2020-2021
TRANSMISSION PLAN

California ISO

March 17, 2021
Revised Draft

Foreword to Revised Draft 2020-2021 Transmission Plan

This revised draft transmission plan reflects a number of changes from the draft plan released on February 1, 2021. To assist our stakeholders following the transmission plan cycle, a few changes were made as summarized below:

- Updated tables in Chapter 3 with the deliverable study amounts and interconnection service capacity values for those area deliverability constraints that had not been identified.
- Updated section 8.5 with the forecast of CAISO high voltage transmission access charge trended from first year of transmission.

A number of clarifications and edits have also been added throughout the plan.

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Executive Summary

The California Independent System Operator Corporation's 2020-2021 Transmission Plan provides a comprehensive evaluation of the CAISO transmission grid to address grid reliability requirements, identify upgrades needed to successfully meet California's policy goals, and explore projects that can bring economic benefits to consumers. In doing so, the plan relies heavily on key inputs from state agencies in translating legislative policy into actionable policy-driven inputs.

This plan is updated annually, and culminates in an CAISO Board of Governors (Board) approved transmission plan that identifies the needed transmission solutions and authorizes cost recovery through CAISO transmission rates, subject to regulatory approval, as well as identifying non-transmission solutions that will be pursued in other venues as an alternative to building additional transmission facilities. It is prepared in the larger context of supporting important energy and environmental policies while maintaining reliability through a resilient electric system.

The transmission plan is developed through a comprehensive stakeholder process and relies heavily on coordination with key energy state agencies – the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) – for key inputs and assumptions regarding electricity demand side forecast assumptions as well as supply side development expectations. Both remain critical, building on past transmission planning efforts, as integrated resource planning considerations need to focus not only on accessing renewable generation but also accessing the necessary integration resources to effectively operate the grid in a future of high volumes of renewable generation, and distributed energy resources and shifting customer needs necessitate a high degree of coordination in supply side and demand side forecasting.

The focus of each year's transmission planning efforts is recalibrated each year to reflect the status of a range of issues at that time. The aggressive pace of the electric power industry transformation in California continues to set the context for the CAISO's annual transmission plan, and also the progress made in previous transmission planning processes to identify and address needs proactively. Key trends in this year's transmission plan include the following:

- Load forecast growth continues to remain relatively flat, resulting in part from continued statewide emphasis on energy efficiency and behind-the-meter generation. Also, there has been no material increase in the pace of retirement of non-renewable generation as these resources continue to play a role in renewable integration and overall supply sufficiency in periods of low renewable generation output. As a result, transmission expansion planning needs continue to remain relatively modest overall given past efforts at addressing emerging reliability needs;
- The CAISO's policy-driven transmission studies were based on a 60 percent RPS policy base portfolio provided by the CPUC, together with sensitivity portfolios based on higher approximately 71 percent – RPS levels. Consistent with past studies, this transmission planning cycle did not reveal the need for major transmission expansion to achieve the 60 percent RPS goal set out in SB 100 for 2030. Sensitivities performed at higher –

approximately 71 percent – RPS levels are demonstrating increased likelihood for reinforcement needs, with specifics depending upon the ultimate portfolio development in future CPUC integrated resource planning efforts;

- This planning cycle provided the first opportunity to fully explore the impacts of a number of major study and process changes, including criteria and model refinements, that were developed through the course of the 2019-2020 planning cycle. These changes were advanced to address emerging issues as well as issues identified through the extensive core and special study work undertaken in the 2018-219 planning cycle, and included refinements to renewable generation pricing and curtailment models, energy storage dispatch modeling, local capacity technical study criteria, deliverability criteria for system and local resources, and a methodology for ensuring adequacy of transmission availability for resources providing flexible capacity needs. In particular, the enhanced deliverability methodology is providing new and updated information helpful the CPUC in developing future renewable generation portfolios for future transmission planning cycles.
- A number of studies that were initially developed on an exploratory basis, and documented as "special studies" in the past have since transitioned to being included in each year's transmission plans as "other studies" outside of the CAISO's tariff-based requirements but nonetheless critical to addressing evolving and future concerns. This includes frequency response studies and the newly adopted flexible generation capacity deliverability analysis. Given this re-categorization, the CAISO did not undertake any additional "special studies" in this year's planning cycle.
- The longer term requirements for gas-fired generation for system and flexible capacity requirements continue to be examined in the CPUC integrated resource planning processes, and the indications are that the gas-fired generation fleet – with the exception of the planned retirement of those relying on coastal waters for one-through-cooling – will be relied upon for the foreseeable future for those purposes. Accordingly, the conservative approach employed in the 2018-2019 and 2019-2020 transmission planning cycles for assigning a value to upgrades potentially reducing local gas-fired generation capacity requirements has also been employed in this planning cycle;
- The CAISO continued its more extensive comprehensive analysis of potential mitigations to eliminate or materially reduce local capacity requirement dependence on gas-fired generation. In the 2018-2019 and 2019-2020 planning cycles, the CAISO undertook a more in-depth analysis of local capacity requirements, including consideration of potential alternatives to eliminate or materially reduce local capacity requirement needs. In the CAISO's annual local capacity technical study process conducted in early 2020, the CAISO also examined charging capabilities in local capacity areas, to explore the possibility of using energy storage to reduce reliance on gas-fired generation to meet local capacity requirements. Building on both of those efforts, the CAISO undertook in this planning cycle a more comprehensive analysis to assess the alternatives to materially reduce or eliminate reliance on gas-fired generation considering both

transmission and storage opportunities, although this work was undertaken recognizing that it is largely informational for the reasons set out above;

- The CASIO, as part of this planning cycle, conducted studies to assess impact of various PSPS scenarios in the PG&E area. The objective of this assessment was to identify load at risk and potential system reliability risks under various PSPS scenarios developed and to develop potential mitigations to alleviate impact of future PSPS events from long-term planning perspective. No opportunities for transmission projects to reasonably mitigate the impacts of PSPS events have been identified. The CAISO will continue to coordinate with PG&E to evaluate mitigation options within the utilities' wildfire mitigation plan to be able to exclude the high impact facilities identified from the future PSPS events and continue to assess need for the similar assessment in other parts of the system in future planning cycles.
- Four interregional transmission projects were submitted to the CAISO in this, the first year of the biennial interregional coordination process the CAISO has established with our neighboring planning regions and the "intake" year for new interregional transmission projects to be proposed. Following the submission and successful screening of the ITP submittals, the CAISO coordinated its ITP evaluation with the other relevant planning regions; NorthernGrid and WestConnect. None of the projects were selected through the interregional coordination process with the CAISO's neighboring planning regions for further review in the second year of the biennial process.; and,
- Overall, the 2019-2020 Transmission Plan includes a very modest increase in new reliability needs, continued refinement of modeling and study capabilities for meeting future challenges and issues, and study methodology refinements to inform future transmission planning processes, including CPUC integrated resource planning issues. The CAISO's continuing efforts to increase opportunity for non-transmission alternatives, particularly preferred resources and storage, will remain a key focus of the transmission planning analysis.

Our comprehensive evaluation of the areas listed above resulted in the following key findings:

- The CAISO identified 3 transmission projects with an estimated cost of less than 5 million as needed to maintain transmission system reliability;
- In reviewing previously approved projects in the PG&E service territory that were identified in the last planning cycle as needing more review, two projects will continue to be on hold. The need for both of these projects can be met wholly or largely by appropriately located battery resources that are otherwise needed for system capacity purposes according to the CPUC-provided resource portfolios. Accordingly, the CAISO will work with the CPUC and load serving entities to seek to have the battery storage located to meet these needs as well as serving system capacity purposes.
- Consistent with past studies of transmission system capabilities to achieve RPS levels beyond 33 percent, no policy-driven transmission was considered for approval in this planning cycle to achieve 60 percent RPS goal established in SB 100, and sensitivities have been undertaken at higher, up to 71 percent RPS levels, identifying potential

reinforcement needs subject to resource location considerations in future CPUC integrated resource planning efforts;

- No economic-driven transmission projects are recommended for approval in this planning cycle;
- The CAISO tariff sets out a competitive solicitation process for eligible reliability-driven, policy-driven and economic-driven regional transmission facilities found to be needed in the plan. No transmission projects in this transmission plan include facilities eligible for competitive solicitation through the CAISO's competitive solicitation process.

Progress also continued in this planning cycle, continuing and completing the work initiated in the 2018-2019 Transmission Plan and 2019-2020 Transmission Plan, in exploring issues emerging as the generation fleet continues to transform as the state pursues greenhouse gas reduction goals.

Summaries of the transmission planning process and some of the key collaborative activities with the CPUC and the CEC are provided below. This is followed by additional details on each of the key study areas and associated findings described above.

The Transmission Planning Process

The transmission plan primarily identifies three main categories of transmission solutions: reliability, public policy and economic needs. The plan may also include transmission solutions needed to maintain the feasibility of long-term congestion revenue rights, provide a funding mechanism for location-constrained generation projects or provide for merchant transmission projects. The CAISO also considers and places a great deal of emphasis on the development of non-transmission alternatives, both conventional generation and in particular, preferred resources such as energy efficiency, demand response, renewable generating resources and energy storage programs. Though the CAISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive plan, these can be identified as the preferred mitigation in the same manner that operational solutions are often selected in lieu of transmission upgrades. Further, load modifying preferred resource assumptions are also incorporated into the load forecasts adopted through state energy agency activities that the CAISO supports, and provide an additional opportunity for preferred resources to address transmission needs.

The transmission planning process is defined by three distinct phases of activity that are completed in consecutive order across a time frame called a planning cycle. The planning cycle begins in January of each year, with the development of the study plan – phase 1. Phase 2, which includes the technical analysis, selection of solutions and development of the transmission plan for approval by the CAISO Board of Governors, extends beyond a single year and concludes in March of the following year. If Phase 3 is required, engagement in a competitive solicitation for prospective developers to build and own new transmission facilities identified in the Board-approved plan, it takes place after the March approval of the plan. This results in the initial development of the study plan and assumptions for one cycle to be well underway before the preceding cycle has concluded, and each transmission plan being referred to by both the year it commenced and the year it concluded. The 2019-2020 planning cycle, for example, began in January 2019 and the 2019-2020 Transmission Plan was approved in March 2020.

Planning Assumptions and State Agency Coordination

The 2020-2021 planning assumptions and scenarios were developed through the annual agency coordination process the CAISO, CEC and CPUC have in place and performed each year to be used in infrastructure planning activities in the coming year. This alignment effort continues to improve infrastructure planning coordination within the three core processes:

- Long-term forecasts of energy demand produced by the CEC as part of its biennial Integrated Energy Policy Report (IEPR),
- Biennial integrated resource planning (IRP) proceedings conducted by the CPUC, replacing the previous long term procurement plan (LTPP) proceedings, and
- Annual transmission planning processes performed by the CAISO.

In this coordination effort, the agencies considered assumptions such as demand, supply and system infrastructure elements, and the RPS generation portfolios proposed by the CPUC.

The CPUC's input was communicated via a decision[1] adopting a portfolio designed to ensure that the electric sector is on track to help the State achieve its statewide 2030 greenhouse gas (GHG) reduction target established through SB 350 at least cost while maintaining electric service reliability and meeting other State goals, and also meeting 60 percent electric industry-specific RPS goals established in the more recent SB 100. This portfolio, based on a statewide electricity sector target of 46 MMT in 2030, was also used for economic study purposes. Anticipating higher renewable generation requirements going forward, the CPUC communicated sensitivity portfolios achieving higher – up to 71 percent – RPS levels that were tied to a statewide electricity sector target of 30 MMT in 2030.

These assumptions were further vetted by stakeholders through the CAISO's stakeholder process which resulted in this year's study plan.[2]

The CAISO considers the agencies' successful effort coordinating the development of the common planning assumptions to be a key factor in promoting the CAISO's transmission plan as a valuable resource in identifying grid expansion necessary to maintain reliability, lower costs or meet future infrastructure needs based on public policies.

[1] Decision 20-03-028 released on March 26, 2020 which, for the purposes of the CAISO 2020-21 transmission planning cycle, recommended (a) the 2017-2018 Preferred System Portfolio (PSP) adopted in Decision 19-04-040, with updates to the baseline and some generation locations as detailed in the current decision, as the reliability base case and the policy-driven base case, (b) the 2019-2020 Reference System Portfolio (RSP) adopted in the Decision, with the 46 million metric ton greenhouse gas target in 2030, as a policy-driven sensitivity, and (c) a portfolio based on the 30 million metric ton scenario, to test the impact of energy-only deliverability status for some generators on congestion and curtailment, as a second policy-driven sensitivity. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF

[2] The 2019-2020 Transmission Planning Process Unified Planning Assumptions and Study Plan, April 3, 2019, is available at: http://www.caiso.com/Documents/Final2019-2020StudyPlan.pdf

Key Reliability Study Findings

During the 2020-2021 cycle, CAISO staff performed a comprehensive assessment of the CAISO controlled grid to ensure compliance with applicable NERC reliability standards and CAISO planning standards and tariff requirements. The analysis was performed across a 10-year planning horizon and modeled a range of on-peak and off-peak system conditions. The CAISO's assessment considered facilities across voltages of 60 kV to 500 kV, and where reliability concerns existed, the CAISO identified transmission solutions to address these concerns or assessed the ability of previously approved projects to meet those needs. This plan proposes approving 3 reliability-driven transmission projects representing an investment of less than $5 million in infrastructure additions to the CAISO controlled grid, seven of which are located in the PG&E service territory.

Renewables Portfolio Standard Policy-driven Transmission Assessment

As noted above, the CPUC's input was set out via a decision[3] that provided resource planning assumptions to the CAISO. The CPUC communicated a base portfolio based on its "46 MMT scenario" that results in approximately a 60 percent RPS, and sensitivity portfolios for policy-driven planning efforts.

The CAISO has accordingly performed policy-driven study assessments of the 46 MMT scenario and did not identify any new Category 1 policy-driven transmission needs. The CAISO is not recommending any new transmission solutions at this time for policy purposes.

A summary of the various transmission elements already underway for supporting California's renewables portfolio standard is shown in Table 1.1-1. These elements are composed of the following categories:

- Major transmission projects that have been previously-approved by the CAISO and are fully permitted by the CPUC for construction;
- Additional major transmission projects that the CAISO interconnection studies have shown are needed for access to new renewable resources but are still progressing through the permit approval process; and
- Major transmission projects that have been previously approved by the CAISO but are not yet permitted.

Table 1.1-1: Elements of 2020-2021 CAISO Transmission Plan Supporting 60 Percent Renewable Energy Goals

[3] Decision 20-03-028 released on March 26, 2020 which, for the purposes of the CAISO 2020-21 transmission planning cycle, recommended (a) the 2017-2018 Preferred System Portfolio (PSP) adopted in Decision 19-04-040, with updates to the baseline and some generation locations as detailed in the current decision, as the reliability base case and the policy-driven base case, (b) the 2019-2020 Reference System Portfolio (RSP) adopted in the Decision, with the 46 million metric ton greenhouse gas target in 2030, as a policy-driven sensitivity, and (c) a portfolio based on the 30 million metric ton scenario, to test the impact of energy-only deliverability status for some generators on congestion and curtailment, as a second policy-driven sensitivity. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF

Transmission Facility	In-Service Date
Transmission Facilities Approved, Permitted and Under Construction	
West of Devers Reconductoring	2021
Lugo – Eldorado series cap and terminal equipment upgrade	2022
Lugo-Mohave series capacitors	2022
Wilson-Le Grand 115 kV line reconductoring	2022
Additional Major Network Transmission Identified as Needed in CAISO Interconnection Agreements but not Permitted	
None at this time	
Policy-Driven Transmission Elements Approved but not Permitted	
Warnerville-Bellota 230 kV line reconductoring	2024
Additional Policy-Driven Transmission Elements Recommend for Approval	
None identified in 2020-2021 Transmission Plan	

Key Economic Study Findings

The CAISO's economic planning study is an integral part of the CAISO's transmission planning process and complements the reliability-driven and policy-driven analysis by exploring economic-driven network upgrades that may create opportunities to reduce ratepayer costs within the CAISO. The studies used a production cost simulation as the primary tool to identify potential economic development opportunities and in assessing those opportunities. While reliability analysis provides essential information about the electrical characteristics and performance of the CAISO controlled grid, an economic analysis provides essential information about transmission congestion which is a key input in identifying potential study areas, prioritizing study efforts, and assessing benefits by identifying grid congestion and assessing economic benefits created by congestion mitigation measures. Other end-use ratepayer cost saving benefits such as reducing local capacity requirements in transmission-constrained areas can also provide material benefits. Note that other benefits and risks – which cannot always be quantified – must also be taken into account in the ultimate decision to proceed with an economic-driven project.

In the economic planning analysis performed as part of this transmission planning cycle in accordance with the unified planning assumptions and study plan, approved reliability and policy network upgrades and those recommended for approval in this plan were modeled in the economic planning database. This ensured that the results of the analysis would be based on a transmission configuration consistent with the reliability and public policy results documented in this transmission plan.

Beyond screening congestion results to select key focus areas for detailed economic studies, the CAISO:

- Received a number of economic study requests, which included projects that would more reasonably be categorized as interregional transmission projects;
- Completed an expanded 10-year local capacity technical study examining transmission and storage alternatives to reduce local gas-fired generation capacity requirements, and selected a subset of local capacity areas for detailed economic analysis where options appeared potentially viable.

A number of the above proposals and submissions overlapped, enabling them to be studied in single study areas.

The CAISO's studies were impacted by certain conditions existing in this planning cycle:

- The longer term requirements for gas-fired generation for system and flexible capacity requirements continues to be examined, both in the CPUC integrated resource planning process as well as CAISO studies – studies conducted outside of the annual transmission planning process for purposes of supporting CPUC efforts.
- As the existing gas-fired generation fleet is expected to be needed for system capacity purposes through the foreseeable future, the CAISO continued to take a conservative approach in this planning cycle in assigning a value to upgrades potentially reducing local gas-fired generation capacity requirements.

While the CAISO tariff allows the CAISO to limit the number of economic evaluations to five or less, the CAISO studied 17 areas, sub-areas, and transmission constraints, this entailed consideration of 22 proposals and alternatives in this year's planning cycle.

In summary, no new projects were found to be needed as economic-driven projects in the 2020-2021 planning cycle.

Several paths and related projects will be monitored in future planning cycles to take into account improved WECC wide production cost simulation model, further consideration of suggested changes to CAISO economic modeling, and further clarity on renewable resources supporting California's renewable energy goals.

Interregional Transmission Coordination Process

The CAISO's 2020-2021 transmission planning cycle marked the beginning of the third biennial cycle since interregional coordination processes were put in place addressing the requirements of FERC Order No. 1000.

Four interregional transmission projects were submitted to the CAISO in this "intake" year for new interregional transmission projects to be proposed. Following the submission and successful screening of the ITP submittals, the CAISO coordinated its ITP evaluation with the other relevant planning regions; NorthernGrid and WestConnect. None of the projects were selected through the interregional coordination process with the CAISO's neighboring planning regions for further review in the second year of the biennial process.

Non-Transmission Alternatives and Preferred Resources

The CAISO has routinely emphasized exploring preferred resources[4] and other non-transmission alternatives to conventional transmission to meet emerging reliability needs. Through reliance on existing resources as a matter of course as potential mitigations for identified needs, area-specific studies[5] and continued efforts to refine understanding of the necessary characteristics for resources such as slow response demand response to provide local capacity[6], the CAISO's applications have expanded beyond the CAISO's original methodology[7] set in place some years ago. Further, in the 10-Year Local Capacity Technical Study developed through this planning cycle, , the CAISO provided detailed information regarding the characteristics of the local capacity area needs that are the basis for assessing non-transmission and preferred resource solutions, and studied the benefits that can be achieved by transmission alternatives working in concert with local storage. The CAISO is also continuing to support the implementation of solutions for transmission needs consisting of combinations of transmission reinforcements and procurement of preferred resources in the LA Basin, in Oakland, and the Moorpark sub-area. As noted above, the CAISO has also identified two projects approved in the PG&E service territory that may be wholly or largely replaced with battery storage. Please refer to section 8.2.

Informational Studies

As in past transmission planning cycles, the CAISO undertook additional informational studies to help inform future transmission planning or resource procurement processes. The CAISO has identified the need to perform a number of these studies on an ongoing basis, at least for the foreseeable future, and has therefore documented these studies in the "other studies" in chapter 6, instead of categorizing them as "special studies".

Frequency Response and Dynamic System Modeling

Consistent with the 2018-2019 and 2019-2020 transmission planning cycle, the CAISO undertook frequency response studies and reported on associated modeling improvement efforts as an ongoing study process inside the annual planning cycle despite not being a tariff-based obligation.

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4 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.

5 See generally CEC Docket No. 15-AFC-001, and see "Moorpark Sub-Area Local Capacity Alternative Study," August 16, 2017, available at http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

6 Further analysis of the necessary characteristics for "slow response" demand response programs was undertaken initially through special study work associated with the 2016-2017 Transmission Plan, and the analysis continued into 2017 through a joint stakeholder process with the CPUC. See "Slow Response Local Capacity Resource Assessment California ISO – CPUC joint workshop," presentation, October 4, 2017, http://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf.

7 "Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process," September 4, 2013, http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014TransmissionPlanningProcess.pdf.

Reliance on Gas-fired Generation in Local Capacity Areas

The CAISO continued its more extensive comprehensive analysis of potential mitigations to eliminate or materially reduce local capacity requirement dependence on gas-fired generation. In the 2018-2019 and 2019-2020 planning cycles, the CAISO undertook a more in-depth analysis of local capacity requirements, including consideration of potential alternatives to eliminate or materially reduce local capacity requirement needs. In the CAISO's annual local capacity technical study process conducted in early 2020, the CAISO also examined charging capabilities in local capacity areas, to explore the possibility of using energy storage to reduce reliance on gas-fired generation to meet local capacity requirements. Building on both of those efforts, the CAISO undertook in this planning cycle a more comprehensive analysis to assess the alternatives to materially reduce or eliminate reliance on gas-fired generation considering both transmission and storage opportunities, although this work was undertaken recognizing that it is largely informational, given the current expectations that the existing gas fired generation fleet will be required for the foreseeable future for system capacity requirements.

Flexible Capacity Deliverability Requirements

The CAISO developed a methodology and tested the deliverability of flexible capacity in the 2019-2020 transmission planning cycle, recognizing that the tests applied to ensure deliverability of system capacity may not reflect the conditions and limitations that could constrain the ability of flexible capacity resources to provide ramping when most needed. That methodology was again employed in this planning cycle.

The flexible deliverability test relies on the deliverability assessment and adds new tests to address scenarios not already covered in the deliverability assessment. A testing procedure was developed to monitor the generation pockets for flexible deliverability. However, no study and requirements will be proposed to be considered for enforcement on new generators in the generation interconnection study procedure until 1) it becomes clear how the flexible capacity will be counted, especially for the wind and solar capacity through the FRACMOO2 or follow-up initiative, 2) the revised on-peak and off-peak deliverability methodologies are approved and adopted, and 3) the transmission planning process analysis identifies flexible deliverability constraints. The assessment did not identify any flexible deliverability concerns.

PG&E Area Wildfire Impact Assessment

The CAISO, as part of this planning cycle, conducted studies to assess impact of various PSPS scenarios in the PG&E area. The objective of this assessment was to identify load at risk and potential system reliability risks under various PSPS scenarios developed and to develop potential mitigations to alleviate impact of future PSPS events from long-term planning perspective. The assessment was conducted as a standalone study recognizing that the analysis extends beyond the existing NERC, WECC and CAISO standards and potential mitigations would be advanced as reliability driven projects that could require revisiting CAISO planning standards. No opportunities for transmission projects to reasonably mitigate the impacts of PSPS events have been identified. The CAISO will continue to coordinate with PG&E to evaluate mitigation options within the utilities' wildfire mitigation plan to be able to exclude the high impact facilities identified from the future PSPS events and continue to assess need for the similar assessment in other parts of the system in future planning cycles.

Conclusions and Recommendations

The 2020-2021 Transmission Plan provides a comprehensive evaluation of the CAISO transmission grid to identify upgrades needed to adequately meet California's policy goals, address grid reliability requirements and bring economic benefits to consumers. This year's plan identified 3 transmission projects, estimated to cost a total of less than $5 million, as needed to maintain the reliability of the CAISO transmission system. The CAISO has also identified two previously approved transmission projects that can be wholly or largely replaced by appropriately sited battery storage.

Chapter 1

1 Overview of the Transmission Planning Process

1.1 Purpose

A core CAISO responsibility is to identify and plan the development of solutions to meet the future needs of the CAISO controlled grid. Fulfilling this responsibility includes conducting an annual transmission planning process (TPP) that culminates in an CAISO Board of Governors (Board) approved, comprehensive transmission plan. The plan identifies needed transmission solutions and authorizes cost recovery through CAISO transmission rates, subject to regulatory approval. The plan also identifies non-transmission solutions that will be pursued in other venues to avoid building additional transmission facilities if possible. This document serves as the comprehensive transmission plan for the 2020-2021 planning cycle.

The CAISO has prepared this plan in the larger context of continuing to support important energy and environmental policies and assisting the transition to a cleaner, lower emission future while maintaining reliability through a resilient electric system. This entails not only transitioning to lower emission sources of electricity, but also considering evolving forecasts and expectations being set for transitions in how and when electricity is used. While each year's transmission plan is based on the best available forecast information at the time the plan is prepared, the CAISO considers and adapts to changing forecasts to ensure a cost effective and reliable transmission system meeting the demands placed on it in these rapidly changing times.

Each year's transmission plan is a product of timing, reflecting the particular status of various initiatives and industry changes in the year the plan is developed, as well as the progress in parallel processes to address future needs. The 2020-2021 Transmission Plan is heavily influenced by the success in past transmission planning cycles to address historical reliability issues and greenhouse gas emissions reductions goals as well various state agency processes and proceedings to meet renewable energy targets. It is also heavily influenced by the current direction set for resource planning, and in particular, considerations of forecast increased reliance on energy storage coupled with other resources to meet emerging capacity and energy requirements, in addition to the currently perceived need to maintain much if not all of the existing gas-fired generation fleet over the planning horizon.

The emerging issues and challenges are discussed in more detail in section 1.2 below.

Within this context, the transmission plan's primary purpose is to identify – based on the best available information at the time this plan was prepared – needed transmission facilities based upon three main categories of transmission solutions: reliability, public policy, and economic needs. The CAISO may also identify in the transmission plan any transmission solutions needed to maintain the feasibility of long-term congestion revenue rights, provide a funding mechanism for location-constrained generation projects, or provide for merchant transmission projects. In recommending solutions for identified needs, the CAISO takes into account an array of considerations. Furthering the state's objectives of a cleaner future plays a major part in those considerations.

The CAISO identifies needed reliability solutions to ensure transmission system performance complies with all North American Electric Reliability Corporation (NERC) standards and Western Electricity Coordinating Council (WECC) regional criteria, and CAISO transmission planning standards. The reliability studies necessary to ensure such compliance comprise a foundational element of the transmission planning process. During the 2020-2021 planning cycle, CAISO staff performed a comprehensive assessment of the CAISO controlled grid to verify compliance with applicable NERC reliability standards. The CAISO performed this analysis across a 10-year planning horizon and modeled a range of peak, off-peak, and partial-peak conditions. The CAISO assessed the transmission facilities under CAISO operational control, ranging in voltage from 60 kV to 500 kV. The CAISO also identified plans to mitigate observed concerns considering upgrading transmission infrastructure, implementing new operating procedures, installing automatic special protection schemes, and examining the potential for conventional and non-conventional resources (preferred resources including storage) to meet these needs. Although the CAISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive transmission plan, it can identify them as the preferred mitigation solutions in the same manner that it can opt to pursue operational solutions in lieu of transmission upgrades and work with the relevant parties and agencies to seek their implementation.

This transmission plan documents CAISO analyses, results, and mitigation plans.[8] These topics are discussed in more detail below.

Public policy-driven transmission solutions are those needed to enable the grid infrastructure to support state and federal directives. In recent transmission planning cycles, the focus of public policy analysis has been predominantly on planning to ensure achievement of California's renewable energy goals. The trajectory to achieving the 33 percent renewables portfolio standard set out in the state directive SBX1-2 has essentially been achieved, and this plan focuses on the greenhouse gas emissions reductions objectives set out in Senate Bill (SB) 350[9] and, in particular, the 60 percent RPS by 2030 objective in Senate Bill (SB) 100[10] that became

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8 This document provides detail of all study results related to transmission planning activities. However, consistent with the changes made in the 2012-2013 transmission plan and subsequent transmission plans, the ISO has not included in this year's plan the additional documentation necessary to demonstrate compliance with NERC and WECC standards but not affecting the transmission plan itself. The ISO has compiled this information in a separate document for future NERC/FERC audit purposes. In addition, detailed discussion of material that may constitute Critical Energy Infrastructure Information (CEII) is restricted to appendices that the ISO provides only consistent with CEII requirements. The publicly available portion of the transmission plan provides a high level, but meaningful, overview of the comprehensive transmission system needs without compromising CEII requirements.

9 SB 350, The Clean Energy and Pollution Reduction Act of 2015 (Chapter 547, Statutes of 2015) was signed into law by Governor Jerry Brown on October 7, 2015. Among other provisions, the law established clean energy, clean air, and greenhouse gas (GHG) reduction goals, including reducing GHG to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050. The law also established targets to increase retail sales of qualified renewable electricity to at least 50 percent by 2030, that have now been superseded by the provisions of Senate Bill 100.

10 SB 100, the 100 Percent Clean Energy Act of 2018, also authored by Senator Kevin De León, was signed into law by Governor Jerry Brown on September 10, 2018. Among other provisions, SB 100 built on existing legislation including SB 350 and revised the previously established goals to achieve the 50 percent renewable resources target by December 31, 2026, and to achieve a 60 percent target by December 31, 2030. The bill also set out the state policy that eligible renewable energy resources and zero-carbon

law in September, 2018. Accordingly, the CPUC provided to the CAISO a renewable generation portfolio reflecting approximately 60 percent RPS[11] for reliability, base policy and economic study purposes, and sensitivity portfolios representing up to approximately a 71 percent RPS objective[12] for further policy-driven analysis.

The portfolio provided for reliability, base policy and economic study purposes continues to utilize the 2017-2018 Preferred System Plan developed by the CPUC – with some updates – as the location of too much capacity in the portfolios developed in the 2019-2020 IRP cycle was considered too uncertain to jump directly to transmission investments at this stage with either of those portfolios. The CPUC acknowledged that this inherently separates the transmission investment decisions from the procurement direction given to the LSEs via the adoption of the 2019-2020 Reference System Plan, and that more real-world experience with how and where the LSEs are making investments toward the realization of the 2019-2020 RSP is necessary to have higher confidence in the need for transmission in specific locations to support these generation and storage resources. Portfolios developed in the 2019-2020 IRP proceeding, however, were provided for sensitivity studies. The CAISO expects that the results of the sensitivity studies will be helpful in future CPUC integrated resource planning efforts that will also take into account more aggressive goals aligned with broader GHG reductions.

Economic-driven solutions are those that provide net economic benefits to consumers as determined by CAISO studies, which includes a production simulation analysis. Typical economic benefits include reductions in congestion costs and transmission line losses and access to lower cost resources for the supply of energy and capacity. As renewable generation continues to be added to the grid, with the inevitable economic pressure on other existing resources, economic benefits will also have to take into account cost effective mitigations of renewable integration challenges as well as potential reductions to the generation fleet located in local capacity areas. In the 2018-2019 and 2019-2020 planning cycles, the CAISO undertook a more in-depth analysis of local capacity requirements, including consideration of potential alternatives to eliminate or materially reduce local capacity requirement needs. In the CAISO's annual local capacity technical study process conducted in early 2020, the CAISO also examined charging capabilities in local capacity areas, to explore the possibility of using energy storage to reduce reliance on gas-fired generation to meet local capacity requirements. Building on both of those efforts, the CAISO undertook in this planning cycle a more comprehensive analysis to assess the alternatives to materially reduce or eliminate reliance on gas-fired generation considering both transmission and storage opportunities.

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resources supply 100 percent of retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

[11] Decision 20-03-028 released on March 26, 2020 which, for the purposes of the CAISO 2020-21 transmission planning cycle, recommended (a) the 2017-2018 Preferred System Portfolio (PSP) adopted in Decision 19-04-040, with updates to the baseline and some generation locations as detailed in the current decision, as the reliability base case and the policy-driven base case, (b) the 2019-2020 Reference System Portfolio (RSP) adopted in the Decision, with the 46 million metric ton greenhouse gas target in 2030, as a policy-driven sensitivity, and (c) a portfolio based on the 30 million metric ton scenario, to test the impact of energy-only deliverability status for some generators on congestion and curtailment, as a second policy-driven sensitivity. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF

[12] id.

Accordingly, the 2020-2021 Transmission Plan, and the scope of policy and economic studies in particular, were largely influenced by:

1. Inclusion of a “policy-driven” base case with a 60 percent RPS objective from the CPUC’s 2017-2018 integrated resource planning process and two sensitivity portfolios from the 2019-2020 cycle of the CPUC’s integrated resource planning process.
2. Completing a comprehensive detailed study of local capacity technical requirements considering storage and transmission that could substantially reduce or eliminate gas-fired generation requirements in local capacity areas.
3. The 2020-2021 Transmission Plan being the first year of the two-year interregional coordination planning process, with the first year being the “intake year” in which interregional projects can be proposed by stakeholders for consideration.

Through the course of the 2020-2021 planning cycle, the CAISO also advanced and implemented a number of major study and process changes, including in particular changes to the CAISO’s deliverability assessment framework for system and local resources. The planning cycle also reflects the development of a major mapping exercise for unprecedented volumes of generic storage resources in the sensitivity cases discussed above, with this effort led by the CPUC and supported by the CAISO. The 2020-2021 Transmission Plan also continues with the migration of special studies into a more permanent category of “other studies” in the plan itself, now that the need has been identified to perform these analyses on an annual basis, such as frequency response studies and flexible capacity deliverability analysis.

1.2 Structure of the Transmission Planning Process

The annual planning process is structured in three consecutive phases with each planning cycle identified by a beginning year and a concluding year. Each annual cycle begins in January but extends beyond a single calendar year. For example, the 2019-2020 planning cycle began in January 2019 and concluded in March 2020.

Phase 1 includes establishing the assumptions and models for use in the planning studies, developing and finalizing a study plan, and specifying the public policy mandates that planners will adopt as objectives in the current cycle. This phase takes roughly three months from January through March of the beginning year.

In Phase 2, the CAISO performs studies to identify the solutions to meet the various needs that culminate in the annual comprehensive transmission plan. This phase takes approximately 12 months and ends with Board approval of the transmission plan. Thus, phases 1 and 2 take 15 months to complete. Identifying non-transmission alternatives that the CAISO is relying upon in lieu of transmission solutions also takes place at this time. It is critical that parties responsible for approving or developing those non-transmission alternatives are aware of the reliance being placed on those alternatives.

Phase 3 includes the competitive solicitation for prospective developers to build and own new regional transmission facilities identified in the Board-approved plan. In any given planning cycle, phase 3 may or may not be needed depending on whether the final plan includes regional transmission facilities that are open to competitive solicitation in accordance with criteria specified in the CAISO tariff.

In addition, the CAISO may incorporate into the annual transmission planning process specific transmission planning studies necessary to support other state or industry informational requirements to efficiently provide study results that are consistent with the comprehensive transmission planning process. In this cycle, these focus primarily on grid transformation issues and incorporating renewable generation integration studies into the transmission planning process.

1.2.1 Phase 1

Phase 1 generally consists of developing and completing the annual unified planning assumptions and study plan.

The unified planning assumptions establish a common set of assumptions for the reliability and other planning studies the CAISO performs in phase 2. The starting point for the assumptions is the information and data derived from the comprehensive transmission plan developed during the prior planning cycle. The CAISO adds other pertinent information, including network upgrades and additions identified in studies conducted under the CAISO's generation interconnection procedures and incorporated in executed generator interconnection agreements (GIA). In the unified planning assumptions the CAISO also specifies the public policy requirements and directives that it will consider in assessing the need for new transmission infrastructure.

Development of the unified planning assumptions for this planning cycle benefited from the ongoing coordination efforts between the California Public Utilities Commission (CPUC), California Energy Commission (CEC), and the CAISO, building on the staff-level, inter-agency process alignment forum in place to improve infrastructure planning coordination within the three core processes:

- Long-term forecasts of energy demand produced by the CEC as part of its biennial Integrated Energy Policy Report (IEPR);
- Biennial Integrated Resource Planning (IRP) proceedings conducted by the CPUC; and,
- The Annual Transmission Planning Process (TPP) performed by the CAISO.

That forum resulted in improved alignment of the three core processes and agreement on an annual process to be undertaken in the fall of each year to develop planning assumptions and scenarios to be considered in infrastructure planning activities in the upcoming year. The assumptions include demand, supply, and system infrastructure elements, including the renewables portfolio standard (RPS) portfolios, and are discussed in more detail in section 1.3.

The results of that annual process fed into this 2019-2020 transmission planning process and was communicated via decisions[13] in the 2019-2020 IRP process.

[13] Decision 20-03-028 released on March 26, 2020:
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF

The CAISO added public policy requirements and directives as an element of transmission planning process in 2010. Planning transmission to meet public policy directives is also a national requirement under Federal Energy Regulatory Commission (FERC) Order No. 1000. It enables the CAISO to identify and approve transmission facilities that system users will need to comply with specified state and federal requirements or directives. The primary policy directive for the last number of years' planning cycles has been California's renewables portfolio standard. As discussed later in this section, the CAISO's study work and resource requirements determination for reliably integrating renewable resources is continuing on a parallel track outside of the transmission planning process, but the CAISO has continued to incorporate those requirements into annual transmission plan activities.

The CAISO formulates the public policy-related resource portfolios in collaboration with the CPUC, and with input from other state agencies including the CEC and the municipal utilities within the CAISO balancing authority area. The CPUC, as the agency that oversees the bulk of the supply procurement activities within the CAISO area, plays a primary role formulating the resource portfolios.

The resource portfolios have played a crucial role in identifying needed public policy-driven transmission elements in the past. Meeting the renewables portfolio standard has entailed developing substantial amounts of new renewable generating capacity, which in turn required new transmission for delivery. The CAISO has managed the uncertainty as to where the generation capacity will locate by balancing the need to have sufficient transmission in service in time to support the renewables portfolio standard against the risk of building transmission in areas that do not realize enough new generation to justify the cost of such infrastructure. This has entailed applying a "least regrets" approach, whereby alternative resource development portfolios or scenarios are formulated through the processes described above, then the CAISO identifies the needed transmission to support each portfolio and selects for approval those transmission elements that have a high likelihood of being needed and well-utilized under multiple scenarios.

The study plan describes the computer models and methodologies to be used in each technical study, provides a list of the studies to be performed and the purpose of each study, and lays out a schedule for the stakeholder process throughout the entire planning cycle. The CAISO posts the unified planning assumptions and study plan in draft form for stakeholder review and comment. Stakeholders may request specific economic planning studies to assess the potential economic benefits (such as congestion relief) in specific areas of the grid. The CAISO then selects high priority studies from these requests and includes them in the study plan published at the end of phase 1. The CAISO may modify the list of high priority studies later based on new information such as revised generation development assumptions and preliminary production cost simulation results.

1.2.2 Phase 2

In phase 2, the CAISO performs all necessary technical studies, conducts a series of stakeholder meetings and develops an annual comprehensive transmission plan for the CAISO controlled grid. The comprehensive transmission plan specifies the transmission solutions required to meet the infrastructure needs of the grid, including reliability, public policy, and economic-driven needs. In phase 2, the CAISO conducts the following major activities:

- Performs technical planning studies described in the phase 1 study plan and posts the study results;
- Provides a request window for stakeholders to submit reliability project proposals in response to the CAISO's technical studies, demand response, storage or generation proposals offered as alternatives to transmission additions or upgrades to meet reliability needs, Location Constrained Resource Interconnection Facilities project proposals, and merchant transmission facility project proposals;
- Evaluates and refines the portion of the conceptual statewide plan that applies to the CAISO system as part of the process to identify policy-driven transmission elements and other infrastructure needs that will be included in the final comprehensive transmission plan;
- Coordinates transmission planning study work with renewable integration studies performed by the CAISO for the CPUC integrated resource planning proceeding to determine whether policy-driven transmission facilities are needed to integrate renewable generation, as described in tariff section 24.4.6.6(g);
- Reassesses, as needed, significant transmission facilities starting with the 2011-2012 planning cycle that were in GIP phase 2 cluster studies to determine — from a comprehensive planning perspective — whether any of these facilities should be enhanced or otherwise modified to more effectively or efficiently meet overall planning needs;
- Performs a "least regrets" analysis of potential policy-driven solutions to identify those elements that should be approved as category 1 transmission elements,[14] which is intended to minimize the risk of constructing under-utilized transmission capacity while ensuring that transmission needed to meet policy goals is built in a timely manner;
- Identifies additional category 2 policy-driven potential transmission facilities that may be needed to achieve the relevant policy requirements and directives, but for which final approval is dependent on future developments and should therefore be deferred for reconsideration in a later planning cycle;

[14] In accordance with the least regrets principle, the transmission plan may designate both category 1 and category 2 policy-driven solutions. Using these categories better enables the ISO to plan transmission to meet relevant state or federal policy objectives within the context of considerable uncertainty regarding which grid areas will ultimately realize the most new resource development and other key factors that materially affect the determination of what transmission is needed. Section 24.4.6.6 of the ISO tariff specifies the criteria considered in this evaluation.

- Performs economic studies, after the reliability projects and policy-driven solutions have been identified, to identify economically beneficial transmission solutions to be included in the final comprehensive transmission plan;
- Performs technical studies to assess the reliability impacts of new environmental policies such as new restrictions on the use of coastal and estuarine waters for power plant cooling, which is commonly referred to as once through cooling and AB 1318 legislative requirements for CAISO studies on the electrical system reliability needs of the South Coast Air Basin;
- Conducts stakeholder meetings and provides public comment opportunities at key points during phase 2; and,
- Consolidates the results of the above activities to formulate a final, annual comprehensive transmission plan that the CAISO posts in draft form for stakeholder review and comment at the end of January and presents to the Board for approval at the conclusion of phase 2 in March.

Board approval of the comprehensive transmission plan at the end of phase 2 constitutes a finding of need and an authorization to develop the reliability-driven facilities, category 1 policy-driven facilities, and the economic-driven facilities specified in the plan. The Board's approval enables cost recovery through CAISO transmission rates of those transmission projects included in the plan that require Board approval.[15] As indicated above, the CAISO solicits and accepts proposals in phase 3 from all interested project sponsors to build and own the regional transmission solutions that are open to competition.

By definition, category 2 solutions identified in the comprehensive plan are not authorized to proceed after Board approval of the plan, but are instead re-evaluated during the next annual cycle of the planning process. At that time, based on relevant new information about the patterns of expected development, the CAISO will determine whether the category 2 solutions satisfy the least regrets criteria and should be elevated to category 1 status, should remain category 2 projects for another cycle, or should be removed from the transmission plan.

As noted earlier, phases 1 and 2 of the transmission planning process encompass a 15-month period. Thus, the last three months of phase 2 of one planning cycle will overlap phase 1 of the next cycle, which also spans three months. The CAISO will conduct phase 3, the competitive solicitation for sponsors to compete to build and own eligible regional transmission facilities reflected in the final Board-approved plan.[16]

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[15] Under existing tariff provisions, ISO management can approve transmission projects with capital costs equal to or less than $50 million. The ISO includes such projects in the comprehensive plan as pre-approved by ISO management and not requiring Board approval.

[16] These details are set forth in the BPM for Transmission Planning, https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Transmission%20Planning%20Process.

1.2.3 Phase 3

Phase 3 takes place after Board approves the plan if there are projects eligible for competitive solicitation. Projects eligible for competitive solicitation include regional reliability-driven, category 1 policy-driven, or economic-driven transmission solutions, except for regional transmission solutions that are upgrades to existing facilities. Local transmission facilities are not subject to competitive solicitation.

This requires one clarification in the consideration of storage that may be found to be needed as a transmission asset. Note that the determination of eligibility is made at the end of Phase 2, and before the competition is held. Transmission connected resources are resources that are connected to the CAISO controlled grid, with Regional resources being greater than 200 kV, and Local resources being lower than 200 kV. Storage as a transmission asset may be connected to the transmission system at a level that differs from the transmission issue it has been identified to resolve, just like other transmission assets. For example, the CAISO may identify a Regional need, but identify storage – as a transmission asset - connecting at a Local level as the best solution or as a possible solution. Notwithstanding the treatment for allocation to transmission access charges, the CAISO has consistently interpreted eligibility criteria to be more, not less supportive of competition, and therefore considers a "greenfield" solution such as a storage transmission asset to be eligible for competition if it can be met equally well by a local or regional facility, but is not eligible for competition if only a local facility will meet the need.

If the approved transmission plan includes regional transmission facilities eligible for competitive solicitation, the CAISO will commence phase 3 by opening a window for the entities to submit applications to compete to build and own such facilities. The CAISO will then evaluate the proposals and, if there are multiple qualified project sponsors seeking to finance, build, and own the same facilities, the CAISO will select an approved project sponsor by comparatively evaluating all of the qualified project sponsors based on the tariff selection criteria. Where there is only one qualified project sponsor, the CAISO will authorize that sponsor to move forward to project permitting and siting.

1.3 Key Inputs and Other Influences

Section 1.3 provides background and detail on key inputs into the 2020-2021 transmission planning process, as described in section 1.2 above. In addition to the key study plan inputs received from state agencies described in section 1.2.1 above, the CAISO must address a growing range of considerations to ensure those objectives are enabled and ensure overall safe, reliable, and efficient operation through its planning process. These efforts include the continued growth of renewable generation on the CAISO system, whether grid-connected or behind-the-meter at end customer sites, the phase out of using coastal water for once-through-cooling at thermal generating stations, and a growing range of strategies, policy priority areas, emerging technologies and risks and opportunities to either achieve energy use reductions or impacts on energy consumption. Many of these are no longer stand-alone solutions – they can achieve great outcomes if properly planned and implemented in concert with the right volumes of other mitigations, or fail to provide the expected benefits if implemented in isolation or carelessly.

These trends, including the continued rapid expansion of behind-the-meter solar generation, have created new and more complex operating paradigms for which the CAISO must consider in planning the grid, as discussed in the 2017-2018 Transmission Plan. In its transmission planning processes, the CAISO therefore considers factors and trends reaching beyond the more specific and well-defined challenges of the past, such as the phasing out of gas-fired generation relying on coastal waters for once-through cooling as well as the early retirement of the San Onofre Nuclear Generating Station and the planned retirement of Diablo Canyon Nuclear Generating Station commencing in 2024.

These new challenges and potential solutions must also consider the emergence of new policy and operating frameworks that will be relied upon to develop and coordinate the supply of, and demand for, electricity in the future.

The changing generation resource fleet inside California and the continued exploration of regionalism as a means to maximize the benefits of renewable generation development is both changing the nature of interchange with the CAISO's neighboring balancing authority areas and increasing the variability in flows on a more dynamic basis. The continued growth in participation in the CAISO's energy imbalance market is resulting in more dynamic import and export conditions.

The rest of this subsection discusses the key inputs as well as a number of the emerging issues and other actions being taken to advance the understanding or implementation of those issues in the future — whether special study activities, CAISO policy initiatives or regulatory proceedings.

1.3.1 Load Forecasting and Distributed Energy Resources Growth Scenarios

1.3.1.1 Base Forecasts

As discussed earlier, the CAISO continues to rely on load forecasts and load modifier forecasts prepared by the California Energy Commission (CEC) through its Integrated Energy Policy Report (IEPR) processes. The combined effects of flat or declining gross load forecasts and reductions in those net load forecasts due to behind-the-meter generation and energy efficiency programs continue to significantly impact the planning process.

The increasing variable loading on the transmission system is resulting in more widely varying voltage profiles, resulting in an increased need for reactive control devices to maintain acceptable system voltages.

The rapid deployment of behind-the-meter generation is driving changes in forecasting, planning and operating frameworks for both the transmission system and generation fleet. The rapid acceleration of behind-the-meter rooftop solar generation installations in particular has led to the shift in many areas of the peak "net sales" — the load served by the transmission and distribution grids — to shift to a time outside of the traditional daily peak load period. In particular, in several parts of the state, the peak load forecast to be served by the transmission system is lower and shifted out of the window when grid-connected solar generation is available.

These efforts have now resulted in the development of the 2019 California Energy Demand Revised Forecast 2020-2030 (CED 2019) adopted by the California Energy Commission (CEC) on January 22, 2020[17] that the CAISO is using in the 2020-2021 transmission planning process. This forecast includes full hourly load forecasting models for both consumption and load modifiers, and this information will play a key role in the more complex analysis of emerging system needs and the effectiveness of use-limited preferred resources as part of meeting those needs.

1.3.1.2 Further Demand Side Drivers

Through the Energy Storage and Distributed Energy Resources (ESDER) stakeholder initiatives, the CAISO has been actively engaged in enhancing the ability of distributed energy resources (DERs) to participate in the CAISO markets.

Further consideration of a range of industry trends and needs also drive an increased range of uncertainty about future requirements—with current energy efficiency programs driving demand down, but decarbonizing other sectors such as transportation potentially causing increased demand in new and previously unseen consumption patterns. In the future, fuel substitution, as a subset of energy efficiency, may increase demand as well.

Also, the CAISO will continue to explore the possibility for demand-side management tools to play a role in mitigating local reliability needs; those processes are considered as part of the resource planning processes discussed in the next subsection.

1.3.2 Resource Planning and Portfolio Development

Facilitating the coordination of the three major processes discussed earlier – the CPUC's IRP process, the CEC's IEPR process, and the CAISO's transmission planning process – and addressing renewable generation requirements specifically, the CAISO and the CPUC have a memorandum of understanding under which the CPUC provides the renewable resource portfolio or portfolios for the CAISO to analyze in the CAISO's annual transmission planning process. The portfolio development has transitioned from the CPUC's previous long term procurement plan proceedings to the current IRP proceedings.

Resource planning has informed past planning cycles by focusing primarily on informing policy-driven transmission needs to support state policy objectives on the development of renewable generation, and the role local resources—whether conventional or preferred resources—can play in meeting local reliability needs.

Along with other drivers, the shifting of the net sales peak to later hours – largely due to the rapid growth of behind-the-meter solar generation combined with steadily increasing volumes of grid-connected solar generation – is increasing the emphasis placed on how renewable integration resources such as batteries are forecast and mapped to specific locations in the portfolio development process. This is compounded by some level of unanticipated retirements of gas-fired generation as well as continued load growth projections.

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

This has resulted in a significant expansion of the focus of the renewable portfolio development process from focusing predominantly on renewable resources to a significant emphasis being placed on the renewable integration needs driven by various renewable resource options. In particular, with solar photovoltaic resources continuing to be the predominant forecast renewable resource, significant amounts of storage resources are now being forecast to complement the solar resources. This in turn has led to a significant effort on behalf of the CPUC to consider how to map steadily growing volumes of storage projects for transmission planning purposes over previous years' plans. In this transmission planning cycle, grid connected storage additions by 2030 range from 2,104 MW in the base portfolio to 8,873 MW and 12,657 MW in the two sensitivity portfolios. As discussed in more detail in chapter 3, the mapping efforts have focused on mapping baseline resources where actual project development is advancing, and allowing the CAISO to locate generic resources in the base case where CAISO study results demonstrate benefits. For the much larger volume of generic resources in sensitivity cases, the mapping considers both hybrid or co-located resources and standalone resources, and considers opportunities both inside and outside local capacity requirement areas. These sensitivities are largely informational, and, together with the CAISO's studies of the potential for storage to meet future local capacity requirements described earlier, will inform future planning activities.

As discussed below, the anticipated pace of storage development has also triggered enhancements of market participation frameworks for standalone and co-located or hybrid storage. In the second quarter of 2020, for the first time, more storage capacity was in the CAISO interconnection queue than renewable generation, and approximately half of the storage shared a site with renewable generation. These different resource types bring new challenges to forecasting and mapping their projected development given their differing operating characteristics and differing requirements to charge from the grid.

