2020-2021 Transmission Planning Process Unified Planning Assumptions and Study Plan

June 19, 2020

Final

Revision 1

Foreword to Revision 1 of the Final 2020-2021 Transmission Planning Process Unified Planning Assumptions and Study Plan

On June 14, 2020 the final interregional transmission project evaluation plans were finalized and posted on the ISO's public website. The 2020-2021 Transmission Planning Process Unified Planning Assumptions and Study Plan was revised to include these evaluation plans as described in section 5 of this document and included in Appendix B.

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1 Introduction

As set forth in Section 24 of the California ISO tariff on the Transmission Planning Process and in the Transmission Planning Process (TPP) Business Practice Manual (BPM), the TPP is conducted in three phases. This document is being developed as part of the first phase of the TPP, which entails the development of the unified planning assumptions and the technical studies to be conducted as part of the current planning cycle. In accordance with revisions to the TPP that were approved by FERC in December 2010, this first phase also includes specification of the public policy objectives the CAISO will adopt as the basis for identifying policy-driven transmission elements in Phase 2 of the TPP that will be an input to the comprehensive planning studies and transmission plan developed during Phase 2. Phase 3 will take place after the approval of the plan by the CAISO Board if projects eligible for competitive solicitation were approved by the Board at the end of Phase 2. If you would like to learn more about the CAISO's TPP, please go to:

- Section 24 of the California ISO tariff located at: http://www.caiso.com/rules/Pages/Regulatory/Default.aspx
- Transmission Planning Process BPM at: http://www.caiso.com/rules/Pages/BusinessPracticeManuals/Default.aspx .

The objectives of the unified planning assumptions and study plan are to clearly articulate the goals and assumptions for the various public policy and technical studies to be performed as part of Phase 2 of the TPP cycle. These goals and assumptions will in turn form the basis for CAISO approval of specific transmission elements and projects identified in the 2020-2021 comprehensive transmission plan at the end of Phase 2. The CAISO intends to continue updating the High Voltage TAC model for inclusion in the final draft transmission plan, as it has in the past. An opportunity to review the previous year's model for comments will be provided during the year, and has not been scheduled at this time.

The CAISO has collaboratively worked with the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) to align the planning assumptions between the CAISO's TPP and the CPUC's Integrated Resource Plan (IRP) process, as well as the demand forecast assumptions embodied in the 2019 IEPR adopted by the CEC on February 20, 2020[1].

[1] https://ww2.energy.ca.gov/2019_energypolicy/documents/#demand

1.1 Overview of 2020-2021 Stakeholder Process Activities and Communications

Section 2 of this document presents general information regarding stakeholder activities and communications that will occur during this planning cycle.

1.1.1 Stakeholder Meetings and Market Notices

During each planning cycle, the CAISO will conduct at least four stakeholder meetings to present and acquire stakeholder input on the current planning effort. These stakeholder meetings are scheduled and designed around major activities in Phase 1 and Phase 2 of the TPP. Additional meetings for each stage may be scheduled as needed. These meetings provide an opportunity for the CAISO to have a dialogue with the stakeholders regarding planning activities and to establish the foundation upon which stakeholders may comment and provide other necessary input at each stage of the TPP.

The current schedule for all three phases of the 2020-2021 transmission planning cycle is provided in Table 1.1-1. Should this schedule change or other aspects of the 2020-2021 transmission planning cycle require revision, the CAISO will notify stakeholders through a CAISO market notice which will provide stakeholders information about revisions that have been made. As such, the CAISO encourages interested entities to register to receive transmission planning related market notices. To do so, go to the following to submit the Market Notice Subscription Form:

http://www.caiso.com/informed/Pages/Notifications/MarketNotices/MarketNoticesSubscriptionForm.aspx

Table 1.1-1: Schedule for the 2020-2021 planning cycle

Phase	No	Due Date	2020-2021 Activity
Phase 1	1	December 17, 2019	The CAISO sends a letter to neighboring balancing authorities, sub-regional, regional planning groups requesting planning data and related information to be considered in the development of the Study Plan.
	2	December 17, 2019	The CAISO issues a market notice announcing a thirty-day comment period requesting demand response assumptions and generation or other non-transmission alternatives to be considered in the Unified Planning Assumptions.
	3	January 17, 2020	PTO's, neighboring balancing authorities and regional/sub-regional planning groups provide CAISO the information requested No.1 above.
	4	January 17, 20120	Stakeholders provide CAISO the information requested No.2 above.
	5	February 21, 2020	The CAISO develops the draft Study Plan and posts it on its website
	6	February 28, 2020	The CAISO hosts public stakeholder meeting #1 to discuss the contents in the Study Plan with stakeholders
	7	February 28 - March 14, 2020	Comment period for stakeholders to submit comments on the public stakeholder meeting #1 material and for interested parties to submit Economic Planning Study Requests to the CAISO
	8	March 31, 2020	The CAISO specifies a provisional list of high priority economic planning studies, finalizes the Study Plan and posts it on the public website
Phase 2	9	August 14, 2020	The CAISO posts preliminary reliability study results and mitigation solutions
	10	August 14, 2020	Request Window opens
	11	August 26, 2020	The CAISO will post base scenario base cases for each planning area used in the reliability assessment
	12	September 15, 2020	PTO's submit reliability projects to the CAISO
	13	September 23-24, 2020	The CAISO hosts public stakeholder meeting #2 to discuss the reliability study results, PTO's reliability projects, and the Conceptual Statewide Plan with stakeholders
	14	September 23 – October 7, 2020	Comment period for stakeholders to submit comments on the public stakeholder meeting #2 material[2]

[2] The ISO will target responses to comments ideally within three weeks of the close of comment periods, and no later than the next public stakeholder event relating to the Transmission Plan.

Phase	No	Due Date	2020-2021 Activity
	15	October 15, 2020	Request Window closes
	16	October 30, 2020	The CAISO post final reliability study results
	17	November 13, 2020	The CAISO posts the preliminary assessment of the policy driven & economic planning study results and the projects recommended as being needed that are less than $50 million.
	18	November 17, 2020	The CAISO hosts public stakeholder meeting #3 to present the preliminary assessment of the policy driven & economic planning study results and brief stakeholders on the projects recommended as being needed that are less than $50 million.
	19	November 17 – December 1, 2020	Comment period for stakeholders to submit comments on the public stakeholder meeting #3 material
	20	December 16 – 17, 2020	The CAISO Board of Governors meeting provides opportunity for stakeholder comments directly to Board of Governors.
	21	January 31, 2021	The CAISO posts the draft Transmission Plan on the public website
	22	February 2021	The CAISO hosts public stakeholder meeting #4 to discuss the transmission project approval recommendations, identified transmission elements, and the content of the Transmission Plan
	23	Approximately two weeks following the public stakeholder meeting #4	Comment period for stakeholders to submit comments on the public stakeholder meeting #4 material
	24	March 2021	The CAISO finalizes the Transmission Plan and presents it to the CAISO Board of Governors for approval
	25	End of March, 2021	The CAISO posts the Final Board-approved Transmission Plan on its site
Phase 3	26[3]	April 1, 2021	If applicable, the CAISO will initiate the process to solicit proposals to finance, construct, and own elements identified in the Transmission Plan eligible for competitive solicitation

[3] The schedule for Phase 3 will be updated and available to stakeholders at a later date.

1.1.2 Responses to CAISO's data request

The CAISO received six responses to the Data Request Letter:

- Hetch Hetchy Water & Power provided topology change-files, updated dynamic model and updated capability curves.
- Horizon West provided study data for Suncrest SVC.
- Trans Bay Cable provided contingency list.
- Salt River Project responded with no additional comment on top of planning information provided in WECC cases.
- Bonneville Power Administration responded with no additional comment on top of planning information provided in WECC cases.
- Transmission Agency of Northern California provided information about planning data and also indicated that reliability planning data (important for the reliability planning assessments as required by the NERC TPL-001-4) is already available through WECC.

1.2 Stakeholder Comments

The CAISO will provide stakeholders with an opportunity to comment on all meetings and posted materials. Stakeholders are requested to submit comments in writing to regionaltransmission@caiso.com within two weeks after the stakeholder meetings. The CAISO will post these comments on the CAISO Website. The CAISO will target responses to comments ideally within three weeks of the close of comment periods, and no later than the next public stakeholder event relating to the Transmission Plan.

1.3 Availability of Information

The CAISO website is the central place for public and non-public information. For public information, the main page for documents related to 2020-2021 transmission planning cycle is the "Transmission Planning" section located at http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx on the CAISO website.

Confidential or otherwise restricted data, such as Critical Energy Infrastructure Information (CEII) is stored on the CAISO secure transmission planning webpage located on the market participant portal at https://portal.caiso.com/tp/Pages/default.aspx. In order to gain access to this secured website, each individual must have a Non-Disclosure Agreement (NDA) executed with the CAISO.

The procedures governing access to different classes of protected information is set forth in Section 9.2 of the Transmission Planning BPM (BPM). As indicated in that section, access to specified information depends on whether a requesting entity meets certain criteria set forth in the CAISO tariff. The NDA application and instructions are available on the CAISO website at http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx under the *Accessing transmission data* heading.

2 Reliability Assessments

The CAISO will analyze the need for transmission upgrades and additions in accordance with NERC Standards and WECC/CAISO reliability criteria. Reliability assessments are conducted annually to ensure that performance of the system under the CAISO controlled grid will meet or exceed the applicable reliability standards. The term "Reliability Assessments" encompasses several technical studies such as power flow, transient stability, and voltage stability studies. The basic assumptions that will be used in the reliability assessments are described in sections 3.1-3.15. Generally, these include the scenarios being studied, assumptions on the modeling of major components in power systems (such as demand, generation, transmission network topology, and imports), contingencies to be evaluated, reliability standards to be used to measure system performance, and software or analytical tools.

2.1 Reliability Standards and Criteria

The 2020-2021 transmission plan will span a 10-year planning horizon and will be conducted to ensure the CAISO-controlled grid is in compliance with the North American Electric Reliability Corporation (NERC) standards, WECC regional criteria, and CAISO planning standards across the 2021-2030 planning horizon.

2.1.1 NERC Reliability Standards

The CAISO will analyze the need for transmission upgrades and additions in accordance with NERC reliability standards, which set forth criteria for system performance requirements that must be met under a varied but specific set of operating conditions. The following NERC reliability standards are applicable to the CAISO as a registered NERC planning authority and are the primary driver of the need for reliability upgrades:[4]

TPL-001-5: Transmission System Planning Performance Requirements[5]; and

NUC-001-3 Nuclear Plant Interface Coordination.[7]

[4] http://www.nerc.com/page.php?cid=2%7C20

[5] Analysis of Extreme Events or NUC-001 are not included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.

2.1.2 WECC Regional Criteria

The WECC System Performance TPL-001-WECC-CRT-3.2[6] Regional Criteria are applicable to the CAISO as a Planning Coordinator and set forth planning criterion for near-term and long-term transmission planning within the Interconnection of the WECC.

2.1.3 California ISO Planning Standards

The California ISO Planning Standards specify the grid planning criteria to be used in the planning of CAISO transmission facilities.[7] These standards cover the following:

- Address specifics not covered in the NERC reliability standards and WECC regional criteria;
- Provide interpretations of the NERC reliability standards and WECC regional criteria specific to the CAISO-controlled grid; and,
- Identify whether specific criteria should be adopted that are more stringent than the NERC standards or WECC regional criteria.

2.2 Frequency of the study

The reliability assessments are performed annually as part of the CAISO's TPP.

2.2.1 Use of past studies

The annual Transmission Planning Process (TPP) Reliability Assessment is performed mainly in accordance with study requirements set forth in NERC TPL-001-5 Standard. Within the Standard, the Requirement R2.6 allows for use of past studies to support the planning assessment. Starting this cycle, the CAISO will evaluate areas known to have no major changes compared to assumptions made in prior planning cycles for potential use of past studies.

On a high level, the process will include three major steps. 1) Data collection, 2) evaluation of data for extent of change and 3) drawing conclusion based on the extent of change in data and considering other area specific factors.

[6] https://www.wecc.org/Reliability/TPL-001-WECC-CRT-3.2.pdf

[7] http://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf

2.3 Study Horizon and Years

The studies that comply with TPL-001-5 will be conducted for both the near-term[8] (2021-2025) and longer-term[9] (2026-2030) per the requirements of the reliability standards.

Within the identified near and longer term study horizons the CAISO will be conducting detailed analysis on years 2022, 2025 and 2030. If in the analysis it is determined that additional years are required to be assessed the CAISO will consider conducting studies on these years or utilize past studies[10] in the areas as appropriate.

2.4 Study Areas

The reliability assessments will be performed on the bulk system (north and south) as well as the local areas under the CAISO controlled grid. Figure 2.4-1 shows the approximate geographical locations of these study areas. The full-loop power flow base cases that model the entire Western Interconnection will be used in all cases. These 16 study areas are shown below.

- Northern California (bulk) system – 500 kV facilities and selected 230 kV facilities in the PG&E system
- PG&E Local Areas:
    - Humboldt area;
    - North Coast and North Bay areas;
    - North Valley area;
    - Central Valley area;
    - Greater Bay area;
    - Greater Fresno area;
    - Kern Area; and
    - Central Coast and Los Padres areas.
- Southern California (bulk) system – 500 kV facilities in the SCE and SDG&E areas and the 230 kV facilities that interconnect the two areas.
- SCE local areas:
    - Tehachapi and Big Creek Corridor;
    - North of Lugo area;
    - East of Lugo area;
    - Eastern area; and

[8] System peak load for either year one or year two, and for year five as well as system off-peak load for one of the five years.
9 System peak load conditions for one of the years and the rationale for why that year was selected.
10 Past studies may be used to support the Planning Assessment if they meet the following requirements:
1. For steady state, short circuit, or stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. 2. For steady state, short circuit, or stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

- o Metro area.
- San Diego Gas & Electric (SDG&E) main transmission
- San Diego Gas & Electric (SDG&E) sub-transmission
- Valley Electric Association (VEA) area[11]
- CAISO overall bulk system

Figure 2.4-1: Approximated geographical locations of the study areas

[11] GridLiance West Transco LLC (GWT) owns 230kV facilities in VEA's service territory. VEA operates and maintains GWT's 230kV facilities. In this report, VEA normally refers to VEA's service territory. When identifying specific projects or specific PTOs, VEA or GWT will be used depending upon who owns the facilities specified or the PTO referenced.

2.5 Transmission Assumptions

2.5.1 Transmission Projects

The transmission projects that the CAISO has approved will be modeled in the study. This includes existing transmission projects that have been in service and future transmission projects that have received CAISO approval in the 2019-2020 or earlier CAISO transmission plans. Currently, the CAISO anticipates the 2019-2020 transmission plan will be presented to the CAISO board of governors for approval in March 2020. Projects put on hold will not be modeled in the starting base case.

2.5.2 Reactive Resources

The study models the existing and new reactive power resources in the base cases to ensure that realistic reactive support capability will be included in the study. These include generators, capacitors, static var compensators (SVCs), synchronous condensers and other devices. In addition, Table A4-1 of Appendix A provides a list of key existing reactive power resources that will be modeled in the studies. For the complete list of these resources, please refer to the base cases which are available through the CAISO secured website.

2.5.3 Protection System

To help ensure reliable operations, many Remedial Action Schemes (RAS), Protection Systems, safety nets, Under-voltage Load Shedding (UVLS) and Under-frequency Load Shedding (UFLS) schemes have been installed in some areas. Typically, these systems shed load, trip generation, and/or re-configure system by strategically operating circuit breakers under select contingencies or system conditions after detecting overloads, low voltages or low frequency. The major new and existing RAS, safety nets, and UVLS that will be included in the study are listed in section A5 of Appendix A. Per WECC's RAS modeling initiative, the CAISO has been modeling RAS in power flow studies for some areas in previous planning cycles as they were made available by the PTOs. The CAISO will continue the effort of modeling RAS in this planning cycle in working with the PTOs with a target to have model for all RAS in the CAISO controlled grid.

2.5.4 Control Devices

Expected automatic operation of existing and planned devices will be modeled in the studies. These control devices include:

- All shunt capacitors
- Dynamic reactive supports such as static var compensators and synchronous condensers at several locations such as Potrero, Newark, Rector, Devers, Santiago, Suncrest, Miguel, San Luis Rey, San Onofre, and Talega substations
- Load tap changing transformers
- DC transmission line such as PDCI, IPPDC, and Trans Bay Cable Projects
- Imperial Valley phase shifting transformers

2.6 Load Forecast Assumptions

2.6.1 Energy and Demand Forecast

The assessment will utilize the 2019 California Energy Demand Revised Forecast 2020-2030 adopted by the California Energy Commission (CEC) on January 22, 2020[12] using the corresponding LSE and BA Table Mid Baseline spreadsheet with applicable AAEE. The 2019 CED Forecast also includes 8760-hourly demand forecasts for the three major Investor Owned Utility (IOU) TAC areas[13].

During 2019, the CEC, CPUC and CAISO engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in the planning and procurement processes. To that end, the 2019 IEPR final report, adopted on February 20, 2020, based on the IEPR record and in consultation with the CPUC and the CAISO, recommends using the Mid Additional Achievable Energy Efficiency (AAEE) scenario for system-wide and flexibility studies for the CPUC LTPP and CAISO TPP studies. However, for local area studies, because of the local nature of reliability needs and the difficulty of forecasting load and AAEE at specific locations and estimating their daily load-shape impacts, using the Low AAEE scenario is more prudent at this time.

The CEC forecast information is available on the CEC website at:

http://www.energy.ca.gov/2019_energypolicy/documents/

In general, the following are guidelines on how load forecasts are used for each study area.

- The 1-in-10 weather year, mid demand baseline case with low AAEE savings load forecasts will be used in PG&E, SCE, SDG&E, and VEA local area studies including the studies for the local capacity requirement (LCR) areas.
- The 1-in-5 weather year, mid demand baseline with mid AAEE savings load forecast will be used for system studies
- The 1-in-2 weather year, mid demand baseline with mid AAEE savings load forecast will be used for production cost study.

Valley Electric Association, Inc. (VEA) joined the California ISO control area in 2013. While most customers of load serving entity reside in Nevada, a relatively small portion of VEA's service territory extends into parts of California. As such, the Energy Commission routinely develops forecasts of electricity sales to be used in assessing statewide progress toward meeting California's Renewable Portfolio Standard, as well as forecasts of VEA's peak load to inform the California ISO's transmission planning process (TPP).

[12] https://ww2.energy.ca.gov/2019_energypolicy/documents/#demand

[13] https://www.energy.ca.gov/2018_energypolicy/documents/cedu_2018-2030/2018_demandforecast.php

Initially, the Energy Commission's method for forecasting VEA's electricity load considered only growth occurring in the California portion of their territory—the portion for which detailed data was readily available. During the course of the California ISO's 2019-2020 TPP, VEA raised concerns that a significant amount of load growth was occurring in the Nevada portion of their territory that was not reflected in the *California Energy Demand Updated Forecast, 2018-2030 (CEDU 2018)* but that could be impactful for the transmission study. VEA provided additional data to the Energy Commission and Energy Commission staff (staff) committed to a more holistic approach to forecasting VEA load growth in response.

For the *California Energy Demand 2020 – 2030 Preliminary Forecast (CED 2019 Preliminary*), staff used econometric methods to prepare electricity sales and peak demand forecasts for the VEA service territory in its entirety. Additionally, staff reviewed documentation of new service requests provided by VEA and determined that an incremental adjustment to non-residential sales projections would be appropriate to account for additional planned electricity demand from new commercial cannabis cultivation facilities that would otherwise not be captured in a forecast using econometric methods.

Following a similar process, the CEC has provided a forecast for the VEA area for the CAISO's 2020-2021 TPP, and VEA will continue to provide the necessary information to the CEC. The following information by customer sector will be needed by the CEC for this purpose: historic sales, historic (and projected if available) electricity rates, historic (and projected if available) installed capacity of BTM resources by technology, forecasts of sales and peak demand forecasts (including documentation of forecast methods), and supporting documentation for any significant incremental loads.

2.6.2 Methodologies to Derive Bus Level Forecast

Since load forecasts from the CEC are generally provided for a larger area, these load forecasts do not contain bus-level load forecasts which are necessary for reliability assessment. Consequently, the augmented local area load forecasts developed by the participating transmission owners (PTOs) will also be used where the forecast from the CEC does not provide detailed bus-level load forecasts. Descriptions of the methodologies used by each of the PTOs to derive bus-level load forecasts using CEC data as a starting point are described below.

2.6.2.1 *Pacific Gas and Electric Service Area*

The method used to develop the PG&E base case loads is an integrative process that extracts, adjusts and modifies the information from the transmission and distribution systems and municipal utility forecasts. The melding process consists of two parts. Part 1 deals with the PG&E load. Part 2 deals with the municipal utility loads.

PG&E Loads in Base Case

The method used to determine the PG&E loads is similar to the one used in the previous year's studies. The method consists of determining the division loads for the required 1-in-5 system or 1-in-10 area base cases as well as the allocation of the division load to the transmission buses.

Determination of Division Loads

The annual division load is determined by summing the previous year division load and the current division load growth. The initial year for the base case development method is based heavily on the most recent recorded data. The division load growth in the system base case is determined in two steps. First, the total PG&E load growth for the year is determined. Then this total PG&E load growth is allocated to the division, based on the relative magnitude of the load growths projected for the divisions by PG&E's distribution planners. For the 1-in-10 area base case, the division load growth determined for the system base case is adjusted to the 1-in-10 temperature using the load temperature relation determined from the most recent load and temperature data of the division.

Allocation of Division Load to Transmission Bus Level

Since the base case loads are modeled at the various transmission buses, the division loads developed need to be allocated to those buses. The allocation process is different depending on the load types. PG&E classifies its loads into four types: conforming, non-conforming, self-generation and generation-plant loads. The conforming, non-conforming and self-generation loads are included in the division load. Because of their variability, the generation-plant loads are not included in the division load. Since the non-conforming and self-generation loads are assumed to not vary with temperature, their magnitude would be the same in the 1-in-2 system, 1-in-5 system or the 1-in-10 area base cases of the same year. The remaining load (the total division load developed above, less the quantity of non-conforming and self-generation load) is the conforming load, which is then allocated to the transmission buses based on the relative magnitude of the distribution level forecast.

Muni Loads in Base Case

Municipalities provide PG&E their load forecast information. If no information is provided, PG&E supplements such forecast. For example, if a municipal utility provided only the 1-in-5 loads, PG&E would determine the 1-in-2 and 1-in-10 loads by adjusting the 1-in-5 loads for temperature in the same way that PG&E would for its load in that area.

For the 1-in-5 system base cases, the 1-in-5 loads are used. For the 1-in-10 area base cases, the 1-in-10 loads are used if the municipal loads are in the area of the area base case, otherwise, the 1-in-2 loads would be used.

