California ISO

2019-2020 Transmission Planning Process Unified Planning Assumptions and Study Plan

April 3, 2019

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Table of Contents

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 ISO 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 ISO 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 ISO'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 ISO approval of specific transmission elements and projects identified in the 2019-2020 comprehensive transmission plan at the end of Phase 2. ISO 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 provided during the year, and has not been scheduled at this time.

The ISO has collaboratively worked with the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) to align the planning assumptions between the ISO's TPP and the CPUC's Integrated Resource Plan (IRP) process, as well as the demand forecast assumptions embodied in the 2017 IEPR adopted by the CEC on January 9, 2019[1].

[1] https://www.energy.ca.gov/2018_energypolicy/documents/

2 Overview of 2019-2020 Stakeholder Process Activities and Communications

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

2.1 Stakeholder Meetings and Market Notices

During each planning cycle, the ISO will conduct at least four stakeholder meetings to present and acquire stakeholder input on the current planning effort. These stakeholder meetings are scheduled and designed around major activities in Phase 1 and Phase 2 of the TPP. Additional meetings for each stage may be scheduled as needed. These meetings provide an opportunity for the ISO 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 2019-2020 transmission planning cycle is provided in Table 2-1. Should this schedule change or other aspects of the 2019-2020 transmission planning cycle require revision; the ISO will notify stakeholders through an ISO market notice which will provide stakeholders information about revisions that have been made. As such, the ISO 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 2-1: Schedule for the 2019-2020 planning cycle

Phase	No	Due Date	2019-2020 Activity
Phase 1	1	December 17, 2018	The ISO sends a letter to neighboring balancing authorities, sub-regional, regional planning groups requesting planning data and related information to be considered in the development of the Study Plan.
	2	December 17, 2018	ISO issues a market notice announcing a thirty-day comment period requesting demand response assumptions and generation or other non-transmission alternatives to be considered in the Unified Planning Assumptions.
	3	January 17, 2019	PTO's, neighboring balancing authorities and regional/sub-regional planning groups provide ISO the information requested No.1 above.
	4	January 17, 2019	Stakeholders provide ISO the information requested No.2 above.
	5	February 21, 2019	The ISO develops the draft Study Plan and posts it on its website
	6	February 28, 2019	The ISO hosts public stakeholder meeting #1 to discuss the contents in the Study Plan with stakeholders
	7	February 28 - March 14, 2019	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 ISO
	8	March 29, 2019	The ISO 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, 2019	The ISO posts preliminary reliability study results and mitigation solutions
	10	August 15, 2019	Request Window opens
	11	August 26, 2019	The ISO will post base scenario base cases for each planning area used in the reliability assessment
	12	September 15, 2019	PTO's submit reliability projects to the ISO
	13	September 25-26, 2019	The ISO hosts public stakeholder meeting #2 to discuss the reliability study results, PTO's reliability projects, and the Conceptual Statewide Plan with stakeholders
	14	September 25 – October 9, 2019	Comment period for stakeholders to submit comments on the public stakeholder meeting #2 material[2]

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

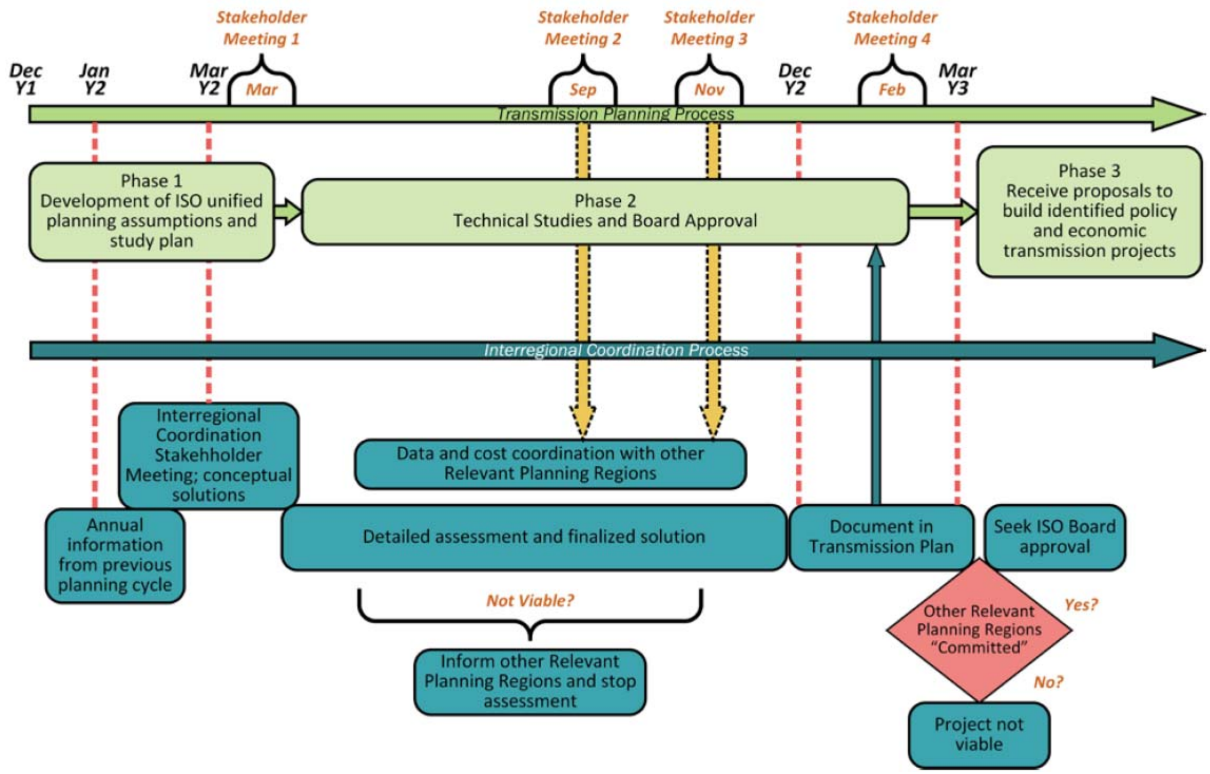
Phase	No	Due Date	2019-2020 Activity
	15	October 15, 2019	Request Window closes
	16	October 31, 2019	ISO post final reliability study results
	17	November 14, 2019	The ISO posts the preliminary assessment of the policy driven & economic planning study results and the projects recommended as being needed that are less than $50 million.
	18	November 18, 2019	The ISO 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 18 – December 2, 2019	Comment period for stakeholders to submit comments on the public stakeholder meeting #3 material
	20	December 18 – 19, 2019	ISO Board of Governors meeting provides opportunity for stakeholder comments directly to Board of Governors.
	21	January 31, 2020	The ISO posts the draft Transmission Plan on the public website
	22	February 2020	The ISO hosts public stakeholder meeting #4 to discuss the transmission project approval recommendations, identified transmission elements, and the content of the Transmission Plan
	23	Approximately two weeks following the public stakeholder meeting #4	Comment period for stakeholders to submit comments on the public stakeholder meeting #4 material
	24	March 2020	The ISO finalizes the Transmission Plan and presents it to the ISO Board of Governors for approval
	25	End of March, 2020	ISO posts the Final Board-approved Transmission Plan on its site
Phase 3	26[3]	April 1, 2020	If applicable, the ISO will initiate the process to solicit proposals to finance, construct, and own elements identified in the Transmission Plan eligible for competitive solicitation

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

2.3 Interregional Coordination

During the ISO's 2019-2020 planning cycle, the ISO will continue to participate and advance interregional transmission coordination along with the other western planning regions within the broader landscape of the western interconnection. The interregional transmission coordination process entered the second year of its coordination cycle on January 1, 2018. Figure 2.3-1 illustrates the interregional coordination process for the odd year of the 2 year cycle.

Figure 2.3-1 Odd Year Interregional Coordination Process



The ISO will keep stakeholders informed about its interregional activities through the stakeholder meetings identified in Table 2 1: Schedule for the 2019-2020 planning cycle. 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

Commensurate with its 2019-2020 planning activities, the ISO will continue supporting the implementation of the WECC Anchor Data Set (ADS) which was approved by the WECC Board of Directors in December 2016. The purpose of the ADS is to establish consistent processes and protocols for gathering planning data that include reviews for consistency and completeness, and to generate production cost, power flow, and dynamic models with a common representation of the loads, resources, and transmission across the Western Interconnection 10 years in the future. The ADS will resolve existing inconsistencies and facilitate consistent data application for the western planning regions, WECC and other stakeholders in the Western Interconnection. The planning regions are currently and will continue to be engaged with WECC staff in the development of the processes and protocols that will govern data quality between the planning regions, existing MOD-032 processes, and WECC in support of the ADS' implementation.

2.4 Stakeholder Comments

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

2.5 Availability of Information

The ISO website is the central place for public and non-public information. For public information, the main page for documents related to 2019-2020 transmission planning cycle is the "Transmission Planning" section located at http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx on the ISO website.

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

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 ISO tariff. The NDA application and instructions are available on the ISO website at http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx under the *Accessing transmission data* heading.

3 Reliability Assessments

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

3.1 Reliability Standards and Criteria

The 2019-2020 transmission plan will span a 10-year planning horizon and will be conducted to ensure the ISO-controlled grid is in compliance with the North American Electric Reliability Corporation (NERC) standards, WECC regional criteria, and ISO planning standards across the 2020-2029 planning horizon.

3.1.1 NERC Reliability Standards

The ISO 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 ISO as a registered NERC planning authority and are the primary driver of the need for reliability upgrades:[4]

TPL-001-4:	Transmission System Planning Performance Requirements[5]; and
NUC-001-3	Nuclear Plant Interface Coordination.[5]

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

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

3.1.2 WECC Regional Criteria

The WECC System Performance TPL-001-WECC-CRT-3[6] Regional Criteria are applicable to the ISO as a planning authority and set forth additional requirements that must be met under a varied but specific set of operating conditions.[7]

3.1.3 California ISO Planning Standards

The California ISO Planning Standards specify the grid planning criteria to be used in the planning of ISO 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 ISO-controlled grid; and,
- Identify whether specific criteria should be adopted that are more stringent than the NERC standards or WECC regional criteria.

3.2 Frequency of the study

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

3.3 Study Horizon and Years

The studies that comply with TPL-001-4 will be conducted for both the near-term[9] (2020-2024) and longer-term[10] (2025-2029) per the requirements of the reliability standards.

Within the identified near and longer term study horizons the ISO will be conducting detailed analysis on years 2021, 2024 and 2029. If in the analysis it is determined that additional years are required to be assessed the ISO will consider conducting studies on these years or utilize past studies[11] in the areas as appropriate.

[6] https://www.wecc.biz/Reliability/TPL-001-WECC-CRT-3.pdf
[7] http://compliance.wecc.biz/application/ContentPageView.aspx?ContentId=71
[8] http://www.caiso.com/Documents/ISOPlanningStandards-September62018.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.
[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.

3.4 Study Areas

The reliability assessments will be performed on the bulk system (north and south) as well as the local areas under the ISO controlled grid. Figure 3.4-1 shows the approximate geographical locations of these study areas. The full-loop power flow base cases that model the entire Western Interconnection will be used in all cases. These 16 study areas are shown below[12].

