model 2030 Base Case. The WestConnect 2028 PCM was reviewed and updated by WestConnect during Quarters 2, 3, and 4 of the 2020-21 planning cycle, and the Quarter 3 updates included assumptions from the WECC 2030 Anchor Dataset (ADS) interconnection-wide 10-year PCM ("2030 ADS PCM V1.0"), dated June 30, 2020. These updates were consistent with the process described below, which focuses on what updates were completed with the WECC 2030 ADS PCM V1.0 dataset as the reference.

Generation:

- WestConnect's latest 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 14** provides a summary by fuel category of the generation updates made to the WECC 2030 ADS PCM V1.0. The positive (or negative) values represent the capacity (in MWs) and resulting generated energy (in GWh) added to (or removed from) the WECC 2030 ADS PCM V1.0 in order to create the WestConnect 2030 Base Case PCM.

Table 14: Generation Differences from WECC 2030 ADS PCM V1.0.
Percentages are in reference to the totals in the WECC 2030 ADS PCM V1.0

Fuel Category	Differences, WestConnect less WECC PCM				Annual Generation (GWh)		Capacity (MW)	
	Annual Generation		Capacity					
	GWh	%	MW	%	WestConnect	WECC	WestConnect	WECC
Coal	(27,251)	-37.6%	(3,968)	-31.6%	45,282	72,533	8,573	12,540
Gas	22,751	17.2%	3,299	8.8%	154,651	131,899	40,618	37,319
Water	(1,335)	-6.4%	(613)	-6.5%	19,630	20,965	8,854	9,467
Uranium	2,568	8.1%	129	3.2%	34,116	31,548	4,132	4,003
Solar PV	1,867	7.0%	(1,718)	-12.0%	28,704	26,837	12,653	14,371
Solar Thermal	(29)	-3.6%	(106)	-24.9%	766	795	319	425
Wind	2,967	10.7%	776	9.2%	30,820	27,853	9,214	8,438
Bio	316	91.8%	(6)	-5.2%	659	344	102	108
Geothermal	(4,544)	-38.3%	(35)	-2.1%	7,318	11,862	1,581	1,616
BESS	2,155	154.4%	819	37.0%	3,551	1,396	3,034	2,215
Other	(288)	-1.6%	401	3.4%	17,862	18,150	12,102	11,702
Overall	**(822)**		**(1,023)**		**343,360**	**344,182**	**101,181**	**102,204**

- Through coordination with the California ISO and San Diego Gas & Electric (SDG&E), two solar resources located at the Hassayampa substation in the WECC 2030 ADS PCM V1.0 were excluded from the WestConnect models. "Mesquite Solar 5" (300 MW) was found in the California ISO generation queue, but has not been modeled in recent WECC Base Cases so was determined to be too tentative for inclusion in the WestConnect regional models. "SILVER RIDGE MOUNT SIGNAL 3" (250 MW) was found to be duplicative of the "DW GEN2 G3A_23442_1" and "DW GEN2 G3B_23443_1" resources in the WECC 2030 ADS PCM V1.0 (Tenaska Imperial Solar Energy Center West & South resources in the WestConnect 2030 Base Case).

- The behind-the-meter distributed generation (BTM-DG) assumptions were retained from the WECC 2030 ADS PCM V1.0 which modeled them on the resource-side, with the exception of the TEPC load area (for which the BTM-DG and DR shapes were merged with the load shapes to model the BTM-DG and DR on the load-side). **Table 15** summarizes the amount of BTM-DG by area represented in the WestConnect 2030 Base Case PCM.

Table 15: Behind-the-Meter Distributed Generation

Area Name	Capacity (MW)	Generation (GWh)	Capacity Factor (%)	Dispatch at Area Peak Load (% of Capacity)
AZPS	2,815	6,377	26%	48%
BANC	716	1,493	24%	45%
EPE	316	746	27%	65%
IID	199	452	26%	69%
LDWP	745	1,611	25%	76%
NEVP	599	1,380	26%	70%
PNM	132	300	26%	58%
PSCO	1,513	2,969	22%	66%
SPPC	83	177	24%	63%
SRP	438	997	26%	52%
TEPC	433	996	26%	67%
WACM	60	119	22%	53%
WALC	324	732	26%	66%

Load: WestConnect made minor modifications to the load shapes and forecasts included in the WECC 2030 ADS PCM V1.0. No changes were made to the load forecasts for areas outside of WestConnect. **Figure 8** and **Figure 9** 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 BAAs rather than specific utilities. The "PF Load" – load in the WestConnect 2030 Heavy Summer Base Case – is provided for a frame of reference, though, some difference between the PCM and power flow ("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's 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 (except for TEPC) whereas the PF model loads may or may not contain BTM-DG.
- The economic model loads in the charts below include exports out of Western Interconnection via the direct current interties along the east side of the Western Interconnection – whereas they are not included in the PF load in the charts below.

Figure 8: WestConnect PCM Areas' Annual Demand (GWh) in WestConnect 2030 Base Case (PCM)

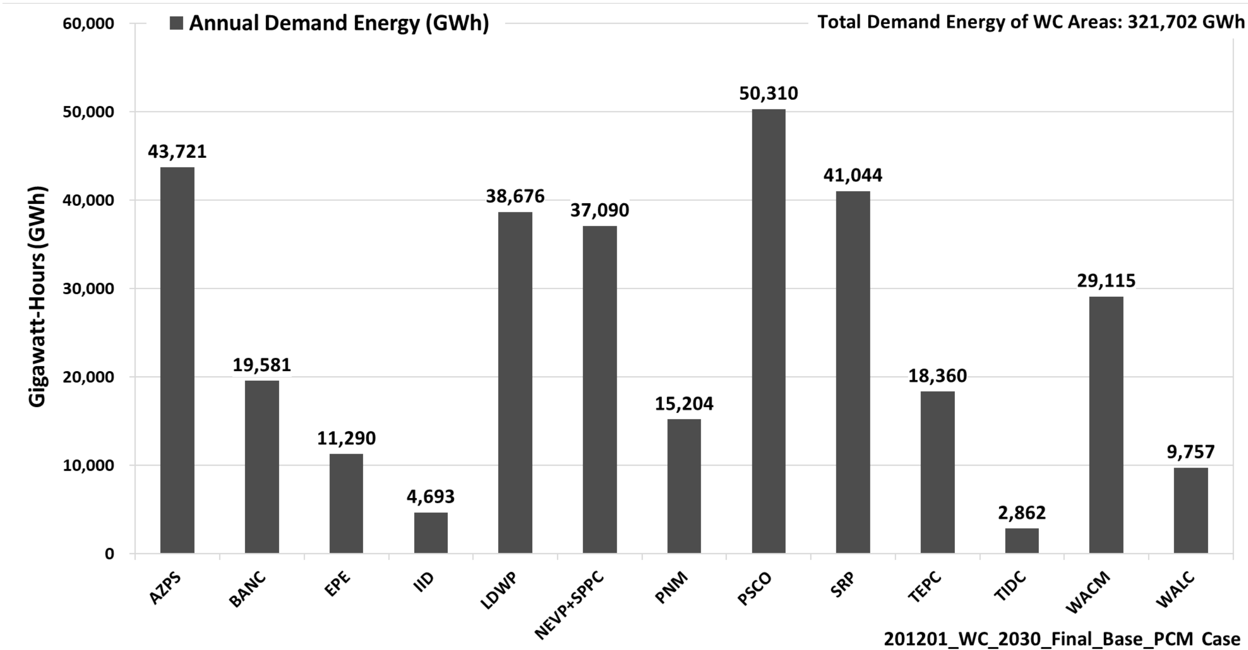
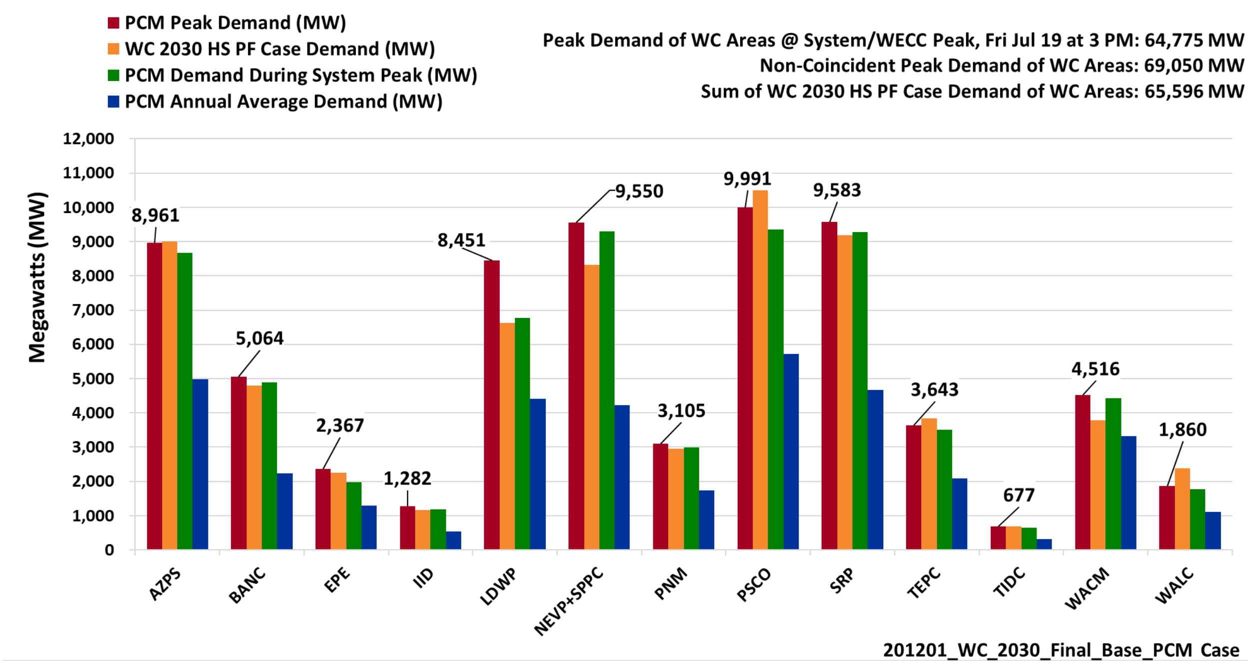


Figure 9: WestConnect PCM Areas' Peak Demand, Demand During System Peak, and Average Demand (MW) in WestConnect 2030 Base Case (PCM), shown with the Demand of the 2030 Heavy Summer Base Case



Transmission: The WECC 2030 ADS PCM V1.0 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.

- Increased branch monitoring in the WestConnect footprint: Monitored transmission elements greater than 90 kV in WestConnect, greater than 200 kV outside of WestConnect, and all phase shifting transformers (PST) (phase angle regulators, or PAR).
- Updated interface definitions.

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 2030 Heavy Summer Base Case.
- Fuel price forecasts and emission rate assumptions were initially pulled from the WECC 2030 ADS PCM V1.0 and subsequently updated with new coal prices accepted by the WECC PCDS during their meeting on April 14, 2020 as well as Member feedback. These assumptions are included in Appendix A of the Model Development Report.
- Reserve requirements modeling was updated from what was represented in the WECC 2030 ADS PCM V1.0. These assumptions are summarized below:
    - Contingency Reserves: the default assumptions are provided below. LADWP and PNM provided higher spinning reserve assumptions to better represent their Balancing Authority's (BA's) operating practices.
        - Assumed a 50/50 split between spinning and non-spinning.
        - 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).
        - Kept non-spinning requirement unmodeled since neither dataset currently has quick-start generator designations.
        - Kept spinning requirement modeled at BA and Reserve Sharing Group (RSG); however, a single set of RSG spinning requirements was modeled similar to the WECC 2030 ADS PCM V1.0, except that RSG_RM was removed and the TPWR, PSCO, and WACM areas were included in RSG_NW.
    - Regulation Ancillary Service (AS) assumptions shown in **Table 16** 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, 2018 (link).
    - Load Following AS assumptions shown in **Table 16** were based on the CPUC SERVM model for their 2018-19 IRP (link).

Table 16. Regulation and Load Following Ancillary Service Assumptions in WestConnect 2030 Base Case

AS	Ramping Response Requirement (minutes)	Requirement (at RSG level)	What it represents	What can contribute
Regulation Up	10	1.5% of Load	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 10% of Maximum Capacity)***
Load Following Up	20	2.5% of load	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		***Same as Reg Down contributors***

- ○ Frequency Response AS assumptions were based on system-wide values from the NERC 2019 Frequency Response Annual Analysis (FRAA). This and the related assumptions are summarized in **Table 17**.