Emerging resource sufficiency concerns have also accelerated focus on near to mid-term resource planning, with resource planning and development activities underway in a number of proceedings in, and in parallel with, the CPUC's IRP process. These other proceedings include continued participation by the CAISO, the CPUC, CEC and other state agencies in the State Water Resources Control Board proceedings associated with gas-fired generation employing once-through-cooling, additional consideration of resource requirements in the CPUC's Resource Adequacy processes, and most recently in the CPUC's Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021 issued November 20, 2020.

The near term concerns arose from several factors, including shifts in peak electric demand to later in the year and later in the day, which reduces the ability of solar generation to meet peak capacity requirements; changes in the method for calculating the qualifying capacity of wind and solar resources resulting in lower qualifying capacity for these resources than previously determined; uncertainty regarding the level of imports on which California can depend in the future as other states also shift towards using more renewable energy resources; and some unanticipated non-OTC generator retirements.

During the course of the 2019-2020 transmission planning cycle, the CPUC launched a "procurement track" of the 2017-2018 integrated resource plan proceeding, based on CPUC staff analysis of available near-term supply for system resource adequacy. The CPUC staff analysis found a near-term capacity shortfall and, as a result, the CPUC issued Decision 19-11-016[18] on November 7, 2019 authorizing incremental procurement of system-level resource adequacy capacity of 3,300 MW by all jurisdictional load-serving entities (LSEs). The incremental resources are required to come online at least 50 percent by August 1, 2021, 75 percent by August 1, 2022, and 100 percent by August 1, 2023. In addition to this incremental procurement, the CPUC also recommended that the State Water Resources Control Board (Water Board) extend the once-through-cooling (OTC) compliance deadlines for four units currently slated to retire by December 31, 2020, for periods of up to three years. The OTC resources will serve as a hedge against potential delays to the incremental builds and address near-term operational needs.

On August 14 and 15, 2020, the California Independent System Operator Corporation (CAISO) was forced to institute rotating electricity outages in California in the midst of a West-wide extreme heat wave. Following these emergency events, Governor Gavin Newsom requested that, after taking actions to minimize further outages, the CAISO, the California Public Utilities Commission (CPUC), and the California Energy Commission (CEC) report on the root causes of the events leading to the August outages. The Final Root Cause Analysis[19] confirmed that the three major causal factors contributing to the August outages were related to extreme weather conditions, resource adequacy and planning processes, and market practices. Focusing on the resource-related issues in particular that relate to infrastructure concerns:

- The climate change-induced extreme heat wave across the western United States resulted in demand for electricity exceeding existing electricity resource adequacy (RA) and planning targets.
- In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours. This made balancing demand and supply more challenging during the extreme heat wave.

Although August 14 and 15 were the primary focus of the analysis because the rotating outages occurred during those days, August 17 through 19 were projected to have much higher supply shortfalls. If not for the leadership of the Governor’s office to mobilize a statewide mitigation effort, California was also at risk of further rotating outages on those days. As a result of the resource supply concerns evidenced by these events, the CPUC has launched additional procurement activities and emergency supply activities focusing on the summer of 2021 and 2022.

Further compounding these emerging resource supply concerns associated with the first two of the three contributing factors discussed above is the planned retirement of Diablo Canyon Nuclear Generating Station with Unit 1 retiring in 2024 and Unit 2 in 2025, placing more

[18] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF

[19] Final Root Cause Analysis, Mid-August 2020 Extreme Heat Wave, January 13, 2021. http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

importance upon timely decisions and actions in the ongoing IRP process. The CPUC's schedule established in Rulemaking 20-05-003 anticipates a decision regarding analysis of the retirement of Diablo Canyon in the second quarter of 2021.[20]

The above activities were occurring in parallel with the CPUC's development of resource portfolios provided to the CAISO for transmission planning purposes, and the related transmission planning study process leading to the development of this 2020-2021 Transmission Plan.

1.3.2.1 Renewable Portfolios provided via the Integrated Resource Planning Process

The CPUC issued a decision[21] on May 1, 2019 at the end of the 2017-2018 Integrated Resource Planning cycle, adopting a preferred system portfolio designed to ensure that the electric sector is on track to help the state achieve its statewide 2030 greenhouse gas (GHG) reduction target established through SB 350 at least cost while maintaining electric service reliability and meeting other State goals, and also meeting the electric industry-specific RPS goals established in the more recent SB 100. As the CPUC's focus was on the more aggressive goals related to GHG reductions from the electricity sector taking into account input from the California Air Resources Board (CARB)[22], the RPS goals have become more of a floor in CPUC consideration of portfolios that are targeting more aggressive reductions for the electricity sector to align with statewide GHG reduction goals.

Accordingly, the adopted preferred system portfolio met a state-wide GHG emission target of 42 million metric tons (MMT) by 2030, which represents a 50% reduction in electric sector GHG emissions from 2015 levels and a 61% reduction from 1990 levels. It was also assessed as achieving a 60 percent RPS target that meets the 2030 goal of SB 100 as discussed below, which was established after the IRP process had commenced, but before the IRP process was completed.

On March 26, 2020, the CPUC released Decision 20-03-028 in the 2019-2020 IRP proceeding which, for the purposes of the CAISO 2020-2021 transmission planning cycle, recommended use of the 46 MMT[23] 2017-2018 Preferred System Portfolio (PSP) adopted in Decision 19-04-040, with updates to the baseline and some generation locations as detailed in the current

[20] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M347/K608/347608446.PDF

[21] CPUC Decision 19-04-040 dated April 25, 2019, issued May 1, 2019, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K437/287437887.PDF

[22] The CPUC chose to adopt a 2030 statewide electricity GHG emissions planning target of 42 MMT in Decision 18-02-018, taking into account the range of scenarios provided in the 2017 Climate Change Scoping Plan in draft form in January 20, 2017, and ultimately approved by CARB on December 14, 2017. The 2017 Climate Change Scoping Plan outlines the regulations, programs, and other mechanisms needed to reduce GHG emissions in California. The California Global Warming Solutions Act of 2006 - Assembly Bill 32 (AB 32) created a comprehensive, multi-year program to reduce greenhouse gas (GHG) emissions in California. AB 32 required CARB to develop a Scoping Plan that describes the approach California will take to reduce GHGs to achieve the goal of reducing emissions to 1990 levels by 2020. The Scoping Plan was first approved by the Board in 2008 and must be updated every five years. https://ww3.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf?_ga=2.185410026.2108179798.1578097422-1787807483.1523971494

[23] Decision 20-03-028 clarified that 46 MMT is equivalent to the 42 MMT target set in D.18-02-018, because it includes certain combined heat and power projects in the electric sector that were previously attributed to the industrial sector. Page 2, Decision 20-03-028. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF

decision, as the reliability base case and the policy-driven base case. Decision 20-03-028 recognized the concern that the location of too much capacity in the portfolios developed in the 2019-2020 IRP cycle was considered too uncertain to jump directly to transmission investments at this stage with either of those portfolios. The CPUC acknowledged that this inherently separated the transmission investment decisions from the procurement direction given to the LSEs via the adoption of the 2019-2020 Reference System Plan, and that more real-world experience with how and where the LSEs are making investments toward the realization of the 2019-2020 RSP is necessary to have higher confidence in the need for transmission in specific locations to support these generation and storage resources.

Portfolios developed in the 2019-2020 IRP proceeding, however, were provided for sensitivity studies via Decision 20-03-028. These consisted of (1) the 2019-2020 Reference System Portfolio (RSP) adopted in the Decision, with the 46 million metric ton greenhouse gas target in 2030, as a policy-driven sensitivity, and (2) a portfolio based on the 30 million metric ton scenario, to test the impact of energy-only deliverability status for some generators on congestion and curtailment, as a second policy-driven sensitivity. The CAISO expects that the results of the sensitivity studies will be helpful in future CPUC integrated resource planning efforts that will also take into account more aggressive goals aligned with broader GHG reductions.

1.3.2.2 Consideration of the reliance on the gas-fired generation fleet

As noted above, CPUC Decision 19-04-040 providing RPS portfolios into the 2019-2020 planning cycle reiterated that in an earlier CPUC decision[24], the Commission found that while no new natural gas-fired power plants are identified in the 2030 new resource mix, the modeling showed that existing gas-fired plants – other than those relying on once-through-cooling and scheduled for retirement - are needed in 2030 as operable and operating resources, providing a renewable integration service. It was recognized that eliminating natural gas-fueled resources altogether by 2030, while maintaining reliability, would require technological solutions well beyond any of those that have been surfaced or analyzed in the proceeding to date.[25] This perspective regarding the need to maintain the existing natural gas-fired power plants over the planning horizon was also reinforced by the other resource planning activities noted above. Notwithstanding, in developing the preferred system portfolio in the CPUC's 2017-2018 integrated resource planning process and set out in CPUC Decision 19-04-040, the CPUC adopted a 40-year life for fossil-fueled resources as a proxy for potential retirements. The 40 year life assumption has therefore been used in the 2020-21 transmission planning process. However, it continues to be recognized that a transmission plan recommendation for a transmission project's approval based solely on 40-year life retirement assumptions would be unlikely, and such circumstances would need to be considered on a case-by-case basis.

Notwithstanding the strong indications that the existing gas-fired generation fleet will be needed into the foreseeable future for supply adequacy, the CAISO has over a number of years conducted additional studies on a largely informational basis to provide better insights and

[24] CPUC Decision 18-02-018: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K771/209771632.PDF.

[25] CPUC Decision 19-04-040, p. 132: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K437/287437887.PDF

understandings of the opportunities and issues associated with gas-fired generation retirement. Study efforts focusing on reducing costs to consumers by reducing local capacity requirements and shifting away from reliance on gas-fired generation for those needs will need to take into account the renewable integration benefits the generation may provide and the system needs to retain that generation in prioritizing study efforts and in committing to alternatives to reduce local capacity needs.

The CAISO initiated special studies in the 2016-2017 transmission planning cycle, with additional analysis extending into the 2017-2018 time frame, to assess the risks, to understand the risk of a material amount of similarly situated generation retiring more or less simultaneously, ostensibly for economic reasons,. Those studies did not find new geographic areas of concern exposed to local reliability risk if faced with retirements at levels that approached the limit of acceptable system capacity outside of the pre-existing local capacity areas.

In the 2018-2019 and 2019-2020 planning cycles, the CAISO undertook a more in-depth analysis of local capacity requirements, including consideration of potential alternatives to eliminate or materially reduce local capacity requirement needs.

In the CAISO's annual local capacity technical study process conducted in early 2020, the CAISO also examined charging capabilities in local capacity areas, to explore the possibility of using energy storage to reduce reliance on gas-fired generation to meet local capacity requirements.

Building on these previous efforts, the CAISO undertook in this 2020-2021 planning cycle a more comprehensive analysis to assess the alternatives to materially reduce or eliminate reliance on gas-fired generation considering both transmission and storage opportunities. Please refer to section 4.10.

1.3.2.3 Offshore Wind Generation

The portfolios provided for study in the 2020-2021 transmission planning cycle consider California and modest levels of out-of-state wind generation, but do not include the exploration of offshore wind potential.

The CAISO has, however, studied transmission system capabilities within the generator interconnection and deliverability allocation process in recent years, based on interconnection application totaling up to 10 GW of generation. The bulk of the interest in the central coast area. In response to stakeholder inquiries, the CAISO has reviewed the interconnection studies prepared in those processes and identified that the transmission system in the central coast area can accommodate approximately 5 to 6 GW of offshore wind generation interconnecting in the area of the Diablo Canyon Power Plant that will be retiring by the end of 2025, and the Morro Bay area where gas-fired generation has retired. It should be noted that the owners of the Diablo Canyon Power Plant retain certain deliverability retention options for repowering that can remain in effect for up to three years following the retirement of the nuclear plant. The north coast area, however, would require transmission development to incorporate a material amount of new offshore wind development.

Scenarios considering different levels of offshore wind development are being considered for the development of a sensitivity portfolio for the 2021-2022 transmission planning cycle.

1.3.2.4 Coordination with CPUC Resource Adequacy Activities

Along with other drivers, the shifting of the net sales peak to later hours – largely due to the rapid growth of behind-the-meter solar generation – combined with steadily increasing volumes of grid-connected solar generation has led to the need to broadly revisit resource planning assessments and certain CAISO transmission assessment methodologies that underpin resource planning efforts. This has become most apparent in considering the alignment of long term integrated resource planning efforts with the CPUC's administration of the state's resource adequacy program. While longer term planning studies have focused on more granular approaches of studying comprehensive forecasts and load and resource profiles, the near term resource adequacy programs have focused on methodologies to tabulate resource characteristics to guide short term resource contracting of existing resources to meet near term needs. In this regard, evolving load shapes and increased dependence on use-limited resources including storage require additional consideration of how various resource types contribute to meeting resource adequacy needs overall. An example of this consideration is the incorporation of effective load carrying capability methodologies used by the CPUC in assessing capacity benefits of new resources.

Along with other stakeholders, the CAISO has supported and encouraged a broader review of the current resource adequacy framework in the CPUC's current resource adequacy proceeding. In the CPUC's "Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years", the Commission noted that:

> *"[g]iven the passage of time and the rapid changes occurring in California's energy markets, it may be worthwhile to re-examine the basic structure and processes of the Commission's [resource adequacy] program."*[26]

The CAISO strongly supports this re-examination and provided several proposals to improve the fundamental structure of the CPUC's resource adequacy program especially in light of the transforming grid. To effectively and efficiently maintain grid reliability while incorporating greater amounts of preferred and intermittent clean, green resources, the resource adequacy program must ensure both procurement of the right resources in the right locations and with the right attributes, and the procurement of a resource adequacy portfolio that meets the system's energy needs all hours of the year. Simply stacking resource capacity values to meet an hourly forecast peak is no longer relevant and not a prudent long-term resource adequacy practice given the system's growing reliance on intermittent and availability limited resources.

To help reform and inform the resource adequacy provisions, the CAISO launched its ongoing resource adequacy enhancements initiative. In this initiative, the CAISO is investigating

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[26] *Order Instituting Rulekmaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2010 Compliance Years*, CPUC Proceeding No. R.17-09-020, at p. 3 (OIR), October 4, 2017, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M196/K747/196747674.PDF.

resource adequacy policy and design changes that incentivize and support transitioning to a clean, green grid that relies more on variable and energy-limited resources, awards resources that are the most reliable and dependable, and ensures that both peak capacity and system energy needs are met all hours of the year. The CAISO continues to collaborate with the CPUC and participate in the CPUC's resource adequacy proceeding to ensure that a viable and coordinated resource adequacy framework is adopted to ensure reliability and advance California's clean energy goals.

As well, the events of August, 2020 have also led to the CAISO's participation in the CPUC's proceeding launched on November 20, 2020 via its Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021 issued November 20. The CAISO's participation in that process includes recommendations for (interim) changes to certain resource adequacy requirements that include in particular an increase to the existing planning reserve margin and application of the planning reserve margin to both peak load periods as well as hours of critical need in the post-solar window period.

Evolving Transmission Deliverability Assessment Requirements Supporting Resource Adequacy Programs

The same drivers leading to the CPUC's development of effective load carrying capability (ELCC) methodologies in considering the usefulness of particular resources in meeting load requirements also affect the CAISO transmission assessment methodologies that underpin resource planning efforts.

Historically, the CAISO to perform on-peak deliverability studies to ensure system needs are met at periods of greatest need. The methodology used to consider the deliverability of various resources, such that the resources can provide capacity into the state's resource adequacy program, was developed at a time where the bulk of the capacity – gas-fired generation in particular – was fully dispatchable. Comparatively small levels of renewable generation were treated as incremental to the "core" of other dispatchable resources, and incorporated into deliverability methodologies taking into account their output characteristics, which were also relied upon by the CPUC in assessing qualifying capacity levels. However, with the significant levels of both grid-connected and behind-the-meter generation being developed, this incremental approach is no longer viable either in determining the contribution of these resources to resource adequacy needs or transmission deliverability assessments, especially in considering additional procurement.

Beginning with the 2018 resource adequacy compliance year, the CPUC replaced the exceedance-based qualifying capacity calculation for wind and solar with an ELCC-based approach to account for the growth of renewable energy resources. This reflected that the incremental reliability benefit of adding more solar hits a saturation point after enough capacity is installed. Additional solar resources provide a much lower incremental reliability benefit to the system than the initial solar resources, because their output profile ceases to align with the peak hour of demand on the transmission system which has shifted to later in the day due to the proliferation of behind-the-meter solar. The shift also indicated the need to revisit the application of the deliverability methodology used by the CAISO to both award "full capacity deliverability status" for local and system capacity purposes, and to assess deliverability in transmission planning and reliability studies.

In response to this change, the CAISO conducted an initiative[27] in 2019 to revise the on-peak deliverability methodology assumptions. The primary objective of this proposal was to align the renewable resource output levels used in on-peak deliverability assessments with the later peak load periods now being experienced on the CAISO system and also recognize the capacity benefits solar resources can still provide during other hours of the day. Accordingly, to assess on-peak deliverability, the CAISO developed methodology changes to study both "high system need" scenarios and "secondary system need" scenarios. The high system need scenario represents conditions when a capacity shortage is most likely to occur. This scenario occurs when the system reaches peak demand with low solar output. The secondary system need scenario represents conditions when the capacity shortage risk will increase if the renewable generation, when producing at a significant output level, is not deliverable. In this scenario, the system load is modeled to represent the peak gross consumption level (i.e., total electricity consumption including consumption served by behind-the-meter resources) and solar output is modeled at a significantly higher output than in the high system need scenario. If the addition of a resource under this scenario causes a deliverability deficiency determined based on a deliverability test and the limiting transmission constraint is not identified in the high system need scenario, then the constraint can be classified as an area constraint with optional transmission upgrades.

At the same time, generation developers noted that the existing deliverability study process, combined with the "full capacity deliverability status" conferred on resources meeting those requirements, was the one mechanism available and relied upon by developers to ensure that generation would not be exposed to excessive curtailment due to transmission limitations. Although transmission upgrades to deliver renewable energy reliably and economically are evaluated and approved through the CAISO transmission planning process, concerns remain with the ability of the transmission planning process to identify on a timely basis the upgrades to facilitate generation development, especially local transmission upgrades that depend on the exact point of interconnection of the future generation. Therefore, the CAISO initiative considered both modifications to the deliverability methodology to address requirements at peak system needs, and to renewable energy delivery during hours outside of the summer peak load period to ensure some minimal level of protection to otherwise potentially unlimited curtailment.

The existing tariff also requires the CAISO to perform informational off-peak deliverability studies. The CAISO therefore revised the previous off-peak informational deliverability assessment to make it a binding study and to identify transmission upgrades needed to avoid excessive renewable curtailment.

The CAISO introduced the changes first in the generation interconnection reassessment studies conducted in early 2020, then the Cluster 12 phase II interconnection studies and Cluster 13 phase I interconnection studies, and then the 2020-2021 policy driven transmission planning studies. Please refer to chapter 3.

[27] https://stakeholdercenter.caiso.com/StakeholderInitiatives/Generation-deliverability-assessment

Although this first cycle will provide considerable understanding of the impact of the changes, the interaction with other aspects of transmission planning, state resource planning and generation development activities may need another full cycle to assess. For example, the generation development community has already responded to the potential deliverability methodology changes with considerable interest in adding storage at existing solar generation sites – or sites under development – to at least somewhat restore the resource adequacy capacity previously anticipated for those sites under previous CPUC resource adequacy rules, and continue to utilize the deliverability those sites may provide under the CAISO's changes to its deliverability methodology. As part of this transition, the CAISO offered the generation community a "batch" process late in 2019 and early in 2020 to create the opportunity for existing or planned generation to add storage to those sites through a "material modification assessment" process to capitalize on the transition in ELCC methodologies and the CAISO's deliverability methodology. This led to the advancement of over 8,000 MW of potential storage development that is now progressing through the CAISO interconnection queue.

Further, when the CAISO Board of Governors approved the CAISO's proposed deliverability methodology in December 2019, it asked CAISO management to report back to the Board of Governors on the transition after the first annual study cycle is complete, assuming FERC approved the changes and the CAISO implements the changes in the 2020 studies. [28] This will be done in the second quarter of 2021, after this transmission plan has been approved.

1.3.2.5 Other Renewable Integration Issues and Initiatives

As the amount of renewable generation on the CAISO system grows – whether grid-connected or behind-the-meter at end customer sites – the CAISO must address a broader range of considerations to ensure overall safe, reliable and efficient operation. Specifically, the changing nature and location of generation resources and their diurnal output pattern combined with evolving load profiles, change the resulting demands on the transmission system.

The CAISO currently conducts a range of studies to support the integration of renewable generation, including planning for reliable deliverability of renewable generation portfolios (chapter 3), generation interconnection process studies conducted outside of the transmission planning process but closely coordinated with the transmission planning process, and renewable integration operational studies that the CAISO has conducted outside of the transmission planning process – but which are now being incorporated into the transmission planning processes as supplemental information. These latter studies form the basis of determinations of system - capacity and related flexibility - needs discussed earlier.

The genesis of the CAISO's analysis of flexibility needs was the CPUC 2010-2011 Long-term Procurement Plan (LTPP) proceeding (in docket R.10-05-006), wherein the CAISO completed an initial study of renewable integration flexible generation requirements under a range of future scenarios, and the CAISO has continued to analyze those issues. The CAISO's efforts have led to a number of changes in market dispatch and annual resource adequacy program

[28] Although the ISO is seeking to have the changes in effect for both generator interconnection studies and transmission planning studies performed in 2020, the generation interconnection studies will provide useful input to inform renewable portfolio development for portfolios that would be used in transmission planning studies conducted in 2021. Accordingly, it can take more than one year for all of the implications of the transition to be resolved.

requirements, including considering uncertainty in the market optimization solution and developing flexible resource adequacy capacity requirements in the state's resource adequacy program. In addition to those promising enhancements, the CAISO launched a stakeholder process to address a number of potential areas requiring further refinement. Of particular concern is ensuring the system maintains and incentivizes sufficient fast and flexible resources to address uncertainty and flexibility from an infrastructure perspective since "the flexible capacity showings to date indicate that the flexible capacity product, as currently designed, is not sending the correct signal to ensure sufficient flexible capacity will be maintained long-term."[29]

This effort also led to the CAISO's development of a methodology to assess the adequacy of the transmission system to access flexible capacity — the "flexible capacity" equivalent of deliverability assessed for local and system capacity. The CAISO initially considered that this could be addressed through the generation interconnection process, with alignment in the annual transmission planning process, much like system resource adequacy capacity and deliverability issues are currently addressed. Through more detailed consideration of the generation resource fleet and the grid, this issue was instead incorporated into a separate study expected to be performed in each year's transmission planning studies. If in the future issues emerge that need to be addressed through the generation interconnection process, it will be revisited at that time. The study was conducted for the first time in the 2019-2020 transmission planning cycle, and has been repeated in this planning cycle. Please refer to chapter 6.

Past special study efforts and other initiatives have, in addition to the above, also led to the need to review and upgrade generation models used in frequency response studies discussed in more detail below. This builds on the frequency response analysis the CAISO conducted in the 2015-2016 planning cycle, where the CAISO observed that simulated results varied from real-time actual performance – necessitating a review of the generator models employed in CAISO studies. This has in turn led to the development of a rigorous multi-year program to ensure generation owners are providing valid and tested models, as discussed below, and the CAISO appreciates the efforts made to date by market participants to address these issues. The frequency response studies themselves were then elevated from the "special study" category to an annual study expected to be conducted each year for the foreseeable future. Please refer to chapter 6.

1.3.2.6 Non-Transmission Alternatives and Preferred Resources

The CAISO continues to support preferred resources, including storage, as a means to meet local transmission system needs.

Since implementing the current transmission planning process in 2010, the CAISO has considered and placed a great deal of emphasis on assessing non-transmission alternatives, both conventional generation and, in particular, preferred resources such as energy efficiency, demand response, renewable generating resources, and those energy storage solutions that

[29] Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2 Supplemental Issue Paper: Expanding the Scope of the Initiative, November 8, 2016, at p.3, available at http://www.caiso.com/Documents/SupplementalIssuePaper-FlexibleResource AdequacyCriteria-MustOfferObligationPhase2.pdf.

are not transmission. Although the CAISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive transmission plan, it can identify them as the preferred mitigation solutions in the same manner that it can opt to pursue operational solutions in lieu of transmission upgrades. Further, load modifying preferred resource assumptions incorporated into the load forecasts adopted through state energy agency activities provide an additional opportunity for preferred resources to address transmission needs. This is progressively becoming more complex, as reliance on preferred resources including energy storage is taking a larger role in the California Public Utilities Commission's (CPUC's) resource planning to successfully integrate higher volumes of renewable generation. As a result, the CAISO is having to consider a growing number of scenarios both in assessing potential reliability concerns and in assessing the effectiveness of potential mitigations.

To increase awareness of the role of preferred resources, section 8.3 summarizes how preferred resources will address specific reliability needs. In addition, discussion throughout chapter 2 show the reliance on preferred resources to meet identified needs on an area-by-area study basis.

The CAISO's approach, as noted in previous transmission plans, has focused on specific area analysis, and testing the effectiveness of the resources provided by the market into the utility procurement processes for preferred resources as potential mitigations for identified reliability concerns.

This approach is set out in concept in the study plan for this planning cycle, developed in phase 1 of the planning process as described below. It has built on and refers to a methodology the CAISO presented in a paper issued on September 4, 2013,[30] as part of the 2013-2014 transmission planning cycle to support California's policy emphasizing use of preferred resources[31] — 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. In addition to developing a methodology the CAISO could apply annually in each transmission planning cycle, the paper also described how the CAISO would apply the proposed methodology in future transmission planning cycles. That methodology for assessing the necessary characteristics and effectiveness of preferred resources to meeting local needs was further advanced and refined through the development of the Moorpark Sub-area Local Capacity Alternative Study released on August 16, 2017.[32] In addition, the CAISO has developed a methodology as discussed in section 6.6 of the 2017-2018 Transmission Plan for examining the necessary characteristics for slow response local capacity resources – a subset of preferred resources – which both builds and expands on the analysis framework of

[30] "Consideration of alternatives to transmission or conventional generation to address local needs in the transmission planning process," September 4, 2013, http://www.caiso.com/Documents/Paper-Non-ConventionalAlternatives-2013-2014Transmission PlanningProcess.pdf.

[31] To be precise, the term "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 ISO uses the term more generally here consistent with the preference for certain resources in lieu conventional generation.

[32] *See generally* CEC Docket No. 15-AFC-001, and *see* "Moorpark Sub-Area Local Capacity Alternative Study," August 16, 2017, available at http://www.caiso.com/Documents/Aug16_2017_MoorparkSub-AreaLocalCapacityRequirementStudy-PuentePowerProject_15-AFC-01.pdf.

preferred resources. These efforts, with the additional detail discussed below, help scope and frame the necessary characteristics and attributes of preferred resources in considering them as potential alternatives to meeting identified needs. The CAISO must also consider the cost effectiveness and other benefits these alternatives provide.

In examining the benefits preferred resources can provide, the CAISO relies heavily on preferred resources identified through various resource procurement proceedings as well as proposals received in the request window and other stakeholder comment opportunities in the transmission planning processes.

High potential areas:

In addition to providing opportunities for preferred resources including storage to be proposed in meeting needs that are being addressed within the year's transmission plan, each year's transmission plan also identifies areas where reinforcement may be necessary in the future, but immediate action is not required. The CAISO expects developers interested in developing and proposing preferred resources as mitigations in the transmission planning process to take advantage of the additional opportunity to review those areas and highlight the potential benefits of preferred resource proposals in their submissions into utilities' procurement processes. To assist interested parties, each of the planning area discussions in chapter 2 contains a section describing the preferred resources that are providing reliability benefits, and the CAISO has summarized areas where preferred resources are being targeted as a solution or part of a solution to address reliability issues in section 8.3. Further, as noted earlier, the CAISO has expanded the scope of the biennial 10 year local capacity technical requirements study to provide additional information on the characteristics defining the need in the areas and sub-areas, to further facilitate consideration of preferred resources. Please refer to chapter 6.

Energy storage to meet identified needs:

As discussed earlier, the rapidly increasing forecasts of energy storage requirements – to support renewable integration – is creating new challenges in mapping those resources for transmission planning purposes. However, the mapping of generic storage resources for system requirements, even if mapped to an area that would address transmission system needs, does not ensure that the resources will in fact be procured in those areas. This requires more deliberate analysis and need determination, as is conducted for other preferred resources, and coordination with the CPUC – or other local regulatory agency as the case may be – to effectuate the procurement.

Storage played a major role in the assessment of the viability of preferred resource alternatives in the LA Basin studies and Moorpark Sub-area Local Capacity Alternative Study, as well as the Oakland Clean Energy Initiative approved in the 2017-2018 Transmission Plan and modified in the 2018-2019 Transmission Plan.

Existing resource procurement mechanisms can support and have supported storage resources providing these services through the CAISO's wholesale markets coupled with procurement directed by the CPUC. This approach ensures that system resources or resources within a transmission constrained area operate together to meet grid reliability needs, and enables the storage resource to participate broadly in providing value to the market. In the case of electric storage resources, procurement also may result in distribution-connected resources and in behind-the-meter resources that do not participate in the CAISO's wholesale markets. In the system resource context, the storage resources would be functioning primarily as market resources, with contractual obligations to the off-taker to provide certain services supporting local reliability.

At the same time, the market and regulatory framework for storage that is meeting energy market and transmission system needs is also evolving. Utilization of electric storage resources is a significant issue to the CAISO given the industry development underway and the growing role storage will play in supporting renewable integration. As the dependence on energy storage is expected to grow considerably in the future, the CAISO is examining the means by which it can ensure these resources participating in the market are appropriately positioned to meet reliability needs without unduly limiting market participation opportunities. The CAISO is exploring these issues in the CAISO's on-going energy storage and distributed energy resources initiative and in its resource adequacy enhancements initiative.[33]

Energy storage solutions can be a transmission resource or a non-transmission alternative (e.g. market-based). The CAISO has considered storage in both contexts in the transmission planning process, although market-based approaches have generally prevailed and their implementation is more advanced.

Energy storage as a transmission asset:

The CAISO has also studied in past planning cycles several potential applications of energy storage proposed as transmission assets, including the Dinuba storage project approved in the 2017-2018 Transmission Plan. An important consideration in evaluating storage projects as an option to meeting transmission needs is whether or not the storage facility is operating as transmission to provide a transmission service and meet transmission needs. In other words, the CAISO assesses whether the resource is functioning as a transmission facility. In making this assessment, considering prior FERC direction and the CAISO tariff, storage as a transmission asset must:

- Provide a transmission function (*e.g.*, voltage support, mitigate thermal overloads)[34];
- Meet an CAISO-determined transmission need under the tariff (reliability, economic, public policy)[35]; and,
- "Be the more efficient or cost-effective solution to meet the identified need"[36] and "If a transmission solution is required to meet an economic need, the CAISO must determine

[33] Details on the CAISO's energy storage and distributed energy resources intiative and the resource adequacy enhancements initiative can be found here: http://www.caiso.com/StakeholderProcesses/

[34] *Western Grid Development, LLC,* 130 FERC ¶61,056 at PP 43-46, 51-52 *order on reh'g,* 133 FERC ¶61,029 at PP 11-18.

[35] *Nevada Hydro Company, Inc.,* 164 FERC ¶61,197 at PP 22-25 (2018).

[36] ISO Tariff Section 24.4.6.2., re selecting a transmission solution for an identified reliability need.

> if the benefits of the transmission solution outweigh the costs. The benefits of the solution may include a calculation of any reduction in production costs, congestion costs, transmission losses, capacity, or other electric supply costs, *resulting from improved access to cost-efficient resources*"[37] (emphasis added).

Further, if the storage facility meets the above parameters and is selected as a regional transmission solution to meet a transmission need, it would be subject to competitive solicitation.

This direction provides that the determination of eligibility for transmission asset – and regulated rate recovery through the CAISO tariff – is not only based on <u>if</u> a transmission need is being met, but <u>how</u> the storage project meets the need. As a result, it is necessary to consider this question individually for each storage project.

In evaluating the efficacy of the storage as a solution to meet identified needs, it is also important to consider if the resource can also earn market-based revenues for providing market services when not required for specific transmission services. Although the historical assumption had been that transmission assets could not also provide other market services or access other market-based revenue streams, FERC issued a policy statement "Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery"[38] in 2017 clarifying the potential for electric storage resources to receive cost-based rate recovery for transmission services while also receiving market-based revenues for providing market services. In 2018, the CAISO launched its storage as a transmission asset initiative (SATA) to investigate the possibility of allowing storage to serve as a transmission asset while also providing opportunities to participate in the wholesale electricity market.

In vetting this policy, it became apparent that many of the same issues regarding dispatch and state-of-charge management that apply to market resources providing reliability services also apply to storage devices procured as transmission assets that are also participating in the market. The CAISO therefore placed the storage as a transmission asset initiative (regarding the potential to also earn market revenue) on hold while these operational issues are vetted in the CAISO's on-going energy storage and distributed energy resources initiative and in its resource adequacy enhancements initiative discussed above.

Despite the fact that a mechanism does not currently exist for storage as a transmission asset to access market revenues, the CAISO considered potential market revenues as benefits for energy storage projects as transmission, as appropriate. The CAISO in this transmission planning cycle has continued its assumption from recent planning cycles that, unless the transmission services very specifically conflict with providing potential market services, market revenues could be accessed through an appropriately structured power purchase agreement or the eventual advancement of the SATA initiative.

[37] ISO Tariff Section 24.4.6.7, re economic needs

[38] *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,051 (2017), at P 9, https://www.ferc.gov/whats-new/comm-meet/2017/011917/E-2.pdf.

Other Use-limited resources, including demand response:

The CAISO continues to support integrating demand response, which includes bifurcating and clarifying the various programs and resources as either supply side or load-modifying. Activities such as participating in the CPUC's demand response-related proceedings support identifying the necessary operating characteristics that demand response should have to fulfill a role in meeting transmission system and local capacity needs.

Further analysis of the necessary characteristics for "slow response" demand response programs was undertaken initially through special study work associated with the 2016-2017 Transmission Plan, and the analysis continued into 2017 through a joint stakeholder process with the CPUC.[39] In 2019, the CAISO vetted the market processes it will use to dispatch slow demand response resources on a pre-contingency basis.[40]

This work has helped guide the approach the CAISO is taking in the more comprehensive study of local capacity areas in this planning cycle examining both the load shapes and characteristics underpinning local capacity requirements, discussed earlier in this section.

1.3.3 System Modeling, Performance, and Assessments

1.3.3.1 System modeling requirements and emerging mandatory standards

Exploring an increased role for preferred resources to address both traditional and emerging needs poses new technical challenges. The grid is already being called upon to meet broader ranges of generating conditions and more frequent changes from one operating condition to another, as resources are committed and dispatched on a more frequent basis and with higher ramping rates and boundaries than in the past. This necessitates managing thermal, stability, and voltage limits constantly and across a broader range of operating conditions.

Also, this has led to the need for greater accuracy in planning studies, and in particular, to the special study initiative undertaken in the 2016-2017 planning cycle reviewing all generator models for use in dynamic stability studies and frequency response analysis.

The efforts undertaken in subsequent planning cycles reaffirmed the practical need to improve generator model accuracy in addition to ensuring compliance with NERC mandatory standards. (Refer to section 6.3.3.1.) However, the effort also identified underlying challenges with obtaining validated models for a large – and growing – number of generators that are outside of the bounds of existing NERC mandatory standards and for which the CAISO is dependent on tariff authority. The CAISO has made significant progress in establishing and implementing a more comprehensive framework for the collection of this data, and will be continuing with its efforts, in coordination with the Participating Transmission Owners, to collect this important information and ensuring validated models are provided by generation owners.

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[39] See "Slow Response Local Capacity Resource Assessment California ISO – CPUC joint workshop," presentation, October 4, 2017, http://www.caiso.com/Documents/Presentation_JointISO_CPUCWorkshopSlowResponseLocalCapacityResourceAssessment_Oct42017.pdf.

[40] Local Resource Adequacy with Availability-Limited Resources and Slow Demand Response Draft Final Proposal found here: http://www.caiso.com/InitiativeDocuments/DraftFinalProposal-LocalResourceAdequacy-AvailabilityLimitedResources-SlowDemandResponse.pdf

1.4 Interregional Transmission Coordination per FERC Order No. 1000

Beginning in January 2020 a new biennial Interregional Transmission coordination cycle was initiated. This biennial coordination cycle spans two CAISO annual transmission planning cycles, being this 2020-2021 transmission planning cycle and the 2021-2022 transmission planning cycle. Following guiding principles largely developed through coordination activities, the CAISO along with the other Western Planning Regions[41] continued to participate and advance interregional transmission coordination within the broader landscape of the western interconnection. These guiding principles were established to ensure that an annual exchange and coordination of planning data and information was achieved in a manner consistent with expectations of FERC Order No. 1000. They are documented in the CAISO's Transmission Planning Business Practice Manual as well as in comparable documents of the other Western Planning Regions. Since the 2020-2021 biennial interregional coordination cycle was initiated, the Western Planning Regions have held one Annual Interregional Coordination Meeting on February 27, 2020 to provide all stakeholders an opportunity to engage with the Western Planning Regions on interregional related topics.[42]

The CAISO hosted its submission period in the first quarter of 2020 in which proponents were able to request evaluation of an interregional transmission project (ITP). The submission period began on January 1 and closed March 31st with four interregional transmission projects being submitted to the CAISO. Of the four project submitted, three projects were submitted into the 2018-2019 cycle. Following the submission and successful screening of the ITP submittals, the CAISO coordinated its ITP evaluation with the other relevant planning regions; NorthernGrid and WestConnect.

The CAISO considered all ITP proposals in its 2020-2021 TPP and did not identify a CAISO need for the proposed ITPs. Consistent with the Order No. 1000 Common Interregional Tariff, the CAISO was not required to consider the proposed ITPs beyond the CAISO's 2020-2021 TPP planning cycle. Commensurate with this outcome, no further consideration of the submitted ITPs will be required in the 2021-2022 TPP. Please refer to chapter 5.

[41] Western planning regions are the California ISO, NorthernGrid, and WestConnect.

[42] Documents related to the 2018-2019 interregional transmission coordination meetings are available on the ISO website at http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=76EEDF6D-5C04-4245-BA62-01D832E1E5E4

1.5 ISO Processes coordinated with the Transmission Plan

The CAISO coordinates the transmission planning process with several other CAISO processes. These processes and initiatives are briefly summarized below.

1.5.1 Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

In July 2012, FERC approved the GIDAP, which significantly revised the generator interconnection procedures to better integrate those procedures with the transmission planning process. The CAISO applied the GIDAP to queue cluster 5 in March 2012 and all subsequent queue clusters. Interconnection requests submitted into cluster 4 and earlier will continue to be subject to the provisions of the prior generation interconnection process (GIP).

The principal objective of the GIDAP was to ensure that going forward the CAISO would identify and approve all major transmission additions and upgrades to be paid for by transmission ratepayers under a single comprehensive process — the transmission planning process — rather than having some projects come through the transmission planning process and others through the GIP.

The most significant implication for the transmission planning process at this time relates to the planning of policy-driven transmission to achieve the state's renewables portfolio standard. In that context, the CAISO plans the necessary transmission upgrades to enable the deliverability of the renewable generation forecast in the base renewables portfolio scenario provided by the CPUC, unless specifically noted otherwise. Every RPS Calculator portfolio the CPUC has submitted into the CAISO's transmission planning process for purposes of identifying policy-driven transmission to achieve 33 percent RPS has assumed deliverability for new renewable energy projects.[43] More recently, the portfolios provided to the CAISO via the CPUC's integrated resource planning proceeding for consideration in the 2018-2019 transmission planning cycle and later cycles identified both deliverable generation (full capacity deliverability status) and energy-only generation by area.

Through the GIDAP, the CAISO then allocates the resulting MW volumes of transmission plan deliverability to those proposed generating facilities in each area that are the most viable based on a set of project development milestones specified in the tariff.

As set out in Appendix DD (GIDAP) of the CAISO tariff, the CAISO calculates the available transmission plan deliverability (TPD) in each year's transmission planning process in areas where the amount of generation in the interconnection queue exceeds the available deliverability, as identified in the generator interconnection cluster studies. In areas where the amount of generation in the interconnection queue is less than the available deliverability, the transmission plan deliverability is sufficient. In this year's transmission planning process, the CAISO considered queue clusters up to and including queue cluster 13.

[43] RPS Calculator User Guide, Version 6.1, p. A-17. ("In prior versions of the RPS Calculator (v.1.0 – v.6.0), all new renewable resources were assumed to have full capacity deliverability status (FCDS).") Available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5686.

Interconnection customers proposing generating facilities that are not allocated transmission plan deliverability, but who still want to build their projects and obtain deliverability status, are responsible for funding needed delivery network upgrades at their own expense without being eligible for cash reimbursement from ratepayers.

The GIDAP studies for each queue cluster also provide information that supports future planning decisions. Each year, the CAISO validates the capability of the planned system to meet the needs of renewable generation portfolios that have already been provided. The CAISO augments this information with information about how much additional generation can be deliverable beyond the previously-supplied portfolio amounts with the results of the generator queue cluster studies. The results are provided each year to the CPUC for consideration in developing the next round of renewable generation portfolios.

1.5.2 Distributed Generation (DG) Deliverability

The CAISO developed a streamlined, annual process for providing resource adequacy (RA) deliverability status to distributed generation (DG) resources from transmission capacity in 2012 and implemented it in 2013. The CAISO completed the first cycle of the new process in 2013 in time to qualify additional distributed generation resources to provide RA capacity for the 2014 RA compliance year.

The CAISO annually performs two sequential steps. The first step is a deliverability study, which the CAISO performs within the context of the transmission planning process, to determine nodal MW quantities of deliverability status that can be assigned to DG resources. The second step is to apportion these quantities to utility distribution companies — including both the investor-owned and publicly-owned distribution utilities within the CAISO controlled grid — who then assign deliverability status, in accordance with CAISO tariff provisions, to eligible distributed generation resources that are interconnected or in the process of interconnecting to their distribution facilities.

In the first step, during the transmission planning process the CAISO performs a DG deliverability study to identify available transmission capacity at specific grid nodes to support deliverability status for distributed generation resources without requiring any additional delivery network upgrades to the CAISO controlled grid and without adversely affecting the deliverability status of existing generation resources or proposed generation in the interconnection queue. In constructing the network model for use in the DG deliverability study, the CAISO models the existing transmission system, including new additions and upgrades approved in prior transmission planning process cycles, plus existing generation and certain new generation in the interconnection queue and associated upgrades. The DG deliverability study uses the nodal DG quantities specified in the base case resource portfolio that was adopted in the latest transmission planning process cycle to identify public policy-driven transmission needs, both as a minimal target level for assessing DG deliverability at each network node and as a maximum amount that distribution utilities can use to assign deliverability status to generators in the current cycle. This ensures that the DG deliverability assessment aligns with the public policy objectives addressed in the current transmission planning process cycle and precludes the possibility of apportioning more DG deliverability in each cycle than was assumed in the base case resource portfolio used in the transmission planning process. As the amounts of distributed generation forecast in the recent renewable generation portfolios have declined from previous years, this creates less opportunity for this process to identify and allocate deliverability status to new resources. Please refer to chapter 3.

In the second step, the CAISO specifies how much of the identified DG deliverability at each node is available to the utility distribution companies that operate distribution facilities and interconnect distributed generation resources below that node. FERC's November 2012 order stipulated that FERC-jurisdictional entities must assign deliverability status to DG resources on a first-come, first-served basis, in accordance with the relevant interconnection queue. In compliance with this requirement, the CAISO tariff specifies the process whereby investor-owned utility distribution companies must establish the first-come, first-served sequence for assigning deliverability status to eligible distributed generation resources.

Although the CAISO performs this new DG deliverability process as part of and in alignment with the annual transmission planning process cycle, its only direct impact on the transmission planning process is adding the DG deliverability study to be performed in the latter part of Phase 2 of the transmission planning process.

1.5.3 Critical Energy Infrastructure Information (CEII)

The CAISO protects CEII as set out in the CAISO's tariff.[44] Release of this information is governed by tariff requirements. In previous transmission planning cycles, the CAISO has determined — out of an abundance of caution on this sensitive area — that additional measures should be taken to protect CEII information. Accordingly, the CAISO has placed more sensitive detailed discussions of system needs into appendices that are not released through the CAISO's public website. Rather, this information can be accessed only through the CAISO's market participant portal after the appropriate nondisclosure agreements are executed.

1.5.4 Planning Coordinator Footprint

The CAISO released a technical bulletin that set out its interpretation of its planning authority/planning coordinator area in 2014, [45] in part in response to a broader WECC initiative to clarify planning coordinator areas and responsibilities.

Beginning in 2015, the CAISO reached out to several "adjacent systems" that are inside the CAISO's balancing authority area and were confirmed transmission owners, but which did not appear to be registered as a planning coordinator to determine whether they needed to have a planning coordinator and, if they did not have one, to offer to provide planning coordinator services to them through a fee based planning coordinator services agreement. Unlike the requirements for the CAISO's participating transmission owners who have placed their facilities under the CAISO's operational control, the CAISO is not responsible for planning and approving

[44] ISO tariff section 20 addresses how the ISO shares Critical Energy Infrastructure Information (CEII) related to the transmission planning process with stakeholders who are eligible to receive such information. The tariff definition of CEII is consistent with FERC regulations at 18 C.F.R. Section 388.113, *et. seq*. According to the tariff, eligible stakeholders seeking access to CEII must sign a non-disclosure agreement and follow the other steps described on the ISO website.

[45] Technical Bulletin – "California ISO Planning Coordinator Area Definition" (created August 4, 2014, last revised July 28, 2016 to update URL for Appendix 2), http://www.caiso.com/Documents/TechnicalBulletin-CaliforniaISOPlanningCoordinatorAreaDefinition.pdf.

mitigations to identified reliability issues under the planning coordinator services agreement – but only verifying that mitigations have been identified and that they address the identified reliability concerns. In essence, these services are provided to address mandatory standards via the planning coordinator services agreement, separate from and not part of the CAISO's FERC-approved tariff governing transmission planning activities for facilities placed under CAISO operational control. As such, the results are documented separately, and do not form part of this transmission plan.

The CAISO has executed planning coordinator services agreements with Hetch Hetchy Water and Power, the Metropolitan Water District, the City of Santa Clara, and most recently with the California Department of Water Resources. Since the execution of these agreements the CAISO has conducted the relevant study efforts to meet the mandatory standards requirements for these entities within the framework of the annual transmission planning process and has met all requirements to fulfill its planning coordinator responsibilities for these entities in accordance with the implementation schedules agreed upon with each entity.

In addition to the entities discussed above, the CAISO is also providing planning coordinator services under a separate agreement to Southern California Edison for a subset of its facilities that are not under CAISO operational control but which were found to be Bulk Electric System as defined by NERC. Considering the entirety of the CAISO controlled grid, the CAISO is not anticipating a need to offer these services to other parties, as the CAISO is not aware of other systems inside the boundaries of the CAISO's planning coordinator footprint requiring these services.

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Chapter 2

2 Reliability Assessment – Study Assumptions, Methodology and Results

2.1 Overview of the CAISO Reliability Assessment

The CAISO annual reliability assessment is a comprehensive annual study that includes:

- Power flow studies;
- Transient stability analysis; and,
- Voltage stability studies.

The annual reliability assessment focus is to identify facilities that demonstrate a potential of not meeting the applicable performance requirements specifically outlined in section 2.2.

This study is part of the annual transmission planning process and performed in accordance with section 24 of the CAISO tariff and as defined in the Business Process Manual (BPM) for the Transmission Planning Process. The Western Electricity Coordinating Council (WECC) full-loop power flow base cases provide the foundation for the study. The detailed reliability assessment results are provided in Appendix B and Appendix C.

2.1.1 Backbone (500 kV and selected 230 kV) System Assessment

Conventional and governor power flow and stability studies were performed for the backbone system assessment to evaluate system performance under normal conditions and following power system contingencies for voltage levels 230 kV and above. The backbone transmission system studies cover the following areas:

- Northern California — Pacific Gas and Electric (PG&E) system; and
- Southern California — Southern California Edison (SCE) system and San Diego Gas and Electric (SDG&E) system.

2.1.2 Regional Area Assessments

Conventional and governor power flow studies were performed for the local area non-simultaneous assessments under normal system and contingency conditions for voltage levels 60 kV through 230 kV. The regional planning areas are within the PG&E, SCE, SDG&E, and Valley Electric Association (VEA) service territories and are listed below:

- 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.
- SCE local areas
  - Tehachapi and Big Creek Corridor;
  - North of Lugo area;
  - East of Lugo area;
  - Eastern area; and
  - Metro area.
- Valley Electric Association (VEA) area
- San Diego Gas Electric (SDG&E) local area

2.1.3 Peak Demand

The CAISO-controlled grid peak demand in 2020 was 47,236 MW and occurred on September 6 at 5:43 p.m. The following were the peak demand for the four load-serving participating transmission owners' service areas:

PG&E peak demand occurred on August 14, 2020 at 6:29 p.m. with 21,103 MW;

SCE peak demand occurred on August 18, 2020 at 1:13 p.m. with 23,714 MW;

SDG&E peak demand occurred on September 30, 2020 at 5:00 p.m. with 4,646 MW; and

VEA peak demand occurred on August 18, 2020 at 16:55 p.m. with 144 MW.

Most of the CAISO-controlled grid experiences summer peaking conditions and thus was the focus in all studies. For areas that experienced highest demand in the winter season or where historical data indicated other conditions may require separate studies, winter peak and summer off-peak studies were also performed. Examples of such areas are Humboldt and the Central Coast in the PG&E service territory.

2.2 Reliability Standards Compliance Criteria

The 2020-2021 Transmission Plan spans a 10-year planning horizon and was conducted to ensure the CAISO-controlled-grid is in compliance with the North American Electric Reliability Corporation (NERC) standards, Western Electricity Coordinating Council (WECC) regional criteria, and CAISO planning standards across the 2021-2030 planning horizon. Sections 2.2.1 through 2.2.4 below describe how these planning standards were applied for the 2020-2021 study.

2.2.1 NERC Reliability Standards

2.2.1.1 System Performance Reliability Standards

The CAISO analyzed the need for transmission upgrades and additions in accordance with NERC reliability standards, which provide criteria for system performance requirements that must be met under a varied but specific set of operating conditions. The following NERC reliability standards are applicable to the CAISO as a registered NERC planning authority and are the primary drivers determining reliability upgrade needs:

- TPL-001-4 Transmission System Planning Performance Requirements[46]; and
- NUC-001-3 Nuclear Plant Interface Coordination.

2.2.2 WECC Regional Criteria

The WECC TPL system performance criteria are applicable to the CAISO as a planning authority and sets forth additional requirements that must be met under a varied but specific set of operating conditions.[47]

2.2.3 California CAISO Planning Standards

The California CAISO Planning Standards specify the grid planning criteria to be used in the planning of CAISO transmission facilities.[48] These standards:

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

46 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.

47 https://www.wecc.biz/Standards/Pages/Default.aspx

48 http://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf

2.3 Study Assumptions and Methodology

The following sections summarize the study methodology and assumptions used for the reliability assessment.

2.3.1 Study Horizon and Years

The studies that comply with TPL-001-4 were conducted for both the near-term[49] (2021-2025) and longer-term[50] (2026-2030) per the requirements of the reliability standards. Within the identified near and longer term study horizons the CAISO conducted detailed analysis on years 2022, 2025 and 2030.

2.3.2 Transmission Assumptions

2.3.2.1 Transmission Projects

The study included existing transmission in service and the expected future projects that have been approved by the CAISO but are not yet in service. Refer to Table 8.1-1 and Table 8.1-2 of chapter 8 (Transmission Project Updates) for the list of previously approved projects that are not yet in service. Projects put on hold were not modeled in the starting base case. Previously approved transmission projects that were not included in the base cases are identified below in the local area assessments.

Also included in the study cases were generation interconnection related transmission projects that were included in executed Large Generator Interconnection Agreements (LGIA) for generation projects included in the base case.

