2024-2025 Transmission Planning Process
Unified Planning Assumptions
And Study Plan

Febuary 21, 2024

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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 2024-2025 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 2023 IEPR adopted by the CEC on February 14th, 2024[1].

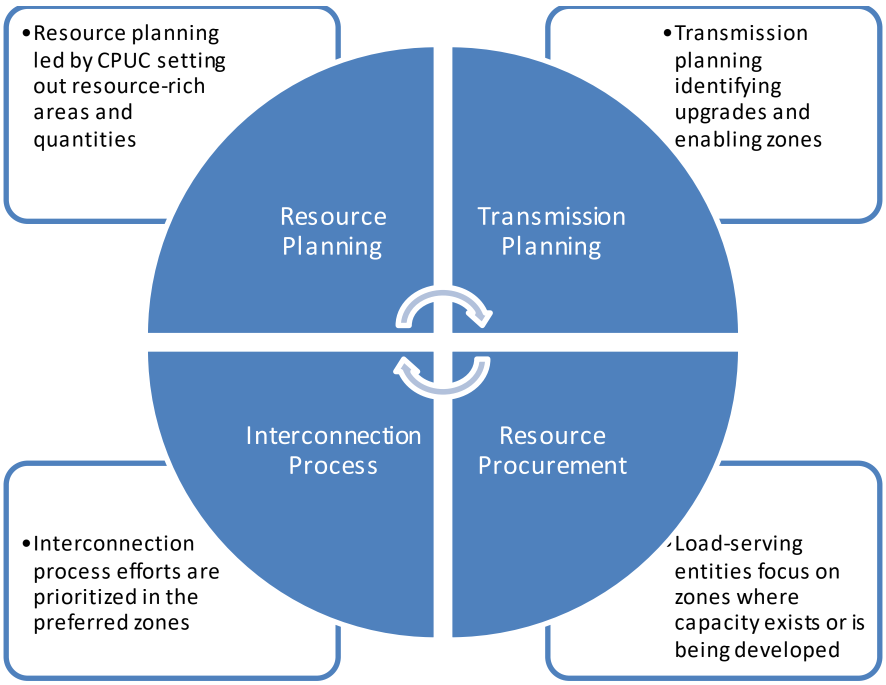
As set out in the MOU, expectations are that the CPUC[2] will continue to provide resource planning information to the ISO as it did for this transmission planning cycle. The ISO will develop a final transmission plan, initiate the transmission projects and communicate to the electricity industry specific geographic zones that are being targeted for transmission projects along with the capacity being made available in those zones. The CPUC will in turn provide

[1] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2023-integrated-energy-policy-report

[2] In addition to the needs of the jurisdictional load serving entities in the ISO's footprint, the CPUC currently works to include the needs of the publicly owned utilities and other non-CPUC-jurisdictional utilities in its resource planning efforts for the ISO balancing authority area, and this is an issue that will be receiving additional attention in this planning cycles to ensure the needs of these parties are being addressed.

clear direction to load-serving entities to focus their energy procurement in those key transmission zones, in alignment with the transmission plan.

To bring this more coordinated approach full circle, the ISO will also give priority to interconnection requests located within those same zones in its generation interconnection process.



1.1 Overview of 2024-2025 Stakeholder Process Activities and Communications

This section 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 transmission planning process. 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 2024-2025 transmission planning process is provided in Table 1.1-1. Should this schedule change or other aspects of current transmission planning process 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: Current Schedule for the 2024-2025 planning cycle

Phase	No	Due Date	2024-2025 Activity
Phase 1	1	December 28, 2023	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 28, 2023	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 29, 2024	PTO's, neighboring balancing authorities and regional/sub-regional planning groups provide CAISO the information requested No.1 above.
	4	January 29, 2024	Stakeholders provide CAISO the information requested No.2 above.
	5	February 21, 2024	The CAISO develops the draft Study Plan and posts it on its website
	6	February 28, 2024	The CAISO hosts public stakeholder meeting #1 to discuss the contents in the Study Plan with stakeholders
	7	February 28 – March 13, 2024	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 29, 2024	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 15, 2024	The CAISO posts preliminary reliability study results and mitigation solutions
	10	August 15, 2024	Request Window opens
	11	August 30, 2024	The CAISO will post base scenario base cases for each planning area used in the reliability assessment
	12	September 14, 2024	PTO's submit reliability projects to the CAISO
	13	September 25-26, 2024	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 26-October 10, 2024	Comment period for stakeholders to submit comments on the public stakeholder meeting #2 material[3]

[3] 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.

Phase	No	Due Date	2024-2025 Activity
	15	October 15, 2024	Request Window closes
	16	October 31, 2024	The CAISO post final reliability study results
	17	November 12, 2024	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 14, 2024	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 14- November 28, 2024	Comment period for stakeholders to submit comments on the public stakeholder meeting #3 material
	20	December 11 – 12, 2024	The CAISO Board of Governors meeting provides opportunity for stakeholder comments directly to Board of Governors.
	21	March 31, 2025	The CAISO posts the draft Transmission Plan on the public website
	22	April 15, 2025	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	April 15 – April 29, 2025	Comment period for stakeholders to submit comments on the public stakeholder meeting #4 material
	24	May, 2025	The CAISO finalizes the Transmission Plan and presents it to the CAISO Board of Governors for approval
	25	May 30, 2025	The CAISO posts the Final Board-approved Transmission Plan on its site
Phase 3	26[4]	June 1, 2025	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

[4] 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 the following responses to the Data Request Letter:

- California Department of Water Resources (CDWR) provided outage detail, including units with expected greater than 6 month outage.
- City of Palo Alto (CPAU) provided Summer Peak High Load Sensitivity Forcasted data for 2024-2040, including 1-in-2, 1-in-5, and 1-in-10 MW values.
- IID provided the most up-to-date outage and RAS files.
- LSPower provided an updated set of steady state and transient stability contingency lists for outages involving DesertLink's Harry Allen-Eldorado (HAE) facilities. These include both near team "2025" topology and longer term "2028" topology.
- Northern California Power Agency (NCPA) provided the 2023 Inter-Agency Resource Plan (2023 IARP) adopted by the NCPA Commission for use in the 2024-2025 Transmission Plan.
- NextEra has provided TransBay Cable HVDC model and Suncrest SVC model submittals for TPP basecase development. NextEra has clarified that there are no changes from the previous model to include no planned outages, no generation interconnections, no customer load connected, and transmission contingencies are unchanged.
- Hetch Hetchy Water & Power (HHWP) provided change files with the most recent system changes, updated HHWP qtab information, and up to date dynamic models.
- Silicon Valley Power (SVP) provided load forecast and network change files from 2024 to 2039. SVP clarified that all the change files are based on the 2023 base PSLF model received by PG&E in November 2023.
- Transmission Agency of Northern California (TANC) indicated that reliability planning data (important for the reliability planning assessments as required by the NERC TPL-001-5) is already available through WECC and that TANC does not have any additional reliability planning data for the CAISO to consider in the 2024-2025 Transmission Planning Process. However, TANC provided comments related to automatic system operation, contingencies, spare equipment availability and other planning information requested in the CAISO letter.
- Turlock Irrigation District (TID) has provided OTG files for Transmission Contingencies that may impact the CAISO system, informations on potential outages with greater than 1 year lead time, as the TID BA load forecast.

- Western Area Power Administration (WAPA) has provided OTG file with WAPA-SNR additional contingencies for consideration of inclusion into the 2024-2025 CAISO Transmission Planning Process.

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 2024-2025 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://mpp.caiso.com/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 2.1-2.13. 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, and reliability standards to be used to measure system performance, and software or analytical tools.

2.1 Reliability Standards and Criteria

The 2024-2025 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 2024-2034 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

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

NUC-001-3 Nuclear Plant Interface Coordination.[6]

2.1.2 WECC Regional Criteria

The WECC System Performance TPL-001-WECC-CRT-3.2[7] 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 WECC Interconnection.

[5] TPL-001-5 modified Category P5 single point of failure & R2.4.5 requirements will be implemented based on the TPL-001-5 Implementation plan dates.

[6] 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

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

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.[8] 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 Transmission Planning Process (TPP).

2.2.1 Use of past studies

The annual 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. Similar to the previous TPP 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.

2.2.2 Study Horizon and Years

The studies that comply with TPL-001-5 will be conducted for both the near-term[9] (2026-2029) and longer-term[10] (2029-2034) 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 2026, 2029 and 2034. Additionally, for long-term scenario, 2039 will also be studied. If in the analysis it is determined that additional years are required to be assessed the

[8] https://www.caiso.com/Documents/ISO-Planning-Standards-Effective-Feb22023.pdf

[9] 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.

[10] System peak load conditions for one of the years and the rationale for why that year was selected.

CAISO will consider conducting studies on these years or utilize past studies[11] in the areas as appropriate.

2.3 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 2.3-1 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 18 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
  - Metro area.
- San Diego Gas & Electric (SDG&E) area
- Valley Electric Association (VEA) area[12]
- CAISO overall bulk system

[11] 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.

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

Figure 2.3-1: Approximated geographical locations of the study areas

2.4 Transmission Assumptions

2.4.1 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 2023-2024 or earlier CAISO transmission plans. Currently, the CAISO anticipates the 2024-2025 transmission plan will be presented to the CAISO board of governors for approval in May 2025. Projects put on hold will not be modeled in the starting base case.

2.4.2 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 A5-1 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.

2.4.3 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 working with the PTOs with a target to model all RAS in the CAISO controlled grid.

2.4.4 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 lines such as PDCI, IPPDC, and Trans Bay Cable Projects
- Imperial Valley phase shifting transformers

2.5 Load Forecast Assumptions

2.5.1 Energy and Demand Forecast

The assessment will utilize the 2023 California Energy Demand Update (CEDU) Forecast 2023-2040 adopted by the California Energy Commission (CEC) on February 14, 2024[13] using the corresponding LSE and BA Table Mid Baseline spreadsheet with applicable Additional Achievable Energy Efficiency (AAEE), Additional Achievable Fuel Substitution (AAFS) and Additional Achievable Transportation Electrification (AATE) load modifiers. The 2023 CEDU Forecast also includes 8760-hourly demand forecasts for the three major Investor Owned Utility (IOU) TAC areas as well as for the entire CAISO.

The CAISO engaged in collaborative discussion with CEC and CPUC on how to consistently account for reduced energy demand from energy efficiency in the planning and procurement processes. To that end, the 2023 IEPR final report, adopted on February 14, 2024 based on the IEPR report and in consultation with the CPUC and the CAISO, recommends using the Mid Demand-AAEE Scenario 3, AAFS Scenario 3 and AATE Scenario 3 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, AAEE, AAFS and AATE at specific locations and estimating their daily load-shape impacts, using the Mid Demand-AAEE Scenario 2, AAFS Scenario 4 and AATE Scenario 3 is recommended.

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

https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2023-integrated-energy-policy-report

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 local reliability scenario (with AAEE Scenario 2, AAFS Scenario 4 and AATE Scenario 3) 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 planning (with AAEE Scenario 3, AAFS Scenario 3 and AATE Scenario 3) load forecasts will be used for system studies
- The 1-in-2 weather year, mid demand baseline planning (with AAEE Scenario 3, AAFS Scenario 3 and AATE Scenario 3) load forecasts will be used for production cost study.

Valley Electric Association, Inc. (VEA) joined the California ISO control area in 2013. While most customers of the 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

[13] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2023-integrated-energy-policy-report

California's Renewable Portfolio Standard, as well as forecasts of VEA's peak load to inform the California ISO's transmission planning process.

To ensure the VEA load forecast has incorporated relevant information, VEA may provide local data to the Energy Commission and Energy Commission staff committed to a more holistic approach to forecasting VEA load growth in response. The following information by customer sector may be provided by VEA to 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.

The CEC staff typically uses econometric methods to prepare electricity sales and peak demand forecasts for the VEA service territory in its entirety. Additionally, the CEC staff may review documentation of new service requests provided by VEA and determines whether an incremental adjustment to non-residential sales projections would be appropriate to account for additional planned electricity demand that would otherwise not be captured in the forecast using econometric methods.

Single Managed Forecast Set for Electricity Planning

The following list describes the current agreement among the lead staff of the joint agencies and California ISO:

1. CPUC IRP Reference System Plan, Preferred System Plan, and California ISO TPP economic studies:
    - Baseline annual energy and annual peak demand
    - AAEE Scenario 3 annual energy and peak demand
    - AAFS Scenario 3 annual energy and peak demand
    - AATE Scenario 3 annual energy and peak demand
    - 1-year-in-2 peak event weather conditions
2. **California ISO TPP policy studies and bulk system studies:**
    - Baseline annual energy and annual peak demand
    - AAEE Scenario 3 annual energy and peak demand
    - AAFS Scenario 3 annual energy and peak demand
    - AATE Scenario 3 annual energy and peak demand
    - 1-year-in-5 peak event weather conditions
    - Planning Forecast hourly loads

- o CEC staff allocations of AAEE, AAFS, and AATE to load buses used in transmission planning related studies

3. **California ISO TPP policy studies and local system studies:**

    - o Baseline annual energy and annual peak demand
    - o AAEE Scenario 2 (Mid-Low) annual energy and peak demand
    - o AAFS Scenario 4 (Mid-High) annual energy and peak demand
    - o AATE Scenario 3 annual energy and peak demand
    - o 1-year-in-10 peak event weather conditions
    - o CEC staff allocations of AAEE, AAFS, and AATE to load buses used in transmission planning related studies

2.5.2 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.

2.5.3.1 CEC Staff Methodology for Load Modifier Allocation to Load Busses

Power flow modeling requires future year load forecasts at the level of transmission busses as one of the key inputs. The CAISO approach to this is more complex than for many other users of power flow models, because of the increasing emphasis on inclusion of energy policy impacts and multiple entities contributing portions of the overall set of load bus inputs.

Three basic elements are needed:

1. The CEC demand forecast of TAC area loads, at both CAISO-wide coincident basis and an individual TAC-area non-coincident basis, for each of several levels of peak weather severity is the control total.
2. The CEC provides an assessment of individual transmission load bus impacts resulting from its assessment of three types of load modifiers that are included in the determination of system peak hour loads. The three types of policy-based load modifiers are:
    a. Utility energy efficiency programs, California or federal building and appliance standards, and other federal, state, or local programs;
    b. Utility program to incent substitution of electricity to replace combustion fuels (natural gas and propane) in buildings and industry;

   c. Regulations of California Air Resources Board emission reduction mandates as well as similar mandates of local air quality management districts
3. IOU projections of CEC system-level or TAC-level load by load bus without the impacts assessed the CEC for load modifiers as described in item 2b above.

The CAISO and IOUs work together to populate the load portion of the power flow base cases guided by the above approach.

The detailed approach that the CEC uses for each of the three categories of load modifiers are discussed in the two sections below. These descriptions are accurate for the 2023-24 TPP cycle (using CEC 2022 IEPR demand forecasts), but limited revisions will be undertaken for the 2024-25 TPP cycle which are described in summary fashion at the end of each section.

Additional Achievable Energy Efficiency (AAEE) and Fuel Substitution (AAFS) Load from IEPR 2022

The load bus analysis that the CEC conducts each year for CAISO allocates the CEC's AAEE and AAFS load modifier forecasts to IOU and POU substations and WECC busbars. The CEC sends CAISO two excel workbooks for this analysis, with the first workbook containing load bus results for coincident CAISO peak load, and the second workbook containing load bus results for non-coincident Utility peak load. Coincident peak load bus results contain peak hour MW AAEE and AAFS results that are reported at the same peak dates (month, day, and hour) for each Utility, and can only vary by IEPR forecast scenario and year. Non-coincident peak load bus results contain peak hour MW AAEE and AAFS results that can have varying peak dates (month, day, and hour) for each Utility, IEPR forecast scenario, and year.

The first stage of the load bus analysis is to work in conjunction with CPUC to send out a data request to the IOUs to receive 24 hours of MW load that was observed by each Utility for two peak dates. The first date we request is for the day that each Utility's system peaked in the previous year, which will change amongst each IOU, while the second date is for the day that the CAISO system peaked in the previous year. MW loads from the IOUs are reported by the transmission planning WECC busbars that the IOUs and CAISO agree on for power flow modeling purposes and are disaggregated by eight customers sectors. These sectors include residential, commercial, industrial, mining/extraction, ag/pumping, transportation/communication/utility, streetlighting and other. Three customer sectors (transportation/communication/utility, streetlighting and other) are summed up with the Commercial sector to aggregate the IOU MW load to just five customer sectors used in the load bus analysis. Further geographic granularity for these WECC busbars is requested by asking for a list of ZIP codes that detail where end-use customers are connected to a given WECC bus or substation, and the ZIP code locations of each substation.

The second stage of the load bus analysis is to create groups within each AAEE and AAFS scenario that aggregates the load modifier annual energy projections into groupings of the individual programs that were modeled at the annual energy level. This step sets the stage for allocating each group according to different distribution shares across the whole set of load busses with each utility area. For the load bus analysis that was delivered to CAISO in March of

2023, the CEC's AAEE and AAFS scenarios were aggregated into 5 major programmatic groups. The first three groups of AAEE and AAFS results dealt primarily with new construction oriented programs/standards (such as Title 24 and Local Government Ordinances) that have a greater level of geographic granularity than the other modeled programs. The fourth group of AAEE and AAFS results contains programs that have no clear distinction that splits the impacts between new construction or existing/retrofit building improvements and are expected to be distributed according to existing customer sector loads, unlike groups 1-3. The fifth and final group of AAEE and AAFS results separate out the fuel substitution impacts of CARB's zero emission space and water heater measure from the 2022 SIP Strategy that is modeled using CEC's Fuel Substitution Scenario Analysis Tool (FSSAT).

After determining which programs modeled in AAEE and AAFS (and now also inclusive of FSSAT) are assigned to the 5 defined groups, the annual load modifiers are run through the CEC's energy efficiency and fuel substitution hourly tools. Hourly AAEE and AAFS results get produced for each group and for each Electric Utility to be used in the load bus analysis. The electric utilities for which the hourly results are reported include PGE, SCE, and SDGE for the IOUs (at the TAC level), and SMUD, LADWP, NCNC (exclusive of SMUD), IID, BUGL, NorCal Other, and SoCal Other for the POUs. NorCal Other accounts for the smaller POUs in northern California, while SoCal Other accounts for the smaller POUs in southern California. Once these hourly AAEE and AAFS hourly forecasts have been created, they are brought into the CEC's load bus analysis R script to be reformatted and to remove any previous year's load modifier impacts from the forecast.

The third stage of the load bus analysis is to determine which month, day, and 24 hour period of MW load impacts to use from the AAEE and AAFS hourly results for each year, utility, and IEPR forecast scenario (planning forecast and local reliability scenario). Hourly Demand Forecasts for the current IEPR cycle are downloaded from the CEC's website for the CAISO system and the three TAC area IOUs for a total of eight files (four for the planning forecast and four for the local reliability scenario). The two CAISO system hourly demand forecast files are used for the coincident CAISO peak load bus analysis, while the six TAC area IOU hourly demand forecast files are used for the non-coincident peak load bus analysis. Each forecast file is brought into the load bus analysis R script to determine, for each forecast year, the month, day, and hour the managed net forecast peaks for the CAISO system and each TAC area IOU in the planning scenario and local reliability scenario.