Table 17. Frequency Response Ancillary Service Assumptions in WestConnect 2030 Base Case

AS	Ramping Response Requirement (minutes)	Requirement (at RSG level)	What it represents	What can contribute
Frequency Response	1	1,253	• Response to frequency changes within one minute • 50% of constraint assumed to be met by hydro and renewable resources (full constraint is 2,506 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 2030 ADS PCM V1.0

values to peak and off-peak wheeling charges based on the latest Open Access Transmission Tariff (OATT) rate. These assumptions are provided in Appendix A of the Model Development Report. The WECC 2030 ADS PCM V1.0 also contained additional wheeling charges associated with modeling carbon emission charges applicable to California, and these rates were updated. Planning Subcommittee 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 2030 ADS PCM V1.0 by the WECC Production Cost Data Subcommittee (PCDS) were implemented. Refer to the "Carbon emission charges updates" topic below for more details.
- The WECC 2030 ADS PCM V1.0 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 2028 PCM, pulling in updates based on the WECC 2030 ADS PCM V1.0, 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 Appendix A of the 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's output for certain plants.
- Carbon emission charges updates: Details are below, in 2020 dollars.
  - California: Updated to $64.293/MT based on the WECC PCDS' recommendation (CEC's 2019 IEPR Revised Carbon Price Projections) ("California Carbon Price Assumption")
    - In addition, the reduced emission factor for NW imports was also updated to 0.0117 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.
  - Alberta: Updated to $31.742/MT based on an Osler article RE Alberta carbon pricing
  - British Columbia: Updated to $49.015/MT based on British Columbia's Carbon Tax

5.1.2 Economic Sensitivity Models

Models were developed for sensitivity studies on the 2030 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 Planning Subcommittee determined four sensitivities of interest, and their assumptions are summarized below. The detailed assumptions are provided in Section 4.1 of the MDR.

1. **2030 High Load Sensitivity Case**: The hourly load shapes of the Balancing Authority Areas (BAAs) within WestConnect were scaled up so their annual peak and energy was beyond their values in the 2030 Base Case. The WestConnect BAAs total coincident annual peak load and load energy in this case ended up being higher than the 2030 Base Case by 8,644 MW (14%) and 45,591 GWh (15%), respectively.
2. **2030 Low Hydro Sensitivity Case**: The hydro modeling was replaced with WECC's 2001-based hydro modeling developed by WECC in conjunction with their 2024 Common Case PCM dataset. The system-wide hydro generation of this case ended up being lower than in the 2030 Base Case by 40,249 GWh (17%).
3. **2030 High Gas Price Sensitivity Case**: All the natural gas prices were increased to 140% of their value in the 2030 Base Case.
4. **2030 System-Wide Carbon Emission Cost Sensitivity Case**: Applied CO_2 emission charges to all generators in WECC.

5.2 Study Method

The PS conducted the study and reviewed the 2030 Base Case 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). 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.[13]

5.3 Study Results and Findings

The objective of the economic assessment was to arrive at 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.

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[13] 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.

There was no significant congestion to identify a regional need in the Base Case economic assessment. For completeness, the Planning Subcommittee conducted the sensitivity studies described above and confirmed that their different assumptions were not hiding potential regional congestion. Evaluations of each multi-TO system congestion issue in the Base Case results are summarized below. The PS determined all issues to be local and not regional in nature. More details, including the congestion results of the sensitivity cases, are provided in Appendix B.

1. Story – Pawnee 230kV Line #1 was congested for 434 hours in the 2030 Base Case, amounting to $5,997K in congestion cost. Xcel/PSCO and TSGT provided the rationale for why this should not identify a regional need:
    - Observed congestion on this line does not warrant establishing this as a regional need. The total congestion hours are low and historic flow for this line on BA Peak day has been well below line capacity. Further, there are concerns with the confidence level of having a singular data point. PSCo would encourage multiple futures and years to allow for averaging of results. Additionally, the line itself and the Pawnee terminal are fully owned by PSCo. The Story terminal equipment has mixed ownership, with PSCo having full ownership of some equipment. This makes the congestion on this facility more similar to a single TO facility in nature.
2. Gila River Panda 500/230kV Transformer #1 was congested for 154 hours in the 2030 Base Case, amounting to $5,164K in congestion cost. APS and SRP provided the rationale for why this should not identify a regional need:
    - Minimal hours of congestion. Further, this specific transformer is unique in that APS has no ownership, however APS has 100% rights for the entire transformer capacity. Further, the congestion manifesting itself here is a result of market energy sales since APS has no ownership in Gila River generation.
3. WECC Transfer Path 29 (Intermountain – Gonder 230kV) was congested for 139 hours in the 2030 Base Case, amounting to $894K in congestion cost. LADWP and NVE provided the rationale for why this should not identify a regional need:
    - The observed congestion is insignificant both by hours and by cost. PACE's generation is one of the contributors and WECC Transfer Path 29 shares transfer capacity with WECC Transfer Path 32 (Pavant – Gonder 230kV and Intermountain – Gonder 230kV).
4. Dave Johnston – Laramie River 230kV Line #1 was congested for 24 hours in the 2030 Base Case, amounting to $795K in congestion cost. TSGT provided the rationale for why this should not identify a regional need:
    - Only 24 hours of congestion is very minor (<1% of the year) and can be considered noise.
5. WECC Transfer Path 30 (TOT 1A) was congested for 33 hours in the 2030 Base Case, amounting to $499K in congestion cost. TSGT provided the rationale for why this should not identify a regional need:
    - Only 33 hours of congestion is very minor (<1% of the year) and can be considered noise.

6. WECC Transfer Path 36 (TOT 3) was congested for 4 hours in the 2030 Base Case, amounting to $295K in congestion cost. TSGT provided the rationale for why this should not identify a regional need:
    - Only 4 hours of congestion is very minor (<1% of the year) and can be considered noise and does not warrant a regional need. Cost and hours are insignificant and would not justify capital investment.
7. Uvas – Alta Luna 115kV Line #1 was congested for 14 hours in the 2030 Base Case, amounting to $108K in congestion cost. TSGT and EPE provided the rationale for why this should not identify a regional need:
    - Only 14 hours of congestion is very minor (<1% of the year) and can be considered noise. Furthermore, the 115 kV UVAS substation interconnection proposed in EPE's future transmission plans will be constructed under the auspices of the EPE/Tri-State Interconnection Agreement. Therefore, any mitigations on the EPE and/or Tri-State systems required for this 115 kV interconnection will be evaluated and constructed under that Agreement.
8. WECC Transfer Path 32 (Pavant – Gonder 230kV and Intermountain – Gonder 230kV) was congested for 12 hours in the 2030 Base Case, amounting to $79K in congestion cost. LADWP and NVE provided the rationale for why this should not identify a regional need:
    - The observed congestion is insignificant both by hours and by cost. Also, there's a potential for rating increase of WECC Transfer Path 32 in the west-to-east direction if needed. The Pavant – Gonder 230kV line is between NVE & PacifiCorp.
9. Midway PS – Midway BR 230kV Line #1 was congested for 1 hour in the 2030 Base Case, amounting to $2K in congestion cost. Xcel/PSCO provided the rationale for why this should not identify a regional need:
    - This level of congestion does not warrant a regional need. Cost and hours are insignificant and would not justify capital investment.

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 identified during the regional economic and reliability needs assessments are further evaluated to determine if they were driven by enacted Public Policy Requirements; and
2. Stakeholders are given an opportunity to review Public Policy Requirements impacting the WestConnect region and the local projects driven by those Public Policy Requirements and suggest to WestConnect that the Public Policy Requirements may result in possible regional public policy-driven transmission needs.

6.1 Study Method

WestConnect began the evaluation of regional transmission needs driven by Public Policy Requirements for the 2020-21 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 18 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 2020-21 planning cycle, the WestConnect 2030 economic and reliability models reflect these public policies' conditions for the study year 2030. Company goals, although not Public Policy Requirements, such as the PNM Commitment to Carbon Free by 2040[14], were also considered in the development of the base models.

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

785 **Table 18. Enacted Public Policies Which Informed the2030 WestConnect Planning Models**

Enacted Public Policy	Description	Driving Local Transmission Projects in Models
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	**Yes**
California SB100	Requires Investor-owned utilities (IOUs) and municipal utilities to meet a 60% renewable portfolio standard ("RPS") by 2030	**Yes**
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	**Yes**
Colorado HB10-1001	Established Colorado Renewable Energy Standard (RES) to 30% by 2020 for IOUs (Xcel & Black Hills)	**Yes**
Colorado HB10-1365	Requires rate regulated utilities in CO with coal-fired generation to reduce emissions on the smaller of 900 MW of generation of 50% of a company's coal generation fleet. Full implementation to be achieved by 12/31/2017	**Yes**
Colorado SB13-252	Requires cooperative utilities to generate 20% of their electricity from renewables by 2020	**Yes**
New Mexico Energy Transition Act (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	**Yes**
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	No

Enacted Public Policy	Description	Driving Local Transmission Projects in Models
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	No
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.	No
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	No
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.	No

Enacted Public Policy	Description	Driving Local Transmission Projects in Models
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.	No
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.	No
SRP Sustainable Energy Goal[15]	• SRP plans to add 1,000 megawatts (MW) of solar energy by 2025. • Reduce the amount of CO_2 emitted (per megawatt-hour) by 62% from 2005 levels by 2035 and by 90% by fiscal year 2050.	No

[15] *The SRP Sustainable Energy Goal was established and approved by a Board of elected officials. That Board is SRP’s governing entity, analogous to the Arizona Corporation Commission, which regulates other Arizona utilities. Accordingly, SRP’s Board-approved energy goals are considered enacted public policy.*

Enacted Public Policy	Description	Driving Local Transmission Projects in Models
Nevada Renewable Portfolio Standard (most recent update SB358 2019)	The portfolio standard must require each provider to generate, acquire or save electricity from portfolio energy systems or efficiency measures in an amount** that not less than specific percentages (listed below) of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year. • For calendar years 2015 through 2019, inclusive, 20%. • For calendar year 2020, 22%. • For calendar year 2021, 24%. • For calendar years 2022 and 2023, 29%. • For calendar years 2024 through 2026, inclusive, 34%. • For calendar years 2027 through 2029, inclusive, 42%. • For calendar year 2030 and for each calendar year thereafter, 50%. **Is calculated based on number of renewable energy credits; reference Nevada Revised Statute ("NRS") 704.7821: Establishment of portfolio standard; requirements; treatment of certain solar energy systems; portfolio energy credits; renewable energy contracts and energy efficiency contracts; exemptions; regulations.	No
Nevada SB123	To reduce emissions from coal-fired generators, requires reduction of at least 800 MW generation capacity from coal-fired generation plants, addition of at least 350 MW of generating capacity from renewable energy facilities, and construction of at least 550 MW of generating capacity from other types of generating plants by 2020.	No
Nevada SB146 (2017)	Requires NV Energy to submit a Distributed Resource Plan (DRP) and evaluate all projects for Non-Wires Alternatives	No
Nevada SB254 (2019)	Sets statewide greenhouse gas reduction goals in line with the 2015 Paris Agreement	No
Nevada SB299 (2019)	Creates an electric school bus pilot program	No
Nevada SB374	Requires net metering be available to each customer-generator who submits a request to the company.	No

Enacted Public Policy	Description	Driving Local Transmission Projects in Models
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	No
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	No
Texas Substantive Rule 25.181 (Energy Efficiency Rule)	Require utilities to meet certain energy efficiency targets	No

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 19, 2020 WestConnect Stakeholder meeting, as well as at the open PMC meeting held the day prior. A map of local TO planned projects that are driven by Public Policy Requirements was also presented. 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 purposes of collecting suggestions of possible regional public policy-driven transmission needs. The stakeholder comment window was open from November 19, 2020 through December 3, 2020 and invited comments on WestConnect's reliability and economic needs assessment results in addition to suggestions of possible regional public policy-driven transmission needs. No stakeholder comments were received by WestConnect.

6.2 Case Development for Evaluating Progress Towards Public Policy Requirements

During the model development process, there was interest in seeing whether the WestConnect economic models indicated a renewable energy penetration trajectory consistent with enacted public policies. To address this interest WestConnect conducted a high-level accounting and comparison of each PCM Area's energy sales and renewable energy via the process 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 RE for the SRP PCM Area also included

specific hydro and a combined solar & battery generation that was counted as RE based on SRP's plan to meet its enacted public policy, but hydro was otherwise not counted as RE. The Reserve Capacity Distribution settings in the 2030 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 2030 Base Case PCM and compared with these same values from the 2028 Base Case PCM and the 2026 Base Case PCM from the previous two 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 10** shows the results of the renewable energy check, which the Planning Subcommittee determined show a reasonable trend towards WestConnect members meeting enacted public policies. **Table 19** 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 19, 2020.