2.3.2.2 Reactive Resources

Existing and new reactive power resources were modeled in the study base cases to ensure realistic voltage support capability. These resources include generators, capacitors, static var compensators (SVCs) and other devices. Refer to area-specific study sections for a detailed list of generation plants and corresponding assumptions. Two of the key reactive power resources that were modeled in the studies include the following:

- All shunt capacitors in the SCE service territory; and,
- Static var compensators or static synchronous compensators at several locations such as Potrero, Newark, Humboldt, Rector, Devers and Talega substations.

For a complete resources list, refer to the base cases available at the CAISO Market Participant Portal secured website (https://portal.caiso.com/Pages/Default.aspx).[51]

49 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.

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

51 This site is available to market participants who have submitted a non-disclosure agreement (NDA) and is approved to access the portal by the ISO. For instructions, go to http://www.caiso.com/Documents/Regional%20transmission%20NDA.

2.3.2.3 Protection Systems

To help ensure reliable operations, many special protection systems (SPS), safety nets, UVLS and UFLS schemes have been installed in some areas. Typically, these systems trip load and/or generation by strategically tripping 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 included in the study are listed in Appendix A.

2.3.2.4 Control Devices

Several control devices were modeled in the studies. These control devices are:

- All shunt capacitors in SCE and other areas;
- Static var compensators and synchronous condensers at several locations such as Potrero, Newark, Rector, Devers, and Talega substations;
- DC transmission line such as PDCI, IPPDC, and Trans Bay Cable Projects (note the PDCI Upgrade Project – to 3220 MW – was approved in 2017); and,
- Imperial Valley flow controller; (*e.g.*, phase shifting transformer).

For complete details of the control devices that were modeled in the study, refer to the base cases that are available through the CAISO Market Participant Portal secure website.

2.3.3 Load Forecast Assumptions

2.3.3.1 Energy and Demand Forecast

The assessment used the California Energy Demand Updated Forecast, 2020-2030 adopted by California Energy Commission (CEC) on January 22, 2020[52].

During 2019, the CEC, CPUC and CAISO reviewed the issue of how to consistently account for reduced energy demand from energy efficiency in the planning and procurement processes. To that end and consistent with past transmission plans, the 2019 IEPR final report, also adopted on January 22, 2020, recommended 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 CAISO TPP cycles. 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 for local studies has since been considered prudent.

The 1-in-10 load forecasts were modeled in each of the local area studies. The 1-in-5 coincident peak load forecasts were used for the backbone system assessments as the backbone system covers a broader geographical area with significant temperature diversity. More details of the demand forecast are provided in the discussion sections of each of the study areas.

In the 2020-2021 transmission planning process, the CAISO used the CEC energy and demand forecast for the base scenario analysis identified in section 2.3.8.1. The CAISO conducts

52 https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report/2019-iepr

sensitivities on a case by case basis and to comply with the NERC TPL-001-4 mandatory reliability standard; these and other forecasting uncertainties were taken into account in the sensitivity studies identified in section 2.3.8.2. The CAISO has continued to work with the CEC on the hourly load forecast issue during the development of 2018 IEPR.

2.3.3.2 Self-Generation

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

PV Self-generation installed capacity for mid demand scenario by PTO and forecast climate zones are shown in Table 2.3-1. Output of the self-generation was selected based on the time of day of the study using the end-use load and PV shapes for the day selected.

Table 2.3-1: Mid demand baseline PV self-generation installed capacity by PTO[53]

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

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

Behind-the-meter storage installed capacity for mid demand scenario by PTO and forecast climate zones is shown in Table 2.3-2. These resources were netted to load in the 2020-2021 transmission planning process base cases

Table 2.3-2 Mid demand baseline behind-the-meter storage installed capacity by PTO

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

Outputs of the self-generation PV and storage were selected based on the time of day of the study using the end-use load and PV shapes for the day selected.

2.3.4 Generation Assumptions

Generating units in the area under study were dispatched at or close to their maximum power (MW) generating levels for the peak demand bases cases. Qualifying facilities (QFs) and self-generating units were modeled based on their historical generating output levels. Renewable generation was dispatched as identified in section 2.3.4.2.

2.3.4.1 Generation Projects

In addition to generators that are already in-service, new generators were modeled in the studies depending on the status of each project.

2.3.4.2 Renewable Generation

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

The CPUC's Proposed Decision "2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning" adopted on March 26, 2020 recommended transmitting the 2018 Preferred System Portfolio as the TPP Base Case, and the 2019 RSP and 2019 30 MMT EO Portfolio as the TPP Policy-driven Sensitivity Cases.The CPUC's Proposed Decision recommended transmittal of the base portfolio along with the two sensitivity portfolios to be used in the 2020-2021 TPP. The base portfolio was transmitted for the purpose of being studied as part of the reliability assessment, policy-driven and economic assessment in the 2020-2021 TPP.

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

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

2.3.4.3 Thermal generation

For the latest updates on new generation projects, please refer to CEC website under the licensing section[54]. The CAISO also relies on other data sources to track the statuses of additional generator projects to determine the starting year new projects may be modeled in the base cases.

2.3.4.4 Hydroelectric Generation

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

2.3.4.5 Generation Retirements

Existing generators that have been identified as retiring are listed in table A2-1 of Appendix A. These generators along with their step-up transformer banks are modeled as out of service starting in the year they are assumed to be retired.

In addition to the identified generators the following assumptions were made for the retirement of generation facilities:

- Nuclear Retirements – Diablo Canyon was modeled offline based on the OTC compliance dates;
- Once Through Cooled (OTC) Retirements – As identified in Appendix A;
- Renewable and Hydro Retirements – Assumed these resource types stay online unless there is an announced retirement date; and,
- Other Retirements – Unless otherwise noted, assumed retirement based resource age of 40 years or more.

2.3.4.6 OTC Generation

Modeling of the once-through cooled generating units, listed in table A3-1 of Appendix A, followed the compliance schedule from the State Water Resources Control Board's (SWRCB) policy on OTC plants with the following exceptions:

- generating units that are repowered, replaced or having firm plans to connect to acceptable cooling technology; and,
- all other OTC generating units were modeled off line beyond their compliance dates.

[54] Licensing section: http://www.energy.ca.gov/sitingcases/all_projects.html

The above assumptions were made, and analysis performed, prior to the current consideration of extensions being sought to certain OTC generating units' compliance dates to address overall supply sufficiency concerns[55]. These extensions are not yet in place, and the objective of the transmission planning process in any event is to enable the retirements – when system supply sufficiency concerns are addressed - unencumbered by local constraints.

2.3.4.7 2012 LTPP Authorization Procurement

OTC replacement local capacity amounts in southern California that were authorized by the CPUC under the LTPP Tracks 1 and 4 were considered along with the procurement activities to date from the utilities. Table 2.3-4 provides the local capacity resource additions and the study year in which the amounts were first modeled based on the CPUC LTPP Tracks 1 and 4 authorizations. Table 2.3-5 provides details of the study assumptions using the utilities' procurement activities to date, as well as the CAISO's assumptions for potential preferred resources for the San Diego area.

Table 2.3-3: Summary of 2012 LTPP Track 1 & 4 Maximum Authorized Procurement

LCR Area	LTPP Track-1		LTPP Track-4[56]	
	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

Notes: Amounts shown are total including gas-fired generation, preferred resources and energy storage

55 CPUC Decision 19-11-016, "DECISION REQUIRING ELECTRIC SYSTEM RELIABILITY PROCUREMENT FOR 2021-2023, November 7, 2019, Issues November 13, 2019, available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K825/319825388.PDF

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

Table 2.3-4: 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[57]	124.04	37.92	263.64	5	1,382	1,812.60
SCE's procurement for the Moorpark Sub-area[58]	6.00	5.66	0	0	0	11.66
SDG&E's procurement[59]	19 (approved)	0	83.5[60] (approved)	4.5 (approved)	800[61]	907

2.3.5 Preferred Resources and Energy Storage

Commensurate with tariff Section 24.3.3(a), the CAISO sent a market notice to interested parties seeking suggestions about demand response programs and generation or non-transmission alternatives that should be included as assumptions in the study plan. In response, the CAISO received demand response and energy storage information for consideration in planning studies from Pacific Gas & Electric (PG&E). PG&E provided a bus-level model of PG&E's demand response (DR) programs for the inclusion in the 2020-2021 Transmission Plan Unified Planning Assumptions and Study Plan.

Methodology

The CAISO issued a paper[62] on September 4, 2013, in which it presented a methodology to support California's policy emphasis on the use of preferred resources – specifically energy efficiency, demand response, renewable generating resources and energy storage – by considering how such resources can constitute non-conventional solutions to meet local area needs that otherwise would require new transmission or conventional generation infrastructure. The general application for this methodology is in grid area situations where a non-conventional alternative such as demand response or some mix of preferred resources could be selected as the preferred solution in the CAISO's transmission plan as an alternative to the conventional transmission or generation solution.

In previous planning cycles, the CAISO applied a variation of this new approach in the LA Basin and San Diego areas to evaluate the effectiveness of preferred resource scenarios developed by SCE as part of the procurement process to fill the authorized local capacity for the LA Basin

[57] 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.

[58] SCE-selected RFO procurement (A. 14-11-016) for the Moorpark sub-area is currently at the CPUC for review and consideration.

[59] 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.

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

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

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

and Moorpark areas. In addition to these efforts focused on the overall LA Basin and San Diego needs, the CAISO also made further progress in integrating preferred resources into its reliability analysis focusing on other areas where reliability issues were identified.

As in the 2018-2019 planning cycle, reliability assessments in the current planning cycle considered a range of existing demand response amounts as potential mitigations to transmission constraints. The reliability studies also incorporated 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 and subsequent authorizations. 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 were 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 were identified in the initial assessment, additional rounds of assessments were 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 was then be performed, if considered necessary given the mix of resources in the particular area, to account for the specific characteristic of each resource including use or energy limitation in the case of demand response and energy storage. An example of such a study is the special study the CAISO performed for the CEC in connection with the Puente Power Project proceeding to evaluate alternative local capacity solutions for the Moorpark area[63]. The CAISO will continue to use the methodology developed as part of the study to evaluate these types of resources.

Demand Response

Section 6.6 of the CAISO 2017-2018 Transmission Plan provided a status update on the progress to identify the necessary characteristics for slow response local capacity resources, such that the resources can be relied upon to meet reliability needs. For long term transmission expansion studies, the methodology described above and in section 3.8.2 of the 2019-2020 study plan was utilized for considering fast-response DR and slow-response PDR resources[64].

The DR Load Impact Reports filed with the CPUC on April 3, 20l7, and other supply-side DR procurement incremental to what is assumed in the Load Impact Reports, 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

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

[64] For local capacity requirement studies, slow response DR will be utilized once the necessary characteristics have been accepted in the CPUC’s RA proceedings, as indicated in the CAISO’s comments in the RA proceeding.

supply-side DR has on the system. A description of the total supply-side DR capacity assumptions[65] is shown in Table 2.3-6.

Table 2.3-5: Existing DR Capacity Range in Local Area Reliability Studies

Supply-side DR (MW):		PG&E	SCE	SDG&E	All IOUs	Assumed Market	Assumed 30 minute responsive
Load Impact Report, 1-in-2 weather year condition portfolio-adjusted August 2027 ex-ante DR impacts at CAISO peak							
BIP		300	610[66]	6.74	917	RDRR	Yes
AP-I			50[67]	0.0	50	RDRR	Yes
AC Cycling Res[68]		61	56	7.18	124	PDR	Yes
AC Cycling Non-Res		0	20[69]	1.79	22	PDR	Yes
CBP		103[70]	143[71]	8.44	254	PDR	No
Other procurement program DR							
SCE LCR RFO,[72] post 2018			5.0		5	RDRR	Yes
DRAM[73]	2017	56.4	56.2	12	125	PDR[74]	No
	2018	79.5	88.5	13.9	182		
	2019	90.1	99.2	15.7	205		

DR capacity was 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 were modeled offline in the initial reliability study cases and were used as potential mitigation in those planning areas where reliability concerns are identified.

The factors shown in Table 2.3-7 were applied to the DR projections to account for avoided distribution losses.

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65 http://www.cpuc.ca.gov/General.aspx?id=6442451972

66 D.16-06-029 authorizes SCE to use existing BIP funds to gain 5 MW of incremental load impact for the program.

67 D.16-06-029 authorizes SCE to use existing AP-I funds to gain 4 MW of incremental load impact for the program.

68 AC Cycling programs include Smart AC (PG&E), SDP (SCE), and Summer Saver (SDG&E)

70 D.16-06-029 approved PG&E's request to terminate its AMP program. It is assumed that 82 MW from PG&E's AMP program will migrate to PG&E's CBP program.

71 D.16-06-029 approved SCE's request for an extension of its AMP program through 2017. However, it is assumed that 93 MW from SCE's AMP program will migrate to its CBP program by 2026.

72 SCE LCR RFO refers to procurement authorized in D.14-03-004 with contract approved in D.15-11-041

73 Demand Response Auction Mechanism (DRAM) is a 4-year pilot program with contract lengths set at a maximum of one year.

74 Although the 2017 DRAM solicitation could include a mix of Reliability Demand Response Resource (RDRR) and Proxy Demand Resource (PDR), for modeling we will assume it is all PDR absent more definitive information.

Table 2.3-6: Factors to Account for Avoided Distribution Losses

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

Energy Storage

CPUC Decision (D.)13-10-040 established a 2020 procurement target of 1,325 MW installed capacity of new energy storage units within the CAISO planning area, with 700 MW to be transmission-connected, 425 MW to be distribution-connected, and 200 MW to be customer-side. D.13-10-040 also allocated procurement responsibilities for these amounts to each of the three major IOUs. Energy storage to be procured by SCE and SDG&E to fill the local capacity amounts authorized under the CPUC 2012 LTPP decision discussed above was subsumed within the 2020 procurement target as well as other authorizations.

More recent CPUC approvals have also led to additional or more targeted grid-connected energy storage development.

CPUC Resolution E-4791 was adopted on May 26, 2016 and was issued to address electrical reliability risks due to the (then) moratorium on injections into the Aliso Canyon Natural Gas Storage Facility. This led to the expedited development of storage in by both SDG&E and SCE.

The CPUC is currently reviewing applications by SCE for a total of 195 MW and 780 MWh of energy storage projects that are needed to meet local capacity requirements in the Santa Clara area. These resources are part of a multi-faceted solution approved by the CAISO in the 2017-2018 Transmission Plan for the Moorpark and Santa Clara sub-areas that also included the stringing of a fourth Moorpark-Pardee 230 kV circuit on existing double circuit towers

In the 2017-2018 Transmission Plan, the CAISO also approved the Oakland Clean Energy Initiative, which included storage and preferred resources as a component of the overall plan. The portfolio procurement need for the previously approved project, has been updated due to the increase in the area’s load forecast and based on the latest Northern Oakland area load profile. The portfolio need has increased to about 36 MW and 173 MWh for 2024 from storage to sufficiently meet the current forecasted reliability need as set out in section 2.5.5.3.

The CPUC issued Resolution E-4949 on November 8, 2018 approving battery storage projects adopted to eliminate or reduce the need for (then) California ISO-issued backstop contracts for three natural gas-fired generation plants in the Greater Bay area. The CPUC had adopted Resolution E-4909 in January 2018, authorizing PG&E to hold competitive solicitations for energy storage and/or preferred resources, to reduce or eliminate the need for reliability must run (RMR) contracts in three subareas and mitigate the exercise of market power. Table 2.3-8 includes the battery energy storage system projects that were approved by the CPUC in response to the resolution.

Table 2.3-7: CPUC-Approved PG&E Contracts for Storage to Replace Natural Gas-Fired Generation in Northern California[75]

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

The procurement activities to date have been summarized by the CEC in Table 2.3-9 and the study assumption volumes are set out in each area's study sub-section later in this chapter.

Table 2.3-8: IOU Existing and Proposed Energy Storage Procurement[76]

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

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

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

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

The above information does not include storage procured as transmission assets that are not participating in the electricity market.

2.3.6 Firm Transfers

Power flow on the major internal paths and paths that cross balancing authority boundaries represents the transfers 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. The capability and power flows modeled in each scenario on these paths in the northern area assessment[77] are listed in Table 2.3-10.

Table 2.3-9: Major paths and power transfer ranges in the Northern California assessment[78]

Path	Transfer Capability/SOL (MW)	Scenario in which Path was stressed
Path 26 (N-S)	4000[79]	Summer Peak
PDCI (N-S)	3220[80]	
Path 66 (N-S)	4800[81]	
Path 15 (N-S)	-5400[82]	Spring Off Peak
Path 26 (N-S)	-3000	
Path 66 (N-S)	-3675	Winter Peak

For the spring off-peak cases in the northern California study, Path 15 flow was adjusted to a level to bring it as close to its rating limit of 5400 MW (S-N) as possible. This is typically done by increasing the import on Path 26 (S-N) into the PG&E service territory. However, the cases may not have enough resources due to retirements and may have other limitations, so it was not always possible to model high Path 15 flow in south-to-north direction. Some light load

[77] These path flows were modeled in all base cases.

[78] 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)

[79] May not be achievable under certain system loading conditions.

[80] PDCI Upgrade Project – to 3220 MW – was approved in 2017

[81] The Path 66 flows was modeled to the applicable seasonal nomogram for the base case relative to the Northern California hydro dispatch.

[82] May not be achievable under certain system loading conditions

cases model Path 26 flow close to 3000 MW in the south-to-north direction which is its rating limit.

Similarly, Table 2.3-11 lists major paths in southern California along with their current Transfer Capability (TC) or System Operating Limit (SOL) for the planning horizon and the target flows to be modeled in the southern California assessment.

Table 2.3-10: Major Path flow ranges in southern area (SCE and SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Near-Term Target Flows (MW)	Scenario in which Path was stressed, if applicable
Path 26 (N-S)	4,000	4,000	Summer Peak
PDCI (N-S)	3220	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)	400	0 to 250	Summer Peak
Path 45 (S-N)	800	0 to 300	Off Peak

2.3.7 Operating Procedures

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

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

2.3.8 Study Scenarios

2.3.8.1 Base Scenarios

The main study scenarios cover critical system conditions driven by several factors such as:

Generation:

Existing and future generation resources were modeled and dispatched to reliably operate the system under stressed system conditions. More details regarding generation modeling is provided in section 2.3.4.

Demand Level:

Since most of the CAISO footprint is a summer peaking area, summer peak conditions were 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, represented 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 were 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 or winter off-peak were also 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 were studied for both the summer and winter peak conditions. Table 2.3-12 lists the studies that were conducted in this planning cycle.

Path flows:

For local area studies, transfers on import and monitored internal paths were modeled as required to serve load in conjunction with internal generation resources. For bulk system studies, major import and internal transfer paths were stressed as described in section 2.3.4.9 to assess their FAC-013-2 Transfer Capability or FAC-014-2 System Operating Limits (SOL) for the planning horizon, as applicable. Table 2.3-12 summarizes these study areas and the corresponding base scenarios for the reliability assessment.

Table 2.3-11: Summary of study areas, horizon and peak scenarios for the reliability assessment

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

2.3.8.2 Sensitivity study cases

In addition to the base scenarios that the CAISO assessed in the reliability analysis for the 2020-2021 transmission planning process, the CAISO assessed the sensitivity scenarios identified in Table 2.3-13. The sensitivity scenarios are to assess impacts of specific assumptions on the reliability of the transmission system. These sensitivity studies include impacts of load forecast, generation dispatch, generation retirement and transfers on major paths.

Table 2.3-12: Summary of Study Sensitivity Scenarios in the CAISO Reliability Assessment

Sensitivity Study	Near-term Planning Horizon		Long-Term Planning Horizon
	2022	2025	2030
Summer Peak with high CEC forecasted load	-	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-
Off peak with heavy renewable output and minimum gas generation commitment	Southern California Bulk SCE Local Areas SDG&E Main[83]	PG&E Bulk PG&E Local Areas	-
Summer Peak with heavy renewable output and minimum gas generation commitment	PG&E Bulk PG&E Local Areas Southern California Bulk SCE Local Areas SDG&E Main	-	-
Summer Peak with high SVP forecasted load			PG&E Greater Bay Area
Summer Peak with forecasted load addition	VEA Area	VEA Area	
Summer Off peak with heavy renewable output		VEA Area	
Summer Peak with Retirement of QF Generations	-	-	PG&E Kern Area
Summer Peak without Facility Rerates			PG&E Bulk PG&E Local Areas

[83] The off-peak sensitivity case with heavy renewable output and minimum gas generation commitment is based on the 2022 Spring Off-Peak Case rather than the 2025 Spring Off-Peak Case as indicated in the study plan.

2.3.9 Contingencies

In addition to the system under normal conditions (P0), the following contingencies were evaluated as part of the study. These contingencies lists have been made available on the CAISO secured website.

Single contingency (Category P1)

- The assessment considered all possible Category P1 contingencies based upon the following:
- Loss of one generator (P1.1)[84]
- Loss of one transmission circuit (P1.2)
- Loss of one transformer (P1.3)
- Loss of one shunt device (P1.4)
- Loss of a single pole of DC lines (P1.5)

Single contingency (Category P2)

- The assessment considered 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 considered 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)[85]
- 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)

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

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

Multiple contingency (Category P4)

The assessment considered 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 considered 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)

Multiple contingency (Category P6)

The assessment considered 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 considered the Category P7 contingencies for the loss of a common structure as follows:

- Any two adjacent circuits on common structure[86] (P7.1)
- Loss of a bipolar DC lines (P7.2)

Extreme Event contingencies (TPL-001-4)

As a part of the planning assessment the CAISO assessed Extreme Event contingencies per the requirements of TPL-001-4; however the analysis of Extreme Events have not been included within the Transmission Plan unless these requirements drive the need for mitigation plans to be developed.

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

2.3.10 Study Methodology

As noted earlier, the backbone and regional planning region assessments were performed using conventional analysis tools and widely accepted generation dispatch approaches. These methodology components are briefly described below.

2.3.10.1 Study Tools

The GE PSLF program 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 was 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 was used to evaluate system performance following the contingencies of equipment at voltage level 230 kV and higher.

2.3.10.2 Technical Studies

The section explains the methodology that were used in the study:

Steady State Contingency Analysis

The CAISO performed power flow contingency analyses based on the CAISO Planning Standards[87] which are based on the NERC reliability standards and WECC regional criteria for all local areas studied in the CAISO controlled grid and with select contingencies outside of the CAISO controlled grid. The transmission system was evaluated under normal system conditions NERC Category P0 (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.

Depending on the type and technology of a power plant, several G-1 contingencies represent an outage of the whole power plant (multiple units)[88]. 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 are 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 simulated 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 included the impact of subsequent tripping of transmission elements where relay loadability limits are exceeded and generators where simulations show generator

[87] California ISO Planning Standards are posted on the ISO website at http://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf

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

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 are performed in accordance with PRC-023 Standard 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.

Post Transient Analyses

Post Transient analyses was 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.

Post Transient Voltage Stability Analyses

Post Transient Voltage stability analyses was 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.

Post Transient Voltage Deviation Analyses

Contingencies that showed significant voltage deviations in the power flow studies were selected for further analysis using WECC standards of 8% voltage deviation for P1 events.

Voltage Stability and Reactive Power Margin Analyses

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 guide for voltage support and reactive power, approved by WECC Technical Study Subcommittee (TSS) on March 30, 2006, was used for the analyses in the CAISO controlled grid. According to the guide, load is increased by 5% for Category P1 and 2.5% for other contingencies Category P2-P7 and studied to determine if the system has sufficient reactive margin. This study was conducted in the areas that have voltage and reactive concerns throughout the system.

Transient Stability Analyses

Transient stability analyses was also conducted as part of bulk area system assessment and local for critical contingencies to determine if the system is stable and exhibits positive damping of oscillations and if transient stability criteria are met as per WECC criteria and CAISO Planning Standards.

2.4 PG&E Bulk Transmission System Assessment

2.4.1 PG&E Bulk Transmission System Description

A simplified map of the PG&E bulk transmission system is shown in Figure 2.4-1.

Figure 2.4-1: Map of PG&E bulk transmission system

The 500 kV bulk transmission system in northern California consists of three parallel 500 kV lines that traverse the state from the California-Oregon border in the north and continue past Bakersfield in the south. This system transfers power between California and other states in the northwestern part of the United States and western Canada. The transmission system is also a gateway for accessing resources located in the sparsely populated portions of northern California, and the system typically delivers these resources to population centers in the Greater Bay Area and Central Valley. In addition, a large number of generation resources in the central California area are delivered over the 500 kV systems into southern California. The typical direction of power flow through Path 26 (three 500 kV lines between the Midway and Vincent substations) is from north-to-south during on-peak load periods and in the reverse direction during off-peak load periods. However, depending on the generation dispatch and the load value in northern and southern California, Path 26 may have north-to-south flow direction during off-peak periods also. The typical direction of power flow through Path 15 (Los Banos-Gates #1 and #3 500 kV lines and Los Banos-Midway #2 500 kV line) is from south-to-north during off-peak load periods and the flows can be either south-to-north or north-to-south under peak conditions. The typical direction of power flow through California-Oregon Intertie (COI, Path 66) and through the Pacific DC Intertie (bi-pole DC transmission line connecting the Celilo Substation in Washington State with the Sylmar Substation in southern California) is from north-to-south during summer on-peak load periods and in the reverse direction during off-peak load periods in California, which are the winter peak periods in Pacific Northwest.

Because of this bi-directional power flow pattern on the 500 kV Path 26 lines and on COI, both the summer peak (N-S) and spring off-peak (S-N) flow scenarios were analyzed, as well as peak and off-peak sensitivity scenarios with high renewable generation output and low gas generation output. Post transient contingency analysis was also performed for all flow patterns and scenarios (seven base cases and three sensitivity cases) described in section 2.4.2 below. Transient stability studies were performed for the selected six cases: four base cases – 2025 and 2030 Summer Peak and 2025 and 2030 Spring off-Peak and two sensitivity cases: 2025 Summer Peak with high CEC forecast and 2025 spring off-Peak with high renewable and low gas generation output.

2.4.2 Study Assumptions and System Conditions

The northern area bulk transmission system study was performed consistent with the general study methodology and assumptions described in section 2.3. The CAISO-secured website lists the contingencies that were performed as a part of this assessment. In addition, specific methodology and assumptions that are applicable to the northern area bulk transmission system study are provided in the next sections. The studies for the PG&E bulk transmission system analyzed the most critical conditions: summer peak and spring off-peak cases for the years 2022, 2025 and 2030; and winter off-peak peak case for 2030. In addition, 3 sensitivity cases were studied: the 2022 Summer Peak case with high renewable and low gas generation output, 2025 spring off-Peak case with high renewable and low gas generation output and 2025 Summer Peak with high CEC forecasted load. All single and common mode 500 kV system outages were studied, as well as outages of large generators and contingencies involving stuck circuit breakers and delayed clearing of single-phase-to-ground faults. Also, extreme events such as contingencies that involve a loss of major substations and all transmission lines in the same corridors were studied.

Generation and Path Flows

The bulk transmission system studies use the same set of generation plants that are modeled in the local area studies. The total generation in each of the local planning areas within the PG&E system are provided in Section 2.5.

Since the studies analyzed the most critical conditions, the flows on the interfaces connecting northern California with the rest of the WECC system were modeled at or close to the paths' flow limits, or as high as the generation resource assumptions allowed. Due to retirement of several large OTC power plants in northern California, flow on Path 26 between northern and southern California was modeled in some summer peak cases below its 4000 MW north-to-south rating. For the same reason and due to new renewable generation projects in the area, flow on Path 15 in some off-peak cases was modeled significantly below its 5400 MW south to north rating. Table 2.4-1 lists all major path flows affecting the 500 kV systems in northern California along with the hydroelectric generation dispatch percentage in the area.

Table 2.4-1: Major import flows and Northern California Hydro generation level for the northern area bulk study

Scenario Type	Description	COI	Path 15	Path 26	PDCI	N.Cal Hydro, %
		MW	MW	MW	MW	
Base Line	2022 Summer peak load conditions.	4790 N-S	1340 N-S	3950 N-S	3220 N-S	77%
Base Line	2022 Spring off-peak load conditions.	60 S-N	4710 S-N	2980 S-N	960 S-N	77%
Base Line	2025 Summer peak load conditions.	4770 N-S	90 N-S	3570 N-S	3200 N-S	82%
Base Line	2025 Spring off-peak load conditions.	3590 S-N	590 S-N	1800 N-S	1000 S-N	57%
Base Line	2030 Summer peak load conditions.	4510 N-S	2170 N-S	2400 N-S	3210 N-S	84%
Base Line	2030 Spring off-peak load conditions.	3610 S-N	500 S-N	800 N-S	200 S-N	45%
Base Line	2030 Winter off-peak load conditions.	2800 S-N	1660 S-N	2680 S-N	100 S-N	55%
Sensitivity	2022 Summer peak load conditions with high renewables and minimum gas	4800 N-S	400 N-S	3450 N-S	3200 N-S	77%
Sensitivity	2025 Summer peak load conditions with high CEC forecasted load	4800 N-S	1150 N-S	2420 N-S	3220 N-S	77%
Sensitivity	2025 spring off-peak load conditions with high renewables and minimum gas	1000 S-N	1220 N-S	4000 N-S	1000 S-N	57%

All power flow cases included certain amount of renewable resources, which was dispatched at different levels depending on the case studied. The assumptions on the generation installed capacity and the output are summarized in Table 2.4-2.

Table 2.4-2. Generation Assumptions – PG&E Bulk System

Study Case	Scenario Type	Description	Solar		Wind		Hydro		Thermal		Battery Storage	
			Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
2022_Spr_Off-peak	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	4,555	0	1,676	911	9,329	4,751	17,660	5,282	1,003	0
2022_sum_peak_hi_renew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	4,555	4,311	1,676	1,026	9,329	6,717	17,660	3,076	1,003	0
2022_Summer_peak	Baseline	2022 summer peak load conditions. Peak load time - hours ending 18:00.	4,555	456	1,676	1,026	9,329	6,877	17,660	12,437	1,003	0
2025_Spr_off-Peak_hi_renew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	4,555	3,793	1,676	1,057	9,329	3,776	17,660	2,182	1,039	0
2025_Spr_off-Peak	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	4,555	3,698	1,676	334	9,329	3,779	17,660	2,084	1,039	0
2025_Summer_peak_hi_CEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	4,555	97	1,676	1,167	9,329	6,910	17,660	13,968	1,039	0
2025_Summer_peak	Baseline	2025 summer peak load conditions. Peak load time - hours ending 18:00.	4,555	168	1,676	529	9,329	7,056	17,660	14,242	1,039	0
2030_Spr_off-Peak	Baseline	2030 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	4,555	2,608	1,676	331	9,329	2,766	17,660	2,819	1,050	-988
2030_Summer_peak	Baseline	2030 summer peak load conditions. Peak load time - hours ending 19:00.	4,555	0	1,676	694	9,329	7,611	17,660	14,488	1,050	0
2030_Wint_off-pk	Baseline	2030 winter off-peak load conditions. Off-peak load time - hours ending 04:00.	4,555	0	1,676	215	9,329	3,763	17,660	7,139	1,050	-996

Load Forecast

Per the CAISO planning criteria for regional transmission planning studies, the demand within the CAISO area reflects a coincident peak load for 1-in-5-year forecast conditions for the summer peak cases. Loads in the off-peak case were modeled at approximately 50-60 percent of the 1-in-5 summer peak load level. Table 2.4-3 shows the assumed load levels for selected areas under summer peak and non-peak conditions. The table shows gross PG&E load in all the cases studied and the load modifiers: Additional Achievable Energy Efficiency, output of the Behind the Meter solar PV generation, and it also shows the load for irrigational pumps and hydro pump storage plants if they are operating in the pumping mode. In the base cases, pumping load is modeled as negative generation. Net load is the gross load with the Additional Achievable Energy Efficiency and the output of the Behind the Meter solar PV generation subtracted and the pumping load added.

Table 2.4-3: Load and Load Modifier Assumptions – PG&E Bulk System

BASE CASE	Scenario Type	Description	Gross PG&E Load	AAEE	Behind the Meter PV		Net Load	Demand Response		Pumps (Irrigation and pump-storage)
					Installed	Output		Total	D2	
			MW	MW	MW	MW	MW	MW	MW	MW
2022 Summer peak load conditions.	Base Line	2022 Summer peak load conditions. Peak load time -hour ending 18:00	26,898	336	6,903	1,196	**25,366**	492	291	599
2022 Spring off-peak load conditions.	Base Line	2022 Spring off-peak load conditions. Off-peak load time - hour ending 20:00	17,551	199	6,903	0	**17,352**	492	291	1,529
2025 Summer peak load conditions.	Base Line	2025 Summer peak load conditions. Peak load time - hour ending 18:00	27,243	561	8,477	678	**26,004**	492	291	616
2025 Spring off-peak load conditions.	Base Line	2025 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	14,045	326	8,477	6,781	**6,938**	492	291	1,546
2030 Summer peak load conditions.	Base Line	2030 Summer peak load conditions. Peak load time - hour ending 19:00	27,902	939	11,044	0	**26,963**	492	291	624
2030 Spring off-peak load conditions.	Base Line	2030 Spring off-peak load conditions. Off-peak load time - hour ending 13:00	13,997	538	11,044	8,836	**4,623**	492	291	1,949
2030 Winter off-peak load conditions.	Base Line	2030 Winter off-peak load conditions. Off-peak load time - hour ending 4:00	12,546	648	11,044	0	**11,898**	492	291	1,565
2022 Summer peak load conditions with high renewables and minimum gas	Sensitivity	2022 Summer peak load conditions with high renewables and minimum gas	26,799	336	6,903	6,834	**19,629**	492	291	599
2025 Summer peak load conditions with high CEC forecasted load	Sensitivity	2025 Summer peak load conditions with high CEC forecasted load	27,243	0	8,477	254	**26,989**	492	291	616
2025 spring off-peak load conditions with high renewables and minimum gas	Sensitivity	2025 spring off-peak load conditions with high renewables and minimum gas	14,021	326	8,477	8,392	**5,303**	492	291	1,546

Existing Protection Systems

Extensive SPS or RAS are installed in the northern California area's 500 kV systems to ensure reliable system performance. These systems were modeled and included in the contingency studies. Comprehensive details of these protection systems are provided in various CAISO operating procedures, engineering and design documents.

2.4.3 Assessment and Recommendations

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standards requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The CAISO study assessment of the northern bulk system yielded the following conclusions:

The starting cases used Security Constrained Generation Dispatch. Thus, no Category P0 overloads were observed on the PG&E Bulk system on the facilities 230 kV and above. Several overloads that were observed under normal conditions on the 115 kV transmission lines could be mitigated by congestion management – reducing generation connected to these transmission lines and therefore not discussed further. The 60 kV and 70 kV facilities are not considered to be Bulk Electric System (BES), therefore, their overloads are also not discussed here further. These overloads are considered in the local area studies.

Heavy loading above 95% under normal system conditions was observed on one 500 kV line, Gates-Midway, under 2022 spring off-peak conditions. This transmission line was not overloaded under contingency conditions.

Also, heavy loading was observed on the 500/230 kV Table Mountain transformer under off-peak conditions with high hydro generation connected to this transformer in the sensitivity case. Loadings on the Table Mountain and other 500/230 kV transformers in the North PG&E area (Olinda and Round Mountain) under off-peak load conditions depend on the output of hydro generation connected to the 230 kV sides of these transformers. With high hydro generation output from these units and low load, the 500/230 kV transformers may overload. The 500/230 kV transformers in North PG&E may also overload with single and double contingencies.

There were no 230 kV lines that were overloaded or heavily loaded under normal system conditions due to optimal generation dispatch in the base cases.

- Two Category P1 overloads were identified under summer peak conditions in the base cases on the 500 kV transmission lines prior to the Round Mountain Statcom installation. These overloads were observed on the two circuits in the same corridor: Round Mountain-Table Mountain # 1 and # 2 500 kV lines with an outage of the parallel circuit. After installation of the Round Mountain Statcom that will be connected to these transmission lines off the new Fern Road Substation, both northern and southern circuits on both Round Mountain-Table Mountain 500 kV lines may overload with an outage of the parallel circuit. The overloaded lines will be Round Mountain-Fern Road # 1 and # 2 and Fern Road-Table Mountain # 1 and # 2.

  Four Category P1 overloads were identified on the 500/230 kV transformers. Round Mountain and Table Mountain transformers may overload with single contingencies of 500/230 kV transformers or 500 kV lines in the Northern part of PG&E. These overloads may occur under off-peak load conditions with high output of hydro generation in Northern California connected to the 230 kV sides of these transformers. Table Mountain 500/230 kV transformer was identified as overloaded only in the sensitivity case. Also, Gates 500/230 kV transformers # 11 or # 12 may overload with outages of the parallel Gates transformers.

  There were no 230 transmission lines that were identified as overloaded under Category P1 contingencies, but Eight Mile-Tesla 230 kV line showed high loading with an outage of the Table Mountain 500/230 kV transformer under spring off-peak load conditions.

- Under a Category P2 contingency, Round Mountain-Table Mountain # 1 500 kV line may also overload prior to installation of the Round Mountain Statcom and the circuit # 1 between the Fern Road and Table Mountain may overload after the Statcom installation. These Category P2 contingencies include an outage of the parallel 500 kV Round Mountain-Table Mountain 500 kV circuit, or the parallel Fern Road-Table Mountain circuit. The Round Mountain-Fern Road 500 kV circuit # 2 may overload under Category P2 contingency involving the parallel Round Mountain-Fern Road 500 kV circuit.

  Other Category P2 overloads include Table Mountain 500/230 kV transformer under spring off-peak conditions with the contingencies that involve an outage of a 500/230 kV transformers or 500 kV lines in the area. These overloads were identified only in the off-peak sensitivity case. No 230 kV facilities overloads were identified with P2 contingencies.

- Under Category P3 contingencies with an outage of one of the Diablo Canyon generation units and another transmission facility, in addition to the facilities that were overloaded under Categories P0 and P1, also Malin-Round Mountain 500 kV line #1 was identified as overloaded in the 2022 Summer peak sensitivity case with an outage of the parallel Malin-Round Mountain 500 kV line. Another transmission facility that may overload with a Category P3 contingency appeared to be Delevan-Cortina 230 kV transmission line if one of the Diablo nuclear units will be out together with the Olinda-Tracy 500 kV line. It was assumed that there were no system adjustments between the contingencies.
- Thirty five P6 overloaded facilities were identified in the studies in the base cases. Out of these, ten overloads were identified under summer peak conditions including three pairs of the 500 kV transmission lines in the same corridors.

  There were many more transmission facilities that overloaded with Category P6 contingencies under off-peak load conditions, than under peak load conditions. This is mainly explained by relatively high generation output in the off-peak cases while the load was low. However, there were overloads caused by generators being off-line due to the off-peak conditions while local loads still were high. There were total twenty six P6 overloads under these conditions in the base cases. Out of these, the Midway-Vincent 500 kV line # 2 also showed overload under peak load conditions with a Category P6 contingency. There were no other 500 kV transmission line overloads in the base cases under off-peak load conditions with Category P6 contingencies.

  There were six 500/230 kV transformers overloaded under off-peak load conditions with Category P6 contingencies.

  230 kV transmission facilities Category P6 overloads included three transmission lines in the San Jose area, ten 230 kV lines between Gold Hill and Tesla and three 230 kV lines in the Moss Landing and Fresno areas. There were three Category P6 115 kV overloads identified under off-peak conditions.

  Additional two 500/230 kV transformers (Tesla # 6 and Los Banos) were identified as overloaded only in the sensitivity cases, the first under peak, the second under off-peak load conditions. In the P6 studies, no generation re-dispatch was assumed after the first contingency.
- Nine overloaded facilities were identified with the 500 kV double contingencies in the same corridors, two under peak conditions, and three under off-peak conditions in the base and sensitivity cases and four only in the sensitivity cases.
- High voltages were observed on 500 kV system in Central California after Diablo Canyon Nuclear Power Plant retires, but they were mitigated by the Gates Dynamic Reactive Support Project. Low voltages, but still within the limits, were observed on the Round Mountain and Table Mountain 500 kV substations with the Category P3 contingencies prior to the Round Mountain Dynamic Reactive Support Project. No system adjustments between contingencies were assumed for the Category P3 contingencies.

- No voltage deviation or reactive margin concerns were identified in the studies. It was assumed that all appropriate RAS are in service for all double line outages that were studied.
- Dynamic stability studies used the new WECC composite load model to reflect more accurate load composition and load parameters. The load model parameters were updated. The composite load model included distributed solar PV generation modeled with the latest models that are more detailed than the distributed generation models used previously. The composite load model used the new modular option.
- The studies showed that some renewable projects tripped due to under-voltage, under-frequency or other dynamic issues. This generation tripping could be due to modelling issues. In addition, some load and distributed generation was tripped off with three-phase faults by the composite load model due to low voltages. Some small generators located close to the simulated three-phase faults went out-of-step with double contingencies and were tripped. Also several contingencies indicated some under-voltage load tripping. No criteria violations were identified in the studies.

The CAISO-proposed solutions to mitigate the identified reliability concerns are the following:

- Manage COI flow according to the seasonal nomograms
- Implement SPS to bypass series capacitors on both 500 kV transmission lines between Round Mountain and Table Mountain if any of these lines overloads.
- Implement installation of dynamic reactive support on the Round Mountain 500 kV Substation that was approved in the 2018-2019 Transmission Planning Process. It will be installed 11 miles south of Round Mountain and connected to the new Fern Road Substation where both Round Mountain-Table Mountain 500 kV lines will be looped.
- Implement installation of dynamic reactive support on the Gates 500 kV Substation that was approved in the 2018-2019 Transmission Planning Process ,

For overloads that are managed with congestion management or operating within the defined path nomograms, upgrades could be considered if congestion is observed in the production simulation and the upgrades are determined to be economically-driven. The following facilities were identified as being overloaded with the reliability mitigation plans being congestion management and operating path flows within the nomograms

- Moss Landing-Las Aguilas 230 kV transmission line
- Table Mountain 500/230 kV transformer
- Round Mountain 500/230 kV transformer
- Delevan-Cortina 230 kV line
- 230 kV lines between Gold Hill and Tesla

Other proposed mitigation solutions for thermal overloads

- Upgrade terminal equipment on the Table Mountain-Rio Oso 230 kV line

- Implement congestion management after first contingency for Category P6 overloads.
- If the Moss Landing and/or Metcalf power plants retire, the mitigation plan for Category P6 contingencies in the Metcalf-Tesla-Moss Landing-Los Banos area that result in losing the 500 kV source will be needed.

High voltages were observed on 500 kV system in Central California after Diablo Canyon Nuclear Power Plant retires. To mitigate the voltage issues, in the 2018-2019 TPP, it was proposed to install dynamic reactive support on the Round Mountain and Gates 500 kV Substations. These projects were approved and planned to be implemented in 2024.

2.4.4 Request Window Proposals

There was one proposed transmission project submitted to the CAISO through the Request Window for the PG&E Bulk system. The project was submitted by the Great Basin Transmission LLC and was named Southwest Intertie Project (SWIP)-North. The map of the proposed project is shown in Figure 2.4-1.

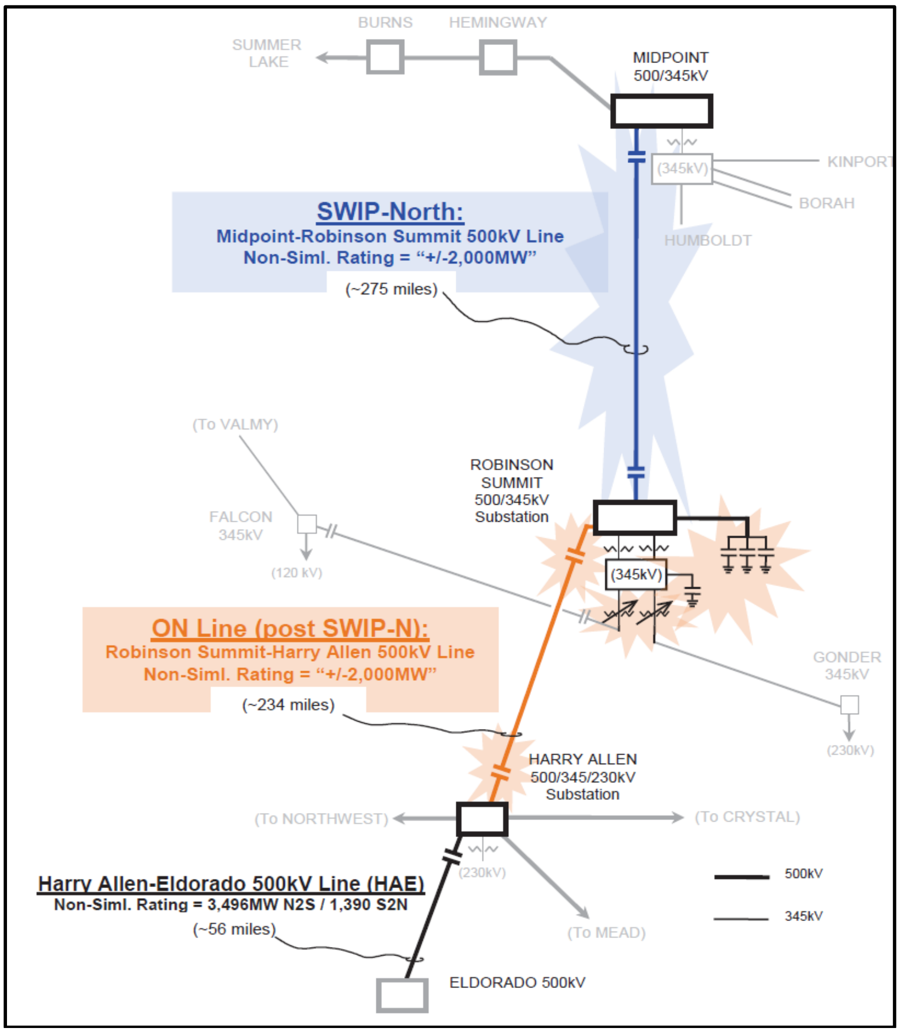
Figure 2.4-1. Preliminary Route of the SWIP North Project

Great Basin Transmission, LLC (GBT) is an affiliate of LS Power.
The proposed project is a 1000 MW transmission capacity path from Midpoint 500 kV substation in Idaho Power to Harry Allen 500 kV, a CAISO boundary substation. This 1000 MW transmission capacity path comprises of LS Power's transmission rights on Southwest Intertie

Project-North (SWIP-N) and the existing transmission path between Robinson Summit & Harry Allen 500 kV substations (ON Line), as shown in Figure 2.4-1. The project also includes an optional 500 MW, 6-hour battery storage project located at either the Midpoint substation, Eldorado substation, or both and is proposed to be operated by CAISO as a Transmission Asset. The project proponents claim that the addition of battery storage further enhances benefits of the project, which will include allowing delivery of renewables from diverse out of state locations such as Idaho and Northern Nevada and providing certainty that firm, GHG-free energy will be deliverable during the evening peak hours.

The proposed in-service date of the SWIP-N project, as well as the additional battery storage is June 2024. Figure 2.4-2 shows single-line diagram of the project.

Figure 2.4-2. Single-line Diagram of the SWIP North (SWIP-N) Project



The objective of the SWIP-N proposal is to address thermal overloads on the Bulk transmission system in Northern California and during various operating conditions while still allowing high California Oregon Intertie (COI) North to South flows. Additionally, SWIP-N can ease reliance on COI and Path 26 post-contingency RAS schemes & operating nomograms, which include tripping generation units and/or reduce COI and Path 26 flows. SWIP-N by itself can increase transfer capacity on COI path and ease congestion; in concert with the bulk energy shifting battery storage project, it can ensure delivery of between 500-1000 MW of emission free energy imports during evening peak hours, or at times of greatest need.

SWIP-N is a new 275 mile, 500 kV single circuit AC transmission line that connects the Midpoint 500 kV substation in southern Idaho to the Robinson Summit 500 kV substation in NV Energy. SWIP-N is in Phase 2B of the WECC Path Rating process and is expected to achieve a “bidirectional” WECC-approved path rating of approximately 2,000 MW. The existing ON Line is also expected to achieve a “bidirectional” rating of 2000 MW once SWIP-N is constructed.

SWIP-N addresses several thermal overloads on the bulk transmission system in northern California during summer peak conditions and other operating conditions with high California Oregon Intertie (COI) North to South flows. However, not all overloads identified in the 2020-2021 TPP in the area may be mitigated by the SWIP-N project.

The CAISO reviewed this proposal. Although the CAISO agrees that the proposed project can mitigate the identified overloads that it claims to mitigate, we don’t consider that there is a reliability need for such project, since the overloads can be mitigated with substantially lower cost by operating within the COI nomogram or by congestion management reducing generation in the area of overloads. The project appears to be rather an economic project than a reliability project. This project can be submitted as economic in the next Transmission Planning cycle.

2.4.5 Recommendations

The bulk system assessment identified a number of P1 to P7 contingencies that result in transmission constraints. The recommended solutions to mitigate the identified reliability concerns are the following:

- Manage COI flow according to the seasonal nomograms
- Implement SPS to bypass series capacitors on the Round Mountain-Fern Road-Table Mountain 500 kV lines # 1 and # 2 if any of these lines overloads.
- Implement installation of dynamic reactive support on the Round Mountain 500 kV Substation that was approved in the 2018-2019 Transmission Planning Process. This reactive support will be installed 11 miles south of Round Mountain and connected to the Round Mountain-Table Mountain 500 kV lines # 1 and # 2.
- Implement installation of dynamic reactive support on the Gates 500 kV Substation that was approved in the 2018-2019 Transmission Planning Process ,

For overloads that are managed with congestion management or operating within the defined path nomograms, upgrades could be considered if congestion is observed in the production simulation and the upgrades are determined to be economically-driven. The following facilities were identified as being overloaded with the reliability mitigation plans being congestion management and operating path flows within the nomograms

- Moss Landing-Las Aguilas 230 kV transmission line
- Table Mountain 500/230 kV transformer
- Round Mountain 500/230 kV transformer
- Delevan-Cortina 230 kV line
- 230 kV lines between Gold Hill and Tesla

Other proposed mitigation solutions for thermal overloads

- Upgrade terminal equipment on the Table Mountain-Rio Oso 230 kV line
- Implement congestion management after first contingency for Category P6 overloads.
- If the Moss Landing and/or Metcalf power plants retire, the mitigation plan for Category P6 contingencies in the Metcalf-Tesla-Moss Landing-Los Banos area that result in losing the 500 kV source will be needed.

High voltages were observed on 500 kV system in Central California after Diablo Canyon Nuclear Power Plant retires. To mitigate the voltage issues, in the 2018-2019 TPP, it was proposed to install dynamic reactive support on the Round Mountain and Gates 500 kV Substations. These projects were approved and planned to be implemented in 2024.

2.5 PG&E Local Areas

2.5.1 Humboldt Area

2.5.1.1 Area Description

The Humboldt area covers approximately 3,000 square miles in the northwestern corner of PG&E's service territory. Some of the larger cities that are served in this area include Eureka, Arcata, Garberville and Fortuna. The highlighted area in the adjacent figure provides an approximate geographical location of the PG&E Humboldt area.

Humboldt's electric transmission system is comprised of 60 kV and 115 kV transmission facilities. Electric supply to this area is provided primarily by generation at Humboldt Bay power plant and local qualifying facilities. Additional electric supply is provided by transmission imports via two 100 mile, 115 kV circuits from the Cottonwood substation east of this area and one 80 mile 60 kV circuit from the Mendocino substation south of this area.

Historically, the Humboldt area experiences its highest demand during the winter season. Accordingly, system assessments in this area include the technical studies for the scenarios under summer peak and winter peak conditions that reflect different load conditions mainly in the coastal areas.

2.5.1.2 Area-Specific Assumptions and System Conditions

In accordance with TPL-001-4 Requirement R2.6, this area relied on the past studies from the 2019-2020 Transmission Planning Process.

A new "no rerate" sensitivity was included in this year's study plan. The new sensitivity scenario was studied for the Humboldt Area this year and was performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO-secured participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Humboldt Area study are provided in Table 2.5-1 and Table 2.5-2.