For the coincident peak load bus analysis, the yearly system peak dates found from the CAISO system hourly demand forecast are used to filter the hourly AAEE and AAFS results to a 24 hour profile of MW impacts. This is done for each forecast year, building sector, and utility. This filtering process leaves the AAEE and AAFS scenarios that are part of either the planning forecast or local reliability scenario. As mentioned above, these coincident peak dates do not change amongst the IOUs or POUs, so there would only be a variation in the peak dates between the forecast years and the two forecast scenarios.

The non-coincident peak load bus analysis follows the same filtering process as the coincident peak analysis above, but it uses the yearly peak dates found from the individual PGE, SCE, and

SDGE TAC area hourly demand forecast files. It also uses different peak dates for each forecast year and each IOU. For SMUD, NCNC, and NorCal Other, the PGE TAC peak hour for each forecast year determines the 24-hour day to assign the AAEE and AAFS impacts. This approach follows for LADWP, IID, BUGL, and SoCal Other, using the SCE TAC peak hour for each forecast year.

The fourth stage of the load bus analysis is to create the allocation shares that will assign the Utility based AAEE and AAFS load modifiers to the IOU and POU WECC busbars. Different IOU allocation shares are used for the various AAEE and AAFS group combinations, while the same POU allocation shares are used for all AAEE and AAFS groups.

For the IOU allocation shares used on the Groups 1-3 AAEE and AAFS load modifiers, both historical and forecasted new construction data from various sources are used. The major data source for these shares is the California new construction residential housing forecast (by County) that comes from Moody's Analytics. A historic new construction forecast for 2015-2020 that is by county and city is then used to disaggregate the county-based Moody's forecast into a county- and city-wide forecast. Finally, to map the WECC busbars and ISO IDs (from the CPUC data request) to the city and county Moody's new construction forecast, a ZIP code to city and county map provided by USPS is used. Shares are then created for each forecast year and IOU by dividing the number of new homes that a WECC busbar and ISO ID combination serve by the total number of homes served by a given Utility. These shares are summed from a city and county level to a utility level of geography for use in the load bus analysis R script.

For the IOU allocation shares used on the groups 4-5 AAEE and AAFS load modifiers, the confidential 24 hour-profiles of MW load data for peak days that were requested from the IOUs is used. Using the MW load data, shares are created for each customer sector and Utility combination by dividing the MW value for each WECC bus and ISO ID combination by the total MW load seen for the chosen sector and Utility. This share creation process is done separately for each of the 24 hour-profiles of MW load data for peak days received from the IOUs and is done once using the Utility peak date MW values and once using the CAISO peak date MW values. In the end, two sets of shares are created for each IOU, with the first set made with the MW load data on the day that the utility peaked and the second set made with the MW load data on the day that the CAISO system peaked. This process allows for the creation of allocation shares that vary by utility, sector, hour of day, and system peak type (CAISO vs Utility), which improves the accuracy of spreading the CEC's hourly AAEE and AAFS load to WECC busses.

The POU allocation shares used on the groups 1-5 AAEE and AAFS load modifiers are created using forecasted MW load data (for a single year) from CAISO's previous year Power Flow Base Case by dividing load bus values by the sum of load bus values by utility. Forecast peak MW data is provided for each WECC Bus in a POU territory at single future year (for the 2022 load bus analysis, this future year was 2027), and then gets split into MW values for Northern vs Southern POUs. After the North vs South split is finished, certain groups of utilities are merged to form a new set of utility names used in the load bus analysis. The three utility names used for the northern POUs are SMUD, NCNC (exclusive of SMUD) and North (all other northern POUs), while the four utility names used for the southern POUs are LADWP, BUGL, IID, and South (all other southern POUs). Using these new utility names, shares are created by dividing the MW load seen at a single WECC bus in each POU territory by the total MW load seen by all the WECC busses in the same POUs territory. Unlike the IOU shares, these shares created for the POUs do not differ by either sector or year. These shares will only vary based on which POU is being processed.

The fifth stage of the load bus analysis is to apply the allocation shares to the AAEE and AAFS peak MW results for the planning forecast and local reliability scenario. The IOU AAEE and AAFS MW loads for groups 1-3 are distributed using the new construction-based shares, while the MW loads for groups 4 and 5 are distributed to the customer sector-based shares created using the confidential load data from the IOUs. For POU AAEE and AAFS peak MW projections, since source data did not provide sector or ZIP level detail, we could not include program groups in the share creation. This meant that the POU MW results for groups 1-5 were applied to the same POU share for each group. Once the IOU and POU AAEE and AAFS peak MW results are allocated to the WECC BUS numbers, Substation names, and ISO IDs, they are split to create two peak forecast datasets, one for the peak hour results, and one for the 24 hours of peak results. In the peak hour results dataset, the AAEE and AAFS values are further split up to separate the coincident peak results from the non-coincident peak results, which will be output into two separate files. The 24 hours of peak day results, however, stay as one output file, and only show coincident and non-coincident results for PGE, SCE, and SDGE service territories, as hourly load data (for the peak day) was not provided by the POUs.

Changes to AAEE and AAFS Load Bus Analysis Process for IEPR 2023

The load bus analysis for the 2023 IEPR is expected to follow the same process for assigning hourly peak MW load for AAEE and AAFS to WECCBUS and substations that was used for the 2022 IEPR load bus analysis. This includes using the same methods for creating the IOU and POU Utility to WECCBUS shares and continuing to split the AAEE and AAFS hourly savings into different groups. To determine which peak dates to provide substation level AAEE and AAFS hourly results for, CEC staff only looked at coincident and non-coincident summer peak values for the 2022 IEPR load bus analysis. As a result of discussions with CAISO transmission planning staff, for the 2023 IEPR, CEC staff will now expand the analysis to include 24-hour profiles for the dates of coincident and non-coincident peaks for the summer peak hour, the winter peak hour, the winter off peak hour, and the spring off peak hour. By diversifying the seasonal impacts of AAEE and AAFS hourly MW load, a more detailed and nuanced look at the added or removed MW load at substations is possible. CAISO staff expects that by improving its off peak condition assessments using these seasonally differentiated AAEE and AAFS results that this will lead to more accurate power flow modeling results.

Allocation of Additional Acheivable Transportation Electrification (AATE) Load from IEPR 2022

For transmission impact studies based on the IEPR 2022 electricity demand forecast, CAISO requested that the CEC determine transportation-related load impacts for CAISO annual coincident and non-coincident peak hours. The deliverables provided load impacts of AATE Scenario 3 in the IEPR 2022 forecast at the transmission substation level and incremental to base year.

The Transportation load bus allocation begins with determining proportional shares of energy by ZIP codes for light-duty vehicles (LDV) and medium- and heavy-duty vehicles (MDHD) separately. A variety of datasets were used in this assignment of energy to capture different assumptions about the geography of vehicle charging behavior. The following writeup describes the methodologies for assigning shares of transportation-associated electricity demand to ZIP codes for LDV and MDHD respectively, and for subsequently allocating demand to transmission-level substations.

Light Duty Vehicles

For LDV, the energy remains at the forecast zone level, as in the IEPR electricity demand forecast, and is first split up into the following shares to be further disaggregated by different methods. The percentages listed below are the proportional share of statewide energy demand that is then further allocated by each dataset.

For Forecast Zones 0 and 3:

1. Major highway traffic data by ZIP codes – 45%
2. Gasoline retail sales for light-duty vehicle by ZIP codes – 45%
3. DMV vehicle registration data by ZIP codes – 10%

For Forecast Zones 1, 2, 4 through 20:

1. DMV vehicle registration data by ZIP codes – 70%
2. Historical commercial WECC bus loads by ZIP codes – 15%
3. Gasoline retail sales for light-duty vehicle by ZIP codes – 5%
4. DCFC Charger Stations by ZIP codes – 5%
5. Major highway traffic data by ZIP codes – 5%

Each dataset incorporates assumptions about a different type of light-duty vehicle charging. To start, DMV vehicle registration data represented potential at-home charging locations, and historical loads for commercial sector captured potential workplace or other commercial charging. Gasoline retail sales data and known DCFC charger station data were used to represent potential locations of public charging; traffic data for major highways also captured public charging, but with a focus on long distance travel. All of these datasets were used to disaggregate light-duty load in forecast zones 1, 2, and 4 through 20 from forecast zones to ZIP codes. Due to higher gasoline consumption per vehicle and higher traffic per human population density observed in forecast zones 0 and 3, the allocation of energy to ZIP codes for these two zones was concentrated on major highway traffic data and gasoline retail sales data.

Medium and Heavy Duty Vehicles

Once the electricity demand resulting from freight and service trucks in AATE was summed up to the statewide total for MDHD, the following shares of statewide MDHD energy were used to be further disaggregated by different methods. As with the light-duty methodology, the percentages listed below are the proportional share of statewide energy demand that is then further allocated by each dataset.

For freight and service trucks:

1. Freight travel data from California Statewide Travel Demand Model (CSTDM) by ZIP codes – 50%

2. Diesel retail sales by ZIP codes – 25%

3. Diesel retail sales by ZIP codes for which the Army Corps of Engineers' cumulative "hubness" score of 100 or less – 5%

4. Diesel retail sales by ZIP codes for which the Army Corps of Engineers' cumulative "hubness" score of more than 100 – 15%

5. Transportation Refrigeration Unit (TRU) applicable facilities data from CARB – 5%

Each dataset reflects assumptions about different types of medium- and heavy-duty charging. To begin with, the freight movement data from the California Statewide Travel Demand Model (CSTDM) provided origins and destinations for modeled freight movement within the state, capturing a mixture of potential depot and public charging. Also, as a starting point, CARB's dataset on TRU applicable facilities data was incorporated to represent some potential depot charging at facilities that may be likely to have additional charging for refrigeration purposes; future iterations will strive to include more comprehensive data on commercial facilities with freight activity.

Diesel retail sales data provided potential locations of public charging for trucks, and was used both on its own and with further weighting provided by a measure of freight traffic optimization called "hubness." This "hubness" score was developed by the Army Corps of Engineers for the California Transportation Commission (CTC)'s Senate Bill 671 Clean Freight Corridor Efficiency Assessment. The Army Corps of Engineers used real-world traffic datasets to perform an optimization of existing truck service stations as candidate locations for zero-emissions infrastructure that would minimize freight traffic diversion. After performing many runs of the statewide optimization, the number of times a particular census tract appeared in the runs was counted as a metric termed "hubness," indicating a high degree of suitability for serving as a hub for truck refueling. Certain ZIP codes with higher hubness scores were given additional shares of energy to reflect an assumption that these locations would be more likely to have existing logistical and other trucking services suitable for MDHD charging infrastructure.

For buses, electricity demand is produced by bus category for the IEPR forecast, so the load associated with buses was allocated to ZIP codes by distinct data sources that correlate to each of the four key bus categories:

1. Urban Buses – Bus stock data from CARB's Innovative Clean Transit inventory by ZIP codes

2. Demand Response Buses – Bus stock data from CARB's Innovative Clean Transit inventory by ZIP codes

3. School Buses – CARB school bus stock data from 2017-2018 by ZIP codes

4. Shuttle Buses – CARB airport shuttle stock data by ZIP codes

A crucial component of this disaggregation methodology for AATE was the conservation of energy at both the annual level and forecast zone level for LDV and MDHD respectively. In other words, the annual load for LDV was conserved for each year and for each forecast zone, ensuring that this load matches the energy results that were used for the IEPR 2022 electricity demand forecast. This same energy conservation was also performed for MDHD.

Allocation to Substations

After GWh were assigned ZIP codes for LDV and MDHD, the AATE load was then prepared for the peak hours of requested coincident and non-coincident peak days. Since the adopted 2022 IEPR hourly demand forecast files are incremental to 2021, the hourly demand output for AATE was regenerated to be incremental to 2022. A simple subtraction of AATE load in 2022 from all other forecast years would not be sufficient, due to the way that transportation load shapes are applied on an annual basis. This new hourly demand file for AATE, made incremental to 2022, provided the total peak hour MW for LADWP, SMUD, SCE, PGE, and SDGE respectively.

For the three IOUs (SCE, PGE, SDGE), the ZIP code GWh assigned for LDV and MDHD in previous steps was then scaled to the peak hour load shape for the ZIP code's TAC area, resulting in a peak load for each ZIP code.

A crosswalk of ZIP codes and WECCBUS IDs was used to generate the percent of each ZIP code's peak load that would then be assigned to a WECCBUS peak load for the hour. For PGE, a further layer of disaggregation was needed to crosswalk to ISO Bus IDs. Notably, staff assumed that substations with that shared the same associated ZIP code would have an equally divided share of the ZIP code peak load. For example, if a ZIP code had three associated substations, each substation would receive a third of the ZIP code peak load. These peak load assignments for each substation (WECCBUS ID) were summed for all ZIP code-level transportation peak loads to an associated substation.

In contrast, since CAISO requested that load allocation to non-IOU planning areas (NCNC, BUGL) and POUs be reported separately, additional energy proportioning for those regions was performed. Annual loads for NCNC and BUGL were derived from Form 1.1c (LSE and BA Planning Forecast, Electricity Deliveries to End Users by Agency (GWh)). Staff then calculated a percent of annual transportation load for each forecast year's peak hour within a TAC and by duty from the IEPR 2022 hourly demand files. Because the CEC does not currently have load shapes specific to NCNC and BUGL, the peak hour's percent of annual load for the nearest

TAC area (PGE for NCNC, SCE for BUGL) was applied to the annual loads from Form 1.1c to create a peak hour MW value for LDV and MDHD.

To distinguish energy for POUs within a TAC area, forecasted load data from CAISO's previous year Power Flow Base Case that was available to the CEC for POU substations were used to derive an assumed proportion of TAC area load that belongs to POUs. This proportion of POU load within a TAC area was applied to the total TAC peak load, creating the POU peak load for LDV and MDHD in each forecast year. POUs residing in the SCE TAC were labeled as “South” and POUs residing in the PGE TAC were labelled as “North.” With the requested POUs’ peak hour loads determined for each forecast year, energy shares of each substation within its POU were used to split the peak hour load to the respective substations.

The final deliverables to the CAISO for AATE load allocation were two workbooks – one for CAISO-wide coincident peaks and one for non-coincident peaks by TAC area – that contained the peak hour transportation-related load impacts for each transmission substation within both IOUs and POUs and for both LDV and MDHD.

Changes to AATE Load Bus Analysis Process for IEPR 2023

In alignment with aforementioned updates to the AAEE and AAFS analyses, the AATE load bus analysis for 2023 IEPR will also expand from only the 24-hour profile of the annual peak day to include 24-hour profiles for the all coincident and non-coincident peak dates for of the summer off peak day, winter peak day, winter off peak day, and spring off peak day. This will allow the impacts of seasonality for AATE hourly load to be further analyzed in the CAISO’s power flow modeling resultsstudies.

As for key data inputs of the AATE load bus analysis, Tthroughout a process of collaborative engagement with CPUC and IOUs on the Freight Infrastructure Proposal Planning process development throughout during 2023, CEC staff identified potential improvements to specific data inputs in the AATE methodology for load bus allocation were identified. Although the general flow and framework for AATE load bus analysis will remain the same as in the IEPR 2022 cycle, the specific datasets used for allocating AATE load are subject to change as CEC staff explore new data. Ddiscussions between CPUC, IOUs, and CEC led to the determination that particular attention would be needed for for load busses along key corridors of freight transportation that have high volumes of freight-related travel and for specific locations of interest, such as ports and border crossings. Such load busses should receive increased allocations in comparison to the IEPR 2022 analysis. In addition, CEC staff identified crucial errors in the crosswalk of WECCBUS substations and ZIP codes previously provided for IEPR 2022, which led to potential misallocation of transportation-related loads. These findings have led to the following planned updates for AATE load bus analysis of IEPR 2023:

- New data from IOUs
  - Using GIS shapefiles provided by IOUs to create a more accurate mapping of WECCBUS substations to ZIP codes.
  - Analyzing historical load from sub-metered EV chargers provided by IOUs in latest data request.

- Additional methodological improvements from CEC staff
  - Incorporating CARB's Large Entity Reporting data to include more truck fleet bases.
  - Further improvements of LDV DCFC methodscharger datasets
  - Port-specific substation allocationUsing truck traffic volume data along freight corridors
  - Exploring different weights for disaggregation methods by MDHD truck class to capture differences in expected charging behavior

2.5.2.2 Pacific Gas and Electric Service Area

The methodology employed to establish PG&E power flow base case loads involves a comprehensive process that integrates and refines information sourced from the CEC IEPR, transmission and distribution systems and municipal utility forecasts.

PG&E Loads in Power Flow Base Case

The process used to calculate PG&E loads mirrors the methodology from previous studies. It involves determining division loads for the required 1-in-5 heat wave for system study cases or 1-in-10 heat wave for area base cases, along with allocating these division loads to transmission buses. PG&E's load comprises several components: conforming load, nonconforming load, self-generation, station service loads, load modifiers (AAEE, AAFS, and AATE) and MUNI loads. PG&E organizes its service territory into 20 divisions for planning studies. Subsequently, these 20 divisions are combined to form seven planning areas within the service territory.

Determination of Division Loads

The annual division load is determined by summing the previous year division load and the current division load growth. Thus, the key steps are the determination of the initial year division summer peak load and the annual summer peak load growth.

The method for establishing the initial year in the base case development heavily relies on recent recorded data, specifically focusing on daily peak loads and peak temperatures during the summer months from the past 2 to 5 years. These datasets are chosen as the primary database to create initial year summer peak load forecasts. The initial year's summer peak load forecast, serving as the starting point for each division, is determined by calculating both the 1-in-5 and 1-in-10 heat wave summer peak loads specific to each division. This calculation involves referencing the 1-in-5 and 1-in-10 high temperatures particular to each division, which are established based on historical temperature data spanning several decades. To develop these forecasts, a load-temperature correlation is established for each division. This correlation is derived from the analysis of recorded daily peak loads and daily peak temperatures within each division during the summer months. After getting the net starting point for each division, behind-meter-PV (BTM-PV) output at the division peak time is added back to get the gross starting point for the division.

In the system 1-in-5 heat wave load forecast, which is designed for assessing high voltage systems ranging from 230-500 kV, the CEC IEPR (California Energy Commission Integrated Energy Policy Report) 1-in-5 heat wave demand forecast serves as the basis. To make this forecast more reflective of the actual conditions, several adjustments are made by subtracting system loss and adding station service and self-generation loads. The initial year's PG&E division load is obtained by allocating the CEC 1-in-5 heat wave Year 1 forecast to each division using its gross starting point and coincidence factor. Subsequently, the following year's PG&E division load is determined by allocating the load growth indicated in the CEC 1-in-5 forecast to each division, considering the distribution load growth within each division in relation to the overall system load growth.