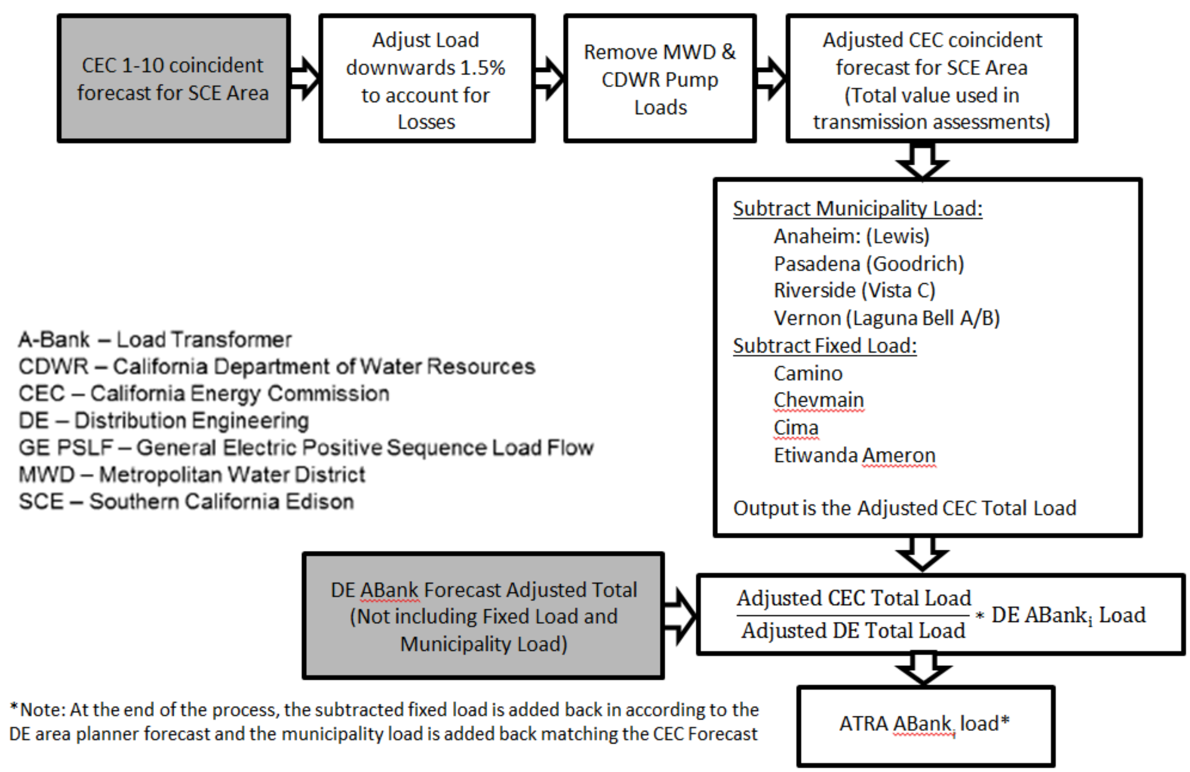
Behind-the-meter PV (BTM-PV)

BTM-PV will be modeled as a component of the load model. Using the DG field on the PSLF load model the total nameplate capacity of the DG will be represented under PDGmax field, and the actual output will be based on the scenario. The total nameplate capacity is specified by the CEC, the allocation and location for projected DG is derived from the latest Distribution Resource Plan (DRP) filed with the CPUC as provided by Distribution Planning.

2.6.2.2 *Southern California Edison Service Area*

The following figure identifies the steps in developing SCE's A-Bank load model.

Figure 2.6-1: SCE A-Bank load model



<u>Behind-the-meter PV (BTM-PV)</u>

BTM-PV will be modeled as a component of the load model. Using the DG field on the PSLF load model the total nameplate capacity of the DG will be represented under PDGmax field, and the actual output will be based on the scenario. The total nameplate capacity is specified by the CEC, the allocation and location for projected DG is derived from the latest DRP filed with the CPUC as provided by Distribution Planning.

2.6.2.3 *San Diego Gas and Electric Service Area*

The substation load forecast reflects the actual, measured, true maximum coincident load on the substation distribution transformer(s). This maximum load is obtained either from SCADA historical data or in a few cases other sources (i.e. transmission data, meter data or legacy systems). If a correlation of load to weather is found, that measured maximum load is then weather normalized (i.e. value you expect 5 out of 10 years) as well as adversed (i.e. value you expect 1 out of 10 years) to produce a weather adjusted substation load. The weather adjusted substation load, is then adjusted based on location specific values such as, load growth from special allocation and DER growth, both utilizing the 2016 California Energy Demand Updated issued by the CEC. Additionally, an adjustment is made for the removal of the largest generation at the substation which was on during peak (generation larger than 500kW) and economic variables. The final distribution substation values are then adjusted across SDG&E so that area loads plus losses sum to the CEC 90/10 forecast. Thus, two substation loads for each distribution bus are modeled: the non-coincident load, and the coincident load.

The distribution substation annual forecast submitted to transmission planning is a non-coincident adverse peak forecast. The distribution substation forecast will always be higher than the system forecast which is a coincident forecast that is adjusted to a peak that would be expected 1 out of 10 years.

Behind-the-meter PV (BTM-PV)

BTM-PV will be modeled as a component of the load model. Using the DG field on the PSLF load model the total nameplate capacity of the DG will be represented under PDGmax field, and the actual output will be based on the scenario. The total nameplate capacity is specified by the CEC, the allocation and location for projected DG is derived from the latest DRP filed with the CPUC as provided by Distribution Planning.

2.6.2.4 *Valley Electric Association Service Area*

The VEA develops its substation load forecast from trending three-year historical non-coincident peak load data. The forecast is then adjusted with future known load changes. The CEC develops Statewide Energy Demand Forecasts, including a VEA forecast adjusted for weather, energy efficiency or other forecast considerations. VEA then compares its forecast with the CEC forecast to develop loads for the various TPP base case models.

2.6.2.5 *Bus-level Load Adjustments*

The bus-level loads are further adjusted to account for BTM-PV and supply-side distribution connected (WDAT) resources that don’t have resource ID.

2.6.3 Power Factor Assumptions

In the PG&E area assessment, power factors at all substations will be modeled using the most recent historical values obtained at corresponding peak, off-peak, and light load conditions. Bus load power factor for near term (year 2022 and 2025) will be modeled based on the actual data recorded in the EMS system. For the subsequent study years a power factor of 0.97 lagging for summer peak cases, and 0.99 leading factor for winter off-peak cases, will be used.

In the SCE area assessment, an active to reactive power (watt/var) ratio of 25-to-1 (or power factor of 0.999) measured at the high side of the A-Bank (230/115 kV or 230/66 kV) will be assumed for the SCE transmission substation loads.

The watt/var ratio is a result of SCE commitment to its program to optimize reactive power planning and capacitor bank availability during heavy summer peak load periods in its distribution and sub-transmission systems. The objective of the SCE’s reactive power program was to ensure a watt/var ratio of 25 to 1.

In the SDG&E area, power factors at all substations will be modeled based on the actual peak load data recorded in the EMS system for the year 2021. For the subsequent study years a power factor of 0.995 will be used.

In the VEA area assessment, reactive power loads at all substations will be modeled using the maximum historical seasonal values over the past four years. These values will be utilized in near-term TPP cases. For the long-term TPP cases a power factor at the transmission/distribution interface points of 0.97 lagging for summer peak cases, and 0.99 leading for winter off-peak cases, will be used.

2.6.4 Self-Generation

Baseline consumption peak demand in the CEC demand forecast is reduced by projected impacts of self-generation serving on-site customer load. Most of the increase in self-generation over the forecast period comes from PV. The CAISO wide self-generation PV capacity is projected to reach 21,148 MW in the mid demand case by 2030. In 2020-2021 TPP base cases, baseline PV generation production will be modeled explicitly. The CED forecast 2020-2030 also includes behind-the-meter storage as a separate line item. The combined CAISO wide, residential and non-residential behind-the-meter storage is projected to reach about 1,819 MW in the mid demand case by 2030. Behind-the-meter storage will not be modeled explicitly in 2020-2021 TPP base cases due to lack of locational information and limitation within the GE PSLF tool to model more than one distributed resources behind each load.

PV Self-generation installed capacity for mid demand scenario by PTO and forecast climate zones are shown in Table 2.6-1. Output of the self-generation will be selected based on the time of day of the study using the end-use load and PV shapes for the day selected.

Behind-the-meter storage installed capacity for mid demand scenario by PTO and forecast climate zones is shown in Table 2.6-2. These resources will be netted to load in the 2020-2021 TPP base cases,

Table 2.6-1: Mid demand baseline PV self-generation installed capacity by PTO[14]

PTO	Forecast Climate Zone	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PGE	Central Coast	533	583	634	688	744	802	861	923	987	1052
	Central Valley	1438	1592	1723	1840	1951	2062	2174	2287	2402	2520
	Greater Bay Area	1670	1898	2073	2219	2355	2489	2625	2764	2904	3046
	North Coast	463	485	506	528	551	573	597	620	644	669
	North Valley	312	339	358	374	390	406	421	435	448	462
	Southern Valley	1791	1976	2142	2300	2456	2613	2773	2935	3099	3265
	PG&E Total	6207	6873	7435	7948	8446	8945	9451	9964	10485	11013
SCE	Big Creek East	443	482	515	544	570	597	627	663	706	760
	Big Creek West	237	263	290	317	347	378	411	443	469	486
	Eastern	950	1030	1111	1190	1269	1348	1422	1490	1555	1619
	LA Metro	1647	1909	2161	2394	2599	2777	2937	3087	3234	3379
	Northeast	762	856	947	1033	1114	1190	1262	1330	1394	1454
	SCE Total	4038	4540	5023	5478	5900	6291	6659	7013	7358	7698
SDGE	SDGE	1586	1768	1916	2023	2104	2173	2239	2304	2370	2436
CAISO Total		**11832**	**13180**	**14374**	**15449**	**16450**	**17409**	**18348**	**19281**	**20212**	**21148**

[14] Based on self-generation PV calculation spreadsheet provided by CEC.

Table 2.6-2: Mid demand baseline behind-the-meter storage installed capacity by PTO[15]

PTO	Forecast Climate Zone	2021		2022		2023		2024		2025		2026		2027		2028		2029		2030	
		Storage-Res	Storage-NonRes	Storage-Res	Storage-NonRes	Storage-Res	Storage-NonRes	Storage-Res	Storage-NonRes	Storage-Res	Storage-NonRes	Storage-Res	Storage-NonRes	Storage-Res	Storage-NonRes	Storage-Res	Storage-NonRes	Storage-Res	Storage-NonRes	Storage-Res	Storage-NonRes
PGE	Central Coast	10	10	14	11	17	13	20	14	23	16	27	18	30	19	34	21	37	23	41	24
	Central Valley	17	27	22	32	27	36	32	40	38	44	43	48	49	52	55	57	61	61	67	65
	Greater Bay Area	59	34	80	39	101	44	123	49	146	54	170	59	194	65	219	70	245	75	270	80
	North Coast	12	6	16	7	20	8	23	8	27	9	31	9	36	10	40	10	44	11	49	12
	North Valley	2	1	2	1	3	2	3	2	4	2	4	3	5	3	5	3	6	3	6	4
	Southern Valley	10	11	12	12	15	14	18	15	21	17	25	18	28	19	31	21	34	22	38	24
PG&E Total		110	89	145	102	182	115	220	129	260	142	300	155	341	168	384	182	427	195	471	208
SCE	Big Creek East	2	6	3	7	4	8	5	9	5	10	6	11	7	12	8	13	9	14	10	15
	Big Creek West	7	7	9	8	11	10	13	11	15	12	18	13	21	14	23	15	26	17	29	18
	Eastern	14	15	18	17	22	19	27	22	31	24	36	26	41	29	46	31	51	33	56	36
	LA Metro	42	126	56	148	72	170	89	191	107	213	125	235	145	256	165	278	186	300	207	321
	Northeast	8	31	10	37	13	42	15	47	18	53	21	58	24	64	27	69	30	74	34	80
SCE Total		74	185	97	217	122	248	148	280	177	312	206	343	237	375	270	406	303	438	336	470
SDGE	SDGE	59	48	76	55	93	62	111	68	130	75	149	82	167	88	186	95	206	102	225	108
CAISO Total		**243**	**322**	**318**	**374**	**397**	**425**	**480**	**477**	**566**	**528**	**655**	**580**	**746**	**632**	**840**	**683**	**935**	**735**	**1032**	**786**

[15] Based on behind-the-meter storage calculation spreadsheet provided by CEC.

2.7 Generation Assumptions

2.7.1 Generation Projects

In addition to generators that are already in-service, new generators will be modeled in the studies as generally described below. Depending on the status of each project, new generators will be assigned to one of the five levels below:

- Level 1: Under construction
- Level 2: Regulatory approval received
- Level 3: Application under review
- Level 4: Starting application process
- Level 5: Press release only

Based on this classification, the following guidelines will be used to model new generators in the base cases for each study.

Up to 1-year Operating Cases: Only generation that is under construction (Level 1) and has a planned in-service date within the time frame of the study will be modeled in the initial power flow case.

2-5-year Planning Cases: Generation that is under construction (Level 1) and has a planned in-service date within the time frame of the study will be modeled in the initial power flow case.

Conventional generation in pre-construction phase with executed LGIA and progressing forward will be modeled off-line but will be available as a non-wire mitigation option.

OTC repowering projects will be modeled in lieu of existing resources as long as they have power purchase approval from the CPUC or other Local Regulatory Agency (LRA) and are projected to be in service within the timeframe of the study.

Contracted renewable generation with all permitting and necessary transmission approved and expected to be in-service within 5-years may also be modeled in the relevant cases (level 2 status). As described in the Renewable Generation section below, the baseline resource information provided by the CPUC as part of the RESOLVE model used in integrated resource planning (IRP), the latest information regarding contract status available to the PTOs and CAISO's interconnection agreement status will be utilized for modeling specific contracted renewable generation. For the 2025 study scenarios, generation from the Base Portfolio developed and provided by the CPUC will be used, as necessary. Given the data availability, generic dynamic data may be used for this future generation.

6-10-year Planning Cases: Only generation that is under construction or has received regulatory approval (Levels 1 and 2) and generation in the 2-5 year Planning Cases will be modeled in the area of interest of the initial power flow case. If additional generation is required to achieve an acceptable initial power flow case, then generation from Levels 3, 4, and 5 may be used. However, generally Level 3, 4, and 5 generation should only be used when they are outside the area of study, so that the generation's impact on the facility addition requirements will be minimized.

2.7.2 Renewable Generation

The CPUC adopted the integrated resource planning (IRP) process designed to ensure that the electric sector is on track to help the State achieve its 2030 greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals.

The CPUC's Proposed Decision[16] mailed on February 21, 2020 recommended transmittal of a base portfolio along with two sensitivity portfolios to be used in the 2020-2021 TPP. The base portfolio was transmitted for the purpose of being studied as part of the reliability assessment, policy-driven and economic assessment in the 2020-2021 TPP.

As part of the 2019-2020 IRP, the CPUC staff developed the portfolios using RESOLVE capacity expansion model. RESOLVE documentation specifies that renewable resources under development with CPUC-approved contracts with the three investor-owned utilities are assumed to be part of the baseline assumptions. The CAISO will work with the CPUC to identify such resources and model these in the reliability assessment base cases. The CAISO may supplement this scenario with information regarding contracted RPS resources that are under construction as of March 2020. The generic resources selected as portfolio resources are at a geographic scale that is too broad for transmission planning purpose which required specific interconnection locations. The CEC and CPUC staff refined the geographically coarse resource portfolios into plausible network modeling locations for the purpose of transmission analysis.

The CPUC staff report (Release 1[17] and Release 2[18]) describes the methodology and results of the 2019 busbar mapping process performed by the CPUC and CEC with support from CAISO. Busbar mapping results[19] posted by the CEC staff show specific substations recommended for modeling generic portfolios resources as part of the 2020-2021 TPP.

2.7.3 Thermal generation

For the latest updates on new generation projects, please refer to the CEC website under the licensing section (http://www.energy.ca.gov/sitingcases/all_projects.html). In addition, the CAISO may also use other data sources to track the statuses of additional generator projects to determine the starting year new projects may be modeled in the base cases. Table A2-1 of Appendix A lists

16 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M327/K750/327750339.PDF

17 file://homefiles/home/sbarave/profile/Downloads/Modeling_Assumptions_2020_2021_TPP-Report-Release1%20(5).pdf

18 To be posted by the CPUC at - https://www.cpuc.ca.gov/General.aspx?id=6442464144

19 https://caenergy.databasin.org/galleries/eab0ce3a5be447ce928a310e80c65c8d#expand=208848

new thermal generation projects in construction or pre-construction phase that will be modeled in the base cases.

2.7.4 Hydroelectric Generation

During drought years, the availability of hydroelectric generation production can be severely limited. In particular, during a drought year the Big Creek area of the SCE system has experienced a reduction of generation production that is 80% below average production. It is well known that the Big Creek/Ventura area is a local capacity requirement area that relies on Big Creek generation to meet NERC Planning Standards. The Sierra, Stockton and Greater Fresno local capacity areas in the PG&E system also rely on hydroelectric generation. For these areas, the CAISO will consider drought conditions when establishing the hydroelectric generation production levels in the base case assumptions.

2.7.5 Generation Retirements

Existing generators that have been identified as retiring are listed in Table A3-1 of Appendix A. These generators along with their step-up transformer banks will be modeled as out of service starting in the year they are assumed to be retired. Their models are to be removed from base cases only when they have been physically taken apart and removed from the site. Exception: models can be removed prior to physical removal only when approved plans exist to use the site for other reasons.

In addition to the identified generators the following assumptions will be made for the retirement of generation facilities.

Nuclear Retirements –Diablo Canyon will be modeled off-line based on the OTC compliance dates,

Once Through Cooled Retirements – As identified in section 3.7.6.

Renewable and Hydro Retirements – Assumes these resource types stay online unless there is an announced retirement date.

Other Retirements – Unless otherwise noted, assumes retirement based resource age of 40 years or more. Table A4-2 of Appendix A includes a list of generators that will be modeled offline based on this criterion unless they have an existing contract that runs beyond their assumed retirement age.

2.7.6 OTC Generation

Modeling of the once-through cooled (OTC) generating units follows the compliance schedule from the SWRCB's Policy on OTC plants with the following exception:

- Generating units that are repowered, replaced or having firm plans to connect to acceptable cooling technology, as illustrated in Table 3.7-5. This table also includes early retirements of some OTC generating units to accommodate repowering projects, which received the CPUC approval for the Power Purchase and Tolling Agreements (PPTAs) and as well as the certificate to construct and operate from the CEC.

- All other OTC generating units will be modeled off-line beyond their compliance dates or planned retirement dates provided by the generating owners except for the units that have been recommended for compliance schedule extension by the Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS)[20] for the State Water Resources Control Board's consideration and decision;

- Generating units with acceptable Track 2[21] mitigation plan that was approved by the State Water Resources Control Board.

2.7.7 LTPP Authorization Procurement

OTC replacement local capacity amounts in southern California that were authorized by the CPUC under the LTTP Tracks 1 and 4 will be considered along with the procurement activities to date from the utilities. Table 2.7-1 provides the local capacity resource additions and the study year in which the amounts will be first modeled based on the CPUC LTPP Tracks 1 and 4 authorizations. Table 2.7-2 provides details of the study assumptions using the utilities' procurement activities to date, as well as the CAISO's assumptions for potential preferred resources for San Diego area.

Table 2.7-1: Summary of 2012 LTPP Track 1 & 4 Maximum Authorized Procurement[22]

LCR Area	LTTP Track-1		LTTP Track-4[23]	
	Amount (MW)(1)	Study year in which addition is to be first modeled	Amount (MW)(1)	Study year in which addition is to be first modeled
Moorpark Sub-area	290	2021	0	N/A
West LA Basin / LA Basin	1400-1800	2021	500-700	2021

(1) Amounts shown are total including gas-fired generation, preferred resources and energy storage

[20] https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/final_report.pdf

[21] Track 2 requires reductions in impingement mortality and entrainment to a comparable level to that which would be achieved under Track 1, using operational or structural controls, or both (https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/rs2015_0018.pdf).

[22] Maximum authorized procurement is different than approved contract (i.e., Power Purchase & Tolling Agreement) procurement. Maximum authorized procurement is the ceiling amount authorized by the CPUC without specific contracts. The approved PPTA procurement is the selected procurement with specific contracts between the LSE and the provider that have been approved by the CPUC for actual execution.

[23] CPUC Decision for LTPP Track 4 (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008104.PDF)

Table 2.7-2: Summary of SCE area 2012 LTPP Track 1 & 4 Procurement Activities to date

	LTPP EE (MW)	Behind the Meter Solar PV (NQC MW)	Storage 4-hr (MW)	Demand Response (MW)	Conventional resources (MW)	Total Capacity (MW)
SCE's procurement for the Western LA Basin[24]	124.04	37.92	263.64	5	1,382	1,812.60
SCE's procurement for the Moorpark sub-area	6.00	5.66	195[25]	0	0	206.66

For further details on new resources see Table A2-1 "Planned generation". The portion of authorized local capacity derived from energy limited preferred resources such as demand response and battery storage will be modeled offline in the initial base cases and will be used as mitigation once reliability concerns are identified.

2.7.8 Distribution connected resources modeling assumption

Table 2.7-3 below outlines modeling assumptions for distribution connected resources in the TPP base cases.

Table 2.7-3: Modeling assumptions of distribution connected resources

POI	Size (MW)	CAISO Resource ID	PSLF Modeling	Comment
Behind-the-meter	N/A	N/A	Model as component of load	BTM resources aggregated to 0.5 MW or greater could have resource ID
In-front-of-the-meter	>0.5	Yes	Model as individual generator at T/D interface	0.5 MW is the minimum size requirement for resource ID
In-front-of-the-meter	>10	No	Model as individual generator at T/D interface	Load forecast may need to be adjusted for modeling these resources as generator.
In-front-of-the-meter	<10	No	Model as aggregated generator at T/D interface	Aggregate only the resources of same technology

[24] SCE-selected RFO procurement for the Western LA Basin was approved by the CPUC with PPTAs per Decision 15-11-041, issued on November 24, 2015.

[25] SCE procured 95 MW of the 195 MW energy storage under the ACES program.

2.8 Preferred Resources[26]

In complying with tariff Section 24.3.3(a), the CAISO sent a market notice to interested parties seeking suggestions about demand response programs and generation or non-transmission alternatives that should be included as assumptions in the study plan. The CAISO received a submission from PG&E with the DR inputs to be included in the 2020-2021 transmission planning process within the PG&E planning area.

2.8.1 Methodology

The CAISO issued a paper[27] on September 4, 2013, in which it presented a methodology to support California's policy emphasis on the use of preferred resources – specifically energy efficiency, demand response, renewable generating resources and energy storage – by considering how such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure. The general application for this methodology is in grid area situations where a non-conventional alternative such as demand response or some mix of preferred resources could be selected as the preferred solution in the CAISO's transmission plan as an alternative to the conventional transmission or generation solution.

In previous planning cycles, the CAISO applied a variation of this new approach in the LA Basin and San Diego areas to evaluate the effectiveness of preferred resource scenarios developed by SCE as part of the procurement process to fill the authorized local capacity for the LA Basin and Moorpark areas. In addition to these efforts focused on the overall LA Basin and San Diego needs, the CAISO also made further progress in integrating preferred resources into its reliability analysis focusing on other areas where reliability issues were identified.

As in the 2019-2020 planning cycle, reliability assessments in the current planning cycle will consider a range of existing demand response amounts as potential mitigations to transmission constraints. The reliability studies will also incorporate the incremental uncommitted energy efficiency amounts as projected by the CEC, distributed generation based on the CPUC Default RPS Portfolio and a mix of preferred resources including energy storage based on the CPUC LTPP 2012 local capacity authorization. These incremental preferred resource amounts are in addition to the base amounts of energy efficiency, demand response and "behind the meter" distributed or self-generation that is embedded in the CEC load forecast.

For each planning area, reliability assessments will be initially performed using preferred resources other than energy-limited preferred resources such as DR and energy storage to identify reliability concerns in the area. If reliability concerns are identified in the initial assessment, additional rounds of assessments will be performed using potentially available demand response and energy storage to determine whether these resources are a potential solution. If these

[26] To be precise, "preferred resources" as defined in CPUC proceedings applies more specifically to demand response and energy efficiency, with renewable generation and combined heat and power being next in the loading order. The term is used more generally here consistent with the more general use of the resources sought ahead of conventional generation.

[27] http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf

preferred resources are identified as a potential mitigation, a second step - a preferred resource analysis may then be performed, if considered necessary given the mix of resources in the particular area, to account for the specific characteristic of each resource including use or energy limitation in the case of demand response and energy storage. An example of such a study is the special study the CAISO performed for the CEC in connection with the Puente Power Project proceeding to evaluate alternative local capacity solutions for the Moorpark area[28]. The CAISO will continue to use the methodology developed as part of the study to evaluate these types of resources.

As part of the 2019-2020 IRP, 2000 MW of storage was provided in the base portfolio. Although the specific locations of these storage projects have yet to be determined, they can be considered as potential mitigation options, as needed, to address specific transmission reliability concerns identified in the reliability assessment. If a storage option is considered, it could be for informational purposes only and would be clearly documented, as a potential option to be pursued through a resource procurement process. In some situations the storage could be approved as a transmission asset[29].

2.8.2 Demand Response

For long term transmission expansion studies, the methodology described above will be utilized for considering fast-response DR and slow-response PDR resources. In 2017, the CAISO performed a study to assess the availability requirements of slow-response resources, such as demand response, to count for local resource adequacy.[30] The study found that at current levels, most existing slow-response DR resources appear to have the required availability characteristics needed for local RA if dispatched pre-contingency as a last resort, with the exception of minimum run time duration limitations. The CAISO will address duration limitations through the annual Local Capacity Requirements stakeholder process through hourly load and resource analysis.