Table 2.5-1: Humboldt load and load modifier assumption

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
						Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
1	HUMB-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours ending 18:00.	124	1	15	0	124	4	3
2	HUMB-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours ending 18:00.	128	1	18	0	126	4	3
3	HUMB-2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours ending 19:00.	128	1	18	0	126	4	3
4	HUMB-2022-SOP	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	110	1	15	0	110	4	3
5	HUMB-2025-SOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	86	0	18	14	72	4	3
6	HUMB-2022-WP	Baseline	2022 winter peak load conditions. Peak load time - hours ending 19:00.	137	1	15	0	136	4	3
7	HUMB-2025-WP	Baseline	2025 winter peak load conditions. Peak load time - hours ending 19:00.	140	2	18	0	139	4	3
8	HUMB-2030-WP	Baseline	2030 winter peak load conditions. Peak load time - hours ending 19:00.	146	3	23	0	144	4	3
9	HUMB-2025-SP-HiCEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	128	0	18	0	128	4	3
10	HUMB-2025-SOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	86	0	18	17	69	4	3
11	HUMB-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	124	1	15	15	109	4	3
12	HUMB-2030-SP-xReRates	Sensitivity	2030 summer peak load conditions with QF retirement sensitivity	144	9	46	0	135	3	3

Table 2.5-2: Humboldt generation assumption

S. No.	Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	HUMB-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours ending 18:00.	0	0	0	0	0	5	0	259	172
2	HUMB-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours ending 18:00.	0	0	0	0	0	5	0	259	187
3	HUMB-2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	5	0	259	187
4	HUMB-2022-SOP	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	0	0	0	0	0	5	0	259	187
5	HUMB-2025-SOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	0	0	0	0	0	5	0	259	187
6	HUMB-2022-WP	Baseline	2022 winter peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	5	0	259	229
7	HUMB-2025-WP	Baseline	2025 winter peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	5	0	259	15
8	HUMB-2030-WP	Baseline	2030 winter peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	5	0	259	15
9	HUMB-2025-SP-HiCEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	0	0	0	0	0	5	0	259	187
10	HUMB-2025-SOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	0	0	0	0	0	5	0	259	187
11	HUMB-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	0	0	0	0	0	5	0	259	15
12	HUMB-2030-SP-xReRates	Sensitivity	2030 summer peak load conditions with QF retirement sensitivity	0	0	0	0	0	5	0	259	187

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with an exception of the approved projects identified in Table 2.5-3 that were not modeled in the study scenario base cases.

Table 2.5-3: Humboldt Approved Project not Modeled in Base Case

Project Name	TPP Approved In	Current ISD
None		

2.5.1.3 Assessment Summary

In accordance with TPL-001-4 Requirement R2.6, this area relied on the past studies from the 2019-2020 Transmission Planning Process.

Due to the change in contingency definition for Garberville SVC, there was a new P1 contingency that resulted in voltage violations in the Garberville 60kV area for study years 2022 and 2030. The CAISO is recommending to continue to monitor as there wasn't a violation in the 2025 study year.

One previously approved project, Maple Creek Reactive support, is recommended to be relocated to Willow Creek 60kV due to infrastructure limitations at the Maple Creek Substation. Since Willow Creek is an adjacent station and would address the need in the area for a lower cost, it is recommended that a 10 MVA STATCOM be installed at Willow Creek 60kV substation. The new estimated cost for the project is $7-$14M.

Summary of review of previously approved projects

There is no previously approved projects in the Humboldt area not modeled in the study cases either due to constructability issues, cost increase or misalignment of scope of the project and nature of the current need.

Table 2.5-4: Recommendation for previously approved projects not modeled in the study cases

Project Name	Recommendation
None	None

Details of the review of previously approved projects not modeled in study cases are presented in Appendix B.

2.5.1.4 Request Window Submissions

There are no Request Window submissions for the Humboldt Area.

2.5.1.5 Consideration of Preferred Resources and Energy Storage

In accordance with TPL-001-4 Requirement R2.6, this area relied on the past studies from the 2019-2020 Transmission Planning Process. As such, the consideration of preferred resources and energy storage in Humboldt area is same as presented in the 2019-2020 Transmission Plan.

Table 2.5-5: Reliability Issues in Sensitivity Studies

Facility	Category
None	

2.5.1.6 Recommendation

Since this area relied on the use of the 2019-2020 TPP reliability assessment and no further issues have been identified, no mitigation is recommended for the Humboldt area.

One previously approved project, Maple Creek reactive support, is recommended to have scope change to relocate to the adjacent Willow Creek 60kV substation.

2.5.2 North Coast and North Bay Areas

2.5.2.1 Area Description

The highlighted areas in the adjacent figure provide an approximate geographical location of the North Coast and North Bay areas.

The North Coast area covers approximately 10,000 square miles north of the Bay Area and south of the Humboldt area along the northwest coast of California. It has a population of approximately 850,000 in Sonoma, Mendocino, Lake and a portion of Marin counties, and extends from Laytonville in the north to Petaluma in the south. The North Coast area has both coastal and interior climate regions. Some substations in the North Coast area are summer peaking and some are winter peaking. A significant amount of North Coast generation is from geothermal (The Geysers) resources. The North Coast area is connected to the Humboldt area by the Bridgeville-Garberville-Laytonville 60 kV lines. It is connected to the North Bay by the 230 kV and 60 kV lines between Lakeville and Ignacio and to the East Bay by 230 kV lines between Lakeville and Vaca Dixon.

North Bay encompasses the area just north of San Francisco. This transmission system serves Napa and portions of Marin, Solano and Sonoma counties.

The larger cities served in this area include Novato, San Rafael, Vallejo and Benicia. North Bay's electric transmission system is composed of 60 kV, 115 kV and 230 kV facilities supported by transmission facilities from the North Coast, Sacramento and the Bay Area. Like the North Coast, the North Bay area has both summer peaking and winter peaking substations. Accordingly, system assessments in this area include the technical studies for the scenarios under summer peak and winter peak conditions that reflect different load conditions mainly in the coastal areas.

2.5.2.2 Area-Specific Assumptions and System Conditions

In accordance with TPL-001-4 Requirement R2.6, this area relied on the past studies from the 2019-2020 Transmission Planning Process.

A new "no rerate" sensitivity was included in this year's study plan. The new sensitivity scenario was studied for the North Coast North Bay Area this year and was performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO-secured participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the North Coast and North Bay Area study are shown in Table 2.5-5 and Table 2.5-6.

Table 2.5-5: North Coast and North Bay load and load modifier assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
						Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
1	NCNB-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours ending 18:00.	1,489	12	464	0	1,477	16	10
2	NCNB-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours ending 18:00.	1,511	19	567	0	1,492	16	10
3	NCNB-2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours ending 19:00.	1,567	33	743	0	1,534	16	10
4	NCNB-2022-SOP	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	1,094	10	464	0	1,084	16	10
5	NCNB-2025-SOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	833	0	567	454	380	16	10
6	NCNB-2022-WP	Baseline	2022 winter peak load conditions. Peak load time - hours ending 19:00.	1,312	13	464	0	1,299	16	10
7	NCNB-2025-WP	Baseline	2025 winter peak load conditions. Peak load time - hours ending 19:00.	1,331	22	567	0	1,308	16	10
8	NCNB-2030-WP	Baseline	2030 winter peak load conditions. Peak load time - hours ending 19:00.	1,380	39	743	0	1,341	16	10
9	NCNB-2025-SP-HiCEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	1,511	0	567	0	1,511	16	10
10	NCNB-2025-SOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	833	0	567	561	272	16	10
11	NCNB-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	1,489	12	464	459	1,018	16	10
12	NCNB-2030-SP-xReRates	Sensitivity	2030 summer peak load conditions with QF retirement sensitivity	1,567	33	743	0	1,534	16	10

Table 2.5-6: North Coast and North Bay generation assumptions

S. No.	Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	NCNB-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours ending 18:00.	0	0	0	0	0	25	12	1,535	760
2	NCNB-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours ending 18:00.	0	0	0	0	0	25	12	1,535	757
3	NCNB-2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	25	17	1,535	750
4	NCNB-2022-SOP	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	0	0	0	0	0	25	3	1,535	732
5	NCNB-2025-SOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	0	0	0	0	0	25	3	1,535	725
6	NCNB-2022-WP	Baseline	2022 winter peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	25	12	1,535	760
7	NCNB-2025-WP	Baseline	2025 winter peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	25	12	1,535	757
8	NCNB-2030-WP	Baseline	2030 winter peak load conditions. Peak load time - hours ending 19:00.	0	0	0	0	0	25	17	1,535	750
9	NCNB-2025-SP-HiCEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	0	0	0	0	0	25	12	1,535	757
10	NCNB-2025-SOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	0	0	0	0	0	25	12	1,535	778
11	NCNB-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	0	0	0	0	0	25	2	1,535	760
12	NCNB-2030-SP-xReRates	Sensitivity	2030 summer peak load conditions with QF retirement sensitivity	0	0	0	0	0	25	12	1,535	750

The transmission modeling assumption is consistent with the general assumptions described in section 2.3.

2.5.2.3 Assessment Summary

In accordance with TPL-001-4 Requirement R2.6, this area relied on the past studies from the 2019-2020 Transmission Planning Process.

There are no new overloads observed in the North Coast and North Bay area. However, CAISO recommends expanding scope of the previously approved Fulton-Fitch Mountain 60 kV Line Increase (Fulton-Hopland 60 kV Line) Project as CAISO has identified the Fitch Mountain Tap #2 60 kV overloads in the previous assessment and that the rerate would not adequately mitigate the overload. The scope of the previously approved project will be expanded to include reconductoring 0.07 mile line of Fitch Mountain Tap #2 60 kV line.

2.5.2.4 Request Window Submissions

There was no project submission in the North Coast North Bay area in the 2020 request window.

2.5.2.5 Consideration of Preferred Resources and Energy Storage

In accordance with TPL-001-4 Requirement R2.6, this area relied on the past studies from the 2019-2020 Transmission Planning Process. As such, the consideration of preferred resources and energy storage in the North Coast and North Bay area is same as presented in the 2019-2020 Transmission Plan.

Table 2.5-7: Reliability Issues in Sensitivity Studies

Facility	Category
None	

2.5.2.6 Recommendation

Since this area relied on the use of the 2019-2020 TPP reliability assessment and no further issues have been identified, no mitigation is recommended for the North Coast North Bay area.

However, the CAISO recommends expanding scope of the following previously approved project.

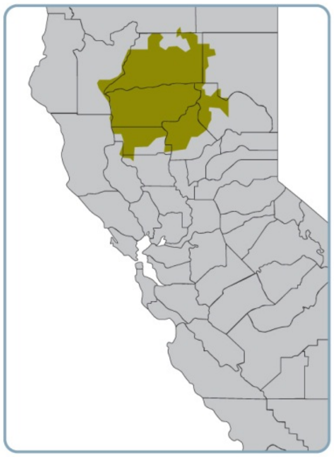
- Fulton-Fitch Mountain 60 kV Line Increase (Fulton-Hopland 60 kV Line)

  The expanded scope will include reconductoring of the 0.07 mile line of Fitch Mountain Tap #2 60 kV line. Estimated additional cost is $500k.

2.5.3 North Valley Area

2.5.3.1 Area Description

The North Valley area is located in the northeastern corner of the PG&E's service area and covers approximately 15,000 square miles. This area includes the northern end of the Sacramento Valley as well as parts of the Siskiyou and Sierra mountain ranges and the foothills. Chico, Redding, Red Bluff and Paradise are some of the cities in this area. The adjacent figure depicts the approximate geographical location of the North Valley area.



North Valley's electric transmission system is composed of 60 kV, 115 kV, 230 kV and 500 kV transmission facilities. The 500 kV facilities are part of the Pacific AC Intertie between California and the Pacific Northwest. The 230 kV facilities, which complement the Pacific AC Intertie, also run north-to-south with connections to hydroelectric generation facilities. The 115 kV and 60 kV facilities serve local electricity demand. In addition to the Pacific AC Intertie, one other external interconnection exists connecting to the PacifiCorp system. The internal transmission system connections to the Humboldt and Sierra areas are via the Cottonwood, Table Mountain, Palermo and Rio Oso substations.

Historically, North Valley experiences its highest demand during the summer season; however, a few small areas in the mountains experience highest demand during the winter season. Accordingly, system assessments in this area included technical studies using load assumptions for these summer peak conditions.

2.5.3.2 Area-Specific Assumptions and System Conditions

The North Valley Area power flow study was performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO-secured market participant portal provides more details of contingencies that were performed as part of this assessment. With regards to transient stability studies and in accordance with TPL-001-4 Requirement R2.6, this area relied on the past studies from the 2019-2020 Transmission Planning Process in which no transient stability issues were identified in North Valley area. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the North Valley Area study are shown in Table 2.5-8 and Table 2.5-9.

Table 2.5-8: North Valley load and load modifier assumptions

Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
NVLY-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours between 18:00 and 19:00.	869	7	353	0	862	36	28
NVLY-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours between 18:00 and 19:00.	898	11	434	0	887	36	28
NVLY-2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours between 18:00 and 19:00.	937	19	563	0	918	36	28
NVLY-2022-SOP	Baseline	2022 spring off-peak load conditions. Off-peak load time – hours ending 20:00.	405	6	353	0	399	36	28
NVLY-2025-SOP	Baseline	2025 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	312	0	434	347	-35	36	28
NVLY-2025-SP-HiCEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	898	0	434	0	898	36	28
NVLY-2025-SOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	312	0	434	429	-117	36	28
NVLY-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	869	7	353	349	513	36	28
NVLY-2030-SP-xReRates	Sensitivity	2030 summer peak load conditions with no rerates	937	19	563	0	918	36	28

Table 2.5-9: North Valley generation assumptions

Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
NVLY-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours between 18:00 and 19:00.	0	0	0	103	68	1,768	1,622	1,067	718
NVLY-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours between 18:00 and 19:00.	0	0	0	103	68	1,792	1,566	1,067	734
NVLY-2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours between 18:00 and 19:00.	0	0	0	103	68	1,752	1,597	1,067	658
NVLY-2022-SOP	Baseline	2022 spring off-peak load conditions. Off-peak load time – hours ending 20:00.	0	0	0	103	57	1,768	1,268	1,067	414
NVLY-2025-SOP	Baseline	2025 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	0	0	0	103	21	1,792	888	1,067	97
NVLY-2025-SP-HiCEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	0	0	0	103	68	1,792	1,566	1,067	752
NVLY-2025-SOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	0	0	0	103	64	1,768	1,646	1,067	405
NVLY-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	0	0	0	103	64	1,768	1,646	1,067	405
NVLY-2030-SP-xReRates	Sensitivity	2030 summer peak load conditions with no rerates	0	0	0	103	68	1,752	1,597	1,067	658

The transmission modeling assumption is consistent with the general assumptions described in section 2.3.

2.5.3.3 Assessment Summary

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2020-2021 reliability assessment of the PG&E North Valley Area has identified several reliability concerns consisting of thermal overloads and voltage criteria violations under Category P0 to P7 contingencies most of which are addressed by previously approved projects. Details of the reliability assessment are presented in Appendix B.

The following new overloads and voltage issues were observed in the North Valley area.

Palermo – Wyandotte 115 kV Line Section Overload

An overload under P0 condition was identified on a short section (0.05 circuit miles) of the Palermo – Wyandotte 115 kV line terminating at the Wyandotte substation in the near term. The CAISO is recommending approval of the "Palermo-Wyandotte 115 kV Line Section Reconductoring project which includes reconductoring of the short line section and removing any limiting component. The estimated cost of this project is $0.125M to $0.250M and in-service date is May 2023. In the interim the area will rely on operating action plan.

Overload on 115 kV and 60 kV Network Connecting to Cottonwood Substation

The P5-5 (Failure of a non-redundant relay) contingency at Cottonwood 230 kV bus overloads the underlying 115 kV and 60 kV network connected to the Cottonwood substation under the peak load scenario in the near term. The CAISO recommendation is the protection upgrade at Cottonwood 230 kV substation.

Round Mountain – Cottonwood 230 kV Line Overload

The P5-5 (Failure of a non-redundant relay) contingency at Round Mountain 230 kV bus overloads the Round Mountain – Cottonwood 230 kV Line under the peak load scenario in the near term. The CAISO recommendation is the protection upgrade at Round Mountain 230 kV substation.

Oregon Trail 115 kV bus Low Voltage Issue

A P2-1 contingency on the Cascade – Cottonwood 115 kV Line at Oregon Trail, and the subsequent trip of the Cascade – Crag View 115 kV line due to SPS action, results in low voltage in the area under the peak load scenario in the near term. This voltage issue will be addressed as part of the overall plan to address voltage issues across the PG&E system that are further discussed in Appendix B.

Sycamore Creek – Notre Dame – Table Mountain 115 kV Line Overload

In the near term, an overload was identified on the Sycamore Creek – Notre Dame Junction section of the Sycamore Creek – Notre Dame – Table Mountain 115 kV line following the P2-1 contingency of opening the Butte end of the Butte – Sycamore Creek 115 kV Line without a fault. The CAISO continues to work with the PTO to finalize the evaluation of the above alternatives and will recommend an alternative to address the issue in future TPP cycles.

Glen #3 60 kV line from Anita to Chico JCT Overload

Due to increase in load forecast, Glen #3 60 kV line from Anita to Chico JCT overloads under P0 condition in the long term. The CAISO will continue to monitor the load forecast in future planning cycles.

2.5.3.4 Request Window Submissions

Palermo-Wyandotte 115 kV Line Section Reconductoring Project

PG&E proposed the Palermo-Wyandotte 115 kV Line Section Reconductoring Project to address P0 issue on a short section (0.05 circuit miles) of the line terminating at the Wyandotte substation. The proposed project scope includes the reconductoring of the short line section with a higher capacity conductor and to remove any limiting component to achieve the full conductor capacity. The project is expected to cost $0.125 million to $0.250 million with an estimated in-service date of May 2023. The CAISO's recommendation is to approve the project.

2.5.3.5 Consideration of Preferred Resources and Energy Storage

As presented in Section2.5.2, about 11 MW of AAEE and around 434 MW of installed behind-the-meter PV reduced the North Valley Area load in 2025 by about 1%. This year's reliability assessment for North Valley Area included "high CEC forecast" sensitivity case for year 2025 which modeled no AAEE. A comparison of the reliability issues identified in the 2024 summer peak baseline case and the "high CEC forecast" sensitivity case shows that facility overloads shown in Table 2.5-10 are potentially avoided due to reductions in net load:

Table 2.5-10: Reliability Issues in Sensitivity Studies

Facility	Category
Keswick - Cascade 60 kV	P6
Table Mountain - Butte #1 115 kV	P2
Paradise - Table Mountain 115 kV	P2

Furthermore, more than 28 MW of demand response is modeled in the North Valley Area. These resources are modeled offline in the base case and are used as potential mitigations as needed. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

2.5.3.6 Recommendation

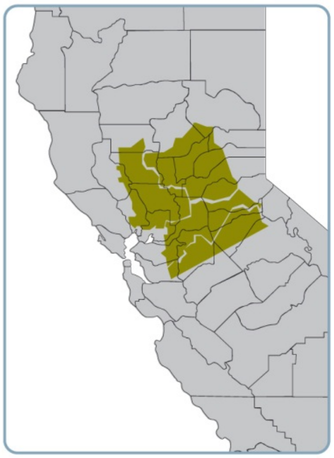
Based on the studies performed in the 2020-2021 transmission planning cycle, several reliability concerns were identified for the PG&E North Valley Area. These concerns consisted of thermal overloads and voltage concerns under Category P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the North Valley area. To address new reliability issues identified in this cycle, the CAISO is recommending the approval of the Palermo-Wyandotte 115 kV Line Section Reconductoring Project to address P0 issue on the line section. The CAISO is also recommending protection upgrades at Cottonwood 230 kV and Round Mountain 230 kV substations to address overload under P5-5 contingency.

The CAISO continues to work with the PTO to address P2-1 overload on Sycamore Creek – Notre Dame – Table Mountain 115 kV and the P2-1 low voltage at Oregon Trail 115 kV bus. The remaining issues are only under sensitivity scenario or in the long term. The CAISO continues to monitor those issues in future planning cycles.

2.5.4 Central Valley Area

2.5.4.1 Area Description

The Central Valley area is located in the eastern part of PG&E's service territory. This area includes the central part of the Sacramento Valley and it is composed of the Sacramento, Sierra, Stockton and Stanislaus divisions as shown in the figure below.



Sacramento Division

The Sacramento division covers approximately 4,000 square miles of the Sacramento Valley, but excludes the service territory of the Sacramento Municipal Utility District and the Roseville Electric. Cordelia, Suisun, Vacaville, West Sacramento, Woodland and Davis are some of the cities in this area. The electric transmission system is composed of 60 kV, 115 kV, 230 kV and 500 kV transmission facilities. Two sets of 230 and 500 kV transmission paths make up the backbone of the system.

Sierra Division

The Sierra division is located in the Sierra-Nevada area of California. Yuba City, Marysville, Lincoln, Rocklin, El Dorado Hills and Placerville are some of the major cities located within this area. Sierra's electric transmission system is composed of 60 kV, 115 kV and 230 kV transmission facilities. The 60 kV facilities are spread throughout the Sierra system and serve many distribution substations. The 115 kV and 230 kV facilities transmit generation resources from north-to-south. Generation units located within the Sierra area are primarily hydroelectric facilities located on the Yuba and American River water systems. Transmission interconnections to the Sierra transmission system are from Sacramento, Stockton, North Valley, and the Sierra Pacific Power Company (SPP) in the state of Nevada (Path 24).

Stockton Division

Stockton division is located east of the Bay Area. Electricity demand in this area is concentrated around the cities of Stockton and Lodi. The transmission system is composed of 60 kV, 115 kV and 230 kV facilities. The 60 kV transmission network serves downtown Stockton and the City of Lodi. Lodi is a member of the Northern California Power Agency (NCPA), and it is the largest city that is currently served by the 60 kV transmission network. The 115 kV and 230 kV facilities support the 60 kV transmission network.

Stanislaus Division

Stanislaus division is located between the Greater Fresno and Stockton systems. Newman, Gustine, Crows Landing, Riverbank and Curtis are some of the cities in the area. The transmission system is composed of 230 kV, 115 kV and 60 kV facilities. The 230 kV facilities connect Bellota to the Wilson and Borden substations. The 115 kV transmission network is located in the northern portion of the area and it has connections to qualifying facilities generation located in the San Joaquin Valley. The 60 kV network located in the southern part of the area is a radial network. It supplies the Newman and Gustine areas and has a single connection to the transmission grid via two 115/60 kV transformer banks at Salado.

Historically, the Central Valley area experiences its highest demand during the summer season. Accordingly, system assessments in these areas included technical studies using load assumptions for the summer peak conditions.

2.5.4.2 Area-Specific Assumptions and System Conditions

The Central Valley Area power flow study was performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO-secured market participant portal provides more details of contingencies that were performed as part of this assessment. With regards to transient stability studies and in accordance with TPL-001-4 Requirement R2.6, this area relied on the past studies from the 2019-2020 Transmission Planning Process in which no transient stability issues were identified in Central Valley area. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Central Valley Area study are shown in Table 2.5-11 and Table 2.5-12.

Table 2.5-11: Central Valley load and load modifier assumptions

Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
CVLY-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours ending 19:00.	4,054	33	1,556	0	4,021	101	59
CVLY-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours ending 19:00.	4,150	53	1,917	0	4,097	101	59
CVLY-2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours ending 19:00.	4,381	93	2,459	0	4,287	101	59
CVLY-2022-SpOP	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	2,044	28	1,556	0	2,016	101	59
CVLY-2025-SpOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	1,572	0	1,917	1533	39	101	59
CVLY-2025-SP-Hi-CEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	3,904	0	1,917	58	3,846	101	59
CVLY-2025-SpOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	1,572	0	1,917	1898	(326)	101	59
CVLY-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	3,897	47	1,556	1540	2,310	101	59

Table 2.5-12: Central Valley generation assumptions

Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
CVLY-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours ending 19:00.	12	38	1	1125	611	1401	1136	1,408	1,104
CVLY-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours ending 19:00.	12	38	1	1021	553	1427	1140	1,408	1,058
CVLY-2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours ending 19:00.	12	38	1	1019	552	1379	954	1,402	1,025
CVLY-2022-SpOP	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	12	38	1	1125	600	1401	1086	1,408	253
CVLY-2025-SpOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	12	38	19	1021	197	1427	779	1,408	223
CVLY-2025-SP-Hi-CEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	12	38	1	1021	553	1427	1140	1,408	1,049
CVLY-2025-SpOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	12	38	35	1125	676	1401	1267	1,408	270
CVLY-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	12	38	35	1125	676	1401	1364	1,408	420

The transmission modeling assumptions were consistent with the general assumptions described in section 2.3.

2.5.4.3 Assessment Summary

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2020-2021 reliability assessment of the PG&E Central Valley Area has identified several reliability concerns consisting of thermal overloads and voltage criteria violations under Category P0 to P7 contingencies most of which are addressed by previously approved projects. The areas where additional mitigation requirement were identified are discussed below.

In the Near-term planning horizon a number of overloads were observed that will be addressed when the previously approved projects are complete and in-service. In the interim, the CAISO will continue to rely on operational action plans to mitigate the constraints.

The following new overloads and voltage issues were observed in the Central Valley area.

Vaca – Plainfield 60 kV Line Overload

The total load at Plainfield and Winters substations that are radially supplied by the Vaca – Plainfield 60 kV Line loads the line to around 34 MW by year 2025 and 36 MW by year 2030 which causes P0 overload on the line. In 2018-2019 TPP the CAISO recommended PG&E reconfigure the Plainfield substation and connect load bank #1 to the E. Nicolaus substation. The CAISO recommends PG&E continue that practice. The CAISO will continue to monitor the load forecast in this area in future planning cycles.

Placerville and Eldorado Area

P2-1 contingencies resulted in high loading (97%) on the Gold Hill – Eldorado 115 kV lines in the baseline scenario in2030. Overloads were identified in the area for the P2-1 contingency in the rerate sensitivity case in 2030. The CAISO will continue to monitor the forecast load in the Placerville and Eldorado area to address the forecast P2-1 overloads in 2029.

Tesla 115 kV Bus

P2-4 contingency at Tesla 115 kV substation resulted in overloads and voltage issues in the underlying 115 kV network in the area. The CAISO is considering either an SPS or the upgrade of the Tesla 115 kV substation to address this issue. Alternatives for the SPS and the substation upgrade will be evaluated in the next planning cycle and the preferred solution will be recommended.

Manteca #1 60 kV Line Section Overload

An overload under P0 condition was identified on a short section (1.13 circuit miles) of the Manteca #1 60 kV line between Manteca Jct. and Banta Carbona Tap in the near term. The CAISO is recommending approval of the "Manteca #1 60 kV Line Section Reconductoring" project which includes reconductoring of the overloaded line section and removing any limiting component. The estimated cost of this project is $1.4M to $2.8M and in-service date is May 2024. In the interim the area will rely on operating action plan.

Kasson – Kasson Junction 1 115 kV Line Section Overload

An overload under P1 condition was identified on a short section (0.08 circuit miles) of the 115 kV line section between Kasson Junction 1 and Kasson 115 kV substation. The CAISO is recommending approval of the "Kasson – Kasson Junction 1 115 kV Line Section Reconductoring" project which includes reconductoring of the overloaded line section and removing any limiting component. The estimated cost of this project is $0.25M to $0.5M and in-service date is May 2023. In the interim the area will rely on operating action plan.

Brighton – Davis 115 kV Line Overload

An overload under P1 condition was identified on the Brighton – Davis 115 kV line for the contingency of the Brighton – West Sacramento 115 kV line. The CAISO continues to work with the PTO to finalize the evaluation of alternative mitigation measures and will recommend an alternative to address the issue in future TPP cycles.

Overload on the 115 kV Network between Gold Hill, Drum, and Rio Oso substations

The P5-5 (Failure of a non-redundant relay) contingency at Gold Hill 230 kV bus overloads the underlying 115 kV network between Gold Hill, Drum, and Rio Oso 115 kV substations under the peak load scenario. The CAISO recommendation is the protection upgrade at Gold Hill 230 kV substation.

Overload on the 115 kV Network between Bellota and Manteca 115 kV substations

The P5-5 (Failure of a non-redundant relay) contingency at Bellota 230 kV bus overloads the underlying 115 kV network between Bellota and Manteca 115 kV substations under the peak load scenario. The CAISO recommendation is the protection upgrade at Bellota 230 kV substation.

Salado – Newman #1 and #2 60 kV Overload

P1 contingency of one of the Salado – Newman #1 or #2 60 kV lines under peak load condition overloads the remaining line. There is an operating procedure currently in place to manage the area. The CAISO is working with PG&E to assess different alternatives to address the issue and recommends to continue to rely on the operating procedure while other mitigation measures are being evaluated.

Kasson – Louise 60 kV and Manteca – Louise 60 kV Lines Overload

The P1 contingency of the Kasson 115/60 kV transformer overloads the Kasson – Louise 60 kV and Manteca – Louise 60 kV lines. This issue is currently managed by Kasson SPS which trips the Kasson – Louise 60 kV line following the P1 contingency of Kasson 115/60 kV transformer. The CAISO is working with PG&E to assess different alternatives to address the issue and recommends to continue to rely on the SPS while other mitigation measures are being evaluated

Drum – Rio Oso #2 115 kV Line Overload

An overloads was identified on the Drum – Rio Oso #2 115 kV line under the P2-1 contingency of opening the Higgins end of the Drum – Higgins 115 kV line without a fault. The CAISO recommends an SPS to either trip or run back generation in the area to address the overload.

Drum – Higgins 115 kV Line Overload

An overload on Drum – Higgins 115 kV line was identified under P7 contingency of Placer – Gold Hill #1 and #2 115 kV lines in the year 2030. The CAISO will continue to monitor the load forecast in the area and will address the issues with an SPS as a potential mitigation measure.

2.5.4.4 Request Window Submissions

There were two projects submitted into the 2019 Request Window.

Manteca #1 60 kV Line Section Reconductoring Project

PG&E proposed the Manteca #1 60 kV Line Section Reconductoring Project to address P0 issue on a short section (1.13 circuit miles) of the line between Manteca Jct. and Banta Carbona Tap. The proposed project scope includes the reconductoring of the line section with a higher capacity conductor and to remove any limiting component to achieve the full conductor capacity. The project is expected to cost $1.4 million to $2.8 million with an estimated in-service date of May 2024. The CAISO's recommendation is to approve the project.

Kasson – Kasson Junction 1 115 kV Line Section Reconductoring Project

PG&E proposed the Kasson – Kasson Junction 1 115 kV Line Section Reconductoring Project to address P1 issue on a short section (0.08 circuit miles) of the line between Kasson Junction 1 and Kasson 115 kV substation. The proposed project scope includes the reconductoring of the line section with a higher capacity conductor and to remove any limiting component to achieve the full conductor capacity. The project is expected to cost $0.25 million to $0.5 million with an estimated in-service date of May 2023. The CAISO's recommendation is to approve the project.

2.5.4.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.1, about 53 MW of AAEE and more than 1,917 MW of installed behind-the-meter PV reduced the Central Valley Area load in 2025 by about 1.3%. This year's reliability assessment for the Central Valley Area included the "high CEC forecast" sensitivity case for year 2025 which modeled no AAEE. Comparisons between the reliability issues identified in the 2025 summer peak baseline case and the "high CEC forecast" sensitivity case show that the facility overloads shown in Table 2.5-13 are potentially avoided due to reduction in net load:

Table 2.5-13: Reliability Issues in Sensitivity Studies

Facility	Category
Bellota -Riverbank-Melones 115 kV Line	P2
Brighton – Davis 115 kV Line	P7
West Sacramento – Rio Oso 115 kV Line	P5
Manteca #1 60 kV Line	P1, P2
Curtis – MI-Wuk 115 kV Line	P2
Spring Gap – MI-Wuk 115 kV Line	P2
Palermo – Pease 115 kV Line	P7

Furthermore, more than 59 MW of demand response are modeled in the Central Valley Area. These resources are modeled offline in the base case and are used as potential mitigations. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

2.5.4.6 Recommendation

Based on the studies performed for the 2020-2021 Transmission Plan, several reliability concerns were identified for the PG&E Central Valley Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Central Valley area. To address new reliability issues identified in this cycle, the CAISO is recommending approval of the Manteca #1 60 kV Line Section Reconductoring Project to address P0 issue on the line and the Kasson – Kasson Junction 1 115 kV Line Section Reconductoring Project to address P1 issue. The CAISO is also recommending an SPS to address the P2-1 issue at Higgins 115 kV substation, and the protection upgrade at Gold Hill 230 kV and Bellota 230 kV substations to address the P5-5 issue. The CAISO is working with PG&E to address P2-4 issue at Tesla 115 kV substation through either an SPS or substation upgrade, P1 issue on Brighton – Davis 115 kV line, P1 overloads in Salado – Newman 60 kV area, and P1 overload on Kasson – Louise 60 kV and Manteca – Louise 60 kV lines. The remaining issues are only observed under the sensitivity scenario or in the long term. The CAISO will continue to monitor those issues and will mitigate them if the issues are identified in future assessments.

2.5.5 Greater Bay Area

2.5.5.1 Area Description

The Greater Bay Area (or Bay Area) is at the center of PG&E's service territory. This area includes Alameda, Contra Costa, Santa Clara, San Mateo and San Francisco counties as shown in the adjacent illustration. To better conduct the performance evaluation, the area is divided into three sub-areas: East Bay, South Bay and San Francisco-Peninsula.

The East Bay sub-area includes cities in Alameda and Contra Costa counties. Some major cities are Concord, Berkeley, Oakland, Hayward, Fremont and Pittsburg. This area primarily relies on its internal generation to serve electricity customers. The South Bay sub-area covers approximately 1,500 square miles and includes Santa Clara County. Some major cities are San Jose, Mountain View, Morgan Hill and Gilroy. Los Esteros, Metcalf, Monta Vista and Newark are the key substations that deliver power to this sub-area. The South Bay sub-area encompasses the De Anza and San Jose divisions and the City of Santa Clara. Generation units within this sub-area include Calpine's Metcalf Energy Center, Los Esteros Energy Center, Calpine Gilroy Power Units, and SVP's Donald Von Raesfeld Power Plant. In addition, this sub-area has key 500 kV and 230 kV interconnections to the Moss Landing and Tesla substations. Lastly, the San Francisco-Peninsula sub-area encompasses San Francisco and San Mateo counties, which include the cities of San Francisco, San Bruno, San Mateo, Redwood City and Palo Alto. The San Francisco-Peninsula area presently relies on transmission line import capabilities that include the Trans Bay Cable to serve its electricity demand. Electric power is imported from Pittsburg, East Shore, Tesla, Newark and Monta Vista substations to support the sub-area loads.

Trans Bay Cable became operational in 2011. It is a unidirectional, controllable, 400 MW HVDC land and submarine-based electric transmission system. The line employs voltage source converter technology, which will transmit power from the Pittsburg 230 kV substation in the city of Pittsburg to the Potrero 115 kV substation in the city and county of San Francisco.

The CAISO Planning Standards were enhanced in 2014 to recognize that the unique characteristics of the San Francisco Peninsula form a credible basis for considering for approval corrective action plans to mitigate the risk of outages for extreme events that are beyond the level that is applied to the rest of the CAISO controlled grid.

2.5.5.2 Area-Specific Assumptions and System Conditions

The Greater Bay Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO-secured participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Greater Bay Area study are provided in Table 2.5-14 and Table 2.5-15.

The transmission modeling assumptions are consistent with the general assumptions described in section 2.3.

Table 2.5-14 Greater Bay Area load and load modifier assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV Installed (MW)	BTM-PV Output (MW)	Net Load (MW)	Demand Total (MW)	Demand D2 (MW)
1	2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours ending 18:00.	8,825	66	1,781	257	8,502	182	95
2	2022-WP	Baseline	2022 winter peak load conditions. Peak load time - hours ending 19:00.	7,246	67	1,781	0	7,179	182	95
3	2022-SpOP	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	7,100	53	1,781	0	7,047	182	95
4	2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	8,825	66	1,781	1763	6,996	182	95
5	2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours ending 18:00.	9,071	102	2,289	229	8,740	182	95
6	2025-WP	Baseline	2025 winter peak load conditions. Peak load time - hours ending 19:00.	7,450	117	2,289	0	7,333	182	95
7	2025-SpOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	5,531	0	2,289	1831	3,700	182	95
8	2025-SP-Hi-CEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	9,071	0	2,289	229	8,842	182	95
9	2025-SpOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	5,531	0	2,289	2266	3,265	182	95
10	2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours ending 19:00.	9,347	173	2,955	0	9,174	182	95
11	2030-WP	Baseline	2030 winter peak load conditions. Peak load time - hours ending 19:00.	7,659	203	2,955	0	7,456	182	95
12	2030-SP-Non-Rerate	Sensitivity	2030 summer peak load conditions. Peak load time - hours ending 19:00.	9,347	173	2,995	0	9,174	182	95
13	2030-SVP	Sensitivity	2030 summer peak load conditions with high SVP load sensitivity	9,347	173	2,955	0	9,174	182	95

Note: Includes PG&E load only. DR and storage are modeled offline in starting base cases.
Includes PG&E load only.
DR and storage are modeled offline in starting base cases.

Table 2.5-15 Greater Bay Area generation assumptions

S. No.	Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours ending 18:00.	80	25	2	264	124	0	0	7321	5491
2	2022-WP	Baseline	2022 winter peak load conditions. Peak load time - hours ending 19:00.	80	25	0	264	28	0	0	7321	4799
3	2022-SpOP	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	80	25	0	264	120	0	0	7321	1176
4	2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	80	25	24	264	135	0	0	7321	929
5	2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours ending 18:00.	116	25	2	264	118	0	0	7321	5419
6	2025-WP	Baseline	2025 winter peak load conditions. Peak load time - hours ending 19:00.	116	25	0	264	28	0	0	7321	4591
7	2025-SpOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	116	25	23	264	44	0	0	7321	1233
8	2025-SP-Hi-CEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	116	25	2	264	90	0	0	7321	5492
9	2025-SpOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	116	25	22	264	137	0	0	7321	1178
10	2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours ending 19:00.	116	25	2	264	97	0	0	7321	5054
11	2030-WP	Baseline	2030 winter peak load conditions. Peak load time - hours ending 19:00.	116	25	0	264	28	0	0	7321	5265
12	2030-SP-Non-Rerate	Sensitivity	2030 summer peak load conditions. Peak load time - hours ending 19:00.	116	25	2	264	98	0	0	7321	5053
13	2030-SVP	Sensitivity	2030 summer peak load conditions with high SVP load sensitivity	116	25	2	264	79	0	0	7321	5076

Note: Includes PG&E load only. DR and storage are modeled offline in starting base cases.
Includes PG&E load only.
DR and storage are modeled offline in starting base cases.

2.5.5.3 Assessment Summary

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2020-2021 reliability assessment identified several reliability concerns consisting of thermal overloads under Category P1 to P7 contingencies, most of which are addressed by previously approved projects. The areas where additional mitigation requirements were identified are discussed below.

Los Esteros-Nortech 115 kV line overload

Multiple Category P1, P2 and P7overloads were identified on the Los Esteros-Nortech 115 kV line in both the short and long term. The P2 overload at the NRS substation is seen in 2022 and gets progressively worse in the later years.

To mitigate these overloads, the CAISO is working with PG&E to develop a project which could include reconductoring the 115 kV line.

Contra Costa area substation upgrade project

Multiple Category P2 contingency driven overloads were identified in both the short and long term in the area. The overloads are primarily due to different Bus/Breaker contingency at the 230 kV Contra Costa substation which results in both the line and generation loss at the substation. To mitigate these overloads, the CAISO is working with PG&E to develop a project which could include potentially include upgrading the substation or sectionalizing the 230 kV bus.

Metcalf 500/230 kV Transformer Overloads

Category P6 contingency driven long term overloads were identified on the Metcalf 500/230 kV transformer banks. The overloads are primarily due to loss of two out of the three transformers at the Metcalf 500 kV substation. The project is considered as a long term reliability alternative and CAISO will not approve and continue to monitor the long term reliability issue in the subsequent cycles. However, the project is considered as an alternative for potential Local Capacity Requirement (LCR) reductions in the Greater bay area subarea for which a detailed discussion is included in Chapter 4

Estimated cost of this project is between $22M to $32M and in-service date is 2024.

Metcalf 230 kV Substation Upgrade

Multiple Category P2 contingency driven overloads were identified on the Metcalf 230/115 kV T/F Banks in both the short and long term. The overloads are primarily due to P2-4 breaker contingency at the 230 kV Metcalf substation which results in loss of multiple lines and transformer at the substation.

To mitigate these overloads, the CAISO is working with PG&E to develop a project which could include adding a sectionalizing breakers on the Metcalf 230 kV bus.

Moraga- Sobrante (on-hold project)

Multiple Category P2 contingency driven overloads were identified on the Moraga-Sobrante 115 kV line in the long term. The CAISO had recommended the project to be put on hold in the last cycle and recommends to continue the project on hold for this cycle as well. Request Window Submissions

The CAISO received 4 submissions in the 2020 Request Window in the Greater Bay Area.

Metcalf 500/230 kV Transformers Dynamic Series Reactor Project

Pacific Gas & Electric (PG&E) proposed a project, Metcalf 500/230 kV Transformers Dynamic Series Reactor Project, targeting thermal overloads on the Metcalf 500/230 kV transformers. The project includes installing smart valves in series with the three 500/230 kV transformers on the low voltage side at Metcalf Substation. The Smart Valves will remain 0 ohm in normal conditions. Once a transformer at Metcalf substation is overloaded, the Smart Valves connected to the transformer will operate to introduce inductive reactance (2 ohm) and mitigate the overload. The project is considered as a long term reliability alternative and CAISO will not approve and continue to monitor the long term reliability issue in the subsequent cycles. However, the project is considered as an alternative for potential Local Capacity Requirement (LCR) reductions in the Greater bay area subarea for which a detailed discussion is included in Chapter 4

Request Window Submission –HWT: Contra Costa - Pittsburg 230 kV Transmission System

Horizon West proposed a project, Contra Costa - Pittsburg 230 kV Transmission System, targeting thermal overloads in Contra Costa-Newark 230 kV corridor. Horizon West proposed a new 230 kV 9.3 Mile underground transmission line or a 8.8 Mile submarine cable from Contra Costa to Pittsburg substation.

The project as proposed has higher cost compared to other alternatives considered and also doesn't address all reliability issues identified in the Contra Costa-Newark 230 kV corridor. Hence, the CAISO determined that the Contra Costa - Pittsburg 230 kV Transmission System is not the appropriate solution for reliability issues identified in Contra Costa-Newark 230 kV corridor. However, the project is considered as an alternative for potential Local Capacity Requirement (LCR) reductions in the Contra Costa subarea for which a detailed discussion is included in Chapter 4.

Request Window Submission HWT– Metcalf 230 kV substation

Horizon West proposed a project, Metcalf 230 kV substation, targeting transformer thermal overloads at Metcalf 230 kV substation. Horizon West proposed a new HWT-Metcalf 230/115 kV substation that will expand the capacity of the existing Metcalf substation by installing two new 230/115 kV transformers and relocating the existing Piercy-Metcalf and Bailey J2 - Metcalf 115 kV lines to terminate at the new HWT-Metcalf substation. This proposed new substation will be connected to the existing 230 kV substation by two short 230 kV lines

The project as proposed has higher cost compared to other alternatives considered. Hence, the CAISO determined that the Metcalf 230 kV substation is not appropriate solution for reliability issues identified in the area. However, the project is considered as an alternative for potential Local Capacity Requirement (LCR) reductions in the San Jose subarea for which a detailed discussion is included in Chapter 4.

Request Window Submission- Santa Teresa 115/21 kV Substation

PG&E submitted Santa Teresa 115/21 kV substation load interconnection projects for CAISO's review and concurrence. The need for this new Santa Teresa Substation was driven by new loads requesting to be interconnected to the PG&E system. There is no distribution capacity available in the project vicinity to serve them. This project will provide the distribution capacity to serve new and existing customers and improve service reliability and operating flexibility in the South San Jose area. The CAISO concurs with the load interconnection submission.

2.5.5.4 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.5.2, about 102 MW of AAEE and more than 2000 MW of installed behind-the-meter PV reduced the Greater Bay Area load in 2025 by about 5%. This year's reliability assessment for Greater Bay Area included the "high CEC forecast" sensitivity case for year 2025 which modeled no AAEE. Comparisons between the reliability issues identified in the 2025 summer peak baseline case and the "high CEC forecast" sensitivity case show that the facility overloads shown in Table 2.5-16 are potentially avoided due to reduction in net load.

Table 2.5-16: Reliability Issues Avoided due to AAEE

Facility	Category
Cayetano-Lone Tree (USWP-Cayetano) 230kV Line	P2
Contra Costa-Contra Costa Sub 230kV Line	P2
Oleum-Christie 115kV Line	P7
Las Positas-Newark 230kV Line	P2
Los Esteros-Nortech 115 kV Line	P2

Furthermore, about 116 MW of demand response and 182 MW of battery energy storage are modeled in the Greater Bay Area in the year 2025. These resources are modeled offline in the base case and are used as potential mitigations. Utilization of these resources mitigated overloads in Oakland and San Jose areas and helped reduce thermal overloads on Metcalf transformer banks as well.

2.5.5.5 Recommendation

Based on the studies performed in the 2020-2021 transmission planning cycle Transmission Plan, several reliability concerns were identified for the PG&E Greater Bay Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Greater Bay area.

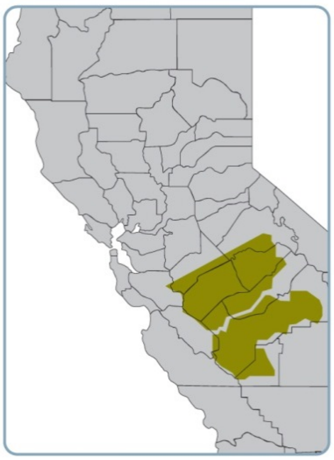
Stakeholders submitted 3 projects through the Request Window in the Greater Bay Area in this cycle. Out of 3 projects submitted, the CAISO found no project needed for reliability and none of the projects are recommended for approval. The projects are either not considered as reliability alternative as the submission does not meet a reliability need identified by the CAISO, or instead may be considered in the economic study process if found applicable.

Moraga-Sobrante 115 kV line reconductor, is being recommended to continue on hold due to the long term reliability issues identified in this cycle.

2.5.6 Greater Fresno Area

2.5.6.1 Area Description

The Greater Fresno Area is located in the central to southern PG&E service territory. This area includes Madera, Mariposa, Merced and Kings Counties, which are located within the San Joaquin Valley Region. The adjacent figure depicts the geographical location of the Fresno area.



The Greater Fresno area electric transmission system is composed of 70 kV, 115 kV and 230 kV transmission facilities. Electric supply to the Greater Fresno area is provided primarily by area hydro generation (the largest of which is Helms Pump Storage Plant), several market facilities and a few qualifying facilities. It is supplemented by transmission imports from the North Valley and the 500 kV lines along the west and south parts of the Valley. The Greater Fresno area is composed of two primary load pockets including the Yosemite area in the northwest portion of the shaded region in the adjacent figure. The rest of the shaded region represents the Fresno area.

The Greater Fresno area interconnects to the bulk PG&E transmission system by 12 transmission circuits. These consist of nine 230 kV lines; three 500/230 kV banks; and one 70 kV line, which are served from the Gates substation in the south, Moss Landing in the west, Los Banos in the northwest, Bellota in the northeast, and Templeton in the southwest. Historically, the Greater Fresno area experiences its highest demand during the summer season but it also experiences high loading because of the potential of 900 MW of pump load at Helms Pump Storage Power Plant during off-peak conditions. The largest generation facility within the area is the Helms plant, with 1212 MW of generation capability. Accordingly, system assessments in this area include the technical studies for the scenarios under summer peak and off-peak conditions that reflect different operating conditions of Helms. Significant transmission upgrades have been approved in the Fresno area in past transmission plans, which are set out in chapter 8.

2.5.6.2 Area-Specific Assumptions and System Conditions

The Greater Fresno Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO market participant portal provides more details of contingencies that were analyzed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the study are shown in Table 2.5-17 and Table 2.5-18.

Table 2.5-17 Greater Fresno Area load and load modifier assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
						Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
1	GFA-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours ending 19:00.	3,848	33	1,556	0	3,815	51	22
2	GFA-2022-SpOP	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	1,349	21	1,686	0	1,328	51	22
3	GFA-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	3,221	27	1,686	1669	1,525	51	22
4	GFA-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours ending 19:00.	3,389	44	2,042	0	3,345	51	22
5	GFA-2025-SpOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	1,038	0	2,042	1633	(595)	51	22
6	GFA-2025-SP-Hi-CEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	3,389	0	2,042	0	3,389	51	22
7	GFA-2025-SpOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	1,038	0	2,042	2021	(983)	51	22
8	GFA-2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours ending 19:00.	3,606	78	2,782	0	3,528	51	22
9	GFA-2030-SP-xReRates	Sensitivity	2030 summer peak load conditions with no rerate	3,606	78	2,782	0	3,528	51	22

Table 2.5-18: Greater Fresno Area generation assumptions

S. No.	Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	GFA-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours ending 19:00.	313	2980	30	13	7	1880	1799	1,386	1,170
2	GFA-2022-SpOP	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	313	2980	0	13	7	1880	-344	1,386	567
3	GFA-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	313	2980	2726	13	8	1880	1234	1,386	136
4	GFA-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours ending 19:00.	313	2980	30	13	7	1880	1735	1,386	1,139
5	GFA-2025-SpOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	313	2980	2173	13	3	1880	-397	1,386	390
6	GFA-2025-SP-Hi-CEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	313	2980	30	13	7	1880	1672	1,386	1,104
7	GFA-2025-SpOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	313	2980	1721	13	9	1880	-401	1,386	117
8	GFA-2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours ending 19:00.	313	2980	27	13	7	1880	1772	1,386	1,174
9	GFA-2030-SP-xReRates	Sensitivity	2030 summer peak load conditions with no rerate	313	2980	30	13	7	1880	1788	1,386	1,193

2.5.6.3 Assessment Summary

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2019-2020 reliability assessment of the PG&E Greater Fresno Area has identified several reliability concerns consisting of thermal overloads under Category P1 to P7 contingencies most of which are addressed by previously approved projects. The areas where additional mitigation requirements were found to be needed are discussed below.

Wilson-Atwater 115 kV Area overloads

There were several P6 overloads in this area for all Baseline scenarios. The mitigation is for the P6 is to do Operational Switching post first contingency while the long-term mitigation would be to expand the Atwater SPS.

McCall 115 kV Area overloads

There was a P6 contingency Sanger-Reedley 115kV & McCall-Reedley 115kV, causing overload on the Reedley-Wahtoke 115kV section of the McCall-Reedley 115kV line, Sanger-Reedley 115kV line and Reedley-Piedra 115kV line. This contingency also caused low voltage at Reedley and Wahtoke 115kV. The mitigation would be an SPS to drop the load at Wahtoke.

There were P2 overloads on the McCall 500/230kV TB #2 and #3 in 2025 and 2030 baseline scenario as well as a sensitivity scenario. The recommendation for this issue is to continue to monitor future load forecast in the area.

P5 overloads

There were P5 contingencies – Hammonds 115kV #1 bus (failure of non-redundant relay), Herndon 115kV #1 bus (failure of non-redundant relay), Gates section D & E 230kV #1 bus (failure of non-redundant relay) resulted in overloads on several 115 kV and 230 kV lines in the baseline and sensitivity cases. The mitigation is a recommendation to add redundant relay protection.

Long-term overload issues

There were several P1-P7 overloads identified in the 2030 summer peak baseline scenario. These include Wilson-Oro Loma(Oro Loma-El Nido) 115kV Line, Panoche-Schindler 115kV line, Los Banos 230/70kV TB, Los Banos-Pacheco 70kV line, Herndon-Bullard 115kV line, Herndon-Manchester 115kV line, and GWF-Contandina-Jackson 115kV line, California Ave-Sanger 115kV Line and McCall 230/115kV TB #3. The recommendation is to continue to monitor future load forecast for these issues.