In the area 1-in-10 load forecast, which is designed for assessing local area networks operating within the voltage range of 60-230 kV, the CEC IEPR (California Energy Commission Integrated Energy Policy Report) 1-in-10 heat wave demand forecast load growth data is utilized. To make this forecast more representative of the actual conditions, a couple of adjustments are implemented by subtracting system loss and adding station service and self-generation loads. The first year's PG&E division load is determined by adding the division Year 1 load growth to the division gross starting point. Each division's Year 1 load growth is calculated based on the CEC 1-in-10 heat wave demand forecast Year 1 growth, adjusted according to its gross starting point. For subsequent years, each division's load growth is derived by allocating the CEC 1-in-10 heat wave load growth forecast to each division. This allocation process is guided by the relative magnitude of the Distribution division level 1-in-10 load growth, ensuring that future division loads align with the expected development of the system. The following year's division load is calculated by adding the division load growth to the previous year's division load, reflecting the evolving energy demand within each division.

Allocation of Division Load to Transmission Bus Level

In the process of allocating division loads to the various transmission buses, PG&E considers distinct approaches for different load types. PG&E categorizes its loads into four types: conforming, non-conforming, self-generation, and station service loads.

Notably, non-conforming, self-generation, and station service loads are assumed to remain constant, unaffected by temperature variations. Hence, their magnitude remains unchanged in both the 1-in-5 heat wave system base case, and the 1-in-10 heat wave local area base cases for the same year.

The remaining load, which includes the total division load minus the quantity of non-conforming, self-generation, and station service loads, constitutes the conforming load. This conforming load is then allocated to the transmission buses based on the relative magnitude of the distribution planning load forecast.

In both of system 1-in-5 heat wave and local area 1-in-10 heat wave load forecast, after allocation of division load to transmission bus level, there are other load elements need to be added/adjusted to the base cases:

- non-conforming load
- BTM-PV
- CEC load modifiers AAEE, AAFS and AATE
- Distribution Planning (DP) Hot Banks
- Municipal (Muni) Forecasts

DP Hot Banks
The DP Hot Banks interim process involves several key steps in coordination between Distribution Planning (DP) and the Transmission Planning (TP) to address potential underestimations of load forecast in areas of high growth. The process is as follows:

- DP works with TP to ensure correct substation mapping and identifies areas of high growth (including EV loads).
- DP reviews TP load forecast at bank level for the high growth areas and identifies the “Hot Banks” where loading could be underestimated.
- TP Area Planners review DP proposal of “hot bank” and agree (or seeking further clarification) on the DP forecast loading level.
- Area 1-in-10 cases updates the bank loading for the “Hot Banks”.

This interim process ensures a coordinated effort between DP and TP to identify potential areas where the load forecasts might not adequately account for significant growth. By identifying and addressing these "Hot Banks", the process aims to improve recent development of load forecasts that may not be factored in the CEC demand forecast in time, particularly in regions experiencing rapid development or increased energy demand such as data center loads, cultivation farming, etc.

Muni Loads in Base Case

Municipalities provide PG&E with their load forecast information. If the municipalities' total load forecasts differ from the CEC 1-in-5 and 1-in-10 demand forecasts, PG&E adjusts their bus-level loading (excluding nonconforming loads), according to the CEC forecasts. This adjustment ensures that the total loads align with the CEC forecasts, maintaining consistency across the entire system.

If municipalities do not provide their load forecast information, PG&E supplements such forecasts to ensure that the information gap is covered adequately.

For the 1-in-5 system base cases, the 1-in-5 heat wave load forecasts provided by the municipalities are utilized in the calculations. For the 1-in-10 heat wave local area base cases, the 1-in-10 load forecasts are used.

Behind-the-meter PV (BTM-PV)
the BTM-PV is integrated as a component of the load model in the following manner:

Modeling within Load Model: BTM-PV is included as part of the load model. The GE PSLF power flow software load model's DG field represents the total nameplate capacity of the DG under the PDGmax field, while the actual output is based on specific scenarios in the ISO TPP Study Plan.

Specification and Allocation: The total nameplate capacity for BTM-PV is provided by the CEC (California Energy Commission). The allocation and location of projected DG are derived from the latest DG information provided by PG&E Distribution Planning.

2.5.2.3 Southern California Edison Service Area

SCE's A-Bank Load modeling is illustrated in Figure 2.5-4. The main steps are as follows[14]:

1. Start with the California Energy Demand (CED) or California Energy Demand Update (CEDU) Forecast adopted by the California Energy Commission (CEC). The CED is provided in an odd-year Integrated Energy Policy Report (IEPR) such as 2023 IEPR, and the CEDU is provided for an even-year IEPR (i.e., 2022 IEPR). The weather-adjusted load forecast will be used depending on whether the study to be performed is a local reliability assessment, or CAISO-wide (i.e., regional) assessment. For local reliability assessment, a 1-in-10 heat wave load forecast will be used.

2. Adjust load downwards by a specific percentage, as provided by the CEC, to account for transmission losses.

3. Remove Metropolitan Water District (MWD) and California Department of Water Resources (CDWR) pump loads.

4. After Step 3, it becomes Adjusted CEC coincident forecast for SCE TAC Area. This is the total value used in the SCE Annual Transmission Reliability Assessment/CAISO Transmission Planning Process (ATRA/TPP).

5. Subtract Municipality Load (Anaheim, Pasadena, Riverside, and Vernon) and Fixed Load (e.g., Chevmain) to determine the Adjusted CEC Total Load for SCE Load Serving Entity (LSE).

6. Obtain the Subarea (i.e., LA Basin, Big Creek/Ventura, North of Lugo) Load Scaling Factor by dividing the Adjusted CEC Subarea Total Load by the Adjusted SCE Subarea Total Load (SCE's internal load forecast).

7. Calculate the <u>Modified ATRA A-Bank</u> Demand Forecast by multiplying the Subarea Load Scaling Factor by the SCE Busbar Loads. The Municipality Load and Fixed Load subtracted in Step 5 are added to complete load model.

8. Calculate the <u>Adjusted ATRA A-Bank Load</u> by subtracting the sum of <u>AAEE</u>, <u>AAFS</u>, and <u>AATE</u> (after adding distribution losses) from the Modified ATRA A-Bank Demand Forecast and subtracting the <u>BTM-PV Production</u> as shown in equation 1. The example in the third diagram in this section provides an illustration for how SCE models the CEC forecast, BTM-PV Production, and load modifiers in four (4) load bus components.

   Equation 1: Adjusted ATRA A-Bank Load =

   Modified ATRA A-Bank Load – {Σ (AAEE + AAFS + AATE)} – BTM-PV Production

   where

14 The underlined items are the components that are included in the Example in the third diagram of this section.

Modified ATRA A-Bank Load: see item 7 above and the following SCE A-Bank Load Methodology diagram; the total of all A-bank loads represents the Adjusted CEC total load for the SCE LSE area

Adjusted ATRA A-Bank Load = one of the four load components in power flow model (see Example)
AAEE = negative value (second bus-bar load component)
AAFS = typically positive value (third bus-bar load component)
AATE = positive value (fourth bus-bar load component)
BTM-PV Production = negative "load" value (aka positive "generation production" value – see Example)

The following illustrates disaggregation of the CEC's demand forecast to SCE bus-bar load levels.

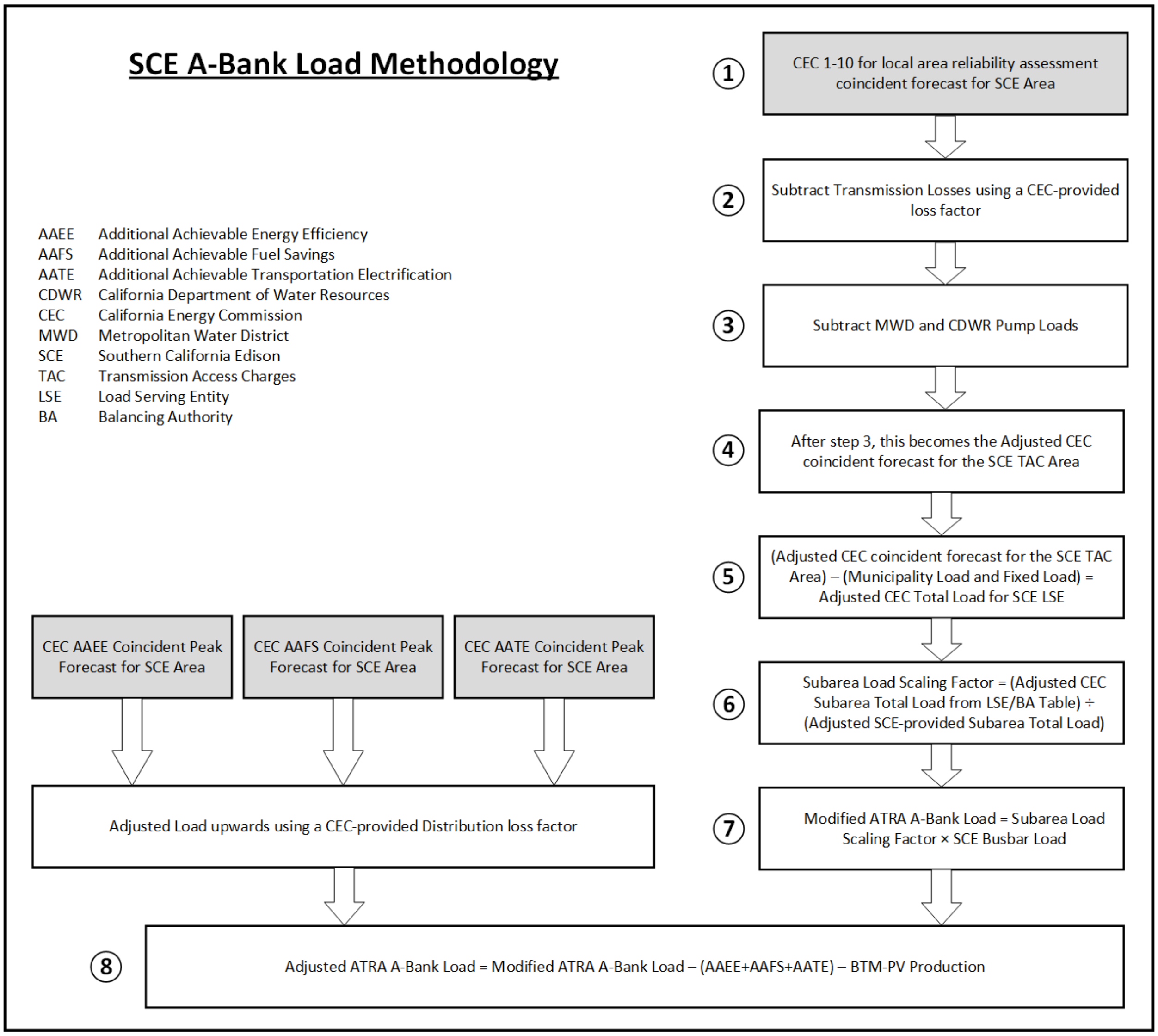


Figure 2.5-4:. SCE A-Bank Load Methodology

Behind-the-meter PV (BTM-PV)

The Behind-the-meter PV modeling is illustrated in Figure 2.5-5. The main steps are as follows:

1. SCE Transmission Planning Process BTM-PV: First, the existing and forecasted BTM-PV generation is mapped to a Bulk Electric System (BES) load bus based on a forecasting climate zone map provided by the CEC.
2. BTM-PV Annual Incremental Forecast. The percent allocation is calculated by dividing each BES bus BTM-PV Production by the sum of all BES BTM-PV Production within the same climate zone. The incremental BTM-PV Production is then allocated by multiplying the self-generation PV forecast, provided by the CEC, by the calculated percent allocation for each BES load bus.

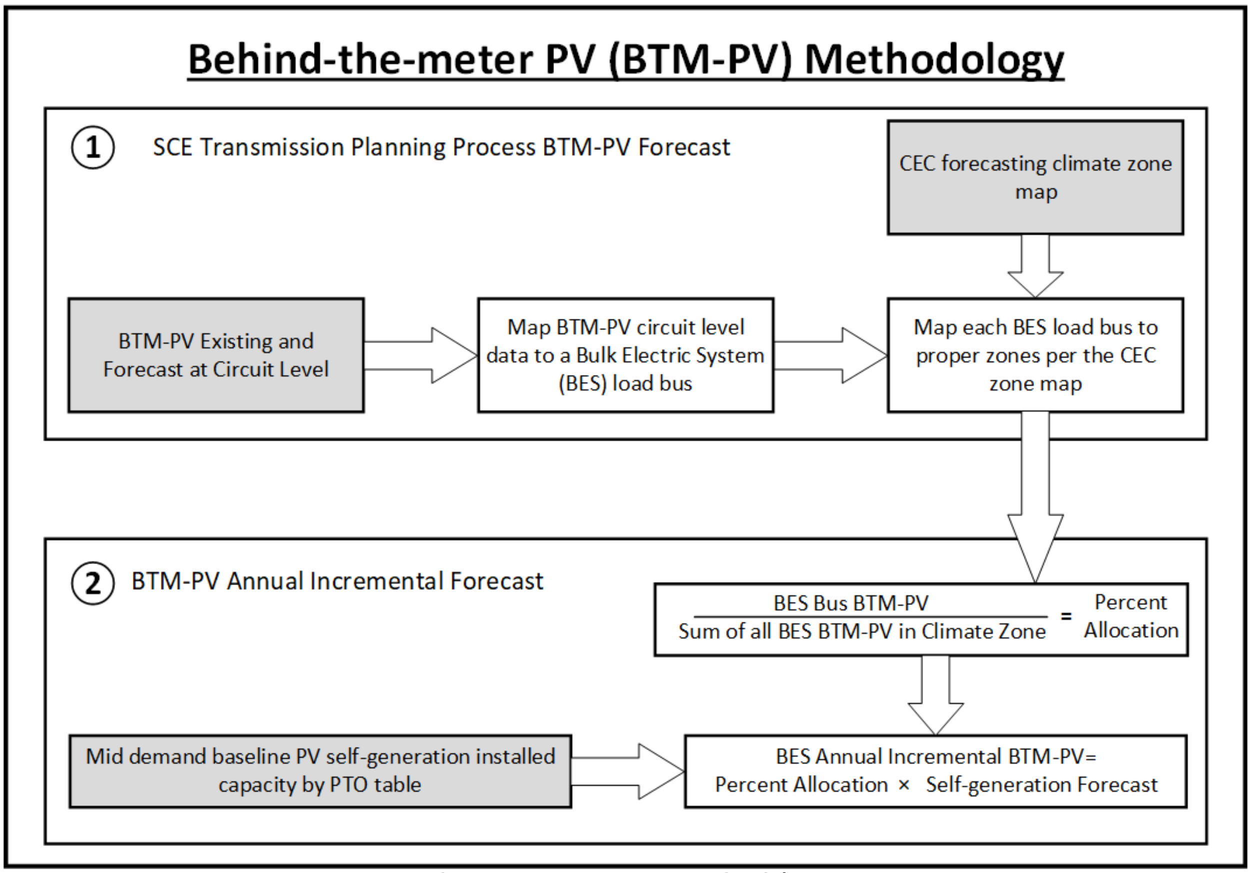


Figure 2.5-5. BTM-PV Methodology

A theoretical example of the calculation of A-Bank load and BTM-PV generation at a fictitious bus is shown in the following Figure 2.5-6.

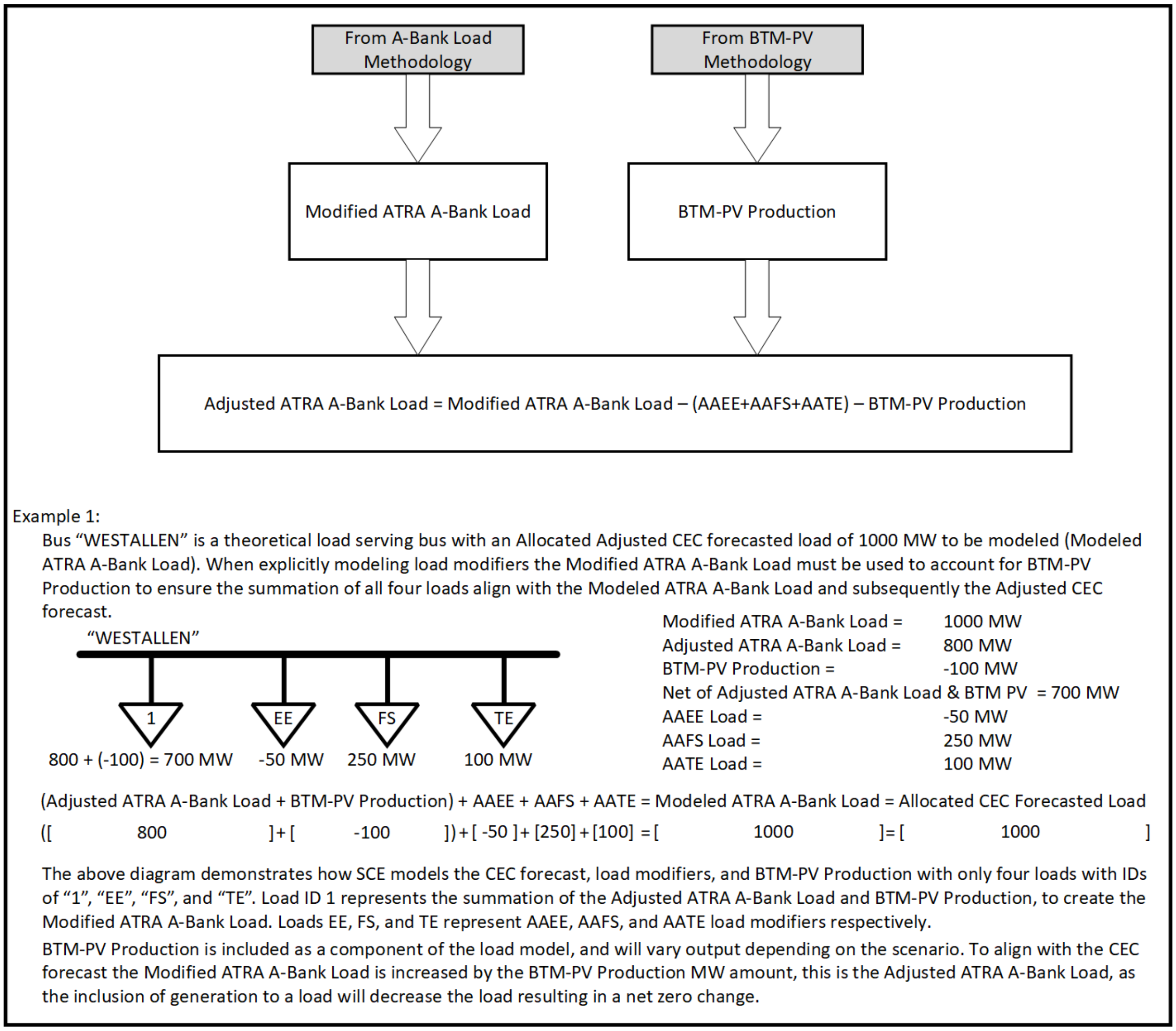


Figure 2.5-6. Example of calculation of A-Bank load and BTM-PV Production at a fictitious bus

2.5.2.4 San Diego Gas and Electric Service Area

SDG&E derives its coincident substation-level forecasts by adjusting its distribution non-coincident substation-level load forecast values so that the sum of all coincident loads, load bus modifiers, and transmission losses equals to the California Energy Commission (CEC's) 1-in-10 system load forecast for the SDG&E area. Consequently, every load bus in the SDG&E area includes five load components that are modeled explicitly in its TPP power flow model: SDG&E's non-coincident substation-level load forecast, SDG&E's coincident load forecast adjusted to the CEC forecast, and the three load modifiers including Additional Achievable Energy Efficiency (AAEE), Additional Achievable Transportation Electrification (AATE), and

Additional Achievable Fuel Substitution (AAFS). VEA develops its substation load forecast from trending three-year historical non-coincident peak.