The CAISO has developed a methodology that will allow the CAISO to dispatch slow response demand response resources after the completion of the CAISO's day-ahead market run as a preventive measure to maintain local capacity area requirements in the event of a potential contingency. Specifically, the methodology allows the CAISO to assess whether there are sufficient resources and import capability in a local capacity area to meet forecasted load without using slow response demand response. If the assessment shows insufficient generation and import capability in the local area, the CAISO will use the new methodology to determine which and how much of the available slow response demand response it should commit after the completion of the day-ahead market via exceptional dispatch to reduce load for some period

[28] https://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf

[29] Currently storage as a transmission asset cannot receive market revenues, and efforts to allow such market revenues have been temporarily put on hold. The following presentation provides more information: http://www.caiso.com/InitiativeDocuments/Presentation-Storage-TransmissionAsset-Jan142019.pdf

[30] CAISO-CPUC Joint Workshop, Slow Response Local Capacity Resource Assessment:

https://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacity ResourceAssessment_Oct42017.pdf during the next operating day to meet the anticipated insufficiency. The CAISO plans to implement this solution in Fall of 2020 for the 2021 RA year.

The IOUs submitted information of their existing DR programs and allocation to substations, in response to the CAISO's solicitation for input on DR assumptions, serve as the basis for the supply-side DR planning assumptions included herein. Transmission and distribution loss-avoidance effects shall continue to be accounted for when considering the load impacts that supply-side DR has on the system. Table 2.8-1 describes supply-side DR capacity assumptions for the three IOUs.

Table 2.8-1: Existing DR Capacity Range for Each IOU Load Serving Entities within CAISO BA

PG&E

PG&E Portfolio-Adjusted DR Load Impacts for CAISO Peaking Conditions, August 2019, 1-in-2 Weather			
DR Program	**MW**	**Level of Dispatch**	**Response time**
Base Interruptible Program (BIP)	254	System-wide SubLAP RDRR	30 minutes
Capacity Bidding Program (CBP)	32	System-wide SubLAP PDR	Day Ahead
Peak Day Pricing (PDP)	9	System-wide	Day Ahead
SmartRate™	6	System-wide	Day Ahead
SmartAC™	51	System-wide SubLAP Selected 21 Substations PDR	None required
DRAM	163		>30 Minutes
Total	**515**		

SCE

Load Impact Report, 1-in-2 weather year condition portfolio-adjusted August 2029 ex-ante DR impacts at CAISO peak				
Supply-side DR (MW)	**MW**	**Assumed Market Model**	**Response time**	**Level of Dispatch**
Base Interruptible Program 15 Minute (BIP-15)	125	RDRR	20 Minutes or Less	System-wide, Sublap, A-Bank
Base Interruptible Program 30 Minute (BIP-30)	435	RDRR	30 Minutes	
Agricultural and Pumping Interruptible (API)	38	RDRR	20 Minutes or Less	A-bank
Summer Discount Plan Residential (SDP-R)	102	RDRR	20 Minutes or Less	
Summer Discount Plan Commercial (SDP-C)	9	RDRR	20 Minutes or Less	System-wide, Sublap, A-Bank
Smart Energy Program	124	RDRR	20 Minutes or Less	
Capacity Bidding Program Day-Ahead (CBP-DA)	6	PDR	Day ahead	System-wide, Sublap
Capacity Bidding Program Day-Of (CBP-DO)	16	PDR	> 30 Minutes	
DRAM	91.6 (Not modeled)	PDR	>30 Minutes	
Total	**855**			

SDG&E[31]

DR Load Impact – SDG&E Portfolio Adjusted for CAISO Peaking Conditions, August, Weather 1-in-2			
DR Program	**MW**	**Level of Dispatch**	**Response time**
Base Interruptible Program (BIP)	2	System-wide SubLAP RDRR	20 minutes
	4.74		30 minutes
Capacity Bidding Program (CBP)	8.44	System-wide SubLAP PDR	>30 Minutes
Peak Day Pricing (PDP)	0	System-wide PDR	>30 Minutes
Smart Energy Program	8.97	System-wide PDR	>30 Minutes
DRAM	15.7		>30 Minutes
Total	**39.85**		

DR capacity will be allocated to bus-bar using the method defined in D.12-12-010, or specific bus-bar allocations provided by the IOUs. The DR capacity amounts will be modeled offline in the initial reliability study cases and will be used as potential mitigation in those planning areas where reliability concerns are identified.

The following factors in Table 2.8-2 will be applied to the DR projections to account for avoided distribution losses.

Table 2.8-2: Factors to Account for Avoided Distribution Losses

	PG&E	SCE	SDG&E
Distribution loss factors	1.067	1.051	1.071

2.8.3 Energy Storage

CPUC Decision (D.)13-10-040 established a 2020 procurement target of 1,325 MW installed capacity of new energy storage units within the CAISO planning area. Of that amount, 700 MW shall be transmission-connected, 425 MW shall be distribution-connected, and 200 MW shall be customer-side. D.13-10-040 also allocates procurement responsibilities for these amounts to each of the three major IOUs. Energy storage that will be procured to fill the local capacity amounts authorized under the CPUC 2012 LTPP decision and CPUC Resolutions E-4791 and E-4949 are subsumed within the Approved Procurement.

[31] Based on last year's information. SDG&E DR modeling will be updated based on the latest information from SDGE.

Table 2.8-3: IOU Existing and Proposed Energy Storage Procurement[32]

PTO	Category	In-service	Under Construction / Approved Procurement			Total
			2022	2025	2030	
PG&E	Transmission	0	615.5	0	0	615.5
	Distribution	6.5	0	0	0	6.5
	Customer	113	135	154	277	679
	Hybrid Generation	0	0	0	0	0
SCE	Transmission	100	0	0	0	100
	Distribution	65	245	0	0	310
	Customer	158	156	174	318	806
	Hybrid Generation	20	0	0	0	20
SDG&E	Transmission	77.5	290	0	0	367.5
	Distribution	37.6	49.5	0	0	87.1
	Customer	63	67	75	128	333
	Hybrid Generation	0	0	0	0	0
Total		641	1402	403	723	3325

These storage capacity amounts will be modeled in the initial reliability base cases using the locational information as well as the in-service dates provided by CPUC.

2.9 Major Path Flows and Interchange

Power flow on the major internal paths and paths that cross Balancing Authority boundaries represents the transfers that will be modeled in the study. Firm Transmission Service and Interchange represents only a small fraction of these path flows, and is clearly included. In

[32] Final 2018 CEC IEPR Update Volume II https://www.energy.ca.gov/2018_energypolicy/documents

general, the northern California (PG&E) system has 4 major interties with the outside system and southern California. Table 2.9-1 lists the capability and power flows that will be modeled in each scenario on these paths in the northern area assessment[33].

Table 2.9-1: Major Path flows in northern area (PG&E system) assessment[34]

Path	Transfer Capability/SOL (MW)	Scenario in which Path will be stressed
Path 26 (N-S)	4000[35]	Summer Peak
PDCI (N-S)	3220[36]	
Path 66 (N-S)	4800[37]	
Path 15 (N-S)	-5400[38]	Spring Off Peak
Path 26 (N-S)	-3000	
PDCI (N-S)	-1000[39]	
Path 66 (N-S)	-3675	Winter Peak

For the summer off-peak cases in the northern California study, Path 15 flow is adjusted to a level close to its rating limit of 5400 MW (S-N). This is typically done by increasing the import on Path 26 (S-N) into the PG&E service territory. The Path 26 is adjusted between 1800 MW south-to-north and 1800 MW north-to-south to maintain the stressed Path 15 as well as to balance the loads and resources in northern California. Some light load cases may model Path 26 flow close to 3000 MW in the south-to-north direction which is its rating limit.

Similarly, Table 2.9-2 lists major paths in southern California along with their current Transfer Capability (TC) or System Operating Limit (SOL) for the planning horizon and the target flows to be modeled in the southern California assessment.

33 These path flows will be modeled in all base cases.

34 The winter coastal base cases in PG&E service area will model Path 26 flow at 2,800 MW (N-S) and Path 66 at 3,800 MW (N-S)

35 May not be achievable under certain system loading conditions.

36 Current operational limit is 3210 MW.

37 The Path 66 flows will be modeled to the applicable seasonal nomogram for the base case relative to the northern California hydro dispatch.

38 May not be achievable under certain system loading conditions

39 Current operational limit in the south to north direction is 1000 MW.

Table 2.9-2: Major Path flows in southern area (SCE and SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Near-Term Target Flows (MW)	Scenario in which Path will be stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
Path 26 (N-S)	3,000	0 to 3,000	Spring Off Peak
PDCI (N-S)	3220[40]	3220	Summer Peak
West of River (WOR)	11,200	5,000 to 11,200	Summer Peak
East of River (EOR)	10,100	4,000 to 10,100	Summer Peak
San Diego Import	2765~3565	2,400 to 3,500	Summer Peak
SCIT	17,870	15,000 to 17,870	Summer Peak
Path 45 (N-S)	600[41]	0 to 408	Summer Peak
Path 45 (S-N)	800	0 to 300	Spring Off Peak

2.10 Operating Procedures

Operating procedures, for both normal (pre-contingency) and emergency (post-contingency) conditions, are modeled in the studies.

Please refer to http://www.caiso.com/thegrid/operations/opsdoc/index.html for the list of publicly available Operating Procedures.

[40] Current operational limit is 3210 MW.

[41] Path 45 north-to-south is currently rated at 408 MW and expected to be uprated to 600 MW for summer season by summer on 2020

2.11 Study Scenario

2.11.1 Base Scenario

The base scenario covers critical system conditions driven by several factors such as:

Generation:

Existing and future generation resources are modeled and dispatched to reliably operate the system under stressed system conditions. More details regarding generation modeling is provided in section 4.7.

Demand Level:

Since most of the CAISO footprint is a summer peaking area, summer peak conditions will be evaluated in all study areas. With hourly demand forecast being available from CEC, all base scenarios representing peak load conditions, for both summer and winter, will represent hour of the highest net (managed) load. The net peak hour reflects changes in peak hours brought on by demand modifiers. Furthermore, for the coincident system peak load scenarios, the hour of the highest net load will be consistent with the hour identified in the CEC demand forecast report. For the non-coincident local peaks scenarios, the net peak hour may represent hour of the highest net load for the local area. Winter peak, spring off-peak, summer off-peak or summer partial-peak will also be studied for areas in where such scenarios may result in more stress on system conditions. Examples of these areas are the coastal sub-transmission systems in the PG&E service area (e.g. Humboldt, North Coast/North Bay, San Francisco, Peninsula and Central Coast), which will be studied for both the summer and winter peak conditions. Table 2.11-1 lists the studies that will be conducted in this planning cycle.

Path flows:

For local area studies, transfers on import and monitored internal paths will be modeled as required to serve load in conjunction with internal generation resources. For bulk system studies, major import and internal transfer paths will be stressed as described in Section 4.9 to assess their FAC-013-2 Transfer Capability or FAC-014-2 System Operating Limits (SOL) for the planning horizon, as applicable.

The base scenarios for the reliability analysis are provided in Table 2.11-1.

Table 2.11-1: Summary of Base Scenario Studies in the CAISO Reliability Assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2022	2025	2030
Northern California (PG&E) Bulk System	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak Winter Off-Peak
Humboldt	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter peak
North Valley	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Kern	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
Southern California Bulk transmission system	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Metro Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Northern Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE North of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE East of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Eastern Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SDG&E main transmission	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SDG&E sub-transmission	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Valley Electric Association	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak

2.11.2 Baseline Scenario Definitions and Renewable Generation Dispatch for System-wide Cases[42]

Table 2.11-2: Baseline Scenario Definitions and Renewable Generation Dispatch

PTO	Scenario	Day/Time			BTM-PV			Transmission Connected PV			Transmission Connected Wind			% of managed peak load		
		2022	2025	2030	2022	2025	2030	2022	2025	2030	2022	2025	2030	2022	2025	2030
PG&E	Summer Peak	7/28 HE 18	See CAISO	See CAISO	17%	See CAISO	See CAISO	10%	See CAISO	See CAISO	62%	See CAISO	See CAISO	100%	See CAISO	See CAISO
PG&E	Spring Off Peak	4/26 HE 20	See CAISO	See CAISO	0%	See CAISO	See CAISO	0%	See CAISO	See CAISO	55%	See CAISO	See CAISO	69%	See CAISO	See CAISO
PG&E	Winter Off peak			11/9 HE 4			0%			0%			13%			44%
PG&E	Winter peak	12/12 HE 19	12/8 HE 19	12/9 HE 19	0%	0%	0%	0%	0%	0%	13%	13%	13%	75%	77%	79%
SCE	Summer Peak	9/6 HE 16	9/2 HE 17	9/3 HE 19	44%	23%	0%	51%	21%	0%	20%	25%	40%	100%	100%	100%
SCE	Spring Off Peak	4/27 HE 20	See CAISO	See CAISO	0%	See CAISO	See CAISO	0%	See CAISO	See CAISO	39%	See CAISO	See CAISO	63%	See CAISO	See CAISO
SDG&E	Summer Peak	9/7 HE 19	9/3 HE 19	9/4 HE 19	0%	0%	0%	0%	0%	0%	33%	33%	33%	100%	100%	100%
SDG&E	Spring Off Peak	4/27 HE 20	See CAISO		0%	See CAISO		0%	See CAISO		80%	See CAISO		65%	See CAISO	
VEA	Summer Peak	9/6 HE 16	9/2 HE 17	9/3 HE 19				51%	21%	0%				100%	100%	100%
VEA	Spring Off Peak	4/3 HE 12	See CAISO					96%	See CAISO					31%	See CAISO	

PTO	Scenario	Day/Time	BTM-PV			Transmission Connected PV			Transmission Connected Wind			% of non-coincident PTO managed peak load		
			PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE
CAISO	2030 Summer Peak	9/3 HE 19	0%	0%	0%	0%	0%	0%	42%	40%	33%	95%	100%	98%
	2030 Spring Off Peak	4/7 HE 13	80%	81%	80%	92%	94%	95%	20%	34%	30%	16%	23%	14%
	2025 Summer Peak	9/2 HE 18	8%	5%	4%	4%	2%	1%	32%	32%	27%	94%	99%	95%
	2025 Spring Off Peak	4/6 HE 13	80%	81%	80%	92%	94%	95%	20%	34%	30%	24%	28%	18%

[42] Data in this table, except for the transmission connected renewable dispatch, are derived from CEC hourly forecast. As such, the scenario descriptions and corresponding renewable dispatch are applicable to system-wide cases only and may not be applicable to non-coincident local peak cases which may represent different hour than the hour the system-wide case represent. The transmission connected renewable dispatch are derived from solar and wind profiles used in production cost model.

Note: Biomass, biogas and geothermal renewable generations are to be dispatched at NQC for all base scenarios.

2.11.3 Sensitivity Studies

In addition to the base scenario studies that the CAISO will be assessing in the reliability analysis for the 2020-2021 transmission planning process, the CAISO will also be conducting sensitivity studies identified in Table 2.11-3. The sensitivity studies are to assess impacts of changes to specific assumptions on the reliability of the transmission system. These sensitivity studies include impacts of load forecast, generation dispatch, generation retirement and transfers on major paths.

Table 2.11-3: Summary of Sensitivity Studies in the CAISO Reliability Assessment

Sensitivity Study	Near-term Planning Horizon		Long-Term Planning Horizon
	2022	2025	2030
Summer Peak with high CEC forecasted load	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-
Off peak with heavy renewable output and minimum gas generation commitment	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-
Summer Peak with heavy renewable output and minimum gas generation commitment	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-	-
Summer Peak with high SVP forecasted load			PG&E Greater Bay Area
Summer Peak with forecasted load addition	VEA Area	VEA Area	
Summer Off peak with heavy renewable output		VEA Area	
Summer Peak with Retirement of QF Generations	-	-	PG&E Kern Area
Summer Peak without Facility Rerates			PG&E Bulk PG&E Local Areas

2.11.4 Sensitivity Scenario Definitions and Renewable Generation Dispatch

Table 2.11-4: Sensitivity Scenario Definitions and Renewable Generation Dispatch

PTO	Scenario	Starting Baseline Case	BTM-PV		Transmission Connected PV		Transmission Connected Wind		Comment
			Baseline	Sensitivity	Baseline	Sensitivity	Baseline	Sensitivity	
PG&E	Summer Peak with high CEC forecasted load	2025 Summer Peak	3%	3%	2%	2%	71%	71%	Load increased by turning off AAEE
	Off peak with heavy renewable output and minimum gas generation commitment	2025 Spring Off-peak	80%	99%	92%	99%	20%	64%	Solar and wind dispatch increased to average of 20% exceedance values
	Summer Peak with heavy renewable output and minimum gas generation commitment	2022 Summer Peak	17%	99%	10%	99%	62%	62%	Solar and wind dispatch increased to 20% exceedance values
	Summer Peak with Retirement of QF Generations	2030 Summer Peak	0%	0%	0%	0%	42%	42%	All QF facilities in Kern area turned off
	Summer Peak with high SVP forecasted load	2030 Summer Peak	0%	0%	0%	0%	42%	42%	Use SPV's forecast for 2030
	Summer Peak without Facility Rerates	2030 Summer Peak	0%	0%	0%	0%	42%	42%	Study to be performed using regular (non-rerated) facility ratings
SCE	Summer Peak with high CEC forecasted load	2025 Summer Peak	23%	23%	21%	21%	25%	25%	Load increased per CEC high load scenario
	Off peak with heavy renewable output and minimum gas generation commitment	2025 Spring Off-peak	81%	91%	94%	99%	34%	67%	Solar and wind dispatch increased to 20% exceedance values
	Summer Peak with heavy renewable output and minimum gas generation commitment	2022 Summer Peak	44%	91%	51%	99%	20%	0%	Solar and wind dispatch decreased with net load unchanged
SDG&E	Summer Peak with high CEC forecasted load	2025 Summer Peak	0%	0%	0%	0%	33%	33%	Load increased per CEC high load scenario
	Off peak with heavy renewable output and minimum gas generation commitment	2025 Spring Off-peak	80%	96%	95%	96%	30%	51%	Solar and wind dispatches increased to 20% exceedance values with net load unchanged at 57% of summer peak
	Summer Peak with heavy renewable output and minimum gas generation commitment	2022 Summer Peak	0%	96%	0%	96%	33%	51%	Solar and wind dispatches increased to 20% exceedance values
VEA	Summer Peak with forecasted load addition	2022 Summer Peak			51%	51%			Load increase reflect future load service request
	Summer Peak with forecasted load addition	2025 Summer Peak			21%	21%			Load increase reflect future load service request
	Off-peak with heavy renewable output	2025 Spring Off-peak			0%	96%			Modeled active GIDAP projects in the queue

2.12 Study Base Cases

The power flow base cases from WECC will be used as the starting point of the CAISO transmission plan base cases. Table 2.12-1 shows WECC base cases will be used to represent the area outside the CAISO control area for each study year. For dynamic stability studies, the latest WECC Master Dynamics File (from November 1, 2019) will be used as a starting point. Dynamic load models will be added to this file.

Table 2.12-1: Summary of WECC Base Cases used to represent system outside CAISO

Study Year	Season	WECC Base Case	Year Published
2022	Summer Peak	20HS3a1	2019
	Winter Peak	20HW3a1	2019
	Spring Off-Peak	20LSP1sa1	2019
2025	Summer Peak	25HS2a1	2019
	Winter Peak	25HW2a1	2019
	Spring Off-Peak	20LSP1sa1	2019
2030	Summer Peak	30HS1a1	2019
	Winter Peak	30HW1a1	2019
	Spring Off-Peak	30LSP1Sa1	2019
	Winter Off-Peak	30LSP1Sa1	2019

During the course of developing the transmission plan base cases, the portion of areas that will be studied in each WECC base case will be updated by the latest information provided by the PTOs. After the updated topology has been incorporated, the base cases will be adjusted to represent the conditions outlined in the Study Plan. For example, a 2024 summer peak base case for the northern California will use 24HS2a1 base case from WECC as the starting point. However, the network representation in northern California will be updated with the latest information provided by the PTO followed by some adjustments on load level or generation dispatch to ensure the case represents the assumptions described in this document. This practice will result in better accuracy of network representation both inside and outside the study area.

The CAISO will identify known or expected outages of generation or transmission facilities within the near-term planning horizon, which begins January 1, 2021, and will provide list of such outages in the Final Study Planbased on information obtained from PTOs, generation owners and other entities along with relevant data from the CAISO Outage Management System (OMS). Assessment will be performed for the P0 and P1 categories for the known outages expected to produce more severe system impacts unless the known outage has comparable post-contingency system conditions and configuration such as those following P3 or P6 category events.

The assessment will be used to identify issues or conflicts associated with the planned outages. This may involve comparing simulation results with and without the planned outages for the critical contingencies identified. In accordance with Requirement R4 of IRO-017-1, the CAISO and PTOs will collaborate with RC West in developing solutions for the planned outage related issues affecting the near term transmission planning horizon.

Table 2.12-2 provides known[43] or expected outages of generation or transmission facilities in the near-term planning horizon, which begins January 1, 2021, based on information obtained from PTOs, generation owners and other entities along with relevant data from the CAISO Outage Management System (OMS). Outages applicable to non-study years will be modeled in future planning cycles as shown.

Table 2.12-2: Known or expected outages of generation and transmission facilities in the near-term planning horizon[44]

Outage ID	PTO Area	Facility Affected	Outage Description
6001393	PG&E	Moss Landing	Gen outage
5125026 5125031 8300563 8300677	SCE	High Desert Power Project	Plant Maintenance

The assessment will be used to identify issues or conflicts associated with the planned outages. This may involve comparing simulation results with and without the planned outages for the critical contingencies identified. In accordance with Requirement R4 of IRO-017-1, the CAISO and PTOs will collaborate with RC West in developing solutions for the planned outage related issues affecting the near term transmission planning horizon.

43 TPL-001-4 Requirement R1 section 1.1.2

44 Planned outages are subject to change.

2.13 Contingencies:

In addition to the system under normal conditions (P0), the following categories of contingencies on the BES equipment will be evaluated as part of the study. For the non-BES facilities under CAISO operational control, as mentioned in section 3.1.3, TPL-001-5 categories P0, P1 and P3 contingencies will be evaluated. These contingencies lists will be made available on the CAISO secured website.

Single contingency (Category P1)
The assessment will consider all possible Category P1 contingencies based upon the following:

- Loss of one generator (P1.1)[45][46]
- Loss of one transmission circuit (P1.2)
- Loss of one transformer (P1.3)
- Loss of one shunt device (P1.4)
- Loss of a single pole of DC lines (P1.5)

Single contingency (Category P2)
The assessment will consider all possible Category P2 contingencies based upon the following:

- Loss of one transmission circuit without a fault (P2.1)
- Loss of one bus section (P2.2)
- Loss of one breaker (internal fault) (non-bus-tie-breaker) (P2.3)
- Loss of one breaker (internal fault) (bus-tie-breaker) (P2.4)

Multiple contingency (Category P3)
The assessment will consider the Category P3 contingencies with the loss of a *generator unit* followed by system adjustments and the loss of the following:

- Loss of one generator (P3.1)[47]
- Loss of one transmission circuit (P3.2)
- Loss of one transformer (P3.3)
- Loss of one shunt device (P3.4)
- Loss of a single pole of DC lines (P3.5)

Multiple contingency (Category P4)
The assessment will consider the Category P4 contingencies with the loss of multiple elements caused by a stuck breaker (non-bus-tie-breaker for P4.1-P4.5) attempting to clear a fault on one of the following:

- Loss of one generator (P4.1)
- Loss of one transmission circuit (P4.2)
- Loss of one transformer (P4.3)
- Loss of one shunt device (P4.4)
- Loss of one bus section (P4.5)
- Loss of a bus-tie-breaker (P4.6)

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[45] Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.
[46] All generators with nameplate rating exceeding 20 MVA must be included in the contingency list
[47] Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.

Multiple contingency (Category P5)
The assessment will consider the Category P5 contingencies with delayed fault clearing due to the failure of a non-redundant component of protection system protecting the faulted element to operate as designed, for one of the following:

- Loss of one generator (P5.1)
- Loss of one transmission circuit (P5.2)
- Loss of one transformer (P5.3)
- Loss of one shunt device (P5.4)
- Loss of one bus section (P5.5)

Multiple contingency (Category P6)
The assessment will consider the Category P6 contingencies with the loss of two or more (non-generator unit) elements with system adjustment between them, which produce the more severe system results.