Figure 10. Sum of Energy Sales, Renewable Generation, and Overall RE as % of Energy Sales Based on Single-Year Results from the 2030 Base Case PCM and the Base Case PCM's from previous planning cycles

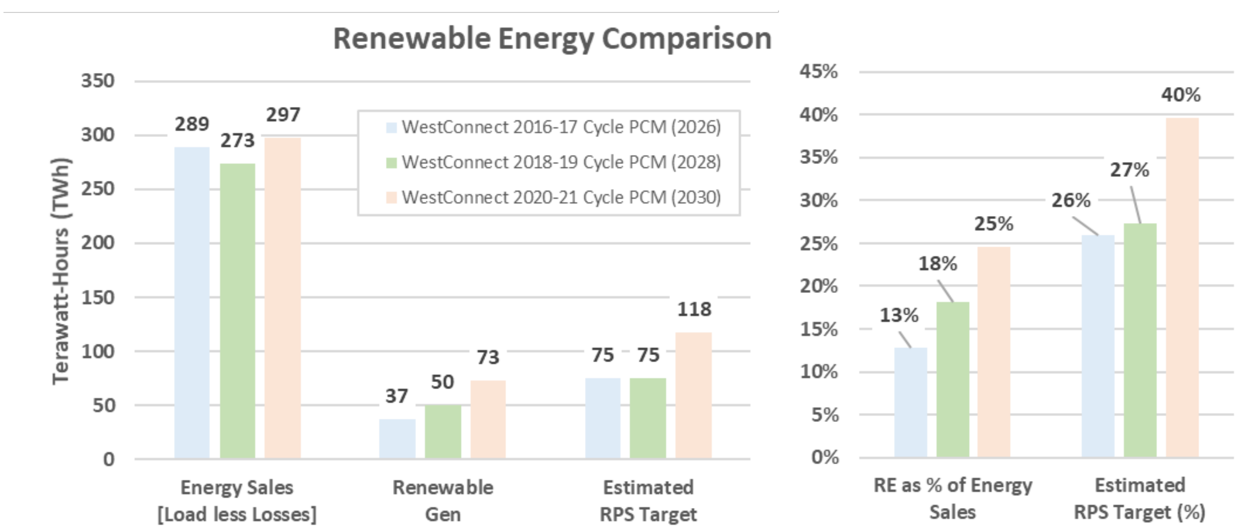

Table 19. BAA Losses and Served Load Including Losses used to calculate the WestConnect Energy Sales in the Renewable Energy Check

BAA	Losses (MWh)	Served Load Includes Losses (MWh)
AZPS	1,236,080	44,432,928
BANC	658,492	20,239,556
EPE	308,374	11,463,913
IID	158,792	4,416,263
LDWP	908,888	37,910,278
NEVP+SPPC	1,141,331	37,163,031
PNM	406,059	14,832,892
PSCO	1,455,003	51,117,735
SRP	1,259,463	41,359,275
TEPC	530,484	18,799,324
WACM	519,517	28,699,977
WALC	325,626	9,981,756
Total	**8,908,109**	**320,416,929**

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 19, 2020 stakeholder meeting, which included the results of the regional reliability and economic needs assessments, 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 2020-21 regional Planning Process. The WestConnect PMC approved the 2020-21 WestConnect Regional Transmission Needs Assessment Report on December 16, 2020 which did not identify any regional transmission needs driven by Public Policy Requirements

7 Regional Transmission Plan

Based on the findings from the 2020-21 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 2020-21 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 2020-21 Regional Transmission Plan is identical to the 2020-21 Base Transmission Plan and it does not include any additional regional projects.

The full list of 2020-21 Regional Transmission Plan projects is provided 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.[16] 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 2020-21 planning cycle. Further, open stakeholder meetings to discuss the WestConnect regional Planning Process were conducted on February 12, 2020, November 19, 2020, February 18, 2021, and November 18, 2021. The meetings were announced through WestConnect's website and stakeholder distribution lists, and all stakeholders were invited to attend.

In response to stakeholder feedback during the 2018-19 planning cycle, the PMC developed a new Stakeholder Tracking Document and an accompanying Stakeholder Comments webpage through which the PMC collects, tracks, and resolves stakeholder comments and concerns going forward.

8.2 Interregional Coordination

WestConnect coordinates its planning data and information with the three other established Planning Regions in the Western Interconnection (California Independent System Operator, ColumbiaGrid, and Northern Tier Transmission Group) by:

- Participating in annual interregional coordination meetings;
- 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

[16] *At times, the PS and PMC convenes 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."*

- 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. [17]

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.

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, 2020, so that WestConnect could coordinate the ITP evaluation process with all other Relevant Planning Regions.

WestConnect received the following ITP submittals for the 2020-21 Planning Process:

- Cross-Tie Transmission Line
- Northwest Tie Upgrade
- SWIP North Project
- TransWest Express – WY-IPP DC Project
- TransWest Express – IPP-Crystal AC Project
- TransWest Express – Crystal-Eldorado AC 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 2020-21 Planning Process, the submitted ITPs were not studied in this planning cycle.

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

9 Scenario Studies

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 2, 2019 through January 3, 2020. Several proposed scenarios were received and subsequently reviewed by the PS during public meetings on January 14, 2020 and on February 11, 2020. During the meetings, the PS discussed the proposed scenarios, member feedback, and the number of scenarios that would be appropriate to study. These conversations led to the inclusion of two scenarios in the final Study Plan: a Committed Uses ("CU") scenario involving an economic assessment and a New Mexico Export Stress ("NME") scenario involving a reliability assessment. The purpose of the CU scenario was to examine the impacts of modeling contractual rights to transmission capacity and potentially allow for improved modeling in the WestConnect economic assessments. The intent of the NME scenario was to evaluate the reliability of the WestConnect regional system during conditions during New Mexico overgeneration conditions.

The PS finalized the study scopes and developed the models required to complete the two scenario assessments. **Table 20** summarizes each scenario and the core questions that the studies were designed to investigate.

Table 20: Scenario Case Descriptions & Core Questions

Scenario	Description of Case	Core Questions to Investigate
Committed Uses	Using Open Access Same-Time Information System ("OASIS") and Energy Imbalance Market ("EIM") Energy Transfer System Resources ("ETSRs") data[18], assumptions were developed to represent firm transmission capacity reservations, firm available transfer capability ("FATC"), total transfer capability ("TTC"), and additional inter-BA transfer flexibility provided by the EIM. These assumptions were used to enhance the wheeling path modeling of the 2030 Base Case PCM.	• Can OASIS data be leveraged to effectively develop the initial CU assumptions? • Did adding CU assumptions to the wheeling path model produce more reasonable results than the Base PCM? • Which set of CU assumptions produced more reasonable results, "with EIM" or "without EIM"?

[18] *The OASIS data included data from the Open Access Technology International (OATI) OASIS website (http://www.oasis.oati.com/) and the California ISO OASIS website (http://oasis.caiso.com/).*

Scenario	Description of Case	Core Questions to Investigate
New Mexico Export	Using the WestConnect-approved 2030 Base Case PCM, a power flow snapshot was developed based on the system conditions in Hour 12 on April 2nd (1200 Mountain Standard Time). This hour was selected by the PS during their meeting on December 15, 2020, as a system condition representative of high New Mexico export to the rest of the Western Interconnection. The New Mexico export amounted to 2,046 MW during that hour.[19]	During high New Mexico export conditions, how reliable is the WestConnect regional transmission system?

9.1 Case Development

The information in this section summarizes each scenario model and provides details about the major assumptions incorporated into the cases.

9.1.1 Committed Uses Scenario

The CU scenario was designed to address the 2030 Base Case PCM's limited representation of contractual rights to – i.e., "committed uses" of – transmission capacity. The focus of the scenario was to improve the real-world accuracy of the WestConnect production cost model by preventing its market optimization methods from encroaching on existing inter-area firm commitments of the transmission system. Due to the complexities of enhancing the modeling of intra-BA transmission rights (e.g., contract paths within a given transmission provider or BA footprint) the Planning Subcommittee agreed to focus the scenario modeling on inter-BA transmission representation and resulting power flows/BA-to-BA interchange.

Several types of committed uses were considered and handled in the CU scenario study. The modeling approach for each is summarized below.

- **Represent all remotely contracted or owned resources** – These committed uses were retained from the 2030 Base Case PCM to represent certain generators (or generator shares) having procured firm transmission rights to deliver their output to the receiving BA; however, the modeling was updated so as not to double-count this capacity with the "Firm Transmission Rights" assumption described in the next bullet. In the 2030 Base Case PCM, these committed uses were modeled as generator exemptions to transmission hurdle rates, which applied a

[19] The New Mexico export was originally calculated from PNM Exports less those going to EPE and was 2,054 MW in Hour 12 on April 2nd; however, the New Mexico export calculation was later refined to include the collective flow exiting New Mexico from the PNM and EPE areas, resulting in the 2,046 MW of New Mexico export in Hour 12 on April 2nd.

$0/MWh hurdle rate to the flow they induced on inter-BA flows. In the CU cases, the generator exemptions were removed from the generator shares remotely committed to BAs in WestConnect and their capacity was reconciled into the PTP transmission rights assumption.

- **Represent inter-area firm point-to-point (“PTP”) transmission rights as sunk cost** – FATC and TTC data was collected for all inter-BA transmission contract paths on OASIS and was aggregated to match the BA-to-BA wheeling paths in the PCM. For each wheeling path, the FATC value was subtracted from the TTC value to arrive at the assumed MWs of previously reserved transmission. A $0/MWh hurdle rate was applied to this amount of flow during the PCM’s commitment and dispatch optimizations to reflect the fact that costs associated with this firm transmission are a sunk cost and there is no incremental cost to the rights holder to use the capacity to schedule power between areas. Flow on the inter-area wheeling path above the MWs of reserved transmission capacity up to the TTC value was modeled with the non-firm tariff rate (the hurdle rate in the 2030 Base Case PCM). This modeling approach ensures that area-to-area transfers that occur beyond the firm transmission capacity are not charged an incremental transmission rate.
- **Limit BA exports to sum of inter-area contract path TTCs** – In the CU scenario the BA-to-BA wheeling paths were modeled with an upper limit equal to the sum of inter-area contract path TTCs, in contrast to the 2030 Base Case PCM in which flows between areas can occur up to the sum of the simultaneous physical limit of the individual lines between areas. To allow the solution to converge in extreme instances in which a given area must have higher inter-area flows to maintain reliability, this upper limit was implemented as a soft constraint where flows above the sum of the inter-area TTCs were available but at a high hurdle rate of $750/MWh – an arbitrarily high value used so that such instances were easily identifiable for further investigation, as needed, during the validation of results. Implementing this constraint was based on several assumptions the Planning Subcommittee determined to be reasonable: (1) actual system operations schedules cannot exceed the TTC of a given contract path, (2) the model’s simulated physical flows are roughly commensurate with schedules that would occur in system operations, (3) “loop flows” or unscheduled flows are typically minimal, and (4) and operating limit violations rarely happen. By limiting inter-area flows to contract path TTCs, the model should not over-state the ability of one area to export to another.
- **Focus resource commitment on serving local BA load** – The wheeling path modeling was updated to severely limit the inter-area flows to 25% of the inter-area TTC *during the commitment optimization*. This change was made in the CU scenario to reflect the assumption that each BA in WestConnect generally makes its unit commitment decisions with the goal of reliably and economically serving its own load, based on its internal cost and operational objectives. This update is in contrast to the 2030 Base Case PCM’s representation of a single optimized grid with unit commitment decisions based on system-wide cost minimization. This severe limitation on inter-area flows was specific to the unit commitment optimization. If the previously discussed transmission commitments summed to a value that was higher than 25% of the inter-area TTC assumption, then that higher value was used for setting the MWs of interchange available to influence a given areas unit commitment. Similar to the limitation of BA exports to sum of inter-area contract path TTCs (above bullet), this limitation was implemented as a soft constraint with a high hurdle rate of $750/MWh imposed on any flow above this amount to ensure the solution would converge in extreme instances in which a higher inter-area

flow was necessary in the commitment optimization to maintain reliability – again an arbitrarily high value used so that such instances were easily identifiable for further investigation, as needed, during the validation of the results. By economically incenting the model to develop a unit commitment schedule that is focused on serving local BA load, this overall unit commitment is less optimal and more consistent with actual system operations.

- **Representation of EIM-dedicated transmission capacity** – This assumption leveraged publicly available data on ETSRs, which represent the MWs of transmission capacity between EIM entities available in the market optimization. The ETSR data was collected for all existing EIM participating areas (2019 ETSR data[20]), the 75th percentile of fifteen-minute market (FMM) and real-time market (RTM) ETSR capacity was calculated, and the minimum of the FMM and RTM values was used as a conservative EIM capacity assumption. This amount was given a $0/MWh hurdle rate in the model's dispatch optimization, which is roughly consistent with how the EIM actually functions. It was noted that a valuable enhancement would be to allow for logic that dynamically updates the tariff thresholds in the commitment and dispatch since it would allow greater flexibility when representing dependencies between the Day-Ahead and Real-Time markets. The Planning Subcommittee acknowledged that this EIM capacity representation does not represent all of the nuances of participation in the EIM and decided to evaluate two PCM cases, one with and one without the EIM capacity assumptions.

  Future EIM participating areas were identified based on their announced intention to join the EIM between now and the 2030 study year.[21] As there was no ETSR data applicable to the wheeling paths between these areas, the EIM capacity for the wheeling paths between the existing EIM participating areas, which averaged to 26% of those wheeling paths' TTC and 11% of the sum of the thermal ratings of branches making up those wheeling paths, was leveraged to estimate the EIM capacity assumption for wheeling paths between future EIM participating area. More specifically, the wheeling path's TTC was multiplied by 26%, the sum of the thermal ratings of branches making up the wheeling path was multiplied by 11%, and the lesser of these two values was used as the final EIM capacity for the inter-EIM wheeling path.