With the load components mentioned above, SDG&E utilizes coincident load forecast adjusted to the CEC demand forecast to perform reliability assessments as part of the TPP process. In some instances, the non-coincident substation-level load forecast is utilized in special scenarios such as reliability assessment of a local load pocket area, The use of the non-coincident load level, which may contribute to an aggregated load higher than the CEC demand forecast for the overall San Diego area, will be reviewed on a case-by-case basis for specific load interconnection requests. For this scenario where loads modeled are not accounted for in the CEC Integrated Energy Policy Report (IEPR) forecast, SDG&E will work with the ISO for further validation and concurrence of the load interconnection input assumptions prior to performing applicable planning studies.

Development of the non-coincident distribution substation-load forecast begins with assessing the historical peak loads for the distribution substations to establish a reference point for future forecast projections. The historical substation peak loads are obtained through either historical Supervisory Control and Data Acquisition (SCADA) data, or monthly-recorded substation metering data, or cumulative advanced metering infrastructure (AMI) data. Once the actual peak loads and time-stamps have been determined for the distribution substations, the historical peak demand is evaluated considering factors such as anticipated new load additions, load transfers, loss of a generator connected to the distribution circuits, weather conditions at the time of the historical peak, etc. These factors may result in adjustments to the historical loads to produce the reference points for developing the substation load forecast. Concurrently, various system information is captured as necessary to assist in disaggregation of the CEC's system-level projections of load and DER additions to the bus bar level.

Behind-the-meter PV (BTM-PV)

BTM-PV will be modeled as a component of the load model. Using the DG field on the GE PSLF power flow program load model, the total nameplate capacity of the DG will be represented under PDGmax field, and the production output will be based on the base case scenarios from the ISO TPP Study Plan. The total nameplate capacity is provided by the CEC and used to do a bus-level allocation of the BTM-PV.

2.5.2.5 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 aligns its forecast with the CEC forecast to develop loads for the various TPP base case models.

2.5.2.6 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.

2.5.3 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 (2 year and 5 year out) 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, power factors at all substations will be modeled using the previous year's historical values obtained for peak, off-peak and light load conditions for the near term base cases (2 year and 5 year out). For the long term base case (10 year out), the average historical power factor for each planning area is used.

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 2026 study case. 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.

2.5.4 Self-Generation

Baseline 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 behind-the-meter PV (BTM-PV) capacity is projected to reach 16,576 MW in the mid demand case by 2034. In 2024-2025 TPP base cases, BTM-PV generation production will be modeled explicitly. The CEDU 2023-2040 forecast 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 2,434 MW maximum output in the mid demand case by 2034. Behind-the-meter storage will not be modeled explicitly in 2024-2025 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. However it will be accounted for by netting to the load.

BTM-PV installed capacity for mid demand scenario by PTO and forecasting climate zones are shown in Table 2.5-1. Output of the BTM-PV 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 forecasting climate zones is shown in Table 2.5-2. These resources will be netted to load in the 2024-2025 TPP base cases.

A forecasting climate zone map provided by CEC is included below in Figure 2.5-5, which can be used in allocating BTM-PV to various areas for bus level forecasting.

Table 2.5-1: Mid demand baseline PV self-generation installed capacity by PTO[15]

PTO	Forecast Climate Zone	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
PGE	Central Coast	625	682	742	803	865	928	990	1051	1112	1172	1231	1289	1347
	Central Valley	1813	1958	2108	2263	2422	2582	2742	2902	3059	3213	3359	3499	3630
	Greater Bay Area	2114	2286	2471	2666	2872	3082	3296	3514	3731	3946	4157	4362	4561
	North Coast	598	646	696	746	798	848	898	948	996	1043	1089	1133	1176
	North Valley	373	400	429	459	491	523	554	586	617	647	676	703	729
	Southern Valley	2258	2414	2575	2739	2904	3068	3229	3389	3544	3693	3836	3973	4105
	PG&E Total	**7781**	**8387**	**9020**	**9677**	**10352**	**11030**	**11710**	**12388**	**13058**	**13713**	**14348**	**14959**	**15548**
SCE	Big Creek East	536	571	607	644	681	717	754	791	829	868	907	947	986
	Big Creek West	304	328	353	380	408	437	467	498	529	562	595	628	661
	Eastern	1163	1229	1297	1364	1432	1501	1572	1645	1718	1792	1865	1937	2006
	LA Metro	1842	1984	2138	2302	2477	2658	2849	3047	3255	3470	3691	3918	4148
	Northeast	908	980	1059	1144	1233	1328	1428	1532	1641	1753	1868	1985	2105
	SCE Total	**4753**	**5092**	**5455**	**5834**	**6231**	**6642**	**7069**	**7513**	**7973**	**8445**	**8926**	**9414**	**9906**
SDGE	**SDGE**	**1876**	**1999**	**2129**	**2265**	**2404**	**2544**	**2685**	**2826**	**2967**	**3107**	**3245**	**3380**	**3514**
CAISO Total		**14409**	**15477**	**16604**	**17776**	**18987**	**20216**	**21464**	**22728**	**23998**	**25265**	**26518**	**27754**	**28968**

Draft Editorial Note:

Table 2.5-1 Currently values in this table are from 2023-24 values. Final study plan will have updates based on the information to be received from the CEC.

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

Table 2.5-2: Mid demand baseline behind-the-meter storage installed capacity by PTO[16]

PTO	Forecast Climate Zone	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
PGE	Central Coast	95	122	149	177	206	236	266	298	330	362	396	430	464
	Central Valley	192	251	313	377	444	513	585	659	735	814	895	978	1063
	Greater Bay Area	60	78	96	115	135	156	178	200	223	246	270	295	320
	North Coast	13	17	21	25	30	34	39	44	49	54	59	64	70
	North Valley	69	87	105	123	142	161	181	200	221	241	261	282	303
	Southern Valley	487	630	777	930	1088	1251	1420	1593	1772	1955	2142	2334	2529
	PG&E Total	**916**	**1185**	**1461**	**1747**	**2045**	**251**	**2669**	**2994**	**3330**	**3672**	**4023**	**4383**	**4749**
SCE	Big Creek East	26	31	36	41	46	51	56	61	66	71	76	81	87
	Big Creek West	28	35	43	52	60	69	77	87	96	106	116	126	136
	Eastern	53	66	79	93	107	121	135	150	165	181	197	214	231
	LA Metro	224	273	323	375	427	480	535	590	647	705	764	824	885
	Northeast	73	88	103	119	135	151	168	185	202	219	237	255	274
	SCE Total	**404**	**494**	**585**	**679**	**774**	**872**	**971**	**1072**	**1176**	**1282**	**1390**	**1500**	**1613**
SDGE	**SDGE**	**149**	**183**	**218**	**253**	**289**	**326**	**364**	**402**	**441**	**481**	**521**	**562**	**604**
CAISO Total		**1469**	**1862**	**2264**	**2679**	**3108**	**1449**	**4004**	**4468**	**4947**	**5435**	**5934**	**6445**	**6966**

Draft Editorial Note:

Table 2.5-2 Currently values in this table are from 2023-24 values. Final study plan will have updates based on the information to be received from the CEC.

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

Figure 2.5-3: CEC forecasting climate zone map

2.6 Resource Assumptions

2.6.1 New Resource Inclusion Criteria

New resources will be modeled in the studies as generally described below. Depending on the status of each resource, new resources will be assigned to one of the three levels below:

- Level 1: Resource projects that have become operational
- Level 2:
    - o Resource projects on the CPUC's in-development resource list; or
    - o Resource projects, if any, that are not on the CPUC in-development resource list but are known to have commenced construction or have a power purchase agreement (PPA) with a load serving entity (LSE). For clarity, simply having executed generation interconnection agreement (GIA) is not sufficient to meet the resource inclusion criteria.
- Level 3: Generic resources that are included in the CPUC IRP base portfolio for use in the ISO's current transmission planning cycle to meet long term greenhouse gas emission and reliability (resource adequacy) targets.

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

Year 1 Operating Cases:

- Level 1 resources
- Level 2 resources that have commenced construction and have planned in-service dates within the time frame of the study.

Year 2-5 Planning Cases:

- Level 1 resources
- Level 2 resources with planned in-service dates within the 2-5 year time frame of the study.

Year 6 and beyond Planning Cases:

- Level 1 resources.
- Level 2 resources with planned in-service dates within the time frame of the study.
- Level 3 resources with a planned in-service date within the time frame of the study.

2.6.2 IRP Portfolio Resources

The integrated resource planning (IRP) process is designed to ensure that the electric sector is on track to achieve the State's greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals. The IRP process develops resource portfolios annually as a key input to the CAISO's transmission planning process. The resources portfolios include a base portfolio, which is used in reliability, policy-driven, and economic assessments, and one or more sensitivity portfolios, which are typically used in the policy-driven assessment that is covered in section 3.

The CPUC has issued Decision 24-02-047[17] recommending transmittal of the 2023 Preferred System Plan as the base portfolio along with a sensitivity portfolio with high gas retirement assumptions for use in the 2024-2025 TPP. The base portfolio is designed to reduce statewide yearly GHG emissions from the electric sector to 25 MMT by 2035 with load based on the CEC's 2022 IEPR Demand Forecast. The base portfolio is comprised of in-development resources, IRPs of all LSEs and additional generic resources that are selected to achieve policy and reliability targets. The CAISO will model only the in-development resources in the near term study cases based on their in service dates in accordance with the data provided by the CPUC. The CAISO may supplement the data with information regarding contracted resources and resources that are under construction as of March 2024. Generic portfolio resources will be modeled in the long-term study cases.

CPUC staff, in collaboration with CEC and CAISO staff, have mapped the resources in the portfolios to the substation busbar level for use in the CAISO's 2024-2025 TPP.

[17] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M525/K918/525918033.PDF

Table 2.6-1: Resource additions in the base and sensitivity portfolios (in MW)

	Base Portfolio		Sensitivity Portfolio	
Resource	**2034**	**2039**	**2034**	**2039**
Biomass	171	171	22	22
Geothermal	1,969	1,969	3,961	5,089
Hydro (small)	-	-	-	-
Wind (in state)	6,123	7,023	5,739	5,739
Wind (out of state)	6,096	9,096	6,066	7,066
Offshore Wind	3,855	4,531	-	-
Solar	18,989	30,682	20,559	52,186
Customer Solar	-	-	-	-
Battery Storage	16,576	22,822	12,171	24,917
Long Duration Energy Storage (LDES)	1,030	1,080	3,280	3,680
Total	**54,808**	**77,374**	**51,799**	**98,699**

2.6.3 Thermal generation

For the latest updates on new generation projects, please refer to the CEC website under the licensing section (https://www.energy.ca.gov/programs-and-topics/topics/power-plants/alphabetical-power-plant-listing). 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.

2.6.4 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.

2.6.5 Generation Retirements

Existing generators that have been identified as retiring are listed here:

http://www.caiso.com/Documents/AnnouncedRetirementAndMothballList.xlsx

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 online in the near and mid term and off-line in the long-term scenarios based on the extension,

Once Through Cooled Retirements – As identified in section 2.7.6.

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

Other Thermal Generation Retirements – Other thermal generators will be assumed to be retired in the long term base cases based on the Gas Capacity Not Retained Assumption List for the Base Case and Sensitivity Portfolios provided by CPUC[18]. The list identifies the specific units to be assumed retired for each category of thermal generation (CCGT and Peakers, CHPs) based on the selection criteria described in the workbook.

2.6.6 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 A2 in Appendix A. This table also includes 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 approved for compliance schedule extension by the State Water Resources Control Board [19] for helping to meet CAISO's system capacity need for the 2022-2024 timeframe;

[18] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp/gasnotretained_mappingresults.xlsx

[19] https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_policy_2020/otc2020.pdf

- Generating units with acceptable Track 2[20] mitigation plan that was approved by the State Water Resources Control Board.

2.6.7 Distribution connected resources modeling assumption

Table 2.6-2 below outlines modeling assumptions for distribution connected resources in the TPP base cases.

Table 2.6-2: 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
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

2.7 Preferred Resources[21]

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.

2.7.1 Methodology

The CAISO issued a paper[22] 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

[20] 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).

[21] 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.

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

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 previous planning cycles, 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 and fuel substitution amounts as projected by the CEC and a mix of preferred resources including energy storage based on the CPUC 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 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[23]. The CAISO will continue to use the methodology developed as part of the study to evaluate these types of resources.

As part of the 2024-2025 IRP, 16,576 MW of battery storage was provided in the base portfolio as listed in Table 2.6-1 and will be modeled in the year 2034 base cases. These resources can be considered as potential mitigation options, including in earlier years if 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

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

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[24].

2.7.2 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.[25] 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 during the next operating day to meet the anticipated insufficiency.

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 2.7-1, Table 2.7-2, and Table 2.7-3 describe supply-side DR capacity assumptions for each IOU Load Serving Entities within CAISO BA.

[24] 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

[25] CAISO-CPUC Joint Workshop, Slow Response Local Capacity Resource Assessment:
https://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf

Table 2.7-1: PG&E Existing DR Capacity Range

PG&E Portfolio-Adjusted DR Load Impacts for CAISO Peaking Conditions, August,1-in-2 Weather			
DR Program	**MW**	**Market Model/Level of Dispatch**	**Response time**
Base Interruptible Program (BIP)	169.2	System-wide SubLAP RDRR	30 minutes
Capacity Bidding Program (CBP)	33.8	System-wide SubLAP PDR	Day Ahead
Emergency Load Reduction Program (ELRP)	82.3	System-wide	Day Ahead and Real time
Peak Day Pricing (PDP)	15.2	System-wide	Day Ahead
SmartRate™	4.3	System-wide	Day Ahead
SmartAC™	23.9	System-wide SubLAP Selected 21 Substations PDR	None required
DRAM	NA		>30 Minutes
Total	**328.7**		

Table 2.7-2: SCE Existing DR Capacity Range

Load Impact Report, 1-in-2 weather year condition portfolio-adjusted August 2023 ex-ante DR impacts at CAISO peak			
Supply-side DR (MW)	**MW**	**Market Model/Level of Dispatch**	**Response time**
Base Interruptible Program 15 Minute (BIP-15)	178	RDRR	20 Minutes or Less
Base Interruptible Program 30 Minute (BIP-30)	334	RDRR	30 Minutes
Agricultural and Pumping Interruptible (API)	30	RDRR	20 Minutes or Less
Summer Discount Plan Residential (SDP-R)	141	RDRR, with DAM economic	20 Minutes or Less
Summer Discount Plan Commercial (SDP-C)	15	RDRR, with DAM economic	20 Minutes or Less
Smart Energy Program	39	RDRR, with DAM economic	20 Minutes or Less
Capacity Bidding Program Day-Ahead (CBP-DA)	4	PDR	Day Ahead
Capacity Bidding Program Day-Of (CBP-DO)	2	PDR	> 30 Minutes
Demand Response Auction Mechanism (DRAM)	103	PDR	> 30 Minutes
Base Interruptible Program 15 Minute (BIP-15)	178	RDRR	20 Minutes or Less
Total	**846**		

Table 2.7-3: SDG&E Existing DR Capacity Range

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)	0	Full - Based on CAISO Award	20 min
Capacity Bidding Program (CBP)	1.9	Full - Based on CAISO Award	Notices are either Day Ahead (4 pm) or Day Of
Critical Peak Pricing (CPP)	4.81	Full - Based on CAISO Award	Day Ahead (4 pm)
AC Saver – Day Ahead	0	Full - Based on CAISO Award	Day Ahead (4 pm)
AC Saver – Day Of	0	Full - Based on CAISO Award	Day Of
DRAM (demonstrated capacity)	17.72	Based on CAISO Award to the DRP	NA - Not bid into the CAISO by SDG&E
Total	**24.43**		

Draft Editorial Note:

Table 2.7-2 for SCE currently includes DR values from the 2023-2024 TPP. These values will be updated in the final study plan based on the information to be received.

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 2.7-4 will be applied to the DR projections to account for avoided distribution losses.

Table 2.7-4: Factors to Account for Avoided Distribution Losses

	PG&E	SCE	SDG&E
Distribution loss factors	1.091	1.068	1.082

2.7.3 Energy Storage

The CAISO models the existing, under construction and/or approved procurement status energy storage projects in the reliability base cases. For the purpose of this table, co-located resources have their own respective market IDs as compared to hybrid resources that have a single market ID. The CAISO relies on multiple sources, including but not limited to PTO inputs, CEC forecast and generation interconnection queue to update the numbers in the Table 2.7-5.

Table 2.7-5: IOU Existing, Under-construction or included in CPUC portfolio [26]

PTO	Category	In-service	Under Construction / CPUC portfolio		
			2026	2029	2034
PG&E	Transmission (Stand alone and co-located)	2272	TBD	TBD	TBD
	Front of the meter Distribution including co-located	TBD	TBD	TBD	TBD
	Behind the meter Customer (Residential and Non-Residential)	TBD	TBD	TBD	TBD
	Hybrid Generation [27]	257	TBD	TBD	TBD
SCE	Transmission (Stand alone and co-located)	5777	TBD	TBD	TBD
	Front of the meter Distribution including co-located	TBD	TBD	TBD	TBD
	Behind the meter Customer (Residential and Non-Residential)	TBD	TBD	TBD	TBD
	Hybrid Generation	1844	TBD	TBD	TBD
SDG&E	Transmission (Stand alone and co-located)	865	TBD	TBD	TBD
	Front of the meter Distribution including co-located	128	TBD	TBD	TBD
	Behind the meter Customer (Residential and Non-Residential)	TBD	TBD	TBD	TBD
	Hybrid Generation	0	TBD	TBD	TBD

Draft Editorial Note:

Remaining data in the Table 2.7-5 will be updated in the final study plan based on the information to be received from the PTOs and the in-development and generic resource details as part of the portfolio mapping from CPUC.