Multiple contingency (Category P7)
The assessment will consider the Category P7 contingencies for the loss of a common structure as follows:

- Any two adjacent circuits on common structure[48] (P7.1)
- Loss of a bipolar DC lines (P7.2)

Extreme contingencies (TPL-001-5)

As a part of the planning assessment the CAISO assesses Extreme Event contingencies per the requirements of TPL-001-5; however the analysis of Extreme Events will not be included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.

[48] Excludes circuits that share a common structure or common right-of-way for 1 mile or less.

2.14 Study Tools

The General Electric Positive Sequence Load Flow (GE PSLF) is the main study tool for evaluating system performance under normal conditions and following the outages (contingencies) of transmission system components for post-transient and transient stability studies. PowerGem TARA is used for steady state contingency analysis. However, other tools such as DSA tools software may be used in other studies such as voltage stability, small signal stability analyses and transient stability studies. The studies in the local areas focus on the impact from the grid under system normal conditions and following the Categories P1-P7 outages of equipment at the voltage level 60 through 230 kV. In the bulk system assessments, governor power flow will be used to evaluate system performance following the contingencies of equipment at voltage level 230 kV and higher.

2.14.1 Technical Studies

The section explains the methodology that will be used in the study:

2.14.2 Steady State Contingency Analysis

The CAISO will perform power flow contingency analyses based on the CAISO Planning Standards[49] which are based on the NERC reliability standards and WECC regional criteria for all local areas studied in the CAISO controlled grid and with select contingencies outside of the CAISO controlled grid. The transmission system will be evaluated under normal system conditions NERC Category P0 (TPL 001-5), against normal ratings and normal voltage ranges, as well as emergency conditions NERC Category P1-P7 (TPL 001-5) contingencies against emergency ratings and emergency voltage range as identified in Section 4.1.6.

Depending on the type and technology of a power plant, several G-1 contingencies represent an outage of the whole power plant (multiple units)[50]. Examples of these outages are combined cycle power plants such as Delta Energy Center and Otay Mesa power plant. Such outages are studied as G-1 contingencies.

Line and transformer bank ratings in the power flow cases will be updated to reflect the rating of the most limiting component. This includes substation circuit breakers, disconnect switches, bus position related conductors, and wave traps.

The contingency analysis will simulate the removal of all elements that the protection system and other automatic controls are expected to disconnect for each contingency without operator intervention. The analyses will include the impact of subsequent tripping of transmission elements

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[49] California ISO Planning Standards are posted on the ISO website at http://www.caiso.com/Documents/ISOPlanningStandards-November22017.pdf

[50] Per California ISO Planning standards Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard

where relay loadability limits are exceeded and generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations unless corrective action plan is developed to address the loading and voltages concerns.

Power flow studies will be performed in accordance with PRC-023 to determine which of the facilities (transmission lines operated below 200 kV and transformers with low voltage terminals connected below 200 kV) in the Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities below 200 kV that must meet PRC-023 to prevent potential cascade tripping that may occur when protective relay settings limit transmission load ability.

2.14.3 Post Transient Analyses

Post Transient analyses will be conducted to determine if the system is in compliance with the WECC Post Transient Voltage Deviation Standard in the bulk system assessments and if there are thermal overloads on the bulk system.

2.14.4 Post Transient Voltage Stability Analyses

Post Transient Voltage stability analyses will be conducted as part of bulk system assessment for the outages for which the power flow analyses indicated significant voltage drops, using two methodologies: Post Transient Voltage Deviation Analyses and Reactive Power Margin analyses.

2.14.5 Post Transient Voltage Deviation Analyses

Contingencies that showed significant voltage deviations in the power flow studies will be selected for further analysis using WECC standards.

2.14.6 Voltage Stability and Reactive Power Margin Analyses

Contingencies that showed significant voltage deviations in the power flow studies may be selected for further analysis using WECC standards. As per WECC regional criterion, voltage stability is required for the area modeled at a minimum of 105% of the reference load level or path flow for system normal conditions (Category P0) and for single contingencies (Category P1). For other contingencies (Category P2-P7), post-transient voltage stability is required at a minimum of 102.5% of the reference load level or path flow. The approved guide for voltage support and reactive power, by WECC TSS on March 30, 2006, will be utilized for the analyses in the CAISO controlled grid. According to the guideline, load will be increased by 5% for Category P1 and 2.5% for other contingencies Category P2-P7 and will be studied to determine if the system has sufficient reactive margin. This study will be conducted in the areas that have voltage and reactive concerns throughout the system.

2.14.7 Transient Stability Analyses

Transient stability analyses will also be conducted as part of bulk area system assessment for critical contingencies to determine if the system is stable and exhibits positive damping of oscillations and if transient stability criteria are met as per WECC criteria and CAISO Planning Standards. No generating unit shall pull out of synchronism for planning event P1. For planning events P2 through P7: when a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any transmission system elements other than the generating unit and its directly connected facilities.

The analysis will simulate the removal of all elements that the protection system and other automatic controls are expected to disconnect for each contingency without operator intervention. The analyses will include the impact of subsequent:

- Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a fault where high speed reclosing is utilized.
- Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability.
- Tripping of transmission lines and transformers where transient swings cause protection system operation based on generic or actual relay models.

The expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities will be simulated when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

2.15 Corrective Action Plans

Corrective action plans will be developed to address reliability concerns identified through the technical studies mentioned in the previous section. The CAISO will consider both transmission and non-transmission alternatives in developing the required corrective action plans. Within the non-transmission alternative, consideration will be given to both conventional generation and in particular, preferred resources such as energy efficiency, demand response, renewable generating resources and energy storage programs. In making this determination, the CAISO, in coordination with each Participating TO with a PTO Service Territory and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects, demand-side management, special protection systems, generation curtailment, interruptible loads, storage facilities or reactive support. The CAISO uses deficiencies identified in sensitivity studies mostly to help develop scope for corrective action plans required to mitigate deficiencies identified in baseline studies. However, the CAISO might consider developing corrective action plan for deficiencies identified in sensitivity studies on a case by case basis.

3 Policy Driven RPS Transmission Plan Analysis

With FERC's approval of the CAISO's revised TPP in December 2010, the specification of public policy objectives for transmission planning was incorporated into phase 1 of the TPP.

3.1 Public Policy Objectives

The TPP framework includes a category of transmission additions and upgrades to enable the CAISO to plan for and approve new transmission needed to support state or federal public policy requirements and directives. The impetus for the "policy-driven" category was the recognition that California's renewable energy goal would drive the development of substantial amounts of new renewable supply resources over the next decade, which in turn would drive the majority of new transmission needed in the same time frame. It was also recognized that new transmission needed to support the state's renewable energy goal would most likely not meet the criteria for the two predominant transmission categories of reliability and economic projects.

Evaluation of the need for policy-driven transmission elements begins in Phase 1 with the CAISO's specification, in the context of the unified planning assumptions and study plan, of the public policy objectives it proposes to adopt for transmission planning purposes in the current cycle. For the 2020-2021 planning cycle, the overarching public policy objective is the state's mandate for meeting renewable energy targets and greenhouse gas (GHG) reduction target by 2030 as described in Senate Bill (SB) 350 as well as in Senate Bill (SB) 100. For purposes of the TPP study process, this high-level objective is comprised of two sub-objectives: first, to support the delivery of renewable energy over the course of all hours of the year, and second, to support Resource Adequacy (RA) deliverability status for the renewable resources identified in the portfolio as requiring that status.

The CAISO and the CPUC have a memorandum of understanding under which the CPUC provides the renewable resource portfolio or portfolios for CAISO to analyze in the CAISO's annual TPP. The CPUC adopted the integrated resource planning (IRP) process designed to ensure that the electric sector is on track to help the State achieve its 2030 greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals.

3.2 Renewable portfolios to be analyzed for policy-driven assessment

In order to provide a general planning direction to the electric sector, the CPUC is expected to adopt a portfolio of energy resources to meet this 2030 GHG reduction target. CPUC's Proposed Decision[51] mailed on February 21, 2020 recommended transmittal of a base portfolio along with

[51] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M327/K750/327750339.PDF

two sensitivity portfolios to the CAISO to be studied as part of the policy-driven assessment in 2020-2021 TPP.

As part of the 2019-2020 IRP, the CPUC staff developed the “base” and “sensitivity” portfolios using RESOLVE capacity expansion model. RESOLVE documentation specifies that renewable resources under development with CPUC-approved contracts with the three investor-owned utilities are assumed to be part of the baseline assumptions. The CAISO will work with the CPUC to identify such resources and model these in the reliability assessment base cases. The CAISO may supplement this scenario with information regarding contracted RPS resources that are under construction as of March 2019. The generic resources selected as portfolio resources are at a geographic scale that is too broad for transmission planning purpose which required specific interconnection locations. The CEC and CPUC staff refined the geographically coarse resource portfolios into plausible network modeling locations for the purpose of transmission analysis.

CPUC staff report (Release 1[52] and Release 2[53]) describes methodology and results of the 2019 busbar mapping process performed by the CPUC and CEC with support from CAISO. Busbar mapping results[54] posted by the CEC staff show specific substations recommended for modeling generic portfolios resources as part of the 2020-2021 TPP.

3.3 Coordination with Phase II of GIP

According to tariff Section 24.4.6.5 and in order to better coordinate the development of potential infrastructure from transmission planning and generation interconnection processes the CAISO may coordinate the TPP with generator interconnection studies. In general, Network Upgrades and associated generation identified during the Interconnection Studies will be evaluated and possibly included as part of the TPP. The details of this process are described below.

Generator Interconnection Network Upgrade Criteria for TPP Assessment

Beginning with the 2012-2013 planning cycle, generator interconnection Network Upgrades may be considered for potential modification in the TPP if the Network Upgrade:

- Consists of new transmission lines 200 kV or above and have capital costs of $100 million or more;
- Is a new 500 kV substation that has capital costs of $100 million or more; or
- Has a capital cost of $200 million or more.

Notification of Network Upgrades being assessed in the TPP

In approximately June of 2019 the CAISO will publish the list of generator interconnection Network Upgrades that meet at least one of these criteria and have been selected for consideration in TPP Phase 2. The comprehensive Transmission Plan will contain the results of the CAISO's

52 file://homefiles/home/sbarave/profile/Downloads/Modeling_Assumptions_2020_2021_TPP-Report-Release1%20(5).pdf

53 To be posted by the CPUC at - https://www.cpuc.ca.gov/General.aspx?id=6442464144

54 https://caenergy.databasin.org/galleries/eab0ce3a5be447ce928a310e80c65c8d#expand=208848

evaluation of the identified Network Upgrades. Network Upgrades evaluated by the CAISO but not modified as part of the comprehensive Transmission Plan will proceed to Generator Interconnection Agreements (GIAs) through the Generator Interconnection and Deliverability Allocation Procedure (GIDAP) and will not be further addressed in the TPP. Similarly, GIP Network Upgrades that meet the tariff criteria but were not evaluated in the TPP will proceed to GIAs through the GIDAP.

All generation projects in the Phase II cluster study have the potential to create a need for Network Upgrades. As a result, the CAISO may need to model some or all of these generation projects and their associated transmission upgrades in the TPP base cases for the purpose of evaluating alternative transmission upgrades. However, these base cases will be considered sensitivity base cases in addition to the base cases developed under the Unified Planning Assumptions. These base cases will be posted on the CAISO protected web-site for stakeholder review. Study results and recommendations from these cases will be incorporated in the comprehensive transmission plan.

Transmission Planning Deliverability

Section 8.9 of the GIDAP specifies that an estimate of the generation deliverability supported by the existing system and approved transmission upgrades will be determined from the most recent Transmission Plan. Transmission plan deliverability (TPD) is estimated based on the area deliverability constraints identified in recent generation interconnection studies without considering local deliverability constraints. For study areas in which the TPD is greater than the MW amount of generation in the CAISO interconnection queue, TPD is not quantified.

4 Economic Planning Study

The CAISO will perform an Economic Planning Study as part of the current planning cycle to identify potential congestion and propose mitigation plans. The study will quantify the economic benefits for the CAISO ratepayers based on Transmission Economic Assessment Methodology (TEAM). Through the evaluation of the congestion and other benefits, and review of the study requests, the CAISO will determine the high priority studies to be conducted during the 2020-2021 transmission planning cycle.

4.1 Renewable Generation

The CPUC adopted the integrated resource planning (IRP) process designed to ensure that the electric sector is on track to help the State achieve its 2030 greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals.

The Proposed Decision from the CPUC to recommend transmittal of a base portfolio along with two sensitivity portfolios will be used in the 2020-2021 TPP. The Base Portfolio will be used in economic assessment in the 2020-2021 TPP.

4.2 Congestion and Production Benefit Assessment

Production cost simulation is used to identify transmission congestion and quantify the energy benefit based on TEAM. The production cost model (PCM) will be developed, using the 2030 anchor dataset (ADS) PCM as the staring database[55], based on the same assumptions as the Reliability Assessment and Policy Driven Transmission Plan Analysis with the following exception:

- The 1-in-2 demand forecast will be used in the assessment.

The Economic Planning Study will conduct hourly analysis 2030 (the 10th planning year) through production simulation, and for year 2025 (the 5th planning year) as optional if it is needed for providing a data point in the production benefit assessment for transmission project economic justification.

4.3 Study Request

As part of the requirements under the CAISO tariff and Business Practice Manual, Economic Planning Study Requests are to be submitted to the CAISO during the comment period following the stakeholder meeting to discuss this Study Plan. The CAISO will consider the Economic Planning Study Requests as identified in section 24.3.4.1 of the CAISO Tariff.

[55] The 2030 ADS PCM is developed in the Western Interconnection ADS process, and is scheduled to be available by June 30, 2020.

Table 4.3-1: Economic study requests

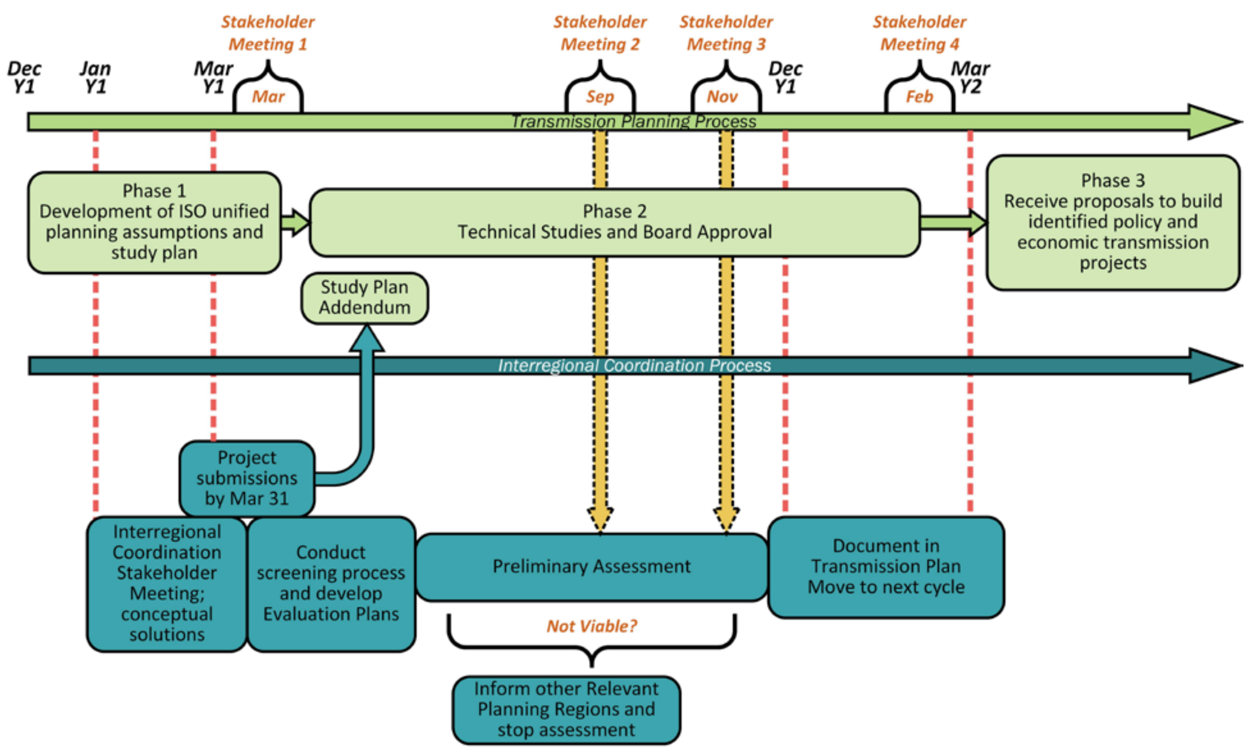
No.	Study Request	Submitted By	Location
1	Congestion on Doublet Tab to Friars 138 kV in SDG&E area	Calpine Corporation	Southern California SDG&E area
2	Congestion on Gates to Tulare Lake 70 kV in PG&E Fresno area	conEdison Development	Northern California PG&E area
3	GridLiance West/VEA system upgrades	GridLiance West LLC	Southern Nevada GridLiance/VEA
4	COI congestion and SWIP-North project	LS Power Development LLC	California/Oregon, Idaho/Nevada
5	Flow Control for Congestion Reduction on the California-Oregon Intertie (COI)	SmartWires	Northern California PG&E area
6	Economic Study Requests to Reduce Local Capacity Requirements (LCR) Using Power Flow Control	SmartWires	a. South Bay – Moss Landing sub-area b. Ames-Pittsburg-Oakland sub-area c. Fresno area d. Western LA Basin sub-area
7	Path 26 congestion study	SouthWestern Power Group	Northern/Southern California PG&E and SCE areas
8	Pacific Transmission Expansion Project (PTE Project)	Western Grid Development LLC	Northern/Southern California PG&E and SCE areas

5 Interregional Coordination

During the CAISO's 2020-2021 planning cycle, the CAISO will, in coordination with the other western planning regions, initiate the 2020-2021 interregional transmission coordination cycle. During the even year of the interregional transmission coordination cycle the CAISO will complete the following key activities:

- Host an open window (January 1 through March 31) for proposed interregional transmission projects to be submitted to the CAISO for consideration in the CAISO's 2020-2021 TPP planning cycle;
- Participate in a western planning regions' stakeholder meeting; and
- In coordination with other Relevant Planning Regions[56], prepare evaluation process plans for all interregional transmission projects submitted to and validated by the CAISO. Once the evaluation process plans have been finalized, they will be included in Appendix B of this study plan. Figure 4.2-1 illustrates the interregional coordination process for the odd year of the 2 year cycle.

Figure 4.2-1 Even Year Interregional Coordination Process



[56] A Relevant Planning Region means, with respect to an interregional transmission project, the western planning regions that would directly interconnect electrically with the interregional transmission project, unless and until such time as a Relevant Planning Region determines that such interregional transmission project will not meet any of its regional transmission needs, at which time it would no longer be considered a Relevant Planning Region.

The CAISO will keep stakeholders informed about its interregional activities through the stakeholder meetings identified in Table 1.1-1. Current information related to the interregional transmission coordination effort may be found on the interregional transmission coordination webpage is located at the following link:

http://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx

Looking to the even year of the interregional transmission coordination process, a new planning region, NorthernGrid, is being formed and will likely become operation sometime in early 2020. NorthernGrid will encompass the areas currently organized through the Northern Tier Transmission Group and ColumbiaGrid. Once NorthernGrid is fully operational, the Northern Tier and ColumbiaGrid planning regions will be dissolved. While the process to finalize the NorthernGrid planning region remains in progress, the CAISO, in coordination with representatives of the WestConnect planning region, remain engaged with the entities associated with the transition to NorthernGrid to ensure that the coordination processes that have been in place and utilized for the last two interregional transmission coordination cycles will remain in place. Any modifications will be handled through the interregional transmission coordination process.

6 Other Studies

6.1 Local Capacity Requirement Assessment

6.1.1 Near-Term Local Capacity Requirement (LCR)

The local capacity studies focus on determining the minimum MW capacity requirement within each of local areas inside the CAISO Balancing Authority Area. The Local Capacity Area Technical Study determines capacity requirements used as the basis for procurement of resource adequacy capacity by load-serving entities for the following resource adequacy compliance year and also provides the basis for determining the need for any CAISO "backstop" capacity procurement that may be needed once the load-serving entity procurement is submitted and evaluated.

Scenarios

The near-term local capacity studies will be performed for at least 2 years:

- 2021 – Local Capacity Area Technical Study
- 2025 – Mid-Term Local Capacity Requirements

Please note that in order to meet the CPUC deadline for capacity procurement by CPUC-jurisdictional load serving entities, the CAISO will complete the LCR studies approximately by May 1, 2020.

Load Forecast

The latest available CEC load forecast, at the time of base case development, will be used as the primary source of future demand modeled in the base cases. The 1-in-10 load forecast for each local area is used.

Transmission Projects

CAISO-approved transmission projects will be modeled in the base case. These are the same transmission project assumptions that are used in the reliability assessments and discussed in the previous section.

Imports

The LCR study models historical imports in the base case; the same as those used in the RA Import Allocation process

Methodology

A study methodology documented in the LCR manual will be used in the study. This document is posted on CAISO website at:

http://www.caiso.com/Documents/2021LocalCapacityRequirementsFinalStudyManual.pdf

Tools

GE PSLF and PowerGEM TARA will be used in the LCR study.

Since LCR is part of the overall CAISO Transmission Plan, the Near-Term LCR reports will be posted on the 2020-2021 CAISO Transmission Planning Process webpage.

6.1.2 Long-Term Local Capacity Requirement Assessment

Based on the alignment[57] of the CAISO transmission planning process with the CEC Integrated Energy Policy Report (IEPR) demand forecast and the CPUC Integrated Resource Plan (IRP), the long-term LCR assessment is to take place every two years. The long-time LCR study was performed in the 2018-2019 Transmission Plan and therefore the 2020-2021 transmission planning process will include a 10 year out study.

6.2 Long-Term Congestion Revenue Rights (LT CRR)

The CAISO is obligated to ensure the continuing feasibility of Long Term CRRs (LT-CRRs) that are allocated by the CAISO over the length of their terms. As such, the CAISO, as part of its annual TPP cycle, shall test and evaluate the simultaneous feasibility of allocated LT-CRRs, including, but not limited to, when acting on the following types of projects: (a) planned or proposed transmission projects; (b) Generating Unit or transmission retirements; (c) Generating Unit interconnections; and (d) the interconnection of new Load. While the CAISO expects that released LT-CRRs will remain feasible during their full term, changes to the interconnected network will occur through new infrastructure additions and/or modifications to existing infrastructure. To ensure that these infrastructure changes to the transmission system do not cause infeasibility in certain LT-CRRs, the CAISO shall perform an annual Simultaneous Feasibility Test (SFT) analysis to demonstrate that all released CRRs remain feasible. In assessing the need for transmission additions or upgrades to maintain the feasibility of allocated LT- CRRs, the CAISO, in coordination with the PTOs and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects, demand-side management, Remedial Action Schemes, constrained-on Generation, interruptible loads, reactive support, or in cases where the infeasible LT- CRRs involve a small magnitude of megawatts, ensuring against the risk of any potential revenue shortfall using the CRR Balancing Account and uplift mechanism in Section 11.2.4 of the CAISO tariff.

6.3 Frequency Response Assessment

The CAISO has conducted studies into frequency response and headroom requirements for potential over-supply conditions since the 2014-2015 transmission planning processes. The study results indicated acceptable frequency performance within WECC; however the CAISO's frequency response may fall below the CAISO frequency response obligation specified in NERC reliability standard BAL-003-1. While these initial studies were conducted as special studies –

[57] http://www.caiso.com/Documents/TPP-LTPP-IEPR_AlignmentDiagram.pdf

optional studies not required by the CAISO tariff – these will now be conducted as an ongoing study requirement supporting mandatory standards efforts.

Compared to the CAISO's actual system performance during disturbances, the study results seem optimistic because actual frequency responses for some contingencies were lower than the dynamic model indicated and further model validation was found to be needed to ensure that governor response in the simulations aligns with the actual response on the system.

The model validation was initiated in the 2016-2017 planning cycle and continued in the 2018-2019 transmission planning process. The CAISO will continue to assess the validation of models as a separate effort and will conduct future frequency response assessments using the updated generator models that are available from the generator owners.