The WestConnect members reviewed the FATC, TTC, Firm Transmission Rights, and EIM assumptions (collectively termed the "CU assumptions") developed from the OASIS and EIM ETSR data, with and without reconciliations between the Firm Transmission Rights and remotely contracted or owned resource capacity, to ensure the assumptions were reasonable. **Table 21** shows the final CU assumptions and **Figure 11** provides an illustration of how one direction of an example wheeling path was modeled to represent the CU assumptions.

[20] The 2019 ETSR data included nine BAs: AZPS, BCHA, CISO, IPCO, NEVP, PACE, PACW, PGE, and PSEI. The Trading Hub PCM regions (TH_PV, TH_Mead, and TH_Malin) were also included if they were logical intermediaries between these BAs.

[21] Future EIM participating areas included 11 BAs: BANC, BPAT, LDWP, NEVP, PNM, PSCO, SRP, TEPC, TIDC, WACM, and WAUW. The Trading Hub PCM regions (TH_PV, TH_Mead, and TH_Malin) were also included if they were logical intermediaries between these BAs.

Table 21: Committed Uses Assumed by PCM Wheeling Path

PCM Wheeling Path[22]	Committed Uses (MW) and Their Corresponding Direction					
	Firm Transmission Rights		TTC		EIM Capacity[23]	
	Forward	Backward	Forward	Backward	Forward	Backward
W07_NW_BPAT+__CA_BANC+	0	0	0	0	0	0
W09_NW_BPAT+__CA_LDWP	490	200	1,240	589	155	154
W13_NW_BPAT+__SW_NVE	125	19	300	200	30	30
W17_NW_NWMT+__RM_WACM	90	0	90	45	0	0
W24_BS_IPCO__SW_NVE	352	130	743	682	743	682
W26_BS_PACE__CA_LDWP	0	265	1,023	1,194	120	120
W27_BS_PACE__RM_WACM	877	345	2,592	2,352	679	616
W28_BS_PACE__SW_AZPS	550	311	696	1,054	696	1,054
W29_BS_PACE__SW_NVE	164	130	739	710	654	645
W30_BS_PACE__SW_WALC	0	5	0	5	0	0
W31_RM_PSCO__SW_PNM	52	200	110	200	29	33
W32_RM_WACM__RM_PSCO	531	255	1,931	1,486	506	389
W33_RM_WACM__SW_PNM	184	200	329	469	86	123
W34_RM_WACM__SW_WALC	1,236	569	1,494	1,494	0	0
W35_SW_AZPS__CA_CISO	51	345	3,071	2,209	3,071	2,209
W36_SW_AZPS__CA_IID	0	0	75	75	0	0
W37_SW_AZPS__CA_LDWP	0	25	1,492	1,500	191	191
W38_SW_AZPS__SW_PNM	686	1,494	1,146	2,368	260	260
W39_SW_AZPS__SW_SRP	722	3,126	2,356	5,495	731	907
W40_SW_AZPS__SW_TEPC	997	230	1,216	772	304	202
W41_SW_AZPS__SW_WALC	1,217	992	4,290	2,337	0	0
W42_SW_NVE__CA_CISO	50	54	4,377	3,921	4,377	3,921
W43_SW_NVE__CA_LDWP	590	443	1,903	1,720	477	451
W44_SW_NVE__SW_WALC	0	0	0	0	0	0
W45_SW_PNM__SW_EPE	472	184	1,834	869	0	0
W46_SW_PNM__SW_WALC	159	170	269	269	0	0
W47_SW_SRP__CA_CISO	0	0	0	0	0	0
W48_SW_SRP__SW_TEPC	1,976	692	2,409	1,837	417	417
W49_SW_SRP__SW_WALC	722	439	832	1,057	0	0
W50_SW_TEPC__SW_EPE	668	530	888	1,228	0	0
W51_SW_TEPC__SW_PNM	774	825	1,770	1,770	209	209
W52_SW_WALC__CA_CISO	60	0	120	0	0	0

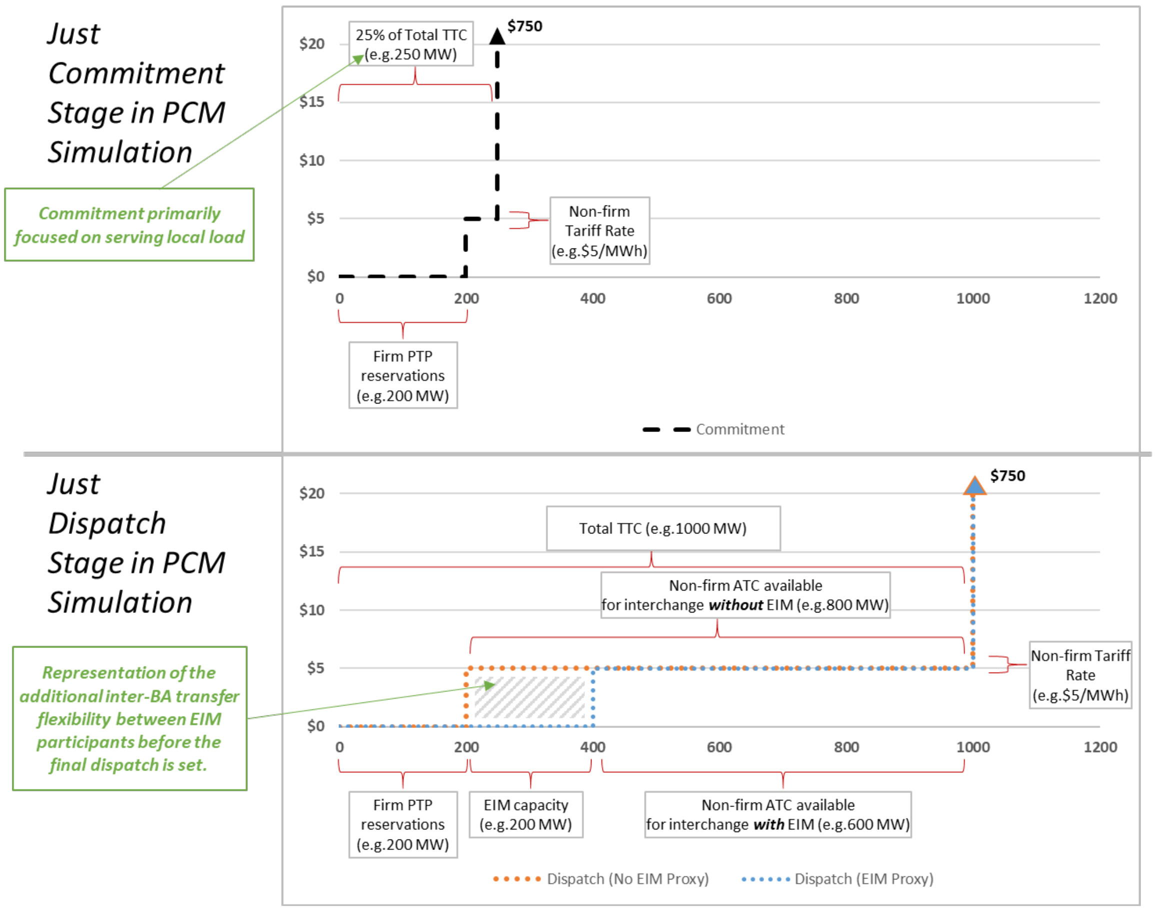
[22] *The names include the PCM regions involved and the PCM regions are analogous to BAs (e.g., SW_AZPS is the AZPS BA): <Wheeling Path ID>_<From PCM Region(s)>__<To PCM Region(s)>. There are two aggregations of multiple PCM regions designated with a "+": (1) NW_BPAT+ includes NW_BPAT, NW_CHPD, NW_DOPD, NW_GCPD, NW_SCL, or NW_TPWR; (2) CA_BANC+ includes CA_BANC and CA_TIDC.*

[23] *The EIM capacity assumption was only implemented in the dispatch step of "with EIM" CU PCM.*

PCM Wheeling Path[22]	Committed Uses (MW) and Their Corresponding Direction					
	Firm Transmission Rights		TTC		EIM Capacity[23]	
	Forward	Backward	Forward	Backward	Forward	Backward
W53_SW_WALC__CA_IID	0	87	275	275	0	0
W54_SW_WALC__CA_LDWP	350	284	382	435	0	0
W55_SW_WALC__SW_TEPC	305	370	1,221	1,133	0	0
W56_CA_CISO__CA_BANC+	95	525	329	329	86	86
W58_CA_IID__CA_CISO	962	22	962	600	0	0
W59_CA_LDWP__CA_CISO	737	94	7,061	5,162	1,850	1,353
W61_RM_WACM__SW_AZPS	600	553	1,677	999	195	195
Wa1_SW_TH_PV__CA_CISO	N/A[24]	104	N/A	N/A	N/A	0
Wa2_SW_TH_PV__SW_AZPS	N/A	568	N/A	N/A	N/A	1,071
Wa3_SW_TH_PV__SW_SRP	N/A	0	N/A	N/A	N/A	656
Wb1_SW_TH_Mead__SW_WALC	N/A	0	N/A	N/A	N/A	0
Wb2_SW_TH_Mead__SW_NVE	N/A	162	N/A	N/A	N/A	907
Wb3_SW_TH_Mead__SW_AZPS	N/A	0	N/A	N/A	N/A	0
Wb4_SW_TH_Mead__SW_SRP	N/A	505	N/A	N/A	N/A	731
Wb5_SW_TH_Mead__CA_CISO	N/A	0	N/A	N/A	N/A	268
Wb6_SW_TH_Mead__CA_LDWP	N/A	0	N/A	N/A	N/A	377
Wc1_NW_TH_Malin__NW_BPA+	N/A	415	N/A	N/A	N/A	0
Wc2_NW_TH_Malin__NW_PACW	N/A	0	N/A	N/A	N/A	79
Wc3_NW_TH_Malin__CA_BANC+	N/A	1,064	N/A	N/A	N/A	234
Wc4_NW_TH_Malin__CA_CISO	N/A	2,588	N/A	N/A	N/A	160

[24] *For wheeling paths involving the Trading Hub PCM regions (TH_PV, TH_Mead, and TH_Malin), the CU assumptions were only applied for Firm Transmission Rights and EIM Capacity into the Trading Hub.*

Figure 11: Hurdle rate ($/MWh) vs transfer capability (MW) for one direction of an example wheeling path in the CU PCM cases assuming 1,000 MW of TTC, 800 MW of FATC, 200 MW of Firm Transmission Rights or Firm PTP reservations, and 200 MW of EIM Capacity



9.1.2 New Mexico Export Stress Scenario

The NME scenario was developed to test the reliability of the WestConnect regional system under a condition with high power flows from New Mexico to the rest of Western Interconnection. Historically, net flow is almost always into New Mexico. This is especially true on the major interfaces between New Mexico and the rest of the system, including WECC Transfer Path 48 (North New Mexico, NM2) and WECC Transfer Path 47 (Southern New Mexico, NM1), which flow in the north/northwest-to-south/southeast direction. As New Mexico adds more solar and wind onto its system (particularly resources contracted to remote areas such as California), certain conditions cause the combined areas of PNM and EPE to have more generation than load to serve, particularly in light-load conditions in the spring and fall. This creates the opportunity for economic (transactional) exports out of New Mexico, as well as physical exports of power (i.e., actual power flow, which are different than energy transactions).

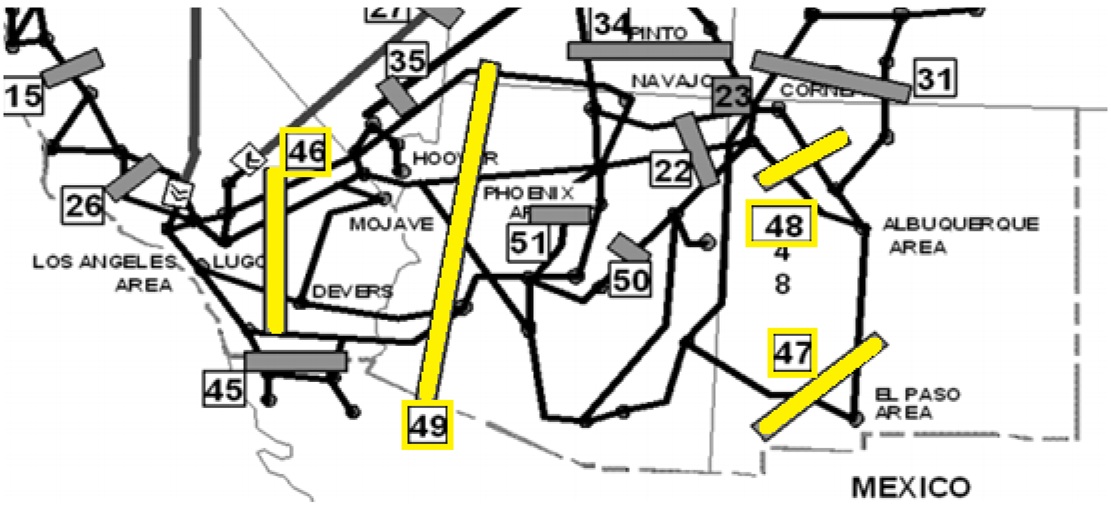
The NME scenario was based on conditions observed in the WestConnect 2030 Base Case PCM. The modeling results were filtered for hours in which there were power flows from New Mexico to the rest of the Western Interconnection. In total, the export condition was observed in 40% of the hours in the study 2030 year, but the PS focused on a review of hours which had both (1) high New Mexico exports – near or above 2,000 MW – and (2) significant east-to-west flow in western Arizona on WECC Transfer Path 46 (West of Colorado River). **Table 22** identifies the condition selected by the PS for study: Hour

12 of April 2nd. During this condition, flow out of New Mexico are 2,046 MW and flow on Path 46 is 6,482 MW.