Spring off-peak only overloads

There were some P2, P6, P7 overloads identified in the spring off-Peak cases such as Panoche-Gates #1 and #2 230kV lines, Gates-Mustang #1 and #2 230kV lines, Gregg-Ashland 230kV lines, Gates-Arco 230kV Line, Warnerville-Wilson, Le Grand Chowchilla 115kV line, Chowchilla-Kerckhoff 115kV line, and Herndon-Woodward 115kV line. The recommended mitigation is generation redispatch.

Fresno 115kV and 70kV area voltage concerns

In the Yosemite 70kV area, P0 Low voltages were identified in the baseline scenarios. This is under review. In the 2025 and 2030 summer peak baseline scenario for categories P1, P2, P3 and P6, some low voltages were identified in the Oro Loma area 115kV and 70kV systems. Low voltages were also identified in Coalinga 70 kV under P2, P3 and P6 and in Reedley 70kV under P1, P2 and P6 contingencies in the 2025 and 2030 baseline cases. The CAISO will continue to monitor future load forecast for these issues.

2.5.6.4 Request Window Submissions

There was no project submission in the Fresno area in the 2020 request window

2.5.6.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.6.2, about 44 MW of AAEE reduced the Greater Fresno Area load in 2025 by about 1.3%. This year's reliability assessment for the Greater Fresno Area included the "high CEC forecast" sensitivity case for the year 2025 which modeled no AAEE. Comparisons between the reliability issues identified in the 2025 summer peak baseline case and the "high CEC forecast" sensitivity case are shown in Table 2.5-19 and indicate these facility overloads are potentially avoided due to reductions in net load.

Table 2.5-19: Reliability Issues in Sensitivity Studies

Facility	Category
Wilson-Merced #2 115 kV Line	P1, P2,P7
Schindler-Coalinga #2 70 kV Line (S0526 Tap-Pleasant Valley)	P2,P5
Schindler 115/70 kV Transformer Bank 1	P2,P5
Five Points-Huron-Gates 70 kV Line (Five points-Calflax)	P2,P5
Schindler-Five Points 70 kV Line	P5

Furthermore, about 51 MW of demand response is modeled in Greater Fresno Area. These resources are modeled offline in the base case and are used as potential mitigations. Utilization of these resources helped reduce some of the thermal overloads identified, but didn't completely alleviate the overloads.

2.5.6.6 Recommendation

Based on the studies performed for the 2020-2021 Transmission Plan, several reliability concerns were identified for the PG&E Greater Fresno Area. These concerns consisted of thermal overloads and voltage concerns under categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Greater Fresno Area. Sensitivity Scenarios do show worsening overloads for most elements.

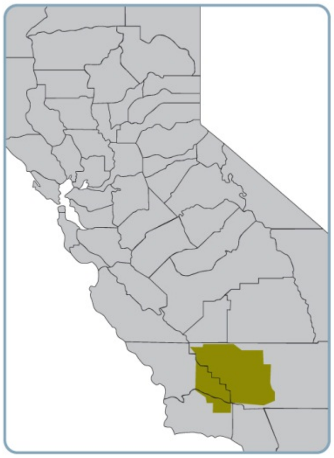
In this TPP cycle, the CAISO recommends to Install Redundant protection at the Gates 230kV Bus, Herndon 115kV Bus and Hammonds 115kV Bus to mitigate P5 contingency driven issues. The CAISO also recommends the Wahtoke SPS to drop load at Wahtoke for the loss of McCall-Reedley 115kV line and Sanger-Reedley 115kV line.

In regards to the reliance on non-consequential load loss per TPL-001-4 footnote 12 in the near-term for an overload driven by a P1, P2.1 or P3 contingency, the Greater Fresno Area assessment found no instances for which the interim action plan has reliance on non-consequential load loss.

2.5.7 Kern Area

2.5.7.1 Area Description

The Kern area is located south of the Yosemite-Fresno area and north of the southern California Edison's (SCE) service territory. Midway substation, one of the largest substations in the PG&E system, is located in the Kern area and has 500 kV transmission connections to PG&E's Diablo Canyon, Gates and Los Banos substations as well as SCE's Vincent substation. The figure on the left depicts the geographical location of the Kern area.



The bulk of the power that interconnects at Midway substation transfers onto the 500 kV transmission system. A substantial amount also reaches neighboring transmission systems through Midway 230 kV and 115 kV transmission interconnections. These interconnections include 230 kV lines to Yosemite-Fresno in the north as well as 115 and 230 kV lines to Los Padres in the west. Electric customers in the Kern area are served primarily through the 230/115 kV transformer banks at Midway, Kern Power Plant (Kern PP) substations and local generation power plants connected to the lower voltage transmission network.

2.5.7.2 Area-Specific Assumptions and System Conditions

The Kern Area study was performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO market participant portal provides more details of contingencies that were analyzed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the study are shown in Table 2.5-20 and Table 2.5-21.

Table 2.5-20 Kern Area load and load modifier assumptions

Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
					Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
KERN-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours ending 20:00.	1,769	14	614	0	1,755	75	57
KERN-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours ending 20:00.	1,855	23	705	0	1,832	75	57
KERN-2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours ending 20:00.	2,001	40	884	0	1,961	75	57
KERN-2022-SOP	Baseline	2022 spring off-peak load conditions. Off-peak load time – hours ending 20:00.	1,071	11	614	0	1,060	75	57
KERN-2025-SOP	Baseline	2025 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	846	0	705	564	282	75	57
KERN-2025-SP-HiCEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	1,855	0	705	0	1,855	75	57
KERN-2025-SOP-HiRene	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	846	0	705	698	148	75	57
KERN-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	1,769	14	614	607	1,148	75	57
KERN-2030-SP-xRerates	Sensitivity	2030 summer peak load conditions with no rerates	2,001	40	884	0	1,961	75	57
KERN-2030-SP-QF	Sensitivity	2030 summer peak load conditions with QF retirement sensitivity	2,001	40	884	0	1,961	75	57

Note:
DR and storage are modeled offline in sarting base cases.

Table 2.5-21 Kern Area generation assumptions

Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
				Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
KERN-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours ending 20:00.	2	614	6	0	0	29	25	3,447	2,765
KERN-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours ending 20:00.	0	614	6	0	0	29	18	3,447	2,689
KERN-2030-SP	Baseline	2030 summer peak load conditions. Peak load time - hours ending 20:00.	0	614	6	0	0	29	18	3,447	2,797
KERN-2022-SOP	Baseline	2022 spring off-peak load conditions. Off-peak load time – hours ending 20:00.	2	614	0	0	0	29	25	3,447	1,568
KERN-2025-SOP	Baseline	2025 spring off-peak load conditions. Off-peak load time – hours ending 13:00.	0	614	517	0	0	29	18	3,447	460
KERN-2025-SP-HiCEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	0	614	0	0	0	29	18	3,447	2,823
KERN-2025-SOP-HiRene	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	0	614	488	0	0	29	18	3,447	460
KERN-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	2	614	593	0	0	29	18	3,447	543
KERN-2030-SP-xRerates	Sensitivity	2030 summer peak load conditions with no rerates	0	614	6	0	0	29	18	3,447	2,797
KERN-2030-SP-QF	Sensitivity	2030 summer peak load conditions with QF retirement sensitivity	0	614	6	0	0	29	18	3,447	1,971

Note:
DR and storage are modeled offline in sarting base cases.

The transmission modeling assumption is consistent with the general assumptions described in section 2.3.

2.5.7.3 Assessment Summary

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. The details of the planning assessment results are presented in Appendix B. The reliability assessment identified several reliability concerns consisting of thermal overloads, low voltage and voltage deviation under various Category P1 to P7 contingencies in both the baselines and sensitivity cases. The majority of reliability issues are addressed by previously approved projects and/or continued reliance on existing summer setups for the area.

There were several short and long term Category P1, P2, P6 and P7 reliability issues in the Tevis 115 and Wheeler ridge 230 kV areas that could not be mitigated without the Wheeler Ridge Junction Station Project. This project was put on hold in the 2019-20 TPP. The CAISO is recommending procurement of a 95 MW 4 hour energy storage option to mitigate the 115 kV issues on the Kern-Lamont 115 kV system. The cost of this option was compared against several options, including reconductoring of the 115 kV lines, and was determined to be the lowest cost based on CPUC recommendation of including only the interconnection cost and not the full capital cost of the energy storage projects that are otherwise needed for system capacity purposes according to the CPUC-provided resource portfolios. The issues related to Kern-Magunden-Witco 115kV are primarily P6 and P7 issues. The CAISO will be relying on the operating solutions to mitigate these issues.

For the 230 kV issues seen in the studies, the CAISO is exploring several options such as reconductoring the existing Midway-Wheeler ridge 230 kV lines, new 230 kV line either from the Midway 230 kV or Kern 230 kV to Wheeler ridge 230 kV substation. These 230 kV options will be further evaluated in the next planning cycle to include any potential generation developments in the area as well. In the interim, the CAISO will be relying on the interim action plan to mitigate the reliability issues in the area.

The CAISO recommends keeping the Wheeler Ridge Junction Station project on hold pending procurement of the battery in the 115 kV system and until the evaluation of 230 kV options are completed.

2.5.7.4 Request Window Submissions

There were no request window submissions for Kern Area.

2.5.7.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.7.2, about 23 and 40 MW of AAEE reduced the Kern Area net load by 1 and 2 % in 2025 and 2030 respectively .Similar to last year, this year’s reliability assessment for Kern Area included the “high CEC forecast” sensitivity case for year 2025 which modeled no AAEE and no PV output. Comparisons between the reliability issues identified in the 2025 summer peak baseline case and the “high CEC forecast” sensitivity case show that following facility overloads shown in Table 2.5-22 are diminished or eliminated due to reduction in net load.

Table 2.5-22: Reliability Issues in Sensitivity Studies

Facility	Category
Kern PP-Westpark #1 & # 2 115 kV Line	P6
Kern-Magunden-Witco 115 kV Line (Kern Oil Jct-Magunden)	P6
Midway-Tupman-Renfro 115 kV Line (Tupman Tap 1-Tupman)	P2
Kern-Stockdale 115 kV Line (Kern Power-Tevis J1 & Kern Power-Tevis J2)	P2

Furthermore, about 75 MW of demand response and 2 MW of battery energy storage are modeled in Kern Area. These resources are modeled offline in the base case and are used as potential mitigation. Utilization of these resources helped reduce some of the thermal overloads identified, however, didn't completely alleviate the overloads. In addition, The CAISO also analyzed the battery energy storage solutions in conjunction with other transmission solutions to mitigate the reliability issues identified with the on hold Wheeler ridge Junction project.

2.5.7.6 Recommendation

Based on the studies performed for the 2020-2021 Transmission Plan, several reliability concerns were identified for the PG&E Kern Area. These concerns consisted of thermal overloads and voltage concerns under Categories P0 to P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Kern area.

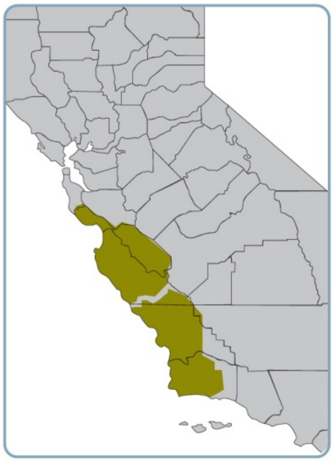
The CAISO is recommending procurement of a 95 MW 4 hour energy storage option to mitigate the 115 kV issues on the Kern-Lamont 115 kV system. The cost of this option was compared against several options, including reconductoring of the 115 kV lines, and was determined to be the lowest cost based on CPUC recommendation of including only the interconnection cost and not the full capital cost of the energy storage projects that are otherwise needed for system capacity purposes according to the CPUC-provided resource portfolios. The issues related to Kern-Magunden-Witco 115kV are primarily P6 and P7 issues. The CAISO will be relying on the operating solutions to mitigate these issues.

For the 230 kV issues seen in the studies, the CAISO is exploring several options such as reconductoring the existing Midway-Wheeler ridge 230 kV lines, new 230 kV line either from the Midway 230 kV or Kern 230 kV to Wheeler ridge 230 kV substation. These 230 kV options will be further evaluated in the next planning cycle to include any potential generation developments in the area as well. In the interim, the CAISO will be relying on the interim action plan to mitigate the reliability issues in the area.

2.5.8 Central Coast and Los Padres Areas

2.5.8.1 Area Description

The PG&E Central Coast division is located south of the Greater Bay Area and extends along the Central Coast from Santa Cruz to King City. The green shaded portion in the figure on the left depicts the geographic location of the Central Coast and Los Padres areas.



The Central Coast transmission system serves Santa Cruz, Monterey and San Benito counties. It consists of 60 kV, 115 kV, 230 kV and 500 kV transmission facilities. Most of the customers in the Central Coast division are supplied via a local transmission system out of the Moss Landing Substation. Some of the key substations are Moss Landing, Green Valley, Paul Sweet, Salinas, Watsonville, Monterey, Soledad and Hollister. The local transmission systems are the following: Santa Cruz-Watsonville, Monterey-Carmel and Salinas-Soledad-Hollister sub-areas, which are supplied via 115 kV double circuit tower lines. King City, also in this area, is supplied by 230 kV lines from the Moss Landing and Panoche substations, and the Burns-Point Moretti sub-area is supplied by a 60 kV line from the Monta Vista Substation in Cupertino. Besides the 60 kV transmission system interconnections between Salinas and Watsonville substations, the only other interconnection among the sub-areas is at the Moss Landing substation. The Central Coast transmission system is tied to the San Jose and De Anza systems in the north and the Greater Fresno system in the east. The total installed generation capacity is 2,900 MW, which includes the 2,600 MW Moss Landing Power Plant, which is scheduled for compliance with the SWRCB Policy on OTC plants by the end of 2020.

The PG&E Los Padres division is located in the southwestern portion of PG&E's service territory (south of the Central Coast division). Divide, Santa Maria, Mesa, San Luis Obispo, Templeton, Paso Robles and Atascadero are among the cities in this division. The city of Lompoc, a member of the Northern California Power Authority, is also located in this area. Counties in the area include San Luis Obispo and Santa Barbara. The 2400 MW Diablo Canyon Power Plant (DCPP) is also located in Los Padres. Most of the electric power generated from DCPP is exported to the north and east of the division through 500 kV bulk transmission lines; in terms of generation contribution, it has very little impact on the Los Padres division operations. There are several transmission ties to the Fresno and Kern systems with the majority of these interconnections at the Gates and Midway substations. Local customer demand is served through a network of 115 kV and 70 kV circuits. With the retirement of the Morro Bay Power Plants, the present total installed generation capacity for this area is approximately 950 MW. This includes the recently installed photovoltaic solar generation resources in the Carrizo Plains, which includes the 550 MW Topaz and 250 MW California Valley Solar Ranch facilities on the Morro Bay-Midway 230 kV line corridor. The total installed capacity does not include the 2400 MW DCPP output as it does not serve the load in the PG&E's Los Padres division.

2.5.8.2 Area-Specific Assumptions and System Conditions

The Central Coast and Los Padres areas study was performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO-secured participant portal provides more details of contingencies that were performed as part of this assessment. In addition, specific assumptions related to area load levels, load modifiers, generation dispatch and transmission modeling assumptions for various scenarios used for the Central Coast and Los Padres areas study are shown in Table 2.5-23 and Table 2.5-24. For this planning cycle the Central Coast and Los Padres area relied on the use of past studies from the 2019-2020 TPP for all year two (2022) studies in both baseline and sensitivity.

Table 2.5-23: Central Cost and Los Padres Area load and load modifier assumptions

S. No.	Study Case	Scenario Type	Description	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
						Installed (MW)	Output (MW)		Total (MW)	D2 (MW)
1	CCLP-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours between 19:00 and 20:00.	1,189	9	434	0	1,180	27	15
2	CCLP-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours between 19:00 and 20:00.	1,243	15	504	0	1,228	27	15
3	CCLP-2030-SP	Baseline	2030 summer peak load conditions. Peak load time -hours between 19:00 and 20:00.	1,324	26	631	0	1,297	27	15
4	CCLP-2022-SOP	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	911	7	434	0	904	27	15
5	CCLP-2025-SOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	710	0	504	403	307	27	15
6	CCLP-2022-WP	Baseline	2022 winter peak load conditions. Peak load time - hours ending 19:00.	1,006	9	434	0	997	27	15
7	CCLP-2025-WP	Baseline	2025 winter peak load conditions. Peak load time - hours ending 19:00.	1,054	16	504	0	1,038	27	15
8	CCLP-2030-WP	Baseline	2030 winter peak load conditions. Peak load time - hours ending 19:00.	1,122	28	631	0	1,094	27	15
9	CCLP-2025-SP-HiCEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	1,243	0	504	0	1,243	27	15
10	CCLP-2025-SOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	710	0	504	499	211	27	15
11	CCLP-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	1,189	9	434	429	751	27	15
12	CCLP-2030-SP-xRerates	Sensitivity	2030 summer peak load conditions with no rerates	1,324	26	631	0	1,297	27	15

Table 2.5-24: Central Cost and Los Padres Area generation assumptions

S. No.	Study Case	Scenario Type	Description	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
					Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
1	CCLP-2022-SP	Baseline	2022 summer peak load conditions. Peak load time - hours between 19:00 and 20:00.	598	841	0	101	44	0	0	2718	1098
2	CCLP-2025-SP	Baseline	2025 summer peak load conditions. Peak load time - hours between 19:00 and 20:00.	598	816	0	101	44	0	0	2718	1143
3	CCLP-2030-SP	Baseline	2030 summer peak load conditions. Peak load time -hours between 19:00 and 20:00.	598	816	0	101	44	0	0	2718	1143
4	CCLP-2022-SOP	Baseline	2022 spring off-peak load conditions. Off-peak load time - hours ending 20:00.	598	841	0	101	56	0	0	2718	274
5	CCLP-2025-SOP	Baseline	2025 spring off-peak load conditions. Off-peak load time - hours ending 13:00.	598	816	773	101	20	0	0	2718	163
6	CCLP-2022-WP	Baseline	2022 winter peak load conditions. Peak load time - hours ending 19:00.	598	841	0	101	13	0	0	2718	1098
7	CCLP-2025-WP	Baseline	2025 winter peak load conditions. Peak load time - hours ending 19:00.	598	816	0	101	13	0	0	2718	1098
8	CCLP-2030-WP	Baseline	2030 winter peak load conditions. Peak load time - hours ending 19:00.	598	816	0	101	13	0	0	2718	1098
9	CCLP-2025-SP-HiCEC	Sensitivity	2025 summer peak load conditions with hi-CEC load forecast sensitivity	598	816	0	101	44	0	0	2718	1143
10	CCLP-2025-SOP-HiRenew	Sensitivity	2025 spring off-peak load conditions with hi renewable dispatch sensitivity	598	816	766	101	65	0	0	2718	451
11	CCLP-2022-SP-HiRenew	Sensitivity	2022 summer peak load conditions with hi-renewable dispatch sensitivity	598	841	681	101	63	0	0	2718	163
12	CCLP-2030-SP-xRerates	Sensitivity	2030 summer peak load conditions with no rerates	598	816	0	101	44	0	0	2718	1143

The transmission modeling assumption is consistent with the general assumptions described in section 2.3 with the exception of approved projects shown in Table 2.5-25 which were not modeled in the base cases.

Table 2.5-25: Central Coast / Los Padres approved projects not modeled in base case

Project Name	TPP Approved In	Current ISD
None		

2.5.8.3 Assessment Summary

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B. The 2020-2021 reliability assessment of the PG&E Central Coast and Los Padres areas have identified several reliability concerns consisting of thermal overloads under Category P0 to P7 contingencies most of which are addressed by previously approved projects.

One previously approved project, Coburn-Oil Fields 60kV System, is recommended to be relocated to the adjacent San Ardo 60kV substation due to physical constraint at the Oil Fields substation and the radial topology of the local system.

The areas where additional mitigation requirements were identified are discussed below.

Summary of review of previously approved projects

There is one previously approved active project in the Central Coast/Los Padres area not modeled in the study cases due to constructability issues, cost increase or misalignment of scope of the project and nature of the current need. The final recommendation for the project not modeled in the study cases is shown in Table 2.5-26.

Table 2.5-26: Recommendation for previously approved projects not modeled in the study cases

Project Name	Recommendation
North of Mesa Upgrades (previously Midway – Andrew)	On Hold

Details of the review of previously approved projects not modeled in study cases are presented in Appendix B.

North of Mesa Upgrades (Previously Midway-Andrew) Project

The previously approved Midway-Andrew 230 kV project approved in the 2012-2013 TPP. The Midway-Andrew 230 kV project was not modelled in the base case due to the fact that it was split into two separate projects in the 2018-2019 TPP cycle, the North of Mesa Upgrades and the South of Mesa Upgrades. The South of Mesa Upgrades was approved in the 2018-2019 TPP cycle, it was recommended that the North of Mesa upgrades remain on hold so further study assessments could be performed. In this cycle the reliability assessment identified severe P2, P6 and P7 thermal overloads in the 115 kV system supplied from the Mesa substation, thus mitigation is still required. In addition, the load forecast and profile in the area does not provide periods for maintenance to facilities where the next contingency would not result in load loss in the area.

North of Mesa Upgrade Alternatives

- Alternative 1: Build Andrew 230/115 kV substation, energize Diablo – Midway 500 kV line at 230 kV and connect to Andrew substation, and loop-in the SLO – Santa Maria 115 kV line to Andrew and Mesa substations.
- Alternative 2: Build Andrew 500/115 kV substation on Diablo – Midway 500 kV line, and loop-in the SLO – Santa Maria 115 kV line to Andrew and Mesa substations.
- Alternative 3: Procure approximately 50 MW 4 hour BESS at Mesa 115kV substation to address maintenance window. Utilize existing Mesa, Divide and Santa Maria UVLS for peak load conditions.

The estimated cost for alternative 1 of the North of Mesa Upgrades is $114 to $144 million with an expected in-service date of 2026, after Diablo generation has retired and one of the 500 kV lines can be converted to 230 kV. Alternative 2 provides the same support that option one does but keeps the 500 kV line from Diablo to Midway intact for future use. This alternative is significantly more expensive than all of the other options at approximately $300 million.

Alternative 3 provides sufficient maintenance window within winter months for facilities in the area as required by the CAISO planning standards. For the reliability issues during the peak conditions, the existing UVLSs could continue to be relied upon, with some potential modification in terms of centralized operation of these UVLSs since the driving contingencies are P2, P6, and P7. This would offer a much lower cost solution. The cost of this option was compared against several options, including reconductoring of the 115 kV lines, and was determined to be the lowest cost based on CPUC recommendation of including only the interconnection cost and not the full capital cost of the energy storage projects that are otherwise needed for system capacity purposes according to the CPUC-provided resource portfolios. As such, the CAISO recommends alternative 3 as the mitigation plan for procurement of approximately 50 MW 4 hour BESS at Mesa 115kV substation to address maintenance window and for North of Mesa upgrade project to remain on hold pending procurement of the battery storage

2.5.8.4 Request Window Submissions

Lopez 230/115 kV Transmission Project

Horizon West Transmission, LLC proposed the Lopez 230/115 kV Transmission project

The proposed solution is to build new Lopez 230/115 kV substation, convert Diablo – Midway 500 kV to 230 kV, and loop-in the San Luis Obispo – Santa Maria 115 kV line into Lopez and Mesa substations. The recommendation is given to reconductor the loop-in segment from Mesa and Lopez 115 kV to higher ratings (250 MVA) to fully mitigate the remaining 115 kV system overloads. The project scope is to:

- convert a single existing Diablo Canon-Midway 500 kV line to 230 kV operation.
- cut in and connect to dead end structures outside of the new HWT Lopez 230 kV substations.
- build new 230 kV substation: 3 bays – 3 breakers – ring bus.
- 230-115 kV Transformer 400 MVA SN, 463 MVA SE – no LTC.
- 2 115 kV bays – 2 breakers – Main and Transfer Bus.
- 115 kV cut in and connect to dead end structures outside of the new Lopez 230/115 kV substation.
- Reconductor Santa Maria – San Luis Obispo 115 kV line and loop into the existing Mesa 115 kV and new 115 kV Lopez bus, 228 MVA SN, 286 MVA SE.
- Modify the existing SPS or consider small scale Energy Storage project (25 MW) interconnecting at Sisquoc 115 kV to address the remaining 115 kV overloads for the P2 contingency: Mesa 230 kV 2D and 1D overloading Santa Maria – Fairway Tap 115 kV.

The project is intended to address the post contingency thermal and voltage collapse issues for reliability issues identified in the 2020-2021 TPP.

This project would address similar reliability issues as the North of Mesa Upgrades, which is recommended for approval. The Lopez 2030/115 kV project would also likely cost more than the North of Mesa upgrades once incumbent costs are added to the estimated $75M project cost. The projects expected in service date is Dec 2025.

2.5.8.5 Consideration of Preferred Resources and Energy Storage

As presented in Section 2.5.8.2, about 15 and 26 MW of AAEE reduced the Central Coast and Los Padres Area net load by 1 and 2% in 2025 and 2030 respectively. This year's reliability assessment for Central Coast and Los Padres Area included the "high CEC forecast" sensitivity case for year 2025 which modeled no AAEE and no PV output. Comparisons between the reliability issues identified in the 2025 summer peak baseline case and the “high CEC forecast” sensitivity case are shown in Table 2.5-27 and indicate that the facility overloads are potentially avoided due to reduction in net load.

Table 2.5-27: Reliability Issues in Sensitivity Studies

Facility	Category
Callendar Sw Sta-Mesa 115 kV Line	P6

Furthermore, about 30 MW of demand response and 598 MW of battery energy storage are modeled in Central Coast and Los Padres Area. These resources are modeled offline in the base case and are used as potential mitigation. Utilization of these resources helped reduce some of the thermal overloads identified, however, didn’t completely alleviate the overloads. In addition, The CAISO also analyzed the battery energy storage solutions in conjunction with other transmission solutions to mitigate the reliability issues identified with the on hold North of Mesa project.

2.5.8.6 Recommendation

Based on the studies performed for the 2020-2021 Transmission Plan, several reliability concerns were identified for the PG&E Central Coast and Los Padres Area. These concerns consisted of thermal overloads and voltage concerns under Categories P2, P6 and P7 contingency conditions. A number of the reliability concerns are addressed by previously approved projects within the Central Coast and Los Padres Area.

One previously approved project, Coburn – Oil Fields 60kV system, is recommended to be relocated to the adjacent San Ardo 60kV substation due to physical constraint at the Oil Fields substation.

To address reliability constraints in the Central Coast and Los Padres Area, the CAISO recommends as the mitigation plan procurement of approximately 50 MW 4 hour BESS at Mesa 115kV substation to address maintenance window and for North of Mesa upgrade project to remain on hold pending procurement of the battery storage.

2.5.9 PG&E System High Voltage Assessment

2.5.9.1 Background and Objective

A system wide voltage studies for the PG&E system was performed as part of the 2017-2018 TPP. The study evaluated the impact of load power factor on high voltage issues and reassessed the effectiveness of the projects that were approved in earlier transmission plans. The followings are a summary of the recommendations from the high voltage study in the 2017-2018 TPP:

- Proceed with the approved voltage support projects to address high voltage issues
- Mitigate issues at 500 kV system with voltage support potentially at Round Mountain and Gates 500 kV areas
- Review and address load power factor issues
- Re-assess the voltage mitigation needs with above measures in place, in future TPP cycles

In the last few years PG&E has implemented number of approved voltage support projects and few others will be in service in the next 2-3 years. In addition, the Round Mountain 500 kV Area and Gates 500 kV Dynamic Reactive Support Projects went through a competitive solicitation process and are planned to be implemented by Ls Power Grid California by 2024.

PG&E in collaboration with the CAISO also reviewed the load power factors across the PG&E system and made adjustments if needed and feasible to bring the load power factor within the limits identified in the CAISO Tariff.

Many of the high voltage issues will be addressed with the implementation of the approved, and with the load power factor adjustments. The objective of the high voltage assessment in PG&E system in this planning cycle is to identify the high voltage issues that still remain in the PG&E system even after the implementation of the above mitigation measures. Additional potential mitigation measures were evaluated with the adjustment of the existing system such as transformer taps and shunt adjustments as the first step.

2.5.9.2 Study Scenarios

A system wide voltage studies for the PG&E system was performed as part of the 2017-2018 TPP. The study evaluated the impact of load power factor on high voltage issues and reassessed the effectiveness of the projects that were approved in earlier transmission plans. The followings are a summary of the recommendations from the high voltage study in the 2017-2018 TPP:

Most of the high voltage issues across the PG&E system occur in the middle of the day in the spring in which the gross load is relatively low and a significant portion of the load is served by the behind-the-meter PV and other solar generation. As a result, the transmission and distribution lines are lightly loaded which results in high voltage across the system. Four spring off peak cases were considered in the 2020-2021 TPP and were used for the PG&E high voltage assessment. Table 2.5-28 provides details of the four base cases.

Table 2.5-28: Study Scenarios for High Voltage Assessment

Study Scenario in 2020-2021 TPP	Date/time	Load Power Factor	COI Flow
2022 Spring off Peak	4/26 HE 20	Historical	~ 0 MW
2025 Spring off Peak	4/7 HE 13	Historical	3,675 MW South to North
2030 Spring off Peak	4/6 HE 13	Tariff limits	3,675 MW South to North
2025 Spring off Peak with High Renewables	This is a sensitivity to 2025 spring off peak case with higher BTM-PV, solar, and wind generation.		

2.5.9.3 Study Results and Potential Mitigation Measures

The details of the high voltage issues across PG&E system that were identified in each of the four study scenarios are provided in Appendix C. The first approach in mitigating the high voltage issues in this study was to adjust the existing system by changing the settings of the transformer taps, switching the existing shunts on or off, and changing the scheduled voltage of the generators. The potential mitigation measure for the remaining high voltage issues were to study adding shunt reactors to reduce the voltage. The details of details of the study results are provided in Appendix B for each planning area in PG&E system and shows that for the most part the high voltage issues could be addressed in the base cases by adjusting the existing system. At a high level the study conclusions could be summarized as follows:

4. With implementation of Round Mountain and Gates STATCOM projects, there are no high voltage issues at the 500 kV system under normal conditions.
5. Most high voltage issues occur in off peak cases representing middle of the day with power factor based on historical data (2025)
6. While there are high voltage issues in most areas, issues in Grater Fresno and Kern areas occur in more scenarios which is in line with operators experience in real time.
7. If feasible, most of the high voltage issues could be addressed by adjusting the existing system.
8. Shunt reactors are required in certain areas to address high voltage issues.

2.5.9.4 High Voltage Assessment Plans in Future TPP Cycles

Additional baseline or sensitivity scenarios will be considered to ensure all the issues and their severity are captured. The followings are potential additional scenarios that will be considered in future planning cycles:

- Long term spring off peak with historical load power factors
- Long term spring off peak with historical load power factors and with COI flow at close to zero to have transmission lines lightly loaded
- Real time snapshots of the system at times with high voltage issues

- Minimum load conditions with low hydro generation

The results and mitigation measures so far were based on P0 condition that in most cases result in higher voltage than contingency conditions. However the effectiveness of the mitigation measures to address the high voltage issues will be studied under both P0 conditions as well as under the P1-P7 contingencies in the study scenarios. If required, additional mitigation measures will be developed and studied under contingency conditions.

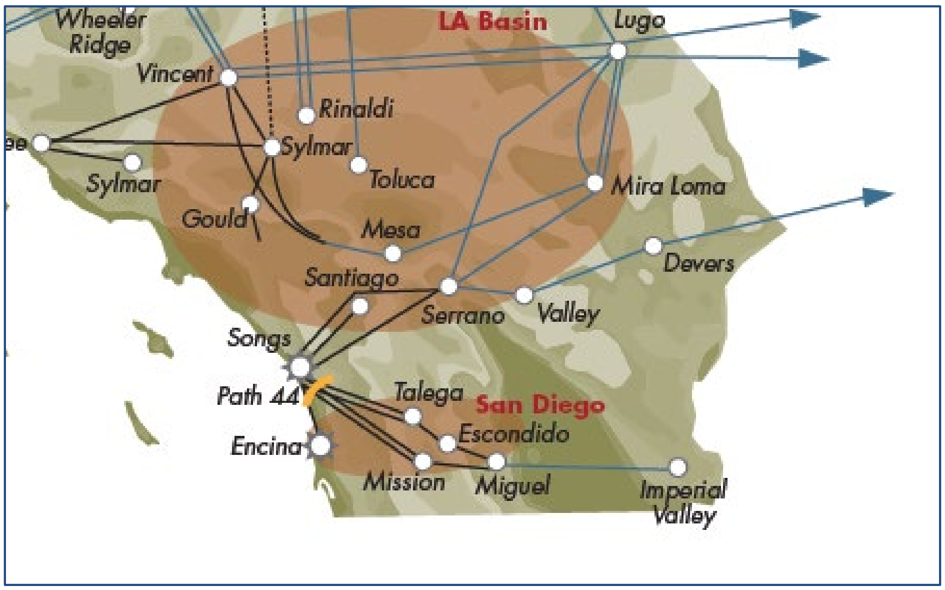
Feasibility of the proposed mitigation measures, especially on system adjustments such as transformer taps and generator scheduled voltage will be further discussed with PG&E and if required modifications will be made in the mitigation measures. Required system enhancements to address high voltage issues will be recommended for approval in future TPP cycles.

2.6 Southern California Bulk Transmission System Assessment

2.6.1 Area Description

The southern California bulk transmission system primarily includes the 500 kV transmission systems of Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) companies and the major interconnections with Pacific Gas and Electric (PG&E), LA Department of Water and Power (LADWP) and Arizona Public Service (APS). An illustration of the southern California's bulk transmission system is shown in Figure 2.6-1.

Figure 2.6-1: Southern California Bulk Transmission System



SCE serves about 15 million people in a 50,000 square mile area of central, coastal and southern California, excluding the City of Los Angeles[89] and certain other cities[90]. Most of the SCE load is located within the Los Angeles Basin. The CEC's gross load growth forecast for the SCE Transmission Access Charge (TAC) area is about 78 MW[91] on the average per year; however, after considering the projection for mid additional achievable energy efficiency (AAEE) and additional achievable PV (AAPV), the demand forecast is declining at an average rate of 32 MW per year[92]. The CEC's 1-in-5 load forecast for the SCE TAC Area includes the SCE service area, and the Anaheim Public Utilities, City of Vernon Light & Power Department, Pasadena Water and Power Department, Riverside Public Utilities, California Department of Water Resources and Metropolitan Water District of southern California pump loads. The 2030

[89] The City of Los Angeles' power need is served by the Los Angeles Department of Water and Power.

[90] Cities of Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Pasadena, Riverside and Vernon have electric utilities to serve their own loads. The City of Cerritos Electric Department serves city-owned facilities, public and private schools and major retail customers.

[91] Based on the CEC-adopted California Energy Demand Forecast 2019-2030 (Form 1.5c) – Mid Demand Baseline Case, No AAEE or AAPV Savings, January 2020 version

[92] Based on the CEC-adopted California Energy Demand Forecast 2019-2030 (Form 1.5c) – Mid Demand Baseline Case, Mid AAEE and AAPV Savings, January 2020 version

summer peak 1-in-5 forecast sales load, including system losses, is 24,268 MW[93]. The SCE area peak load is served by generation that includes a diverse mix of renewables, qualifying facilities, hydro and gas-fired power plants, as well as by power transfers into southern California on DC and AC transmission lines from the Pacific Northwest and the Desert Southwest.

SDG&E provides service to 3.4 million consumers through 1.4 million electric meters in San Diego and southern Orange counties. Its service area encompasses 4,100 square miles from southern Orange County to the U.S. and Mexico border. The existing points of imports are the South of SONGS[94] transmission path, the Otay Mesa-Tijuana 230 kV transmission line and the Imperial Valley Substation.

The 2029 summer peak 1-in-5 forecast load for the SDG&E area including Mid-AAEE, AAPV and system losses is 4,783 MW. Most of the SDG&E area load is served by generation that includes a diverse mix of renewables, qualifying facilities, small pumped storage, and gas-fired power plants. The remaining demand is served by power transfers into San Diego via points of imports discussed above.

Electric grid reliability in southern California has been challenged by the retirement of the San Onofre Nuclear Generating Station and the expected retirement of power plants using ocean or estuarine water for cooling due to OTC regulations. In total, approximately 10,760 MW of generation (8,514 MW gas-fired generation and 2,246 MW San Onofre nuclear generation) in the region has been affected. A total of 5,931 MW of OTC-related electric generation has been retired since 2010. The remaining 4,829 MW of OTC-related gas-fired generation is scheduled to retire in the near term, to comply with the State Water Resources Control Board's Policy on OTC Plants. Some are scheduled to be replaced, such as Alamitos and Huntington Beach, albeit with lower capacity, through the CPUC long-term procurement plan for the local capacity requirement areas in the LA Basin and San Diego. Additionally, consistent with 2020-2021 Transmission Plan, the CAISO has also taken into account the potential retirement of 1,328 MW of aging non-OTC and mothballed generation in the area[95].

To offset the retirement of SONGS and OTC generation, the CPUC in the 2012 LTPP Track 1 and Track 4 decisions authorized SCE to procure between 1900 and 2500 MW of local capacity in the LA Basin area and up to 290 MW in the Moorpark area, and SDG&E to procure between 800 and 1100 MW in the San Diego area.[96] In May 2015, the CPUC issued Decision D.15-05-051 that conditionally approved SDG&E's application for entering into a purchase power and

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93 Based on the CEC-adopted California Energy Demand Forecast 2019-2030 (Form 1.5c) – Mid Demand Baseline Case, Mid AAEE and AAPV Savings, January 2020 version

94 The SONGS was officially retired on June 7, 2013.

95 Includes generating units that are more than forty years of age, as well as units that have been mothballed by the owners.

96 The CPUC Decisions D.13-02-015 (Track 1 for SCE), D.14-03-004 (Track 4 for SCE), D.13-03-029/D.14-02-016 (Track 1 for SDG&E), and D.14-03-004 (Track 4 for SDG&E).

tolling agreement (PPTA) with Carlsbad Energy Center, LLC, for 500 MW[97]. The Decision also required the residual 100 MW of requested capacity to consist of preferred resources or energy storage. In November 2015, the CPUC issued Decision D.15-11-041 to approve, in part, results of SCE's Local Capacity Requirements Request for Offers for the Western LA Basin. The Decision permitted SCE to enter into a PPTA for a total of 1812.6 MW of local capacity that includes 124.04 MW of energy efficiency, 5 MW of demand response, 37.92 MW of behind-the-meter solar photovoltaic generation, 263.64 MW of energy storage, and 1382 MW of conventional (gas-fired) generation. In this analysis, the CAISO considered the authorized levels of procurement and then focused on the results thus far in the utility procurement process – which, in certain cases, is less than the authorized procurement levels.

As set out below, preferred resources and storage are expected to play an important role in addressing the area's needs. As the term "preferred resources" encompasses a range of measures with different characteristics, they have been considered differently. Demand side resources such as energy efficiency programs are accounted for as adjustments to loads, and supply side resources such as demand response are considered as separate mitigations. Further, there is a higher degree of uncertainty as to the quantity, location and characteristics of these preferred resources, given the unprecedented levels being sought and the expectation that increased funding over time will result in somewhat diminishing returns. While the CAISO's analysis focused primarily on the basic assumptions set out below in section 2.6.2, the CAISO has conducted and will continue to conduct additional studies as needed on different resources mixes submitted by the utilities in the course of their procurement processes.

2.6.2 Area-Specific Assumptions and System Conditions

The southern California bulk transmission system steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to area load levels, load modifiers and generation dispatch assumptions for the various scenarios used for the southern California bulk transmission system assessment are provided in Table 2.6-1 and Table 2.6-2.

[97] The Carlsbad Energy Center was energized at the end of 2018.

Table 2.6-1: Southern California Bulk Transmission Demand Side Assumptions

Scenario No.	Case	Gross Load (MW)	AAEE (MW)	BTM-PV (MW)		Net Load (MW)	Demand Response (Installed)	
				Installed	Output		Fast (MW)	Slow (MW)
B1	2022 Summer Peak	25400	282	4540	1998	23120	397	448
B2	2025 Summer Peak	23506	583	5899	295	22628	397	448
B3	2030 Summer Peak	23260	746	7698	0	22514	397	448
B4	2022 Spring Off Peak	15098	178	4540	0	14920	N/A	N/A
B5	2025 Spring Off Peak	11574	163	5899	4778	6633	N/A	N/A
B6	2030 Spring Off Peak	11983	172	7698	6235	5576	N/A	N/A
S1	2025 SP High CEC Load	26789	583	5899	1357	24849	397	448
S2	2022 SOP Heavy Renewable Output & Min. Gas Gen	19229	178	4540	0	19051	N/A	N/A
S3	2022 SP Heavy Renewable Output & Min. Gas Gen.	28103	282	4540	4131	23690	N/A	N/A

Table 2.6-2: Southern California Bulk Transmission Supply Side Assumptions

Scenario No.	Case	Installed Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
			Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2022 Summer Peak	1208	10291	5248	4166	833	1688	445	14231	6017
B2	2025 Summer Peak	1208	10291	206	4166	1295	1688	913	11367	8975
B3	2030 Summer Peak	1229	16315	0	4201	1683	1685	933	11321	7771
B4	2022 Spring Off Peak	1208	10291	2	4166	1625	1688	692	14231	5383
B5	2025 Spring Off Peak	1208	10291	9650	4166	1416	1688	428	11414	512
B6	2030 Spring Off Peak	1229	16082	10636	4208	1431	1688	-517	11484	536
S1	2025 SP High CEC Load	1208	10291	2133	4166	1012	1688	913	11367	9401
S2	2022 SOP Heavy Renewable Output & Min. Gas Gen	1208	10291	10189	4166	2791	1688	692	14231	1810
S3	2022 SP Heavy Renewable Output & Min. Gas Gen.	1208	10291	10189	4166	0	1688	445	14231	3570

Transmission Assumptions

All previously approved transmission projects were modeled in the southern California bulk transmission system assessment in accordance with the general assumptions described in section 2.3.

2.6.2.1 Path Flow Assumptions

The transfers modeled on major paths in the southern California assessment are shown in Table 2.6-3.

Table 2.6-3: Path Flow Assumptions

Path	SOL/Transfer Capability (MW)	2021 SP (MW)	2024 SP (MW)	2029 SP (MW)	2021 LL (MW)	2024 OP (MW)	2024 SP w/High CEC Load (MW)	2024 OP Heavy Ren. (MW)	2024 SP Heavy Ren. (MW)
Path 26 (N-S)	4,000	3,950	3,756	-1,069	180	1,660	3,702	-310	2,391
PDCI (N-S)	3,220	2,500	3,220	3,210	400	1,474	3,220	1,474	2,500
SCIT	17,870	14,129	13,724	13,917	1,963	8,942	14,512	6,907	12,315
Path 46 (WOR)(E-W)	11,200	5,873	6,586	10,645	-133	6,225	6,788	3,340	5,067
Path 49 (EOR)(E-W)	10,100	2,965	3,477	5,245	-2,037	3,670	4,287	636	2,702

2.6.3 Assessment Summary

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix C.

Antelope-Whirlwind 500 kV thermal overload

The Antelope-Whirlwind 500 kV line was overloaded under a Category P6 contingency in the 2025 spring off-peak case and 2022 off-peak with high renewable sensitivity case. The loading concern can be addressed in the operations horizon by generation redispatch after the first contingency.

Besides Antelope-Whirlwind 500kV thermal overload, the Serrano 500/230kV transformers and Vincent 500/230kV transformers were also identified to be overloaded following Category P6 contingencies under multiple sensitivity scenarios. Existing operating procedures would mitigate those issues.

The southern California bulk system assessment did not identify reliability concerns that require corrective action plans to meet TPL 001-4 requirements.

2.6.4 Request Window Project Submissions

The applicable local area sections below detail the request window submittals the CAISO received in the current planning cycle and the results of the CAISO evaluation.

2.6.5 Consideration of Preferred Resources and Energy Storage

Preferred resources and storage were considered in the southern California bulk transmission system assessment as follows.

- As indicated earlier, projected amounts of up to 746 MW of additional energy efficiency (AAEE), and up to 7,698 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 20 percent.
- The existing and planned fast-response demand response amounting 465 MW and energy storage amounting 1,229 MW were used to mitigate any Category P6 or P7 related thermal overloads.
- Since no reliability issues that require mitigation were identified, incremental preferred resources and storage were not considered in the southern California bulk transmission system assessment.

2.6.6 Recommendation

The southern California bulk system assessment did not identify reliability concerns that require new corrective action plans to meet TPL 001-4 requirements. Loading concerns associated with the Antelope-Whirlwind 500 kV line will be addressed with generation redispatch.

2.7 SCE Local Areas Assessment

2.7.1 SCE Tehachapi and Big Creek Area

2.7.1.1 Area Description

The Tehachapi and Big Creek Corridor consists of the SCE transmission system north of Vincent substation. The area includes the following:

WECC Path 26 — three 500 kV transmission lines between PG&E's Midway substation and SCE's Vincent substation with Whirlwind 500 kV loop-in to the third line;

Tehachapi area — Windhub-Whirlwind 500 kV, Windhub – Antelope 500 kV, and two Antelope-Vincent 500 kV lines;

230 kV transmission system between Vincent and Big Creek Hydroelectric project that serves customers in Tulare county; and

Antelope-Bailey 66 kV system which serves the Antelope Valley, Gorman, and Tehachapi Pass areas.

The Tehachapi and Big Creek Corridor area relies on internal generation and transfers on the regional bulk transmission system to serve electricity customers. The area has a forecasted 1-in-10 net load of 2,437 MW in 2030 including the impact of 760 MW of forecast behind-the-meter photovoltaic (BTM PV) generation and 48 MW of additional achievable energy efficiency (AAEE).

The CAISO has approved the following major transmission projects in this area in prior planning cycles:

- San Joaquin Cross Valley Loop Transmission Project (completed);
- Tehachapi Renewable Transmission Project (completed);
- East Kern Wind Resource Area 66 kV Reconfiguration Project (completed); and
- Big Creek Corridor Rating Increase Project (completed).

2.7.1.2 Area-Specific Assumptions and System Conditions

The SCE Tehachapi and Big Creek Corridor Area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the Tehachapi and Big Creek Corridor area study are provided below.

The SCE Tehachapi and Big Creek Corridor area study included five base and three sensitivity scenarios as shown in Table 2.7-1.

Demand-Side Assumptions

The summer peak base cases are based on the CEC mid 1-in-10 year load forecast with low AAEE. The table below provides the demand-side assumptions used in the Tehachapi and Big Creek Corridor area assessment including the impact of BTM PV and AAEE. The load values include distribution system losses.

Table 2.7-1 Tehachapi and Big Creek Areas demand-side assumptions

Scenario No.	Base Case	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response (installed)	
				Installed (MW)	Output (MW)		Fast (MW)	Slow (MW)
B1	2022 Summer Peak	2,607	20	482	212	2,375	67	21
B2	2025 Summer Peak	2,536	35	570	131	2,370	67	21
B3	2030 Summer Peak	2,485	48	760	0	2,437	67	21
B4	2022 Spring Off-Peak	1,627	12	482	0	1,615	N/A	N/A
B5	2025 Spring Light Load	1,045	10	570	462	574	N/A	N/A
S1	2025 SP High CEC Load	2,661	35	570	131	2,495	67	21
S2	2022 SOP Heavy Renewable Output & Min. Gas Gen.	2,065	12	482	439	1,615	N/A	N/A
S3	2022 SP Heavy Renewable Output & Min. Gas Gen.	2,833	20	482	439	2,375	67	21
Note:	*DR and storage are modeled offline in starting base cases.*							

Supply-Side Assumptions

The table below provides a summary of the supply-side assumptions modeled in the Tehachapi and Big Creek Corridor Area assessment including conventional and renewable generation, demand response and energy storage. A detailed list of existing generation in the area is included in Appendix A.

Table 2.7-2 Tehachapi and Big Creek Areas supply-side assumptions

No.	Base Case	Battery Storage (Installed) (MW)	Solar (Grid Connected)		Wind		Hydro		Thermal	
			Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2022 Summer Peak	643	5080	2591	3529	706	1227	637	1,517	559
B2	2025 Summer Peak	643	5080	1040	3529	871	1227	1021	1,517	1,367
B3	2030 Summer Peak	663	6194	0	3523	1412	1233	1018	1,517	765
B4	2022 Spring Off-Peak	643	5080	0	3529	1376	1227	798	1,517	602
B5	2025 Spring Light Load	643	5080	4751	3529	1200	1227	422	1,517	-
S1	2025 SP High CEC Load	643	5080	1040	3529	871	1227	1021	1,517	1,416
S2	2022 SOP Heavy Renewable Output & Min. Gas Gen.	643	5080	5029	3529	2365	1227	847	1,517	-
S3	2022 SP Heavy Renewable Output & Min. Gas Gen.	643	5080	5029	3529	0	1227	637	1,517	-

Note: DR and storage are modeled offline in starting base cases.

Transmission Assumptions

All previously approved transmission projects were modeled in the Tehachapi and Big Creek Corridor Area assessment in accordance with the general assumptions described in section 2.3.

2.7.1.3 Assessment Summary

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The Tehachapi and Big Creek Areas assessment identified the following steady state and transient stability issues in the base and/or sensitivity cases under the contingency conditions indicated.

- Whirlwind 500/230 kV transformer overload in the 2025 spring off-peak case under P1 and P6 conditions. The transformers were overloaded under P0 conditions in the 2022 spring off-peak sensitivity case with high renewable output and minimum gas generation.
- Antelope–Neenach 66 kV line overload in the 2025 spring off-peak case under P1 and P2 conditions
- Big Creek 2–Big Creek 3 230 kV line overload in the cases with heavy Big Creek Hydro dispatch under P6 conditions

- Antelope 230/66 kV transformer overload in the 2025 and 2030 summer peak cases under P6 conditions
- Neenach–Bailey/Westpac junction 66 kV line overload in the 2025 summer peak sensitivity case with high renewable output and minimum gas generation under P0 conditions
- Voltage collapse in the Antelope–Bailey 66 kV system in all of the summer peak and the 2022 spring off-peak cases under P6 conditions
- Loss of synchronism of Big Creek Hydro generators to in the 2030 summer peak case under P6 conditions
- Local instability in the Antelope–Bailey 66 kV system in the 2030 summer peak case under P6 conditions.

The steady state and transient stability issues identified above can be mitigated in the operations horizon without relying on non-consequential load loss by using existing RAS or such operational measures as re-dispatching resources, reconfiguring the system or utilizing available spares as further discussed in Appendix B. As a result, no further corrective action was considered.

2.7.1.4 Request Window Project Submissions

The CAISO did not receive request window submissions for the SCE Tehachapi and Big Creek Corridor Area in this planning cycle.

2.7.1.5 Consideration of Preferred Resources and Energy Storage

Preferred resources and storage were considered in the SCE Tehachapi and Big Creek Corridor Area assessment as follows.

- As indicated earlier, projected amounts of up to 48 MW of additional energy efficiency (AAEE), and up to 760 MW of distributed generation were used to avoid potential reliability issues by reducing area load by up to 9 percent.
- The Tehachapi and Big Creek Corridor Area reliability assessment did not identify need for additional preferred resources and storage resources in the area.

2.7.1.6 Recommendation

The SCE Tehachapi and Big Creek Corridor area assessment identified several steady state and transient stability related issues. Existing RAS and operating solutions such as re-dispatching resources, reconfiguring the system or utilizing available spares as described in more detail in Appendix B can be utilized to address the issues identified. As a result, no further corrective action was considered.

2.7.2 SCE North of Lugo Area

2.7.2.1 Area Description

The North of Lugo (NOL) transmission system serves San Bernardino, Kern, Inyo and Mono counties. The figure below depicts the geographic location of the north of Lugo area, which extends more than 270 miles.