As part of the 2024-2025 IRP, 16,576 MW of battery storage was provided in the base portfolio as listed in Table 2.6-1 and will be modeled in the year 2034 base cases. These storage

[27] Hybrid Generation for all PTO's assumption is based on CPUC base portfolio list

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.

2.8 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 general, the northern California (PG&E) system has 4 major interties with the outside system and southern California. Table 2.8-1 lists the capability and power flows that will be modeled in each scenario on these paths in the northern area assessment[28].

Table 2.8-1: Major Path flows in northern area (PG&E system) assessment[29]

Path	Transfer Capability/SOL (MW)	Scenario in which Path will be stressed
Path 26 (N-S)	4,000[30]	Summer Peak
PDCI (N-S)	3,100[31]	
Path 66 (N-S)	4,800[32]	
Path 15 (N-S)	-5,400[33]	Spring Off Peak
Path 26 (N-S)	-3,000	
PDCI (N-S)	-975[34]	
Path 66 (N-S)	-3,675	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

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

29 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)

30 May not be achievable under certain system loading conditions.

31 Current operational limit is 3100 MW.

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

33 May not be achievable under certain system loading conditions

34 Current operational limit in the south to north direction is 975 MW.

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, 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.

Table 2.8-2: Major Path flows in southern area (SCE and SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Target Flows (MW)	Scenario in which Path will be stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
Path 26 (S-N)	3,000	0 to 3,000	Spring Off Peak
PDCI (N-S)	3,210[35]	3,100	Summer Peak
PDCI (S-N)	975[36]	975	Spring Off Peak
West of River (WOR) (E-W)	12,150	0 to 11,200	Summer Peak
East of River (EOR) (E-W)	10,100	1,400 to 10,100	Summer Peak
East of River (EOR) (W-E)		2,000 to 7,500	Summer Peak/Spring Off peak
San Diego Import	2,765~3,565	2,400 to 3,500	Summer Peak
Path 45 (N-S)	600	0 to 600	Summer Peak
Path 45 (S-N)	800	0 to 300	Spring Off Peak
Harry Allen-Eldorado (Path 84) (N-S)	3496	1000-3000	Spring Off Peak/Summer Peak
Harry Allen-Eldorado (Path 84) (S-N)	1390	500-1000	Summer Peak/Spring Off-Peak

2.9 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/market/Pages/TransmissionOperations/Default.aspx for the list of publicly available Operating Procedures.

[35] WECC Existing Path rating is 3200MW, Current operational limit is 3100 MW.

[36] WECC Existing Path rating is 3100MW, Current operational limit is 975 MW.

2.10 Study Scenario

2.10.1 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 2.6.

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 2.10-1 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 2.9 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 2.10-1.

Table 2.10-1: Summary of Base Scenario Studies in the CAISO Reliability Assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon	
	2026	2029	2034	2039
California ISO Bulk System			Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak
Northern California (PG&E) Bulk System	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 Summer Off-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 Summer Off-Peak Spring Off-Peak	Summer Peak	
Kern	Summer Peak Spring Off-Peak	Summer Peak Summer Off-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 Summer Off-Peak Spring Off-Peak		
SCE Main Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak Spring Off-Peak	Summer Peak Winter Peak	
SCE Northern Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak Spring Off-Peak	Summer Peak	
SCE North of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak Spring Off-Peak	Summer Peak	
SCE East of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak Spring Off-Peak	Summer Peak	
SCE Eastern Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak Spring Off-Peak	Summer Peak	
SDG&E Area	Summer Peak Spring Off-Peak	Summer Peak Summer Off-Peak Spring Off-Peak	Summer Peak Winter Peak	
Valley Electric Association	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak Winter Peak	

2.10.2 Baseline Scenario Definitions and Renewable Generation Dispatch for System-wide Cases

The data in Table 2.10-2, except for the transmission connected renewable dispatch, is derived from the latest CEC hourly forecast. As such, the scenario descriptions and corresponding renewable dispatch are applicable to CAISO 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.

Table 2.10-2: Baseline Scenario Definitions and Renewable Generation Dispatch

PTO	Scenario	Day/Time				BTM-PV*			Transmission Connected PV			Transmission Connected Wind			% of managed peak load		
		2026	2029	2034	2039	2026	2029	2034	2026	2029	2034	2026	2029	2034	2026	2029	2034
PG&E	Summer Off Peak	N/A	7/25 HE15	N/A	N/A	N/A	82%	N/A	N/A	77%	N/A	N/A	36%	N/A	N/A	85%	N/A
PG&E	Summer Peak	7/22 HE 19	7/25 HE 19	See CAISO	See CAISO	4%	5%	See CAISO	2%	2%	See CAISO	91%	91%	See CAISO	100%	100%	See CAISO
PG&E	Spring Off Peak	4/29 HE 20	4/22 HE 13	See CAISO	N/A	0%	96%	See CAISO	0%	97%	See CAISO	82%	51%	See CAISO	67%	15%	See CAISO
PG&E	Winter Off peak	N/A	N/A	1/29 HE 6	N/A	N/A	N/A	0%	N/A	N/A	0%	N/A	N/A	33%	N/A	N/A	41%
PG&E	Winter peak	12/16 HE 19	12/19 HE 8	1/5 HE 9	N/A	0%	2%	10%	0%	30%	59%	50%	31%	57%	65%	67%	77%
SCE	Summer Off Peak	N/A	8/29 HE 15	N/A	N/A	N/A	74%	N/A	N/A	82%	N/A	N/A	56%	N/A	N/A	98%	N/A
SCE	Summer Peak	8/31 HE 16	8/31 HE17	See CAISO	See CAISO	54%	30%	See CAISO	60%	30%	See CAISO	63%	68%	See CAISO	100%	100%	See CAISO
SCE	Spring Off Peak	4/29 HE 19	3/25 HE 13	See CAISO	N/A	1%	95%	See CAISO	1%	96%	See CAISO	77%	51%	See CAISO	62%	14%	See CAISO
SCE	Winter Peak	N/A	N/A	11/1 HE 18	N/A	N/A	N/A	7%	N/A	N/A	0%	N/A	N/A	66%	N/A	N/A	71%
SDG&E	Summer Off Peak	N/A	9/4 HE 14	N/A	N/A	N/A	83%	N/A	N/A	82%	N/A	N/A	1%	N/A	N/A	86%	N/A
SDG&E	Summer Peak	9/1 HE 17	9/4 HE 17	9/5 HE 17	See CAISO	24%	24%	24%	20%	20%	20%	9%	9%	9%	100%	100%	100%
SDG&E	Spring Off Peak	5/6 HE 19	4/15 HE 13	See CAISO	N/A	1%	100%	See CAISO	0%	95%	See CAISO	63%	30%	See CAISO	69%	8%	See CAISO
SDG&E	Winter Peak	N/A	N/A	12/12 HE 18	N/A	N/A	N/A	1%	N/A	N/A	0%	N/A	N/A	13%	N/A	N/A	76%
VEA	Summer Peak	8/31 HE 16	8/31 HE17	See CAISO	See CAISO	N/A	N/A	N/A	60%	30%	See CAISO	N/A	N/A	See CAISO	100%	100%	See CAISO
VEA	Spring Off Peak	4/29 HE 19	3/25 HE 13	See CAISO	N/A	N/A	N/A	N/A	1%	96%	See CAISO	N/A	N/A	See CAISO	62%	14%	See CAISO
VEA	Winter Peak	N/A	N/A	11/1 HE 18	N/A	N/A	N/A	7%	N/A	N/A	0%	N/A	N/A	66%	N/A	N/A	71%

PTO	Scenario	Day/Time	BTM-PV			Transmission Connected PV [1]			Transmission Connected Wind			% of non-coincident PTO managed peak load		
			PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE
CAISO	2039 Summer peak	9/5 HE 19	0%	0%	0%	0%	0%	0%	42%	41%	40%	100%	88%	96%
	2039 Spring Off peak	4/15 HE 13	88%	98%	100%	98%	98%	99%	47%	56%	57%	15%	27%	21%
	2034 Summer Peak	9/6 HE 18	9%	6%	6%	4%	2%	8%	32%	30%	32%	97%	100%	95%
	2034 Spring Off Peak[2]	3/26 HE 13	88%	100%	95%	96%	95%	97%	51%	51%	42%	14%	14%	7%

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

Draft Editorial Note:

Table 2.10-2 BTM-PV Column currently calculated using Maximum BTM-PV Output. These values will be updated using BTM-PV installed capacity in the final study plan based on the information to be received from the CEC.

2.10.3 Sensitivity Studies

In addition to the base scenario studies that the CAISO will be assessing in the reliability analysis for the 2024-2025 transmission planning process, the CAISO will also be conducting sensitivity studies identified in Table 2.10-3. 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 2.10-3: Summary of Sensitivity Studies in the CAISO Reliability Assessment

Sensitivity Study	Near-term Planning Horizon		Long-term Planning Horizon	
	2026	2029	2034	2039
Summer Peak with high CEC forecasted load	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Area		
Spring shoulder-peak with heavy renewable output or different import level or storage charging	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Area VEA Area	-		
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 Area	-		
Summer Peak with forecasted load addition	VEA Area	VEA Area		
South Bay high load sensitivity			PG&E Greater Bay area	
Summer Peak with retirements identified in 2039 portfolio				Areas impacted by retirements PG&E Greater Bay area LA Basin

2.10.4 Sensitivity Scenario Definitions and Renewable Generation Dispatch

Table 2.10-4: 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 heavy renewable output and minimum gas generation commitment	2026 Summer Peak	4%	99%	2%	99%	91%	62%	Solar and wind dispatch increased to 20% exceedance values
	Spring shoulder-peak with heavy renewable output or different import level	2026 Spring Off-Peak	0%	0%	0%	0%	82%	47%	Different import levels on COI and P26.
	Summer Peak with high CEC forecasted load	2029 Summer Peak	5%	5%	2%	11%	91%	54%	Load increased by turning off AAEE
SCE	Summer Peak with heavy renewable output and minimum gas generation commitment	2026 Summer Peak	54%	99%	60%	99%	63%	67%	Solar and wind dispatch increased to 20% exceedance values
	Spring shoulder-peak with heavy renewable output or different import level or storage charging	2026 Spring Off-Peak	1%	1%	1%	1%	77%	77%	Storage Charging in load pockets.
	Summer Peak with high CEC forecasted load	2029 Summer Peak	30%	30%	30%	30%	68%	68%	Load increased per CEC high load scenario
SDG&E	Summer Peak with heavy renewable output and minimum gas generation commitment	2026 Summer Peak	24%	96%	20%	96%	9%	51%	Solar and wind dispatches increased to 20% exceedance values
	Spring shoulder-peak with heavy renewable output or different import level or storage charging	2026 Spring Off-Peak	1%	1%	0%	0%	50%	50%	Storage Charging in load pockets.
	Summer Peak with high CEC forecasted load	2029 Summer Peak	24%	24%	45%	45%	11%	11%	Load increased per CEC high load scenario
VEA	Summer Peak with forecasted load addition	2026 Summer Peak	N/A	N/A	96%	96%	N/A	N/A	Load increase reflect future load service request
	Summer Peak with forecasted load addition	2029 Summer Peak	N/A	N/A	88%	88%	N/A	N/A	Load increase reflect future load service request
	Spring Off-peak with storage charging	2026 Spring Off-Peak	N/A	N/A	0%	0%	N/A	N/A	Storage charging

The following baselines & sensitivity scenarios will be utilized for dynamic stability assessment in this planning cycle:

- Year-2 off-peak baseline
- Year-2 off-peak (high renewable) sensitivity
- Year-5 peak baseline
- Year-5 peak (high load) sensitivity
- Year-10 peak baseline

2.11 Study Base Cases

The power flow base cases from WECC will be used as the starting point of the CAISO transmission plan base cases[37]. Table 2.11-1 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 available Master Dynamics File (MDF)[38] will be tuned for use with specific WECC starting cases (see paragraph above for study cases that will be used for dynamic stability assessment). Dynamic load models will be added to this file.

Table 2.11-1: Summary of WECC Base Cases used to represent system outside CAISO

Study Year	Season	WECC Base Case	Year Published
2026	Summer Peak	2025 Heavy Summer 3	10/29/2021
	Winter Peak	2023-24 Heavy Winter 3 2024-25 Heavy Winter 3	3/21/2023 Under review
	Spring Off-Peak	2024 Heavy Spring 2	12/18/2023
2029	Summer Peak	2029 Heavy Summer 2	5/8/2023
	Summer Off-Peak	2029 Heavy Summer 2	5/8/2023
	Winter Peak	2028-29 Heavy winter 2	07/05/2023
	Spring Off-Peak	2024 Light Spring 2 2025 Light Spring 1	01/27/2023 Under review
2034	Summer Peak	2034 Heavy Summer 1	10/25/2023
	Spring Off-Peak	2033 Light Spring 1	01/28/2022
	Winter Peak	2033-34 Heavy Winter 1	09/08/2023
2039	Summer Peak Spring off-peak	2034 Heavy Summer 1 2033 Light Spring 1	10/25/2023 01/28/2022

[37] The starting WECC power flow cases and dynamic data are to be used by all applicable PTOs to help facilitate CAISO base case development.

[38] The CAISO used the MDF posted on 2/8/2021 on the WECC website and tuned it for specific WECC power flow cases (see top paragraph above for cases requiring dynamic simulation) as starting cases for further development of the TPP-related study cases.

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 2034 summer peak base case for the northern California will use 34HS1a1 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.

2.12 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 2.1.3, 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)[39][40]
- 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)[41]
- 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)

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

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)

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[42] (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.

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

2.12.1 Known Outages and Outage scheduling Assessment

Requirements R2.1.4 and R2.4.4 of TPL-001-5 require the planning assessment for the near-term transmission planning horizon portion of the steady state analysis [R2.1.4] and stability analysis [R2.4.4] to include assessment of the impact of selected known outages on System performance.

The CAISO Planning Standard also recognizes that scheduled outages are necessary to support reliable grid operations. The CAISO Planning Standard requires the P0 and P1 performance requirements in NERC TPL-001-5 for either BES or non-BES facilities must be maintained during scheduled outages. The standard stipulates Corrective Action Plans must be implemented when it is established through a combination of real-time data and technical studies that there is no window to accommodate necessary scheduled outages.

The CAISO will generally utilize studies of category P1 to P7 events on the year-2 system off-peak load case, which is designed to reflect a heavy load level the system is expected to experience during the period outages are normally planned, to assess the steady state and stability impact of planned outages. For example, each Category P3 and P6 contingency event will also be considered to represent the occurrence of a Category P1 event during the planned outage of a generation or a transmission facility, respectively. Accordingly, these events must meet the performance requirement for P1 for the purposes of the known or planned outage study. If an known outage expected to produce more severe System impacts on the BES is scheduled to take place under system peak conditions, the appropriate system peak base case will be used to perform the know outage study.

The above approach covers known or planned outages that involve single facilities, but not BES bus section outages, circuit breaker outages and construction-related outages that affect multiple facilities. The planned outage study will include planned outages that may affect multiple facilities in order to insure that the system can withstand P1 contingencies during such outages. Those bus section and circuit breaker outages that are known or expected to cause outage scheduling challenges will be selected, based on information provided by the Transmission Operator. Construction-related outages that affect multiple facilities will be studied, based on information provided by the Transmission Owner.

Any issues or conflicts identified with planned outages in the assessment described above will be documented in the IRO-017 Requirement R4[43] Planned Outage Mitigation Plan in addition to the transmission plan.

Table 2.12-1 provides the known or potential outages involving multiple facilities that can cause outage scheduling challenges that are selected for assessment in the current transmission planning cycle based on information obtained from TOs and TOPs. Single element outages are not listed in the table unless they are scheduled to be performed during the summer peak

[43] IRO-017-1 Requirement R4 Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.

season because, as mentioned above, they are assessed using the results of category P1 to P7 contingency studies.

Table 2.12-1: Known outages involving multiple facilities selected for assessment[44]

PTO Area	Scheduled Outage Involving Multiple Facilities	Facilities Affected	Additional Description, If Needed
PG&E	TBD		
SCE	TBD		
SDG&E	TL695 Talega – Basilone 69 kV line[1]	Same	To be evaluated on the 2026 Spring off-peak and Summer peak load conditions
SDG&E	TL6971 Basilone – Japanese Mesa 69 kV line[1]	Same	To be evaluated on the 2026 Spring off-peak and Summer peak load conditions

[1] SDG&E single 69 kV line outages are included because the planning assessment does not normally include P6 outages for non BES facilities.

Draft Editorial Note:

Table 2.12-1 Known outages involving multiple facilities for PGAE and SCE selected for assessment currently includes the values from the 2023-2024 TPP. These values will be updated in the final study plan based on the information to be received from PTO.

2.13 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.

[44] The CAISO will continue to work with PTOs to add and assess any other relevant outages during the course of the assessment.

2.13.1 Technical Studies

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

2.13.2 Steady State Contingency Analysis

The CAISO will perform power flow contingency analyses based on the CAISO Planning Standards[45] 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 2.13.6. For some areas, operations limitation may need to be considered depending upon the specific load characteristic and duration of the emergency ratings.

Depending on the type and technology of a power plant, several G-1 contingencies represent an outage of the whole power plant (multiple units)[46]. 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 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

[45] California ISO Planning Standards are posted on the CAISO website at

http://www.caiso.com/Documents/ISO-Planning-Standards-Effective-Feb22023.pdf

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

potential cascade tripping that may occur when protective relay settings limit transmission load ability.

2.13.3 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.

2.13.4 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.

2.13.5 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.

2.13.6 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.

2.13.7 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.

2.14 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 2024-2025 planning cycle, the overarching public policy objective is the state's mandate for meeting renewable energy and greenhouse gas (GHG) reduction targets 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 economic 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.