7 Contact Information

This section lists the Subject Matter Experts (SMEs) for each technical study or major stakeholder activity addressed in this document. In addition to the extensive discussion and comment period during and after various CAISO Transmission Plan-related Stakeholder meetings, stakeholders may contact these individuals directly for any further questions or clarifications.

Figure 7-1: SMEs for Technical Studies in 2020-2021 Transmission Planning Process

Item/Issues	SME	Contact
Reliability Assessment in PG&E	Binaya Shrestha	bshrestha@caiso.com
Reliability Assessment in SCE	Nebiyu Yimer	nyimer@caiso.com
Reliability Assessment in SDG&E	Frank Chen	fchen@caiso.com
Reliability Assessment in VEA	Meng Zhang	mezhang@caiso.com
Policy-driven Assessment	Sushant Barave	sbarave@caiso.com
Local Capacity Requirements	Catalin Micsa	cmicsa@caiso.com
Economic Planning Study	Yi Zhang	yzhang@caiso.com
Long-term Congestion Revenue Rights	Bryan Fong	bfong@caiso.com

8 Stakeholder Comments and CAISO Responses

Stakeholders are hereby requested to submit their comments to:

regionaltransmission@caiso.com

All the comments the CAISO receives from stakeholders on this 2020-2021 draft study plan and CAISO's responses will be posted to the following link:

http://www.caiso.com/planning/Pages/TransmissionPlanning/2020-2021TransmissionPlanningProcess.aspx

APPENDIX A

System Data

A1 Existing Generation

Table A1-1: Existing generation capacity within the CAISO planning area

PTO	Existing Generation Nameplate Capacity (MW)										
	Nuclear	Natural Gas	Hydro	Solar	Wind	Biogas	Biomass	Geothermal	Battery Storage	Other	Total
PG&E	2352	13756	8394	3618	1434	113	563	1413	7	268	31938
SCE	0	14545	2756	6318	4269	156	2	343	50	952	29391
SDG&E	0	3746	46	2155	601	18	0	0	81	106	6752
VEA	0	0	0	115	0	0	0	0	0	0	115
Total	2352	32047	11195	12206	6304	306	565	1756	138	1326	68195

For detail resource information, please refer to Master Control Area Generating Capability List in OASIS under ATLAS REFERENCE tab at the following link: http://oasis.caiso.com/mrioasis

A2 Once-through Cooled Generation

Table A2-1: Once-through cooled generation in the California ISO BAA

Generating Facility	Owner	Existing Unit/ Technology[58] (ST=Steam CCGT=Combine-Cycled Gas Turbine)	State Water Resources Control Board (SWRCB) Compliance Date	Retirement Date (If already retired or have plans to retire)	Net Qualifying Capacity (NQC) (MW)	Repowering Capacity[59] (MW) and Technology[60] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
Humboldt Bay	PG&E	1 (ST)	12/31/2010	9/30/2010	52	163 MW (10 ICs)	9/28/2010	Retired 135 MW and repowered with 10 ICs (163 MW)
		2 (ST)	12/31/2010		53			
Contra Costa	GenOn	6 (ST)	12/31/2017	April 30, 2013	337	Replaced by 760 MW Marsh Landing power plant (4 GTs)	May 1, 2013	New Marsh Landing GTs are located next to retired generating facility.
		7 (ST)	12/31/2017		337			
Pittsburg	GenOn	5 (ST)	12/31/2017	12/31/2016	312	Retired (no repowering plan)	N/A	
		6 (ST)	12/31/2017		317			
Potrero	GenOn	3 (ST)	10/1/2011	2/28/2011	206	Retired (no repowering plan)	N/A	
Moss Landing	Dynegy	1 (CCGT)	12/31/2020* (see notes at far right column)	N/A	510	The State Water Resources Control Board (SWRCB) approved mitigation plan (Track 2 implementation plan) for Moss Landing Units 1 & 2.	N/A	The State Water Resources Control Board (SWRCB) approved OTC Track 2 mitigation plan for Moss Landing Units 1 & 2.
		2 (CCGT)	12/31/2020* (see notes at far right column)	N/A	510			
		6 (ST)	12/31/2020 (see notes)	1/1/2017	754	Retired (no repowering plan)	N/A	
		7 (ST)	12/31/2020 (see notes)	1/1/2017	756	Retired (no repowering plan)	N/A	
Morro Bay	Dynegy	3 (ST)	12/31/2015	2/5/2014	325	Retired (no repowering plan)	N/A	

[58] Most of the existing OTC units, with the exception of Moss Landing Units 1 and 2, are steam generating units.

[59] The ISO, through Long-Term Procurement Process and annual Transmission Planning Process, worked with the state energy agencies and transmission owners to implement an integrated and comprehensive mitigation plan for the southern California OTC and SONGS generation retirement located in the LA Basin and San Diego areas. The comprehensive mitigation plan includes preferred resources, transmission upgrades and conventional generation.

[60] IC (Internal Combustion), GT (gas turbine), CCGT (combined cycle gas turbine)

Generating Facility	Owner	Existing Unit/ Technology[58] (ST=Steam CCGT=Combine-Cycled Gas Turbine)	State Water Resources Control Board (SWRCB) Compliance Date	Retirement Date (If already retired or have plans to retire)	Net Qualifying Capacity (NQC) (MW)	Repowering Capacity[59] (MW) and Technology[60] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
		4 (ST)	12/31/2015	2/5/2014	325	Retired (no repowering plan)	N/A	
Diablo Canyon Nuclear Power Plant	PG&E	1 (ST)	11/2/2024[61]	11/2/2024	1122	PG&E plans to replace with renewable energy, energy efficiency and energy storage.	N/A	On June 21, 2016, PG&E has announced that it planned to retire Units 1 and 2 by 2024 and 2025, respectively.
		2 (ST)	8/26/2025	8/26/2025	1118			
Mandalay	GenOn	1 (ST)	12/31/2020	2/6/2018	215	Retired (no repowering)		Mandalay generating facility was retired on February 6, 2018.
		2 (ST)	12/31/2020	2/6/2018	215	SCE plans to replace with renewable energy and storage		
Ormond Beach	GenOn	1 (ST)	12/31/2020	12/31/2023	741	To be retired (no repowering)	N/A	On January 23, 2020, the SACCWIS recommended compliance schedule extension for the State Water Board's consideration and decision[62]
		2 (ST)	12/31/2020	12/31/2023	775			
El Segundo	NRG	3 (ST)	12/31/2015	7/27/2013	335	560 MW El Segundo Power Redevelopment (CCGTs)	August 1, 2013	Unit 3 was retired on 7/27/2013.
		4 (ST)	12/31/2015	12/31/2015	335	Retired (no repowering)	N/A	Unit 4 was retired on December 31, 2015.
Alamitos	AES	1 (ST)	12/31/2020	1/1/2020	175	640 MW CCGT on the same property	4/1/2020	Units 1, 2 and 6 were retired on January 1, 2020 to provide emission offsets to repowering project (non-OTC units). Units 3, 4 and 5 were recommended to have
		2 (ST)	12/31/2020	1/1/2020	175			
		3 (ST)	12/31/2020	12/31/2023	332			
		4 (ST)	12/31/2020	12/31/2023	336			
		5 (ST)	12/31/2020	12/31/2023	498			

[61] The State Water Resources Control Board proposed new compliance dates at https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2020/ppamd_updated.docx

[62] https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/final_report.pdf

Generating Facility	Owner	Existing Unit/ Technology[58] (ST=Steam CCGT=Combine-Cycled Gas Turbine)	State Water Resources Control Board (SWRCB) Compliance Date	Retirement Date (If already retired or have plans to retire)	Net Qualifying Capacity (NQC) (MW)	Repowering Capacity[59] (MW) and Technology[60] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
		6 (ST)	12/31/2020	1/1/2020	495			compliance schedule extension by SACCWIS.for the State Water Board's consideration and decision[63]
Huntington Beach	AES	1 (ST)	12/31/2020	1/1/2020	226	644 MW CCGT on the same property	3/1/2020	Unit 1 was retired to provide emission offsets to repowering project (non-OTC units). Unit 2 was recommended to have compliance schedule extension by SACCWIS for the State Water Board's consideration and decision.[64]
		2 (ST)	12/31/2020	12/31/2023	226			
		3 (ST)	12/31/2020	11/1/2012	227			Units 3 and 4 were retired in 2012 and converted to synchronous condensers in June 2013 to operate on an interim basis. On December 31, 2017, these two synchronous condensers were retired.
		4 (ST)	12/31/2020	11/1/2012	227			
Redondo Beach	AES	5 (ST)	12/31/2020	12/31/2021	179	To be retired	N/A	Unit 7 was retired to provide emission offsets to repowering project at Huntington Beach. Units 5, 6 and 8 were recommended to have compliance schedule extension by SACCWIS for the State Water Board's consideration and decision.[65]
		6 (ST)	12/31/2020	12/31/2021	175			
		7 (ST)	12/31/2020	10/1/2019	493			
		8 (ST)	12/31/2020	12/31/2021	496			

63 Ibid.

64 Ibid.

65 Ibid.

Generating Facility	Owner	Existing Unit/ Technology[58] (ST=Steam CCGT=Combine-Cycled Gas Turbine)	State Water Resources Control Board (SWRCB) Compliance Date	Retirement Date (If already retired or have plans to retire)	Net Qualifying Capacity (NQC) (MW)	Repowering Capacity[59] (MW) and Technology[60] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
San Onofre Nuclear Generating Station	SCE/ SDG&E	2 (ST)	12/31/2022	June 7, 2013	1122	Retired (no repowering)	N/A	
		3 (ST)	12/31/2022		1124			
Encina	NRG	1 (ST)	12/31/2017	3/1/2017	106	500 MW (5 GTs or peakers) Carlsbad Energy Center, located on the same property as the Encina Power Plant.	12/11/2018	The State Water Resources Control Board approved extension of compliance date for Units 2 through 5 to December 31, 2018 due to delay of in-service date for Carlsbad Energy Center. Encina Units 2 – 5 were retired on December 11, 2018.
		2 (ST)	12/31/2017	12/31/2018[66]	103			
		3 (ST)	12/31/2017	12/31/2018	109			
		4 (ST)	12/31/2017	12/31/2018	299			
		5 (ST)	12/31/2017	12/31/2018	329			
South Bay (707 MW)	Dynegy	1-4 (ST)	12/31/2011	12/31/2010	692	Retired (no repowering)	N/A	Retired 707 MW (CT non-OTC) – (2010-2011)

[66] The State Water Resources Control Board approved extending the compliance date for Encina Units 2 to 5 for one year to December 31, 2018 due to delay of Carlsbad Energy Center in-service date.

A3 Planned Generation

Table A3-1: Planned Generation – Thermal and Solar Thermal

PTO Area	Project	Capacity (MW)	Expected In-service Date
SCE	Huntington Beach Energy Project Unit 6 (CCGT) *	644	2020
	Alamitos Energy Center Unit 8 (CCGT) *	640	2020

Notes:

*These projects have received PPTA approvals from the CPUC as part of Long Term Procurement Plan (LTPP) process.

A4 Retired Generation

Table A4-1: Generation (non-OTC) projected to be retired in planning horizon[67]

PTO Area	Generating Facility	Capacity (MW)	Expected Retirement Date
SCE	Ellwood[68]	54	January 1, 2021

Table A4-2: list of generators in SCE, SDG&E and PG&E areas that will be older than 40 years by 2030

Generating Unit Name / Description	Nameplate Capacity (MW)	COD
SCE Area		
ARCOGN_2_UNITS	264.2	Dec-87
CENTER_2_QF	17.4	Jan-87
CHEVMN_2_UNIT_1	85.3	Jan-76
CHINO_6_CIMGEN	25.2	Dec-87
CHINO_6_SMPPAP	44.0	Nov-85
GLNARM_7_UNIT_1	22.1	Jan-76
GLNARM_7_UNIT_2	22.3	Jan-76
GOLETA_6_ELLWOD	54.0	Aug-74
GOLETA_6_GAVOTA	0.5	Jan-87
HINSON_6_CARBGN	29.3	Jan-82
HINSON_6_SERRGN	38.9	Jan-88
HOLGAT_1_BORAX	15.6	Jun-84
MIRLOM_6_DELGEN	25.9	May-88
MOBGEN_6_UNIT_1	41.9	May-83
OMAR_2_UNIT_1	78.0	May-85
OMAR_2_UNIT_2	78.1	May-85
OMAR_2_UNIT_3	81.4	May-85
OMAR_2_UNIT_4	81.4	May-85
SAUGUS_6_PTCHGN	19.3	Jul-88
SBERDO_2_QF	0.1	Jan-89

[67] Table A4-1 reflects retirement of generation based upon announcements from the generators. The ISO will document generators assumed to be retired as a result of assumptions identified in Section 4.9 as a part of the base case development with the reliability results.

[68] Retirement notice per CPUC General Order 167 was received February 28, 2018, and the ISO is assessing the retirement notice.

Generating Unit Name / Description	Nameplate Capacity (MW)	COD
SEARLS_7_ARGUS	7.5	Apr-83
SNCLRA_6_WILLMT	27.8	Mar-86
SYCAMR_2_UNIT_1	85.0	Jan-87
SYCAMR_2_UNIT_2	85.0	Jan-87
SYCAMR_2_UNIT_3	85.0	Jan-87
SYCAMR_2_UNIT_4	85.0	Jan-87
VERNON_6_GONZL1	5.8	Jan-33
VERNON_6_GONZL2	5.8	Jan-33
Total SCE Area	1,412	--
SDG&E Area		
None		
PG&E Area		
ALMEGT_1_Unit_1	23.4	Jan-86
ALMEGT_1_Unit_2	23.5	Jan-86
BASICE_2_UNITS	120	Mar-89
CHEVCD_6_UNIT	11.5	Jul-82
CHEVCO_6_Unit_1	16.5	Jan-86
CHEVCO_6_Unit_2	8.5	Jun-88
CHEVCY_1_UNIT	24.3	Oct-82
CLRMTK_1_QF	1.25	Dec-83
CSCCOG_1_Unit_1	7	Jan-81
CSCGNR_1_Unit_1	24.75	Jan-87
CSCGNR_1_Unit_2	24.75	Jan-86
DISCOV_1_CHEVRN	48.8	Jun-88
DOUBLC_1_UNITS	52.23	Mar-89
FRITO_1_LAY	6	Jan-86
GILROY_1_UNIT	120	Jan-87
GRNLF1_1_UNITS	49.2	Nov-89
GRNLF2_1_UNIT	49.5	Oct-89
GRZZLY_1_BERKLY	26.35	May-87
KERNFT_1_UNITS	52.4	Jan-89
LODI25_2_Unit_1	23.8	Jan-86
OROVIL_6_UNIT	7.5	Dec-89
SIERRA_1_UNITS	52.43	Feb-89
SMPRIP_1_SMPSON	46.05	Apr-88
SRINTL_6_UNIT	6.9	Mar-87
STAUFF_1_UNIT	4.6	Jun-77
SUNSET_2_UNITS	248	Dec-89
TANHIL_6_SOLART	17	Jan-86

Generating Unit Name / Description	Nameplate Capacity (MW)	COD
UNOCAL_1_UNITS	49.85	May-87
VEDDER_1_SEKERN	34.47	Jan-89
OAK C_7_UNIT 1	55	Jan-78
OAK C_7_UNIT 2	55	Jan-78
OAK C_7_UNIT 3	55	Jan-78
UNCHEM_1_UNIT	11	Jan-83
IBMCTL_1_UNIT_1	50	Jan-84
CALPIN_1_AGNEW	28	Oct-90
CHALK_1_UNIT	47.49	Mar-90
KINGCO_1_KINGBR	23.71	Dec-90
THMENG_1_UNIT_1	24.2	Apr-90
YUBACT_1_SUNSWT	23.98	Dec-90

A5 Reactive Resources

Table A5-1: Summary of key existing reactive resources modeled in CAISO reliability assessments

Substation	Capacity (Mvar)	Technology
Gates	225	Shunt Capacitors
Los Banos	225	Shunt Capacitors
Gregg	150	Shunt Capacitors
McCall	132	Shunt Capacitors
Mesa (PG&E)	100	Shunt Capacitors
Metcalf	350	Shunt Capacitors
Olinda	200	Shunt Capacitors
Table Mountain	454	Shunt Capacitors
Devers	156 & 605 (dynamic capability)	Static VAR Compensator
Rector	200	Static VAR Compensator
Santiago	3x81	Synchronous Condensers
Sunrise San Luis Rey	63	Shunt Capacitors
Southbay / Bay Boulevard	100	Shunt Capacitors
Mira Loma 230kV	158	Shunt Capacitors
Mira Loma 500kV	300	Shunt Capacitors
Suncrest	126	Shunt Capacitors
Penasquitos	126	Shunt Capacitors
San Luis Rey	2x225	Synchronous Condensers
Talega	2x225	Synchronous Condensers
Talega	100	STATCOM
Miguel	2x225	Synchronous Condensers
San Onofre	225	Synchronous Condensers

A6 Special Protection Schemes

Table A6-1: Existing key Special Protection Schemes in the PG&E area

PTO	Area	SPS Name
PG&E	Central Coast / Los Padres	Mesa and Santa Maria Undervoltage SPS
	Central Coast / Los Padres	Divide Undervoltage SPS
	Central Coast / Los Padres	Temblor-San Luis Obispo 115 kV Overload Scheme
	Bulk	COI RAS
	Bulk	Colusa SPS
	Bulk	Diablo Canyon SPS
	Bulk	Gates 500/230 kV Bank #11 SPS
	Bulk	Midway 500/230 kV Transformer Overload SPS
	Bulk	Path 15 IRAS
	Bulk	Path 26 RAS North to South
	Bulk	Path 26 RAS South to North
	Bulk	Table Mt 500/230 kV Bank #1 SPS
	Central Valley	Drum (Sierra Pacific) Overload Scheme (Path 24)
	Central Valley	Stanislaus – Manteca 115 kV Line Load Limit Scheme
	Central Valley	Vaca-Suisun 115 kV Lines Thermal Overload Scheme
	Central Valley	West Sacramento 115 kV Overload Scheme
	Central Valley	West Sacramento Double Line Outage Load Shedding SPS Scheme
	Greater Fresno Area	Ashlan SPS
	Greater Fresno Area	Atwater SPS
	Greater Fresno Area	Gates Bank 11 SPS
	Greater Fresno Area	Helms HTT RAS
	Greater Fresno Area	Helms RAS
	Greater Fresno Area	Henrietta RAS
	Greater Fresno Area	Herndon-Bullard SPS
	Greater Fresno Area	Kerckhoff 2 RAS
	Greater Fresno Area	Reedley SPS
	Greater Bay Area	Metcalf SPS
	Greater Bay Area	SF RAS
	Greater Bay Area	South of San Mateo SPS
	Greater Bay Area	Metcalf-Monta Vista 230kV OL SPS
	Greater Bay Area	San Mateo-Bay Meadows 115kV line OL

PTO	Area	SPS Name
	Greater Bay Area	Moraga-Oakland J 115kV line OL RAS
	Greater Bay Area	Grant 115kV OL SPS
	Greater Bay Area	Oakland 115 kV C-X Cable OL RAS
	Greater Bay Area	Oakland 115kV D-L Cable OL RAS
	Greater Bay Area	Sobrante-Standard Oil #1 & #2-115kV line
	Greater Bay Area	Gilroy SPS
	Greater Bay Area	Transbay Cable Run Back Scheme
	Humboldt	Humboldt – Trinity 115kV Thermal Overload Scheme
	North Valley	Caribou Generation 230 kV SPS Scheme #1
	North Valley	Caribou Generation 230 kV SPS Scheme #2
	North Valley	Cascade Thermal Overload Scheme
	North Valley	Hatchet Ridge Thermal Overload Scheme
	North Valley	Coleman Thermal Overload Scheme

Table A6-2: Existing key Special Protection Schemes in SCE area

PTO	Area	SPS Name
SCE	Northern Area	Antelope-RAS
	Northern Area	Big Creek / San Joaquin Valley RAS
	Northern Area	Whirlwind AA-Bank RAS
	Northern Area	Pastoria Energy Facility RAS (PEF RAS)
	Northern Area	Midway-Vincent RAS (SCE MVRAS)
	North of Lugo	Bishop RAS
	North of Lugo	High Desert Power Project RAS (HDPP RAS)
	North of Lugo	Kramer RAS (Retired)
	North of Lugo	Mojave Desert RAS
	North of Lugo	Victor Direct Load Tripping Scheme
	East of Lugo	Ivanpah RAS
	East of Lugo	Lugo - Victorville RAS
	Eastern Area	Devers RAS
	Eastern Area	Colorado River Corridor RAS
	Eastern Area	Inland Empire Area RAS (Retirement pending)
	Eastern Area	Blythe Energy RAS
	Eastern Area	MWD Eagle Mountain Thermal Overload Scheme
	Eastern Area	Mountain view Power Project Remedial Action Scheme
	Metro Area	El Nido LCR RAS (Replaced with El Nido/El Segundo N-2 CRAS Analytic)

PTO	Area	SPS Name
	Metro Area	El Segundo RAS (Replaced with El Nido/El Segundo N-2 CRAS Analytic)
	Metro Area	South of Lugo (SOL) N-2 RAS
	Metro Area	Mira Loma Low Voltage Load Shedding (LVLS)

Table A6-3: Existing key Special Protection Schemes in the SDG&E

PTO	Area	SPS Name
SDG&E	SDG&E	TL695A at Talega SPS
	SDG&E	TL682/TL685 SPS
	SDG&E	TL633 At Rancho Carmel SPS
	SDG&E	TL687 at Borrego SPS
	SDG&E	TL13816 SPS
	SDG&E	TL13835 SPS
	SDG&E	Border TL649 Overload SPS
	SDG&E	Crestwood TL626 at DE SPS for Kumeyaay Wind Generation
	SDG&E	Crestwood TL629 at CN SPS for Kumeyaay Wind Generation
	SDG&E	Crestwood TL629 at DE SPS for Kumeyaay Wind Generation
	SDG&E	230kV TL 23040 Otay Mesa – Tijuana SPS (currently disabled and will not be enabled until its need is reevaluated with CENACE)
	SDG&E	230kV Otay Mesa Energy Center Generation SPS
	SDG&E	ML (Miguel) Bank 80/81 Overload SPS
	SDG&E	CFE SPS to protect lines from La Rosita to Tijuana
	SDG&E	TL 50001 IV Generator Drop SPS
	SDG&E	TL 50003 IV Generator Drop SPS
	SDG&E	TL 50004 IV Generator Drop SPS
	SDG&E	TL 50005 IV Generator Drop SPS
	SDG&E	TL 50001 IV Generator SPS
	SDG&E	Imperial Valley BK80 RAS
	SDG&E	TL23040 IV 500 kV N-1 RAS
	SDG&E	TL 23054 / TL23055 RAS
	SDG&E	Path 44 South of SONGS Safety Net

APPENDIX B

2020-2021 Interregional Transmission Evaluation Plans

ITP Evaluation Process Plan

Cross-Tie Transmission Project

June 11, 2020

The Interregional Transmission Project (ITP) joint evaluation process provides for planning assumptions and ITP technical data coordination for the individual regional evaluations of an ITP. This evaluation process plan was developed through coordination among the relevant planning regions. Its purpose is to document the outcome of the Western Planning Region's coordination of the basic descriptions, key assumptions, milestones, and key participants in the ITP evaluation process that will be followed in the regional evaluations of the ITP.

The information that follows is specific to the ITP listed in the ITP Submittal Summary below. An ITP Evaluation Process Plan is developed for each ITP that has been properly submitted and accepted into the regional process of the Planning Regions to which it was submitted. ITP project sponsors will be provided an opportunity to review this evaluation process plan before it is finalized by the relevant planning regions who developed this evaluation process plan. Once finalized, the Western Planning Regions will post this evaluation process plan on their public websites.

ITP SUBMITTAL SUMMARY

Project Submitted To:	California ISO, NorthernGrid and WestConnect
Relevant Planning Regions[1]:	NorthernGrid and WestConnect[2]
Cost Allocation Requested From:	California ISO, NorthernGrid and WestConnect

The Relevant Planning Regions identified above developed and have agreed to the ITP Evaluation Process Plan.