The North of Lugo electric transmission system is comprised of 55 kV, 115 kV and 230 kV transmission facilities. In the north, it has inter-ties with Los Angeles Department of Water and Power (LADWP) and Sierra Pacific Power. In the south, it connects to the Eldorado Substation through the Ivanpah-Baker-Cool Water-Dunn Siding-Mountain Pass 115 kV line. It also connects to the Pisgah Substation through the Lugo-Pisgah Nos. 1&2 230 kV lines. Two 500/230 kV transformer banks at the Lugo substation provide access to SCE's main system. The NOL area can be divided into the following sub-areas: north of Control; Kramer/North of Kramer/Cool Water; and Victor specifically.

2.7.2.2 Assumptions and System Conditions

The North of Lugo area steady state and transient stability assessment was performed consistently with the general study assumptions and methodology described in section 2.3. The CAISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the North of Lugo area study are provided in Table 2.7-3 and Table 2.7-4.

Table 2.7-3 North of Lugo Area Demand Side Assumptions

Scenario No.	Case	Gross Load (MW)	AAEE (MW)	BTM-PV (MW)		Net Load (MW)	Demand Response (Installed)	
				Installed	Output		Fast (MW)	Slow (MW)
B1	2022 Summer Peak	1176	6	856	377	793	66	33
B2	2025 Summer Peak	1071	11	1113	256	804	66	33
B3	2030 Summer Peak	842	14	1453	0	828	66	33
B4	2022 Spring Off Peak	504	4	856	0	500	N/A	N/A
B5	2025 Spring Off Peak	1130	3	1113	902	225	N/A	N/A
S1	2025 SP High CEC Load	1113	11	1113	256	846	66	33
S2	2022 SOP Heavy Renewable Output & Min. Gas Gen	1282	4	856	779	499	N/A	N/A
S3	2022 SP Heavy Renewable Output & Min. Gas Gen.	1578	6	856	779	793	N/A	N/A

Table 2.7-4 North of Lugo Area Supply Side Assumptions

Scenario No.	Case	Installed Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
			Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2022 Summer Peak	110	1003	893	0	0	74	54	1381	425
B2	2025 Summer Peak	110	1003	893	0	0	74	54	1381	1255
B3	2030 Summer Peak	110	1366	1256	0	0	74	54	1381	1255
B4	2022 Spring Off Peak	110	1003	893	0	0	74	54	1381	425
B5	2025 Spring Off Peak	110	1003	893	0	0	74	54	1381	1255
S1	2025 SP High CEC Load	110	1003	211	0	0	74	0	1381	1065
S2	2022 SOP Heavy Renewable Output & Min. Gas Gen	110	1003	993	0	0	74	22	1381	376
S3	2022 SP Heavy Renewable Output & Min. Gas Gen.	110	1003	993	0	0	74	21	1381	695

All previously approved transmission projects were modeled in the North of Lugo area assessment in accordance with the general assumptions described in section 2.3. The following previously approved transmission upgrades were modeled in the 2022, 2025 and 2030 study cases:

- Victor Loop-in Project: Loop in the existing Kramer-Lugo Nos. 1&2 230 kV lines into Victor Substation. (in-service)
- Kramer Reactor Project: Install two 34 Mvar reactors to the 12 kV tertiary winding of the existing 230/115 kV Nos. 1&2 transformers and one 45var shunt reactor at the Kramer 230 kV bus. (in-service)

2.7.2.3 Assessment Summary

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The 2020-2021 reliability assessment of the North of Lugo area has identified thermal overload and high/low voltages issues under Category P1 and P6 contingencies. All of those issues can be mitigated in the operation horizon by relying upon the existing operating procedure or future project. Appendix B has a detailed discussion.

The transient stability assessment identified a voltage recovery and voltage dip violation following a Category P6 contingency. The CAISO recommends relying on existing RAS, and redispatching generation after the first contingency.

2.7.2.4 Request Window Project Submissions

The CAISO received one project submittal through the 2020 request window submission for the SCE North of Lugo Area. Below is a description of the proposal followed by CAISO comments and findings.

Brightline West High Speed Rail – Load Interconnection Request

The project was submitted by SCE as a load interconnection request. The overall project consists of providing two points of service and network upgrade mitigation for the operation of a high-speed electric train from Victorville, CA to Las Vegas, NV. The electric train will take service at the Ivanpah 115kV bus and in the Barstow area via a new substation to be looped into the existing Kramer – Tortilla 115kV line. SCE identified reliability concerns with Barstow area delivery point. The proposed mitigation is to install a 220/115kV transformer bank at Coolwater substation. The preliminary cost estimate is $47 million. The total project cost is $83 million. The proposed in-service date of the interconnection portion of the project is Q1 2023. The proposed in-service date of the Coolwater transformer is Q2 2024.

The CAISO has reviewed and concurred with the network upgrades proposed at the new load substations. The CAISO also concurred with the recommended network upgrades proposed to mitigate the identified reliability concerns.

2.7.2.5 Consideration of Preferred Resources and Energy Storage

Preferred resources and storage were considered in the North of Lugo area assessment as follows.

- Projected amounts of up to 14 MW additional achievable energy efficiency (AAEE), and up to 1,113 MW of distributed generation were used to avoid potential reliability issues by reducing area load.
- The existing and planned fast-response demand response amounting to 66 MW was identified and available in the base and sensitivity cases, but did not need to be activated to address any local transmission concerns in this analysis.
- The NOL Area assessment did not identify a need for additional preferred and storage resources in the area.

2.7.2.6 Recommendation

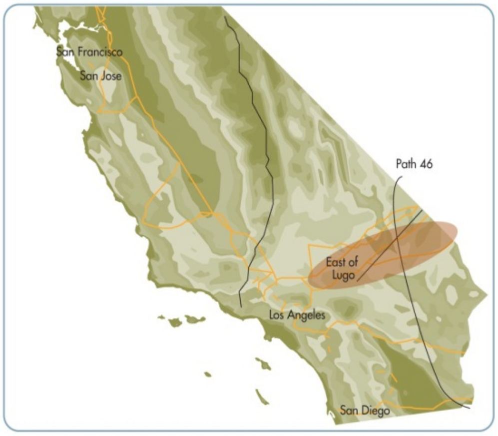
The North of Lugo area assessment identified one category P1 related high voltage issue and several category P6 related thermal overload and low voltage issues. For the high voltage issue, LADWP's future shunt reactor at Inyo 230kV bus would address the concern. For the category P6 related issues, operating solutions, including relying upon existing operating procedures, existing RAS, and congestion management are recommended to address those.

The assessment also identified one transient voltage recovery and voltage dip violation for a category P6 contingency with existing HDPP and Mohave Desert RAS schemes. The CAISO recommends relying on generation redispatch after the first contingency, and RAS.

2.7.3 SCE East of Lugo Area

2.7.3.1 Area Description

The East of Lugo (EOL) area consists of the transmission system between the Lugo and Eldorado substations. The EOL area is a major transmission corridor connecting California with Nevada and Arizona; is a part of Path 46 (West of River), and is heavily integrated with LADWP and other neighboring transmission systems. The SDG&E owned Merchant 230 kV switchyard became part of the CAISO controlled grid and now radially connects to the jointly owned Eldorado 230 kV substation. Merchant substation was formerly in the NV Energy balancing authority, but after a system reconfiguration in 2012, it became part of the CAISO system. The Harry Allen-Eldorado 500 kV line was approved by the CAISO Board of Governors in 2014. The project went in-service in July 2020 and is now part of the EOL system.



The existing EOL bulk system consists of the following:

- 500 kV transmission lines from Lugo to Eldorado and Mohave;
- 230 kV transmission lines from Lugo to Pisgah to Eldorado;
- 115 kV transmission line from Cool Water to Ivanpah; and
- 500 kV and 230 kV tie lines with neighboring systems, including the new Harry Allen-Eldorado line.

2.7.3.2 Area-Specific Assumptions and System Conditions

The East of Lugo area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the East of Lugo area study are provided in Table 2.7-5 and Table 2.7-6.

Table 2.7-5 East of Lugo Area Demand Side Assumptions

Scenario No.	Case	Gross Load (MW)	AAEE (MW)	BTM-PV MW)		Net Load (MW)	Demand Response (Installed)	
				Installed	Output		Fast (MW)	Slow (MW)
B1	2022 Summer Peak	2.18	0	0.19	0.08	2.1	0	0
B2	2025 Summer Peak	2.02	0	0.57	0.13	1.89	0	0
B3	2030 Summer Peak	1.7	0	1.16	0	1.71	0	0
B4	2022 Spring Off Peak	1.32	0	0.19	0	1.32	0	0
B5	2025 Spring Off Peak	0.99	0	0.57	0.46	0.53	0	0
S1	2025 SP High CEC Load	2.12	0	0.57	0.13	1.99	0	0
S2	2022 SOP Heavy Renewable Output & Min. Gas Gen	1.49	0	0.19	0.17	1.32	0	0
S3	2022 SP Heavy Renewable Output & Min. Gas Gen.	2.27	0	0.19	0.17	2.1	0	0

Table 2.7-6 East of Lugo Area Supply Side Assumptions

Scenario No.	Case	Installed Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
			Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2022 Summer Peak	0	1254	639	0	0	0	0	525	0
B2	2025 Summer Peak	0	1254	263	0	0	0	0	525	449
B3	2030 Summer Peak	0	1254	0	0	0	0	0	525	419
B4	2022 Spring Off Peak	0	1254	0	0	0	0	0	525	419
B5	2025 Spring Off Peak	0	1254	1179	0	0	0	0	525	0
S1	2025 SP High CEC Load	0	1254	263	0	0	0	0	525	449
S2	2022 SOP Heavy Renewable Output & Min. Gas Gen	0	1254	1241	0	0	0	0	525	0
S3	2022 SP Heavy Renewable Output & Min. Gas Gen.	0	1254	1241	0	0	0	0	525	0

The transmission modeling assumptions are consistent with the general assumptions described in section 2.3. The transmission upgrade modeled in the 2022 study cases are:

- Harry Allen-Eldorado 500 kV transmission line (in-service)
- Eldorado-Lugo 500 kV series capacitor and terminal equipment upgrade
- Lugo-Mohave 500 kV series capacitor and terminal equipment upgrade
- New Calcite 230 kV Substation and loop into Lugo-Pisgah #1 230 kV line
- Lugo-Victorville 500 kV terminal equipment upgrade and remove ground clearance limitations

2.7.3.3 Assessment Summary

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The SCE East of Lugo area steady state assessment identified one Category P6 system divergence issue in all cases. The system divergence issue could be mitigated by an existing NV Energy protection scheme. The stability analysis performed in the EOL Area assessment did not identify transient issues that require mitigation.

As a result, system additions and upgrades are not identified for the East of Lugo area.

2.7.3.4 Request Window Project Submissions

The CAISO did not receive request window submissions for the SCE East of Lugo area in this planning cycle.

2.7.3.5 Consideration of Preferred Resources and Energy Storage

The SCE East of Lugo area is comprised of high voltage transmission lines and generation facilities with limited customer load, so the assessment did not identify a need for preferred resources and energy storage in the area.

2.7.3.6 Recommendation

The SCE East of Lugo area assessment identified one potential system divergence issue for a Category P6 outage which would be mitigated by an existing protection scheme.

2.7.4 SCE Eastern Area

2.7.4.1 Area Description

The CAISO controlled grid in the SCE Eastern Area serves the portion of Riverside County around Devers Substation. The figure below depicts the geographic location of the area. The system is composed of 500 kV, 230 kV and 161 kV transmission facilities from Vista Substation to Devers Substation and continues on to Palo Verde Substation in Arizona. The area has ties to Salt River Project (SRP), the Imperial Irrigation District (IID), Metropolitan Water District (MWD), and the Western Area Lower Colorado control area (WALC).

The CAISO has approved the following major transmission projects in this area in prior planning cycles:

- West of Devers Upgrade Project (2021) and
- Delaney-Colorado River 500 kV line Project (2021).

2.7.4.2 Area-Specific Assumptions and System Conditions

The SCE Eastern Area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. The summer peak base cases are based on the CEC mid 1-in-10 year load forecast with low AAEE. The load values include distribution system losses. The spring light load and spring off-peak cases assume approximately 28 percent and 63 percent of the net peak load respectively. Specific assumptions related to study scenarios, load, resources and transmission that were applied to the Eastern area study are shown in Table 2.7-7 and Table 2.7-8.

Table 2.7-7 Eastern Area load and load modifier assumptions

S. No.	Base Case	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
				Installed (MW)	Output (MW)		Fast	Slow
B1	2022 Summer Peak	5212	65	885	389	4758	53	5
B2	2025 Summer Peak	5183	131	1088	250	4802	53	5
B3	2030 Summer Peak	5143	177	1384	0	4966	53	5
B4	2022 Off Peak	3063	65	885	0	2997	53	5
B5	2025 Off Peak	2356	131	1088	881	1345	53	5
S1	2025 Peak High CEC Load	5436	131	1088	250	5055	53	5
S2	2022 Off Peak Heavy Renewable Output & Min. Gas Gen.	3868	65	885	805	2997	53	5
S3	2022 Peak Heavy Renewable Output & Min. Gas Gen.	5628	65	885	805	4758	53	5

Table 2.7-8 Eastern Area generation assumptions

S. No.	Base Case	Battery Storage (MW)	Solar		Wind		Hydro		Thermal	
			Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2022 Summer Peak	0	2892	1473	637	127	315	0	4022	2064
B2	2025 Summer Peak	0	2892	607	637	141	315	119	4022	1338
B3	2030 Summer Peak	0	5742	0	679	271	315	119	4022	2871
B4	2022 Off Peak	0	2892	2	637	248	315	51	4022	1356
B5	2025 Off Peak	0	2892	2718	637	216	315	0	4022	0
S1	2025 Peak High CEC Load	0	2892	607	637	141	315	119	4022	2345
S2	2022 Off Peak Heavy Renewable Output & Min. Gas Gen.	0	2892	2863	637	427	315	51	4022	701
S3	2022 Peak Heavy Renewable Output & Min. Gas Gen.	0	2892	2863	637	0	315	0	4022	222

Transmission Assumptions

All previously approved transmission projects were modeled in the Eastern Area assessment in accordance with the general assumptions described in section 2.3.

2.7.4.3 Assessment Summary

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The SCE Eastern area steady state assessment identified a Category P7 contingency-related thermal overload. The stability analysis also identified a Category P7 transient issue. The thermal and stability issues identified can be mitigated in the operations horizon without relying on non-consequential load loss by such operational measures as curtailing generation before the contingency or reconfiguring the system after the initial contingency as discussed in Appendix B.

As a result, system additions and upgrades are not identified for the Eastern area.

2.7.4.4 Request Window Project Submissions

The CAISO did not receive any request window submission for the SCE Eastern Area in this planning cycle.

2.7.4.5 Consideration of Preferred Resources and Energy Storage

No additional grid-connected preferred resources or storage was modeled in the SCE Eastern Area, and the assessment did not identify a need for additional preferred and storage resources in the area.

2.7.4.6 Recommendation

The SCE Eastern area assessment identified category P7 related thermal overload and stability issues. Remedial Action Scheme and operating solutions including curtailing generation before the contingency or reconfiguring the system after the initial contingency are recommended to address the issues.

2.7.5 SCE Metro Area

2.7.5.1 Area Description

The SCE Metro area consists of 500 kV and 230 kV facilities that serve major metropolitan areas in the Los Angeles, Orange, Ventura counties and surrounding areas. The points of interconnections with the external system include Vincent, Mira Loma, Rancho Vista and Valley 500 kV Substations and Sylmar, San Onofre and Pardee 230 kV Substations. The bulk of SCE load as well as most southern California coastal generation is located in the SCE Metro area.

The Metro area relies on internal generation and transfers on the regional bulk transmission system to serve electricity customers. The area has a forecasted 1-in-10 net load of 18,319 MW in 2030 including the impact of 4,673 MW of forecast behind-the-meter photovoltaic (BTM PV) generation and 460 MW of additional achievable energy efficiency (AAEE).

The area will have approximately 4,875 MW of grid-connected generation in 2030 after the retirement of 4,153 MW of generation to comply with the state's policy regarding once-through-cooled (OTC) generation. The California Public Utilities Commission (CPUC) has approved a total of 2,019 MW of conventional generation, preferred resources and energy storage for the area to offset the local capacity deficiency resulting from the retirement of the San Onofre Generating Station and the OTC generating plants.

The CAISO has approved the following major transmission projects in this area in prior planning cycles:

- Mesa 500 kV Substation (March 2022);
- Laguna Bell Corridor Upgrade (December 2020);
- Moorpark-Pardee No. 4 230 kV Circuit Project (June 2021).
- Pardee-Sylmar No. 1 and No. 2 230 kV Lines Rating Increase Project (May 2023)
- Method of Service for Wildlife 230/66 kV Substation (October 2026); and
- Method of Service for Alberhill 500/115 kV Substation (TBD);

2.7.5.2 Area-Specific Assumptions and System Conditions

The SCE Metro Area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific demand and supply-side assumptions for the various scenarios used for the SCE Metro Area assessment are provided in Table 2.7-9 and Table 2.7-10, respectively.

Table 2.7-9: Metro Area demand side assumptions

Base Case	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response (installed)	
			Installed (MW)	Output (MW)		Fast (MW)	Slow (MW)
2022 Summer Peak	19,298	216	2,715	1,195	17,887	237	375
2025 Summer Peak	19,076	370	3,600	828	17,878	237	375
2030 Summer Peak	18,779	460	4,673	0	18,319	237	375
2022 Spring Off-Peak	11,460	143	2,715	0	11,317	N/A	N/A
2025 Spring Light Load	7,989	104	3,600	2,916	4,969	N/A	N/A
2025 SP High CEC Load	20,028	370	3,600	828	18,830	237	375
2022 SOP Heavy Renewable Output & Min. Gas Gen.	7,989	143	2,715	2,471	11,317	N/A	N/A
2022 SP Heavy Renewable Output & Min. Gas Gen.	19,101	216	2,715	2,471	17,888	237	375

Note: DR and storage are modeled offline in starting base cases.

Table 2.7-10: Metro Area supply-side assumptions

Base Case	Battery Storage (Installed) (MW)	Solar (Grid Connected)		Wind		Hydro		Thermal	
		Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
2022 Summer Peak	455	106	54	0	0	43	18	7,748	3,602
2025 Summer Peak	455	106	22	0	0	43	2	4,884	3,493
2030 Summer Peak	455	375	0	0	0	34	20	4,875	3,535
2022 Spring Off-Peak	455	106	0	0	0	43	12	7,748	2,671
2025 Spring Light Load	455	106	99	0	0	43	6	4,884	252
2025 SP High CEC Load	455	106	22	0	0	43	2	4,884	3,680
2022 SOP Heavy Renewable Output & Min. Gas Gen.	455	106	105	0	0	43	12	7,748	1,222
2022 SP Heavy Renewable Output & Min. Gas Gen.	455	106	104	0	0	43	18	7,748	2,652

Note: DR and storage are modeled offline in starting base cases.

Transmission Assumptions

All previously approved transmission projects were modeled in the Metro Area assessment in accordance with the general assumptions described in section 2.3.

2.7.5.3 Assessment Summary

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

The SCE Metro area assessment identified the following thermal overloads in the base and/or sensitivity cases under the contingency conditions indicated.

- Pardee–Sylmar #1 & #2 230 kV lines in the 2030 summer peak case (P6)
- Mesa–Laguna Bell #1 230 kV line in all of the summer peak cases (P6, P7)
- Serrano 500/230 kV transformers in the 2030 summer peak case (P6)
- Vincent 500/230 kV transformers in the 2022 summer peak sensitivity case with heavy renewable output and minimum gas generation commitment (P6)
- Mesa 500/230 kV transformers in the 2022 summer peak sensitivity case with heavy renewable output and minimum gas generation commitment

The thermal loading issues identified can be mitigated in the operations horizon without relying on non-consequential load loss by such operational measures as re-dispatching resources including preferred resources and energy storage or reconfiguring the system before or after the contingency as further discussed in Appendix B.

The assessment also identified low voltages at Goleta substation in the 2030 summer peak case under category P6 conditions. The approved energy storage projects at the substation (current ISD 2021) will address the low voltage. The assessment did not identify stability issues.

2.7.5.4 Request Window Project Submissions

The CAISO did not receive any request window submittals for the SCE Metro Area in this planning cycle.

2.7.5.5 Consideration of Preferred Resources and Energy Storage

Preferred resources and energy storage were considered in the SCE Metro Area assessment as follows.

- As indicated earlier, projected amounts of up to 460 MW of additional energy efficiency (AAEE), and up to 4,673 MW of distributed generation were used to avoid potential reliability issues by reducing area load.
- Up to 237 MW of the existing and planned fast-response demand response and up to 455 MW of existing energy storage were used in the base or sensitivity cases to mitigate thermal overloads and low voltage concerns.

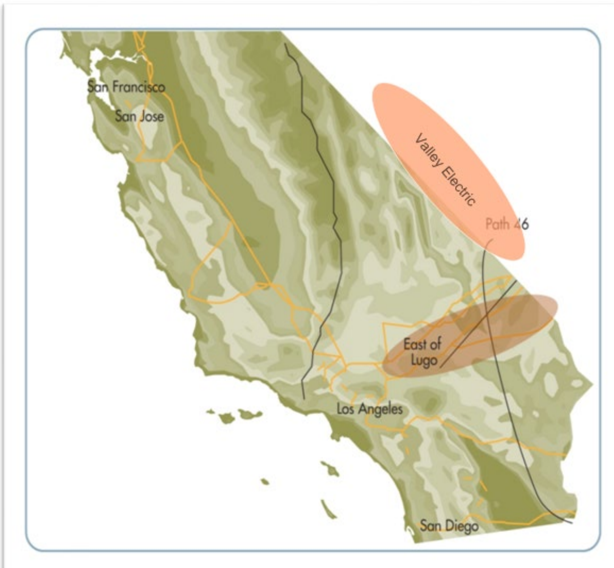
2.7.5.6 Recommendation

The SCE Metro area assessment identified several thermal overloads and a low voltage concern under Category P6 or P7 contingency conditions. Planned resources and operating solutions, such as re-dispatching resources or reconfiguring the system before or after the contingency conditions as described in more detail in Appendix B address the issues identified. As a result no further corrective action plans were considered.

2.8 Valley Electric Association Area

2.8.1 Area Description

The Valley Electric Association (VEA) transmission system is comprised of 230 kV and 138 kV facilities under CAISO control. GridLiance West, LLC (GLW) is the Transmission Owner for the 230 kV facilities in the VEA area. All the distribution load in the VEA area is supplied from the 138 kV system which is mainly supplied through 230/138 kV transformers at Innovation, Pahrump and WAPA's Amargosa substations. The Pahrump and Innovation 230 kV substations are connected to the SCE's Eldorado, NV Energy's Northwest and WAPA's Mead 230 kV substations through three 230 kV lines.



The VEA system is electrically connected to neighboring balancing area systems through the following lines:

- Sloan Canyon – Eldorado 230kV tie line with SCE;
- Mead – Sloan Canyon 230 kV tie line with WAPA;
- Amargosa – Sandy 138 kV tie line with WAPA;
- Jackass Flats – Lathrop Switch 138 kV tie line with NV Energy (NVE); and
- Northwest – Desert View 230 kV tie line with NV Energy.

2.8.2 Area-Specific Assumptions and System Conditions

The VEA area steady state and transient stability assessment was performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO-secured participant portal provides the base cases, stability model data and contingencies that were used in this assessment. In addition, specific assumptions related to study scenarios, load, resources and transmission that were applied to the VEA area study are provided in Table 2.8-1 and Table 2.8-2.

Table 2.8-1: VEA Area Demand Side Assumptions

Scenario No.	Case	Gross Load (MW)	AAEE (MW)	BTM-PV		Net Load (MW)	Demand Response	
				Installed (MW)	Output (MW)		Fast (MW)	Slow (MW)
B1	2022 Summer Peak	169	0	0	0	169	0	0
B2	2025 Summer Peak	177	0	0	0	177	0	0
B3	2030 Summer Peak	191	0	0	0	191	0	0
B4	2022 Spring Off Peak	109	0	0	0	109	0	0
B5	2025 Spring Off Peak	61	0	0	0	61	0	0
S1	2022 Summer Peak with high forecasted load	180	0	0	0	180	0	0
S2	2025 Summer Peak with high forecasted load	207	0	0	0	207	0	0
S3	2025 Off Peak with heavy renewable output	61	0	0	0	61	0	0

Table 2.8-2: VEA Area Supply Side Assumptions

Scenario No.	Case	Installed Storage (MW)	Solar		Wind		Hydro		Thermal	
			Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)	Installed (MW)	Dispatch (MW)
B1	2022 Summer Peak	0	115	59	0	0	0	0	0	0
B2	2025 Summer Peak	0	115	25	0	0	0	0	0	0
B3	2030 Summer Peak	0	820	0	0	0	0	0	0	0
B4	2022 Spring Off Peak	0	115	0	0	0	0	0	0	0
B5	2025 Spring Off Peak	0	115	111	0	0	0	0	0	0
S1	2022 Summer Peak with high forecasted load	0	115	59	0	0	0	0	0	0
S2	2025 Summer Peak with high forecasted load	0	115	25	0	0	0	0	0	0
S3	2025 Off Peak with heavy renewable output	0	820	786	0	0	0	0	0	0

All previously approved transmission projects were modeled in the Valley Electric Association area assessment in accordance with the general assumptions described in section 2.3. The transmission upgrades modeled in the 2022, 2025, and 2030 study cases are:

- New Sloan Canyon (previously named Bob) 230 kV switching station that loops into the existing Pahrump-Mead 230kV Line (in-service)
- New Eldorado-Sloan Canyon 230kV transmission line (in-service)
- Sloan Canyon-Mead 230kV line upgrade
- New Gamebird 230/130kV transformer project

The transmission upgrade on hold and not being modeled in this TPP cycle is:

- New Charleston-Gamebird 138 kV transmission line

2.8.3 Assessment Summary

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements set out in section 2.2. Details of the planning assessment results are presented in Appendix B.

Amargosa 230/138 kV Transformer Overload and 138 kV Low Voltage Issues Mitigation

The VEA area steady state assessment identified thermal overloads on the Amargosa 230/138 kV transformer following multiple Category P6 contingencies involving loss of the new Gamebird 230/138kV transformer or the Gamebird-Sloan Canyon 230kV line under various base and sensitivity scenarios. Load growth in the VEA area was found to be the primary driver behind this reliability issue. The CAISO is working with VEA to develop an operating procedure to radialize the system after the first contingency.

Low voltages at several 138kV buses were also identified for the same Category P6 contingencies. The existing UVLS would trip load in the area and mitigate the low voltage concern.

Pahrump Transformer Overloads

The assessment identified thermal overloads on each of the Pahrump 230/138kV transformer banks following a Category P6 contingency of the other Pahrump transformer and the new Gamebird 230/138kV transformer under the 2030 base and 2025 high load sensitivity scenarios. The mitigation includes relying on the short-term emergency rating of the transformer and performing manual load shedding.

Jackass Flats – Mercury Switch Overloads

The assessment identified thermal overloads on Jackass Flats – Mercury Switch 138 kV line following multiple Category P6 contingencies under the 2030 summer peak base scenario and 2025 off-peak with heavy renewable sensitivity scenario. Congestion management, and RAS identified through GIDAP studies to trip the generation will mitigate this reliability issue.

In addition to the Amargosa transformer overloads, Pahrump transformer overloads and Jackass Flats – Mercury Switch 138 kV line overloads, the assessment identified several Category P1 and P6 related thermal overloads under the 2025 off-peak with heavy renewable sensitivity scenario which could be mitigated by previously identified generation-tripping RASs or congestion management.

The stability analysis performed in the VEA area assessment identified one Category P6 WECC voltage criteria violation. The existing UVLS would mitigate the issue.

2.8.4 Request Window Project Submissions

The CAISO did not receive any request window submissions for the Valley Electric Association area in this planning cycle

2.8.5 Consideration of Preferred Resources and Energy Storage

The VEA area assessment did not identify a need for additional preferred and storage resources in the area.

2.8.6 Recommendation

The VEA area assessment identified several Category P6 thermal overloads under the base and sensitivity scenarios as described in Appendix B. The mitigations include developing new operating procedure; utilizing the facility short-term emergency rating and performing manual load shedding; and congestion management.

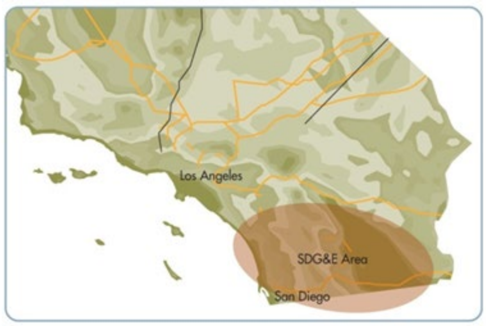
The VEA area assessment identified several Category P1 and P6 thermal overloads under the 2025 heavy renewable sensitivity scenario. The RAS schemes developed in the GIDAP process and congestion management would be able to mitigate all the violations.

The VEA area assessment also identified one Category P6 transient stability WECC voltage violation. The existing UVLS would mitigate the issue.

2.9 SDG&E Area

2.9.1 San Diego Local Area Description

SDG&E is a regulated public utility that provides energy service to 3.6 million consumers through 1.4 million electric meters and more than 873,000 natural gas meters in San Diego and southern Orange counties. The utility's service area spans 4,100 square miles from Orange County to the US-Mexico border, covering 25 communities.



The SDG&E system, includes its main 500/230 kV and 138/69 kV sub-transmission systems. The geographical location of the area is shown in the adjacent illustration. Its 500 kV system consists of the Southwest Powerlink (SWPL) and Sunrise Powerlink (SRPL) systems. The 230 kV transmission lines form an outer loop located along the Pacific coast and around downtown San Diego with an underlying 138 kV and 69 kV sub-transmission system. Rural customers in the eastern part of San Diego County are served by a sparse 69 kV system.

The CAISO approved various transmission projects presented in chapter 8 for this area in previous planning cycles, which will maintain the area reliability and deliverability of resources while meeting policy requirement in the near future. Some of the major system additions are the Sycamore-Penasquitos 230 kV line, the 2nd Miguel-Bay Boulevard 230 kV line, the synchronous condensers at SONGS and San Luis Rey, the Southern Orange County Reliability Enforcement (SOCRE), the phase shifting transformers at Imperial Valley, and the Suncrest SVC (static VAR compensator) facility, and enhancements of existing remedial action schemes (RAS).

The interface of San Diego import transmission (SDIT) consists of SWPL, SRPL, the south of San Onofre (SONGS) transmission path, and the Otay Mesa-Tijuana 230 kV transmission tie with CENACE. The San Diego area relies on internal generation and import through SDIT to serve electricity customers. The area has a forecasted 1-in-10 peak sales load of 4,872 MW in 2030 after incorporating a load reduction of 112 MW of additional achievable energy efficiency (AAEE) and 0 MW of forecast behind-the-meter photovoltaic (BTM PV) generation production as the San Diego peak hour has shifted to HE19:00.

The area is forecast to have approximately 6,545 MW of grid-connected generation by the year 2030, including a total of 2,590 MW renewable generation and 429 MW energy storage resources. A total of 853 MW of conventional generation was recently constructed in the area to offset the local capacity deficiency resulting from the retirement of the San Onofre Generating Station and the Encina generating plants.

2.9.2 Area-Specific Assumptions and System Conditions

The steady state and transient stability assessments on the SDG&E main and sub-transmission systems were performed consistent with the general study assumptions and methodology described in section 2.3. The CAISO-secured participant portal provides the five base cases, stability model data and contingencies that were used in the assessments. In addition, specific assumptions on load of demand-side and resources of supply-side in the baseline and sensitivity scenarios are provided below and in Table 2.9-1.

Demand-Side Assumptions

The summer peak cases are based on the CEC mid 1-in-10 year load forecast with low AAEE. The table below provides the load forecast assumptions including load reduction impact of BTM PV and AAEE on demand side. The load forecast provided by CEC are net demand values including load reduction and system losses. The summer light load and spring off-peak cases assume approximately 18 percent and 65 percent of the net peak load, respectively.

Supply-Side Assumptions

The table below also provides a summary of the supply-side assumptions modeled in the SDG&E main and sub-transmission systems assessments including conventional and renewable generation, and along with energy storage. A detailed list of existing generation in the area is included in Appendix A.

Transmission Assumptions

Transmission modeling assumptions on existing and previously planned transmission projects are consistent with the general assumptions described in section 2.3. In addition, it is assumed that the series capacitors at Miguel and Suncrest 500 kV stations are bypassed in the summer peak baseline and sensitivity cases.

Table 2.9-1: SDG&E Load and Load Modifier Assumptions

Study Case	Scenario	Description	Gross Load (MW)	AAEE (MW)	BTM-PV (MW)		Net Load (MW)	Demand Response (MW)	
					Installed	Output		Total	D2
B1-2022-SP	Baseline	2022 summer peak load condition at Hour Ending 19:00 PST, 9/7	4587	37	1768	0	4587	40	38
B2-2025-SP	Baseline	2025 summer peak load condition at hour ending 19:00 PST, 9/3	4710	66	2104	0	4710	40	38
B3-2030-SP	Baseline	2030 summer peak load condition at Hour Ending 19:00 PST, 9/4	4872	112	2436	0	4872	40	38
B4-2022-OP	Baseline	2022 spring off-peak load condition at hour ending 20:00 PST, 4/27	2982	24	1768	0	2982	40	38
B5-2025-LL	Baseline	2022 spring off-peak/minimal load condition at hour ending 13:00 PST, 4/6	2531	12	2104	1683	848	40	38
S1-2025-SP-HLOAD	Sensitivity	2025 summer peak load condition with high CEC load forecast	4789	66	2104	0	4789	40	38
S2-2022-OP-HRPS	Sensitivity	2022 spring off-peak load condition with heavy renewable output	5001	24	2104	2020	2982	40	38
S3-2025-SP-HRPS	Sensitivity	2025 summer peak load condition with heavy renewable output	6284	37	1768	1697	4587	40	38

Table 2.9 2: SDG&E Generation Resources Assumptions

Study Case	Scenario	Description	Energy Storage (MW)		Solar (MW)		Wind (MW)		Thermal (MW)		Biomass (MW)	
			Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch	Installed	Dispatch
B1-2022-SP	Baseline	2022 summer peak load condition at Hour Ending 19:00 PST, 9/7	429	40	1587	0	709	234	3554	3550	9	9
B2-2025-SP		2025 summer peak load condition at hour ending 19:00 PST, 9/3	429	40	1589	0	778	257	3517	2696	9	9
B3-2030-SP		2030 summer peak load condition at Hour Ending 19:00 PST, 9/4	429	40	1812	0	778	257	3517	3506	9	9
B4-2022-OP		2022 spring off-peak load condition at hour ending 20:00 PST, 4/27	429	-389	1587	0	709	568	3554	0	9	9
B5-2025-LL		2022 spring off-peak/minimal load condition at hour ending 13:00 PST, 4/6	429	-389	1589	1510	778	234	3517	0	9	9
S1-2025-SP-HLOAD	Sensitivity	2025 summer peak load condition with high CEC load forecast	429	40	1589	0	709	234	3517	2760	9	9
S2-2022-OP-HRPS		2022 spring off-peak load condition with heavy renewable output	429	-389	1587	1523	778	397	3554	1976	9	9
S3-2025-SP-HRPS		2025 summer peak load condition with heavy renewable output	429	40	1587	1523	709	362	3554	1799	9	9

Assessment Summary

The CAISO conducted a detailed planning assessment based on the study methodology identified in section 2.3 to comply with the reliability standard requirements of section 2.2. Details of the planning assessment results are presented in Appendix B.

The steady state assessment of the baseline scenarios identified a number of thermal overload concerns under Category P1 to P7 contingencies in the SDG&E main and sub-transmission systems. The sensitivity scenarios assessment identified similar concerns compared to the baseline scenarios. The assessments confirmed that most of these concerns can be mitigated by previously approved projects and operational mitigations including operational procedures, congestion management, and remedial action schemes (RAS). The 30-minute short-term emergency ratings of transmission facilities along with demand response and energy storage resources in the area can be relied upon under contingency to allow time needed for operational actions to re-dispatch conventional generation and preferred resources, reduce CAISO import, adjust the phase shifting transformers at Imperial Valley substation, and bypass series capacitors. The stability analysis performed did not identify any transient issues requiring mitigation. A corrective mitigation requirement found to be needed is to implement a new RAS addressing the P6/P7 thermal overloads on the Friars-Doublet Tap 138 kV line. Please refer to Appendix B for details on these concerns and associated mitigations.

2.9.3 Request Window Project Submissions

The CAISO received a total of one valid project submittals through the 2020 request window submission for the SDG&E main and sub-transmission systems. Below is a description of each proposal followed by CAISO comments and findings.

Rearrange TL23013 and TL6959 Project

This project was proposed by SDG&E as a reliability transmission solution to swap Sycamore Canyon–Penasquitos 230 kV (TL23013) with Mira Sorrento-Penasquitos 69 kV (TL6959) so that TL23013 and Old Town-Pensaquitos 230 kV (TL23071) will not share the same structures. Currently, TL23071 and TL23013 share the same structure while TL6959 and Friars-Penasquitos 138 kV (TL13810) share another structure. The project will require upgrading 2 miles of 138 kV structures for 230 kV operation. The estimated cost of the project is $19 million, and the proposed in-service date is 2026. This project would mitigate the P7 overloads identified on the Friars-Doublet Tap 138 kV line.

The CAISO has proposed a new Remedial Action Scheme to trip generation in the Otay Mesa area and mitigate the P6 and P7 thermal overloads identified on the Friars-Doublet Tap 138 kV line with an estimated cost of $750k. Due to the shorter permitting and construction time and much lower cost of the RAS alternative, the CAISO has selected the RAS alternative instead of the rearrangement of TL23013 and TL6959.

2.9.4 Consideration of Preferred Resources and Energy Storage

As indicated earlier, projected amounts of up to 112 MW energy efficiency (AAEE) and 2,436 MW installed capacity of distributed BTM-PV self-generation were used in the study scenarios for the San Diego area. The BTM-PV self-generation reduces a total of 0 MW of the San Diego load on the San Diego area peak load hour at HE19:00. The load reductions due to the preferred resources has shifted the San Diego peak load hour from HE16:00 to HE19:00, which avoided, deferred, or mitigated various significant reliability concerns identified in current and previous transmission planning cycles, including but not limited to:

- Various thermal overload concerns in SWPL and SRPL for various contingencies
- Voltage instability in the San Diego and LA Basin for Category P6 contingencies
- The south of San Onofre Safety Net taking action for Category P6 contingency
- Bay Boulevard–Silvergate-Old Town 230 kV path overloads for Category P6/P7 contingencies
- Friars-Doublett 138 kV line for Category P6/P7 contingencies
- SCE's Ellis 220 kV south corridor for Category P6 contingencies
- Otay Mesa-Tijuana 230 kV tie line for Category P6 contingency
- Cross-tripping the 230 kV tie lines with CENACE for Category P6 contingencies

The operational and planned battery energy storage and demand response amounting to 389 MW and 40 MW, respectively, were used as potential mitigations in the base and sensitivity scenarios as needed. Utilization of the resources helps to reduce some of the thermal overloads identified in the area.

In this planning cycle, no need for additional preferred resource and battery energy storage systems were identified as a cost-effective mitigation to meet reliability needs in the San Diego area.

The CAISO re-evaluated the need for the following six previously approved sub-transmission projects and also evaluated if battery storage could mitigate the need:

1. TL6983 2nd Pomerado – Poway 69 kV Circuit
2. TL690E Stuart Tap - Las Pulgas 69kV Reconductor
3. TL600 Kearny – Clairemont Tap Reconductor and Loop into Mesa Heights
4. Loop Granite – Granite Tap, TL632A, into Granite and Cancel Los Coches – El Cajon Reconductor, TL631
5. TL605 Silvergate – Urban Reconductor
6. Open Sweetwater Tap (TL603) and Loop into Sweetwater

The CAISO did not identify a reliability or deliverability need for the TL6983 2nd Pomerado-Poway 69 kV circuit Project nor for the TL600 Kearny – Clairemont Tap Reconductor and Loop into Mesa heights Project. Therefore, these two projects will be canceled.

The CAISO did identify a reliability need for the other four projects. A 30 MW/180MWh of six-hour battery storage can mitigate the reliability need for the Loop Granite – Granite Tap, TL632A, into Granite. However, the storage project alternative requires an additional two hours of storage that would not count for system resource adequacy, and the additional cost of the two-hour storage would be similar or more than the cost of the transmission project. Therefore, the transmission project is still needed. The amount of battery storage needed to mitigate the reliability need for the other three projects was in excess of the amount of storage that can be reliably recharged by the local transmission system. Therefore, the following projects are still needed:

1. TL690E Stuart Tap - Las Pulgas 69kV Reconductor
2. Loop Granite – Granite Tap, TL632A, into Granite
3. TL605 Silvergate – Urban Reconductor
4. Open Sweetwater Tap (TL603) and Loop into Sweetwater

2.9.5 Recommendation

The assessments identified a number of thermal overload concerns under Categories P1 to P7 contingencies in the SDG&E main and sub-transmission systems. In response to the CAISO reliability assessment results and proposed alternative mitigations, a total of one valid project submissions was received through the 2020 request window. The CAISO evaluated the alternatives and found a reliability need for one of the projects. Below is a summary of the recommendations for San Diego area:

- The CAISO has identified a reliability need and proposed a new Remedial Action Scheme to trip generation and mitigate the P6 and P7 thermal overloads on the Friars-Doublet Tap 138 kV line.
- The CAISO did not identify a reliability or deliverability need for the TL6983 2nd Pomerado-Poway 69 kV circuit Project nor for the TL600 Kearny – Clairemont Tap Reconductor and Loop into Mesa heights Project. Therefore, these two projects are recommended to be canceled.

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Chapter 3

3 Policy-Driven Need Assessment

3.1 Background

The overarching public policy objective for the California CAISO's Policy-Driven Need Assessment is the state's mandate for meeting renewable energy and greenhouse gas (GHG) reduction targets. For the purposes of the transmission planning process, this high-level objective is comprised of two sub-objectives: first, to support Resource Adequacy (RA) deliverability status for the renewable generation and energy storage resources identified in the portfolio as requiring that status, and second, to support the economic delivery of renewable energy over the course of all hours of the year.

In accordance with the May 2010 memorandum of understanding between the CAISO and the California Public Utilities Commission (CPUC), and in coordination with the California Energy Commission (CEC), the CPUC develops the resource portfolios to be used by the CAISO in its annual transmission planning process. The CAISO utilizes the portfolios transmitted by the CPUC in performing reliability, policy and economic assessments in the transmission planning process, with a particular emphasis on identifying policy-driven transmission solutions pursuant to the CAISO tariff section 24.4.6.6.

The CPUC issued a decision[98] on February 8, 2018 which 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. Subsequently, the CPUC issued a decision[99] on March 26, 2020 that recommended the following scenarios be forwarded by Commission staff with detailed busbar mapping to the extent possible for study in the CAISO 2020-21 TPP:

(a) The 2017-2018 Preferred System Portfolio (PSP) adopted in Decision 19-04-040, with updates to the baseline and some generation locations as detailed in the current decision, as the reliability base case and the policy-driven base case.

(b) The 2019-2020 Reference System Portfolio (RSP) adopted in the decision, with the 46 million metric ton greenhouse gas target in 2030, as a policy-driven sensitivity.

(c) A portfolio based on the 30 million metric ton scenario, to test the impact of energy-only deliverability status for some generators on congestion and curtailment, as a second policy-driven sensitivity.

98 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K878/209878964.PDF

99 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF

The CPUC used the RESOLVE model for creating the portfolios studied as part of the 2020-2021 transmission planning process. The model assumed the renewable resources under development with CPUC-approved contracts to be part of the baseline assumptions while creating the portfolios.

3.2 Objectives of policy-driven assessment

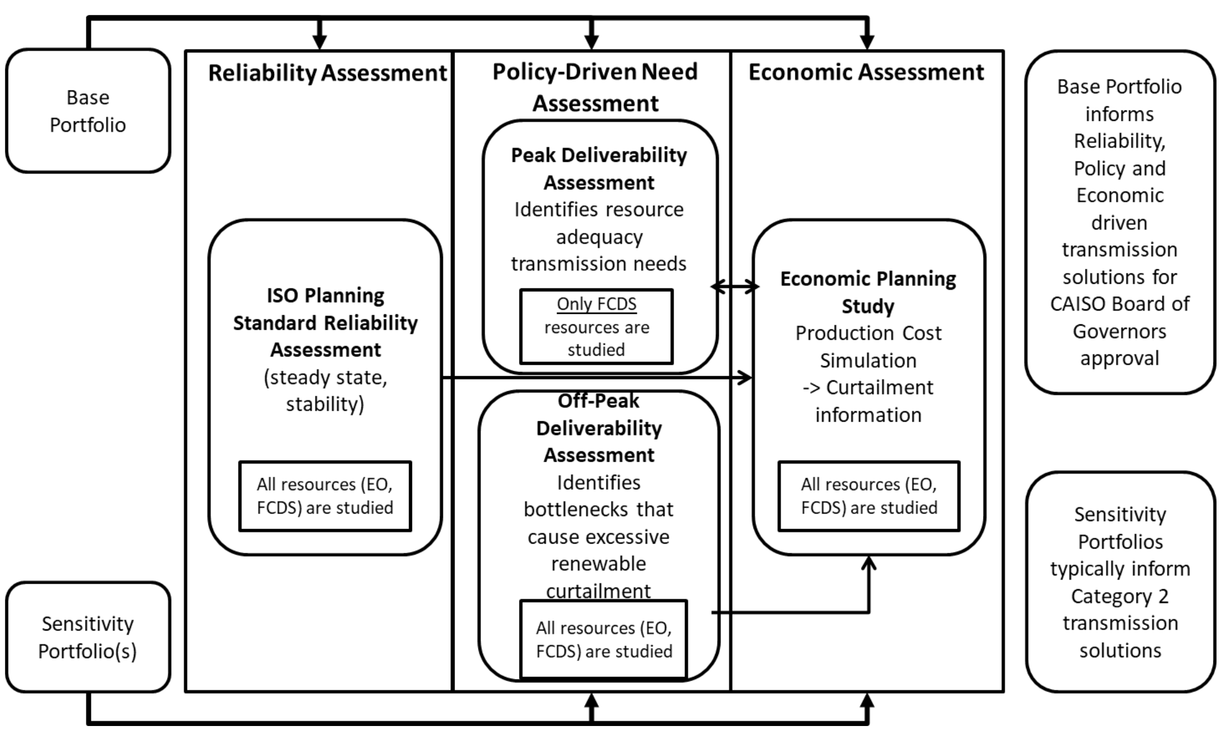
Key objectives of the policy-driven assessment are to:

- Assess the transmission impacts of portfolio resources using:
  - Reliability assessment
  - Peak and Off-peak deliverability assessment; and
  - Production cost simulation
- Identify transmission upgrades or other solutions needed to ensure reliability, deliverability or alleviate excessive curtailment; and
- Gain further insights to inform future portfolio development.

3.3 Study methodology and components

The policy-driven assessment is an iterative process comprised of three types of technical studies as illustrated in Figure 3.3-1. These studies are geared towards capturing the impact of renewable build out on transmission infrastructure, identifying any required upgrades and generating transmission input for use by the CPUC in the next cycle of portfolio development.

Figure 3.3-1: Policy assessment methodology and study components



Reliability assessment

The policy-driven reliability assessment is used to identify constraints that need to be modeled in production cost simulations in order to capture the impact of the constraints on renewable curtailment caused by transmission congestion. The reliability assessment component of the policy-driven assessment is covered by the year-10 reliability assessment presented in chapter 2 and the off-peak deliverability assessment that is performed in accordance with the new deliverability methodology and is presented in this section.

On-peak deliverability assessment

The on-peak deliverability test is designed for resource adequacy counting purposes to identify if there is sufficient transmission capability to transfer generation from a given sub-area to the aggregate of CAISO control area load when the generation is needed most. The CAISO performed the assessment following the on-peak Deliverability Assessment Methodology[100].

Off-peak deliverability assessment

The off-peak deliverability test was performed to identify potential transmission system limitations that may cause excessive renewable energy curtailment. The CAISO performed the assessment following the Off-Peak Deliverability Assessment Methodology[101].

Production cost model simulation (PCM) study

Production cost models for the base and sensitivity renewable portfolios were developed and simulated to identify renewable curtailment and transmission congestion in the CAISO Balancing Authority Area. The PCM for the base portfolio was used in policy assessment and economic assessment as well. The PCM with the sensitivity portfolios were used in policy assessment only. These PCM cases followed the same study assumptions for the CAISO controlled grid, which are consistent with the 2020-2021 TPP study plan. The details of the PCM modeling assumptions and approaches were set out in chapter 4.

3.4 Resource Portfolios

As set out in Section 3.1, a base portfolio and two sensitivity portfolios were transmitted to the CAISO for use in the 2020-2021 transmission planning process policy-driven assessment. The generation resources in the three portfolios mapped to the busbar level are posted to the California Energy Commission's web site at:

Base Portfolio -
https://caenergy.databasin.org/documents/documents/1995d63284044bf3b3debf0a0ce7b2a3/

Sensitivity 1 Portfolio (2019 RSP) –
https://caenergy.databasin.org/documents/documents/b90faf47be4045a398171a5cfac51b87/

Sensitivity 2 Portfolio (2019 RSP) –
https://caenergy.databasin.org/documents/documents/3124eabfe9b14c5083c99f7f080f7551/

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

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

The composition of each of the portfolios by resource type is provided in Table 3.4-1. The table includes resources selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO). The portfolios are comprised of solar, wind, and battery storage and where applicable geothermal and pumped hydro resources. While the base portfolio and Sensitivity 1 assume essentially all of the existing gas-fired generation is retained, Sensitivity 2 assumes 6,456 MW would be retired by 2030.

The base portfolio includes battery storage of up to 2,157 MW/5,504 MWh but the resource is not initially modeled in the policy-driven studies because bus bar mapping information was not provided. Instead the CPUC recommended the CAISO to apply the resource at locations where it can mitigate transmission issues identified.

These FCDS and EO resources are modeled in the reliability assessment, off-peak deliverability assessment and production simulation studies.

Table 3.4-1: Portfolio composition – FCDS+EO resources

	Base	**Sensitivity #1**	**Sensitivity #2**
Solar	6,763	11,017	18,741
Wind	992	3,443	8,279
Geothermal	1,256	-	851
P. Hydro	-	974	2,798
Battery	-	*8,873*	*12,657*
Gas ret.	-	-	*(6,456)*
Total	***9,011***	***24,307***	***36,870***

Table 3.4-2 below provides the composition of the portfolio resources selected with Full Capacity Deliverability Status (FCDS). Only resources with FCDS status are modeled in the peak deliverability assessment.

Table 3.4-2: Portfolio composition – FCDS resources

	Base	**Sensitivity #1**	**Sensitivity #2**
Solar	2,273	8,019	8,216
Wind	188	3,122	3,700
Geothermal	604	-	851
P. Hydro	-	974	2,798
Battery	-	8,873	12,657
Gas ret.	-	-	(6,456)
Total	**3,065**	**20,988**	**21,766**

A detailed breakdown of the generation resources in the three portfolios by zone and type is shown in Table 3.4-3 and Table 3.4-4 below. The former includes both FCDS and EO resources while the later includes only FCDS resources.