Table 22: NM Export and WECC Transfer Path Flow on April 2nd Hour 12

Time (MST)		Flow (MW)				
Date	**Hour**	**NM Export**	**Path 48 – North New Mexico (NM2)**	**Path 47 – Southern New Mexico (NM1)**	**Path 46 – West of Colorado River (WOR)**	**Path 49 – East of Colorado River (EOR)**
4/2/2030	12	2,046	2,606 Southeast →Northwest	346 Southeast →Northwest	6,482 East→West	20 West→East

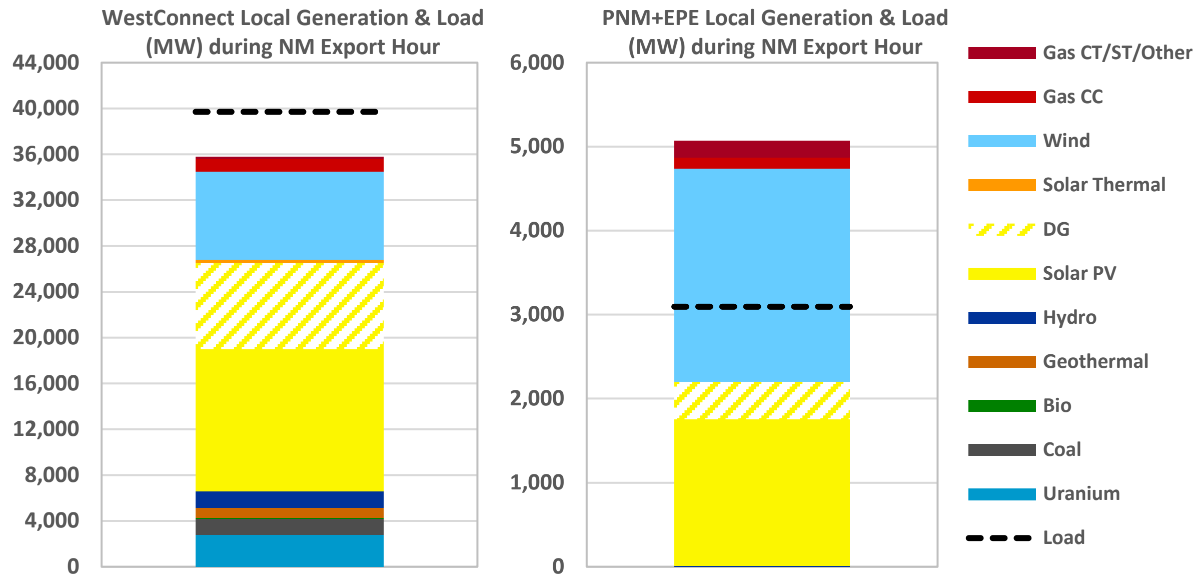
Figure 12: Subset of Map of WECC Transfer Paths, with Those in Table 22 highlighted[25]



The simulated WestConnect and the PNM+EPE load levels and generation dispatch are summarized in **Figure 13**. The gap between the load and the top of the generation stack represents imports into the given region. When the stack is above the load level, this represents exports. In this selected hour, there was 72 MW of curtailed wind in New Mexico in the WestConnect 2030 Base Case PCM.

[25] https://www.wecc.org/Reliability/2007_WI_TransPath_UtilizationStudy.pdf

Figure 13: WestConnect & PNM+EPE Local Generation & Load[26] During Selected NM Export on April 2nd Hour 12



The transmission topology did not change from the Base Case assessments and reflects the 2020-21 Base Transmission Plan additions. The seed case was the approved WestConnect 2030 Light Spring Base Case. The load, imports, and generator dispatch assumptions for cases, both representing distinct light spring system conditions, are provided in **Table 23**.

Table 23: NME Scenario Assumptions for WestConnect Region, compared with those of the 2030 Light Spring Base Case

Metric	2030 Light Spring Base Case	2030 New Mexico Export Scenario	Delta
Load[27] in WestConnect PF Areas[28] (MW)	37,496[29]	25,869[30]	Decreased 31%
New Mexico Import/Export (MW)	Import: 643	Export: 1,793	Switched from net import to net export (379% change)

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[26] This "Load" includes transmission losses as well as any generator models pumping, charging, or otherwise pulling power from the system.

[27] Load value includes reductions from distributed generation (DG).

[28] WestConnect PF Areas included 13 areas in the model: AEPCO, APS, EL PASO, IID, LADWP, NEVADA, NEW MEXICO, PSCOLORADO, SIERRA, SRP, TEP, WAPA L.C., and WAPA R.M.

[29] WestConnect portion of WECC coincident load during representative light load conditions during 1000 to 1400 MDT in spring months of March, April, and May with solar and wind serving a significant but realistic portion of the Western Interconnection total load. Case includes renewable resource capacity consistent with any applicable and enacted public policies.

[30] Note that this load forecast is based on the 1-in-2 load forecasts contained in the production cost model.

Metric	2030 Light Spring Base Case	2030 New Mexico Export Scenario	Delta
Generation Dispatch in WestConnect PF Areas (MW)	Total[31]: 40,880 Thermal: 27,140 Hydro: 3,479 Wind: 3,193 Solar: 6,712 BESS/PSH[32]: 509 Other[33]: -145	Total: 25,722 Thermal: 8,137 Hydro: 1,268 Wind: 6,936 Solar: 12,519 BESS/PSH: -3,053 Other: -87	Total reduced 37% Thermal reduced 70% Hydro reduced 64% Wind increased 117% Solar increased 87% BESS/PSH switched to charging/pumping (700% change) Other got less negative (42% change)
Load in New Mexico and El Paso PF Areas (MW)	3,080	2,414	Decreased 22%
Generation Dispatch in New Mexico and El Paso PF Areas (MW)	Total: 2,583 Thermal: 668 Hydro: 0 Wind: 694 Solar: 1,200 BESS/PSH: 81 Other: -60	Total: 4,587 Thermal: 461 Hydro: 15 Wind: 2,400 Solar: 1,786 BESS/PSH: -16 Other: -60	Total increased 78% Thermal reduced 31% Hydro increased 100% Wind increased 246% Solar increased 49% BESS/PSH switched to charging/pumping (120% change) Other didn't change
Transmission	2020-21 Base Transmission Plan		No change

The dynamic data needed to support the transient stability simulations was sourced from the WestConnect 2030 Light Spring Base Case. No update to the composite load modeling was necessary since the NME snapshot was in the same timeframe: shoulder month at 1100 Pacific Standard Time. However, extensive updates to the WestConnect 2030 Light Spring Base Case's dynamic data were necessary to achieve a flat no disturbance transient simulation. The list below summarizes the types of updates.

- Corrected MVA base discrepancy between steady-state and dynamic data
- Dynamic data netted/deactivated to resolve initialized limit violation
- Dynamic data netted/deactivated to resolve instability

31 *Total is positive generation less negative generation.*

32 *Battery Energy Storage System (BESS) or pumped-storage hydroelectric (PSH) a.k.a. reversible hydro.*

33 *Other generation includes generators representing DC intertie flow along the eastern side of the WestConnect footprint and motor loads.*

- Dynamic data revised to account for different generator operating mode (pumping/charging or generating/discharging)
- Dynamic data set to defaults to resolve instability
- Turned off generators whose dispatch was too low for compatibilities with their dynamic data

9.2 Study Method

9.2.1 Committed Uses Scenario

The PS performed result comparisons between the CU scenario cases and 2030 Base Case PCM in order to determine whether one or both CU scenario cases produced more reasonable results. The results compared included generator commitment hours, inter-BA interchange flow, local BA generation and load, generator production cost, wind and solar curtailment, branch/path congestion cost, and branch/path number of congested hours.

9.2.2 New Mexico Export Stress Scenario

The PS performed the same Study Method as in the Reliability Assessment described in Section 4.2.

9.3 Results and Findings

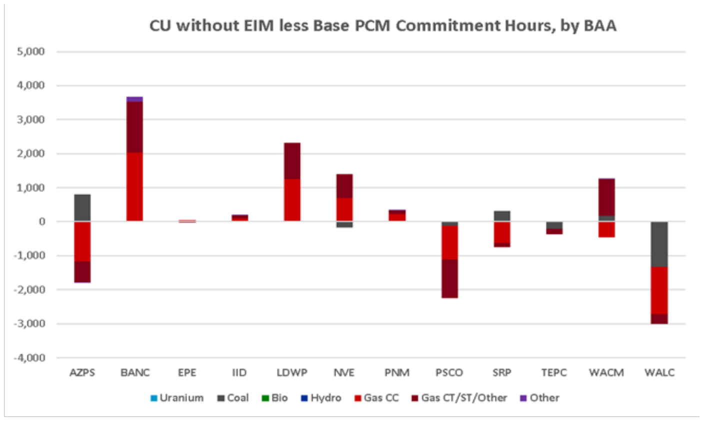
The information in this section summarizes the results and findings of the scenario studies. The detailed results of the Committed Uses Scenario and New Mexico Export Stress Scenario are provided in Appendix A and Appendix B (respectively) of the Scenario Assessment Report.

9.3.1 Committed Uses Scenario

The Planning Subcommittee noted several observations when comparing the results of the CU scenario cases with the 2030 Base Case PCM:

1. BA commitment of internal resource capacity was closer to their load level in the CU scenario cases, which suggests the CU assumptions applied during the commitment optimization are an effective way of limiting the PCM's tendency to optimally commit resources for purposes other than serving local BA load. This led to more resource commitment in the CU scenario cases, as shown in **Figure 14**.

Figure 14: Impact of CU assumption on generator commitment hours.

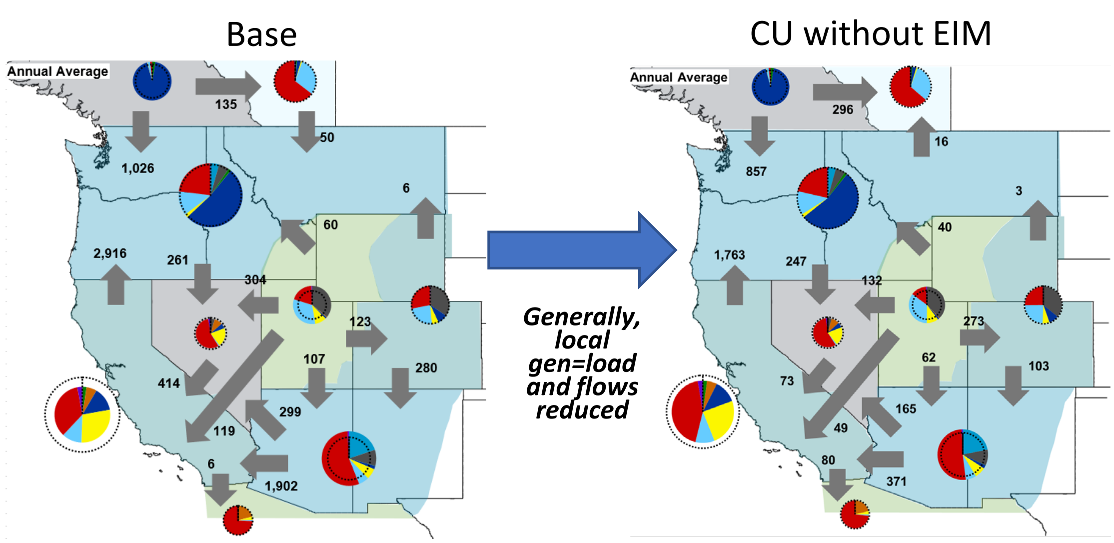


1,501 (0.6%) more commitment hours in WestConnect

2. BA generation dispatch more closely mirrored local/BA load level in the CU scenario cases, which was reasonable given that the CU assumptions in the commitment optimization already closely matched BA load and thereby generally reducing, relative to the Base Case, reliance on imports or exports in the dispatch optimization. However, the lower inter-BA limits in the CU scenario cases (the TTC) still provided the opportunity for inter-BA power flows to balance large excesses or deficits in economic resources when necessary. **Figure 15** provides a high-level visual of how the local generator and load got more similar in the CU scenario cases.