- 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) main transmission
- San Diego Gas & Electric (SDG&E) sub-transmission
- Valley Electric Association (VEA) area[13]
- ISO overall bulk system

[12] The ISO has executed planning coordinator services agreements with Hetch Hetchy Water & Power (HHWP), Silicon Valley Power (SVP), Metropolitan Water District (MWD) of Southern California, and Southern California Edison for a subset of its facilities that are not under ISO operational control but which were found to be Bulk Electric System as defined by NERC, and the ISO will conduct the study efforts to meet the mandatory standards requirements for these entities within the framework of the annual transmission planning process. However, the transmission planning provisions of section 24 of the ISO tariff do not apply to these facilities that are outside of ISO operational control, and the study results will be documented separately for purposes of compliance with mandatory NERC standards and will not be documented in the ISO transmission plan.

[13] 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 3.4-1: Approximated geographical locations of the study areas

3.5 Transmission Assumptions

3.5.1 Transmission Projects

The transmission projects that the ISO 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 ISO approval in the 2018-2019 or earlier ISO transmission plans. Currently, the ISO anticipates the 2018-2019 transmission plan will be presented to the ISO board of governors for approval in March 2019. Projects put on hold will not be modeled in the starting base case.

3.5.2 Reactive Resources

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

3.5.3 Protection System

To help ensure reliable operations, many Remedial Action Schemes (RAS), Protection Systems, safety nets, UVLS and 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 SPS, 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 ISO has been modeling RAS in power flow studies for some areas for the past two cycles as they were made available by the PTOs. The ISO will continue the effort of modeling RAS in this planning cycle in working with the PTOs with a target to have model for all RAS in the ISO controlled grid.

3.5.4 Control Devices

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

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

3.6 Load Forecast Assumptions

3.6.1 Energy and Demand Forecast

The assessment will utilize the 2018 California Energy Demand Updated Forecast 2018-2030 adopted by the California Energy Commission (CEC) on January 9, 2019[14] using the corresponding Corrected LSE and BA Table Mid Baseline spreadsheet with applicable AAEE and AAPV submitted on February 5, 2019. The 2018 CED Forecast also includes 8760-hourly demand forecasts for the three major Investor Owned Utility (IOU) TAC areas[15].

During 2018, the CEC, CPUC and ISO engaged in collaborative discussion on how to consistently account for reduced energy demand from energy efficiency in the planning and procurement processes. To that end, the 2018 IEPR update final report, adopted on January 9, 2019, based on the IEPR record and in consultation with the CPUC and the ISO, recommends using the Mid Additional Achievable Energy Efficiency (AAEE) and Additional Achievable Photovoltaic (AAPV) scenario for system-wide and flexibility studies for the CPUC LTPP and ISO TPP cycles. However, for local area studies, because of the local nature of reliability needs and the difficulty of forecasting load and AAEE at specific locations and estimating their daily load-shape impacts, using the Low AAEE and AAPV scenario is more prudent at this time.

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

http://www.energy.ca.gov/2018_energypolicy/documents/

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

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

3.6.2 Methodologies to Derive Bus Level Forecast

Since load forecasts from the CEC are generally provided for a larger area, these load forecasts may 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

[14] http://www.energy.ca.gov/2018_energypolicy/documents/

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

detailed 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.

3.6.2.1 *Pacific Gas and Electric Service Area*

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

PG&E Loads in Base Case

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

<u>Determination of Division Loads</u>

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

<u>Allocation of Division Load to Transmission Bus Level</u>

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

<u>Muni Loads in Base Case</u>

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

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

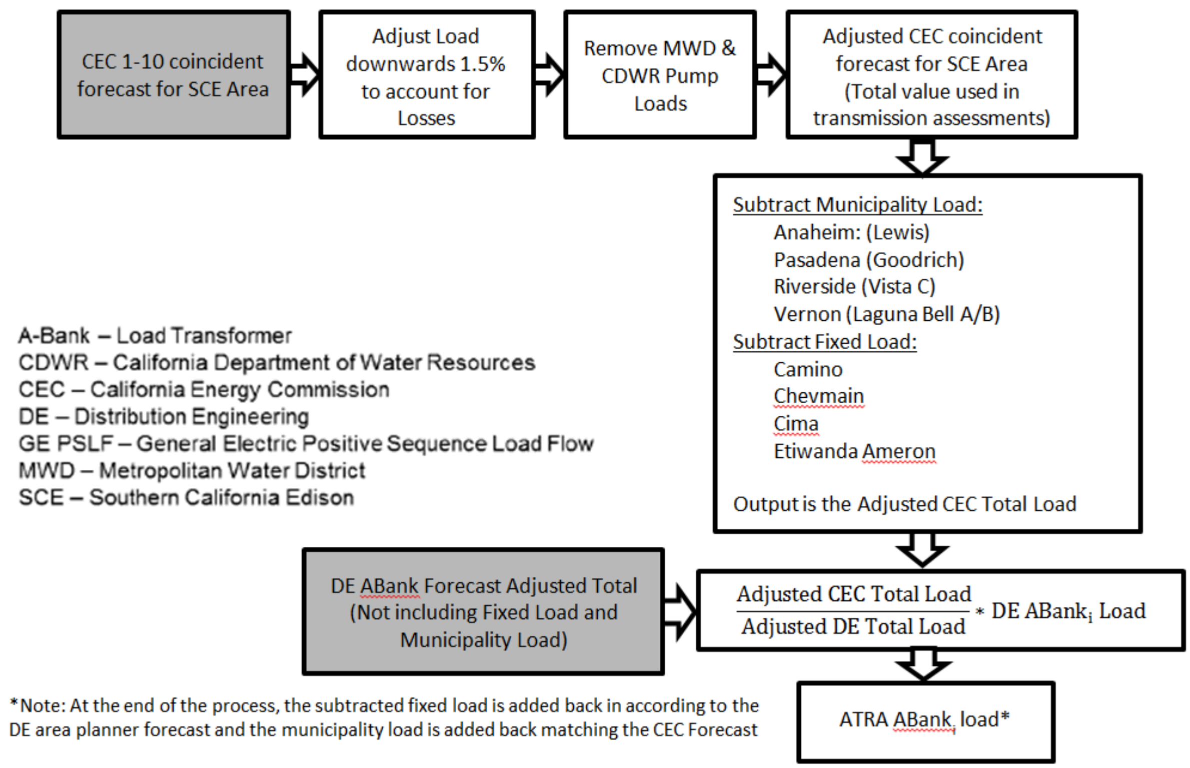
Behind-the-meter PV (BTM-PV)

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

3.6.2.2 *Southern California Edison Service Area*

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

Figure 3.6-1: SCE A-Bank load model



Behind-the-meter PV (BTM-PV)

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

3.6.2.3 *San Diego Gas and Electric Service Area*

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

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

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

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

3.6.2.4 *Valley Electric Association Service Area*

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

3.6.2.5 *Bus-level Load Adjustments*

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

3.6.3 Power Factor Assumptions

In the PG&E area assessment, power factors at all substations will be modeled using the most recent historical values obtained at corresponding peak, off-peak, and light load conditions. Bus load power factor for near term (year 2021 and 2024) will be modeled based on the actual data recorded in the EMS system. For the subsequent study years a power factor of 0.97 lagging for summer peak cases, and 0.99 leading factor for winter off-peak cases, will be used.

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

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

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

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

3.6.4 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 California Energy Demand Updated (CEDU) Forecast 2018-2030 also includes Additional Achievable Photovoltaic (AAPV). AAPV is incremental to the PV in the baseline forecast and, used in developing the managed forecast. ISO wide, combined self-generation PV and AAPV capacity is projected to reach 19,373 MW in the mid demand case by 2029. In 2019-2020 TPP base cases, both baseline PV and AAPV generation production will be modeled explicitly.

PV Self-generation and AAPV installed capacity for mid demand scenario by PTO and forecast climate zones are shown in Tables 3.6-1 and 3.6-2. Output of the self-generation and AAPV will be selected based on the time of day of the study using the end-use load and PV shapes for the day selected.

Table 3.6-1: Mid demand baseline PV self-generation installed capacity by PTO[16]

PTO	Forecast Climate Zone	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PGE	Central Coast	349	396	429	455	483	510	539	568	599	633
	Central Valley	1,182	1,331	1,447	1,542	1,612	1,675	1,738	1,803	1,871	1,945
	Greater Bay Area	1,347	1,558	1,758	1,920	2,075	2,206	2,323	2,433	2,539	2,639
	North Coast	352	394	412	429	463	497	532	566	601	635
	North Valley	258	289	314	334	351	367	382	398	413	428
	Southern Valley	1,556	1,720	1,846	1,959	2,066	2,178	2,296	2,423	2,564	2,722
	PG&E Total	**5,045**	**5,687**	**6,206**	**6,639**	**7,051**	**7,434**	**7,810**	**8,191**	**8,587**	**9,001**
SCE	Big Creek East	375	413	449	485	520	557	594	634	675	722
	Big Creek West	206	228	252	277	304	332	361	389	412	424
	Eastern	816	922	1,015	1,085	1,142	1,197	1,253	1,312	1,373	1,433
	LA Metro	1,288	1,486	1,688	1,876	2,061	2,225	2,370	2,501	2,625	2,744
	Northeast	574	640	707	768	831	897	965	1,037	1,110	1,188
	SCE Total	**3,258**	**3,688**	**4,111**	**4,490**	**4,858**	**5,207**	**5,544**	**5,873**	**6,195**	**6,511**
SDGE	SDGE	1,391	1,498	1,557	1,618	1,679	1,746	1,821	1,907	2,007	2,128
CAISO Total		**9,694**	**10,873**	**11,873**	**12,748**	**13,588**	**14,387**	**15,174**	**15,971**	**16,789**	**17,640**

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

Table 3.6-2: AAPV installed capacity by PTO[17]

PTO	Forecast Climate Zone	2020		2021		2022		2023		2024		2025		2026		2027		2028		2029	
		Mid	Low	Mid	Low	Mid	Low	Mid	Low	Mid	Low	Mid	Low	Mid	Low	Mid	Low	Mid	Low	Mid	Low
PGE	Central Coast	5	5	10	9	16	14	22	18	29	23	35	27	40	31	46	34	52	38	57	42
	Central Valley	16	13	35	28	59	46	82	63	108	80	133	98	158	115	182	132	206	149	230	165
	Greater Bay Area	22	21	47	42	75	64	103	85	130	103	157	121	182	138	206	155	230	171	254	188
	North Coast	5	7	10	12	18	18	26	23	34	29	42	34	49	39	56	43	64	48	71	52
	North Valley	3	3	7	6	11	9	16	13	21	16	25	20	30	23	35	27	39	30	43	33
	Southern Valley	11	9	24	16	42	25	59	35	78	51	97	65	116	80	134	94	151	109	169	123
	PG&E Total	**62**	**58**	**133**	**113**	**222**	**176**	**308**	**238**	**399**	**302**	**489**	**365**	**575**	**426**	**659**	**486**	**742**	**545**	**824**	**603**
SCE	Big Creek East	5	4	10	9	16	14	22	19	28	24	34	29	40	33	46	38	51	43	57	48
	Big Creek West	3	3	6	6	10	9	14	13	17	16	20	19	23	22	26	25	29	28	32	31
	Eastern	13	11	26	23	42	37	57	50	72	64	87	77	102	90	116	103	130	116	144	129
	LA Metro	35	32	71	66	112	100	150	133	187	164	223	193	257	222	289	249	322	276	354	303
	Northeast	14	11	29	24	46	37	63	49	79	62	95	75	111	88	126	100	141	113	156	125
	SCE Total	**70**	**62**	**143**	**128**	**226**	**197**	**305**	**264**	**383**	**329**	**460**	**393**	**533**	**456**	**603**	**516**	**673**	**576**	**743**	**635**
SDGE	SDGE	16	13	33	22	51	38	69	53	87	69	104	85	120	100	136	114	151	128	166	142
	CAISO Total	**148**	**134**	**308**	**263**	**499**	**411**	**682**	**555**	**869**	**700**	**1,053**	**843**	**1,229**	**981**	**1,398**	**1,115**	**1,566**	**1,248**	**1,733**	**1,380**

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

3.7 Generation Assumptions

3.7.1 Generation Projects

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

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

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

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

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

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

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

Contracted renewable generation with all permitting and necessary transmission approved and expected to be in-service within 5-years may also be modeled in the relevant cases. The CPUC's Reliability Base Portfolio and ISO's interconnection agreement status will be utilized as criteria for modeling specific generation. For 2024, generation from the CPUC Default Portfolio described below will be used, as necessary. Given the data availability, generic dynamic data may be used for this future generation.