Table 3.4-3: Portfolio generation resources by zone and type – FCDS + EO[102]

	Base Portfolio (MW)					Sensitivity 1 (MW)					Sensitivity 2 (MW)				
Renewable Tx Zone	**Solar**	**Wind**	**GeoT**	**P. Hydro**	**Total**	**Solar**	**Wind**	**GeoT**	**P. Hydro**	**Total**	**Solar**	**Wind**	**GeoT**	**P. Hydro**	**Total**
Arizona (CAISO)	428				428	2,352				2,352	1,350				1,350
Carrizo		160			160		287			287	600	287			887
Central_Valley_North_Los_Banos		146			146		173			173		173			173
Greater_Imperial			1,256		1,256	548				548	356		716		1,072
GreaterImpOutsideTxZones									974	974				1,216	1,216
Humboldt							34			34		34			34
Inyokern_North_Kramer	554				554	97				97	97				97
Kern_Greater_Carrizo						242	60			302	3,001	60			3,061
Mountain_Pass_El_Dorado						248				248	248				248
North_Victor						300				300	300				300
Northern_California_Ex							866			866		866			866
Riverside_Palm_Springs	1,622	42			1,664									1,582	1,582
SCADSNV						330				330	4,303				4,303
Solano		644			644		542			542		542	135		677
Southern_Nevada (CAISO)	3,006				3,006	862				862	1,727	442			2,169
Tehachapi	1,153				1,153	4,202	275			4,477	4,801	275			5,076
Westlands						1,836				1,836	1,958				1,958
Baja_California							600			600		600			600
New_Mexico							606			606		1,500			1,500
NW_Ext_Tx												1,500			1,500
SW_Ext_Tx												500			500
Wyoming												1,500			1,500
Total	**6,763**	**992**	**1,256**	**0**	**9,011**	**11,017**	**3,443**	**0**	**974**	**15,434**	**18,741**	**8,279**	**851**	**2,798**	**30,669**

102 The table does not include battery storage resources in the portfolios

Table 3.4-4: Portfolio generation resources by zone and type – FCDS only[103]

	Base Portfolio (MW)					Sensitivity 1 (MW)					Sensitivity 2 (MW)				
Renewable Tx Zone	**Solar**	**Wind**	**GeoT**	**P. Hydro**	**Total**	**Solar**	**Wind**	**GeoT**	**P. Hydro**	**Total**	**Solar**	**Wind**	**GeoT**	**P. Hydro**	**Total**
Arizona (CAISO)						1,196				1,196					
Carrizo						287				287		187			187
Central_Valley_North_Los_Banos		146			146		173			173		173			173
Greater_Imperial			604		604								716		716
GreaterImpOutsideTxZones									974	974				1,216	1,216
Humboldt															
Inyokern_North_Kramer	554				554	97				97	97				97
Kern_Greater_Carrizo						97	60			157	121	60			181
Mountain_Pass_El_Dorado											248				248
North_Victor						300				300	300				300
Northern_California_Ex							866			866		866			866
Riverside_Palm_Springs	192	42			234									1,582	1,582
SCADSNV											2,333				2,333
Solano							542			542		464	135		599
Southern_Nevada (CAISO)	802				802	862				862	257	442			699
Tehachapi	725				725	3,402	275			3,677	3,402	275			3,677
Westlands						1,778				1,778	1,458				1,458
Baja_California							600			600		203			203
New_Mexico							606			606					
NW_Ext_Tx												530			530
SW_Ext_Tx												500			500
Wyoming															
Total	**2,273**	**188**	**604**		**3,065**	**8,019**	**3,122**		**974**	**12,115**	**8,216**	**3,700**	**851**	**2,798**	**15,565**

3.4.1 Mapping of portfolio resources to transmission substations

The portfolios that RESOLVE generates are at the renewable transmission zone level as shown in the previous section in the case of renewable resources and location non-specific in the case of battery storage. As a result, the portfolios have to be mapped to the busbar level for use in the CAISO transmission planning process. The resource-to-busbar mapping process is described in the CPUC Staff Report: Modeling Assumptions for the 2020-2021 transmission planning process. Release 1 of the report[104] covers the Base Portfolio while Release 2[105] covers the sensitivity portfolios. The reports outline the methodology and results of the busbar mapping

[103] The table does not include battery storage resources in the portfolios

[104] ftp://ftp.cpuc.ca.gov/energy/modeling/Modeling_Assumptions_2020_2021_TPP-Report-Release1.pdf

[105] ftp://ftp.cpuc.ca.gov/energy/modeling/Modeling_Assumptions_2020_2021_TPP-Report-Release2.pdf

process performed by the CPUC and California Energy Commission (CEC) in collaboration with the CAISO. The busbar mapping results for non-battery resources in each of the portfolios is available on the CEC website[106]. Portfolio non-battery resources were modeled in the CAISO studies in accordance with the results of the mapping process. The busbar mapping of battery storage resources involved additional steps the CAISO followed per CPUC instructions as discussed in the next section.

The objective of mapping resources to specific substations is not to endorse any particular resource project, but rather to enable assessment of the impact of the specified amount of generic generation modeled in the general area. In other words, transmission constraints to be mitigated within the transmission planning process for an assumed portfolio resource build-out within a renewable zone should be independent of which competitively procured resource projects are built within that zone.

3.4.2 Mapping of portfolio energy storage to transmission substations

For the Base Portfolio, the CPUC did not map the generic battery storage (up to 2,157 MW/5,504 MWh) to any specific locations, but instead allowed the CAISO the flexibility to apply the storage where it provides value that can be clearly identified through the transmission planning process. Accordingly, the base portfolio energy storage resources were not modeled in the initial power flow and production simulation models.

For the sensitivity cases, the CPUC mapped the 12,657 MW of generic battery storage (the higher of the amounts in the sensitivity cases; i.e. the amount in Sensitivity 2) to busbars and provided the instructions below for the CAISO to follow in order to obtain the final busbar mapping for Sensitivity 1 and Sensitivity 2.

For the Sensitivity 1 portfolio, the CPUC staff recommended the CAISO incorporate battery storage resources in the following order to meet the total 8,873 MW in the portfolio.

1. Include all base portfolio storage utilized by the CAISO to mitigate reliability needs
2. Include all "High Confidence" battery storage
3. Include "Moderate Confidence" and "LCR Area solutions"

For the Sensitivity 2 portfolio, the CPUC's recommendations for the resource retirement modeling and storage mapping are as follows:

1. Rank all existing generation units by age in the categories of combined cycle (CCGT), combustion turbine (Peaker), and reciprocating engine. Combined heat and power units are excluded from this list since RESOLVE assumes they remain online through 2030.
2. Model offline the oldest units up to but not exceeding the amounts in each category

[106] https://caenergy.databasin.org/documents/documents/1995d63284044bf3b3debf0a0ce7b2a3/ (Base Portfolio mapping)
https://caenergy.databasin.org/documents/documents/b90faf47be4045a398171a5cfac51b87/ (Sensitivity 1)
https://caenergy.databasin.org/documents/documents/3124eabfe9b14c5083c99f7f080f7551/ (Sensitivity 2)

3. If known local area requirements are not met then add battery storage to meet the local area requirement up to known battery storage charging limits[107].
4. If known local area requirements are still not met then local gas generation will be restored in reverse order in steps 1 and 2.
5. If specific local units are turned back on in step 4 then an equal amount of additional system generation capacity will be modeled off-line following steps 1 and 2.

Following the above storage mapping guidelines, Table 3.4-5 lists the final energy storage amount in each category in the CAISO sensitivity 1 and sensitivity 2 cases along with the initial CPUC mapping.

Table 3.4-5: Energy storage mapping results

Category	CPUC Mapping (MW)	CAISO Sensitivity 1 (MW)	CAISO Sensitivity 2 (MW)
High Confidence (MMA)	1,215	1,215	1,215
High Confidence (non-MMA)	1,977	1,977	1,977
Moderate Confidence	4,564	2,739	2,756
LCR Area Solutions	4,902	2,942	6,516
Total	**12,658**	**8,873**	**12,464**

Figure 3.4-1 and Figure 3.4-2 compare the energy storage in the CPUC mapping, the CAISO sensitivity 1 and sensitivity 2 cases by renewable transmission zones and by LCR areas.

[107] Based on the 2025 Local Capacity Technical Report, May 2020

Figure 3.4-1: Energy storage in each renewable transmission zone

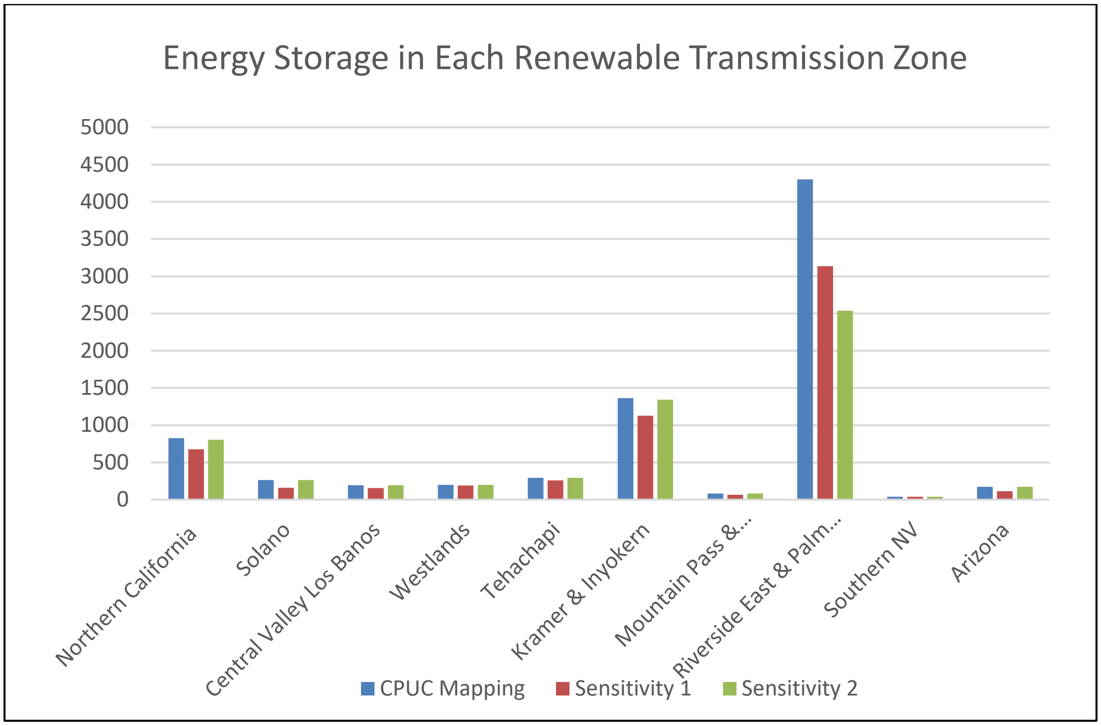
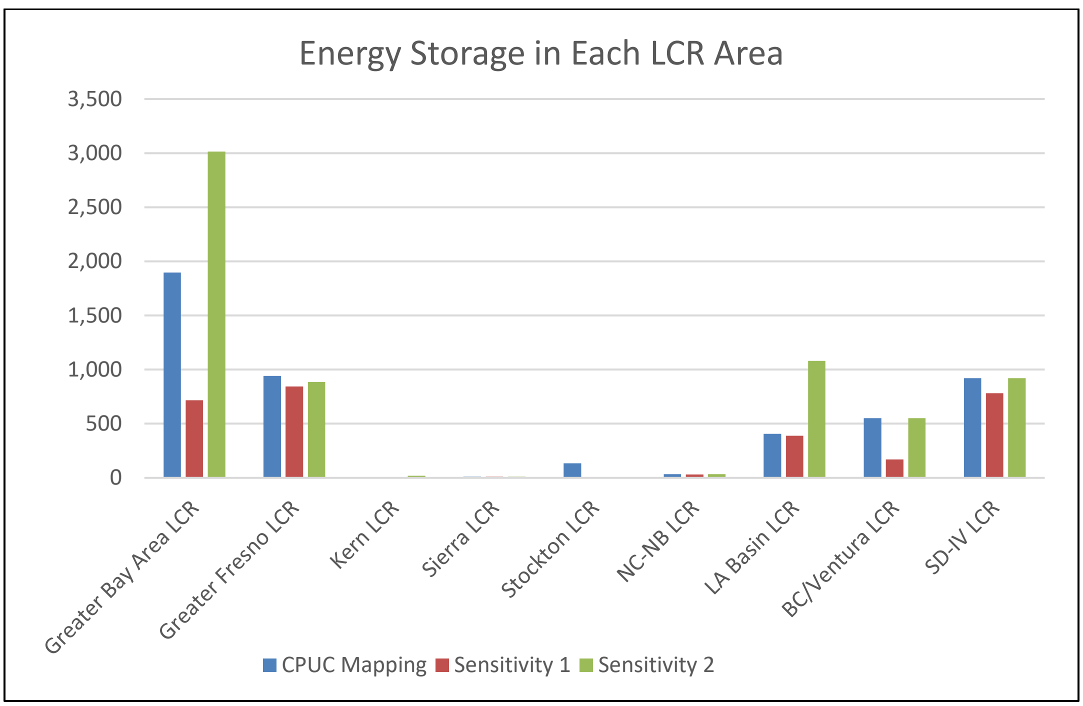


Figure 3.4-2: Energy storage in each LCR area



3.4.3 Transmission capability estimates and utilization by portfolios

One of the key inputs to the co-optimization performed by the RESOLVE model used by the CPUC in portfolio development is a set of transmission capability estimates provided by the CAISO for renewable zones in which candidate resources are selected. The estimated available transmission capability to support future renewable generation is monitored annually through the CAISO transmission planning process. It is important to note that the transmission capability estimates are only one of the several deciding factors utilized for resources selection in the RESOLVE model. The transmission capability estimates apply to the total amount of resources including battery storage in each transmission zone.

The CAISO published a white paper[108] to describe the key sources of information and the methodology used for estimating transmission capability for the specific purpose of providing input into portfolio development as part of the CPUC's IRP process.

Table 3.4-6 and Table 3.4-7 show the utilization of FCDS and EODS transmission capability estimates by the three portfolios, respectively. The portfolio resource amounts in each zone include both non-battery and battery storage resources but exclude resources outside the renewable transmission zones for which transmission capability estimates are not provided. The total available transmission capability values shown are net of any resources that have become operational or have been contracted and thus were added as baseline resources in RESOLVE since the estimates were developed. Values shaded in yellow identify zones where the transmission capability estimates are exceeded. Estimated EODS capability numbers are inclusive of the FCDS estimates. Since Sensitivity-2 Portfolio was developed by relaxing the EODS limits, utilization of EODS capability for the portfolio is assessed using the relaxed EO capability in Table 3.4-7.

[108] https://www.caiso.com/Documents/WhitePaper-TransmissionCapabilityEstimates-InputtoCPUCIntegratedResourcePlanPortfolioDevelopment.pdf

Table 3.4-6: Utilization of FCDS transmission capability estimates[109]

Transmission zones and sub-zones	Estimated Existing System FCDS Capability Adjusted for New Baseline Resources (MW)	FCDS Resources in Portfolios (MW)		
		Base	Sensitivity-1	Sensitivity-2
Northern CA	**1,821**	**-**	**2,240**	**3,064**
- Round mountain	500	-	-	530
- Humboldt	-	-	-	-
- Sacramento River	1,901	-	866	866
- Solano	520	-	700	862
Southern PG&E	**394**	**146**	**2,742**	**2,388**
- Westlands	1,100	-	1,968	1,655
- Kern and Greater Carrizo	624	-	157	181
- Carrizo	400	-	287	187
- Central Valley North & Los Banos	670	146	330	365
Tehachapi	**4,155**	**725**	**3,934**	**3,972**
Greater Kramer (North of Lugo)	**500**	**554**	**1,524**	**1,738**
- North of Victor	300	-	1,326	1,537
- Inyokern and North of Kramer	-	554	959	1,109
- Pisgah	400	-	100	104
Southern CA Desert and Southern	**2,273**	**1,640**	**6,618**	**9,111**
- Eldorado/Mtn Pass (230 kV)	250	102	120	164
- Southern NV (GLW-VEA)	624	700	740	739
- Greater Imperial	1,095	604	600	919
- Riverside East & Palm Springs	2,404	234	5,050	4,791
Total	**9,143**	**3,065**	**17,058**	**20,273**

109 Resource amounts shown do not include pumped hydro resources, battery storage resources and gas-fired generation retirements in the portfolios that are outside the renewable transmission zones.

Table 3.4-7: Utilization of EODS transmission capability estimates[110]

Transmission zones and sub-zones	Estimated Existing System EODS Capability Adjusted for New Baseline Resources (MW)		FCDS + EODS Resources in Portfolios (MW)		
	Original	Relaxed EO capability	Base	Sensitivity -1	Sensitivity -2
Northern CA	**3,721**	**3,721**	**643**	**2,274**	**4,146**
- Round mountain	2,100	2,100	-	-	1,500
- Humboldt	100	100	-	34	34
- Sacramento River	4,501	4,501	-	866	866
- Solano	1,220	1,220	643	700	940
Southern PG&E	**TBD**	**4,474**	**306**	**2,945**	**6,468**
- Westlands	TBD	3,200	-	2,026	2,155
- Kern and Greater Carrizo	TBD	3,804	-	302	3,061
- Carrizo	400	1,100	160	287	887
- Central Valley North & Los	TBD	670	146	330	365
Tehachapi	**4,955**	**5,955**	**1,153**	**4,734**	**5,371**
Greater Kramer (North of Lugo)	**500**	**500**	**554**	**1,524**	**1,738**
- North of Victor	300	300	-	1,326	1,537
- Inyokern and North of Kramer	-	-	554	959	1,109
- Pisgah	400	400	-	100	104
Southern CA Desert and	**8,873**	**12,533**	**6,354**	**8,900**	**17,654**
- Eldorado/Mtn Pass (230 kV)	2,400	4,040	425	203	164
- Southern NV (GLW-VEA)	624	2,094	700	740	2,500
- Greater Imperial	2,995	2,995	1,256	1,148	1,672
- Riverside East & Palm Springs	4,954	5,504	2,092	6,206	7,641
Total	**18,443**	**27,183**	**9,010**	**20,377**	**35,377**

For the Base Portfolio, the total amount of portfolio FCDS resources (excluding resources outside the renewable transmission zones), which amounts to 3,065 MW, is much below the total maximum FCDS capability of 9,143 MW. The estimated FCDS capability is fully utilized or exceeded by FCDS renewable and battery storage resources only in the Greater Kramer zone

110 Resource amounts shown do not include pumped hydro resources, battery storage resources and gas-fired generation retirements in the portfolios that are outside the renewable transmission zones.

and Southern Nevada (GLW-VEA) sub-zone while considerable surplus FCDS capability remains elsewhere. Similarly, the total amount of portfolio resources (FCDS and EODS), which amounts to 9,010 MW, is much less than the total maximum EODS capability of 18,443 MW. The estimated EODS capability is fully utilized or exceeded only in Greater Kramer zone and Southern Nevada (GLW-VEA) sub-zone while considerable surplus EODS capability remains elsewhere.

In Sensitivity 1, the total amount of portfolio FCDS resources in the renewable transmission zones, which amounts to 17,058 MW, exceeds the total maximum FCDS capability of 9,143 MW. The portfolio includes more FCDS resources than the respective FCDS capability estimate in all zones, with the exception of Tehachapi, and six of the fifteen sub-zones. Similarly, the 20,377 MW of total resources in the portfolio exceeds the total maximum EODS capability of 18,443 MW. The estimated EODS capability is exceeded in several zones and subzones.

In Sensitivity 2, the total amount of portfolio FCDS resources in renewable zones, which amounts to 20,273 MW, exceeds the total maximum FCDS capability of 9,143 MW. The portfolio includes more FCDS resources than the respective FCDS capability estimate in all zones, except Tehachapi, and seven of the fifteen sub-zones. Similarly, the 35,377 MW of total portfolio resources in the portfolio exceeds the total maximum relaxed EODS capability of 27,183 MW. The portfolio includes more resources than the respective relaxed EODS capability estimate in all zones, except Tehachapi, and several sub-zones.

It is to be noted that the transmission capability estimates shown above were developed based on the CAISO's previous deliverability methodology and as a result may underestimate available transmission capability for FCDS resources under the revisions to the methodology implemented in 2020. The CAISO intends to update the transmission capability estimates based on the recently revised on-peak and off-peak deliverability methodologies in Q1 of 2021.

3.5 On-Peak Deliverability assessment

The key objectives of the on-peak deliverability assessment of renewable portfolios are to:

- Test deliverability of portfolio resource amounts identified as FCDS in accordance with the deliverability methodology as used in Generation Interconnection and Deliverability Allocation Procedures (GIDAP)
- Identify upgrades needed to ensure deliverability of resource amounts identified as FCDS in the commission-developed renewable portfolios
- Gain insights about FCDS transmission capability estimates and corresponding upgrade information to feed it back into the IRP

3.5.1 On-peak deliverability assessment methodology

The CAISO performed the assessment following the on-peak Deliverability Assessment Methodology[111]. The main steps are described below.

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

Screening for Potential Deliverability Problems Using DC Power Flow Tool

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

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

  or

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

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

Verifying and Refining the Analysis Using AC Power Flow Tool

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

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

3.5.2 On-peak deliverability assessment assumptions and base case

The CAISO performed the on-peak deliverability assessment under two study scenarios – Highest System Need (HSN) and Secondary System Need (SSN). For each scenario, the CAISO developed a master base case for each portfolio for the on-peak deliverability assessment that modeled all the generating resources in the respective portfolio. Key assumptions of the deliverability assessment are described below.

Transmission

The CAISO modeled the same transmission system as in the 2030 peak load base case used in the transmission planning process reliability assessment.

Load modeling

The CAISO modeled a coincident 1-in-5 year heat wave for the CAISO balancing authority area load in the HSN base case. Non-pump load was the 1-in-5 peak load level. Pump load was dispatched within expected range for summer peak load hours. The load in the SSN base case was adjusted from HSN to represent the net customer load in the forecasted peak consumption hour.

Generation capacity (Pmax) in the base case

Pmax in the deliverability assessment represents the study amount of the generator. The CAISO used the most recent summer peak NQC as Pmax for existing non-intermittent generating units. For new energy storage resources, Pmax was the assumed 4-hour discharging capacity. The CAISO assessed both wind and solar generations for maximum output levels specified in the on-peak deliverability assessment methodology. The study amount for wind and solar generation in the HSN scenario and the SSN scenario are shown in Table 3.5-1

Table 3.5-1: Study amount of wind and solar generation in the deliverability assessment

Area	HSN		SSN	
	Solar	Wind	Solar	Wind
SDG&E	3.00%	33.70%	40.20%	11.20%
SCE	10.60%	55.70%	42.70%	20.80%
PG&E	10.00%	66.50%	55.60%	16.30%

Import Levels

The CAISO modeled imports at the maximum summer peak simultaneous historical level (2021 Maximum RA Import Capability) by branch group in the HSN base case. The historically unused existing transmission contracts (ETC) crossing control area boundaries were modeled as zero MW injections at the tie point, but available to be turned on at remaining contract amounts.

The CAISO modeled the highest total net imports during the SSN hours from the 2021 MIC data in the SSN base case. The portfolio generation in the IID area exceeded the 702 MW of expanded MIC from IID, so the portfolio generation in IID was modeled in the base case and included in this TPP Policy deliverability assessment.

3.5.3 On-Peak deliverability assessment results

All three portfolios were studied as part of the 2020-2021 transmission planning process policy-driven deliverability assessment. Renewable generation designated as FCDS in each portfolio was modeled with the maximum dispatch levels as shown in Table 3.5-1. EODS generation was not dispatched in this assessment. Mitigation options considered to address on-peak deliverability constraints include Remedial Action Schemes (RAS), reduction of energy storage behind the constraints and transmission upgrades.

3.5.4 SCE and DCRT area on-peak deliverability results

All renewable zones in Southern California and zones outside of California that are likely to impact the deliverability assessment in the SCE and DCRT study area are shown in Table 3.5-2.

Table 3.5-2: Renewable zones impacting deliverability out of the SCE and DCRT study area

Transmission Zone	Full Capacity Only (MW)		
	Base	SENS-01	SENS-02
Inyokern_North_Kramer	554 solar	1,224 (97 solar, 1,127 BESS)	1,438 (97 solar, 1,341 BESS)
Mountain_Pass_El_Dorado	-	66 BESS	329 (248 solar, 81 BESS)
North_Victor	-	300 solar	300 solar
Riverside_Palm_Springs	234 (192 solar, 42 wind)	3,137 BESS	2,538 BESS
SCADSNV	-	-	2,333 solar
SCADSNV-Riverside_Palm_Springs	-	-	1,582 P.Hydro
Southern_Nevada (CAISO)	802 solar	902 (862 solar, 40 BESS)	739 (257 solar, 442 wind, 40 BESS)
Tehachapi	725 solar	3,934 (3,402 solar, 275 wind, 257 BESS)	3,972 (3,402 solar, 275 wind, 295 BESS)
Arizona	-	1,313 (1,196 solar, 117 BESS)	171 BESS

South of Kramer – Kramer to Victor constraint

The deliverability of renewable and energy storage resources North of Kramer is limited by thermal overloading of the 115kV and 230kV lines between Kramer and Victor under normal condition as shown in Table 3.5-3. This constraint was identified for both the sensitivity portfolios in the SSN scenario. As shown in Table 3.5-4, approximately 480 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades. Looping the existing Kramer – Victor 115kV into Roadway substation could increase the deliverability to 620 MW. To make all FC resource in the sensitivity portfolios deliverable, Kramer – Victor 230kV No. 1 and No. 2 need to be re-conductored to higher ratings. Reducing the amount of battery storage that is mapped behind the constraint in the respective portfolio by the amount shown in the table will also mitigate the constraint.

Table 3.5-3: Deliverability assessment results – South of Kramer – Kramer to Victor constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Roadway – Victor 115kV	Base Case	HSN	<100%	<100%	<100%
		SSN	<100%	103.06%	120.83%
Kramer – Victor 230kV No. 1 & 2	Base Case	HSN	<100%	<100%	<100%
		SSN	<100%	101.82%	114.93%

Table 3.5-4: South of Kramer – Kramer to Victor constraint deliverability constraint summary

Affected renewable transmission zones	Inyokern_North_Kramer		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	100	97	97
Energy storage portfolio MW behind the constraint	0	917.6	1104.5
Mitigation	Not needed	Reconductor Kramer – Victor 230kV lines (~$100M) and loop Kramer – Victor 115kV line into Roadway (~$8M) or reduce battery storage by 438 MW (Sens-1) or 625 MW(Sens-2)	
Deliverable MW w/o mitigation	480 MW w/o mitigation 620 MW with Kramer – Victor 115kV loop-in upgrade		

South of Kramer – Victor to Lugo constraint

The deliverability of renewable and energy storage resources North of Kramer is limited by thermal overloading of Victor – Lugo 230kV lines under normal condition as shown in Table 3.5-5. This constraint was identified for both the sensitivity portfolios in the SSN scenario. As shown in Table 3.5-6, approximately 1,100 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades. To make all FC resource in the sensitivity portfolios deliverable, Kramer – Victor 230kV lines No.1, 2, 3 and 4 need to be re-conductored to higher ratings. Reducing the amount of battery storage that is mapped behind the constraint in the respective portfolio by the amount shown in the table will also mitigate the constraint.

Table 3.5-5: Deliverability assessment results – South of Kramer – Victor to Lugo constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Victor – Lugo 230kV No. 1, 2, 3 & 4	Base case	HSN	<100%	<100%	<100%
		SSN	<100%	103.79%	113.88%

Table 3.5-6: South of Kramer – Victor to Lugo constraint deliverability constraint summary

Affected renewable transmission zones	Inyokern_North_Kramer		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	363	397	397
Energy storage portfolio MW behind the constraint	0	1025.9	1237
Mitigation	Not needed	Reconductor Victor – Lugo 230kV lines (~$250M); or reduce battery storage by 438 MW (Sens-1) or 625 MW(Sens-2)	
Deliverable MW w/o mitigation	1100 MW		

Lugo transformer bank constraint

The deliverability of renewable and energy storage resources in Inyokern North Kramer area is limited by thermal overloading of Lugo 500/230kV transformer banks under normal condition as shown in Table 3.5-7. This constraint was identified for sensitivity-2 portfolio in the SSN scenario. As shown in Table 3.5-8, approximately 1,200 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades. To make all FC resource in the sensitivity portfolios deliverable, a third Lugo 500/230kV transformer bank is needed. Reducing the amount of battery storage that is mapped behind the constraint in Sensitivity-2 portfolio by the amount shown in the table will also mitigate the constraint.

Table 3.5-7: Deliverability assessment results – Lugo transformer bank constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Lugo 500/230kV No. 1 & 2	Base case	HSN	<100%	<100%	<100%
		SSN	<100%	<100%	103.81%

Table 3.5-8: Lugo transformer bank constraint deliverability constraint summary

Affected renewable transmission zones	Inyokern_North_Kramer		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	554	397	397
Energy storage portfolio MW behind the constraint	0	1126	1340.8
Mitigation	Not needed		Lugo 500/230kV No. 3 (~$150M); or reduce battery storage by 625 MW
Deliverable MW w/o mitigation	1200 MW		

Colorado River transformer bank constraint

The deliverability of renewable and energy storage resources interconnecting to the Colorado River 230kV is limited by thermal overloading of Colorado River 500/230kV transformer banks under normal condition as shown in Table 3.5-9. This constraint was identified for Sensitivity-1 portfolio in the SSN scenario. As shown in Table 3.5-10, approximately 1,631 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades. To make all FC resource in the sensitivity portfolios deliverable, a third Colorado River 500/230kV transformer bank is needed. Reducing the amount of battery storage that is mapped behind the constraint in the portfolio by the amount shown in the table will also mitigate the constraint.

Table 3.5-9: Deliverability assessment results – Colorado River transformer bank constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Colorado River 500/230kV No. 1 & 2	Base case	HSN	<100%	100.79%	<100%
		SSN	<100%	122.83%	<100%

Table 3.5-10: Colorado River transformer bank constraint deliverability constraint summary

Affected renewable transmission zones	Riverside_Palm_Springs		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	65	0	0
Energy storage portfolio MW behind the constraint	0	2091	1322
Mitigation	Not needed	Colorado River 500/230kV No. 3 (~$150M); or reduce battery storage by 507 MW	Not needed
Deliverable MW w/o mitigation	1631 MW		

3.5.5 VEA and GLW area on-peak deliverability results

All renewable zones in Southern California and zones outside of California that are likely to impact the deliverability assessment in the VEA and GLW study area are shown in Table 3.5-11:

Table 3.5-11: Renewable zones impacting deliverability out of VEA/GLW study area

TX Zone / Location	Full Capacity Only (MW)		
	Base	SENS-01	SENS-02
Southern_Nevada (CAISO)	700	740 (700 Solar, 40 BESS)	740 (258 Solar, 442 Wind, 40 BESS)

There were no on-peak deliverability constraints identified in VEA and GLW study area in the Base, Sensitivity 1 and Sensitivity 2 portfolios.

3.5.6 SDG&E area deliverability results

All the renewable zones in Southern California and zones outside of California that are likely to impact the deliverability assessment in the SDG&E study area are shown in Table 3.5-12.

Table 3.5-12: Renewable zones impacting deliverability out of SDG&E study area

TX Zone / Location	Full Capacity Only (MW)		
	Base	SENS-01	SENS-02
Greater Imperial (geothermal)	604	-	716
Arizona (solar)	-	1,196	-
Arizona (BESS)	-	111	171
Baja California (wind)	-	600	203
San Diego Sycamore (pumped hydro)	-	487	608
San Diego Imperial Valley LCR Area (BESS)	-	783	920

Avocado 69 kV constraint

The deliverability of energy storage resources in the Avocado 69 kV area is limited by thermal overloading of 69kV lines in the area as shown in Table 3.5-13. This constraint was identified for both of the sensitivity portfolios in the HSN and SSN scenarios. As shown in Table 3.5-14, approximately 20 MW of energy storage generation would be expected to be deliverable without any transmission upgrades. The constraint can be mitigated by installing a RAS to trip generation.

Table 3.5-13: Deliverability assessment results – Avocado 69 kV constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Avocado-Monserate Tap 69 kV	TL691 Avocado-Monserate-Pendleton 69 kV	HSN	<100%	147%	151%
		SSN	<100%	155%	159%
Avocado-Avocado Tap 69 kV		HSN	<100%	100%	<100%
		SSN	<100%	115%	<100%
Monserate-Monserate Tap 69 kV		HSN	<100%	<100%	<100%
		SSN	<100%	102%	<100%
Avocado-Avocado Tap 69 kV	TL698 Avocado-Monserate-Pala 69 kV	HSN	133%	214%	198%
		SSN	148%	231%	208%
Avocado-Avocado Tap 69 kV	TL6932 Lilac-Pala 69 kV	HSN	<100%	<100%	<100%
		SSN	<100%	100%	<100%

Table 3.5-14: Avocado 69 kV deliverability constraint summary

Affected renewable transmission zones	None		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	56	59
Mitigation	None needed	RAS to trip generation	
Deliverable MW w/o mitigation		20 MW	

Doublet Tap-Friars 138 kV constraint

The deliverability of energy storage resources in the Doublet Tap-Friars 138 kV area is limited by thermal overloading of the 138kV line in the area as shown in Table 3.5-15. This constraint was identified for both of the sensitivity portfolios in the HSN and SSN scenarios. As shown in Table 3.5-16, approximately 400 MW of energy storage generation would be expected to be deliverable without any transmission upgrades. The constraint can be mitigated by installing a RAS to trip generation.

Table 3.5-15: Deliverability assessment results – Doublet Tap-Friars 138 kV constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Doublet Tap-Friars 138 kV	Old Town-Penasquitos and Sycamore Penasquitos 230 kV	HSN	<100%	121%	116%
		SSN	<100%	117%	113%

Table 3.5-16: Doublet Tap-Friars 138 kV deliverability constraint summary

Affected renewable transmission zones	None		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	1095	1209
Mitigation	None needed	RAS to trip generation	
Deliverable MW w/o mitigation		400 MW	

Encina-San Luis Rey constraint

The deliverability of renewable and energy storage resources in the Encina 230 kV area is limited by thermal overloading of 230kV lines in the area as shown in Table 3.5-17. This constraint was identified for both of the sensitivity portfolios in the HSN and SSN scenarios. As shown in Table 3.5-18, approximately 750 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades. The constraint can be mitigated by installing a RAS to trip generation.

Table 3.5-17: Deliverability assessment results – Encina-San Luis Rey constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Encina Tap-San Luis Rey 230 kV	Encina-San Luis Rey 230 kV	HSN	<100%	115%	115%
		SSN	<100%	133%	133%
Encina-Encina Tap 230 kV		HSN	<100%	<100%	<100%
		SSN	<100%	<100%	103%
Encina-San Luis Rey 230 kV	San Luis Rey-Encina-Palomar 230 kV	HSN	<100%	<100%	102%
		SSN	<100%	116%	118%
	San Luis Rey-Encina-Palomar 230 kV and - Palomar-Batiquitos 138 kV or - Encina-Palomar 138 kV or - Batiquitos-Shadowridge 138 kV	HSN	<100%	<100%	102%
		SSN	<100%	116%	118%
	San Luis Rey-Encina-Palomar and Palomar-Sycamore 203 kV	HSN	<100%	101%	105%
		SSN	<100%	117%	120%

Table 3.5-18: Encina-San Luis Rey deliverability constraint summary

Affected renewable transmission zones	Imperial, Baja, Arizona		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	1222	203
Energy storage portfolio MW behind the constraint	0	1265	1580
Mitigation	None needed	RAS to trip existing and new generation	
Deliverable MW w/o mitigation		750 MW	

San Marcos-Melrose Tap constraint

The deliverability of energy storage resources in the San Marcos-Melrose Tap 69 kV area is limited by thermal overloading of the San Marcos-Melrose Tap 69 kV line as shown in Table 3.5-19. This constraint was identified for both of the sensitivity portfolios in the HSN and SSN scenarios. As shown in Table 3.5-20, approximately 260 MW of energy storage generation would be expected to be deliverable without any transmission upgrades. The constraint can be mitigated by installing a RAS to trip generation.

Table 3.5-19: Deliverability assessment results – San Marcos-Melrose Tap constraint

Overloaded Facility	**Contingency**		**Flow**		
			BASE	**SENS-01**	**SENS-02**
San Marcos-Melrose Tap 69 kV	Encina-San Luis Rey 230 kV and Encina-San Luis Rey-Palomar 230 kV	HSN	<100%	116%	108%
		SSN	<100%	141%	132%

Table 3.5-20: San Marcos-Melrose Tap deliverability constraint summary

Affected renewable transmission zones	None		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	947	868
Mitigation	None needed	RAS to trip existing and new generation	
Deliverable MW w/o mitigation		260 MW	

National City constraint

The deliverability of energy storage resources in the National City 69 kV area is limited by thermal overloading of the 69 kV lines in the area as shown in Table 3.5-21. This constraint was identified for both of the sensitivity portfolios in the HSN and SSN scenarios. As shown in Table 3.5-22, approximately 100 MW of energy storage generation would be expected to be deliverable without any transmission upgrades. The constraint can be mitigated by installing a RAS to trip generation.

Table 3.5-21: Deliverability assessment results – National City constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
National City-Silvergate 69 kV	Sweetwater-Naval Station Metering 69 kV	HSN	<100%	106%	106%
		SSN	<100%	103%	103%
Sweetwater-National City 69 kV		HSN	<100%	105%	104%
		SSN	<100%	101%	102%

Table 3.5-22: National City deliverability constraint summary

Affected renewable transmission zones	None		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	148	280
Mitigation	None needed	RAS to trip generation	
Deliverable MW w/o mitigation		100 MW	

Montgomery constraint

The deliverability of energy storage resources in the Montgomery 69 kV area is limited by thermal overloading of the Bay Boulevard-Montgomery 69 kV line in the area as shown in Table 3.5-23. This constraint was identified for both of the sensitivity portfolios in the HSN and SSN scenarios. As shown in Table 3.5-24, approximately 90 MW of energy storage generation would be expected to be deliverable without any transmission upgrades. The constraint can be mitigated by installing a RAS to trip generation.

Table 3.5-23: Deliverability assessment results – Montgomery constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Bay Boulevard-Montgomery 69 kV	Bay Boulevard-Montgomery Tap 69 kV	HSN	<100%	110%	116%
		SSN	<100%	<100%	104%

Table 3.5-24: Montgomery deliverability constraint summary

Affected renewable transmission zones	None		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	148	280
Mitigation	None needed	RAS to trip generation	
Deliverable MW w/o mitigation		90 MW	

Otay constraint

The deliverability of energy storage resources in the Otay 69 kV area is limited by thermal overloading of the 69 kV lines in the area as shown in Table 3.5-25. This constraint was identified for both of the sensitivity portfolios in the HSN and SSN scenarios. As shown in Table 3.5-26, approximately 100 MW of energy storage generation would be expected to be deliverable without any transmission upgrades. For the sensitivity 1 portfolio, the constraints can be mitigated by installing a RAS to trip generation. For the sensitivity 2 portfolio, to make all FC resources deliverable, reconductoring of the Otay-Otay Lakes Tap 69 kV line is needed in addition to installing a RAS to trip generation. Reducing the amount of battery storage that is mapped behind the constraint in the portfolio by the amount shown in the table will also mitigate the constraint.

Table 3.5-25: Deliverability assessment results – Otay constraint

Overloaded Facility	Contingency		Flow		
			BASE	**SENS-01**	**SENS-02**
Otay-Otay Lakes Tap 69 kV	Base Case	HSN	<100%	<100%	101%
		SSN	<100%	<100%	<100%
Otay-Bay Boulevard 69 kV #2	TL623 Otay-Imperial Beach-San Ysidro 69 kV	HSN	<100%	<100%	109%
		SSN	<100%	<100%	116%
Otay-Otay Lakes Tap 69 kV		HSN	<100%	<100%	128%
		SSN	<100%	<100%	111%
Otay-Bay Boulevard 69 kV #2	TL649 Otay-Otay Lakes-San Ysidro-Border 69 kV	HSN	<100%	<100%	<100%
		SSN	<100%	<100%	113%
Otay-Bay Boulevard 69 kV #2	TL645 Otay-Bay Boulevard 69 kV #1	HSN	<100%	116%	143%
		SSN	<100%	133%	158%
Otay-Bay Boulevard 69 kV #1	TL646 Otay-Bay Boulevard 69 kV #2	HSN	<100%	109%	133%
		SSN	<100%	126%	150%

Table 3.5-26: Otay deliverability constraint summary

Affected renewable transmission zones	None		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	148	280
Mitigation	None needed	RAS to trip generation	RAS to trip generation; Reconductor Otay-Otay Lakes Tap 69 kV (~$2.3M) or reduce battery storage by 10 MW (Sens-2)
Deliverable MW w/o mitigation		100 MW	

San Luis Rey-San Onofre constraint

The deliverability of renewable and energy storage resources in the San Luis Rey-San Onofre 230 kV area is limited by thermal overloading of the 230 kV line in the area as shown in Table 3.5-27. This constraint was identified for both of the sensitivity portfolios in the HSN and SSN scenarios. As shown in Table 3.5-28, approximately 900 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades. The constraint can be mitigated by installing a RAS to trip generation.

Table 3.5-27: Deliverability assessment results – San Luis Rey-San Onofre constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
San Luis Rey-San Onofre 230 kV #1	San Luis Rey-San Onofre 230 kV #2 and #3	HSN	<100%	101%	<100%
		SSN	<100%	126%	123%

Table 3.5-28: San Luis Rey-San Onofre deliverability constraint summary

Affected renewable transmission zones	Imperial, Baja, Arizona		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	1222	203
Energy storage portfolio MW behind the constraint	0	1321	1639
Mitigation	None needed	RAS to trip generation	
Deliverable MW w/o mitigation		900 MW	

Miramar constraint

The deliverability of energy storage resources in the Miramar 69 kV area is limited by thermal overloading of the 69 kV lines in the area as shown in Table 3.5-29. This constraint was identified for both of the sensitivity portfolios in the HSN and SSN scenarios. As shown in Table 3.5-30, no energy storage generation would be expected to be deliverable without any transmission upgrades. The constraint can be mitigated by installing a RAS to trip generation.

Table 3.5-29: Deliverability assessment results – Miramar constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Miramar-Miramar GT 69 kV	TL664 Miramar GT-Rose Canyon-Penasquitos 69 kV	HSN	<100%	108%	<100%
		SSN	<100%	108%	<100%
Miramar GT-Miramar Tap 69 kV	TL668 Mirmar-Miramar GT 69 kV	HSN	<100%	103%	<100%
		SSN	<100%	103%	<100%

Table 3.5-30: Miramar deliverability constraint summary

Affected renewable transmission zones	None		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	24	25
Mitigation	None needed	RAS to trip generation	
Deliverable MW w/o mitigation		0 MW	

Border constraint

The deliverability of energy storage resources in the Border 69 kV area is limited by thermal overloading of the 69 kV lines in the area as shown in Table 3.5-31. This constraint was identified for the base portfolio and both of the sensitivity portfolios in the HSN and SSN scenarios. As shown in Table 3.5-32, no energy storage generation would be expected to be deliverable without any transmission upgrades. The constraint can be mitigated by adding the new energy storage generation to an existing RAS to trip generation.

Table 3.5-31: Deliverability assessment results – Border constraint

Overloaded Facility	**Contingency**		**Flow**		
			BASE	**SENS-01**	**SENS-02**
Otay-Bay Boulevard 69 kV #2	Border-Salt Creek 69 kV	HSN	<100%	101%	<100%
		SSN	<100%	114%	<100%
Otay-Otay Lake Tap 69 kV		HSN	<100%	<100%	<100%
		SSN	<100%	109%	<100%
Otay Lake Tap-San Ysidro 69 kV		HSN	100%	<100%	<100%
		SSN	<100%	101%	<100%
Otay Lake Tap-Otay 69 kV		HSN	<100%	<100%	<100%
		SSN	112%	<100%	<100%
Otay-Bay Boulevard 69 kV #2	Miguel-Salt Creek 69 kV	HSN	<100%	<100%	<100%
		SSN	<100%	101%	<100%

Table 3.5-32: Border deliverability constraint summary

Affected renewable transmission zones	None		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	148	280
Mitigation	Add storage to existing generation tripping RAS		
Deliverable MW w/o mitigation	0 MW		

3.5.7 PG&E area deliverability results

Table 3.5-33 shows all the renewable zones in northern California and zones outside of California that are likely to impact the deliverability assessment in the PG&E study areas.

Table 3.5-33: Renewable zones impacting deliverability out of PG&E study areas

	Deliverability study capacity (MW)		
Renewable zone	**BASE**	**SENS 1**	**SENS 2**
Central Valley_North_los_Banos	Wind 146	330 Wind 173, BESS 157	365 Wind 173,BESS 192
Kern_Greater_Carizzo	0	157 Solar 97, Wind 60	181 Solar 121, Wind 60,
Humbodlt	0	0	0
Northern_California_Ex	0	2311 Wind 866, BESS 1445	4480 Wind 866, BESS 3614
Solano	0	700 Wind 542, BESS 158	862 Wind 464, GeoT 135, BESS 263
Westlands	0	2816 Solar 1778, BESS 1038	2560 Solar 1458, BESS 1102

With the resource mix specified in Table 3.5-33 modeled in the base cases, the On-Peak deliverability assessment identified the following constraints in PG&E study areas:

Round Mountain 500/230 kV Bank #1 constraint

The deliverability of renewable and energy storage resources in the Round Mountain region is limited by thermal overloading of the Round Mountain 500/230 kV Bank #1 as shown in Table 3.5-34. This constraint was identified in 2 portfolio in the HSN scenario. The proposed mitigation is to open Round Mountain 500/230 kV Bank #1 and drop Colusa generation. Table 3.5-35 provides a deliverability summary of the Round Mountain 500/2300 kV Bank #1 constraint.

Table 3.5-34: Deliverability assessment results – Round Mountain 500/2300 kV Bank #1 constraint

Overloaded Facility	Contingency	Scenario	Flow		
			BASE	SENS 01	SENS 02
Round Mountain 500/230 kV Bank #1	Malin - Round Mountain Line # 1 and # 2 500 kV DLO	HSN	<100%	<100%	112%
		SSN	<100%	<100%	100%

Table 3.5-35: Round Mountain 500/2300 kV Bank #1 constraint deliverability summary

Affected renewable transmission zones	Northern California		
Portfolio	**BASE**	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0		1024
Energy storage portfolio MW behind the constraint	0		0
Mitigation	N/A		Open Round Mountain 500/230 kV Bank #1 and drop Colusa gen
Deliverable MW w/o mitigation	N/A		506

Round Mountain – Cottonwood E. 230 kV constraint

The deliverability of renewable and energy storage resources in the Northern California zone is limited by the thermal overloading of the Round Mountain to Cottonwood E. 230 kV line as shown in Table 3.5-36. This constraint was identified in sensitivity 2 portfolio in the HSN scenario. Table 3.5-37 provides a deliverability summary of the Round Mountain – Cottonwood E. 230 kV constraint. The mitigation is RAS to trip the renewable generation.

Table 3.5-36: Deliverability assessment results – Round Mountain – Cottonwood E. 230 kV constraint

Overloaded Facility	Contingency	Scenario	Flow		
			BASE	SENS 01	SENS 02
Round Mountain–Cottonwood 230 kV lines	Table Mountain-Tesla and Table Mountain-Vaca Dixon 500 kV DLO	HSN	<100%	<100%	103%
		SSN	<100%	<100%	100%

Table 3.5-37: Round Mountain – Cottonwood E. 230 kV constraint deliverability summary

Affected renewable transmission zones	Northern California		
Portfolio	**BASE**	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0		731
Energy storage portfolio MW behind the constraint	0		23
Mitigation	N/A		RAS to trip renewable gen
Deliverable MW w/o mitigation	N/A		619

Cayetano-North Dublin 230 kV constraint

The deliverability of renewable and energy storage resources in the Solano and Northern California zone is limited by the thermal overloading of Cayetano-North Dublin 230 kV line as shown in Table 3.5-38. This constraint was identified in both sensitivity 1 and 2 portfolios in the HSN scenario. As shown in Table 3.5-39, approximately 379 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades.

The same constraint has been previously identified in GIDAP and re-conductoring of Cayetano - North Dublin 230 kV line has been identified as a mitigation. To make all FC resource in the sensitivity portfolios deliverable, Cayetano - North Dublin 230 kV needs to be re-conductored to higher ratings. Reducing the amount of battery storage that is mapped behind the constraint in the respective portfolio by the amount shown in the table will also mitigate the constraint.

Table 3.5-38: Deliverability assessment results - Cayetano - North Dublin 230 kV Line constraint

Overloaded Facility	Contingency	Scenario	Flow		
			BASE	SENS 01	SENS 02
Cayetano-North Dublin 230 kV line	Contra Costa-Moraga Nos. 1 & 2 - 230 kV lines	HSN	<100%	116%	120%
		SSN	<100%	<100%	<100%

Table 3.5-39: Cayetano-North Dublin 230 kV line deliverability constraint summary

Affected renewable transmission zones	Solano and Northern California		
Portfolio	**BASE**	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	121	104
Energy storage portfolio MW behind the constraint	0	316	810
Mitigation	N/A	Reconductor North Dublin-Cayetano 230 kV Line (2.63 miles OH Line & 2.82 UG cable with new UG cable 797 MVA/2000 A ~ $42.4 M) or reduce battery storage by 316 MW in Sens-01 and 535 MW in Sens-02	
Deliverable MW w/o mitigation	N/A	47	379

Las Positas-Newark 230 kV constraint

The deliverability of renewable and energy storage resources in the Solano and Northern California zone is limited by thermal overloading of Las Positas- Newark 230 kV line as shown in Table 3.5-40. This constraint was identified both in sensitivity 1 and 2 portfolios in the HSN scenario. As shown in Table 3.5-41, approximately 482 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades.

The same constraint has been previously identified in GIDAP and re-conductoring of Las Positas-Newark 230 kV line has been identified as a mitigation. To make all FC resource in the sensitivity portfolios deliverable, Las Positas- Newark 230 kV line needs to be re-conductored to higher ratings. Reducing the amount of battery storage that is mapped behind the constraint in the respective portfolio by the amount shown in the table will also mitigate the constraint.

Table 3.5-40: Deliverability assessment results – Las Positas- Newark 230 kV constraint

Overloaded Facility	Contingency	Scenario	Flow		
			BASE	SENS 01	SENS 02
Las Positas-Newark 230 kV line	Contra Costa - Moraga Nos. 1 & 2 - 230 kV lines	HSN	<100%	110%	116%
		SSN	<100%	<100%	<100%

Table 3.5-41: Las Positas - Newark 230 kV deliverability constraint summary

Affected renewable transmission zones	Solano and Northern California		
Portfolio	**BASE**	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	121	104
Energy storage portfolio MW behind the constraint	0	316	810
Mitigation	N/A	Reconductor Las Positas-Newark 230 kV line (~ $12.5 M) or reduce battery storage by 316 MW in Sens-01 and 432 in Sens-02	
Deliverable MW w/o mitigation	N/A	55	482

<u>Contra Costa Bus E-F 230 kV constraint</u>

The deliverability of renewable and energy storage resources in the Solano and Northern California zone is limited by thermal overloading of Contra Costa Bus E to Bus F- 230 kV line, as shown in Table 3.5-42. This constraint was identified in both sensitivity 1 and 2 portfolios in the HSN scenario. As shown in Table 3.5-43, approximately 1269 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades. The constraint can be mitigated by installing a RAS to trip generation.

Table 3.5-42: Deliverability assessment results – Contra Costa Bus E-F - 230 kV constraint

Overloaded Facility	Contingency	Scenario	Flow		
			BASE	SENS 01	SENS 02
Contra Costa Bus E-F 230 kV	Contra Costa - Las Positas and North Dublin -Vineyard 230 kV lines	HSN	<100%	101%	102%
		SSN	<100%	<100%	<100%

Table 3.5-43: Contra Costa Bus E-F 230 kV constraint deliverability summary

Affected renewable transmission zones	Solano and Northern California		
Portfolio	**BASE**	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	542	270
Energy storage portfolio MW behind the constraint	0	506	1073
Mitigation	N/A	RAS to trip generation	
Deliverable MW w/o mitigation	N/A	481	1269

<u>Delevan – Cortina 230 kV constraint</u>

The deliverability of renewable and energy resources in the Northern California zone is limited by thermal overloading of the Delevan to Cortina 230 kV line as shown in Table 3.5-44. This constraint was identified in both sensitivity 1 and 2 portfolios in the HSN scenario. Table 3.5-45 provides a deliverability summary of the Delevan – Cortina 230 kV constraint. The mitigation is RAS to trip the generation.