3. Inter-BA power flows generally reduced system-wide relative to the 2030 Base Case PCM even though the CU assumptions were only applied in and bordering the WestConnect footprint. **Figure 15** provides a high-level visual of how the system-wide power flows got smaller in the CU scenario cases.

Figure 15: Impact of CU assumption on local BA generation and load and inter-BA interchange flow. The multi-colored circles are the generation mix and the black circles are load.



4. The inter-BA power flows between EIM participants were higher in the “with EIM” CU case than in the “without EIM” CU case, which is expected given that the “with EIM” CU assumptions provide less limitations on the inter-BA power flows between EIM participants. **Figure 16** shows the average and aggregate reduction in interchange flows from the 2030 Base Case PCM to the CU scenario cases.

Figure 16: Impact of CU assumption on inter-BA interchange flow.

CU “with EIM” less Base

Difference in Magnitude of Flow	Inter-Area Flow In/Around WestConnect (MW)	Inter-Area Flow Outside WestConnect (MW)
Avg	(103)	(176)
Sum	(4,952)	(4,046)

CU “without EIM” less Base

Difference in Magnitude of Flow	Inter-Area Flow In/Around WestConnect (MW)	Inter-Area Flow Outside WestConnect (MW)
Avg	(105)	(179)
Sum	(5,025)	(4,122)

Note the slightly higher flows in the CU with EIM scenario, which is reasonable since that market tends to increase area-to-area transactions

The study’s process of leveraging OASIS data, combined with subsequent review by WestConnect members and stakeholders, including the California Independent System Operator, was an effective way to develop the initial CU assumptions to forecast inter-BA contractual transmission rights in and bordering the WestConnect footprint in the 2030 future.

The Planning Subcommittee concluded that both CU PCM simulations (“with EIM” and “without EIM”) produced improved results compared to the WestConnect 2030 Base Case PCM and the results of the “without EIM” CU PCM were most reasonable.

9.3.2 New Mexico Export Stress Scenario

This scenario’s results included 5 branch overloads and 6 voltage deviation issues on multi-owner transmission located in Arizona and New Mexico. After dynamic data updates were made to ensure a flat no disturbance transient simulation, there were no transient stability issues when simulating ten member-selected contingencies across the WestConnect footprint.

The case development was successful in that a New Mexico export condition was identified in the WestConnect 2030 Economic Base Case, and this condition was reasonably replicated in a reliability model in terms of load, generation dispatch, and system flows.

The scenario as modeled overstates the number of solar resources located near the Albuquerque area which results in overloaded lines between the Albuquerque area and the Four Corners area under contingency conditions. Since establishing the model, a portion of the generic renewable resources included in the model near Albuquerque have been defined and located in the Four Corners area which is on the other side of the constraints identified in the scenario case. The analysis also does not consider that a significant portion of the solar resources would not be available for export because of co-located battery storage as well as other local battery storage that has yet to be defined. It is expected that low load high solar hours as modeled in the scenario case will be key hours for battery charging. Both of these reduce the available resources leading to overloads identified in the scenario case. PNM believes the case does model flows approaching the transfer capability limits for resources located in central and eastern New Mexico. It is not, however, clear whether this represents a likely dispatch of such resources. To the degree the case's assumed solar resources in New Mexico do not develop, they still represent a reasonable renewable dispatch given they can be considered a proxy for additional wind resources with no co-located battery storage.

The WestConnect 2030 Light Spring Base Case's dynamic data required many updates outside of the WestConnect footprint to achieve a flat no disturbance transient simulation, which indicates there are issues in the dynamic data of the WECC 2030 Light Spring 1-S Base Case (30LSP1S) and – by extension – these issues may still exist in the WECC master dynamics file (MDF) and, if so, will adversely impact WestConnect's next planning cycle. To help resolve these and similar issues in future WECC Base Cases, WestConnect has developed the below recommendations for WECC's consideration and will provide WECC, upon request by WECC, with the details of the dynamic data updates implemented outside of WestConnect during this assessment so WECC can coordinate with the associated data submitters to resolve similar issues in future WECC Base Cases. Acting on these recommendations will not only benefit WestConnect's future assessments, but will undoubtedly benefit WECC's own Round Trip.

1. The issues flagged in the "Steady-State and Dynamics Dashboard" and "Annual Base Case Compilation and Data Check Log" reports provided with each WECC Base Case should be resolved prior to finalizing the case.

2. For generators capable of negative dispatch (e.g., batteries, pumped-storage hydro, motor loads), the WECC MDF should include dynamic data that works with both positive and negative dispatch and associated comments indicating which set of models is appropriate for each mode of operation.

3. The MVA base of the models in the WECC MDF data should match the MVA base of the models in the WECC Base Cases.

4. As part of finalizing a WECC Base Case, the dynamic data should be tested and validated for all generators in the case that are not retired prior to the represented snapshot, including the generators that may be turned off in the particular snapshot (i.e., it could be dispatched in a sensitivity of the system condition).

5. The MDF should indicate any known operational limitations of the dynamic data being used. For instance, the WECC Wind Power Plant Dynamic Modeling Guide indicates that Phase I wind models only provide reasonable representation of the generator when its dispatch is within 25% to 100% of its rated power and this limitation should accompany the use of any these models in the MDF.

Appendix A – 2020-21 Regional Transmission Plan[34]

The tables below include the planned projects in the 2020-21 Regional Transmission Plan, organized by Subregional Planning Group (SPG).

SWAT Base Transmission Plan Projects for 2020-21 Regional Planning Cycle

Sponsor	Project Name	Development Status as of February 2020	Voltage	In 2018-19 Regional Transmission Plan?	In-Service Date
Arizona Electric Power Cooperative	Fort Huachuca - Kartchner Interconnection	Planned	Below 115 kV	**No**	2021
Arizona Electric Power Cooperative	Marana Substation Capacitor Bank	Planned	115 kV	**No**	2021
Arizona Electric Power Cooperative	Schieffelin Project	Planned	230 kV	**No**	2022
Arizona Public Service	Broadway 230kV Lines	Planned	230 kV	**No**	2024
Arizona Public Service	Contrail 230kV Lines	Planned	230 kV	**No**	2023
Arizona Public Service	North Gila - Orchard 230kV Line	Planned	230 kV	**Yes**	2021
Arizona Public Service	Stratus 230kV Lines	Planned	230 kV	**No**	2022
Arizona Public Service	Three Rivers 230kV Lines	Planned	230 kV	**No**	2023
Arizona Public Service	TS17 230kV Lines	Planned	230 kV	**No**	2025
Arizona Public Service	TS2 230kV Lines	Planned	230 kV	**No**	2023
El Paso Electric Company	Add 345 kV ring bus to VADO substation. Split Newman 345 kV to Afton_N 345 kV line tapping in-and-out to VADO 345 kV bus.	Planned	345 kV	**Yes**	2028
El Paso Electric Company	Afton North - Airport Transmission Line	Planned	115 kV	**Yes**	2025
El Paso Electric Company	Afton North Autotransformer	Planned	345 kV	**Yes**	2024
El Paso Electric Company	East side loop expansion Phase 2	Planned	115 kV	**Yes**	2023
El Paso Electric Company	East side loop expansion Phase I	Planned	115 kV	**Yes**	2024

[34] *The project information provided in Appendix A is dated March 18, 2020, the approval date of the WestConnect 2020-21 Regional Study Plan.*

Sponsor	Project Name	Development Status as of February 2020	Voltage	In 2018-19 Regional Transmission Plan?	In-Service Date
El Paso Electric Company	Eastside Loop Expansion Phase I	Planned	115 kV	**Yes**	2024
El Paso Electric Company	Felipe 69 kV Substation Capacitor Bank	Planned	Below 115 kV	**No**	2022
El Paso Electric Company	IND_COMP Substation Capacitor Banks. Previously Picante.	Planned	115 kV	**No**	2022
El Paso Electric Company	Leasburg Substation 33.6 MVA Transformer	Planned	115 kV	**Yes**	2021
El Paso Electric Company	Liberty Substation Capacitor Banks	Planned	115 kV	**No**	2022
El Paso Electric Company	MOONGATE - Jornada Transmission Line	Planned	115 kV	**Yes**	2021
El Paso Electric Company	MOONGATE Substation	Planned	115 kV	**Yes**	2021
El Paso Electric Company	Move Sparks 115/69 kV autotransformer to Felipe substation	Planned	115 kV	**Yes**	2021
El Paso Electric Company	New Afton_N to VADO 115 kV transmission line.	Planned	115 kV	**Yes**	2024
El Paso Electric Company	New Anthony to VADO 115 kV transmission line ckt 2	Planned	115 kV	**Yes**	2026
El Paso Electric Company	New transmission line from VADO 115 kV to Salopek 115 kV ckt 2	Planned	115 kV	**Yes**	2026
El Paso Electric Company	New VADO 115 kV switching station.	Planned	115 kV	**Yes**	2024
El Paso Electric Company	NW2 (Verde) Substation 50 MVA Transformer	Planned	115 kV	**Yes**	2024
El Paso Electric Company	Otero 345 kV Substation	Planned	345 kV	**No**	2022
El Paso Electric Company	Patriot Substation Transformer (T2)	Planned	115 kV	**Yes**	2021
El Paso Electric Company	Pipeline Substation 50 MVA Transformer	Planned	115 kV	**Yes**	2021
El Paso Electric Company	Rio Bosque Substation Transformer (T2)	Planned	Below 115 kV	**No**	2021
El Paso Electric Company	Rio Grande - Sunset (5500) 69 kV Line	Planned	Below 115 kV	**No**	2021
El Paso Electric Company	Rio Grande-Sunset (5600) 69 kV line Reconductor	Planned	Below 115 kV	**No**	2021

Sponsor	Project Name	Development Status as of February 2020	Voltage	In 2018-19 Regional Transmission Plan?	In-Service Date
El Paso Electric Company	Sparks to Felipe 69 kV to 115 kV line upgrade	Planned	115 kV	**Yes**	2021
El Paso Electric Company	Uvas Substation 24 MVA Transformer	Planned	115 kV	**Yes**	2028
El Paso Electric Company	Wrangler - Sparks Transmission Line Reconductor	Planned	115 kV	**No**	2021
Imperial Irrigation District	92kV "R" Line Network Upgrades	Planned	Below 115 kV	**No**	2022
Imperial Irrigation District	El Centro – Imperial Valley 230kV Network Upgrades	Planned	230 kV	**No**	2022
Los Angeles Department of Water and Power	Add voltage support at Toluca Station	Planned	230 kV	**No**	2020
Los Angeles Department of Water and Power	Add voltage support in the LA Basin	Planned	138 kV	**Yes**	2022
Los Angeles Department of Water and Power	Apex-Crystal Transmission Line	Planned	500 kV AC	**Yes**	2023
Los Angeles Department of Water and Power	Barren Ridge Voltage Support	Planned	230 kV	**No**	2021
Los Angeles Department of Water and Power	Castaic-Haskell Canyon 230 kV Line 3	Planned	230 kV	**Yes**	2020
Los Angeles Department of Water and Power	Convert PP1&PP2-Olive 115kV Lines to 230kV Lines	Planned	230 kV	**Yes**	2022
Los Angeles Department of Water and Power	Lugo-Victorville Upgrades	Planned	500 kV AC	**Yes**	2021
Los Angeles Department of Water and Power	McCullough-Victorville series cap upgrade	Planned	500 kV AC	**No**	2024
Los Angeles Department of Water and Power	New Haskell Canyon-Sylmar 230 kV Line 2	Planned	230 kV	**Yes**	2022
Los Angeles Department of Water and Power	New Receiving Station X	Planned	230 kV	**No**	2023

Sponsor	Project Name	Development Status as of February 2020	Voltage	In 2018-19 Regional Transmission Plan?	In-Service Date
Los Angeles Department of Water and Power	New Rosamond Station	Planned	230 kV	**Yes**	2023
Los Angeles Department of Water and Power	Reconductor Barren Ridge - Haskell Canyon 230 kV Line 1	Planned	230 kV	**No**	2022
Los Angeles Department of Water and Power	Re-conductor Rinaldi-Tarzana 230kV Line 1 & 2	Planned	230 kV	**Yes**	2022
Los Angeles Department of Water and Power	Re-conductor Valley-Rinaldi 230 kV Lines 1&2	Planned	230 kV	**Yes**	2020
Los Angeles Department of Water and Power	Re-conductor Valley-Toluca 230 kV Lines 1&2	Planned	230 kV	**Yes**	2022
Los Angeles Department of Water and Power	Scattergood-Olympic Cable B	Planned	230 kV	**Yes**	2023
Los Angeles Department of Water and Power	Sylmar Filter Replacement	Planned	230 kV	**No**	2020
Los Angeles Department of Water and Power	Tarzana-Olympic 1A & 1B 138 kV conversion to 230 kV	Planned	230 kV	**No**	2024
Los Angeles Department of Water and Power	Upgrade CVT and Wave Traps at Victorville Station	Planned	TBD	**No**	2020
Los Angeles Department of Water and Power	Upgrade Rinaldi 230 kV CBs	Planned	230 kV	**Yes**	2022
Los Angeles Department of Water and Power	Upgrade Toluca 500/230 kV Bank H	Planned	500 kV AC	**Yes**	2021
Los Angeles Department of Water and Power	Upgrade Transformer Bank E and F	Planned	230 kV	**Yes**	2021
Los Angeles Department of Water and Power	Victorville 500/287 kV auto-transformer installation	Planned	500 kV AC	**Yes**	2020
NV Energy	Arden - Mead 230kV line upgrade	Planned	230 kV	**No**	2020
NV Energy	Burnham - Fold 138 kV fold into Pebble	Planned	138 kV	**Yes**	2021