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

3.7.2 Renewable Generation

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

The proposed decision[18] issued by the CPUC on March 18, 2019 includes recommendations regarding the resource portfolio(s) for the CPUC to recommend to the ISO to utilize in the 2019-2020 TPP.

The CPUC staff generated the "reliability base" portfolio using RESOLVE capacity expansion model. The final portfolios are posted to the CPUC's website at - http://www.cpuc.ca.gov/General.aspx?id=6442460548.

The "Reliability and Policy-Driven Base Case" portfolio[19] summarizes the new build portfolio being modeled for study in the CAISO's 2019-20 TPP Reliability and Policy-Driven Base Case.

RESOLVE documentation specifies that renewable resources under development with CPUC-approved contracts with the three investor-owned utilities are assumed to be part of the baseline assumptions. The ISO will work with the CPUC to identify such resources and model these in the reliability assessment base cases. The ISO may supplement this scenario with information regarding contracted RPS resources that are under construction as of March 2019. The generic resources selected as portfolio resources are at a geographic scale that is too broad for transmission planning purpose which requires specific interconnection locations. The allocation[20] of these resources in the portfolios to substations on the CAISO-controlled transmission grid was conducted by land-use experts at the CEC. The ISO will use this allocation information to model the portfolio resources in the study process.

3.7.3 Thermal generation

For the latest updates on new generation projects, please refer to the CEC website under the licensing section (http://www.energy.ca.gov/sitingcases/all_projects.html). In addition, the ISO may also use other data sources to track the statuses of additional generator projects to determine the starting year new projects may be modeled in the base cases. Table A3-1 of Appendix A lists new thermal generation projects in construction or pre-construction phase that will be modeled in the base cases.

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[18] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M272/K614/272614400.PDF

[19] http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/IRP_TPP_ReliabilityAndPolicyBaseCase_ToBePosted.xlsx

[20] https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-MISC-03

3.7.4 Hydroelectric Generation

During drought years, the availability of hydroelectric generation production can be severely limited. In particular, during a drought year the Big Creek area of the SCE system has experienced a reduction of generation production that is 80% below average production. It is well known that the Big Creek 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 ISO will consider drought conditions when establishing the hydroelectric generation production levels in the base case assumptions.

3.7.5 Generation Retirements

Existing generators that have announced retiring are listed in Table A4-1 of Appendix A. These generators along with their step-up transformer banks will be modeled as out of service starting in the year they are assumed to be retired. Their models are to be removed from base cases only when they have been physically taken apart and removed from the site. Exception: models can be removed prior to physical removal only when approved plans exist to use the site for other reasons.

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

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

<u>Once Through Cooled Retirements</u> – As identified in section 3.7.6.

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

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

3.7.6 OTC Generation

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

- Generating units that are repowered, replaced or having firm plans to connect to acceptable cooling technology, as illustrated in Table A2-1 of Appendix A. This table also includes potential early retirements of some OTC generating units to accommodate repowering projects, which received the CPUC approval for 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;
- Generating units with acceptable Track 2[21] mitigation plan that was approved by the State Water Resources Control Board.

3.7.6.1 *LTPP Authorization Procurement*

OTC replacement local capacity amounts in southern California that were authorized by the CPUC under the LTTP Tracks 1 and 4 will be considered along with the procurement activities to date from the utilities. Table 3.7-6 provides the local capacity resource additions and the study year in which the amounts will be first modeled based on the CPUC LTPP Tracks 1 and 4 authorizations. Table 3.7-7 provides details of the study assumptions using the utilities' procurement activities to date, as well as the ISO's assumptions for potential preferred resources for San Diego area.

Table 3.7-6: Summary of 2012 LTPP Track 1 & 4 Maximum Authorized Procurement[22]

LCR Area	LTTP Track-1		LTTP Track-4[23]	
	Amount (MW)(1)	Study year in which addition is to be first modeled	Amount (MW) (1)	Study year in which addition is to be first modeled
Moorpark Sub-area	290	2021	0	N/A
West LA Basin / LA Basin	1400-1800	2021	500-700	2021
San Diego	308	2018	500-800	2018

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

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

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

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

Table 3.7-7: Summary of 2012 LTPP Track 1 & 4 Procurement Activities to date

	LTPP EE (MW)	Behind the Meter Solar PV (NQC MW)	Storage 4-hr (MW)	Demand Response (MW)	Conventional resources (MW)	Total Capacity (MW)
SCE's procurement for the Western LA Basin[24]	124.04	37.92	263.64	5	1,382	1,812.60
SCE's procurement for the Moorpark sub-area[25]	6.00	5.66	0	0	0	11.66
SDG&E's procurement[26]	19 (approved)	0	83.5[27] (approved)	4.5 (approved)	800[28]	907

For further details on new resources see Table A3-1 "Planned generation". The portion of authorized local capacity derived from energy limited preferred resources such as demand response and battery storage will be modeled offline in the initial base cases and will be used as mitigation once reliability concerns are identified.

3.8 Preferred Resources[29]

In complying with tariff Section 24.3.3(a), the ISO sent a market notice to interested parties seeking suggestions about demand response programs and generation or non-transmission alternatives that should be included as assumptions in the study plan. The ISO received a submission from PG&E with the DR inputs to be included in the 2019-2020 transmission planning process within the PG&E planning area. In addition the ISO received specific project proposals from the Nevada Hydro Company and Cal Energy Development Company, LLC. These two projects will be considered as an economic study requests and included in section 5.3 of the study plan. In addition the proponents for these projects can submit the projects in the 2019 Request

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

[25] SCE-selected RFO procurement (A. 14-11-016) for the Moorpark sub-area, which includes the 262 MW Puente Power Project, was approved by the CPUC except the 0.5 MW of storage which was rejected along with the refurbishment contract for Ellwood. NRG has withdrawn its application to the CEC for certification of the Puente Power Project.

[26] For additional details on approved and pending projects, see San Diego Gas & Electric applications A.14-07-009, available online at http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=98406519, A.16-03-014 available at https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1603014, and A.17-04-017 available at https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1704017.

[27] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K337/215337477.PDF

[28] The CPUC, in Decisions 14-02-016 and 15-05-051 approved PPTAs for the Pio Pico and Carlsbad Energy Center projects.

[29] 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.

Window as alternatives to specific reliability needs that are identified in the 2019-2020 transmission planning process reliability assessment.

3.8.1 Methodology

The ISO issued a paper[30] on September 4, 2013, in which it presented a methodology to support California's policy emphasis on the use of preferred resources – specifically energy efficiency, demand response, renewable generating resources and energy storage – by considering how such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure. The general application for this methodology is in grid area situations where a non-conventional alternative such as demand response or some mix of preferred resources could be selected as the preferred solution in the ISO's transmission plan as an alternative to the conventional transmission or generation solution.

In previous planning cycles, the ISO 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 ISO also made further progress in integrating preferred resources into its reliability analysis focusing on other areas where reliability issues were identified.

As in the 2018-2019 planning cycle, reliability assessments in the current planning cycle will consider a range of existing demand response amounts as potential mitigations to transmission constraints. The reliability studies will also incorporate the incremental uncommitted energy efficiency amounts as projected by the CEC, distributed generation based on the CPUC Default RPS Portfolio and a mix of preferred resources including energy storage based on the CPUC LTPP 2012 local capacity authorization. These incremental preferred resource amounts are in addition to the base amounts of energy efficiency, demand response and "behind the meter" distributed or self-generation that is embedded in the CEC load forecast.

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

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

proceeding to evaluate alternative local capacity solutions for the Moorpark area[31]. The ISO will continue to use the methodology developed as part of the study to evaluate these types of resources.

3.8.2 Demand Response

For long term transmission expansion studies, the methodology described above will be utilized for considering fast-response DR and slow-response PDR resources. In 2017, the ISO performed a study to assess the availability requirements of slow-response resources, such as demand response, to count for local resource adequacy.[32] 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 ISO will address duration limitations through the annual Local Capacity Requirements stakeholder process through hourly load and resource analysis.

The ISO has concluded through its Resource Adequacy Enhancement initiative that the hourly and 15 minute bidding framework being established through the CAISO's ESDER 3 initiative and the preventive-corrective constraint introduced into the market optimization through the Contingency Modeling Enhancements (CME) initiative will provide a methodology for allowing slow demand response resources to be economically dispatched through the market as a preventive measure in preparing for a possible contingency.

Additionally, an interim solution has been devised for pre-contingency dispatching slow demand response resources, to be used until the ESDER 3 and CME initiatives are implemented.

This implementation framework will allow PDR resources capable of responding within 52.5 minutes (the binding real-time hourly block schedule is communicated at 52.5 minutes before the flow of energy). Accordingly, slow response PDR that can achieve the 52.5 minute threshold will be considered available for meeting local capacity needs as needed. Because of the I implementation complexity for pre-dispatching slow response demand response prior to the "first contingency", reliance on fast response demand response and slow response demand response will be tracked separately.

The IOUs submitted information of their existing DR programs and allocation to substations, in response to the ISO'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. The following table describes supply-side DR capacity assumptions for the three IOUs.

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

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

Table 3.8-1: Existing DR Capacity Range for Each IOU Load Serving Entities within ISO BA

PG&E

PG&E Portfolio-Adjusted for CAISO Peaking Conditions, August, Weather 1-in-2			
DR Program	**MW**	**Level of Dispatch**	**Response time**
Base Interruptible Program (BIP)	219	System-wide SubLAP RDRR	30 minutes
Capacity Bidding Program (CBP)	24	System-wide SubLAP PDR	Day Ahead
Peak Day Pricing (PDP)	52	System-wide	Day Ahead
SmartRate™	6	System-wide	Day Ahead
SmartAC™	42	System-wide SubLAP Selected 21 Substations PDR	None required
DRAM	90		>30 Minutes
Total	**433**		

SCE

Load Impact Report, 1-in-2 weather year condition portfolio-adjusted August 2028 ex-ante DR impacts at CAISO peak				
Supply-side DR (MW)	**MW**	**Assumed Market Model**	**Response time**	**Level of Dispatch**
Base Interruptible Program 15 Minute (BIP-15)	152	RDRR	20 Minutes or Less	System-wide, Sublap, A-Bank
Base Interruptible Program 30 Minute (BIP-30)	434	RDRR	30 Minutes	
Agricultural and Pumping Interruptible (API)	41	RDRR	20 Minutes or Less	A-bank
Summer Discount Plan Residential (SDP-R)	110	PDR	20 Minutes or Less	A-bank
Summer Discount Plan Commercial (SDP-C)	20	PDR	20 Minutes or Less	System-wide, Sublap, A-Bank
Smart Energy Program	148	PDR	20 Minutes or Less	System-wide, Sublap, A-Bank
SCE LCR RFO (Post 2018)	5	RDRR	20 Minutes or Less	System-wide, Sublap, A-Bank
DRAM	176.5	PDR	>30 Minutes	System-wide, Sublap
Total	**1087**			

SDG&E[33]

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)	6.74	System-wide SubLAP RDRR	30 minutes
Capacity Bidding Program (CBP)	8.44	System-wide SubLAP PDR	>30 Minutes
Peak Day Pricing (PDP)	0	System-wide PDR	>30 Minutes
Smart Energy Program	8.97	System-wide PDR	>30 Minutes
DRAM	15.7		>30 Minutes
Total	**39.85**		

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

The following factors will be applied to the DR projections to account for avoided distribution losses.