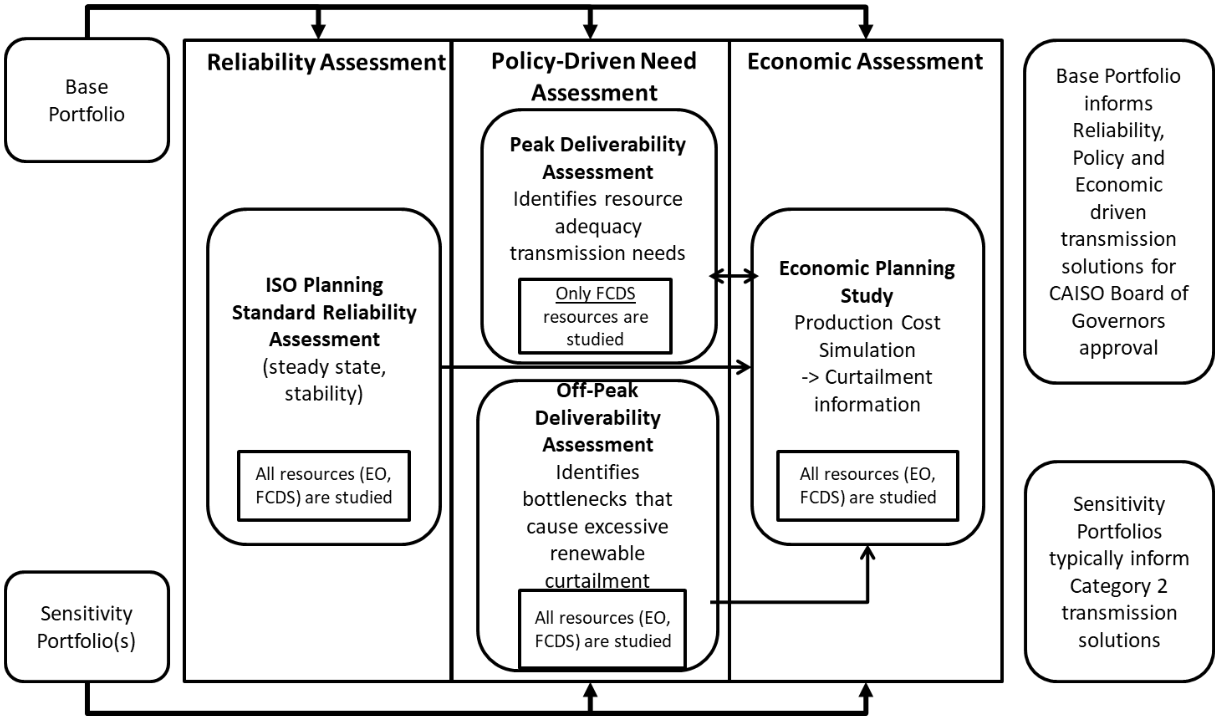
The CAISO and the CPUC have a memorandum of understanding under which the CPUC provides the renewable resource portfolio or portfolios for CAISO to analyze in the CAISO's annual TPP. The CPUC adopted the integrated resource planning (IRP) process designed to ensure that the electric sector is on track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

3.2 Study methodology and components

The policy-driven assessment is an iterative process comprised of three types of technical studies as illustrated in Figure 3.2-1.

These studies are geared towards capturing the impact of renewable build out on transmission infrastructure, identifying any required upgrades and generating transmission input for use by the CPUC in the next cycle of portfolio development.

Figure 3.2-1: Policy-driven assessment methodology and study components



Reliability assessment

The policy-driven reliability assessment is used to identify constraints that need to be modeled in production cost simulations in order to capture the impact of the constraints on renewable curtailment caused by transmission congestion. The reliability assessment component of the policy-driven assessment is covered by the reliability assessment described in Section 2 and the off-peak deliverability assessment that is performed in accordance with the deliverability methodology as described below.

On-peak deliverability assessment

The on-peak deliverability test is designed to ensure portfolio resources selected with full capacity deliverability status (FCDS) are deliverable and can count towards meeting resource adequacy needs. The assessment examines whether sufficient transmission capability exists to transfer generation from a given sub-area to the aggregate of CAISO control area load when the generation is needed most. The CAISO performs the assessment in accordance with the on-peak deliverability assessment methodology[47].

[47] http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf

Off-peak deliverability assessment

The off-peak deliverability test is performed to identify potential transmission system limitations that may cause excessive renewable energy curtailment. The CAISO performs the assessment in accordance with the off-peak deliverability assessment methodology.[48]

Production cost model simulation (PCM) study

Production cost models for the base and sensitivity renewable portfolios will be developed and simulated to identify renewable curtailment and transmission congestion in the CAISO Balancing Authority Area. The PCM for the base portfolio is used in both the policy-driven and economic assessments. The PCM for the sensitivity portfolios is used in the policy assessment only. The details of the PCM assumptions and study methodology are set out in chapter 4.

3.3 Resource portfolios

The CPUC adopts resource portfolios annually as part of its Integrated Resource Planning (IRP) process as a key input to the CAISO's transmission planning process. The CPUC issued Decision 24-02-047[49] recommending transmittal of the 2023 Prefferred System Plan (PSP) as the base portfolio and a sensitivity portfolio with high gas retirement assumptions for use in the 2024-2025 TPP..

The portfolios are comprised of in-development resources, which have been contracted for or have recently come online, and the incremental generic resources that are selected to achieve policy and reliability targets. The CAISO will model the new baseline resources in policy-driven study cases in accordance with the data provided by the CPUC. The CAISO may supplement the data with information regarding contracted resources and resources that are under construction as of March 2024.

The portfolios are designed to reduce statewide yearly GHG emissions from the electric sector to 25 MMT by 2035. They are developed with updated assumptions from California Energy Commission's 2022 Integrated Energy Policy Report demand forecast. The base portfolio is comprised of in-development resources, IRPs of all LSEs and additional generic resources that are selected to achieve the policy and reliability targets. The base portfolio assumes about 7.1 GW of gas capacity including OTC units will be retired by 2039. In contrast, the sensitivity portfolio, which is intended to help develop a better understanding of the transmission changes that could be necessary to accommodate potential future natural gas plant retirements, assumes about 16 GW of gas generation will retire in the same time horizon. The portfolio data is available on the CPUC website and includes:

[48] http://www.caiso.com/Documents/Off-PeakDeliverabilityAssessmentMethodology.pdf

[49] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M525/K918/525918033.PDF

- Modeling Assumptions for the 2024-2025 Transmission Planning Process[50]
- The final busbar mapping dashboards for the base[51] and sensitivity[52] portfolios
- Retirement list of thermal generation units for the base and sensitivity portfolios[53]

In the current planning cycle, the ISO policy driven assessment will be based on the 2034 and 2039 scenarios.

The portfolios are comprised of biomass/biogas, geothermal, solar, in-state, out-of state and offshore wind resources, battery and long duration energy storage. The portfolios consist of resources with Full Capacity (FC) and Energy Only (EO) deliverability status. While both FC and EO resources will be modeled in reliability, off-peak deliverability and economic assessments, only FC resources will be modeled in the on-peak deliverability assessment. In the policy driven deliverability assessment, the ISO will model OOS resources on new transmission at the injection points near the ISO border as identified by the CPUC. OOS resources on existing transmission will be modeled at the resource locations identified by the CPUC. The resources will be dispatched based on the deliverability assessment resource output assumptions provided in Section 3.5.

Table 3.3-1 shows the composition of the base and sensitivity portfolio by resource type for 2034. The 2039 base and sensitivity portfolio composition is shown in Table 3.3-2. The breakdown between FC and EO resources within the portfolios are included in these tables.

[50] The CPUC has not released this document as of the date of this draft study plan.

[51] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp/final_dashboard_24-25tpp.xlsx

[52] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp/dashboard_gasretire_sensitivity_02152024.xlsx

[53] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp/gasnotretained_mappingresults.xlsx

Table 3.3-1: 2034 Base and Sensitivity Portfolio Composition

	Base Portfolio			Sensitivity Portfolio		
Resource Type	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Biomass	171	0	171	22	0	22
Distributed_Solar	260	0	260	329	0	329
Geothermal	1,969	0	1,969	3,961	0	3,961
LDES	1,030	0	1,030	3,280	0	3,280
Li_Battery (4-hour)	14,958	0	14,958	9,305	0	9,305
Li_Battery (8-hour)	1,618	0	1,618	2,867	0	2,867
Offshore Wind	3,855	0	3,855	0	0	0
OOS Wind	6,096	0	6,096	6,066	0	6,066
Solar	8,481	10,248	18,729	10,751	9,479	20,230
Wind, Onshore	5,203	921	6,123	4,885	855	5,739
TOTAL	**43,640**	**11,168**	**54,808**	**41,465**	**10,333**	**51,799**

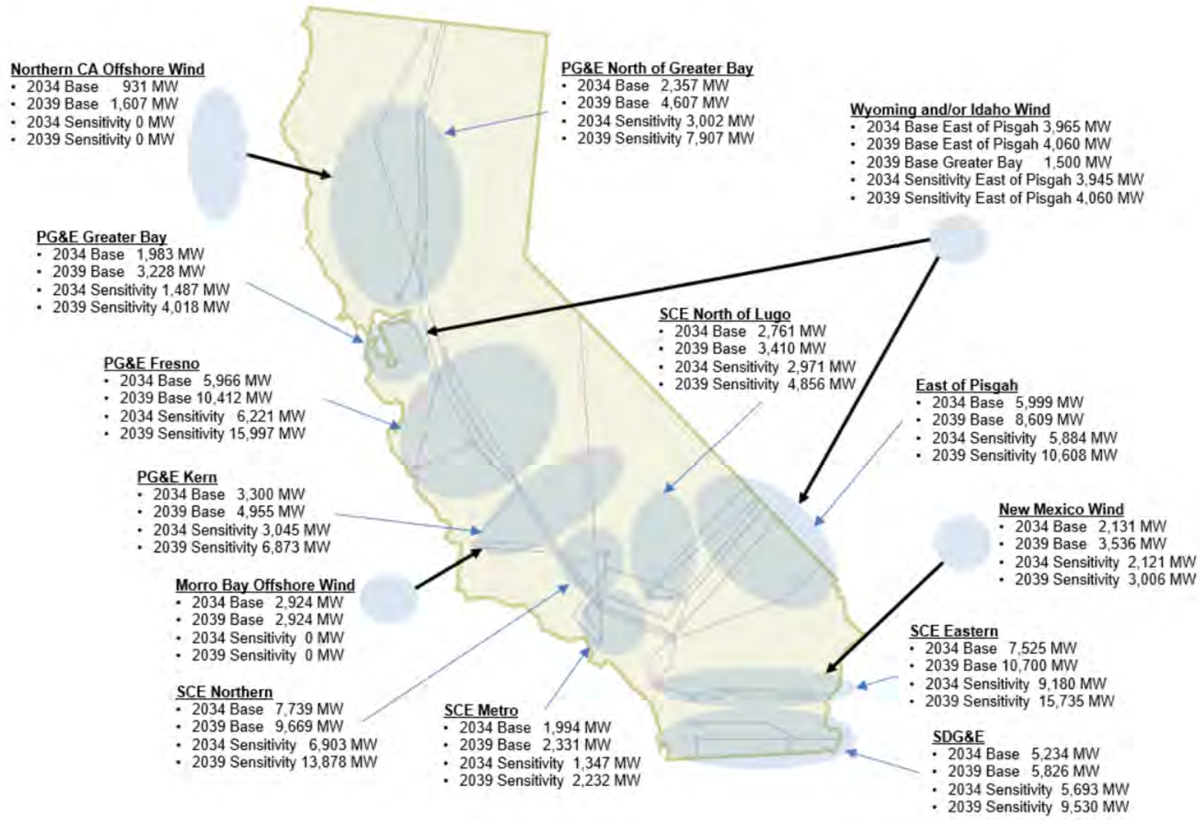
Table 3.3-2: 2039 Base and Sensitivity Portfolio Composition

	Base Portfolio			Sensitivity Portfolio		
Resource Type	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Biomass	171	0	171	22	0	22
Distributed_Solar	283	0	283	335	0	335
Geothermal	1,969	0	1,969	5,089	0	5,089
LDES	1,080	0	1,080	3,680	0	3,680
Li_Battery (4-hour)	15,707	0	15,707	9,305	0	9,305
Li_Battery (8-hour)	7,115	0	7,115	15,612	0	15,612
Offshore Wind	4,531	0	4,531	0	0	0
OOS Wind	9,096	0	9,096	7,066	0	7,066
Solar	10,858	19,541	30,399	21,304	30,547	51,851
Wind, Onshore	6,103	921	7,023	4,885	855	5,739
TOTAL	**56,912**	**20,462**	**77,374**	**67,298**	**31,401**	**98,699**

As part of the 2034 and 2039 Base Portfolios, the net dependable gas capacity not retained totals 3,448 MW and 4,418 MW respectively. The 2034 and 2039 Sensitivity portfolios net dependable gas capacity not retained totals 5,438 MW and 12,274 MW respectively. The amounts are in addition to the scheduled retirement of approximately 3,700 MW of OTC generation.

A geographical depiction of the 2034 and 2039 Base and Sensitivity portfolios are shown below in Figure 3.3-1 which includes the Offshore and Out-of-State wind brought into their respective areas.

Figure 3.3-1: 2034 and 2039 Base and Sensitivity Portfolios by Area



As part of the bus bar mapping process, CPUC utilizes estimated transmission capability information provided by the ISO to calculate transmission capability usage and exceedance of mapped resources across all identified transmission constraints. Table 3.3-3 and Table 3.3-4 provide CPUC's assessment of transmission capability exceedances of known on-peak and off-peak deliverability constraints by the 2034 and 2039 base portfolio, respectively[54].

[54] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp/final_dashboard_24-25tpp.xlsx, Tabs '2034_Exceedance_Summmary' and '2039_Exceedance_Summary'.

Table 3.3-3: CPUC's assessment of 2034 base portfolio transmission capability exceedances

Base Case (2034) Tx Constraint Exceedances		Constraint's White Paper		FCDS Resources Mapped (In-Dev & Generic)				EODS Resources Mapped		Calculated Largest On-peak Exceedance**	Calculated Off-peak Exceedance	White Paper Upgrade Info		CPUC staff estimated likelihood of being triggered
CAISO Zone	Constraint Name	On-Peak Capability (MW)	Off-Peak Capability (MW)	Onshore & Offshore Wind (MW)	Solar (MW)	Storage (MW)	Biomass & Geothermal (MW)	Onshore Wind (MW)	Solar (MW)			Capability Increase (MW)	Estimated Cost (millions)	
PG&E North of Greater Bay	Vaca Dixon-Tesla 500kV Line	1,044	1,415	934	319	468	181	365	420	(837)	None	8,645	$ 2,852	Medium
	Carberry-Round Mountain 230kV Line	14	183	200	-	-	-	10	-	(119)	None	26	$ 180	High
	Rocklin-Pleaseant grove 115kV line	92	226	61	8	50	22	53	12	(27)	None	707	$ 125	Medium
PG&E Greater Bay	Windmaster-Delta pumps 230 kV Line	710	710	256	54	231	85	155	128	(133)	None	6,034	$ 417	Low
	Morganhill-Metcalf 115kV Line	314	314	-	-	354	2	-	-	(299)	None	712	$ 380	Low
	Birds Landing-Contra Costa 230kV Line	836	836	437	288	336	126	237	308	(326)	None	1,766	$ 700	Low
PG&E Kern	Oceano-Calendar 115kV Line	937	174	300	1,363	874	2	10	292	(375)	(296)	1,418	$ 1,008	Medium
	Midway-Q2005 230kV Line	1,396	278	574	2,737	2,151	31	76	1,364	(1,260)	(927)	16,891	$ 940	High
PG&E Fresno	Gates 500/230kV TB #12	3,213	3,148	794	2,540	2,135	34	106	1,614	(157)	None	14,825	$ 35	Medium
	Chowchilla-Le grand 115kV Line	699	908	274	402	714	21	66	275	(320)	None	1,211	$ 550	Low
	Schindler 115/70kV TB #1	399	491	274	382	682	11	66	275	(304)	None	3,160	$ 370	Low
	Panoche-Mendota 115 kV Line	1,798	7	374	408	682	22	66	275	None	(53)	2,019	Same as Schindler 115/70kV	Low
	Moss Landing-Las Aguillas 230 kV Line Off-Peak	2,276	-	325	1,764	1,697	21	65	869	(59)	(593)	1,760 (off-peak)	$ 40	Medium
SCE Northern	South of Magunden	740	500	-	208	1,150	1	-	50	(596)	None	2,000	$ 4,358	Low
SCE Eastern	Devers-Red Bluff	9,050*	16,158*	8,041	1,885	3,040	1,825	239	3,537	(2,124)	None	3,000^	$ 1,022^	Medium
East of Pisgah	Lugo-Victorville Area	10,100	9,600	8,041	1,983	4,190	1,036	239	2,747	(1,716)	None	6,800	$ 2,165	Medium
SDG&E	Chicarita 138 kV	301	301	-	1	447	-	-	-	(437)	None	700	$ 100	High
	Silvergate - Bay Blvd 230 kV	796	929	1,325	200	301	160	239	182	(627)	None	4,754	$ 30	High
	Silvergate-Old Town 230 kV	1,221	1,221	975	200	401	160	189	182	(284)	None	2,522	$ 283	High
	Talega 230 kV	1,205	1,205	-	-	856	-	-	-	(291)	None	2,201	$ 211	High

*Includes capability increase from TPP approved upgrade ^ CAISO staff identified additional upgrade from previous 2021 White Paper

** Includes calculations from IRP baseline resources not in mapped portfolio numbers

Table 3.3-4: CPUC's assessment of 2039 base portfolio transmission capability exceedances