Sponsor	Project Name	Development Status as of February 2020	Voltage	In 2018-19 Regional Transmission Plan?	In-Service Date
NV Energy	Magnolia second 230/138kV Transformer bank	Planned	230 kV	**No**	2020
NV Energy	Pecos #5 230/138kV Transformer	Planned	230 kV	**No**	2022
NV Energy	Reid Gardner - Tortoise #2	Planned	230 kV	**No**	2022
NV Energy	SE2-West Henderson substation	Planned	138 kV	**No**	2021
NV Energy	Sunrise 138/69kV Transformer	Planned	138 kV	**No**	2023
NV Energy	Westside 230kV Switch replacement	Planned	230 kV	**No**	2020
Public Service Company of New Mexico	Alamogordo Voltage Support Phase II	Planned	115 kV	**Yes**	2023
Public Service Company of New Mexico	New San Juan Gas Turbine Project	Planned	345 kV	**No**	2025
Public Service Company of New Mexico	Rio Puerco Switching Station update for Proxy RPS	Planned	345 kV	**No**	2027
Salt River Project	Coolidge - Hayden Reroute 115kV	Planned	115 kV	**Yes**	2022
Salt River Project	Palo Verde – Hassayampa 18-ohm series reactor addition on each of the three lines	Planned	500 kV AC	**No**	2022
Salt River Project	Southeast Power Link	Planned	230 kV	**Yes**	2024
Salt River Project	Superior - Silver King 115kV Reroute	Planned	115 kV	**Yes**	2027
Tri-State Generation and Transmission Association	Clapham SVS	Planned	115 kV	**No**	2022
Tri-State Generation and Transmission Association	Frontier Reactor Addition	Planned	115 kV	**No**	2022
Tri-State Generation and Transmission Association	Hernandez 115/69kV T2 Transformer Replacement	Planned	115 kV	**Yes**	2021
Tri-State Generation and Transmission Association	PEGS Interconnection	Planned	230 kV	**No**	2023
Tri-State Generation and Transmission Association	Rowe 115/24.9kV Transformer Replacement	Planned	115 kV	**Yes**	2020

Sponsor	Project Name	Development Status as of February 2020	Voltage	In 2018-19 Regional Transmission Plan?	In-Service Date
Tri-State Generation and Transmission Association	San Ysidro - Torreon Line Conversion	Planned	Below 115 kV	**No**	2022
Tri-State Generation and Transmission Association	Torreon 115 kV/69 kV Transformer	Planned	115 kV	**No**	2022
Tucson Electric Power	Catron 345/34.5 kV Substation	Planned	345 kV	**No**	2021
Tucson Electric Power	Catron Loop-in to Springerville-Greenlee 345 kV line	Planned	345 kV	**No**	2023
Tucson Electric Power	Cisne 138/13.8 kV Substation	Planned	138 kV	**Yes**	2021
Tucson Electric Power	Corona 138/13.8 kV Substation	Planned	138 kV	**Yes**	2027
Tucson Electric Power	Craycroft Barril 138/13.8 kV Substation	Planned	138 kV	**Yes**	2025
Tucson Electric Power	Del Cerro capacitor Banks	Planned	138 kV	**No**	2020
Tucson Electric Power	DMP 138 kV, Conversion to breaker-and-a-half substation	Planned	138 kV	**No**	2021
Tucson Electric Power	Gateway 138-kV Transmission Line	Planned	138 kV	**Yes**	2023
Tucson Electric Power	Gateway 138-kV Transmission Line (phase 2)	Planned	138 kV	**Yes**	2023
Tucson Electric Power	Gateway 230/138 kV Substation	Planned	230 kV	**Yes**	2023
Tucson Electric Power	Gateway Capacitor Additions	Planned	138 kV	**No**	2023
Tucson Electric Power	Gateway to US/Mexico Border 230-kV Transmission Line	Planned	230 kV	**Yes**	2023
Tucson Electric Power	Greenlee Capacitor Additions	Planned	345 kV	**No**	2021
Tucson Electric Power	Greenlee Loop-in to Springerville-Vail 345 kV line	Planned	345 kV	**No**	2023
Tucson Electric Power	Harrison 138/13.8 kV Substation	Planned	138 kV	**Yes**	2021
Tucson Electric Power	Hartt 138/13.8 kV Substation	Planned	138 kV	**Yes**	2022
Tucson Electric Power	Hedrick 138/13.8 kV Substation	Planned	138 kV	**No**	2024
Tucson Electric Power	Hermosa 138kV Switchyard	Planned	138 kV	**No**	2023
Tucson Electric Power	Hermosa Capacitor Bank Addition	Planned	138 kV	**No**	2023

Sponsor	Project Name	Development Status as of February 2020	Voltage	In 2018-19 Regional Transmission Plan?	In-Service Date
Tucson Electric Power	Irvington - East Loop 138 kV Transmission Line	Planned	138 kV	**No**	2023
Tucson Electric Power	Kantor Capacitor Bank Addition	Planned	138 kV	**Yes**	2023
Tucson Electric Power	Kino Capacitor Addition	Planned	138 kV	**No**	2020
Tucson Electric Power	La Canada to Orange Grove 138-kV Line Re-Conductor	Planned	138 kV	**Yes**	2020
Tucson Electric Power	La-Canada Line Switch	Planned	138 kV	**Yes**	2020
Tucson Electric Power	Lago Del Oro 138/13.8 kV Substation	Planned	138 kV	**No**	2027
Tucson Electric Power	Line 125 Re-conductor & Conversion to Double Circuit	Planned	138 kV	**Yes**	2029
Tucson Electric Power	Loop-in of Hassayampa to Pinal West 500-kV Line with existing Jojoba Substation	Planned	500 kV AC	**Yes**	2021
Tucson Electric Power	Loop-in of Irvington to Robert Bills 138-kV line with new Sonoran substation	Planned	138 kV	**Yes**	2021
Tucson Electric Power	Loop-in of Irvington to South 138-kV Line to Sonoran Substation	Planned	138 kV	**Yes**	2021
Tucson Electric Power	Loop-in of Irvington to Vail 138-kV Line to Sonoran Substation	Planned	138 kV	**Yes**	2021
Tucson Electric Power	Loop-in of North Loop to Rancho Vistoso 138-kV Line to Naranja Substation	Planned	138 kV	**Yes**	2026
Tucson Electric Power	Marana 138/13.8 kV Substation	Planned	138 kV	**Yes**	2023
Tucson Electric Power	Marana 138-kV Transmission Line	Planned	138 kV	**Yes**	2023
Tucson Electric Power	Naranja 138/13.8 kV Substation	Planned	138 kV	**Yes**	2026
Tucson Electric Power	Naranja Capacitor Bank Addition	Planned	138 kV	**Yes**	2029
Tucson Electric Power	Olson 138/13.8 kV Substation	Planned	138 kV	**No**	2026
Tucson Electric Power	Orange Grove to Rilito 138-kV Line Re-Conductor	Planned	138 kV	**Yes**	2020
Tucson Electric Power	Patriot 138/13.8 kV Substation	Planned	138 kV	**No**	2023

Sponsor	Project Name	Development Status as of February 2020	Voltage	In 2018-19 Regional Transmission Plan?	In-Service Date
Tucson Electric Power	Point of Interconnection 138kV Switchyard (Rosemont)	Planned	138 kV	**Yes**	2021
Tucson Electric Power	Rancho Vistoso - Lago Del Oro 138kV Line	Planned	138 kV	**No**	2027
Tucson Electric Power	Rancho Vistoso to La Canada 138-kV Line Re-Conductor	Planned	138 kV	**Yes**	2020
Tucson Electric Power	Re-Conductor Canez to Soniota 138-kV Transmission Line	Planned	138 kV	**No**	2023
Tucson Electric Power	Re-Conductor Kantor to Canez 138-kV Transmission Line	Planned	138 kV	**No**	2023
Tucson Electric Power	Re-Conductor Nogales to Kantor 138-kV Transmission Line	Planned	138 kV	**Yes**	2023
Tucson Electric Power	Sears Wilmot 138/13.8 kV Substation	Planned	138 kV	**No**	2025
Tucson Electric Power	Sonoran 138/46/13.8 kV Substation	Planned	138 kV	**Yes**	2021
Tucson Electric Power	Sonoran to Cisne 138-kV Line	Planned	138 kV	**Yes**	2021
Tucson Electric Power	Sonoran to Vail 138-kV Line Re-Conductor (was Irvington to Vail)	Planned	138 kV	**Yes**	2021
Tucson Electric Power	South Loop 345 kV, Conversion to breaker-and-a-half substation	Planned	345 kV	**Yes**	2023
Tucson Electric Power	Springerville-Catron 345 kV Circuits 1 and 2 Uprate	Planned	345 kV	**No**	2023
Tucson Electric Power	Toro - Rosemont 138kV Line	Planned	138 kV	**Yes**	2021
Tucson Electric Power	Tortolita Capacitor Bank Addition (#2)	Planned	138 kV	**Yes**	2021
Tucson Electric Power	Tortolita Capacitor Bank Addition (#3)	Planned	138 kV	**Yes**	2027
Tucson Electric Power	Tucson to El Camino del Cerro 138-kV Line Re-Conductor	Planned	138 kV	**Yes**	2020
Tucson Electric Power	UofA North 138/13.8 kV Substation (was UA Med)	Planned	138 kV	**No**	2023

Sponsor	Project Name	Development Status as of February 2020	Voltage	In 2018-19 Regional Transmission Plan?	In-Service Date
Tucson Electric Power	Winchester to Vail 345kV line uprate	Planned	345 kV	**No**	2023
Western Area Power Administration - DSW	Bouse – Kofa	Planned	161 kV	**No**	2023
Western Area Power Administration - DSW	Coolidge - Valley Farms	Planned	115 kV	**Yes**	2020
Western Area Power Administration - DSW	Dome Tap-Gila	Planned	161 kV	**Yes**	2020
Western Area Power Administration - DSW	Gila 161 kV substation rebuild	Planned	161 kV	**Yes**	2020
Western Area Power Administration - DSW	Kofa – Dome Tap	Planned	161 kV	**Yes**	2021

CCPG Base Transmission Plan Projects for 2020-21 Regional Planning Cycle

Sponsor	Project Name	Development Status as of February 2020	Voltage	In 2018-19 Regional Transmission Plan?	In-Service Date
Black Hills Energy	Boone - South Fowler 115 kV line.	Planned	115 kV	**No**	2021
Black Hills Energy	Desert Cove-Fountain Valley-MidwayBR 115kV line rebuild	Planned	115 kV	**No**	2020
Black Hills Energy	Hogback 115/69 kV Substation	Planned	115 kV	**No**	2021
Black Hills Energy	North Penrose 115/13.2 kV Distribution Substation	Planned	115 kV	**No**	2021
Black Hills Energy	Nyberg - Airport Memorial 115 kV rebuild.	Planned	115 kV	**No**	2022
Black Hills Energy	Salt Creek 115/13.2 kV Distribution Substation	Planned	115 kV	**No**	2021
Black Hills Energy	West Station - Green Horn 115 kV rebuild.	Planned	115 kV	**No**	2022
Black Hills Energy	West Station - Hogback 115kV	Planned	115 kV	**Yes**	2022
Black Hills Power	Lange - Lookout 230 kV rebuild.	Planned	230 kV	**No**	2021
Black Hills Power	Lange - South Rapid City 230 kV.	Planned	230 kV	**No**	2020
Black Hills Power	Lookout - Wyodak 230 kV rebuild.	Planned	230 kV	**No**	2022
Black Hills Power	Rapid City DC Tie RAS Redesign.	Planned	230 kV	**No**	2020
Black Hills Power	Second 230/69kV Yellow Creek Transformer	Planned	230 kV	**Yes**	2021
Cheyenne Light Fuel and Power	East Business Park - Skyline 115 kV Rebuild.	Planned	115 kV	**No**	2021
Cheyenne Light Fuel and Power	Loop King Ranch - South Cheyenne into West Cheyenne.	Planned	115 kV	**No**	2020
Cheyenne Light Fuel and Power	Loop North Range - Corlett into West Cheyenne.	Planned	115 kV	**No**	2020
Cheyenne Light Fuel and Power	Swan Ranch 115 kV Substation	Planned	115 kV	**Yes**	2021
Platte River Power Authority	Rawhide Unit 1 GSU Replacement	Planned	230 kV	**No**	2021
Platte River Power Authority	Timberline 230/115kV Transformer T3 Replacement	Planned	230 kV	**Yes**	2022