Table 3.8-2: Factors to Account for Avoided Distribution Losses

	PG&E	SCE	SDG&E
Distribution loss factors	1.097	1.051	1.071

3.8.3 Energy Storage

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

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

Table 3.8-3: IOU Existing and Proposed Energy Storage Procurement[34]

Pacific Gas and Electric					
	Target	**On-Line Storage**	**Approved, Some are in Progress**	**Pending Approval**	**Total Procured**
Transmission	310	0	567.5	125	692.5
Distribution	185	6.5	10	20	36.5
Customer	85	26.1	0	20	46.1
Southern California Edison					
	Target	**On-Line Storage**	**Approved, Some are in Progress**	**Pending Approval**	**Total Procured**
Transmission	310	20	100	0	120
Distribution	185	56	65.5	10	131.5
Customer	85	110	195	0	305
San Diego Gas & Electric					
	Target	**On-Line Storage**	**Approved, Some are in Progress**	**Pending Approval**	**Total Procured**
Transmission	80	40	39	0	79
Distribution	55	43.6	13.5	0	57.1
Customer	30	30	0	0	30
Total - All IOUs	1325	332.2	990.5	175	1497.7

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

To be modeled in the TPP base study cases, the ISO needs to know the locations and operational attributes of energy storage resources. The CPUC staff is in the process of collecting the most recent information about procured storage resources and will provide that information to the ISO when it is finished compiling that data. The ISO will then use that information to map storage resources to specific locations and model operations, all of which is expected to be documented in the ISO's study results. As an example of the data that CPUC staff will be updating, the list of procured storage resources that was provided to the ISO in early 2018 is posted to the CPUC website[35].

The following table includes battery energy storage system projects that were approved by the CPUC in response to Resolution E-4949, issued to eliminate or reduce the need for California ISO-issued backstop contracts for three natural gas-fired generation plants.

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

[35] http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/Combined_IOU_Storage_2017update_public.xlsx

Table 3.8-5: CPUC-Approved PG&E Contracts for Storage to Replace Natural Gas-Fired Generation in Northern California[36]

Project	Size (MW)	Term (Years)	On-Line Date
Vistra Moss Landing	300	20	12/1/2020
Hummingbird	75	15	12/1/2020
mNOC AERS	10	10	10/1/2019
Tesla Moss Landing	182.5	20	12/31/2020

If the energy storage project has a two-hour depth then it is de-rated by 50% in order to convert its MW into the amount of capacity actually counting towards RA (since by RA rules output must be sustained for minimum four hours. If a storage unit is discharged and charged at the same power level, it will be assumed it takes the unit 1.2 times as long to charge as it does to discharge. For example, a 50 MW unit with 4 hours of storage will be assumed to take 4.8 hours to charge.

3.8.4 Energy Storage Charging

Energy storage will be modeled in charging mode in shoulder peak and nighttime off-peak reliability cases. Reliability analysis will be performed using these base cases to identify potential operational limitations associated with charging of energy storage facilities. It is assumed that the energy storage facilities will follow the CAISO market dispatch instructions for both charging and discharging. Therefore, necessary corrective action plans will likely be limited to operational procedures for reliability issues driven by charging of energy storage facilities. Also, it doesn't provide a guarantee that energy storage can charge under such system conditions. If an energy storage facility wants the flexibility to charge at any time with low risk of being subject to possible curtailment during the charging cycle, then it should seek such service through the PTO load interconnection process.

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

3.9 Major Path Flows and Interchange

Power flow on the major internal paths and paths that cross Balancing Authority boundaries represents the transfers that will be modeled in the study. Firm Transmission Service and Interchange represents only a small fraction of these path flows, and is clearly included. In general, the northern California (PG&E) system has 4 major interties with the outside system and southern California. Table 3.9-1 lists the capability and power flows that will be modeled in each scenario on these paths in the northern area assessment[37].

Table 3.9-1: Major Path flows in northern area (PG&E system) assessment[38]

Path	Transfer Capability/SOL (MW)	Scenario in which Path will be stressed
Path 26 (N-S)	4000[39]	Summer Peak
PDCI (N-S)	3220[40]	
Path 66 (N-S)	4800[41]	
Path 15 (N-S)	-5400[42]	Spring Off Peak
Path 26 (N-S)	-3000	
Path 66 (N-S)	-3675	Winter Peak

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

Similarly, Table 3.9-2 lists major paths in southern California along with their current Transfer Capability (TC) or System Operating Limit (SOL) for the planning horizon and the target flows to be modeled in the southern California assessment.

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

38 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)

39 May not be achievable under certain system loading conditions.

40 Current operational limit is 3210 MW.

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

42 May not be achievable under certain system loading conditions

Table 3.9-2: Major Path flows in southern area (SCE and SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Near-Term Target Flows (MW)	Scenario in which Path will be stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
PDCI (N-S)	3220[43]	3220	
West of River (WOR)	11,200	5,000 to 11,200	Summer Peak
East of River (EOR)	10,100	4,000 to 10,100	Summer Peak
San Diego Import	2,850	2,400 to 3,500	Summer Peak
SCIT	17,870	15,000 to 17,870	Summer Peak
Path 45 (N-S)	408	0 to 250	Summer Peak
Path 45 (S-N)	800	0 to 300	Off Peak

3.10 Operating Procedures

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

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

[43] Current operational limit is 3210 MW.

3.11 Study Scenario

3.11.1 Base Scenario

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

Generation:

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

Demand Level:

Since most of the ISO 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 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 3.11-1 lists the studies that will be conducted in this planning cycle.

Path flows:

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

The base scenarios for the reliability analysis are provided in Table 3.11-1

Table 3.11-1: Summary of Base Scenario Studies in the ISO Reliability Assessment

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2021	2024	2029
Northern California (PG&E) Bulk System	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak Winter Off-Peak
Humboldt	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter peak
North Valley	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Central Valley (Sacramento, Sierra, Stockton)	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF & Peninsula) Spring Off-Peak	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Kern	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak Spring Off-Peak	Summer Peak Winter Peak
Southern California Bulk transmission system	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Metro Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Northern Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE North of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE East of Lugo Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SCE Eastern Area	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SDG&E main transmission	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
SDG&E sub-transmission	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak
Valley Electric Association	Summer Peak Spring Off-Peak	Summer Peak Spring Off-Peak	Summer Peak

3.11.2 Baseline Scenario Definitions and Renewable Generation Dispatch for System-wide Cases[44]

Table 3.11-2: Baseline Scenario Definitions and Renewable Generation Dispatch

PTO	Scenario	Day/Time (PST)			BTM-PV			Transmission Connected PV			Transmission Connected Wind			% of managed peak load		
		2021	2024	2029	2021	2024	2029	2021	2024	2029	2021	2024	2029	2021	2024	2029
PG&E	Summer Peak	7/22 HE 18	7/2 HE 19	See CAISO	17%	3%	See CAISO	10%	2%	See CAISO	83%	70%	See CAISO	100%	100%	See CAISO
PG&E	Spring Off Peak	4/3 HE 13	4/6 HE 13	See CAISO	80%	81%	See CAISO	100%	98%	See CAISO	55%	2%	See CAISO	34%	29%	See CAISO
PG&E	Winter Off peak			11/10 HE 4			0%			0%			3%			54%
PG&E	Winter peak	12/13 HE 19	12/9 HE 19	12/10 HE 19	0%	0%	0%	0%	0%	0%	16%	2%	9%	75%	76%	75%
SCE	Summer Peak	9/7 HE 16	9/3 HE 16	9/4 HE 19	44%	44%	0%	56%	52%	0%	62%	36%	54%	100%	100%	100%
SCE	Spring Off Peak	4/4 HE 12	5/3 HE 20		80%	0%		99%	0%		52%	46%		33%	69%	
SDG&E	Summer Peak	9/1 HE 19	9/4 HE 19	9/5 HE 19	0%	0%	0%	0%	0%	0%	0%	72%	22%	100%	100%	100%
SDG&E	Spring Off Peak	4/10 HE 13	5/3 HE 20		79%	0%		79%	0%		78%	80%		27%	69%	
VEA	Summer Peak	9/3 HE 16	9/7 HE 16	9/4 HE 19	44%	44%	0%	52%	56%	0%				100%	100%	100%
VEA	Spring Off Peak	4/4 HE 12	5/3 HE 20		80%	0%		99%	0%					33%	69%	

PTO	Scenario	Day/Time (PST)	BTM-PV			Transmission Connected PV			Transmission Connected Wind			% of managed peak load		
		2029	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE
CAISO	Summer Peak	9/4 HE 19	0%	0%	0%	0%	0%	0%	93%	54%	22%	93%	100%	97%
CAISO	Spring Off Peak	4/7 HE 13	80%	81%	79%	100%	98%	98%	55%	54%	22%	21%	26%	17%

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

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

3.11.3 Sensitivity Studies

In addition to the base scenario studies that the ISO will be assessing in the reliability analysis for the 2019-2020 transmission planning process, the ISO will also be conducting sensitivity studies identified in Table 3.11-3. The sensitivity studies are to assess impacts of changes to specific assumptions on the reliability of the transmission system. These sensitivity studies include impacts of load forecast, generation dispatch, generation retirement and transfers on major paths.