ITP SUMMARY

TransCanyon, LLC (TransCanyon) submitted the 213-mile Cross-Tie Transmission Project (Cross-Tie Project) for consideration as an Interregional Transmission Project. Cross-Tie is a proposed 1500 MW, 500 kV single

[1] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

[2] The California ISO has determined that it is not a Relevant Planning Region for the Cross-Tie Transmission Project.

Cross-Tie Transmission Project ITP Evaluation Process Plan
Final June 11, 2020

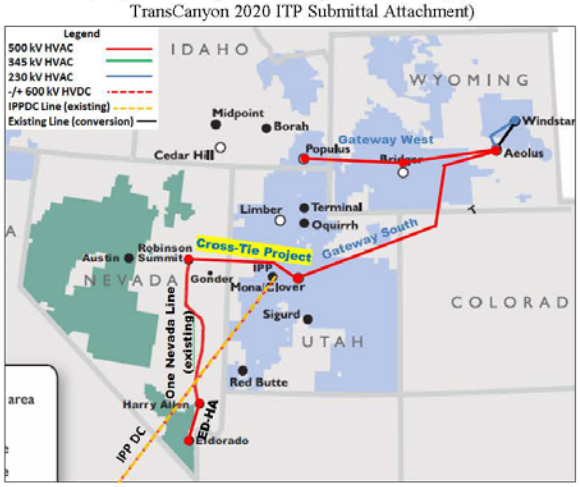
circuit HVAC transmission project that will be constructed between central Utah and east-central Nevada (see Figure 1), connecting PacifiCorp's planned 500-kV Clover substation (in the NorthernGrid planning region) with NV Energy's existing 500 kV Robinson Summit substation (in the WestConnect planning region). The proposed project includes series compensation at both ends of the Cross-Tie transmission line. In addition, series compensation is needed on the existing Robinson Summit to HarryAllen 500-kV line along with phase shifting transformers at Robinson Summit 345-kV.

The project is anticipated to follow existing transmission line corridors. In addition, a significant portion of the routing of the line was previously studied under the Southwest Intertie Project Environmental Impact Statement, which received federal approval in a Record of Decision published in 1994 but was not constructed. Still, the project would be required to satisfy the requirements of the National Environmental Policy Act (NEPA) and the Bureau of Land Management (BLM). Several efforts related to permitting the Cross-Tie Project have been initiated including with the BLM and the Nevada Public Utilities Commission (PUC). High-level briefings were also conducted with select stakeholders including the Utah Governor's Office, and the staff at the Nevada PUC. TransCanyon believes that the risk of failing to obtain necessary administrative approval is considered minimal to moderate.

The Cross-Tie Project obtained Western Electricity Coordinating Council (WECC) Phase 2B status January 31, 2019 with the Phase 2B study plan and base case approved by the Project Review Group.

According to TransCanyon, the project is expected to be in-service by 12/31/2024.

Figure 1: Cross-Tie Project Overview
{Subject to change based on Sponsor's review} (Source: TransCanyon 2020 ITP Submittal Attachment)



ITP EVALUATION BY RELEVANT PLANNING REGIONS

WestConnect is the Planning Region that will lead the coordination among the Relevant Planning Regions involved in this evaluation process. In this capacity, WestConnect will organize and facilitate interregional coordination meetings related to this ITP and document meeting action items and outcomes. For information regarding each Relevant Planning Region's ITP evaluation process, please contact that Planning Region directly.

The following is a summary of each Relevant Planning Region's evaluation process that will be followed to assess the ITP in its regional planning process. Please refer to each Planning Region's current study plan and/or Business Practice Manual for more details regarding its regional transmission planning process.

NorthernGrid

The NorthernGrid Regional Transmission Plan evaluates whether transmission needs within the NorthernGrid region may be satisfied on a regional and interregional basis. While the NorthernGrid Regional Transmission Plan is not a construction plan, it provides valuable regional insight and information for all stakeholders, including developers, to consider and use in their respective decision-making processes.

The first step in developing NorthernGrid's 2020-21 Regional Transmission Plan is to identify the Baseline Projects of Enrolled Parties, the transmission projects included in the Enrolled Parties'Local Transmission Plans plus those projects included in the prior Regional Transmission Plan that will be reevaluated (there will be no reevaluation for this first Regional Transmission Plan). NorthernGrid then evaluates combinations of the Baseline Projects of Enrolled Parties and Alternative Projects to identify whether there may be a combination that effectively satisfies all Enrolled Party Needs ("Regional Combination")

Power flow and dynamic analysis techniques are used to determine if the modeled transmission system topology meets the system reliability performance requirements and transmission needs. The Regional Combination that effectively satisfies all Enrolled Party Needs will be selected into NorthernGrid's Regional Transmission Plan. A more detailed discussion of NorthernGrid's study process can be found in NorthernGrid's Biennial Study Plan posted on NorthernGrid's website.

WestConnect

WestConnect's 2020-21 Regional Study Plan was approved by its Planning Management Committee (PMC) in March of 2020.[3] The study plan describes the system assessments WestConnect will use to determine if there are any regional reliability, economic, or public policy-driven transmission needs. The models for these assessments are built and vetted during Q2 and Q3 of 2020. If regional needs are identified during Q4 of 2020, WestConnect will solicit alternatives (transmission or non-transmission alternatives (NTAs)) from WestConnect members and stakeholders to determine if they have the potential to meet the identified regional needs. If an ITP proponent desires to have their project evaluated as a solution to any identified regional need, they must re-submit their project during this solicitation period (Q5) and complete any outstanding submittal requirements. In late-Q5 and Q6 of the 2020-21 planning cycle, WestConnect will evaluate all properly submitted alternatives to determine whether any meet the identified regional needs, and will determine which alternatives provide the more efficient or cost-effective solution. The more efficient or cost-effective regional projects will be selected and identified in the WestConnect Regional Transmission Plan. Any regional or interregional alternatives that were submitted for the purposes of cost allocation and selected into the Regional Transmission Plan as the more efficient or cost-effective alternative to an identified regional need will then be evaluated for eligibility for regional cost allocation, and subsequently, for interregional cost allocation.[4]

WestConnect regional needs assessments are performed using Base Cases as identified in the regional study plan. Base Cases are intended to represent "business as usual," "current trends," or the "expected future". WestConnect may also conduct information-only scenario studies that look at alternate but plausible futures. In the event regional transmission issues are observed in the assessments of the scenario studies, these issues do not constitute a "regional need", will not result in changes to the WestConnect Regional Transmission Plan

[3] https://doc.westconnect.com/Documents.aspx?NID=18668&dl=1

[4] Please see the WestConnect Business Practice Manual for more information on cost allocation eligibility.

and will not result in Order 1000 regional cost allocation. The WestConnect PMC has ultimate authority to determine how to treat regional transmission issues that are identified in the information-only scenario studies. They will determine whether an issue identified in a scenario —whether it be reliability, economic, or public-policy based—constitutes additional investigation by the Planning Subcommittee.

Cross-Tie Project representatives and other stakeholders are encouraged to participate in the development of the Base Cases to be studied in WestConnect's 2020-21 Planning Cycle. These studies, as outlined in Figure 2, will form the basis for any regional needs that ultimately may lead to ITP project evaluations in 2021. Stakeholders are also encouraged to participate in the development of the scenarios identified in WestConnect's 2020-21 Study Plan. These studies are also outlined in Figure 2.

Figure 2: WestConnect 2020-21 Transmission Assessment Summary

10-Year Base Cases (2030)	10-Year Scenarios (2030)
Heavy Summer Power Flow (reliability) Light Spring Power Flow (reliability) Production Cost Model Base Case (economic)	Committed Uses Study (economic) New Mexico Export Stress Study (reliability)
May result in the identification of regional needs, requires solicitation for alternatives to satisfy identified needs	Informational studies that will not result in the identification of regional needs. Alternative collection and evaluation is optional and is not subject to regional cost allocation

DATA AND STUDY METHODOLOGIES

The coordinated ITP evaluation process strives for consistent planning assumptions and technical data among the Planning Regions evaluating the ITP. Below, the Relevant Planning Regions have summarized the types of studies that will be conducted that are relevant to the Cross-Tie Project evaluation in each Planning Region. Methodologies for coordinating planning assumptions across the Relevant Planning Region processes are also described.

Figure 3: Relevant Planning Region Study Summary Matrix

Planning Study	NorthernGrid	WestConnect

Economic/Production Cost Model	Regional Economic Assessment will be performed on WECC 2030 Anchor Data Set (ADS)	A Regional Economic Needs Assessment will be performed on the WestConnect 2030 Production Cost Model (PCM) Base Case (based on the WestConnect 2028 PCM Base Case and information from the WECC 2028 and 2030 Anchor Datasets [5]
Reliability/Power Flow Assessment	The study scope is being developed – the following WECC power flow base cases are under consideration: 2029-30 Heavy Winter 1 2030 Light Spring 1 2030 Heavy Summer 1 2030 Heavy Spring form WECC ADS PCM export 2030 Heavy Fall from WECC ADS PCM export	A Regional Reliability Needs Assessment will be performed on WestConnect 2030 Heavy Summer and Light Spring cases, which are based off the WECC 2030 HS1 ADS and 2030 LSP1 base cases [6]

Note that the Cross-Tie Project evaluation will be conducted by each Relevant Planning Region in accordance with its approved Order 1000 Regional Planning Process. This includes study methodologies and benefits identified in planning studies.

Data Coordination

The Relevant Planning Regions will strive to coordinate major planning assumptions through the following procedures.

Economic/Production Cost Model

The Relevant Planning Regions intend to use the WECC 2030 Anchor Data Set (ADS) as an input into their regional economic planning studies conducted in 2020 and 2021 (as applicable). The Planning Regions will strive to coordinate major updates made to the 2030 ADS as part of their regional model development efforts.

As an example, the California ISO will update the 2030 ADS to reflect their recently completed 2019-2020 Transmission Plan. NorthernGrid members are working on the 2030 ADS model with WECC staff to incorporate the 2028 ADS topology and 2020 L&R submittals in the 2030 power flow case. WestConnect members will submit to WECC their local transmission plans for 2030 for inclusion in the WECC 2030 Heavy Summer power flow base case, and subsequently the 2030 ADS. These local plans are consistent with

[5] WestConnect ITP Project evaluation is subject to a number of factors, the first and most critical being the identification of regional needs as a part of the 2020-21 Base Case transmission needs assessments.
[6] Id

WestConnect's 2020-21 base transmission plan.

Through this coordination of planning data and assumptions, the Relevant Regions will strive to build a consistent platform of planning assumptions for Economic/Production Cost Model evaluations of the ITP.

Reliability/Power Flow Assessment

Since each Planning Region is unique, key assumptions in load, resource generation dispatch and topology may differ. As such, each Planning Region will develop its models and data that accurately reflect their Planning Region but will seek to coordinate this information with the other Relevant Planning Regions subject to applicable confidentiality agreements. The identification of the starting WECC power flow base cases ("base cases") and significant assumptions or changes a Planning Region may make to a base case are examples of information that will be considered by each Planning Region and coordinated with the other Planning Regions. As such, the inclusion or removal of major regional transmission projects will be coordinated through existing data coordination processes, but the season or hour of study and particular system operating conditions may vary by Planning Region based on its individual regional planning scope and study plan. Project sponsor WECC Path Rating studies may be accessed from the WECC website and used to augment the assessment.

Cost Assumptions

For each Relevant Planning Region to evaluate whether the Cross-Tie Project is a more efficient or cost-effective alternative within their regional planning process, it is necessary to coordinate ITP cost assumptions among the Relevant Planning Regions. For planning purposes, each Relevant Planning Region's cost share of the Cross-Tie Project will be calculated based on its share of the calculated benefits provided to the Region by the Cross-Tie Project (as quantified per that Region's planning process).

The project cost of the Cross-Tie Project, as provided in their ITP Submittal form, is provided below.

Figure 4: Cross-Tie Project Sponsor Cost Information[7]

Project Configuration	Planning Level Cost ($)
Project cost data	$667.0 million (2015 $$)

Following are key assumptions upon which this cost estimate is based that are worth noting to facilitate a comparison of costs to other projects being evaluated:

- Includes initial estimate of $91.0 million for upgrades on the existing system at Robinson Summit substation and on the Robinson Summit to Harry Allen 500-kV transmission line, based on preliminary studies provided as a part of the project submission. The extent of these upgrades will need to be confirmed through additional technical studies and would most likely apply to other projects looking to connect at Robinson Summit.
- Includes AFUDC and overheads of ~$100.0 million (estimated at 17.5% of total costs) per the TEPPC cost calculator.

The following Figure 5 provides a detailed breakdown of the total project cost submitted by TransCanyon

[7] This is a preliminary cost estimate for the project submitted by the project sponsor and developed using the TEPPC capital cost calculator. This information is contingent upon verification by the Planning Regions and may be subject to change during the ITP evaluation process.

for use by Planning Regions for their analysis and cost allocation.

Figure 5: Cross-Tie Project Sponsor Cost Breakdown

Project Component Cost	Per Mile	Total
Clover - Robinson Summit line	$ 2,319,250.45	$ 461,530,838.79
ROW Cost	$ 19,964.14	$ 3,972,864.00
Clover Substation	N/A	$ 10,959,685.80
Robinson Summit	N/A	$ 28,930,423.20
Substation Adjustments	N/A	$ 62,000,000.00
AFUDC/Overhead @17.5%	$ 501,215.01	$ 99,741,787.84
All Costs	$ 2,840,429.60	$ 667,135,599.63

After each Relevant Planning Region identifies their transmission needs and (as applicable) the benefits of the ITP, each Region's project costs for use in the determination of the more efficient or cost-effective alternatives for the region will be determined as follows:

Assumptions

Total Benefits ($) = NorthernGrid (NG) Benefits ($) + WestConnect Benefits ($)

Project Cost ($) = Total capital cost of project, as agreed upon by Regions

Cost Calculations (for Planning Purposes)

NG Cost for Planning Purposes = [NG Benefits/Total Benefits] * Project Cost

WestConnect Cost for Planning Purposes = [WestConnect Benefits/Total Benefits] * Project Cost

Note that this information on cost assumptions applies to costs that will be used for *planning evaluation purposes*. These costs may be different than what is assumed for any relevant cost allocation procedures.

COST ALLOCATION

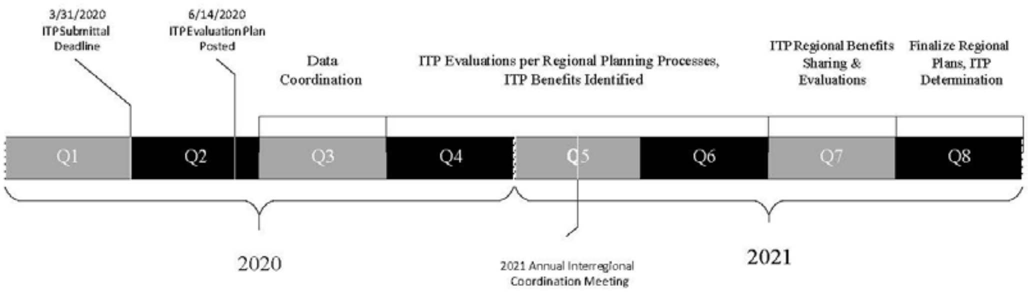
Interregional cost allocation may apply for the Cross-Tie Project for the 2020-2021 cycle.

TransCanyon requested cost allocation from NorthernGrid and from WestConnect and met the necessary requirements within each respective Planning Region's regional process to be considered eligible to request cost allocation. If both NorthernGrid and WestConnect subsequently select the Cross-Tie project in their respective regional transmission plans for purposes of Interregional Cost Allocation, NorthernGrid and WestConnect will individually apply their regional cost allocation methodology to the projected costs of the Cross-Tie project assigned to each region as described in the previous section and in accordance with each region's regional cost allocation methodology. If only one of the two Relevant Planning Regions for the Cross-Tie Project select the project in its regional transmission plan for purposes of Interregional Cost Allocation, and the number of Relevant Planning Regions for the Cross-Tie project is reduced to one, the project will no longer be eligible for interregional cost allocation.

SCHEDULE AND EVALUATION MILESTONES

The ITP will be evaluated in accordance with each Relevant Planning Region's regional transmission planning process during 2020 and (as applicable) 2021. The ITP Evaluation Timeline was created to identify and coordinate key milestones within each Relevant Planning Region's process. Note that in some instances, an individual Planning Region may achieve a milestone earlier than other Regions evaluating the ITP.

Figure 6: ITP Evaluation Timeline



Meetings among the Relevant Planning Regions will be coordinated and organized by the lead Planning Region per this schedule at key milestones such as during the initial phases of the ITP evaluations and during the sharing of ITP regional benefits.

Cross-Tie Transmission Project ITP Evaluation Process Plan 8
Final June 11, 2020 ***ISO Public***

CONTACT INFORMATION

For information regarding the ITP evaluation within each Relevant Planning Region's planning process, please contact that Planning Region directly.

Planning Region:	NorthernGrid
Name:	Dave Angell
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Planning Region:	WestConnect
Name:	Heidi Pacini
Telephone:	(303) 229-9401
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ITP Evaluation Process Plan

SWIP-North

June 14, 2020

The Interregional Transmission Project (ITP) joint evaluation process provides for planning assumptions and ITP technical data coordination for the individual regional evaluations of an ITP. This evaluation process plan was developed through coordination among the relevant planning regions. Its purpose is to document the outcome of the Western Planning Region's coordination of the basic descriptions, key assumptions, milestones, and key participants in the ITP evaluation process that will be followed in the regional evaluations of the ITP.

The information that follows is specific to the ITP listed in the ITP Submittal Summary below. An ITP Evaluation Process Plan is developed for each ITP that has been properly submitted and accepted into the regional process of the Planning Regions to which it was submitted. ITP project sponsors will be provided an opportunity to review this evaluation process plan before it is finalized by the relevant planning regions who developed this evaluation process plan. Once finalized, the Western Planning Regions will post this evaluation process plan on their public websites.

ITP SUBMITTAL SUMMARY

Project Submitted To:	California Independent System Operator ("California ISO"), Northern Tier Transmission Group which was transferred to NorthernGrid, and WestConnect
Relevant Planning Regions[1]:	California ISO[2], NorthernGrid and WestConnect
Cost Allocation Requested From:	California ISO[2], NorthernGrid and WestConnect

The Relevant Planning Regions identified above developed and have agreed to the ITP Evaluation Process Plan.

ITP SUMMARY

Great Basin Transmission, LLC ("GBT"), an affiliate of LS Power, submitted the 275-mile northern portion of the Southwest Intertie Project (SWIP) to the California ISO and NorthernGrid. SWIP-North was also

[1] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

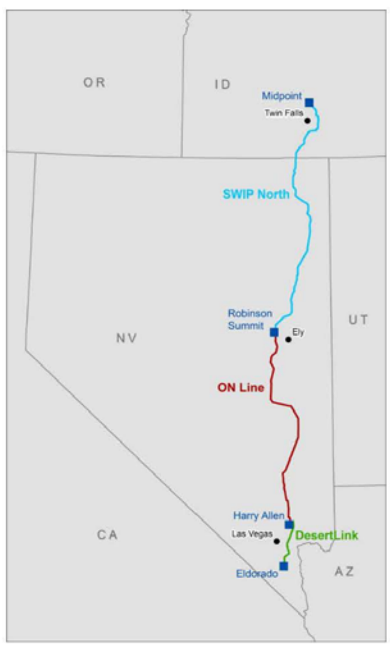
[2] The California ISO has voluntarily agreed to study the SWIP-N line and accept cost allocation if the project is found to be needed by the California ISO and is ultimately constructed.

1

submitted into WestConnect's planning process by the Western Energy Connection (WEC), LLC, a subsidiary of LS Power. The SWIP-North Project connects the Midpoint 500 kV substation (in NorthernGrid) to the Robinson Summit 500 kV substation (in WestConnect) with a 500-kV single circuit AC transmission line. The SWIP is expected to have a bi-directional WECC-approved path rating of approximately 2000 MW. SWIP-North would require a new physical connection at Robinson Summit, but upon completion of SWIP-N a capacity sharing arrangement would be triggered between GBT and NV Energy across the already in-service ON-Line Project and SWIP-N that would provide GBT with control of ~1,000 MW capacity in both directions and include a contract path to California ISO at Harry Allen.

A federally approved route for SWIP-North has been secured by GBT through a right-of-way grant issued by the Department of the Interior's Bureau of Land Management ("BLM") along with an approved Construction, Operation & Maintenance Plan and conditional Notice to Proceed. All NEPA studies and decisions have been completed. Remaining key development activities include completing the WECC path rating process, securing a few remaining private easements, obtaining one local approval, and obtaining a permit to construct from the Public Utilities Commission of Nevada. If LS Power were selected to construct SWIP-North via cost allocation approved through the Interregional Transmission Process, development, final design and construction activities could be completed to support energization of the project within an estimated 36 months.

Figure 1: SWIP-N Map of Preliminary Route
Subject to change at discretion of proponent
(Source: SWIP-N ITP Submittal Attachment)



It is noted that in the event the Energy Gateway West project is built out by PacifiCorp, the northern terminus of SWIP-North could be either the existing Midpoint substation in Jerome County, Idaho, or the proposed new Cedar Hill substation approximately 34 miles south of Midpoint in Twin Falls County, Idaho.

ITP EVALUATION BY RELEVANT PLANNING REGIONS

NorthernGrid is the Planning Region that will lead the coordination among the relevant planning regions involved in this evaluation process. In this capacity, NorthernGrid will organize and facilitate interregional coordination meetings and document meeting action items and outcomes. For information regarding each Relevant Planning Region's ITP evaluation process, please contact that Planning Region directly.

The following is a summary of each Relevant Planning Region's evaluation process that will be followed to assess the ITP in its regional planning process. Please refer to each Planning Region's current study plan and/or Business Practice Manual for more details regarding its regional transmission planning process.

NorthernGrid

The NorthernGrid Regional Transmission Plan evaluates whether transmission needs within the NorthernGrid may be satisfied by regional and/or interregional transmission projects. The NorthernGrid Regional Transmission Plan provides valuable regional insight and information for all stakeholders, including developers, to consider and use in their respective decision-making processes.

The first step in developing NorthernGrid's 2020-21 Regional Transmission Plan is to identify the Baseline Projects of Enrolled Parties. Baseline Projects are the transmission projects included in the Enrolled Parties' Local Transmission Plans plus those projects included in the prior Regional Transmission Plan that will be reevaluated (there will be no reevaluation for this first Regional Transmission Plan). NorthernGrid then evaluates combinations of the Enrolled Parties Baseline Projects and Alternative Projects to identify whether there may be a combination that effectively satisfies all Enrolled Party Needs ("Regional Combination"). Power flow and dynamic analysis techniques are used to determine if the modeled transmission system topology meets the system reliability performance requirements and transmission needs. The Regional Combination that effectively satisfies all Enrolled Party Needs will be selected into NorthernGrid's Regional Transmission Plan. A more detailed discussion of NorthernGrid's study process can be found in NorthernGrid's Study Scope posted on NorthernGrid's website.

WestConnect

WestConnect's 2020-21 Regional Study Plan was approved by its Planning Management Committee (PMC) in March of 2020.[3] The study plan describes the system assessments WestConnect will use to determine if there are any regional reliability, economic, or public policy-driven transmission needs. The models for these assessments are built and vetted during Q2 and Q3 of 2020. If regional needs are identified during Q4 of 2020, WestConnect will solicit alternatives (transmission or non-transmission alternatives (NTAs)) from WestConnect members and stakeholders to determine if they have the potential to meet the identified regional needs. If an ITP proponent desires to have their project evaluated as a solution to any identified regional need, they must re-submit their project during this

[3] https://doc.westconnect.com/Documents.aspx?NID=18668&dl=1

solicitation period (Q5) and complete any outstanding submittal requirements. In late-Q5 and Q6 of the 2020-21 planning cycle, WestConnect will evaluate all properly submitted alternatives to determine whether any meet the identified regional needs, and will determine which alternatives provide the more efficient or cost-effective solution. The more efficient or cost-effective regional projects will be selected and identified in the WestConnect Regional Transmission Plan. Any regional or interregional alternatives that were submitted for the purposes of cost allocation and selected into the Regional Transmission Plan as the more efficient or cost-effective alternative to an identified regional need will then be evaluated for eligibility for regional cost allocation, and subsequently, for interregional cost allocation.[4]

WestConnect regional needs assessments are performed using Base Cases as identified in the regional study plan. Base Cases are intended to represent "business as usual," "current trends," or the "expected future". WestConnect may also conduct information-only scenario studies that look at alternate but plausible futures. In the event regional transmission issues are observed in the assessments of the scenario studies, these issues do not constitute a "regional need", will not result in changes to the WestConnect Regional Transmission Plan and will not result in Order 1000 regional cost allocation. The WestConnect PMC has ultimate authority to determine how to treat regional transmission issues that are identified in the information-only scenario studies. They will determine whether an issue identified in a scenario —whether it be reliability, economic, or public-policy based—constitutes additional investigation by the Planning Subcommittee.