Sponsor	Project Name	Development Status as of February 2020	Voltage	In 2018-19 Regional Transmission Plan?	In-Service Date
Public Service Company of Colorado/ Xcel Energy	Ault-Cloverly 115 kV Transmission Project	Planned	115 kV	**Yes**	2022
Public Service Company of Colorado/ Xcel Energy	Avery Substation	Planned	230 kV	**Yes**	2021
Public Service Company of Colorado/ Xcel Energy	CSU Flow Mitigation 115 kV	Planned	115 kV	**Yes**	2022
Public Service Company of Colorado/ Xcel Energy	Gilman-Avon 115 kV Transmission Line and Cap Bank	Planned	115 kV	**Yes**	2022
Public Service Company of Colorado/ Xcel Energy	Greenwood - Denver Terminal 230kV transmission line	Planned	230 kV	**No**	2022
Public Service Company of Colorado/ Xcel Energy	Mirasol Switching Station 230kV (Formerly Badger Hills)	Planned	230 kV	**Yes**	2022
Public Service Company of Colorado/ Xcel Energy	NREL Substation	Planned	115 kV	**No**	2020
Public Service Company of Colorado/ Xcel Energy	Shortgrass - Cheyenne Ridge 345 kV transmission line	Planned	345 kV	**No**	2020
Tri-State Generation and Transmission Association	Burlington - Burlington (KCEA) 115kV Line Rebuild	Planned	115 kV	**Yes**	2022
Tri-State Generation and Transmission Association	Cahone Interconnection	Planned	115 kV	**No**	2022
Tri-State Generation and Transmission Association	Carey T2	Planned	230 kV	**No**	2021
Tri-State Generation and Transmission Association	Coyote Gulch-Hesperus Interconnection	Planned	115 kV	**No**	2022
Tri-State Generation and Transmission Association	Craig-Meeker 345kV Generator Interconnection	Planned	345 kV	**No**	2022
Tri-State Generation and Transmission Association	Del Camino - Slater Line Uprate	Planned	115 kV	**No**	2021

Sponsor	Project Name	Development Status as of February 2020	Voltage	In 2018-19 Regional Transmission Plan?	In-Service Date
Tri-State Generation and Transmission Association	Erie 230 kV Tie Project	Planned	230 kV	**No**	2023
Tri-State Generation and Transmission Association	Falcon-Midway 115 kV Line Uprate Project	Planned	115 kV	**Yes**	2022
Tri-State Generation and Transmission Association	Fuller 230/115kV Transformer #2	Planned	230 kV	**Yes**	2023
Tri-State Generation and Transmission Association	J.G. Kalcevic	Planned	115 kV	**No**	2020
Tri-State Generation and Transmission Association	La Junta (TS) 2nd 115/69kV, 42 MVA XFMR	Planned	115 kV	**Yes**	2022
Tri-State Generation and Transmission Association	Rolling Hills Substation	Planned	115 kV	**Yes**	2025
Tri-State Generation and Transmission Association	San Luis Valley-Poncha 230 kV Line #2	Planned	230 kV	**Yes**	2025
Tri-State Generation and Transmission Association	Shaw Ranch Substation	Planned	115 kV	**Yes**	2025
Tri-State Generation and Transmission Association	Sisson Project	Planned	115 kV	**No**	2020
Tri-State Generation and Transmission Association	Spanish Peaks II Interconnection	Planned	230 kV	**No**	2022
Tri-State Generation and Transmission Association	Story-North Yuma 230kV Generator Interconnection	Planned	230 kV	**No**	2021
Tri-State Generation and Transmission Association	Wayne Child Phase II - (Formerly Arrow Transmission Project)	Planned	345 kV	**Yes**	2022
Western Area Power Administration - RMR	Big Horn Transmission Improvement	Planned	115 kV	**Yes**	2022
Western Area Power Administration - RMR	Blue Mesa	Planned	115 kV	**Yes**	2025

Sponsor	Project Name	Development Status as of February 2020	Voltage	In 2018-19 Regional Transmission Plan?	In-Service Date
Western Area Power Administration - RMR	Estes-Flatiron 115-kV rebuild	Planned	115 kV	**Yes**	2022
Western Area Power Administration - RMR	Midway KV1A Replacement	Planned	230 kV	**Yes**	2021
Western Area Power Administration - RMR	Pole Creek Tap	Planned	230 kV	**Yes**	2027
Western Area Power Administration - RMR	Sand Creek Tap	Planned	115 kV	**Yes**	2024
Western Area Power Administration - RMR	Stegall Bus Sectionalization	Planned	230 kV	**Yes**	2024

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Sponsor	Project Name	Development Status as of February 2020	Voltage	In 2018-19 Regional Transmission Plan?	In-Service Date
NV Energy	Bannok capacitor	Planned	115 kV	**No**	2020
NV Energy	Bell Creek Capacitor	Planned	115 kV	**No**	2020
NV Energy	California – Bordertown 120kV Line	Planned	115 kV	**Yes**	2025
NV Energy	California Substation upgrade	Planned	115 kV	**Yes**	2022
NV Energy	Coeur Mine Load 35MW	Planned	115 kV	**No**	2022
NV Energy	Dixie Meadows I	Planned	230 kV	**Yes**	2021
NV Energy	Mira Loma Transformer #1 and #2 Rating Increase	Planned	345 kV	**Yes**	2020
NV Energy	Replace Wave Traps on Valmy - Coyote - Humboldt 345kV	Planned	345 kV	**No**	2020
NV Energy	Replace Wave Traps on Valmy-Coyote-Humboldt 345 kV Line	Planned	345 kV	**Yes**	2020
NV Energy	Silver Lake 120 kV Capacitor Bank	Planned	115 kV	**Yes**	2021
NV Energy	West Tracy - Patrick Line	Planned	115 kV	**No**	2020
NV Energy	West Tracy 345/120kV 280 MVA Transformer	Planned	345 kV	**No**	2020
NV Energy	Wild Horse 120kV	Planned	115 kV	**Yes**	2021
Sacramento Municipal Utility District	Hurley - Procter 230 kV Line Re-conductor	Planned	230 kV	**Yes**	2021
Sacramento Municipal Utility District	Hurley 230 kV bus-tie breaker	Planned	230 kV	**Yes**	2023

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Appendix B – Results of Economic Assessment

Full results, including the local/single-system issues, are provided in the slides of the PMC meeting on December 16, 2020.

Table 24: Multi-TO Results of Regional Economic Needs Assessment

Element Information		Congestion Hours (% Hrs) / Cost ($) [& Penalty Cost Component of Congestion Cost (if any)]					Regional Need	Determination
		Base Case	Sensitivity Cases (Results filtered to only show changes to the congestion in the Base Case)					
Owner/ Operator(s)	**Branch/Path Name**	**2030 Base Case**	**High Gas Price Sensitivity**	**High Load Sensitivity**	**Low Hydro Sensitivity**	**System-wide Carbon Emission Cost Sensitivity**		
PSColorado|Tri-State G&T	STORY - PAWNEE 230kV Line #1 (73192_70311_1)	434 (5%) / 5,997K	379 (4%) / 6,116K	385 (4%) / 4,518K	395 (5%) / 4,751K	970 (11%) / 22,410K	**NO**	PSCo & TSGT: observed congestion on this line does not warrant establishing this as a regional need. The total congestion hours are low and historic flow for this line on BA Peak day has been well below line capacity. Further, there are concerns with the confidence level of having a singular data point. PSCo would encourage multiple futures and years to allow for averaging of results. Additionally, the line itself and the Pawnee terminal are fully owned by PSCo. The Story terminal equipment has mixed ownership, with PSCo having full ownership of some equipment. This makes the congestion on this facility more similar to a single TO facility in nature.
Gila River Power, LP|Sundevil Power Holdings, LLC|Salt River Project|Arizona Public Service	GILARIVR - PANDA 500/230kV Transformer #1 (159970_14238_1)	154 (2%) / 5,164K	177 (2%) / 6,837K	399 (5%) / 29,345K* *Penalty Cost: $4,036K (14%)	159 (2%) / 5,889K	146 (2%) / 8,630K	**NO**	APS & SRP: Minimal hours of congestion. Further, this specific transformer is unique in that APS has no ownership, however APS has 100% rights for the entire transformer capacity. Further, the congestion manifesting itself here is a result of market energy sales since APS has no ownership in Gila River generation.

Element Information		Congestion Hours (% Hrs) / Cost ($) [& Penalty Cost Component of Congestion Cost (if any)]					Regional Need	Determination
		Base Case	Sensitivity Cases (Results filtered to only show changes to the congestion in the Base Case)					
Owner/ Operator(s)	**Branch/Path Name**	**2030 Base Case**	**High Gas Price Sensitivity**	**High Load Sensitivity**	**Low Hydro Sensitivity**	**System-wide Carbon Emission Cost Sensitivity**		
Intermountain Power Agency|Sierra Pacific Power Co.	P29 Intermountain-Gonder 230 kV Interface	139 (2%) / 894K	185 (2%) / 1,027K	85 (0.97%) / 556K	208 (2%) / 1,257K	11 (0.13%) / 110K	**NO**	LADWP: The observed congestion is insignificant both by hours and by cost. NVE: defer to LADWP (Congestion is relatively small). PACE's generation is one of the contributors+ path 29 effectively shares transfer capacity with Path 32 (+Pavant-Gonder line).
Basin Electric Power Coop.|Tri-State G&T|PacifiCorp - East	DAVEJOHN - LAR.RIVR 230kV Line #1 (65420_73107_1)	24 (0.27%) / 795K	25 (0.29%) / 617K	30 (0.34%) / 3,255K* *Penalty Cost: $933K (29%)	20 (0.23%) / 629K	38 (0.43%) / 1,602K	**NO**	TSGT: Only 24 hours of congestion is very minor (<1% of the year) and can be considered noise
WAPA L.M.|DG&T|Tri-State G&T	P30 TOT 1A Interface	33 (0.38%) / 499K	42 (0.48%) / 821K	198 (2%) / 57,779K	10 (0.11%) / 54K	47 (0.54%) / 723K	**NO**	TSGT: Only 33 hours of congestion is very minor (<1% of the year) and can be considered noise
Tri-State G&T|WAPA L.M.|PSColorado|Basin Electric Power Coop.	P36 TOT 3 Interface	4 (0.05%) / 295K	4 (0.05%) / 402K	35 (0.40%) / 60,897K* *Penalty Cost: $25,965K (43%)	4 (0.05%) / 218K	4 (0.05%) / 559K	**NO**	TSGT: Only 4 hours of congestion is very minor (<1% of the year) and can be considered noise. PSCo: this level of congestion does not warrant a regional need. Cost and hours are insignificant and would not justify capital investment.

Element Information		Congestion Hours (% Hrs) / Cost ($) [& Penalty Cost Component of Congestion Cost (if any)]					Regional Need	Determination
		Base Case	Sensitivity Cases (Results filtered to only show changes to the congestion in the Base Case)					
Owner/ Operator(s)	**Branch/Path Name**	**2030 Base Case**	**High Gas Price Sensitivity**	**High Load Sensitivity**	**Low Hydro Sensitivity**	**System-wide Carbon Emission Cost Sensitivity**		
TSGT New Mexico|EPE El Paso Electric Company	UVAS - ALTLUNTP 115kV Line #1 (11193_12195_1)	14 (0.16%) / 108K	34 (0.39%) / 284K	266 (3%) / 6,106K	15 (0.17%) / 101K	23 (0.26%) / 379K	**NO**	TSGT & EPE: Only 14 hours of congestion is very minor (<1% of the year) and can be considered noise. Furthermore, the 115 kV UVAS substation interconnection proposed in EPE's future transmission plans will be constructed under the auspices of the EPE/Tri-State Interconnection Agreement. Therefore, any mitigations on the EPE and/or Tri-State systems required for this 115 kV interconnection will be evaluated and constructed under that Agreement.
Intermountain Power Agency|Sierra Pacific Power Co.	P32 Pavant-Gonder InterMtn-Gonder 230 kV Interface	12 (0.14%) / 79K	4 (0.05%) / 46K	14 (0.16%) / 140K		26 (0.30%) / 891K	**NO**	LADWP: The observed congestion is insignificant both by hours and by cost. NVE: Congestion is very small. Also, there's a potential for rating increase of P32 W-E (>235MW) if needed. Pavant-Gonder line is between Sierra & PacifiCorp (NG).
WAPA L.M.|PSColorado	MIDWAYPS - MIDWAYBR 230kV Line #1 (70286_73413_1)	1 (0.01%) / 2K		2 (0.02%) / 14K	1 (0.01%) / 11K	10 (0.11%) / 85K	**NO**	PSCo: this level of congestion does not warrant a regional need. Cost and hours are insignificant and would not justify capital investment.

Multi-Owner Total Congestion Cost:	**$13,833,021**	**$16,149,951**	**$162,610,075**	**$12,910,321**	**$35,389,165**

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