Base Case (2034) Tx Constraint Exceedances		Constraint's White Paper		FCDS Resources Mapped (In-Dev & Generic)				EODS Resources Mapped		Calculated Largest On-peak Exceedance **	Calculated Off-peak Exceedance	White Paper Upgrade Info		CPUC staff estimated likelihood of being triggered
CAISO Zone	Constraint Name	On-Peak Capability (MW)	Off-Peak Capability (MW)	Onshore & Offshore Wind (MW)	Solar (MW)	Storage (MW)	Biomass & Geothermal (MW)	Onshore Wind (MW)	Solar (MW)			Capability Increase (MW)	Estimated Cost (millions)	
PG&E North of Greater Bay	Vaca Dixon-Tesla 500kV Line	1,044	1,415	1,834	474	1,368	181	365	1,215	**(2,351)**	**None**	8,645	$ 2,852	High
	Woodland- Davis 115kV Line	76	76	-	77	135	-	-	297	**(67)**	**(43)**	109	$ 9	High
	Carberry-Round Mountain 230kV Line	14	183	200	-	-	-	10	-	**(119)**	**None**	26	$ 180	High
	Rocklin-Pleaseant grove 115kV line	92	226	61	83	185	22	53	297	**(170)**	**None**	707	$ 125	High
	Bellota-Weber 230kV Line	2,382	2,382	386	928	1,919	56	119	1,217	**(545)**	**None**	460	$ 400	High
PG&E Greater Bay	Windmaster-Delta pumps 230 kV Line	710	710	256	104	371	85	155	468	**(278)**	**None**	6,034	$ 417	Low
	Morganhill-Metcalf 115kV Line	314	314	-	-	404	2	-	-	**(349)**	**None**	712	$ 380	Low
	Birds Landing-Contra Costa 230kV Line	836	836	437	368	596	126	237	818	**(599)**	**None**	1,766	$ 700	Medium
PG&E Kern	Oceano-Calendar 115kV Line	937	174	300	1,598	1,606	2	10	1,466	**(1,130)**	**(677)**	1,418	$ 1,008	High
	Midway-Q2005 230kV Line	1,396	278	574	3,483	4,412	31	76	4,154	**(3,596)**	**(1,460)**	16,891	$ 940	High
PG&E Fresno	Gates 500/230kV TB #12	3,213	3,148	794	3,285	3,786	34	106	4,184	**(1,882)**	**None**	14,825	$ 35	High
	Gates 500/230kV TB #11	3,684	3,856	794	3,831	4,183	34	106	4,664	**(1,863)**	**None**	10,038	High (same upgrade as TB#12)	High
	Tranquility-Helm 230kV Line	2,229	1,170	274	1,772	2,223	22	66	1,614	**(438)**	**None**	2,274	$ 1,500	Medium
	Chowchilla-Le grand 115kV Line	699	908	274	527	988	21	66	505	**(607)**	**None**	1,211	$ 550	Medium
	Los Banos 500/230 kV Bank	8,861*	608*	594	2,959	3,876	28	96	3,304	**None**	**(177)**	-	$ -	Low
	Schindler 115/70kV TB #1	399	491	274	402	896	11	66	440	**(521)**	**None**	3,160	$ 370	Medium
	Panoche-Mendota 115 kV Line	1,798	7	274	648	1,046	11	66	695	**None**	**(210)**	2,019	Same as Schindler 115/70kV	Low
	Moss Landing-Las Aguillas 230 kV Line Off-Peak	2,276	-	325	2,104	2,534	21	65	2,224	**(919)**	**(1,096)**	1,760 (off-peak)	$ 40	High
SCE Northern	South of Magunden	740	500	-	208	1,150	1	-	50	**(596)**	**None**	2,000	$ 4,358	Low
SCE Eastern	Colorado River 500/230 kV	1,035	1,414	-	500	404	-	-	895	**(221)**	**None**	1,370	$ 67	Medium
	Colorado River-Red Bluff	11,521*	11,521*	9,541	2,610	4,148	1,035	239	5,739	**(832)**	**None**	1,170	$ 357	Low
	Devers-Red Bluff	9,050*	16,158*	9,541	2,610	4,773	1,825	239	6,314	**(4,988)**	**None**	3,000^	$ 1,022^	High
East of Pisgah	GLW 230kV Area	2,185*	2,752*	620	1,200	1,654	500	-	2,030	**(520)**	**None**	-	$ -	Low
	Lugo-Victorville Area	10,100	9,600	9,541	2,108	5,552	1,036	239	4,874	**(4,066)**	**None**	6,800	$ 2,165	High
SDG&E	Chicarita 138 kV	301	301	-	1	497	-	-	-	**(487)**	**None**	700	$ 100	High
	Internal San Diego Area	1937*	1,006*	975	200	1,263	160	189	344	**(116)**	**None**	-	$ -	Low
	Encina - San Luis Rey 230 kV	2,688*	2,668*	1,325	450	1,634	160	239	1,219	**(254)**	**None**	-	$ -	Low
	San Luis Rey-San Onofre 230 kV Line	2,837*	6,174	1,325	450	1,622	160	239	1,219	**(85)**	**None**	-	$ -	Low
	Silvergate - Bay Blvd 230 kV	796	929	1,325	200	364	160	239	344	**(690)**	**None**	4,754	$ 30	High
	Silvergate-Old Town 230 kV	1,221	1,221	975	200	464	160	189	344	**(347)**	**None**	2,522	$ 283	High
	Talega 230 kV	1,205	1,205	-	-	998	-	-	-	**(433)**	**None**	2,201	$ 211	High

*Includes capability increase from TPP approved upgrade ^ CAISO staff identified additional upgrade from previous 2021 White Paper
** Includes calculations from IRP baseline resources not in mapped portfolio numbers

3.4 Additional Guidance from CPUC regarding the Portfolios

Draft Editorial Note:

Section 3.4 will be completed as needed in the final study plan when the CPUC's Modeling Assumptions for the 2024-2025 Transmission Planning Process document becomes available.

3.5 Deliverability assessment methodology

3.5.1 On-peak deliverability assessment

On-peak deliverability assessment is performed under two distinct system conditions – the highest system need (HSN) scenario and the secondary system need (SSN) scenario. The HSN scenario represents the period when the capacity shortage is most likely to occur. In this scenario, the system reaches peak sale with low solar output. The highest system need hours represent the hours ending 19 to 22 in the summer months.

The secondary system need scenario represents the period when capacity shortage risk increases if variable resources are not deliverable during periods when the system depends on their high output for resource adequacy. In this scenario, the system load is modeled to represent the peak consumption level and solar output is modeled at a significantly higher output. The secondary system need hours are hours ending 15 to 18 in the summer months.

The ISO performes on-peak deliverability assessment for both HSN and SSN scenarios. For each scenario and each portfolio, the ISO developes a master deliverability assessment base case that models all FCDS portfolio resources. Key assumptions of the deliverability assessment are described below.

Transmission

The ISO will model the same transmission system as in the corresponding 2034 and 2039 peak load base cases that are used in the reliability assessment performed as part of the current transmission planning process.

System load

The ISO will model a coincident 1-in-5 year peak for the ISO balancing authority area load in the HSN base case. Pump load is dispatched within the expected range for summer peak load hours. The load in the SSN base case is adjusted from the HSN case to represent the net customer load at the time of forecasted peak consumption.

Maximum resource output (Pmax) assumptions

Pmax in the on-peak deliverability assessment represents the resource-type specific maximum resource output assumed in the deliverability assessment. For non-intermittent resources, the same Pmax is used in the HSN and SSN scenarios. The most recent summer peak NQC is used as Pmax for existing non-intermittent generating units. For proposed new non-intermittent generators that do not have NQC, the Pmax is set according to the interconnection request. For non-intermittent generic portfolio resources, the FCDS capacity provided in the portfolio is used as the Pmax. For energy storage resources, the Pmax is set to the 4-hour discharging capacity in the HSN scenario and 50% of the 4-hour discharging capacity in the SSN scenario, limited by the requested maximum output from the resource, if applicable. For hybrid projects, the study amount for each technology is first calculated separately. Then the total study amount among all technologies is based on the sum of each technology, but limited by the requested maximum output of the generation project.

Intermittent resources are modeled in the HSN scenario based on the output profiles during the highest system need hours. A 20% exceedance production level for wind and solar resources during these hours sets the Pmax tested in the HSN deliverability assessment. In the SSN scenario, intermittent resources are modeled based on the output profiles during the secondary system need hours. 50% exceedance production level for wind and solar resources during the hours sets the Pmax tested in the SSN deliverability assessment.

The maximum resource output (Pmax) assumptions used in HSN and SSN deliverability assessment are shown in Table 3.5-1

Table 3.5-1: Maximum resource output tested in the deliverability assessment

Area	HSN			SSN		
	SDG&E	SCE	PG&E	SDG&E	SCE	PG&E
Solar	3.0%	10.6%	10.0%	40.2%	42.7%	55.6%
Wind	33.7%	55.7%	66.5%	11.2%	20.8%	16.3%
Out-of-state Wind (NM, WY, ID)	67%			35%		
Off-shore Wind	83%			45%		
Energy Storage	100% or 4-hour equivalent if duration is < 4-hour			50% or 4-hour equivalent if duration is < 4-hour		
Non-Intermittent resources	NQC or 100%					

Import Levels

For the HSN scenario, the net scheduled imports at all branch groups as determined in the latest annual Maximum Import Capability (MIC) assessment set the imports in the study. Approved MIC expansions will be added to the import levels. Historically unused Existing Transmission Contracts (ETC's) crossing control area boundaries are modeled as zero MW injections at the tie point, but available to be turned on at remaining contract amounts for screening analysis. MIC expansions needed to accommodate portfolio resources are added to the import levels. Valid MIC expansion requests are similarly modeled but are not allowed to trigger transmission upgrades.

For the SSN scenario, the hour with the highest total net imports among all secondary system need hours from the latest MIC assessment data will be selected. Net scheduled imports for the hour set the imports in the study. Approved and requested MIC expansions and MIC expansions needed to accommodate portfolio resources are modeled similar to the HSN scenario.

3.5.2 General On-peak deliverability assessment procedure

The main steps of the California ISO on-peak deliverability assessment procedure are described below.

Screening for Potential Deliverability Problems Using DC Power Flow Tool

A DC transfer capability/contingency analysis tool is used to identify potential deliverability problems. For each analyzed facility, an electrical circle is drawn which includes all generating units including unused Existing Transmission Contract (ETC) injections that have a 5% or greater:

Distribution factor (DFAX) = (Δ flow on the analyzed facility / Δ output of the generating unit) *100%

or

Flow impact = (DFAX * Full Study Amount / Applicable rating of the analyzed facility) *100%.

Load flow simulations are performed, which study the worst-case combination of generator output within each 5% Circle.

Verifying and Refining the Analysis Using AC Power Flow Tool

The outputs of capacity units in the 5% Circle are increased starting with units with the largest impact on the transmission facility. No more than 20 units are increased to their maximum output. In addition, no more than 1,500 MW of generation is increased. All remaining generation within the Control Area is proportionally displaced, to maintain a load and resource balance.

When the 20 units with the highest impact on the facility can be increased more than 1,500 MW, the impact of the remaining amount of generation to be increased is considered using a Facility Loading Adder. The Facility Loading Adder is calculated by taking the remaining MW amount available from the 20 units with the highest impact multiplied by the DFAX of each unit. An equivalent MW amount of generation with negative DFAX is also included in the Facility Loading Adder, up to 20 units. If the net impact from the Facility Loading Adders is negative, the impact is set to zero and the flow on the analyzed facility without applying Facility Loading Adders is reported.

The ISO's on-peak deliverability assessment simulation procedure as implemented in PowerGem's Transmission Adequacy & Reliability Assessment (TARA) software will be used to perform the policy-driven on-peak deliverability assessment.

Mitigation Alternatives

Potential mitigation alternatives that will be considered to address on-peak deliverability constraints include but are not limited to Remedial Action Schemes (RAS) and other operating solutions, reduction of portfolio battery storage behind the constraints and transmission upgrades.

3.5.3 Off-peak deliverability assessment

The general off-peak deliverability assessment system study conditions are intended to capture a reasonable scenario for the load, generation, and imports that stress the transmission system, but not coinciding with an oversupply situation. By examining the renewable curtailment data from 2018, a load level of about 55% to 60% of the summer peak load and an import level of about 6000 MW was selected for the off-peak deliverability assessment.

The production of wind and solar resources under the selected load and import conditions varies widely. The production duration curves for solar and wind were examined. The production level under which 90% of the annual energy was selected to set the outputs to be tested in the off-peak deliverability assessment. The dispatch of the remaining generation fleet is set by examining historical production associated with the selected renewable production levels. The hydro dispatch is about 30% of the installed capacity and the thermal dispatch is about 15%. All energy storage facilities are assumed offline.

The dispatch assumptions discussed above apply to both full capacity and energy-only resources. However, depending on the amount of generation in the portfolio, it may be impossible to balance load and resources under such conditions with all portfolio generation dispatched. The dispatch assumptions are applied to all existing, under-construction and contracted generators first, then some portfolio generators if needed to balance load and resources. This establishes a system-wide dispatch base case or master base case that is the starting case for developing each of the study area base cases to be used in the off-peak deliverability assessments. Table 3.5-2 summarizes the generation dispatch assumptions in the master base case.

Table 3.5-2: ISO System-Wide Generator Dispatch Assumptions

	Dispatch Level
Wind	44%
Solar	68%
Battery storage	0%
Hydro	30%
Thermal	15%

The off-peak deliverability assessment may be performed for each study area separately. The study areas in general are the same as the reliability assessment areas in generation interconnection studies.

Study area base cases are created from the system-wide dispatch base case. All generators in the study area, existing or future, are dispatched to a consistent output level. In order to capture local curtailment, the renewable dispatch is increased to the 90% energy level for the study area, which is higher than the system-wide 90% energy level. The study area 90% energy level was determined from representing individual plants in different areas. For out-of-state and off-shore wind, the dispatch values are based on data obtained from NREL for the PCM model.

If the renewables inside the study area are predominantly wind resources (more than 70% of total study area capacity), wind resource dispatch is increased as shown in Table 3.5-3. All the solar resources in the wind pocket are dispatched at the system-wide level of 68%. If the renewables inside the study area are not predominantly wind resources, then the dispatch assumptions in Table 3.5-4 are used. The dispatch assumptions for out-of-state and off-shore wind used in the current study are provided in Table 3.5-5.

Table 3.5-3: Local Area Solar and Wind Dispatch Assumptions in Wind Area

	Wind Dispatch Level	Solar Dispatch Level
SDG&E	69%	68%
SCE	64%	
PG&E	63%	

Table 3.5-4: Local Area Solar and Wind Dispatch Assumptions in Solar Area

	Solar Dispatch Level	Wind Dispatch Level
SDG&E	79%	44%
SCE	77%	
PG&E	79%	

Table 3.5-5: Additional Local Area Dispatch Assumptions

Resource	**Dispatch Level**
Offshore Wind	100%
New Mexico Wind	67%
Wyoming Wind	67%

As the generation dispatch increases inside the study area, the following resource adjustment can be performed to balance the loads and resources:

- Reduce new generation outside the study area (staying within the Path 26, 4000 MW north to south, and 3000 MW south to north limits)
- Reduce thermal generation inside the study area
- Reduce imports
- Reduce thermal generation outside the study area.

Once each study area case has been developed, a contingency analysis is performed for normal conditions and selected contingencies:

- Normal conditions (P0)
- Single contingency of transmission circuit (P1.2), transformer (P1.3), single pole of DC lines (P1.5)
- Multiple contingency of two adjacent circuits on common structures (P7.1) and loss of a bipolar DC line (P7.2).

For overloads identified under such dispatch, resources that can be re-dispatched to relieve the overloads are adjusted to determine if the overload can be mitigated:

- Existing energy storage resources are dispatched to their full four-hour charging capacity to relieve the overload
- Thermal generators contributing to the overloads are turned off
- Imports contributing to the overloads are reduced to the level required to support out-of-state renewables in the portfolios.

Mitigation options will be developed to address the remaining overloads after the re-dispatch. Generators with 5% or higher distribution factor (DFAX) on the constraint are considered contributing generators. The distribution factor is the percentage of a particular generation unit's incremental increase in output that flows on a particular transmission line or transformer under the applicable contingency condition when the displaced generation is spread proportionally, across all dispatched resources available to scale down output proportionally. Generation units are scaled down in proportion to the dispatch level of the unit.

Mitigation Alternatives
Potential alternatives that will be considered to address off-peak deliverability constraints include, but are not limited to, Remedial Action Schemes (RAS) and other operating solutions, dispatching portfolio battery storage behind the constraints in charging mode and transmission upgrades. Transmission upgrades identified to address off-peak deliverability constraints will be considered as candidates for a more thorough evaluation using production cost simulation

3.6 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 2024, 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, if any. The comprehensive Transmission Plan will contain the results of the CAISO's 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 Plan 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. The ISO's latest TPD estimates were published in June 2023[55].

[55] https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=03DCF912-0ECF-4CF9-A304-A05F4ED5B2CD

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 2024-2025 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 greenhouse gas (GHG) reduction target, at least cost, while maintaining electric service reliability and meeting other State goals.

The CPUC IRP base portfolio is transmitted for the purpose of being studied as part of the reliability, policy-driven, and economic assessments. See Chapter 3 for details regarding the portfolio.

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 2034 anchor dataset (ADS) PCM as the staring database[56], 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 the 10th planning year through production simulation, and for 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.

As part of the requirements under the CAISO tariff and Business Practice Manual, Economic Planning Study Requests were to be submitted to the CAISO during the comment period

[56] The 2034 ADS PCM is developed in the Western Interconnection ADS process, which has a two-year cycle. The 2034 ADS PCM is projected to be released in June 2024.

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. Table 4.3-2 includes the Economic Planning Study Requests that were submitted for this planning cycle.

Table 4.3-1: Economic study requests

No.	Study Request	Submitted By	Location

Draft Editorial Note:

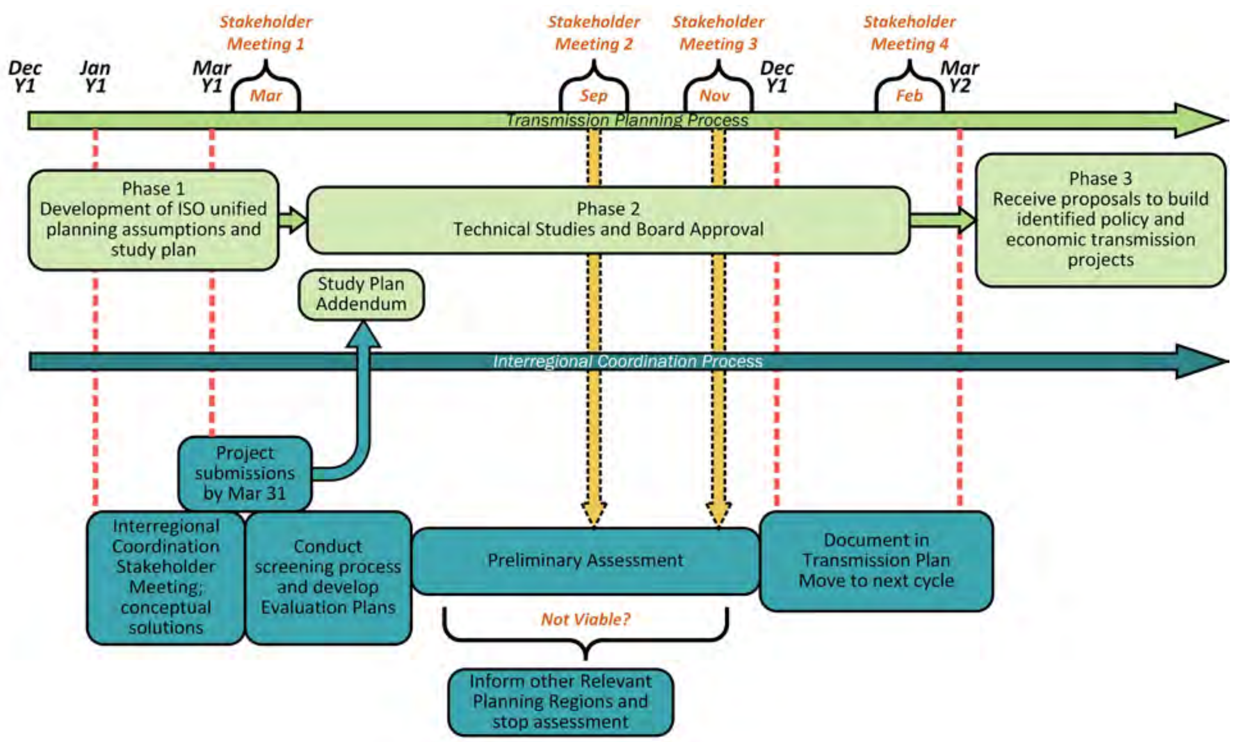
Table 4.3-1 will be updated based upon the economic study requests received in the comment window following the stakeholder meeting for the draft study plan on February 28.