Table 3.11-3: Summary of Sensitivity Studies in the ISO Reliability Assessment

Sensitivity Study	Near-term Planning Horizon		Long-Term Planning Horizon
	2021	2024	2029
Summer Peak with high CEC forecasted load	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-
Off peak with heavy renewable output and minimum gas generation commitment	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-
Summer Peak with heavy renewable output and minimum gas generation commitment	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-	-
Summer Peak with high SVP forecasted load			PG&E Greater Bay Area
Summer Peak with high forecasted load	VEA Area	VEA Area	
Summer Off peak with heavy renewable output		VEA Area	
Retirement of QF Generations	-	-	PG&E Local Areas

3.11.4 Sensitivity Scenario Definitions and Renewable Generation Dispatch

Table 3.11-4: Sensitivity Scenario Definitions and Renewable Generation Dispatch

PTO	Scenario	Starting Baseline Case	BTM-PV		Transmission Connected PV		Transmission Connected Wind		Comment
			Baseline	Sensitivity	Baseline	Sensitivity	Baseline	Sensitivity	
PG&E	Summer Peak with high CEC forecasted load	2024 Summer Peak	3%	3%	2%	2%	70%	70%	Load increased by turning off AAEE
PG&E	Off peak with heavy renewable output and minimum gas generation commitment	2024 Spring Off-peak	81%	99%	98%	99%	2%	64%	Solar and wind dispatch increased to average of 20% exceedance values
PG&E	Summer Peak with heavy renewable output and minimum gas generation commitment	2021 Summer Peak	17%	99%	10%	99%	83%	83%	Solar and wind dispatch increased to 20% exceedance values
PG&E	Retirement of QF Generations	2029 Summer Peak	3%	3%	2%	2%	82%	82%	All QF facilities in local areas turned off
PG&E	Summer Peak with high SVP forecasted load	2029 Summer Peak	3%	3%	2%	2%	82%	82%	Use SPV's forecast for 2029
SCE	Summer Peak with high CEC forecasted load	2024 Summer Peak	44%	44%	56%	56%	62%	62%	Load increased per CEC high load scenario
SCE	Off peak with heavy renewable output and minimum gas generation commitment	2024 Spring Off-peak	0%	91%	0%	99%	46%	67%	Solar and wind dispatch increased to 20% exceedance values with net load unchanged at 69% of summer peak
SCE	Summer Peak with heavy renewable output and minimum gas generation commitment	2021 Summer Peak	44%	91%	52%	99%	36%	67%	Solar and wind dispatch increased to 20% exceedance values
SDG&E	Summer Peak with high CEC forecasted load	2024 Summer Peak	0%	0%	0%	0%	72%	72%	Load increased per CEC high load scenario
SDG&E	Off peak with heavy renewable output and minimum gas generation commitment	2024 Spring Off-peak	0%	96%	0%	96%	80%	80%	Solar dispatch increased to 20% exceedance values with net load unchanged at 69% of summer peak
SDG&E	Summer Peak with heavy renewable output and minimum gas generation commitment	2021 Summer Peak	79%	96%	79%	96%	78%	78%	Solar dispatch increased to 20% exceedance values
VEA	Summer Peak with high forecasted load	2021 Summer Peak	44%	44%	52%	52%	-	-	Load increase reflect future load service request
VEA	Summer Peak with high forecasted load	2024 Summer Peak	44%	44%	56%	56%	-	-	Load increase reflect future load service request
VEA	Off-peak with heavy renewable output	2024 Spring Off-peak	80%	80%	99%	99%	-	-	Model portfolio projects expected to be in-service by 2024

3.12 Study Base Cases

The power flow base cases from WECC will be used as the starting point of the ISO transmission plan base cases. Table 3.12-1 shows WECC base cases will be used to represent the area outside the ISO control area for each study year. For dynamic stability studies, the latest WECC Master Dynamics File (from January 9, 2019) will be used as a starting point. Dynamic load models will be added to this file.

Table 3.12-1: Summary of WECC Base Cases used to represent system outside ISO

Study Year	Season	WECC Base Case
2021	Summer Peak	19HS3a1
	Winter Peak	20HW1a1
	Spring Off-Peak	21LSP1a1
2024	Summer Peak	24HS2a1
	Winter Peak	24HW2a1
	Spring Off-Peak	24HW2a1
2029	Summer Peak	29HS1a1
	Winter Peak	29HW1a1
	Spring Off-Peak	28LSP1
	Winter Off-Peak	29HSP1Sa1

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

The ISO will identify known or expected outages of generation or transmission facilities within the planning horizon, which begins January 1, 2020, with a duration of at least six months and will provide list of such outages in the Final Study Plan. Based on information obtained from PTOs, generation owners and other entities along with relevant data from the ISO Outage Management System (OMS). Planned outages applicable to 2021, 2024 and 2029 will be modeled in the corresponding base cases in the current planning cycle. Outages applicable to non-study years will be modeled in future planning cycles.

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

Table 3.12-2 provides known[45] or expected outages of generation or transmission facilities in the planning horizon, which begins January 1, 2020, with a duration greater than or close to six months based on information obtained from PTOs, generation owners and other entities along with relevant data from the ISO Outage Management System (OMS). Planned outages applicable to 2021, 2024 and 2029 will be modeled in the corresponding base cases in the current planning cycle. Outages applicable to non-study years will be modeled in future planning cycles as shown.

Table 3.12-2: Known or expected outages of generation and transmission facilities in the planning horizon with a duration greater than or close to six months[46]

Outage ID	PTO Area	Facility affected	Change to be modeled in base case	Base cases in which outage will be modeled, if applicable
6558659	PGE	Caribou PH 1	Unit out of service	2021 Spring cases
N/A	SCE	Devers–Vista #2 230 kV line	WOD Project	2021 Summer Peak and Off-peak cases
4573451	SCE	Exxon Company USA Unit 1 & 2 (Goleta_6_EXGEN)	Plant out of service	All cases

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

3.13 Contingencies

In addition to the system under normal conditions (P0), the following categories of contingencies on the BES equipment will be evaluated as part of the study. For the non-BES facilities under ISO operational control, as mentioned in section 3.1.3, TPL-001-4 categories P0, P1 and P3 contingencies will be evaluated. These contingencies lists will be made available on the ISO 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)[47][48]
- Loss of one transmission circuit (P1.2)

[45] TPL-001-4 Requirement R1 section 1.1.2

[46] Planned outages are subject to change.

[47] Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.

[48] All generators with nameplate rating exceeding 20 MVA must be included in the contingency list

- 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)[49]
- Loss of one transmission circuit (P3.2)
- Loss of one transformer (P3.3)
- Loss of one shunt device (P3.4)
- Loss of a single pole of DC lines (P3.5)

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

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

Multiple contingency (Category P5)
The assessment will consider the Category P5 contingencies with delayed fault clearing due to the failure of a non-redundant relay 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)

[49] Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.

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[50] (P7.1)
- Loss of a bipolar DC lines (P7.2)

Extreme contingencies (TPL-001-4)

As a part of the planning assessment the ISO assesses Extreme Event contingencies per the requirements of TPL-001-4; 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.

3.14 Study Tools

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

3.14.1 Technical Studies

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

3.14.2 Steady State Contingency Analysis

The ISO will perform power flow contingency analyses based on the ISO Planning Standards[51] which are based on the NERC reliability standards and WECC regional criteria for all local areas studied in the ISO controlled grid and with select contingencies outside of the ISO controlled grid. The transmission system will be evaluated under normal system conditions NERC Category P0

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

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

(TPL 001-4), against normal ratings and normal voltage ranges, as well as emergency conditions NERC Category P1-P7 (TPL 001-4) contingencies against emergency ratings and emergency voltage range as identified in Section 4.1.6.

Depending on the type and technology of a power plant, several G-1 contingencies represent an outage of the whole power plant (multiple units)[52]. 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 potential cascade tripping that may occur when protective relay settings limit transmission load ability.

3.14.3 Post Transient Analyses

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

3.14.3.1 *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.

3.14.3.2 *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.

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

3.14.4 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 ISO 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.

3.14.5 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 ISO 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.

3.15 Corrective Action Plans

Corrective action plans will be developed to address reliability concerns identified through the technical studies mentioned in the previous section. The ISO 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 ISO, 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 ISO 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 ISO might consider developing corrective action plan for deficiencies identified in sensitivity studies on a case by case basis.

4 Policy Driven RPS Transmission Plan Analysis

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

4.1 Public Policy Objectives

The revised TPP created a category of transmission additions and upgrades to enable the ISO 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 ISO'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 2019-2020 planning cycle, the overarching public policy objective is the state's mandate for meeting renewable energy targets and greenhouse gas (GHG) reduction target by 2030 as described in Senate Bill (SB) 350 as well as in Senate Bill (SB) 100. For purposes of the TPP study process, this high-level objective is comprised of two sub-objectives: first, to support the delivery of renewable energy over the course of all hours of the year, and second, to support Resource Adequacy (RA) deliverability status for the renewable resources identified in the portfolio as requiring that status.

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

4.2 Renewable portfolios to be analyzed for policy-driven assessment

In order to provide a general planning direction to the electric sector, the CPUC is expected to adopt a portfolio of energy resources to meet this 2030 GHG reduction target. The proposed decision[53] issued by the CPUC on March 18, 2019 includes recommendations regarding the resource portfolio(s) for the CPUC to recommend to the ISO to utilize in the 2019-2020 TPP.

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[53] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M272/K614/272614400.PDF

The CPUC staff generated the “policy-driven base” portfolio and “policy-driven sensitivity” portfolios using RESOLVE capacity expansion model. The final portfolios are posted to the CPUC’s website at - http://www.cpuc.ca.gov/General.aspx?id=6442460548.

The “Reliability and Policy-Driven Base Case”[54] portfolio summarizes the new build portfolio being modeled in the CAISO's 2019-20 TPP reliability and policy-driven base case.

The “Policy-Driven Sensitivity Cases”[55] portfolios summarize the new build portfolio being modeled in the CAISO's 2019-20 TPP policy-driven sensitivity cases. Two sensitivity portfolios include (i) a heavily in-state renewable development future, as well as (ii) one based on reliance on out-of-state wind, primarily in Wyoming and New Mexico.

The “base” portfolio is expected to correspond to a statewide electric sector GHG reduction target of 42 million metric tons (MMT) by 2030 as set forth in Senate Bill (SB) 350. The two “sensitivity” portfolios are expected to be designed to satisfy the Senate Bill (SB) 100 requirements of 60 percent RPS by 2030 and achieve a deeper GHG reduction target by 2030, at the statewide electricity emissions level of 32 MMT in the electric sector. The sensitivity portfolios will test the transmission implications of a more aggressive GHG reduction target.

The CPUC staff generated the “base” and “sensitivity” portfolios using RESOLVE capacity expansion model. RESOLVE documentation specifies that renewable resources under development with CPUC-approved contracts with the three investor-owned utilities are assumed to be part of the baseline assumptions. The ISO will work with the CPUC to identify such resources and model these in the reliability assessment base cases. The ISO may supplement this scenario with information regarding contracted RPS resources that are under construction as of March 2019. The generic resources selected as portfolio resources are usually at a geographic scale that is too broad for transmission planning purpose which requires specific interconnection locations. The allocation[56] of these resources in the portfolios to substations on the CAISO-controlled transmission grid was conducted by land-use experts at the CEC. The ISO will use this allocation information to model the portfolio resources in the study process.

4.3 Coordination with Phase II of GIP

According to tariff Section 24.4.6.5 and in order to better coordinate the development of potential infrastructure from transmission planning and generation interconnection processes the ISO 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.

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54 http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/IRP_TPP_ReliabilityAndPolicyBaseCase_ToBePosted.xlsx

55 http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/IRP_TPP_PolicySensitivityCases_ToBePosted.xlsx

56 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-MISC-03

Generator Interconnection Network Upgrade Criteria for TPP Assessment

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

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

Notification of Network Upgrades being assessed in the TPP

In approximately June of 2019 the ISO will publish the list of generator interconnection Network Upgrades that meet at least one of these criteria and have been selected for consideration in TPP Phase 2. The comprehensive Transmission Plan will contain the results of the ISO's evaluation of the identified Network Upgrades. Network Upgrades evaluated by the ISO 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 ISO 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 ISO protected web-site for stakeholder review. Study results and recommendations from these cases will be incorporated in the comprehensive transmission plan.

Transmission Planning Deliverability

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

5 Economic Planning Study

The ISO 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 ISO ratepayers based on Transmission Economic Assessment Methodology (TEAM). Through the evaluation of the congestion and other benefits, and review of the study requests, the ISO will determine the high priority studies to be conducted during the 2019-2020 transmission planning cycle.

5.1 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 will be developed 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 2028 (the 10th planning year) through production simulation, and for year 2023(the 5th planning year) as optional, which is needed for providing a data point in the energy benefit assessment for transmission project economic justification.