SWIP-North representatives and other stakeholders are encouraged to participate in the development of the Base Cases to be studied in WestConnect's 2020-21 Planning Cycle. These studies, as outlined in Figure 2, will form the basis for any regional needs that ultimately may lead to ITP project evaluations in 2021. Stakeholders are also encouraged to participate in the development of the scenarios identified in WestConnect's 2020-21 Study Plan. These studies are also outlined in Figure 2.

Figure 2: WestConnect 2020-21 Transmission Assessment Summary

10-Year Base Cases (2030)	10-Year Scenarios (2030)
Heavy Summer Power Flow (reliability) Light Spring Power Flow (reliability) Production Cost Model Base Case (economic)	Committed Uses Study (economic) New Mexico Export Stress Study (reliability)
May result in the identification of regional needs, requires solicitation for alternatives to satisfy identified needs	Informational studies that will not result in the identification of regional needs. Alternative collection and evaluation is optional and is not subject to regional cost allocation

[4] Please see the WestConnect Business Practice Manual for more information on cost allocation eligibility.

California ISO

The SWIP-North Project was submitted into the 2018-2019 interregional coordination cycle where the California ISO considered the proposed project in the context of California's GHG emission goal where accessing out-of-state renewable resources for California was considered in the proposed project's assessment at a "high" or "cursory" level. The effort to perform an "informational" assessment of California procurement of out-of-state resources was concluded and documented in the 2018-2019 Transmission Plan[5].

California renewable procurement portfolios provided by the California Public Utilities Commission for reliability and policy analysis for the 2020-2021 transmission planning cycle provide direction that all renewable procurement to achieve the state GHG emission goal to be considered by the California ISO's planning process be obtained from within California. As such, the 2020-2021 planning process will consider the SWIP-North Project in the context of congestion relief and economic benefit. If the production cost analysis produces adequate economic benefits to proceed further with the analysis, then powerflow and stability analysis will be performed as well to consider possible benefits to contingency constraints on the bulk system in northern California.

CAISO's power flow and PCM datasets are available on the CAISO's Market Participant portal. That information will be shared with WestConnect and NorthernGrid subject to NDA requirements being met.

DATA AND STUDY METHODOLOGIES

The coordinated ITP evaluation process strives for consistent planning assumptions and technical data among the Planning Regions evaluating the ITP. Below, the Relevant Planning Regions have summarized the types of studies that will be conducted that are relevant to the SWIP-N evaluation in each Planning Region. Methodologies for coordinating planning assumptions across the Relevant Planning Region processes are also described.

Figure 2: Relevant Planning Region Study Summary Matrix

Planning Study	NorthernGrid	WestConnect	California ISO
Economic - Production Cost Model	Regional Economic Assessment will be performed with the WECC 2030 Anchor Data Set (ADS)	A Regional Economic Needs Assessment will be performed on the WestConnect 2030 Production Cost Model (PCM) Base Case (based on the WestConnect 2028 PCM Base Case and information from the	Using the California ISO PCM Base Case, based on the WECC 2030 Anchor Data Set (ADS), GridView will be used to perform production cost simulation. All model information will be shared with WestConnect and NorthernGrid.

[5] http://www.caiso.com/Documents/BoardApproved-2017-2018_Transmission_Plan.pdf

		WECC 2028 and 2030 Anchor Datasets [6]	
Reliability/Power Flow Assessment	The Regional Transmission Plan Study Scope is in development with an expected approval date of mid-July – the following WECC power flow base cases are under consideration: 2029-30 Heavy Winter 1 2030 Light Spring 1 2030 Heavy Summer 1 2030 Heavy Spring WECC ADS PCM export 2030 Heavy Fall WECC ADS PCM export	A Regional Reliability Needs Assessment will be performed on WestConnect 2030 Heavy Summer and Light Spring cases[7]	Depending on the results of the production cost modeling, the GE PSLF may be used to perform steady state and as needed, transient analysis. The WECC 2030 ADS and 2030 LSP1 will be modified as needed to accurately model the California network and resources that reflects the ISO's finalized 2019-2020 transmission plan. The SWIP-North Project will be added to that model. All model information will be shared with NorthernGrid and WestConnect.

Note that the SWIP-N evaluation will be conducted by each Relevant Planning Region in accordance with its approved Order 1000 Regional Planning Process. This includes study methodologies and benefits identified in planning studies.

Data Coordination

The Relevant Planning Regions will strive to coordinate key planning assumptions through the following procedures.

Economic/Production Cost Model

The Planning Regions intend to use the WECC2030 Anchor Data Set (ADS) as an input into their regional economic planning studies conducted in 2020 and 2021 (as applicable). The Planning Regions will strive to coordinate major updates made to the 2030 ADS as part of their regional model development efforts.

[6] WestConnect ITP Project evaluation is subject to a number of factors, the first and most critical being the identification of regional needs as a part of the 2020-21 Base Case transmission needs assessments.
[7] Id

As an example, the California ISO will update the 2030 ADS to reflect their recently completed 2019-2020 Transmission Plan.[8] NorthernGrid members are working on the 2030 ADS model with WECC staff to incorporate the 2028 ADS topology and 2020 L&R submittals in the 2030 power flow case. WestConnect members will submit to WECC their local transmission plans for 2030[9] for inclusion in the WECC 2030 Heavy Summer power flow base case, and subsequently the 2030 ADS. These local plans are consistent with WestConnect's 2020-21 base transmission plan.[10]

Through this coordination of planning data and assumptions, the Relevant Regions will strive to build a consistent platform of planning assumptions for Economic/Production Cost Model evaluations of the ITP.

Reliability/Power Flow Assessment

Since each Planning Region is unique, key assumptions in load, resource generation dispatch and topology may differ. As such, each Planning Region will develop its models and data that accurately reflect their Planning Region but will seek to coordinate this information with the other Relevant Planning Regions subject to applicable confidentiality agreements. The identification of the starting WECC power flow base cases ("base cases") and significant assumptions or changes a Planning Region may make to a base case are examples of information that will be considered by each Planning Region and coordinated with the other Planning Regions. As such, the inclusion or removal of major regional transmission projects will be coordinated through existing data coordination processes, but the season or hour of study and particular system operating conditions may vary by Planning Region based on its individual regional planning scope and study plan. Project sponsor WECC Path Rating studies may be accessed from the WECC website and used to augment the assessment.

Cost Assumptions

For each Relevant Planning Region to evaluate whether the SWIP-N Project is a more efficient or cost-effective alternative within their regional planning process, it is necessary to coordinate ITP cost assumptions among the Relevant Planning Regions. For planning purposes, each Relevant Planning Region's cost share of the SWIP-N Project will be calculated based on its share of the calculated benefits provided to the Region by the SWIP-N (as quantified per that Region's planning process).

The project cost data in the SWIP-N submittal form was marked as "Privileged information not to be released" and therefore has been redacted from this document.

Figure 3: Project Sponsor Cost Information[11]

Project Configuration	Planning Level Cost ($)
Project cost data	Redacted

[8] http://www.caiso.com/Documents/ISOBoardApproved-2019-2020TransmissionPlan.pdf
[9] WestConnect 2020-2021 Base Transmission Plan
[10] https://doc.westconnect.com/Documents.aspx?NID=18668&dl=1
[11] This information is contingent upon verification by the Planning Regions and may be subject to change during the ITP evaluation process

After each Relevant Planning Region identifies their transmission needs and (as applicable) the benefits of the ITP, each Region's project costs for use in the determination of the more efficient or cost-effective alternatives for the region will be determined as follows:

Assumptions

Total Benefits ($) = NorthernGrid Benefits ($) + WestConnect Benefits ($) +California ISO Benefits ($)

Project Cost ($) = Total capital cost of project, as agreed upon by Regions

Cost Calculations (for Planning Purposes)

NorthernGrid Cost for Planning Purposes = [NorthernGrid Benefits/Total Benefits] * Project Cost

WestConnect Cost for Planning Purposes = [WestConnect Benefits/Total Benefits] * Project Cost

California ISO Cost for Planning Purposes = [California ISO Benefits/Total Benefits] *Project Cost

Note that this information on cost assumptions applies to costs that will be used for *planning evaluation purposes*. These costs may be different than what is assumed for any relevant cost allocation procedures.

COST ALLOCATION

Interregional Cost Allocation may apply for the SWIP-N Project for the 2020-2021 cycle.

GBT requested cost allocation from NorthernGrid and the California ISO. WEC requested cost allocation from WestConnect. The project sponsor met the necessary requirements within the NorthernGrid and WestConnect's respective Planning Region's regional processes to be considered eligible to request costs allocation if selected in either region's plan. The California ISO has voluntarily agreed to accept cost allocation if the project is found to be needed by the California ISO and ultimately constructed.

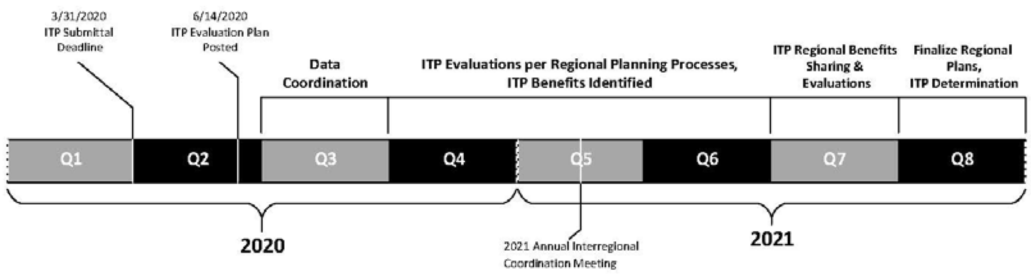
If at least two regions subsequently select the SWIP-North project in their respective regional transmission plans for purposes of Interregional Cost Allocation, each region will individually apply their regional cost allocation methodology to the projected costs of the SWIP-N Project assigned to each region in accordance with each region's regional cost allocation methodology. If only one of the Relevant Planning Regions for the SWIP-N Project select the project in its regional transmission plan for purposes of Interregional Cost Allocation, and the number of Relevant Planning Regions for the SWIP-N Project is reduced to one, the project will no longer be eligible for interregional cost allocation.

SCHEDULE AND EVALUATION MILESTONES

The ITP will be evaluated in accordance with each Relevant Planning Region's regional transmission planning process during 2020 and (as applicable) 2020. The ITP Evaluation Timeline was created to identify and coordinate key milestones within each Relevant Planning Region's process. Note that in some instances, an individual Planning Region may achieve a milestone earlier than other Regions evaluating the ITP.

Meetings among the Relevant Planning Regions will be coordinated and organized by the lead Planning Region per this schedule at key milestones such as during the initial phases of the ITP evaluations and during the sharing of ITP benefits.

Figure 4: ITP Evaluation Timeline



SWIP North ITP Evaluation Process Plan 9
June 14, 2020 ***ISO Public***

CONTACT INFORMATION

For information regarding the ITP evaluation within each Relevant Planning Region's planning process, please contact that Planning Region directly.

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ITP Evaluation Process Plan

Northwest Tie Upgrade Project

June 11, 2020

The Interregional Transmission Project (ITP) joint evaluation process provides for planning assumptions and ITP technical data coordination for the individual regional evaluations of an ITP. This evaluation process plan was developed through coordination among the relevant planning regions. Its purpose is to document the outcome of the Western Planning Region's coordination of the basic descriptions, key assumptions, milestones, and key participants in the ITP evaluation process that will be followed in the regional evaluations of the ITP.

The information that follows is specific to the ITP listed in the ITP Submittal Summary below. An ITP Evaluation Process Plan is developed for each ITP that has been properly submitted and accepted into the regional process of the Planning Regions to which it was submitted. ITP project sponsors will be provided an opportunity to review this evaluation process plan before it is finalized by the relevant planning regions who developed this evaluation process plan. Once finalized, the Western Planning Regions will post this evaluation process plan on their public websites.

ITP SUBMITTAL SUMMARY

Project Submitted To:	California ISO and WestConnect
Relevant Planning Regions[1]:	California ISO and WestConnect
Cost Allocation Requested From:	California ISO and WestConnect

The Relevant Planning Regions identified above developed and have agreed to the ITP Evaluation Process Plan.

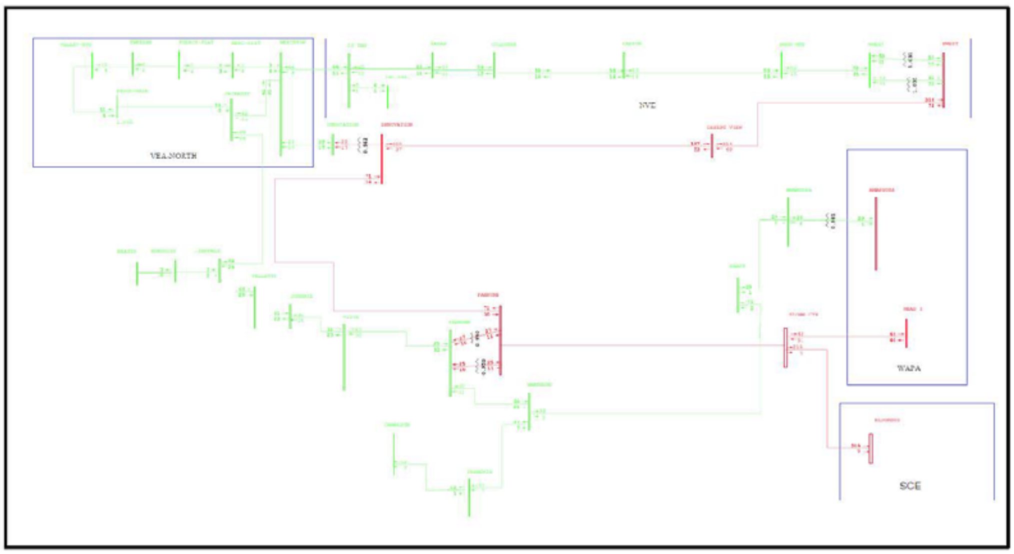
ITP SUMMARY

GridLiance West (GLW) submitted the 47-mile Northwest Tie Upgrade Project (Northwest Tie) for consideration as an Interregional Transmission Project. Northwest Tie is a proposed upgrade of an existing 138 kV transmission line located in southern Nevada (see Figure 1), connecting the GLW/Valley Electric Association (VEA) system (in the CAISO planning region) with NV Energy's existing 230/138 kV transformer bank at Northwest substation (in the WestConnect planning region). The project would include reconductoring necessary line segments and upgrading switching station equipment to allow additional flow bi-directionally on the current

[1] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

Innovation-to-Northwest 138 kV system. Specifically, the proposed project includes rebuilding 47 miles of the Mercury – Northwest 138 kV line, including seven one-position, one-breaker substation crossing switches, and disconnect switches and jumper upgrade at Mercury Switching Station on the Innovation – Mercury 138 kV line. The Indian Springs – Mercury 138 kV segment of this project is a part of Western Electricity Coordinating Council (WECC) Path 81 – Southern Nevada Transmission Interface (SNTI). According to GLW, the project is expected to be in-service by 05/31/2024.

Figure 1: Northwest Tie Upgrade Project Overview
(Source: GLW 2020 ITP Submittal Attachment with bus numbers removed)



ITP EVALUATION BY RELEVANT PLANNING REGIONS

WestConnect is the Planning Region that will lead the coordination among the Relevant Planning Regions involved in this evaluation process. In this capacity, WestConnect will organize and facilitate interregional coordination meetings related to this ITP and document meeting action items and outcomes. For information regarding each Relevant Planning Region's ITP evaluation process, please contact that Planning Region directly.

The following is a summary of each Relevant Planning Region's evaluation process that will be followed to assess the ITP in its regional planning process. Please refer to each Planning Region's current study plan and/or Business Practice Manual for more details regarding its regional transmission planning process.

California ISO

The California ISO will consider the project based on the final 2020-2021 Study Plan[2] and will 'include' it as a potential mitigation option to address relevant reliability, economic, and/or public policy needs that are identified in the ISO's 2020-2021 planning process.

[2] http://www.caiso.com/Documents/Final2020-2021StudyPlan.pdf

The project sponsor states that the proposed project will increase reliability by adding transmission capacity which eliminates transmission line congestion concerns on the Innovation – Mercury – Northwest 138 kV line. The line congestion concerns were identified by the project sponsor and the CAISO in the 2019-2020 TPP. In addition, the proposed project is needed to relieve the identified congestion concerns by adding beneficial transmission capacity to facilitate the delivery of renewable energy.

The project sponsor further states that their production cost modeling (PCM) showed that economic benefits of the Northwest Tie Upgrade would accrue through reduced congestion for the year 2029 with CAISO TPP modifications including the approved Gamebird transformer upgrade as well as the GLW-proposed Pahrump to Sloan Canyon 230 kV upgrade in place. IRP renewable buildout incorporated CEC bus placement and CAISO interconnection queue data. CAISO load was based on CPUC forecast for SERVM, and other Load based on WECC TEPPC/ADS.

WestConnect

WestConnect's 2020-21 Regional Study Plan was approved by its Planning Management Committee (PMC) in March of 2020.[3] The study plan describes the system assessments WestConnect will use to determine if there are any regional reliability, economic, or public policy-driven transmission needs. The models for these assessments are built and vetted during Q2 and Q3 of 2020. If regional needs are identified during Q4 of 2020, WestConnect will solicit alternatives (transmission or non-transmission alternatives (NTAs)) from WestConnect members and stakeholders to determine if they have the potential to meet the identified regional needs. If an ITP proponent desires to have their project evaluated as a solution to any identified regional need, they must re-submit their project during this solicitation period (Q5) and complete any outstanding submittal requirements. In late-Q5 and Q6 of the 2020-21 planning cycle, WestConnect will evaluate all properly submitted alternatives to determine whether any meet the identified regional needs, and will determine which alternatives provide the more efficient or cost-effective solution. The more efficient or cost-effective regional projects will be selected and identified in the WestConnect Regional Transmission Plan. Any regional or interregional alternatives that were submitted for the purposes of cost allocation and selected into the Regional Transmission Plan as the more efficient or cost-effective alternative to an identified regional need will then be evaluated for eligibility for regional cost allocation, and subsequently, for interregional cost allocation.[4]

WestConnect regional needs assessments are performed using Base Cases as identified in the regional study plan. Base Cases are intended to represent "business as usual," "current trends," or the "expected future". WestConnect may also conduct information-only scenario studies that look at alternate but plausible futures. In the event regional transmission issues are observed in the assessments of the scenario studies, these issues do not constitute a "regional need", will not result in changes to the WestConnect Regional Transmission Plan and will not result in Order 1000 regional cost allocation. The WestConnect PMC has ultimate authority to determine how to treat regional transmission issues that are identified in the information-only scenario studies. They will determine whether an issue identified in a scenario —whether it be reliability, economic, or public-policy based—constitutes additional investigation by the Planning Subcommittee.

Northwest Tie Project representatives and other stakeholders are encouraged to participate in the development of the base cases to be studied in WestConnect's 2020-21 Planning Cycle. These studies, as outlined in Figure 2, will form the basis for any regional needs that ultimately may lead to ITP project evaluations in 2021. Stakeholders are also encouraged to participate in the development of the scenarios identified in WestConnect's 2020-21 Study Plan. These studies are also outlined in Figure 2.

[3] https://doc.westconnect.com/Documents.aspx?NID=18668&dl=1

[4] Please see the WestConnect Business Practice Manual for more information on cost allocation eligibility.

Figure 2: WestConnect 2020-21 Transmission Assessment Summary

10-Year Base Cases (2030)	10-Year Scenarios (2030)
Heavy Summer Power Flow (reliability) Light Spring Power Flow (reliability) Production Cost Model Base Case (economic)	Committed Uses Study (economic) New Mexico Export Stress Study (reliability)
May result in the identification of regional needs, requires solicitation for alternatives to satisfy identified needs	Informational studies that will not result in the identification of regional needs. Alternative collection and evaluation is optional and is not subject to regional cost allocation

DATA AND STUDY METHODOLOGIES

The coordinated ITP evaluation process strives for consistent planning assumptions and technical data among the Planning Regions evaluating the ITP. Below, the Relevant Planning Regions have summarized the types of studies that will be conducted that are relevant to the Northwest Tie Project evaluation in each Planning Region. Methodologies for coordinating planning assumptions across the Relevant Planning Region processes are also described.

Figure 3: Relevant Planning Region Study Summary Matrix

Planning Study	California ISO	WestConnect
Economic/Production Cost Model	Using the California ISO PCM Base Case, based on the WECC 2030 Anchor Data Set (ADS), GridView will be used to perform production cost simulation. All model information will be shared with WestConnect.	A Regional Economic Needs Assessment will be performed on the WestConnect 2030 Production Cost Model (PCM) Base Case (based on the WestConnect 2028 PCM Base Case and information from the WECC 2028 and 2030 Anchor Datasets [5]
Reliability/Power Flow Assessment	The GE PSLF will be used to perform steady state and as needed, transient analysis using the WECC 2030 ADS and 2030 LSP1 base cases.	A Regional Reliability Needs Assessment will be performed on WestConnect 2030 Heavy Summer and Light Spring cases, which are based off the WECC 2030 HS1 ADS and 2030 LSP1 base cases [6]

[5] WestConnect ITP Project evaluation is subject to a number of factors, the first and most critical being the identification of regional needs as a part of the 2020-21 Base Case transmission needs assessments.
[6] Id

Note that the Northwest Tie evaluation will be conducted by each Relevant Planning Region in accordance with its approved Order 1000 Regional Planning Process. This includes study methodologies and benefits identified in planning studies.

Data Coordination

The Relevant Planning Regions will strive to coordinate major planning assumptions through the following procedures.

Economic/Production Cost Model

The Relevant Planning Regions intend to use the WECC 2030 Anchor Data Set (ADS) as an input into their regional economic planning studies conducted in 2020 and 2021 (as applicable). The Planning Regions will strive to coordinate major updates made to the 2030 ADS as part of their regional model development efforts.

As an example, the California ISO will update the 2030 ADS to reflect their recently completed 2019-2020 Transmission Plan. NorthernGrid members are working on the 2030 ADS model with WECC staff to incorporate the 2028 ADS topology and 2020 L&R submittals in the 2030 power flow case. WestConnect members will submit to WECC their local transmission plans for 2030 for inclusion in the WECC 2030 Heavy Summer power flow base case, and subsequently the 2030 ADS. These local plans are consistent with WestConnect's 2020-21 base transmission plan.

Through this coordination of planning data and assumptions, the Relevant Regions will strive to build a consistent platform of planning assumptions for Economic/Production Cost Model evaluations of the ITP.

Reliability/Power Flow Assessment

Since each Planning Region is unique, key assumptions in load, resource generation dispatch and topology may differ. As such, each Planning Region will develop its models and data that accurately reflect their Planning Region but will seek to coordinate this information with the other Relevant Planning Regions subject to applicable confidentiality agreements. The identification of the starting WECC power flow base cases ("base cases") and significant assumptions or changes a Planning Region may make to a base case are examples of information that will be considered by each Planning Region and coordinated with the other Planning Regions. As such, the inclusion or removal of major regional transmission projects will be coordinated through existing data coordination processes, but the season or hour of study and particular system operating conditions may vary by Planning Region based on its individual regional planning scope and study plan. Project sponsor WECC Path Rating studies may be accessed from the WECC website and used to augment the assessment.

Cost Assumptions

For each Relevant Planning Region to evaluate whether the Northwest Tie is a more efficient or cost- effective alternative within their regional planning process, it is necessary to coordinate ITP cost assumptions among the Relevant Planning Regions. For planning purposes, each Relevant Planning Region's cost share of the Northwest Tie Project will be calculated based on its share of the calculated benefits provided to the Region by the Northwest Tie (as quantified per that Region's planning process).

The project cost of the Northwest Tie project, as provided in their ITP Submittal form, is provided below.