5. Interregional Coordination

During the CAISO's 2024-2025 planning cycle, the CAISO will, in coordination with the other western planning regions, initiate the 2024-2025 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 2024-2025 TPP planning cycle
- Participate in a western planning regions' stakeholder meeting. The Northern Grid is hosting the meeting on March 26, 2024.
- In coordination with other Relevant Planning Regions[57], 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. A stakeholder call will be held in June 2024 to present the evaluation plans.
- Figure 4.3-1 illustrates the interregional coordination process for the even year of the two year cycle.

Figure 4.3-1 Even Year Interregional Coordination Process



57 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

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:

- 2025 – Local Capacity Area Technical Study
- 2029 – 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, 2024.

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/InitiativeDocuments/FinalStudyManual-2025LocalCapacityRequirements.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 2024-2025 CAISO Transmission Planning Process webpage.

6.1.2 Long-Term Local Capacity Requirement Assessment

Based on the alignment[58] 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 2022-2023 Transmission Plan and therefore the 2024-2025 transmission planning process will include a 10 year out study.

6.2 Maximum Import Capability Expansion Requests

Per section 3.2.2.3 of the Transmission Planning Process Business Practice Manual (TPP BPM), requests to perform deliverability studies in order to expand the maximum import capability must be submitted to the CAISO within 2 weeks after the first stakeholder meeting not later than the time that the study plan comments are due. The maximum import capability expansion requests must identify the intertie(s) (branch group(s)) that require expansion. For an LSE the request must include information about existing resource adequacy contracts. For new transmission owners or other market participants the request must include information on contractual arrangements or other evidence of financial commitments the requestor has already made in order to serve load or meet resource adequacy requirements within the CAISO balancing authority area. The quality of the data must be sufficient for the CAISO to make a determination about the validity of such request as available in the Tariff. The CAISO will maintain confidentiality of data provided except for the requestor name, intertie (branch group) the MW quantity and technology of the expansion request.

First the CAISO will evaluate each maximum import capability expansion request in order to establish if the submitting entity meets the criteria listed in the Tariff Section 24.3.5. The descriptions of valid maximum import capability requests as determined by the CAISO will be included in the final study plan. Than the CAISO will coordinate the valid MIC expansion requests with the policy driven MIC expansion and the total of the two will be used to identify all branch groups that do not have sufficient Remaining Import Capability to cover both the valid MIC expansion requests and the policy driven MIC expansion.

The exact calculation of the target expanded MIC can be found in Reliability Requirements Business Practice Manual (RR BPM) section 6.1.3.5 “Deliverability of Imports”.

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

The interrelation between the target expanded MIC and the generation interconnection process can be found in RR BPM section 6.1.3.6 “Modeling Expended MIC Values in GIP”.

Table 6.2-1 includes the valid Maximum Import Capability expansion requests that were submitted for this planning cycle.

Table 6.2-1: Valid Maximum Import Capability expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Technology
TBD	TBD	TBD	TBD	TBD

The CAISO has received TBD submittals with requests for MIC expansion. They contained TBD distinct requests (a few were duplicates – the LSE provided the request and the supplier provided a requests for the same resource).

Based on the CAISO interpretation of the Tariff and the Transmission Planning BPM (TP BPM) requirements TBD distinct requests qualify as valid requests based on the following factors:

1. TBD.

For the following reasons, TBD distict request do not qualify at this time:

1. TBD.

<u>Important reminder:</u>
In order to avoid the risk of not being able to count a valid RA contract, the CAISO strongly encourages LSEs to first receive the MIC allocation at the branch group of their choice before they sign an external resource (including dynamic schedule and pseudo-ties) to an RA contract. Under the Tariff and RR BPM specified conditions, LSEs have an opportunity to qualify such contracts as New Use Import Commitments in order to receive priority allocation on their choosen intertie for the length of the contract.

6.3 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.

6.4 Frequency Response Assessment

As inverter Based Resources (IBR) become an ever higher proportion of the overall energy resource mix it is important to check on the ability of these units to fulfull their frequency response requirements in all transmission planning scenarios and to track this capability year-over-year. FERC Order 842 states that IBR-based generation must provide frequency response for grid disturbances and newer plants will become a higher proportion than legacy units that do not provide this functionality. The ability of IBR with frequency control enabled to respond to system events must have enough available operating headroom and this must taken into account in the studies.

The objective of this study is to assess the CAISO system frequency response in years 5 and 12 of the system plan and identify performance issues related to frequency response. The study case will be based on the 2028 and 2035 spring off peak cases with the following assumptions on frequency response provided by the IBRs.

Study Assumptions:

- The 2028 and 2035 spring off peak cases will be used for this study. Off-peak base cases have a very high solar plant output making them more suitable for studying the effect of IBR impact on frequency response. The details of the base case including the installed and dispatched IBRs, target path flows are provided in earlier sections of this study plan.

- Composite load models will be used in the dynamic study which will more accurately reflect the dependency of load to frequency.

- The assumption is that DERs do not respond to frequency variations. Tripping of DER on significant frequency variations is assumed based on the NERC SPIDER Guideline recommendations. The settings are such that the DER are not expected to trip in typical frequency events observed in this study.

- In selected scenarios, the online unloaded capacity of non-IBRs in CAISO system will be set at the spinning reserve requirements as much as is possible under that scenario. While it is possible to achieve a particular spinning reserve this can lead to skewed generation patterns that are unrealistic.

Study Scenarios:

Starting with the 2028 and 2035 Spring Off Peak cases, the following scenarios with regards to generator and IBR frequency response will be studied:

- Scenario 1: Frequency response from all new and existing IBRs in CAISO system will have frequency control switched off to establish a baseline. The existing generation pattern will not be modified, nor will any generator statuses be changed from the base case defaults.
- Scenario 2: Frequency response from all new and existing IBRs in CAISO system will have frequency control switched on. As for scenario 1 there is no change in generation output.
- Scenario 3: Frequency response will be enabled for all BESS IBRs assuming 10% headroom. All BESS plants whether in charging or discharging mode are redispatched to this headroom ahead of the contingency.
- Scenario 4: Starting with Scenario 2 it will be assumed that the generator headroom in CAISO areas will be set at minimum spinning reserve.
- Scenario 5: Starting with Scenario 3 it will be assumed that the generator headroom in CAISO areas will be set at minimum spinning reserve.

Study Methodology and Monitored Parameters:

For each of the study scenarios, the trip of two fully dispatched Palo Verde units without a fault, will be simulated for 60 seconds and the following variables will be monitored:

i. System frequency including frequency nadir and settling frequency after primary frequency response

ii. The existing and new IBR output

iii. The total output of all other CAISO generators

iv. The major path flows

v. Frequency response of the WECC and CAISO (MW/0.1 Hz)

vi. Rate of Change of Frequency (ROCOF)

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 9-6.4-1: SMEs for Technical Studies in 2024-2025 Transmission Planning Process

Table 6.4-1

Item/Issues	SME	Contact
Reliability Assessment in PG&E	Preethi Rondla	prondla@caiso.com
Reliability Assessment in SCE	Frank Chen	fchen@caiso.com
Reliability Assessment in SDG&E	Rene Romo	rromodesantos@caiso.com
Reliability Assessment in VEA	Meng Zhang	mezhang@caiso.com
Policy-driven Assessment	Nebiyu Yimer	nyimer@caiso.com
Local Capacity Requirements and Maximum Import Capability Expansion Requests	Catalin Micsa	cmicsa@caiso.com
Economic Planning Study	Yi Zhang	yzhang@caiso.com
Long-term Congestion Revenue Rights	Bryan Fong	bfong@caiso.com

APPENDIX A: System Data

A1 Existing Generation

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

		PG&E	SCE	SDG&E	VEA	Total
Existing Generators Max Generation (MW)	Nuclear	2,300	0	0	0	2,300
	Natural Gas	12,901	13,909	3,129	0	29,938
	Hydro	9,320	3,237	40	0	12,597
	Solar	5,423	11,060	3,044	239	19,766
	Wind	2,002	5,802	702	0	8,506
	Biogas	101	178	10	0	289
	Biomass	430	4	0	0	434
	Geothermal	1,130	552	0	0	1,682
	Battery Storage	2,272	5,777	1,153	65	9,267
	Hybrid	257	1,844	0	0	2,101
	Other	2,304	1,161	785	0	4,250
	Total	38,440	43,523	8,863	304	91,130

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[59] (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[60] (MW) and Technology[61] (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	

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

60 The CAISO, 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.

61 IC (Internal Combustion), GT (gas turbine), CCGT (combined cycle gas turbine)

Generating Facility	Owner	Existing Unit/ Technology[59] (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[60] (MW) and Technology[61] (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)	12/31/2024	11/2/2024	1122		N/A	On September 2, 2022, Governor Newsom signed SB 846 into law, which set a new OTC Policy compliance date for Diablo Canyon Units 1 and 2, conditioned upon the U.S. Nuclear Regulatory Commission extending the plant's operating licenses.[62]
		2 (ST)	12/31/2024[63]	8/26/2025[64]	1118			
Mandalay	GenOn	1 (ST)	12/31/2020	2/6/2018	215	Retired (no repowering) SCE plans to replace with renewable energy and storage		Mandalay generating facility was retired on February 6, 2018.
		2 (ST)	12/31/2020	2/6/2018	215			
Ormond Beach	GenOn	1 (ST)	12/31/2020	12/31/2023[65]	741	To be retired (no repowering)	N/A	The SWRCB has proposed an amendment to extend OTC compliance dates for Units 1 and 2 to 12/31/2026.
		2 (ST)	12/31/2020	12/31/2023[66]	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
		2 (ST)	12/31/2020	1/1/2020	175			

62 Senate Bill 846 (Dodd)

63 Ibid.

64 Ibid.

65 Ibid.

66 Ibid.

Generating Facility	Owner	Existing Unit/ Technology[59] (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[60] (MW) and Technology[61] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
		3 (ST)	12/31/2020	12/31/2023[67]	332			repowering project (non-OTC units). The SWRCB has proposed an amendment to extend compliance dates for Units 3, 4 and 5 to 12/31/2026.
		4 (ST)	12/31/2020	12/31/2023[68]	336			
		5 (ST)	12/31/2020	12/31/2023[69]	498			
		6 (ST)	12/31/2020	1/1/2020	495			
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). The SWRCB has proposed an amendment to extend the compliance date for Unit 2 to 12/31/2026.
		2 (ST)	12/31/2020	12/31/2023[70]	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	12/31/2023	179	To be retired	N/A	Unit 7 was retired to provide emission offsets to repowering project at Huntington Beach. On December 23, 2021, the SWRCB officially amended the compliance schedule for Units 5, 6 and 8.
		6 (ST)	12/31/2020	12/31/2023	175			
		7 (ST)	12/31/2020	10/1/2019	493			
		8 (ST)	12/31/2020	12/31/2023	496			

67 Ibid.

68 Ibid.

69 Ibid.

70 Ibid.

Generating Facility	Owner	Existing Unit/ Technology[59] (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[60] (MW) and Technology[61] (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.	New resources (Carlsbad Energy Center) achieved commercial operation on 12/11/2018	OTC Unit 1 was retired on 12/31/2017. Units 2-5 were retired on 12/31/2018.
		2 (ST)	12/31/2017	12/31/2018[71]	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)

[71] 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 Long-Term Planning Procurement Plan Resources

Table A3-1: Planned Generation

PTO Area	Project	Capacity (MW)	Expected In-service Date
None	None	None	None

Table A3-2: Summary of SCE area 2012 LTPP Track 1 & 4 Procurement and Implementation 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[72]	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[73]	0	0	206.66

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.

[72] 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.

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

A4 Retired Generation

Table A4-1: Generation (non-OTC) projected to be retired in planning horizon[74]

PTO Area	Generating Facility	Maximum Capacity (MW)	First Year Case That Retirement Units are Modeled
PGAE	ALMEGT_1_UNIT_1	23.4	2035
PGAE	ALMEGT_1_UNIT_2	23.5	2035
PGAE	CHEVCD_6_UNIT	1.1	2035
PGAE	CHEVCO_6_UNIT_1	1.6	2035
PGAE	CHEVCY_1_UNIT	4.2	2035
PGAE	CLRMTK_1_QF	0.0	2035
SCE	CONTRL_1_QF	5.6	2035
PGAE	CSCCOG_1_UNIT_1	6.0	2035
PGAE	CSCGNR_1_UNIT_2	24.0	2035
SCE	CUMMNG_6_SUNCT1	3.4	2035
PGAE	FRITO_1_LAY	0.1	2035
SCE	GLNARM_7_UNIT_1	22.1	2035
SCE	GLNARM_7_UNIT_2	22.3	2035
SCE	GOLETA_6_ELLWOD	0.0	2035
SCE	HINSON_6_CARBGN	29.9	2035
PGAE	HOLGAT_1_BORAX	14.7	2035
PGAE	KERNRG_1_UNITS	0.3	2035
PGAE	LODI25_2_UNIT_1	23.8	2035
PGAE	MESAP_1_QF	0.0	2035
PGAE	MOSSLD_1_QF	0.0	2035
PGAE	NEWARK_1_QF	0.3	2035
PGAE	OAK_C_7_UNIT_1	55.0	2035
PGAE	OAK_C_7_UNIT_2	55.0	2035
PGAE	OAK_C_7_UNIT_3	55.0	2035
SCE	OMAR_2_UNIT_1	75.9	2035
SCE	OMAR_2_UNIT_2	77.1	2035
SCE	OMAR_2_UNIT_3	79.1	2035
SCE	OMAR_2_UNIT_4	81.4	2035
SCE	SEARLS_7_ARGUS	4.1	2035
SCE	SNCLRA_2_UNIT	27.5	2035

[74] Table A4-1 reflects retirement of generation based upon announcements from the generators or included in the retirement list of thermal generating units as part of the portfolio. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2023-2024-tpp-portfolios-and-modeling-assumptions/thermal_agebased-ret_assumptions_v011723.xlsx
The CAISO will document generators assumed to be retired as a result of assumptions identified in Section 2.7 as a part of the base case development with the reliability results.

PTO Area	Generating Facility	Maximum Capacity (MW)	First Year Case That Retirement Units are Modeled
SCE	SNCLRA_2_UNIT1	17.6	2035
PGAE	STAUFF_1_UNIT	0.0	2035
PGAE	TANHIL_6_SOLART	17.0	2035
PGAE	UNCHEM_1_UNIT	9.1	2035
PGAE	UNVRSY_1_UNIT_1	35.7	2035

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
Mira Loma 230kV	158	Shunt Capacitors
Mira Loma 500kV	300	Shunt Capacitors
San Luis Rey	63	Shunt Capacitors
Bay Boulevard	100	Shunt Capacitors
Miguel	126	Shunt Capacitors
Escondido	126	Shunt Capacitors
Suncrest	126	Shunt Capacitors
Penasquitos	276	Shunt Capacitors
San Luis Rey	2x225	Synchronous Condensers
Talega	2x225	Synchronous Condensers
Miguel	2x225	Synchronous Condensers
San Onofre	225	Synchronous Condensers
Suncrest	300	Static VAr Compensator

A6 Remedial Action Schemes

Table A6-1: Existing key Remedial Action Schemes in the PG&E area. Additional RAS will be added as needed in the Final Study Plan

PTO	Area	RAS Name
PG&E	Bulk	COI RAS
	Bulk	Colusa RAS
	Bulk	Diablo Canyon RAS
	Bulk	Midway 500/230 kV Transformer Overload RAS

PTO	Area	RAS Name
	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 RAS
	Central Coast / Los Padres	Mesa and Santa Maria Undervoltage RAS
	Central Coast / Los Padres	Divide Undervoltage RAS
	Central Coast / Los Padres	Temblor-San Luis Obispo 115 kV Overload Scheme
	Central Coast / Los Padres	Paso Robles 70 kV Undervoltage RAS
	Central Coast / Los Padres	Coburn Transfer trip
	Central Coast / Los Padres	Carrizo RAS
	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 RAS Scheme
	Greater Fresno Area	Ashlan RAS
	Greater Fresno Area	Atwater RAS
	Greater Fresno Area	FRTRAS
	Greater Fresno Area	Helms RAS
	Greater Fresno Area	Henrietta RAS
	Greater Fresno Area	Herndon-Bullard RAS
	Greater Fresno Area	Kerckhoff 2 RAS
	Greater Fresno Area	Reedley RAS
	Greater Fresno Area	Hatchet Ridge RAS
	Greater Fresno Area	Exchequer Legrand 115kV RAS
	Greater Bay Area	Metcalf RAS
	Greater Bay Area	SF RAS
	Greater Bay Area	South of San Mateo RAS
	Greater Bay Area	Metcalf-Monta Vista 230kV OL RAS
	Greater Bay Area	San Mateo-Bay Meadows 115kV line OL
	Greater Bay Area	Moraga-Oakland J 115kV line OL RAS
	Greater Bay Area	Grant 115kV OL RAS

PTO	Area	RAS Name
	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 RAS
	Greater Bay Area	Transbay Cable Run Back Scheme
	Humboldt	Humboldt – Trinity 115kV Thermal Overload Scheme
	North Valley	Caribou Generation 230 kV RAS Scheme #1
	North Valley	Caribou Generation 230 kV RAS 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 Remedial Action Schemes in SCE area

PTO	Area	RAS 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)
	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 Remedial Action Schemes in the SDG&E

PTO	Area	RAS Name
SDG&E	SDG&E	69kV TL 695B at TA
	SDG&E	69kV TL 682 RAS (currently disabled and will not be enabled until it is reevaluated)
	SDG&E	69kV TL 600 RAS
	SDG&E	69kV TL 684 RAS (currently disabled and will be removed from service in the future)
	SDG&E	69kV TL 686 RAS
	SDG&E	69kV TL 649 RAS
	SDG&E	Crestwood RAS – Remedial Action Scheme for Kumeyaay Wind Generation (currently disabled and will be removed from service in the future)
	SDG&E	Valley Center RAS
	SDG&E	Avocado RAS
	SDG&E	138kV TL 13835A RAS
	SDG&E	138kV TL 13810A RAS
	SDG&E	CENACE Valley Area Trip for Imperial Valley – La Rosita 230kV (TL 23050) Overload (CFE-5A RAS)
	SDG&E	TL23040 IV 500 kV N-1 RAS
	SDG&E	Overload of CENACE's Valle – Costa Path RAS
	SDG&E	230kV Otay Mesa Gen Drop RAS
	SDG&E	TL 23041 / TL 23042 RAS
	SDG&E	TL 23054 / TL 23055 RAS
	SDG&E	230kV TL 23066 RAS
	SDG&E	Miguel BK 80 / BK 81 RAS
	SDG&E	500kV TL 50001 Gen Drop RAS
	SDG&E	500kV TL 50003 Gen Drop RAS
	SDG&E	500kV TL 50004 Gen Drop RAS
	SDG&E	500kV TL 50005 Gen Drop RAS
	SDG&E	South of San Onofre Safety Net