5.2 Local Capacity Areas

The ISO undertook in the 2018-2019 transmission planning process a comprehensive review of alternatives to reduce or eliminate local capacity area requirements for gas-fired generation in 22 areas and sub-areas. The assessment of the remaining local capacity areas and sub-areas will be completed as a continuation of the 2018-2019 planning cycle.

Subsequent recommendations for approval of the identified transmission upgrades will be based on the results of the economic assessments.

5.3 Study Request

As part of the requirements under the ISO tariff and Business Practice Manual, Economic Planning Study Requests were to be submitted to the ISO during the comment period following the stakeholder meeting to discuss this Study Plan. The ISO will consider the Economic Planning Study Requests as identified in section 24.3.4.1 of the ISO Tariff. Table 5.3.1 includes the Economic Planning Study Requests that were submitted for this planning cycle.

Table 5.3.1 Economic study requests

No.	Study Request	Submitted By	Location
1	Lake Elsinore Advanced Pumped Storage Project (“LEAPS”)[57]	Nevada Hydro Company	Southern California
2	California Transmission Project (CTP)[58]	Cal Energy Development Company, LLC	Northern/Southern California
3	GLW/VEA service area transmission upgrade	Gridliance West	Southern Nevada
4	Boardman to Hemingway 500 kV transmission project (B2H)	Idaho Power	Northwest (Oregon/Idaho)
5	SWIP-North	LS Power	Idaho/Nevada
6	Red Bluff to Mira Loma 500 kV line	NextEra Energy Resources (NEER)	Southern California
7	North Gila Imperial Valley #2 (NGIV2)	NGIV2, LLC	Arizona/California
8	Fresno Avenal area upgrade (Gates-Tulare Lake 70 kV line)	PG&E	Northern California

6 Frequency Response Assessment

The ISO has conducted studies into frequency response and headroom requirements for potential over-supply conditions in the 2014-2015, 2015-2016, 2016-2017 and 2018-2019 transmission planning processes. The study results indicated acceptable frequency performance within WECC; however the ISO’s frequency response may fall below the ISO frequency response obligation specified in NERC reliability standard BAL-003-1. While these initial studies were conducted as special studies – optional studies not required by the ISO tariff – these will now be conducted as an ongoing study requirement supporting mandatory standards efforts.

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

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

[57] The submission was received in response to the ISO December 17, 2018 Market Notice for stakeholder input on demand response assumptions and generation or other non-transmission alternatives for consideration in the draft unified planning assumptions and 2019-2020 study plan. Please refer to section 3.8. The link to the market notice is: http://www.caiso.com/Documents/StakeholderInput-2019-2020UnifiedPlanningAssumptions.html

[58] Same as previous footnote above.

7 Local Capacity Requirement Assessment

7.1 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 ISO 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 ISO "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:

- 2020 – Local Capacity Area Technical Study
- 2024 – Mid-Term Local Capacity Requirements

Studies will be performed using assumptions set forth in the Local Capacity Requirements Final Study Manual[59].

Please note that in order to meet the CPUC deadline for capacity procurement by CPUC-jurisdictional load serving entities, the ISO will complete the LCR studies approximately by May 1, 2019.

7.2 Long-Term Local Capacity Requirement Assessment

Based on the alignment[60] of the ISO transmission planning process with the CEC Integrated Energy Policy Report (IEPR) demand forecast and the CPUC Integrated Resource Plan (IRP), the long-term LCR assessment is to take place every two years. The long-time LCR study was performed in the 2018-2019 Transmission Plan and therefore the 2019-2020 transmission planning process will not include a 10 year out study. The ISO undertook in the 2018-2019 transmission planning process a comprehensive review of alternatives to reduce or eliminate local capacity area requirements for gas-fired generation in 22 areas and sub-areas. The assessment of the remaining local capacity areas and sub-areas will be completed as a continuation of the 2018-2019 planning cycle.

[59] http://www.caiso.com/Documents/2020LocalCapacityRequirementsFinalStudyManual.pdf

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

8 Long-Term Congestion Revenue Rights (LT CRR)

The ISO is obligated to ensure the continuing feasibility of Long Term CRRs (LT-CRRs) that are allocated by the ISO over the length of their terms. As such, the ISO, 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 ISO 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 ISO 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 ISO, 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 ISO tariff.

9 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 ISO Transmission Plan-related Stakeholder meetings, stakeholders may contact these individuals directly for any further questions or clarifications.

Table 9-1: SMEs for Technical Studies in 2019-2020 Transmission Planning Process

Item/Issues	SME	Contact
Reliability Assessment in PG&E	Binaya Shrestha	bshrestha@caiso.com
Reliability Assessment in SCE	Nebiyu Yimer	nyimer@caiso.com
Reliability Assessment in SDG&E	Frank Chen	fchen@caiso.com
Reliability Assessment in VEA	Meng Zhang	mzhang@caiso.com
33% RPS Transmission Plan Analysis	Sushant Barave	sbarave@caiso.com
Local Capacity Requirements	Catalin Micsa	cmicsa@caiso.com
Economic Planning Study	Yi Zhang	yzhang@caiso.com
Long-term Congestion Revenue Rights	Bryan Fong	bfong@caiso.com

10 Stakeholder Comments and ISO Responses

Stakeholders are hereby requested to submit their comments to:

regionaltransmission@caiso.com

All the comments the ISO receives from stakeholders on this 2019-2020 draft study plan and ISO's responses will be posted to the following link:

http://www.caiso.com/planning/Pages/TransmissionPlanning/2019-2020TransmissionPlanningProcess.aspx

APPENDIX A: System Data

A1 Existing Generation

Table A1-1: Existing generation plants in PG&E planning area

Planning Area	Generating Plant	Installed Capacity
PG&E - Humboldt	Humboldt Bay	166
	Kekawaka	4.9
	LP Samoa	25
	Fairhaven	17.3
	Blue Lake	12
	Humboldt Area Total	**225**
PG&E - North Coast and North Bay	Santa Fe	160
	Bear Canyon	20
	Westford Flat	30
	Western Geo	38
	Geysers 5	53
	Geysers 6	53
	Geysers 7	53
	Geysers 8	53
	Geysers 11	106
	Geysers 12	106
	Geysers 13	133
	Geysers 14	109
	Geysers 16	118
	Geysers 17	118
	Geysers 18	118
	Geysers 20	118
	SMUD Geo	72
	Potter Valley	11
	Geo Energy	20

Planning Area	Generating Plant	Installed Capacity
	Indian Valley	3
	Sonoma Landfill	6
	Exxon	54
	Monticello	12
	North Coast and North Bay Area Total	**1564**
PG&E - North Valley	Pit River	752
	Battle Creek	17
	Cow Creek	5
	North Feather River	736
	South Feather River	123
	West Feather River	26
	Black Butte	11
	CPV	717
	Hatchet Ridge Wind	103
	QFs	353
	North Valley Area Total	**2,843**
PG&E - Central Valley	Wadham	27
	Woodland Biomass	25
	UC Davis Co-Gen	4
	Cal-Peak Vaca Dixon	49
	Wolfskill Energy Center	60
	Lambie, Creed and Goosehaven	143
	EnXco	60
	Solano	100
	High Winds	200
	Shiloh	300
	Bowman Power House	4

Planning Area	**Generating Plant**	**Installed Capacity**
	Camp Far West (SMUD)	7
	Chicago Park Power House	40
	Chili Bar Power House	7
	Colgate Power House	294
	Deer Creek Power House	6
	Drum Power House	104
	Dutch Plat Power House	49
	El Dorado Power House	20
	Feather River Energy Center	50
	French Meadow Power House	17
	Green Leaf No. 1	73
	Green Leaf No. 2	50
	Halsey Power House	11
	Haypress Power House	15
	Hellhole Power House	1
	Middle Fork Power House	130
	Narrows Power House	66
	Newcastle Power House	14
	Oxbow Power House	6
	Ralston Power House	83
	Rollins Power House	12
	Spaulding Power House	17
	SPI-Lincoln	18
	Ultra Rock (Rio Bravo-Rocklin)	25
	Wise Power House	20
	Yuba City Co-Generation	49
	Yuba City Energy Center	61

Planning Area	Generating Plant	Installed Capacity
	Altamont Co-Generation	7
	Camanche Power House	11
	Co-generation National POSDEF	44
	Electra Power House	101
	Flowind Wind Farms	76
	GWF Tracy Peaking Plant	192
	Ione Energy	18
	Lodi CT	25
	Lodi Stigg	57
	Pardee Power House	29
	Salt Springs Power House	42
	San Joaquin Co-Generation	55
	Simpson Paper Co-Generation	50
	Stockton Co-Generation (Air Products)	50
	Stockton Waste Water Facility	2
	Thermal Energy	21
	Tiger Creek Power House	55
	US Wind Power Farms	158
	West Point Power House	14
	Lodi Energy Center	280
	GWF Tracy Expansion	145
	Beardsley Power House	11
	Donnells Power House	68
	Fiberboard (Sierra Pacific)	6
	Melones Power Plant	119
	Pacific Ultra Power Chinese Station	22
	Sand Bar Power House	15

Planning Area	Generating Plant	Installed Capacity
	Spring Gap Power House	7
	Stanislaus Power House	83
	Stanislaus Waste Co-gen	24
	Tullock Power House	17
	Central Valley Area Total	**3,970**
PG&E - Greater Bay Area	Alameda Gas Turbines	51
	Calpine Gilroy I	182
	Crockett Co-Generation	240
	Delta Energy Center	965
	Marsh Landing	774
	Russell City – East Shore EC	640
	High Winds, LLC	162
	Los Esteros Critical Energy Facility	362
	Los Medanos Energy Center	678
	Mariposa Peaker	200
	Metcalf Energy Center	575
	Oakland C Gas Turbines	165
	Donald Von Raesfeld Power Plant	164
	Riverview Energy Center	61
	Ox Mountain	13
	Gateway Generating Station	599
	Greater Bay Area Total	**5,831**
PG&E - Greater Fresno Area	Fresno Cogen-Agrico	79.9
	Adams_E	19
	Adera Solar	20
	Alpaughn_20S	20
	Alpaughn_50S	50

Planning Area	Generating Plant	Installed Capacity
	Atwell	20
	Avenal	6
	Balch 1 PH	31
	Balch 2 PH	107
	Bulld 12	2.8
	Blackwell Solar	3
	Mendota Biomass Power	25
	Cantua	20
	Chow 2 Peaker Plant	52.5
	Chevron USA (Coalinga)	25
	Chow II Biomass to Energy	12.5
	CID Solar	20
	Citizen Solar B	5
	Coalinga Cogeneration Company	46
	CalPeak Power – Panoche LLC	49
	Crane Valley	0.9
	Corcoran PB	20
	Corcoran City	11
	Dinuba Generation Project	13.5
	El Nido Biomass to Energy	12.5
	EE Kettleman Land	20
	Exchequer Hydro	94.5
	Fresno Waste Water	9
	Friant Dam	27.3
	Fresno Solar West & South	3
	GWF Henrietta Peaker Plant	109.6
	Gates_Dist	30