Figure 4: Northwest Tie Upgrade Project Sponsor Cost Information[7]

Project Configuration	Planning Level Cost ($)
Project cost data	$50.5 million (2020 Dollars)

After each Relevant Planning Region identifies their transmission needs and (as applicable) the benefits of the ITP, each Region's project costs for use in the determination of the more efficient or cost-effective alternatives for the region will be determined as follows:

Assumptions
Total Benefits ($) = California ISO Benefits ($) + WestConnect Benefits ($)
Project Cost ($) = Total capital cost of project, as agreed upon by Regions

Cost Calculations (for Planning Purposes)
California ISO Cost for Planning Purposes = [California ISO Benefits/Total Benefits] * Project Cost
WestConnect Cost for Planning Purposes = [WestConnect Benefits/Total Benefits] * Project Cost

Note that this information on cost assumptions applies to costs that will be used for *planning evaluation purposes*. These costs may be different than what is assumed for any relevant cost allocation procedures.

COST ALLOCATION

Interregional cost allocation may apply for the Northwest Tie for the 2020-2021 cycle.

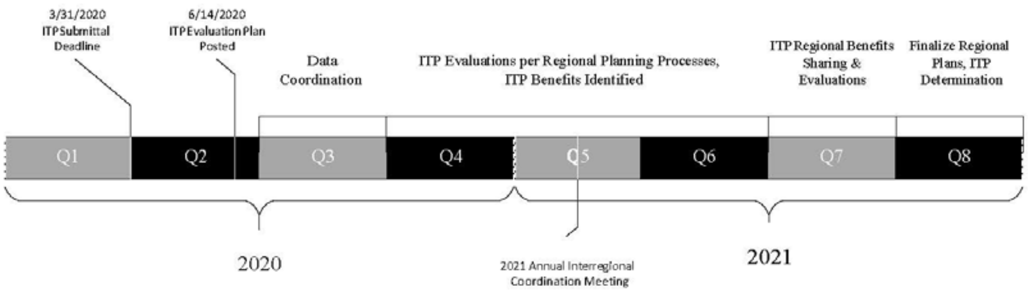
GLW requested cost allocation from California ISO and from WestConnect, and also met the necessary requirements within each respective Planning Region's regional process to be considered eligible to request cost allocation. If both California ISO and WestConnect subsequently select the Northwest Tie in their respective regional transmission plans for purposes of Interregional Cost Allocation, California ISO and WestConnect will individually apply their regional cost allocation methodology to the projected costs of the Northwest Tie project assigned to each region as described in the previous section and in accordance with each region's regional cost allocation methodology. If only one of the two Relevant Planning Regions for the Northwest Tie select the project in its regional transmission plan for purposes of Interregional Cost Allocation, and the number of Relevant Planning Regions for the Northwest Tie Upgrade Project is reduced to one, the project will no longer be eligible for interregional cost allocation.

[7] This information is contingent upon verification by the Planning Regions and may be subject to change during the ITP evaluation process

SCHEDULE AND EVALUATION MILESTONES

The ITP will be evaluated in accordance with each Relevant Planning Region's regional transmission planning process during 2020 and (as applicable) 2021. The ITP Evaluation Timeline was created to identify and coordinate key milestones within each Relevant Planning Region's process. Note that in some instances, an individual Planning Region may achieve a milestone earlier than other Regions evaluating the ITP.

Figure 6: ITP Evaluation Timeline



Meetings among the Relevant Planning Regions will be coordinated and organized by the lead Planning Region per this schedule at key milestones such as during the initial phases of the ITP evaluations and during the sharing of ITP regional benefits.

Northwest Tie Upgrade Project ITP Evaluation Process Plan 8
Final June 11, 2020 ***ISO Public***

CONTACT INFORMATION

For information regarding the ITP evaluation within each Relevant Planning Region's planning process, please contact that Planning Region directly.

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ITP Evaluation Process Plan

TransWest Express Transmission Project

June 14, 2020

The Interregional Transmission Project (ITP) joint evaluation process provides for planning assumptions and ITP technical data coordination for the individual regional evaluations of an ITP. This evaluation process plan was developed through coordination among the relevant planning regions. Its purpose is to document the outcome of the Western Planning Region's coordination of the basic descriptions, key assumptions, milestones, and key participants in the ITP evaluation process that will be followed in the regional evaluations of the ITP.

The information that follows is specific to the ITP listed in the ITP Submittal Summary below. An ITP Evaluation Process Plan is developed for each ITP that has been properly submitted and accepted into the regional process of the Planning Regions to which it was submitted. ITP project sponsors will be provided an opportunity to review this evaluation process plan before it is finalized by the relevant planning regions who developed this evaluation process plan. Once finalized, the Western Planning Regions will post this evaluation process plan on their public websites.

ITP Submittal Summary

Project Submitted To:	California Independent System Operator (California ISO), Northern Tier Transmission Group (NorthernGrid)
Relevant Planning Regions[1]:	California ISO, NorthernGrid
Cost Allocation Requested From:	California ISO

The Relevant Planning Regions identified above developed and have agreed to the ITP Evaluation Process Plan.

1 ITP Summary

The TransWest Express (TWE) Transmission Project consists of three discrete interconnected transmission segments that, when considered together, will interconnect transmission infrastructure in

[1] With respect to an ITP, a Relevant Planning Region is a Planning Region that would directly interconnect electrically with the ITP, unless and until a Relevant Planning Region determines that the ITP will not meet any of its regional transmission needs, at which time it will no longer be considered a Relevant Planning Region.

California ISO NorthernGrid

Wyoming, Utah, and southern Nevada. TransWest has submitted each of the following TWE Project segments as separate ITP submittals:

1. TWE WY-IPP DC Project;

2. TWE IPP-Crystal 500 kV AC Project; and

3. TWE Crystal-Eldorado 500 kV AC Project.

TransWest states that each of these segments can be evaluated by the Western Planning Regions (WPRs) as both individual ITPs and as a unified ITP including either two or three of the interconnected segments. Details of the transmission segments are described as follows:

1. A 405-mile, bi-directional 3,000 MW, ±500 kV, high voltage direct current (HVDC) transmission system with terminals in south-central Wyoming and central Utah (the WY-IPP DC Project);
2. A 278-mile 1,500 MW 500 kV alternating current (AC) transmission line with terminals in central Utah and southeastern Nevada (the IPP-Crystal 500 kV AC Project; and
3. A 50-mile, 1,680 MW 500 kV AC transmission line with terminals in southeastern Nevada and southwestern Nevada (the Crystal-Eldorado 500 kV AC Project).

The TWE Project will interconnect with facilities owned and/or operated by some WestConnect Transmission Owners with Load Serving Obligations (TOLSOs); however, TransWest did not submit the TWE Project to WestConnect. The WestConnect Regional Planning Process considers single-TOLSO needs as local needs to be evaluated by TOLSO(s). Because the TWE Project will meet local needs and does not anticipate meeting any regional needs within WestConnect, TransWest will submit the TWE ITP Project data to individual WestConnect TOLSOs that request such data and requested that the California ISO and NorthernGrid coordinate, as necessary, directly with those TOLSOs during the 2020-2021 regional planning cycle.

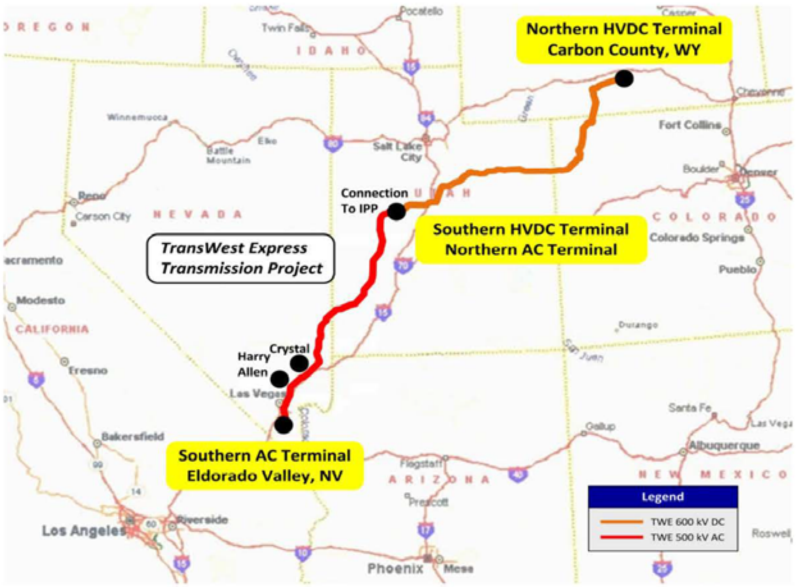
The proposed route of the TWE Project is shown in Figure 1. The TWE Project route has been reviewed and approved through a series of environmental and land use reviews conducted over the past eleven years. The U.S. Department of the Interior, Bureau of Land Management (BLM) and Western Area Power Administration (WAPA) acted as joint lead agencies on the TWE Project Environmental Impact Statement (EIS), which was completed in 2015. Multiple federal, state, local, and tribal authorities participated in the development of the EIS and in finalizing the TWE Project route. BLM, WAPA, the United States Forest Service (USFS), and the U.S. Department of the Interior Bureau of Reclamation (BOR) issued records of decision finalizing and approving the route for the TWE Project on federal lands.2 TransWest has been granted rights-of-way (ROWs) over all of the federal land along the route, which represents about 66% of the TWE Project route. TransWest has nearly completed the acquisition of all remaining ROWs.

2 Evaluation by Relevant Planning Regions

The California ISO has been identified as the Planning Region that will lead the coordination efforts with the other Relevant Planning Regions identified for the ITP. In this capacity, the California ISO will

California ISO NorthernGrid

Figure 1: TransWest Express Transmission Project Route



organize and facilitate interregional coordination meetings and track action items and outcomes of those meetings. For information regarding the ITP evaluation conducted within each Relevant Planning Region's planning process, please contact that Planning Region directly.

Given that the joint evaluation of an ITP is considered to be the joint coordination of the regional planning processes that evaluate the ITP, the following describes how the ITP fits into each Relevant Planning Region's process. This information is intended to serve only as a brief summary of each Relevant Planning Region's process for evaluating an ITP. Please see each Planning Region's most recent study plan and/or Business Practice Manual for more details regarding its overall regional transmission planning process.

2.1 California ISO

The project sponsor states that the TWE Project will provide needed transmission capacity between the Rocky Mountain region and the Desert Southwest and CAISO regions. This additional transmission capacity will provide load serving entities with access to high quality wind generation resources and enhanced market efficiency through broader interregional integration. Moreover, the TWE Project can contribute significantly to the Desert Southwest states meeting statutory and public policy goals to obtain a large percentage of electricity from renewable energy resources, to decrease greenhouse gas emissions, and to move to 100% carbon-free electricity.

The project states that the TWE Project is designed to interconnect with the Bulk Power System in Wyoming, Utah, and Nevada to meet the needs of CAISO, LADWP, and other utilities. The main objective of the TWE Project is to provide additional, efficient incremental transmission capacity to meet the renewable energy and reliability needs of transmission owners in the Desert Southwest and California in a cost-effective manner. Thus, TransWest requests that the California ISO evaluate at least 1,500 MW of the TWE Project capacity as a policy-driven transmission solution with economic and reliability benefits. TransWest further requests that the California ISO evaluate the TWE Project as a potential California ISO Category 2 transmission "regional" solution as well as an interregional transmission project in the 2020-2021 Transmission Planning Process.[2]

The project sponsor states that the California ISO identified the need for additional transmission capacity to deliver new wind generation located in Wyoming to California in a Special Study within the 2016-2017 Transmission Planning Process ("Special Study").[3] In this Special Study, the California ISO determined that there is a "severe shortage of available contractual transmission capacity" (ATC) between the wind resources in Wyoming and California load centers" TransWest referred the California ISO to the findings regarding the "Severe Lack of ATC" as the "pre-project results" that help demonstrate how the proposed TWE Project, as an interregional transmission project, will meet a regional need more efficiently and cost effectively than the identified regional transmission solution.[4,5]

The project sponsor states that the TWE Project will also help the California ISO meet economic and reliability needs. The TWE Project's 500 kV AC capacity between Eldorado, Crystal, and IPP will facilitate higher levels of energy transactions within the California ISO's Energy Imbalance Market and the planned Day-Ahead markets, as well as bilateral energy transactions between entities with diverse resource and load profiles. Adding wind generation resources to the Desert Southwest market will also assist in meeting reliability needs by adding diversity to the grid resources, which the California ISO relies on for reliable operations.

The Project sponsor indicated the ITP submission was for an ITP with cost allocation to the California ISO. The project sponsor seeks consideration of cost allocation for any portion of the TWE Project approved by the California ISO as a transmission solution. The Project sponsor stated they would provide transmission service funded through the sponsor's customers for any portion of the TWE Project not approved by the California ISO as a transmission solution.

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[2] TransWest is not aware of any other proposed regional solutions to meet the need for delivery of Wyoming wind generation to California in the IRP planning horizon. Therefore, there is no other regional solution to compare and eliminate or defer through selection of the TWE Project.

[3] CAISO, Interregional Transmission Project (ITP) Evaluation and 50% RPS Out-of-state Portfolio Assessment (Jan. 4, 2018), available at http://www.caiso.com/Documents/InterregionalTransmissionProjectITPEvaluationand50RPSOut-of-StatePortfolioAssessment.pdf

[4] See CAISO Business Practice Manual, Transmission Planning Process, at 29.

[5] Id. at 8 ("Severe lack of ATC: ATC assessment revealed a severe shortage of available contractual transmission capacity to deliver new Wyoming and New Mexico renewables to California. TWE would provide ~1,500 MW of ATC and is the only ITP that would provide ATC from southwestern Wyoming to southern CA without having to rely on other transmission facilities not owned by the project sponsor.")

The project sponsor states that they seek to include the TWE Project within one or more existing balancing areas to both minimize the proliferation of balancing areas in the Western Interconnect and further integrate the TWE Project within the Bulk Power System. The sponsor requested that the CAISO evaluate the TWE Project, or any portion of the Project's capacity, for inclusion within the CAISO Controlled Grid, independent of whether the project has costs allocated to the CAISO or not.

The California ISO has considered the TWE Project in the forms it was submitted during the 2016-2017 and 2018-2019 interregional transmission coordination cycles. As stated earlier, for the 2020-2021 interregional coordination cycle TransWest has proposed their project as individual segments which can be considered singularly or as a single overall project. TransWest has requested that the California ISO coordinate directly with specific WestConnect entities as the TWE Project is considered in the California ISO's 2020-2021 planning process.

The California ISO acknowledges these requests and will consider them in its consideration of the TWE Project in its 2020-2021 planning cycle. Further, the California ISO notes that as in past interregional coordination cycles, California renewable procurement portfolios provided by the California Public Utilities Commission for reliability and "informational" policy analysis for the 2020-2021 transmission planning cycle will be followed[6].

At this point in time the California ISO has not fully considered how it may study the TWE project in the 2020-2021 planning cycle. However, it is expected that the 2020-2021 planning process will likely consider all three segments of the TWE Project as a single 1500 MW project in the context of an "informational" policy analysis. The 2020-2021 planning process will focus on a reliability assessment and production cost simulations.

The production cost simulation analysis will examine the benefits from importing and exporting surplus resources between California and the Wyoming area using the TWE Project capacity.

The California ISO will develop the detailed modeling information for the GridView and GE PSLF computer programs and exchange that information with WestConnect commensurate with existing data confidentiality requirements.

2.2 NorthernGrid

The NorthernGrid Regional Transmission Plan evaluates whether transmission needs within the NorthernGrid may be satisfied by regional and/or interregional transmission projects. The NorthernGrid Regional Transmission Plan provides valuable regional insight and information for all stakeholders, including developers, to consider and use in their respective decision-making processes.

The first step in developing NorthernGrid's 2020-21 Regional Transmission Plan is to identify the Baseline Projects of Enrolled Parties. Baseline Projects are the transmission projects included in the Enrolled Parties' Local Transmission Plans plus those projects included in the prior Regional Transmission

[6] https://www.cpuc.ca.gov/General.aspx?id=6442464144

Plan that will be reevaluated (there will be no reevaluation for this first Regional Transmission Plan).. NorthernGrid then evaluates combinations of the Enrolled Parties Baseline Projects and Alternative Projects to identify whether there may be a combination that effectively satisfies all Enrolled Party Needs ("Regional Combination"). Power flow and dynamic analysis techniques are used to determine if the modeled transmission system topology meets the system reliability performance requirements and transmission needs. The Regional Combination that effectively satisfies all Enrolled Party Needs will be selected into NorthernGrid's Regional Transmission Plan. A more detailed discussion of NorthernGrid's study process can be found in NorthernGrid's Study Scope posted on NorthernGrid's website.

3 Data and Study Methodologies

The coordinated ITP evaluation process strives for consistent planning assumptions and technical data among the Planning Regions evaluating the ITP. The Relevant Planning Regions have summarized, in Table 1, the types of studies that will be conducted that are relevant to the TWE Project evaluation in each Planning Region. Methodologies for coordinating planning assumptions across the Relevant Planning Region processes are also described.

Table 1: Relevant Planning Region Study Summary Matrix

Planning Study	**California ISO**	**NTTG**
Economic/Production Cost Model	Using the California ISO PCM Base Case, based on the WECC 2030 Anchor Data Set (ADS), GridView will be used to perform production cost simulation. All model information will be shared with NorthernGrid and WestConnect.	Regional Economic Assessment will be performed with the WECC 2030 Anchor Data Set (ADS)
Reliability/Power Flow Assessment	Depending on the results of the production cost modeling, the GE PSLF may be used to perform steady state and as needed, transient analysis. The WECC 2030 ADS and	The Regional Transmission Plan Study Scope is in development with an expected approval date of mid-July – the following WECC power flow base cases are under consideration: 2029-30 Heavy Winter 1 2030 Light Spring 1

	2030 LSP1 will be modified as needed to accurately model the California network and resources that reflects the ISO's finalized 2019-2020 transmission plan. The TWE Project will be added to that model. All model information will be shared with NorthernGrid and WestConnect.	2030 Heavy Summer 1 2030 Heavy Spring WECC ADS PCM export 2030 Heavy Fall WECC ADS PCM export

Note that the TWE Project evaluation will be conducted by each Relevant Planning Region in accordance with its approved Order 1000 Regional Planning Process. This includes study methodologies and benefits identified in planning studies.

4 Data Coordination

The Relevant Planning Regions will strive to coordinate major planning assumptions through the following procedures.

4.1 Economic/Production Cost Model

The Relevant Planning Regions intend to use the WECC 2030 Anchor Data Set (ADS) as an input into their regional economic planning studies conducted in 2019 and 2020 (as applicable). Each Planning Region intends to update the 2030 ADS with their most recent and relevant regional planning assumptions to reflect its starting point transmission topology and generation data.[7] The Planning Regions will strive to coordinate major updates made to the 2030 ADS as part of their regional model development efforts in late Q3, 2020.[8]

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[7] For WestConnect, this update occurs when the WestConnect member Transmission Owners provide their local transmission plans for 2030 to WECC for inclusion in the WECC 2030 Heavy Summer power flow base case, which is used as a starting point for the WECC 2030 ADS.

[8] This schedule is dependent on the 2030 Anchor Data Set being provided by WECC no later than the end of Q2, 2020, and the sharing of planning data or assumptions will be subject to applicable confidentiality requirements in each Planning Region.

As an example, the California ISO will update the 2030 ADS to reflect their recently completed 2019-2020 Transmission Plan[9]. NorthernGrid members are working on the 2030 ADS model with WECC staff to incorporate the 2028 ADS topology and 2020 L&R submittals in the 2030 power flow case. WestConnect members will represent their local transmission plans for 2030.[10]

Through this coordination of planning data and assumptions, the Relevant Regions will strive to build a consistent platform of planning assumptions for Economic/Production Cost Model evaluations of the ITP.

4.2 Reliability/Power Flow Assessment

Since each Planning Region reflects characteristics and a planning focus that is unique, different power flow models are generally needed to appropriately reflect each region's system and key assumptions. As such, each Planning Region will develop its models and data that accurately reflect their Planning Region, but will seek to coordinate this information with the other Relevant Planning Regions subject to applicable confidentiality requirements. The identification of the starting WECC power flow cases ("seed cases" for the purpose of this evaluation plan), and significant assumptions or changes a Planning Region may make to a seed base case are examples of information that will be considered by each Planning Region and coordinated with the other Planning Regions. As such, the inclusion or removal of major regional transmission projects will be coordinated through existing data coordination processes, but the season or hour of study and particular system operating conditions may vary by Planning Region based on its individual regional planning scope and study plan. Project sponsor WECC Path Rating studies may be accessed from the WECC website and used to augment the assessment[11].

4.3 Cost Assumptions

In order for each Relevant Planning Region to evaluate whether the TWE Project is a more efficient or cost-effective alternative within their regional planning process, it is necessary to coordinate ITP cost assumptions among the Relevant Planning Regions. For planning purposes, each Region's cost share of the TWE Project will be calculated based on its share of the calculated benefits provided to the Region by the TWE Project (as quantified per that Region's planning process). The project cost of the TWE Project, as provided in their ITP Submittal form, is provided in Table 2.

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[9] http://www.caiso.com/Documents/ISOBoardApproved-2019-2020TransmissionPlan.pdf

[10] WestConnect 2020-2021 Base Transmission Plan

[11] https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Path%20Rating%20Process%20Logbook.docx&action=default&DefaultItemOpen=1

Table 2: Project Sponsor Cost Information[12]

Project Configuration	Cost ($) (2020$)
TWE WY-IPP DC	$2,100 million
TWE Crystal-Eldorado 500kV AC Project	$180 million
TWE IPP-Crystal 500kV AC Project	$660 million

4.4 Cost Allocation

Interregional cost allocation may apply for the TWE Project for the 2020-2021 cycle.

TransWest Express LLC requested cost allocation from California ISO and met the necessary requirements within the California ISO's regional process to be considered eligible to request cost allocation. Cost allocation was requested from the California ISO. Cost allocation was not requested from either Northern Grid or WestConnect. The project sponsor is in discussion with several WestConnect members with respect to their local planning processes to consider potential funding (cost allocation) of applicable TWE Project Capacity. In addition to these potential funding sources, the Project sponsor stated they would also like to be considered by the California ISO as an ITP without cost allocation where a "merchant" (or participant-funded) transmission model would be employed.

If all costs for any TWE Project segments are fully allocated to the California ISO, the California ISO would consider the applicable TWE Project segment as a regional project and it would be considered in the competitive solicitation process as described in Phase 3 of the California ISO's transmission planning process[13].

[12] This information is contingent upon verification by the Planning Regions and may be subject to change during the ITP evaluation process

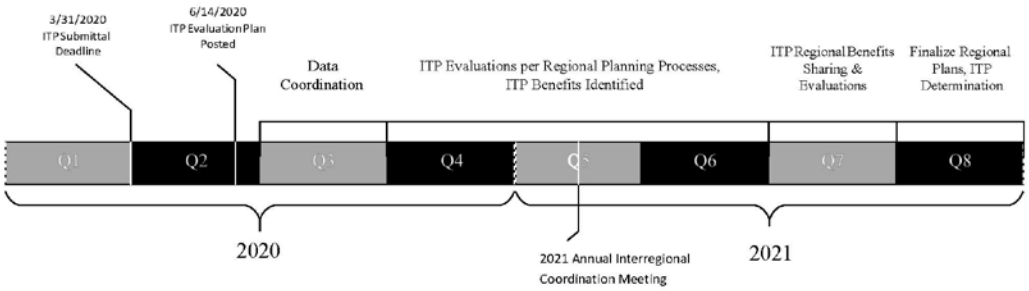
[13] Section 24.5; California ISO Conformed Tariff

California ISO NorthernGrid

5 Schedule and Evaluation Milestones

The ITP will be evaluated in accordance with each Relevant Planning Region's regional transmission planning process during 2020 and (as applicable) 2021. The ITP Evaluation Timeline, shown in Figure 2, was created to identify and coordinate key milestones within each Relevant Planning Region's process. Note that in some instances, an individual Planning Region may achieve a milestone earlier than other Regions evaluating the ITP.

Figure 2: ITP Evaluation Timeline



Meetings among the Relevant Planning Regions will be coordinated and organized by the lead Planning Region per this schedule at key milestones such as during the initial phases of the ITP evaluations and during the sharing of ITP regional benefits.

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6 Contact Information

For information regarding the ITP evaluation within each Relevant Planning Region's planning process, please contact that Planning Region directly.

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