Planning Area	Generating Plant	Installed Capacity
	Giffen_Dist	10
	Guernsey_Dist	20
	HEP Peaker Plant Aggregate	102
	Hanford L.P.	23
	Hass PH Unit 1 &2 Aggregate	146.2
	Helms Pump-Gen	1,212
	J.R. Wood	10.8
	Jgbswlt	2.9
	Kansas	40
	Kent	20
	Kerkhoff PH1	32.8
	Kerkhoff PH2	142
	Kingsburg Cogen	34.5
	Kings River Hydro	51.5
	Kings River Conservation District	112
	Liberty V Lost Hills	20
	Madera	28.7
	McCall	2.5
	McSwain Hydro	10
	Merced Falls	4
	Merced Solar	1.5
	Mission Solar	1.5
	Morelos Del Sol	15
	North Star Solar 1	60
	O'Neill Pump-Gen	11
	Panoche Energy Center	410
	Pine Flat Hydro	189.9

Planning Area	Generating Plant	Installed Capacity
	Quinto Solar PV	107.6
	Sanger Cogen	67.5
	Sandrag	19
	San Joaquin 2	3.2
	San Joaquin 3	4.2
	Schindler	30
	Starwood Panoche	121.8
	Stroud	20
	Stratford	20
	Suncity	20
	SUN Harvest Solar	1.5
	Rio Bravo Fresno (AKA Ultrapower)	26.5
	Vega Solar	20
	Wellhead Power Gates, LLC	49
	Wellhead Power Panoche, LLC	49
	Westlands	38
	Westlands Solar Farm	18
	Wishon/San Joaquin #1-A Aggregate	20.4
	2097 Helton	1.5
	Greater Fresno Area Total	**4,316**
PG&E - Kern Area	Badger Creek (PSE)	49
	Chalk Cliff	48
	Cymric Cogen (Chevron)	21
	Cadet (Chev USA)	12
	Dexzel	33
	Discovery	44
	Double C (PSE)	45

Planning Area	Generating Plant	Installed Capacity
	Elk Hills	623
	Frito Lay	8
	Hi Sierra Cogen	49
	Kern	177
	Kern Canyon Power House	11
	Kernfront	49
	Kern Ridge (South Belridge)	76
	La Paloma Generation	926
	Midsun	25
	Mt. Poso	56
	Navy 35R	65
	Oildale Cogen	40
	Bear Mountain Cogen (PSE)	69
	Live Oak (PSE)	48
	McKittrick (PSE)	45
	Rio Bravo Hydro	11
	Shell S.E. Kern River	27
	Solar Tannenhill	18
	Sunset	225
	North Midway (Texaco)	24
	Sunrise (Texaco)	338
	Sunset (Texaco)	239
	Midset (Texaco)	42
	Lost Hills (Texaco)	9
	University Cogen	36
	New RPS Units	55
	Kern Area Total	**3,543**

Planning Area	Generating Plant	Installed Capacity
PG&E - Central Coast and Los Padres	Moss Landing Power Plant	1,020
	Soledad Energy	10
	Basic Energy Cogen (King City)	133
	King City Peaker	70
	Sargent Canyon Cogen (Oilfields)	45
	Salinas River Cogen (Oilfields)	45
	Diablo Canyon Power Plant	2,400
	Union Oil (Tosco)	6
	Santa Maria	8
	Vandenberg Air Force Base	15
	Topaz	550
	California Valley Solar	250
	Central Coast and Los Padres Area Total	**4,552**

Table A1-2: Existing generation plants in SCE planning area

Planning Area	Generating Plant	Installed Capacity
SCE - Tehachapi and Big Creek Corridor	Big Creek 1-1 Gen 1	19.9
	Big Creek 1-1 Gen 2	21.6
	Big Creek 1-2 Gen 3	21.6
	Big Creek 1-2 Gen 4	31.2
	Big Creek 2-1 Gen 1	50.8
	Big Creek 2-1 Gen 2	52.0
	Big Creek 2-2 Gen 3	18.7
	Big Creek 2-2 Gen 4	19.7
	Big Creek 2-3 Gen 5	17.0
	Big Creek 2-3 Gen 6	18.5
	Big Creek 3-1 Gen 1	35.0
	Big Creek 3-1 Gen 2	35.0
	Big Creek 3-2 Gen 3	35.0
	Big Creek 3-2 Gen 4	41.0
	Big Creek 3-3 Gen 5	39.0
	Big Creek 4 Gen 41	50.4
	Big Creek 4 Gen 41	50.6
	Big Creek 8 Gen 81	24.4
	Big Creek 8 Gen 81	44.0
	Eastwood	207.0
	Mamoth 1G	93.5
	Mamoth 2G	93.5
	Portal	9.6
	Warne 1	38.0
	Warne 2	38.0
	Pandol 1	56.0

Planning Area	Generating Plant	Installed Capacity
	Pandol 2	56.0
	Ultragen	41.0
	Omar 1G	90.8
	Omar 2G	90.8
	Omar 3G	90.8
	Omar 4G	90.8
	SYCCYN 1G	75.0
	SYCCYN 2G	75.0
	SYCCYN 3G	75.0
	SYCCYN 4G	75.0
	Pastoria Energy Facility	770.0
	Manzana Wind Project	189.0
	Pacific Wind Project	140.0
	Coram Brodie Wind Project Expansion	51.0
	Coram Brodie Wind Project Phase 2	51.0
	Alta 2012	720.0
	CPC Alta Wind 4-5 (fka CPC East)	420.0
	CPC Alta Wind 1-3 (fka CPC West)	600.0
	Windstar I Alternate	120.0
	Eastwind	60.0
	Westwind	21.0
	Tehachap	114.4
	WNDT167	120.0
	North Sky River Wind	170.0
	Sky River	76.9
	Catalina Solar	150.0
	KR 3-1	22.8

Planning Area	Generating Plant	Installed Capacity
	KR 3-2	21.5
	LakeGen	18.0
	Wellhead Power Delano	49.9
	Kawgen	18.0
	Avenue	310.0
	Kingsbird	270.0
	AV Solar 1	249.0
	Arbwind	21.8
	Canwind	65.0
	Enwind	47.1
	Encawind	112.9
	Flowind	40.8
	Dutchwind	14.0
	Northwind	19.4
	Oakwind	21.1
	Southwind	13.4
	Zondwind	26.0
	Breeze	12.5
	Midwind	18.0
	Morwind	56.0
	Kern River	24.0
	Borel	10.0
	Alta Vista Suntower Generating Station	66.0
	Antelope Power Plant	20.0
	Down	20.0
	Twilight	20.0
	Antelope Valley PV1	318.5

Planning Area	Generating Plant	Installed Capacity
	Antelope Valley PV2	285.0
	Rising Tree	198.8
	Western Antelope Blue Sky Ranch A	20.0
	First Solar North Rosamond	100.8
	AV Solar Ranch 2-A	20.4
	AV Solar Ranch 2-B	20.4
	RE Astoria	181.1
	RE Camelot	45.0
	RE Columbia	15.0
	TA Acacia	20.0
	SGS Antelope Valley	300.0
	North Rosamond	156.2
	Tehachapi and Big Creek Corridor Total	**8,410.9**
SCE - East of Lugo Area	Desert Star Energy Star	506
	Mountain Pass - Ivanpah Solar	392
	Copper Mountain Solar I	58
	Copper Mountain Solar II	155
	East of Lugo Area Total	**1,111**
SCE - North of Lugo	ALBAG1	140
	BLM E7G	24
	BLM E8G	24
	BLM W9G	19.5
	BORAX I	22
	BSPHYD26	14.18
	BSPHYD34	15.9
	BLM E7G	24
	CALGEN	92.2

Planning Area	Generating Plant	Installed Capacity
	CSA DIABLO 1	15
	CSA DIABLO 2	10
	High Desert Power Plant	854.9
	KERRMGEE	15
	LUNDY	3
	LUZ (8 & 9)	160
	NAVYII4G	22.5
	NAVYII5G	22.5
	NAVYII6G	22.5
	OCASOG2	140
	OXBOW G1	49.8
	POOLE	10.9
	RUSH	11.5
	SEGS 1G	14.2
	SEGS 2G	43.8
	SUNGEN	150
	North of Lugo Area Total	**1,897**
SCE - Eastern Area	Blythe Energy Center	520
	Indigo Peaker	136
	Cabazon Wind	42.6
	Mountainview IV Wind	42
	Wintec 5 Wind	3.7
	Wintec 6 Wind	45
	Pacificorp Wind	2.1
	FPLE Green 1 Wind	8.7
	FPLE Green 2 Wind	3.0
	FPLE Green 3 Wind	6.8

Planning Area	Generating Plant	Installed Capacity
	Wintec 2 Wind	16.5
	Wintec 3 Wind	11.6
	Wintec 4 Wind	16.5
	Seawest 1 Wind	44.4
	Seawest 2 Wind	22.2
	Seawest 3 Wind	22.4
	Renwind Wind	9.0
	Whitewater Wind	66
	Altamesa 4 Wind	40
	Painted Hills Wind	16.9
	Altwind QF 1	32.9
	Altwind QF 2	15.1
	Buchwind QF	17
	Capwind QF	20
	Garnet QF Wind	101.4
	Panaero Wind	30
	Renwind QF 1	6.3
	Renwind QF 2	6.6
	Sanwind QF 1	3.0
	Sanwind QF 2	28.0
	Seawind QF	27
	Terawind QF	22.5
	Transwind QF	40.0
	Venwind QF 1	25.5
	Venwind QF 2	19.3
	CPV Sentinel Peaker	850
	Genesis Solar Energy Project	250

Planning Area	Generating Plant	Installed Capacity
	Desert Sunlight PV Project	550
	McCoy Photovoltaic Project[61]	126.16
	Windustries	9.8
	Edom Hills Wind Farm	20
	Karen Avenue Wind Farm	11.7
	Eastern Area Total	**3,287.66**
SCE Metro Area	Agua Mansa Generating Facility	43
	Alamitos	2,010
	Anaheim CT	41
	AP North Lake Solar	20
	Barre Peaker	45
	Berry Petroleum Placerita	37
	BP West Coast Products	21
	Broadway 3	65
	Calabasas Gas-to-Energy Facility	7
	Canyon Power Plant	195
	Carson Cogeneration Company	47
	Center Area Lumped Units	18
	Center Peaker	45
	Century	36
	Chevron CIC	170.7
	Chiquita Canyon Landfill Generating Facility	7
	City Of Long Beach	28
	Clearwater Power Plant	28
	Corona Energy Partners, Ltd.	30

[61] This project is partially operational at 126.16 MW, with a total capacity of 250 MW

Planning Area	Generating Plant	Installed Capacity
	County Of Los Angeles (Pitchess Honor Ranch)	19
	Coyote Canyon	6
	Devil Canyon	235
	Drews	36
	E. F. Oxnard, Incorporated	34
	El Segundo Energy Center	570
	Ellwood Generating Station	54
	Etiwanda 3 & 4	640
	Etiwanda Hydro Recovery Plant	10
	Foothill Hydro Recovery Plant	8
	Glen Arm Power Plant	132
	Grapeland Peaker	43
	H. Gonzales Gas Turbine	12
	Harbor Cogen Combined Cycle	100
	Houweling Nurseries Oxnard CHP	13.2
	Huntington Beach 1 & 2	452
	Inland Empire Energy Center	670
	L.A. County Sanitation District #2 (Puente Hills B)	47
	Long Beach 1 – 4	260
	Malburg Generating Facility	134
	Mira Loma Peaker	43
	MM West Coast Covina, LLC	6
	Mojave Siphon PH	18
	Mountainview Power Plant	969
	MWD Perris Hydroelectric Recovery Plant	8
	O.L.S. Energy Company- Chino-Mens Inst.	25

Planning Area	Generating Plant	Installed Capacity
	Ormond Beach	1,516
	Procter & Gamble Paper Prod. (Oxnard II)	46
	Redondo	1,356
	Ripon Cogeneration	27
	Riverside Energy Resource Center (RERC)	194
	San Dimas Hydro Recovery Plant	8
	Springs Generation Plant	36
	SPVP044	8
	Sunshine Gas Producers, L.L.C.	20
	Tequesquite Landfill Solar Project	7.5
	Walnut Creek Energy Park	500
	Watson Cogeneration	406
	Weyerhaeuser Company (Formerly Williamette Industries)	13
	Multiple smaller facilities	85.5
	Metro Area Total	**11,661**

Table A1-3: Existing generation plants in SDG&E planning area

Planning Area	Generating Plant	Installed Capacity
SDG&E	Otay Mesa GT1	185.1
	Otay Mesa GT2	185.1
	Otay Mesa ST1	233.5
	Larkspur Border 1	46.0
	Larkspur Border 2	46.0
	Cabrillo	3.1
	Capistrano	5.3
	Carlton Hills	1.6
	Carlton Hills	0.3
	Chicarita	3.7
	Border/Calpeak	48.0
	El Cajon/Calpeak	45.4
	Escondido/Calpeak	48.0
	East Gate	0.3
	MMC-Electrovest (Escondido)	49.5
	Palomar_CT1	162.4
	Palomar_CT2	162.4
	Palomar_ST	240.8
	Goalline	38.4
	Mesa Heights	3.6
	Miramar 1	48.0
	Miramar 2	47.9
	Mission	0.7
	Otay Landfill I	2.8
	Otay Landfill II	2.6

Planning Area	Generating Plant	Installed Capacity
	Covanta Otay 3	3.5
	MMC-Electrovest (Otay)	35.5
	Orange Grove 1	50.0
	Orange Grove 2	50.0
	Sampson	1.0
	San Marcos Landfill	0.7
	El Cajon Energy Center	48.1
	Lake Hodges Pumped Storage 1	20.0
	Lake Hodges Pumped Storage 2	20.0
	BREGGO SOLAR (NQC)	26.0
	Kumeyaay	50.0
	East County	155.0
	Ocotillo Express	265.0
	El Cajon GT	13.0
	Ash	0.9
	Rancho Santa Fe 1	0.4
	Rancho Santa Fe 2	0.3
	Murray	0.2
	Kyocera	0.1
	TERMEX_2_PL1X3	280.1
	TERMEX_2_PL1X3	156.4
	TERMEX_2_PL1X3	156.4
	LAROA2_2_UNITA1	145.2
	LAROA2_2_UNITA1	176.8
	ENERSJ_2_WIND	256
	OCTILO_5_WIND	132.5

Planning Area	Generating Plant	Installed Capacity
	OCTILO_5_WIND	132.5
	BUE GEN	200
	BR GEN1	25.8
	DU GEN1 G1	83.2
	DU GEN1 G2	70.4
	ECO GEN2	20
	DW GEN2 G1	206.7
	DW GEN2 G2	150.3
	DW GEN2 G3A	147.2
	DW GEN2 G3B	105.1
	DW GEN3&4	129.2
	DW GEN3&4	45.6
	SDG&E Area Total	**4,970**

Table A1-4: Existing generation plants in VEA planning area

Planning Area	Generating Plant	Maximum Capacity
VEA	Community Solar (WDAT)	15
	VEA Area Total	**15**

A2 Once-through Cooled Generation

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

Generating Facility	Owner	Existing Unit/ Technology[62] (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[63] (MW) and Technology[64] (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	

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

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

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

Generating Facility	Owner	Existing Unit/ Technology[62] (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[63] (MW) and Technology[64] (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	2025	1122	PG&E plans to replace with renewable energy, energy efficiency and energy storage.	N/A	On June 21, 2016, PG&E has announced that it planned to retire Units 1 and 2 by 2024 and 2025, respectively.
		2 (ST)	12/31/2024	2025	1118			
Mandalay	GenOn	1 (ST)	12/31/2020	2/6/2018	215	Retired (no repowering)		Mandalay generating facility was retired on February 6, 2018.
		2 (ST)	12/31/2020	2/6/2018	215	SCE plans to replace with renewable energy and storage		
Ormond Beach	GenOn	1 (ST)	12/31/2020		741	To be retired (no repowering)	N/A	
		2 (ST)	12/31/2020		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	12/31/2019	175	640 MW CCGT on the same property	4/1/2020	
		2 (ST)	12/31/2020	12/31/2019	175			
		3 (ST)	12/31/2020	12/31/2020	332			
		4 (ST)	12/31/2020	12/31/2020	336			
		5 (ST)	12/31/2020	12/31/2020	498			
		6 (ST)	12/31/2020	12/31/2019	495			
Huntington Beach	AES	1 (ST)	12/31/2020	10/31/2019	226	644 MW CCGT on the same property	3/1/2020	
		2 (ST)	12/31/2020	12/31/2020	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
		4 (ST)	12/31/2020	11/1/2012	227			

Generating Facility	Owner	Existing Unit/ Technology[62] (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[63] (MW) and Technology[64] (approved by the CPUC and CEC)	In-Service Date for CPUC and CEC-Approved Repowering Resources	Notes
								December 31, 2017, these two synchronous condensers were retired.
Redondo Beach	AES	5 (ST)	12/31/2020		179	To be retired	N/A	
		6 (ST)	12/31/2020		175			
		7 (ST)	12/31/2020	10/31/2019	493			
		8 (ST)	12/31/2020		496			
San Onofre Nuclear Generating Station	SCE/ SDG&E	2 (ST)	12/31/2022	June 7, 2013	1122	Retired (no repowering)	N/A	
		3 (ST)	12/31/2022		1124			
Encina	NRG	1 (ST)	12/31/2017	3/1/2017	106	500 MW (5 GTs or peakers) Carlsbad Energy Center, located on the same property as the Encina Power Plant.	12/11/2018	The State Water Resources Control Board approved extension of compliance date for Units 2 through 5 to December 31, 2018 due to delay of in-service date for Carlsbad Energy Center. Encina Units 2 – 5 were retired on December 11, 2018.
		2 (ST)	12/31/2017	12/31/2018 [65]	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)

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

A3 Planned Generation

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

PTO Area	Project	Capacity (MW)	First Year to be Modeled
SCE	Huntington Beach Energy Project Unit 6 (CCGT) *	644	2021
	Alamitos Energy Center Unit 8 (CCGT) *	640	2021

Notes:

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

A4 Retired Generation

Table A4-1: Generation (non-OTC) projected to be retired in planning horizon[66]

PTO Area	Generating Facility	Capacity (MW)	First Year to be retired
SCE	Ellwood[67]	54	January 1, 2021

Table A4-2: list of generators in SCE, SDG&E and PG&E areas that will be older than 40 years by 2029

Generating Unit Name / Description	Nameplate Capacity (MW)	COD
SCE Area		
ARCOGN_2_UNITS	417	Dec-87
CHINO_6_CIMGEN	26	Dec-87
CHINO_6_SMPPAP	44	Nov-85
ETIWND_2_UNIT1	34	Sep-63
GLNARM_7_Unit_1	22	Jan-76
GLNARM_7_Unit_2	22	Jan-76
GOLETA_6_ELLWOD	54	Aug-74
GOLETA_6_GAVOTA	10	Jan-87
OMAR_2_Unit_1	78	May-85
OMAR_2_Unit_2	78	May-85
OMAR_2_Unit_3	81	May-85
OMAR_2_Unit_4	81	May-85
SAUGUS_6_PTCHGN	29	Jul-88
SYCAMR_2_Unit_1	85	Jan-87
SYCAMR_2_Unit_2	85	Jan-87
SYCAMR_2_Unit_3	85	Jan-87
SYCAMR_2_Unit_4	85	Jan-87
VERNON_6_GONZL1	6	Jan-33
VERNON_6_GONZL2	6	Jan-33
SDG&E Area		
None		

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

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

Generating Unit Name / Description	Nameplate Capacity (MW)	COD
PG&E Area		
ALMEGT_1_Unit_1	23.4	Jan-86
ALMEGT_1_Unit_2	23.5	Jan-86
BASICE_2_UNITS	120	Mar-89
CHEVCD_6_UNIT	11.5	Jul-82
CHEVCO_6_Unit_1	16.5	Jan-86
CHEVCO_6_Unit_2	8.5	Jun-88
CHEVCY_1_UNIT	24.3	Oct-82
CLRMTK_1_QF	1.25	Dec-83
CSCCOG_1_Unit_1	7	Jan-81
CSCGNR_1_Unit_1	24.75	Jan-87
CSCGNR_1_Unit_2	24.75	Jan-86
DISCOV_1_CHEVRN	48.8	Jun-88
DOUBLC_1_UNITS	52.23	Mar-89
FRITO_1_LAY	6	Jan-86
GILROY_1_UNIT	120	Jan-87
GRNLF1_1_UNITS	49.2	Nov-89
GRNLF2_1_UNIT	49.5	Oct-89
GRZZLY_1_BERKLY	26.35	May-87
KERNFT_1_UNITS	52.4	Jan-89
LODI25_2_Unit_1	23.8	Jan-86
OROVIL_6_UNIT	7.5	Dec-89
SIERRA_1_UNITS	52.43	Feb-89
SMPRIP_1_SMPSON	46.05	Apr-88
SRINTL_6_UNIT	6.9	Mar-87
STAUFF_1_UNIT	4.6	Jun-77
SUNSET_2_UNITS	248	Dec-89
TANHIL_6_SOLART	17	Jan-86
UNOCAL_1_UNITS	49.85	May-87
VEDDER_1_SEKERN	34.47	Jan-89
OAK C_7_UNIT 1	55	Jan-78
OAK C_7_UNIT 2	55	Jan-78
OAK C_7_UNIT 3	55	Jan-78
UNCHEM_1_UNIT	11	Jan-83
IBMCTL_1_UNIT_1	50	Jan-84

A5 Reactive Resources

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

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

A6 Special Protection Schemes

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

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

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

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

PTO	Area	SPS Name
SCE	Antelope-Bailey	Antelope-RAS
	Big Creek Corridor	Big Creek / San Joaquin Valley RAS
	North of Lugo	Bishop RAS
	North of Lugo	High Desert Power Project RAS
	North of Lugo	Kramer RAS
	Antelope-Bailey	Midway-Vincent RAS
	Antelope-Bailey	Lancaster N-2 Line Loss Tripping Scheme
	Antelope-Bailey	Palmdale N-2 Line Loss Tripping Scheme
	Antelope-Bailey	Pastoria Energy Facility Existing RAS
	North of Lugo	Reliant Energy Cool Water Stability Tripping Scheme
	Eastern Area	West-of-Devers Remedial Action Scheme
	Eastern Area	Colorado River Corridor SPS
	Eastern Area	Inland Empire Area RAS
	Eastern Area	Blythe Energy RAS
	Eastern Area	Eagle Mountain Thermal Overload Scheme
	Metro Area	El Nido N-2 Remedial Action Scheme
	Metro Area	Mountain view Power Project Remedial Action Scheme
	Metro Area	South of Lugo N-2 Remedial Action Scheme
	Metro Area	Mira Loma Low Voltage Load Shedding
	Metro Area	Santiago N-2 Remedial Action Scheme

PTO	Area	SPS Name
	Metro Area	Valley Direct Load Trip Remedial Action Scheme
	Metro Area	El Segundo N-2 Remedial Action Scheme

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

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