Table 3.5-44: Deliverability assessment results – Delevan – Cortina 230 kV constraint

Overloaded Facility	Contingency	Scenario	Flow		
			BASE	**SENS 01**	**SENS 02**
Delevan–Cortina 230 kV line	Table Mountain-Tesla and Table Mountain-Vaca Dixon 500 kV DLO	HSN	<100%	110%	112%
		SSN	<100%	<100%	101%

Table 3.5-45: Delevan – Cortina 230 kV deliverability constraint summary

Affected renewable transmission zones	Northern California		
Portfolio	**BASE**	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	494	494
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation	N/A	RAS to trip generation	
Deliverable MW w/o mitigation	N/A	208	165

Fulton 60 kV lines constraint

The deliverability of renewable and energy storage resources in the Northern California and North coast zone is limited by thermal overloading of Fulton area 60 kV lines, as shown in Table 3.5-46. A category P7 contingency of the Geysers #9-Lakeville and Eagle Rock-Fulton-Silverado 115kV lines results in overloading the Hopland-Cloverdale 60kV Line in the baseline scenario. Also, the constraint was identified in all the three portfolios in the HSN scenario and in sensitivity portfolios in the SSN scenario. As shown in Table 3.5-475, 0 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades. A new RAS is recommended with a thermal relay to monitor the overloading of northern part of the Fulton-Hopland 60kV Line and status of Geysers #9-Lakeville and Eagle Rock-Fulton-Silverado 115kV lines being open. At the onset of both contingency and the line overloading, generations, including, GEYSR5-6, GEYSER78 and GEYSER11 in the Geyser area will be tripped until the overload is mitigated.

Table 3.5-46: Deliverability assessment results – Fulton area 60 kV lines constraint

Overloaded Facility	Contingency	Scenario	Flow		
			BASE	SENS 01	SENS 02
Fulton area 60 kV lines	Geysers #9-Lakeville 230 kV & Eagle Rock-Fulton Silverado 115kV Lines	HSN	104%	109%	109%
		SSN	<100%	104%	112%

Table 3.5-47: – Fulton area 60 kV lines deliverability constraint summary

Affected renewable transmission zones	Northern California and North coast		
Portfolio	**BASE**	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	11	11
Mitigation	RAS to trip generation		
Deliverable MW w/o mitigation	0	0	

Caribou #2 60 kV line constraint

The deliverability of renewable and energy storage resources in the Northern California zone is limited by thermal overloading of Caribou #2 60 kV line, as shown in Table 3.5-48. This constraint was identified in sensitivity 1 in SSN scenario and in sensitivity 2 in HSN scenario. The case diverges in sensitivity 2 SSN scenario. As shown in Table 3.5-49, 0 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades.

Under the existing Plumas Sierra Separation Scheme, mitigation, at the onset of the contingency of Caribou 230/115/60 kV TB 11, the Plumas Sierra area will be islanded with all the load and generation tripped. Consequently, it will address the overload of Caribou #2 60 kV line

Table 3.5-48: Deliverability assessment results – Caribou #2 60 kV line constraint

Overloaded Facility	Contingency	Scenario	Flow		
			BASE	SENS 01	SENS 02
Caribou #2 60 kV line	Caribou 230/115/60 kV TB 11	HSN	<100%	<100%	112%
		SSN	<100%	106%	Diverge

Table 3.5-49: Caribou #2 60 kV line constraint deliverability summary

Affected renewable transmission zones	Northern California		
Portfolio	**BASE**	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	14	23
Mitigation	None needed	Existing RAS will mitigate constraint	
Deliverable MW w/o mitigation	0	0	

Humboldt Bay 60 kV line constraint

The deliverability of existing generation in this area is limited by thermal overloading of the Humboldt Bay 60 kV line as shown in Table 3.5-50. This overloading was caused by the Humboldt Bay generators and occurs only in all of the scenarios as it's an existing issue. As shown in Table 3.5-51, 0 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades. Since the overloads were identified in the base portfolio, CAISO recommends to add the below monitored elements to the Humboldt- Trinity RAS to trip Humboldt Bay generation when the monitored elements are over their emergency line ratings.

Table 3.5-50: Deliverability assessment results – Humboldt Bay 60 kV line constraint

Overloaded Facility	Contingency	Scenario	Flow		
			BASE	**SENS-01**	**SENS-02**
Humboldt Junction – Humboldt 60 kV	Humboldt Bay & Humboldt Bay lines	HSN	109%	109%	109%
		SSN	114%	114%	114%
Humboldt-Bridgeville 115kV Line	Humboldt-Humboldt Bay #2 60kV line	HSN	101%	101%	101%
		SSN	101%	101%	101%

Table 3.5-51: Humboldt Bay 60 kV line constraint deliverability constraint summary

Affected renewable transmission zones	Humboldt		
Portfolio	**BASE**	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation	Add the monitoring elements to the Humboldt Trinity RAS(Cost ~16$M-23$M with 5-7 year estimated duration)		
Deliverable MW w/o mitigation	0		

Gates 500/230 kV TB #11 constraint

The deliverability of renewable and energy storage resources in this area is limited by thermal overloading of the Gates 500/230 kV TB #11 in the area as shown in Table 3.5-52. This constraint was identified for the sensitivity 1 portfolio in the SSN scenario. As shown in Table 3.5-53, approximately 1853 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades for the Sensitivity 1 case. The constraint can be mitigated by adding a RAS to trip generation.

Table 3.5-52: Deliverability assessment results – Gates 500/230 kV TB #11 constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Gates 500/230 kV TB #11	Gates 500/230 kV TB #12	HSN	<100%	<100%	<100%
		SSN	<100%	100.4%	<100%

Table 3.5-53: Gates-Midway 500kV line deliverability constraint summary

Affected renewable transmission zones	Westlands and Greater Carrizo		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	836	632
Energy storage portfolio MW behind the constraint	0	1032	1083
Mitigation	None needed	RAS to trip generation	
Deliverable MW w/o mitigation	None needed	1853 MW	Fully deliverable

If the majority of generation in this zone develops on the 230 kV system then a deliverability upgrade such as a new Gates 500/230 kV bank as identified in GIDAP studies will be required to ensure FCDS for the portfolio resources.

Gates-Midway 500kV line constraint

The deliverability of renewable and energy storage resources in the Gates-Midway 500 kV area is limited by thermal overloading of the 500 kV line in the area as shown in Table 3.5-54. This constraint was identified for both of the sensitivity portfolios in the HSN and SSN scenarios. As shown in Table 3.5-55, approximately 7524 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades for the Sensitivity 2 case and 6155 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades for the Sensitivity 1 case. The constraint can be mitigated by adding a new Gates-Midway 500kV line. Reducing the amount of battery storage that is mapped behind the constraint in the respective portfolio by the amount shown in the table will also mitigate the constraint.

Table 3.5-54: Deliverability assessment results – Gates-Midway 500kV line constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Gates-Midway 500kV line	Base case	HSN	<100%	<100%	124%
		SSN	<100%	102%	124%

Table 3.5-55: Gates-Midway 500kV line deliverability constraint summary

Affected renewable transmission zones	Westlands, Central Valley, Los Banos, Northern California and Solano		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	3726	4043
Energy storage portfolio MW behind the constraint	0	2793	5592
Mitigation	None needed	New Gates-Midway 500 kV line or reduce battery storage by 203 MW in Sens-01 and 2,117 MW in Sens-02	
Deliverable MW w/o mitigation	N/A	6155 MW	7524 MW

Panoche-Gates #1 and #2 230 kV constraint

The deliverability of renewable and energy storage resources in this area is limited by thermal overloading of the Panoche-Gates #1 and #2 230 kV lines in the area as shown in Table 3.5-56. This constraint was identified for the sensitivity 1 and 2 portfolio in the SSN scenarios. As shown in Table 3.5-57, approximately 1046 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades for the Sensitivity 1 case. The constraint can be mitigated by adding a RAS to trip generation.

Table 3.5-56: Deliverability assessment results – Panoche-Gates #1 and #2 230 kV lines

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Panoche-Gates #1 and #2 230 kV lines	Gates-Mustang #1 and #2 230 kV lines	HSN	<100%	<100%	<100%
		SSN	<100%	110%	115%

Table 3.5-57: Panoche-Gates #1 and #2 230 kV lines deliverability constraint summary

Affected renewable transmission zones	Westlands, Central Valley, Los Banos and Northern CA		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	573	626
Energy storage portfolio MW behind the constraint	0	834	878
Mitigation	None needed	RAS to trip generation	
Deliverable MW w/o mitigation	N/A	1045 MW	

Melones-Cottle 230kV line constraint

The deliverability of renewable and energy storage resources in this area is limited by thermal overloading of the Melones-Cottle 230kV line in the area as shown in Table 3.5-58. This constraint was identified for the sensitivity 1 and 2 portfolio in the SSN scenarios. As shown in Table 3.5-59, approximately 318 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades for the Sensitivity 1 case. The constraint can be mitigated by adding a RAS to trip generation.

Table 3.5-58: Deliverability assessment results – Melones-Cottle 230kV line

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Melones-Cottle 230 kV line	Base Case	HSN	<100%	<100%	<100%
		SSN	<100%	101%	<100%
	Gates-Mustang #1 and #2 230 kV lines	HSN	<100%	<100%	<100%
		SSN	<100%	111%	111%

Table 3.5-59: Melones-Cottle 230kV line deliverability constraint summary

Affected renewable transmission zones	Westlands		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	573	626
Energy storage portfolio MW behind the constraint	0	834	878
Mitigation	None needed	Operational solution	RAS to trip generation
Deliverable MW w/o mitigation	N/A	0 MW	318 MW

Borden-Wilson 230 kV constraint

The deliverability of renewable and energy storage resources in this area is limited by thermal overloading of the Borden-Wilson 230 kV in the area as shown in Table 3.5-60. This constraint was identified for the sensitivity 1 and 2 portfolio in the SSN scenarios. As shown in Table 3.5-61, approximately 318 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades for the Sensitivity 1 case. The constraint can be mitigated by adding a RAS to trip generation.

Table 3.5-60: Deliverability assessment results – Borden-Wilson 230 kV line

Overloaded Facility	**Contingency**		**Flow**		
			BASE	**SENS-01**	**SENS-02**
Borden-Storey #1 and Wilson-Storey 230 kV lines	Gates-Mustang #1 and # 2 230 kV	HSN	<100%	<100%	<100%
		SSN	<100%	113%	<100%
Borden-Storey #2 230 kV line	Borden-Storey #1 230 kV	HSN	<100%	<100%	<100%
		SSN	<100%	103%	<100%

Table 3.5-61: Borden-Wilson 230 kV line deliverability constraint summary

Affected renewable transmission zones	Westlands		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	328	252
Energy storage portfolio MW behind the constraint	0	747	786
Mitigation	None needed	RAS to trip generation	
Deliverable MW w/o mitigation	N/A	809 MW	

Gates-Mustang #1 and # 2 230 kV lines

The deliverability of renewable and energy storage resources in this area is limited by thermal overloading of the Gates-Mustang #1 and # 2 230 kV lines in the area as shown in Table 3.5-62. This constraint was identified for the sensitivity 1 and 2 portfolio in the SSN scenarios. As shown in Table 3.5-63, approximately 723 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades. The constraint can be mitigated by adding a RAS to trip generation.

Table 3.5-62: Deliverability assessment results – Gates-Mustang #1 and # 2 230 kV lines

Overloaded Facility	**Contingency**		**Flow**		
			BASE	**SENS-01**	**SENS-02**
Gates-Mustang #1 and # 2 230 kV	Gates-Mustang #1 or # 2 230 kV	HSN	<100%	<100%	<100%
		SSN	<100%	131%	<126%

Table 3.5-63: Gates-Mustang #1 and # 2 230 kV line deliverability constraint summary

Affected renewable transmission zones	Westlands		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	328	252
Energy storage portfolio MW behind the constraint	0	748	776
Mitigation	None needed	RAS to trip generation	
Deliverable MW w/o mitigation	N/A	723 MW	

GWF-Contandina-Jacksson 115 kV line constraint

The deliverability of renewable and energy storage resources in this area is limited by thermal overloading of the GWF-Contandina-Jacksson 115 kV line in the area as shown in Table 3.5-66. This constraint was identified for the sensitivity 1 and 2 portfolio in the SSN scenarios. As shown in Table 3.5-67, approximately 370 MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades. The constraint can be mitigated by adding a RAS to trip generation.

Table 3.5-64: Deliverability assessment results – GWF-Contandina-Jacksson 115 kV line

Overloaded Facility	Contingency		Flow		
			BASE	**SENS-01**	**SENS-02**
GWF-Contandina-Jacksson 115 kV line	Gates-Mustang #1 and # 2 230 kV	HSN	<100%	<100%	<100%
		SSN	<100%	105%	103%

Table 3.5-65: GWF-Contandina-Jacksson 115 kV line deliverability constraint summary

Affected renewable transmission zones	Westlands		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	72	55
Energy storage portfolio MW behind the constraint	0	404	425
Mitigation	None needed	RAS to trip generation	
Deliverable MW w/o mitigation	N/A	370 MW	

Arco-Cholame (Chlomale-cholame Jct) 70 kV line constraint

The deliverability of renewable and energy storage resources in this area is limited by thermal overloading of the Arco-Cholame (Chlomale-cholame Jct) 70 kV line in the area as shown in Table 3.5-68. This constraint was identified for the sensitivity 1 and 2 portfolio in the SSN scenarios. As shown in Table 3.5-69, approximately 51MW of renewable and energy storage generation would be expected to be deliverable without any transmission upgrades. The constraint can be mitigated by reconductoring Arco-Cholame 70 kV line.

Table 3.5-66: Deliverability assessment results – Arco-Cholame (Chlomale-cholame Jct) 70 kV line

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Arco-Cholame (Chlomale-cholame Jct) 70 kV line	Base Case	HSN	<100%	119%	119%
		SSN	<100%	<100%	<100%

Table 3.5-67: Arco-Cholame (Chlomale-cholame Jct) 70 kV line deliverability constraint summary

Affected renewable transmission zones	Westlands		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	60	60
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation	None needed	Reconductor Arco-Cholame 70 kV line	
Deliverable MW w/o mitigation	N/A	51 MW	

3.6 Off-Peak Deliverability assessment

The key objectives of the off-peak deliverability assessment of renewable portfolios are:

- Identify transmission constraints that might result in excessive renewable curtailment in accordance with the deliverability methodology as used in Generation Interconnection and Deliverability Allocation Procedures (GIDAP)
- Identify potential upgrades and other solutions needed to relieve excessive renewable curtailment
- Provide inputs to Production Cost Model for a more thorough evaluation of renewable curtailment

3.6.1 Off-peak deliverability assessment methodology

The CAISO performed the assessment following the on-peak Deliverability Assessment Methodology[112]. The main steps are described below.

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

- Create a CAISO master base case with the load is between 55% and 60% of the summer peak load and the total import is about 6000 MW. The generators are dispatched as shown in Table 3.6-1.

Table 3.6-1: CAISO System-Wide Generator Dispatch Assumptions

	Dispatch Level
wind	44%
solar	68%
battery storage	0
hydro	30%
thermal	15%

Create study area base case from the master base case by increasing renewable dispatch inside the study area. If the renewables inside the study area are predominantly wind resources (more than 70% of total study area capacity), increase wind resource dispatch as shown in Table 3.6-2. All the solar resources in the wind pocket are dispatched at the system-wide level of 68%. If the renewables inside the study area are not predominantly wind resources, then the dispatch assumptions in Table 3.6-3 are used.

Table 3.6-2: Local Area Solar and Wind Dispatch Assumptions in Wind Area

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

Table 3.6-3: Local Area Solar and Wind Dispatch Assumptions in Solar Area

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

- Perform contingency analysis.

  Overloads identified are first mitigated by re-dispatch.

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

The remaining overloads after the re-dispatch may be mitigated by transmission upgrades.

3.6.2 Off-Peak deliverability assessment results

All three portfolios were studied as part of the 2020-2021 transmission planning process policy-driven off-peak deliverability assessment. All renewable generation in each portfolio was dispatched as shown in Section 3.6.1. Energy storage resources are off-line initially.

The potential solutions considered to address off-peak deliverability constraints include Remedial Action Schemes (RAS), dispatching available battery storage behind the constraints, adding energy storage behind the constraints (subject to on-peak deliverability) and transmission upgrades.

3.6.3 SCE and DCRT area off-peak deliverability results

All renewable zones in Southern California and zones outside of California that are likely to impact the off-peak deliverability assessment in the SCE and DCRT study area are shown in Table 3.6-4.

Table 3.6-4: Renewable zones impacting deliverability out of the SCE and DCRT study area

Transmission Zone	Total (FC + EO) (MW)		
	Base	SENS-01	SENS-02
Inyokern_North_Kramer	554 solar	1,224 (97 solar, 1,127 BESS)	1,438 (97 solar, 1,341 BESS)
Mountain_Pass_El_Dorado	-	314 (248 solar, 66 BESS)	329 (248 solar, 81 BESS)
North_Victor	-	300 solar	300 solar
Riverside_Palm_Springs	1,664 (1,622 solar, 42 wind)	3,137 BESS	2567 (29 solar, 2,538 BESS)
SCADSNV	-	330 solar	4303 solar
SCADSNV-Riverside_Palm_Springs	-	-	1,582 P. Hydro
Southern_Nevada (CAISO)	3,006 solar	902 (862 solar, 40 BESS)	2,209 (1,727 solar, 442 wind, 40 BESS)
Tehachapi	1,153 solar	4,734 (4,202 solar, 275 wind, 257 BESS)	5,371 (4,801 solar, 275 wind, 295 BESS)
Arizona	428 solar	2,469 (2,352 solar, 117 BESS)	1,521 (1,350 solar, 171 BESS)

Whirlwind transformer bank constraint

Wind and solar resources interconnecting to Whirlwind 230kV bus are subject to curtailment in both sensitivity portfolios due to normal loading limitation of the Whirlwind 500/230kV transformer banks as shown in Table 3.6-5. The curtailment may be avoided by dispatching energy storage resources interconnecting to Whirlwind 230kV bus in charging mode or by installing a new Whirlwind 500/230kV transformer bank, as shown in Table 3.6-6.

Table 3.6-5: Off-peak deliverability assessment results – Whirlwind transformer bank constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Whirlwind 500/230kV No. 1, 2 & 3	Base Case	<100%	103.3%	106.86%

Table 3.6-6: Whirlwind transformer bank constraint deliverability constraint summary

Affected renewable transmission zones	Tehachapi (Whirlwind)		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	307	1119	1278
Energy storage portfolio MW behind the constraint	0	267	305
Mitigation Options:			
Renewable curtailment (MW)	0	120	240
Energy storage re-dispatched in charging mode (MW)	0	120	240
Transmission upgrades	Not needed	4th Whirlwind 500/230kV (~$100M)	

3.6.4 VEA and GLW area off-peak deliverability results

All renewable zones in Southern California and zones outside of California that are likely to impact the off-peak deliverability assessment in the VEA and GLW study area are shown in Table 3.6-7.

Table 3.6-7: Renewable zones impacting deliverability out of the VEA/GLW study area

TX Zone / Location	Total (FC + EO) (MW)		
	Base	**SENS-01**	**SENS-02**
Southern_Nevada (CAISO)	700	740 (700 Solar, 40 BESS)	2,210 (1,728 Solar, 442 Wind, 40 BESS)
SCADSNV	-	-	290

The solar and wind resources connecting to GLW's Sloan Canyon, Gamebird, Innovation and Desert View 230kV buses are subject to curtailment in the sensitivity 2 off-peak deliverability assessment due to normal loading limitation of multiple 230 kV and 138 kV lines in the GLW and VEA areas and the tie-lines to the neighboring system as shown in Table 3.6-8.

Table 3.6-8: Off-peak deliverability assessment results – VEA/GLW area constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Trout Canyon-Sloan Canyon 230kV line	Base Case	<100%	<100%	214.32%
Mercury SW-Northwest 138kV line	Base Case	<100%	<100%	165.23%-180.38%
Amargosa 230/138kV transformer	Base Case	<100%	<100%	176.13%
Innovation-Desert View 230kV line	Base Case	<100%	<100%	173.05%
Gamebird-Trout Canyon 230kV line	Base Case	<100%	<100%	143.27%
Northwest-Desert View 230kV line	Base Case	<100%	<100%	130.68%
Pahrump-Gamebird 230kV line	Base Case	<100%	<100%	117.15%
Amargosa-Sandy 138kV line	Base Case	<100%	<100%	111.47%
Jackass Flat-Mercury SW 138kV line	Base Case	<100%	<100%	108.53%

About 830 MW of resources need to be curtailed to mitigate all the normal overloads. Adding energy storage is not an applicable solution due to on-peak deliverability constraints.

Several transmission solutions were evaluated to relieve the area deliverability constraints. Those options include rebuilding the existing 230kV lines, installing new 230kV lines, installing 138kV phase shifter at Innovation and Mercury SW, the Interregional Transmission Project (ITP) submitted project of rebuilding Innovation – Northwest 138kV line, and a new Gamebird – Arden 230kV line.

The study concluded that the following three upgrades (identified as Option 3 in Table 3.6-9) along with RAS would mitigate all the overloads identified, with the least cost[113].

- New Innovation – Desert View 230kV No.2 line
- New Desert View – Northwest 230kV No.2 line
- New Gamebird – Arden 230kV line: convert the existing Gamebird – Amargosa 138kV line to a 230kV line and terminate at Arden 230kV substation.

Table 3.6-9 below summaries all the alternative options evaluated to mitigate the VEA/GLW off-peak deliverability constraints.

113 Cost estimates as provided by GLW

Table 3.6-9: Alternative options to mitigate VEA/GLW area deliverability constraints

Options	Pahrump-Sloan Canyon rebuild	Innovation-Desert View reconductor	Desert View-Northwest reconductor	Innovation-North west 138kV rebuild	Pahrump-Sloan Canyon #2	Innovation-Desert View #2	Desert View-North west #2	138 kV Phase Shifter	Gamebird-Arden 230kV	Gen Curtailment (MW)	Cost Estimate ($M)	Inc. MW/ $M
Status Quo										830	0	
Option 1	✓	✓	✓	✓						450	192	1.98
Option 2A					✓	✓	✓			120	112	6.34
Option 2B				✓	✓	✓	✓			110	162	4.44
Option 2C					✓	✓	✓	✓		130	121	5.79
Option 3						✓	✓		✓	0	90	9.22
Option 4			✓	✓	✓	✓				80	162	4.63
Option 4	✓					✓	✓	✓		350	121	3.97
Option 5			✓	✓	✓			✓		300	151	3.51

Table 3.6-10 provides a summary of the VEA/GLW area deliverability constraint[114].

Table 3.6-10: VEA/GLW area deliverability constraint summary

Affected renewable transmission zones	Southern Nevada (CAISO)		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	700	700	2460
Energy storage portfolio MW behind the constraint	0	40	40
Mitigation Options:			
Renewable curtailment (MW)	0	0	830
Energy storage re-dispatched in charging mode (MW)	0	0	N/A
Transmission upgrades	Not needed	Not needed	Option 3 as identified in Table 3.6-9 ($90M) and RAS

[114] The CAISO's Cluster 13, Phase 1 generation interconnection studies have identified concerns with the planned RAS in the Eldorado and VEA areas that need further analysis. The identification and future resolution of these concerns will need to be incorporated in future studies of the Eldorado and VEA area system constraints, and the results of those studies could be considerably different than the results in Table 3.6-10.

3.6.5 SDGE area off-peak deliverability results

All renewable zones in Southern California and zones outside of California that are likely to impact the off-peak deliverability assessment in the SDGE study area are shown in Table 3.6-11.

Table 3.6-11: Renewable zones impacting deliverability out of the SDGE study area

TX Zone / Location	Total (FC + EO) (MW)		
	Base	SENS-01	SENS-02
Greater Imperial (geothermal)	1,256	-	716
Greater Imperial (solar)	-	548	356
Arizona (solar)	428	2,352	1,350
Arizona (BESS)	-	111	171
Baja California (wind)	-	600	600
San Diego Sycamore (pumped hydro)	-	487	608
San Diego Imperial Valley LCR Area (BESS)	-	783	920

There were no off-peak deliverability constraints identified in the SDGE area under base, sensitivity 1 or sensitivity 2 scenarios.

3.6.6 PGE area off-peak deliverability results

All renewable zones in Southern California and zones outside of California that are likely to impact the off-peak deliverability assessment in the PGE study area are shown in Table 3.6-12.

Table 3.6-12: Renewable zones impacting deliverability out of the PGE study area

	Deliverability study capacity (MW)		
Renewable zone	BASE	SENS 1	SENS 2
Central Valley_North_los_Banos	Wind 146	330 Wind 173, 157 BESS	365 Wind 173,BESS 192
Kern_Greater_Carizzo	0	302 Solar 242, Wind 60	3061 Solar 3001, Wind 60
Humbodlt	0	Wind 34	Wind 34
Northern_California_Ex	0	2311 Wind 866, BESS 1445	4480 Wind 866, BESS 3614
Solano	644 Wind	700 Wind 542, BESS 158	940 Wind 542,135 GeoT, BESS 263
Westlands	0	2874 Solar 1836, BESS 1038	3060 Solar 1958, BESS 1102

Dairyland-Le Grand and Le Grand-Chowchilla 115 kV lines

Solar resources interconnecting to this area are subject to curtailment in all portfolios due to normal loading limitation of the Dairyland-Le Grand and Le Grand-Chowchilla 115 kV lines as shown in Table 3.6-13 and Table 3.6-14.

Table 3.6-13: Off-peak deliverability assessment results – Dairyland-Le Grand and Le Grand-Chowchilla 115 kV lines

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Dairyland-Le Grand and Le Grand-Chowchilla 115 kV lines	Panoche-Mendota 115kV line	123%	123%	123%

Table 3.6-14: Dairyland-Le Grand and Le Grand-Chowchilla 115 kV constraint deliverability constraint summary

Affected renewable transmission zones	Westlands		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	22*	22*	22*
Energy storage re-dispatched in charging mode (MW)	0	0	0
Potential mitigation	RAS to trip generation		

**Baseline renewable curtailment*

Gates-Kettlemen 70kV Line constraint

Solar resources interconnecting to Gates 70KV bus are subject to curtailment in all portfolios due to normal loading limitation of the Gates-Kettlemen 70kV line as shown in Table 3.6-15 and Table 3.6-16 .

Table 3.6-15: Off-peak deliverability assessment results – Gates-Kettlemen 70kV line constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Kettlemen-Gates 70 kV line	Base Case	127%	127%	127%

Table 3.6-16: Gates-Kettlemen 70kV line deliverability constraint summary

Affected renewable transmission zones	Westlands		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	10*	10*	10*
Energy storage re-dispatched in charging mode (MW)	0	0	0
Potential mitigation	Reconductor Kettleman-Gates 70 kV line (~13.2M) or 10MW BESS		

Baseline renewable curtailment

Five Points-Huron-Gates 70kV Line constraint

Solar resources interconnecting to Gates 70KV bus are subject to curtailment in all portfolios due to normal loading limitation of the Five Points-Huron-Gates 70kV line as shown in Table 3.6-17 and Table 3.6-18.

Table 3.6-17: Off-peak deliverability assessment results – Five Points-Huron-Gates 70kV line constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Five Points-Huron-Gates 70 kV line	Panoche-Excelciours #1 and #2 115 kV lines	110%	119%	121%

Table 3.6-18: Five Points-Huron-Gates 70kV line constraint deliverability constraint summary

Affected renewable transmission zones	Westlands		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	8*	16*	18*
Energy storage re-dispatched in charging mode (MW)	0	8 MW storage + 8 MW renewables	8 MW storage + 10 MW renewables
Potential mitigation	RAS to trip generation		

**Baseline renewable curtailment*

Gates–Arco–Midway 230 kV lines constraint

Solar resources interconnecting to Arco 230kV bus are subject to curtailment in sensitivity 2 portfolio due to normal loading limitation of the Gates – Arco - Midway 230kV lines as shown in Table 3.6-19 Table 3.6-20.

Table 3.6-19: Off-peak deliverability assessment results – Gates-Arco-Midway 230kV lines constraint

Overloaded Facility	Contingency	Flow		
		BASE	**SENS-01**	**SENS-02**
Gates–Arco–Midway 230 kV lines	Arco – Midway 230 kV line*	<100%	<100%	166%

* Represents worst loading

Table 3.6-20: Gates-Arco-Midway 230kV lines deliverability constraint summary

Affected renewable transmission zones	Greater Carrizo		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	679
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	0	0	229
Energy storage re-dispatched in charging mode (MW)	0	0	0
Potential mitigation	Not needed	Not needed	RAS to Trip Generation

Stockdale – Kern PP 230 kV line constraint

Solar resources interconnecting to Stockdale 230kV bus are subject to curtailment in sensitivity 2 portfolio due to normal loading limitation of the Stockdale – Kern 230kV line as shown in Table 3.6-21 and Table 3.6-22.

Table 3.6-21: Off-peak deliverability assessment results – Stockdale – Kern 230kV line constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Stockdale – Kern PP 230 kV line	Stockdale B – Kern PP #1 230 kV line*	<100%	<100%	138%

* Represents worst loading

Table 3.6-22: Stockdale – Kern PP 230kV line deliverability constraint summary

Affected renewable transmission zones	Greater Carrizo		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	617
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	0	0	129
Energy storage re-dispatched in charging mode (MW)	0	0	0
Potential mitigation	Not needed	Not needed	RAS to Trip Generation

Midway – Renfro – Tupman 115kV line constraint

Solar resources interconnecting to Renfro 115kV bus are subject to curtailment in sensitivity 2 portfolio due to normal loading limitation of the Midway – Renfro – Tupman 115kV line as shown in Table 3.6-23 and Table 3.6-24. Adding storage is not considered a potential mitigation as it would not be deliverable on peak.

Table 3.6-23: Off-peak deliverability assessment results – Midway – Renfro – Tupman 115kV line constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Midway–Renfro–Tupman 115 kV line	Base case*	<100%	<100%	268%

* Represents worst loading

Table 3.6-24: Midway – Renfro – Tupman 115 kV line deliverability constraint summary

Affected renewable transmission zones	Greater Carrizo		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	615
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	0	0	378
Energy storage re-dispatched in charging mode (MW)	0	0	0
Potential mitigation	Not needed	Not needed	Reconductor Tupman Jct 1-Tupman and Tupman Jct 2-Tupman115kV line sections (~$22M) and RAS to trip generation

Wind Gap Jct 1 and 2–Wheeler Ridge 230 kV line constraint

Solar resources interconnecting to Wheeler Ridge 230kV bus are subject to curtailment in sensitivity 2 portfolio due to normal loading limitation of the Wind Gap Jct 1 and 2–Wheeler Ridge 230 kV line as shown in Table 3.6-25 and Table 3.6-26.

Table 3.6-25: Off-peak deliverability assessment results – Wind Gap Jct 1 and 2–Wheeler Ridge 230 kV line constraint

Overloaded Facility	Contingency	Flow		
		BASE	**SENS-01**	**SENS-02**
Wind Gap Jct 1 and 2–Wheeler Ridge 230 kV line	Midway-Wheeler Ridge #1 230 kV or Midway-Wheeler Ridge #2 230 kV lines	<100%	<100%	109%

Table 3.6-26: Wind Gap Jct 1 and 2–Wheeler Ridge 230 kV line deliverability constraint summary

Affected renewable transmission zones	Greater Carrizo		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	552
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	0	0	37
Energy storage re-dispatched in charging mode (MW)	0	0	0
Potential mitigation	Not needed	Not needed	On Hold TPP Wheeler Ridge Jct project or RAS

San Miguel–Coalinga & San Miguel–Union 70 kV line constraint

Solar resources interconnecting to Templeton 230kV bus are subject to curtailment in sensitivity 2 portfolio due to normal loading limitation of the San Miguel–Coalinga & San Miguel–Union 70 kV line as shown in Table 3.6-27 and Table 3.6-28.

Table 3.6-27: Off-peak deliverability assessment results – San Miguel–Coalinga & San Miguel–Union 70 kV line constraint

Overloaded Facility	**Contingency**	**Flow**		
		BASE	**SENS-01**	**SENS-02**
San Miguel–Coalinga & San Miguel–Union 70 kV lines	Templeton-Gates & Gates-Calflatss #1 230 kV lines	<100%	<100%	134%

Table 3.6-28: San Miguel–Coalinga & San Miguel–Union 70 kV line deliverability constraint summary

Affected renewable transmission zones	Greater Carrizo		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	688
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	0	0	244
Energy storage re-dispatched in charging mode (MW)	0	0	0
Potential mitigation	Not needed	Not needed	RAS to Trip Generation

Cottonwood – Round Mountain 230 kV constraint

Solar resources interconnecting to Round Mountain 230 kV bus is subject to curtailment in sensitivity 2 portfolio due to normal loading limitation of the Cottonwood-Round Mountain 230 kV line as shown in Table 3.6-29 and Table 3.6-30.

Table 3.6-29: Off-peak deliverability assessment results – Cottonwood-Round Mountain 230 kV line constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Cottonwood-Round Mountain 230 kV lines	Round Mountain #1 500/230 kV Transformer	<100%	<100%	118%

Table 3.6-30: Cottonwood-Round Mountain 230 kV line constraint deliverability summary

Affected renewable transmission zones	Northern California		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	1603
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	0	0	20
Energy storage re-dispatched in charging mode (MW)	0	0	0
Potential mitigation	Not needed	Not needed	RAS to Trip Generation

3.7 Production cost model simulation (PCM) study

3.7.1 PCM assumptions

The base portfolio and the two sensitivity portfolios described in section 3.4 were utilized for the PCM study in the policy-driven assessment of this planning cycle. Details of PCM assumptions and development can be found in Chapter 4.

3.7.2 Congestion and curtailment results

Table 3.7-1 summarizes the congestion results for the Base, Sensitivity 1, and Sensitivity 2 portfolios. The Base Portfolio was used in both the policy driven study and the economic driven study. The detailed congestion results of production cost simulation for the base portfolio are summarized in the economic assessment chapter (section 4.7). The constraints in this list are ranked in descending order by total congestion cost. Compared with the Base portfolio PCM case, the congestion changes in the sensitivity portfolio cases are attributed to the resource capacity and location changes. Incremental battery storage in the sensitivity cases also contributes to the changes in congestion results.

Table 3.7-1: Congestion summary – three portfolios

		Base		Sensitivity 1		Sensitivity 2	
No.	Aggregated congestion	Cost ($M)	Duration (Hr)	Cost ($M)	Duration (Hr)	Cost ($M)	Duration (Hr)
1	SDGE DOUBLTTP-FRIARS 138 kV	52.74	2,749	72.73	3,417	53.87	2,461
2	SCE Whirlwind Transformer	22.91	295	74.74	892	38.72	730
3	COI Corridor	12.96	329	25.00	484	47.26	748
4	PDCI	8.95	562	5.52	494	8.43	773
5	PG&E Fresno	8.64	4,520	11.59	5,526	9.55	5,134
6	Path 45	7.8	1,453	12.25	1,572	10.31	1,233
7	Path 26 Corridor	6.74	237	4.67	170	12.1	428
8	PG&E Sierra	6.3	439	2.83	251	3.5	247
9	SCE LCIENEGA-LA FRESA 230 kV line	3.59	84	4.54	294	12.15	293
10	SCE Red Bluff-Devers 500 kV	3.42	33	1.55	33	0.51	29
11	Path 60 Inyo-Control 115 kV	3.35	1,666	4.24	2,059	4.05	2,275
12	SCE NOL-Kramer-Inyokern-Control	3.23	266	2.52	1,666	5.93	2,864
13	Path 25 PACW-PG&E 115 kV	2.81	486	2.59	473	7.13	875
14	SCE Antelope 66 kV system	2.77	1,008	5.19	1,730	3.03	1,472
15	Path 42 IID-SCE	2.26	71	0.00	0	0.34	12
16	SDGE IV-San Diego Corridor	0.95	45	1.57	84	1.83	85
17	SCE J.HINDS-MIRAGE 230 kV line	0.65	80	3.12	318	0.45	36
18	SCE Laguna Bell-Mesa Cal	0.64	21	10.95	111	17.05	343
19	SDGE-CFE OTAYMESA-TJI 230 kV line	0.45	107	1.21	221	3.12	528
20	Path 61/Lugo - Victorville	0.38	41	1.11	92	1.96	96
21	San Diego	0.35	155	0.37	576	0.26	814

		Base		Sensitivity 1		Sensitivity 2	
No.	Aggregated congestion	Cost ($M)	Duration (Hr)	Cost ($M)	Duration (Hr)	Cost ($M)	Duration (Hr)
22	San Diego Silver Gate-Bay Boulervard	0.28	20	0.17	6	0.03	2
23	SCE Lugo 500 kV Transformer	0.18	5	0.00	6	0	1
24	SCE Devers 500/230 kV transformer	0.13	2	1.23	109	7.3	369
25	Path 15/CC	0.1	8	0.00	0	0	0
26	PG&E Mosslanding -Lasguilass 230 kV	0.1	7	0.85	149	1.57	495
27	PG&E Cottle - Melones 230 kV	0.06	9	0.00	0	0	0
28	PG&E Gates-CAIFLATSSS 230 kV	0.05	3	0.00	0	0	0
29	PG&E USWP JRW-Cayetano 230 kV	0.05	4	0.03	5	0	3
30	PG&E/Sierra MARBLE transformer	0.04	6	0.03	5	0	5
31	PG&E POE-RIO OSO	0.03	17	0.11	14	0.08	12
32	SCE Serrano-Villa PK 230 kV	0.03	1	0.00	0	0	0
33	VEA	0.03	66	0.07	94	13.67	2,480
34	PG&E North Valley	0.01	1	0.02	2	0	0
35	PG&E Solano	0.01	2	0.02	1	0	0
36	SDGE N.Gila-Imperial Valley 500 kV	0.01	1	0.63	18	0.88	33
37	SDGE-CFE IV-ROA 230 kV line and IV PFC	0.01	2	0.22	52	0.05	26
38	SCE Sylmar - Pardee 230 kV	0	1	0.00	0	0	1
39	PG&E Delevn-Cortina 230 kV	0	1	0.04	2	0.01	1
40	Path 15 Corridor	0	0	0.07	16	0.05	17
41	Path 24 PG&E-NVE Sierra	0	0	0.00	0	0.01	1
42	Path 41 Sylmar transformer	0	0	0.11	7	0.25	13
43	Path 46 WOR	0	0	0.00	0	0.08	2
44	Path 52 Silver Peak-Control 55 kV	0	0	0.00	3	0	0
45	PG&E Carrizo	0	0	0.00	0	27.59	4,519
46	PG&E CC Sub 230 kV transformer	0	0	0.01	119	0.38	1,124
47	PG&E Kelso - Ralph 230 kV	0	0	0.00	0	0	7
48	PG&E Kern	0	0	0.00	0	8.74	1,783
49	PG&E Marshlanding-C.Costa	0	0	0.00	0	0.01	14
50	PG&E Tesla 500 kV Transformer	0	0	0.17	14	0.03	36
51	PG&E VacaDixon - TESLA 500 kV	0	0	0.01	3	0.44	22
52	SCE Pardee-Vincent 230 kV	0	0	0.00	0	0.05	2
53	SCE Antelope - Pardee 230 kV	0	0	0.04	2	0.11	15
54	SCE Ivanpah-MtnPass	0	0	0.00	0	0	1
55	SCE Vincent 500 kV Transformer	0	0	0.09	4	8.34	115
56	SCE Windhub 500 kV transformer	0	0	0.51	28	0.27	20
57	SCE-LADWP Eldorado - McCullough 500 kV	0	0	0.00	0	0.4	7
58	SDGE Sanlusry-S.Onofre 230 kV	0	0	0.00	3	0.03	11

Table 3.7-2 shows wind and solar generation curtailment in the CAISO system in all three portfolio cases. In this table the renewable resources were aggregated by zone based on the transmission constraints to which the resources in the same zone normally contributed in the same direction, or based on geographic locations if there were not obvious transmission constraints nearby. The rows of this table were ranked based on the curtailment amount in the Sensitivity 2 portfolio PCM, which is also used for the battery remapping study as set out in section 3.8.

Similar to the congestion results, changes in the assumptions for renewable and battery storage resources are the key factors for the curtailment changes. Particularly, in some zones, while renewable resources increased in the sensitivity portfolios, the battery storages also increased, which resulted in lower curtailment in these zones, e.g. SCE's Eastern zone, which largely overlaps with the Riverside East renewable zone, and the SDG&E's IV zone, which basically covers the SDG&E's Imperial Valley and East County areas.

Table 3.7-2: Wind and solar curtailment summary – three portfolios

	Base			Sensitivity 1			Sensitivity 2		
Zone	**Generation (GWh)**	**Curtailment (GWh)**	**Ratio**	**Generation (GWh)**	**Curtailment (GWh)**	**Ratio**	**Generation (GWh)**	**Curtailment (GWh)**	**Ratio**
SCE Tehachapi	20,451	4,378	18%	27,641	5,192	16%	26,838	7,447	22%
PG&E Carrizo	1,871	645	26%	2,821	631	18%	7,206	3,971	36%
PG&E Fresno-Kern	7,420	1,565	17%	11,508	1,891	14%	11,294	2,692	19%
SCE EOL	7,349	1,190	14%	4,492	269	6%	16,052	2,527	14%
VEA	1,779	107	6%	1,836	49	3%	4,319	1,884	30%
NM	832	166	17%	2,458	488	17%	5,877	1,551	21%
AZ	2,223	1,174	35%	6,535	1,580	19%	4,311	1,342	24%
NW	5,915	457	7%	5,999	374	6%	10,593	834	7%
SCE NOL	2,792	511	15%	3,203	207	6%	2,579	383	13%
SCE Eastern	10,403	2,264	18%	8,172	379	4%	8,182	369	4%
SDGE IV	5,041	607	11%	8,248	316	4%	7,818	249	3%
SCE Vestal	672	154	19%	735	90	11%	683	142	17%
ID	346	52	13%	350	48	12%	336	62	16%
PG&E Solano	5,016	94	2%	4,912	45	1%	4,903	54	1%
PG&E N. CA	1,032	25	2%	3,363	46	1%	3,163	43	1%
CO	186	33	15%	189	30	14%	180	39	18%
IID	707	75	10%	766	16	2%	747	34	4%
SCE Others	271	48	15%	299	20	6%	289	29	9%
SDGE San Diego	246	34	12%	264	16	6%	263	17	6%
AB	473	11	2%	479	6	1%	473	11	2%
SCE Ventura	27	5	17%	30	3	9%	28	5	15%
Total	**75,051**	**13,595**	**15%**	**94,298**	**11,695**	**11%**	**116,133**	**23,686**	**17%**

3.8 Sensitivity 2 portfolio battery remapping study

3.8.1 Objective of battery remapping and methodology

The objective of the Sensitivity 2 Portfolio battery remapping study is to evaluate if battery storage location and capacity can be further refined in order to reduce transmission congestion and renewable curtailment. For this purpose, the battery storage that was found to be undeliverable in the on-peak deliverability assessment was relocated to locations with high renewable curtailment based on the production simulation results for Sensitivity 2. In addition to relocating the undeliverable battery storage, 194 MW of battery storage in the portfolio that was not previously mapped in PCM was also added to the model[115]. Six of the top seven zones with high curtailment with the exception of the New Mexico zone in Table 3.7-2, which are ranked by curtailment amount, were selected for battery storage addition. The amount of battery capacity allocated to each zone is in proportion to the curtailment ratio, i.e. the ratio of the curtailment amount to the total renewable generation in each zone, with some adjustment due to on-peak deliverability considerations.

Table 3.8-1 lists the reduction needed in battery capacity from the original mapping due to on-peak deliverability constraints.

Table 3.8-1: Re-mapped undeliverable battery capacity

Zone	Bus Name	Bus kV	Bus ID	Original amount (MW)	Deliverable amount (MW)	Reduction needed (MW)
Inyokern_North_Kramer	Roadway	115	24607	93	0	93
	Kramer	230	24701	1,012	480	532
None (San Diego Area)	Otay	69	22604	280	270	10[116]
Westlands, Central Valley, Los Banos, Northern California and Solano	Mosslanding	500	30045	1712	0	1,712[117]
	Mustang	230	30885	425	20	405
Solano and Northern California	Marshlanding 1	230	30518	320	195	125
	Marshlanding 2	230	30519	325	0	325
	Cayetano	230	30530	85	0	85
					Total reduction	3,287

Table 3.8-2 lists the locations where the 3,287 MW of battery storage is re-mapped to along with the capacity allocated. As noted earlier, the re-mapping was done based on the curtailment ratio of each zone in the Sensitivity 2 PCM case. However, the amount of storage allocated to buses

[115] The amount of remapped storage includes 194 MW of the 12,658 MW of energy storage in the portfolio that was not previously mapped in PCM as can be seen from Table 3.4 5, but was modeled in the deliverability assessment case.

[116] The minor discrepancy between the deliverability case and PCM explained in the above footnote includes a 28 MW discrepancy at Otay 69 kV bus. As a result, 18 MW of battery storage was added at the bus in the re-mapping study PCM case.

[117] For the reasons noted in footnote 116, the battery storage reduction at Mosslanding from the original PCM case is 1,544 MW instead of 1,712 MW

located in Carrizo, Fresno-Kern and GridLiance/VEA areas was capped due to on-peak deliverability considerations.

Table 3.8-2: Re-mapped Sensitivity 2 portfolio battery storage to reduce curtailment

Zone	Bus Name	Bus kV	Bus ID	Change (MW)
Tehachapi	Whirlwind	230	29408	1,170
	Vincent	500	24156	944
East of Lugo	Eldorado	500	24042	374
GridLiance/VEA	Trout Canyon	230	189160	60
Arizona	Hassayampa	500	15090	218
Carrizo	Renfro	115	34762	120
	Arco	230	30935	60
	Stckdlea	230	30940	60
	Templeton	230	30905	80
	Wheeler	230	30994	80
Fresno-Kern	Gates D	230	30900	10
	Avnlpark	70	34249	10
	Northstar	115	34195	50
	Helm	230	30873	50
			Total	**3,287**

3.8.2 PCM results with battery remapped

Figure 3.8-1 shows the changes in congestion as a result of the battery remapping in the Sensitivity 2 PCM.

Generally, remapping battery storage based on the methodology described in section 3.8.1 is effective to reduce transmission congestions, especially in the areas where there was a large amount of renewable generators that caused local transmission congestions. For example, the congestion cost of the SCE Whirlwind transformer was reduced by about $21 million per year after relocating 1,170 MW of battery to the Whirlwind 230 kV bus. The congestion cost of the Whirlwind transformers is $38.72 million per year in the Sensitivity 2 PCM before the battery remapping as shown in Table 3.7-1. Similar results were observed at SCE's Vincent transformer, PG&E's Fresno area and Carrizo areas, etc. At some locations, the changes in transmission congestion can be a result of battery remapping in other locations. For example, congestion on the SDG&E's Doublet Tap – Friars 138 kV line, SCE's Devers transformer and Red Bluff – Devers 500 kV line decreased because the incremental battery storage at the Hassayampa substation can absorb some of the surplus renewable generation output and increase the LMP at the sending end of the congested line. Congestion on Path 26, COI, and Path 45 corridors decreased mainly because the battery remapping changed the overall generation dispatch including renewable curtailment and the battery charging and discharging, which improved the overall system operation.

SCE's North of Lugo and Kramer area had lower congestion with the battery remapped although some battery storage was moved away from this area due to the on-peak deliverability constraints. The reduction in congestion in this area mainly resulted from the mitigation of the Kramer to Victor 115 kV line congestion, to which the battery storage in the Kramer area can contribute when discharging. The congestion change in this area is consistent with the on-peak deliverability assessment results.

Congestion in some areas increased slightly with the battery remapped. This can be attributed to the battery remapping directly or the overall generation dispatch change. For example, SCE's Laguna Bell – Mesa 230 kV line congestion increased because the incremental battery storage at Vincent and Whirlwind increased the generation output in the Tehachapi area and pushed more flow onto the Laguna Bell – Mesa 230 kV line. The IV to San Diego corridor congestion increased mainly due to increase in the Suncrest transformer congestion under N-1 contingency because of the overall generation output increase in the Imperial Valley and in Arizona's Hassayampa and Hoodoo Wash areas with the additional battery storage at Hassayampa substation.

Figure 3.8-1: Changes in congestion with battery re-mapping in Sensitivity 2 Portfolio

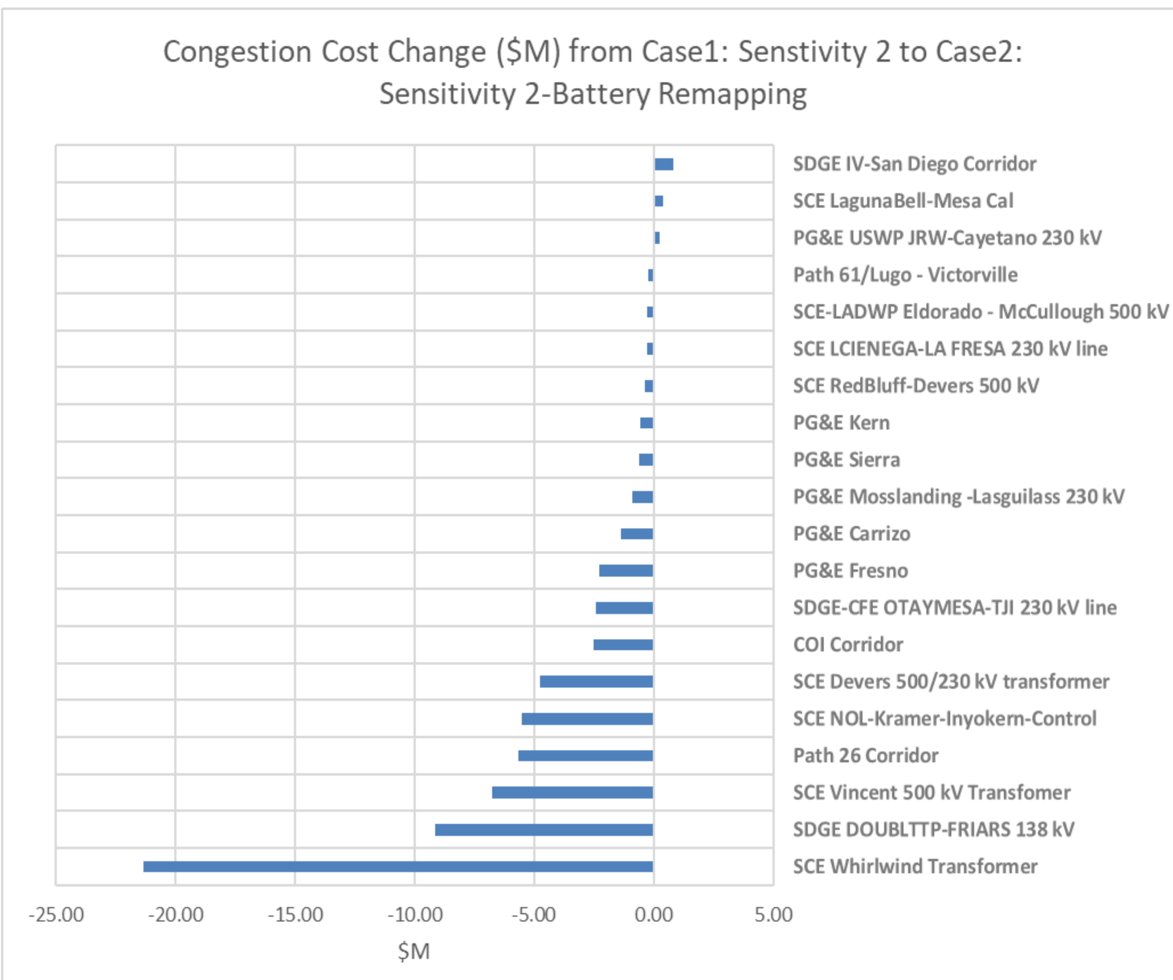


Table 3.8-3 shows the curtailments of wind and solar in the Sensitivity 2 PCM cases before and after the battery remapping. The total renewable curtailment reduced by 2,152 GWh due to battery remapping. The most effective renewable curtailment reduction occurred in SCE's Tehachapi, PG&E's Carrizo, and PG&E's Fresno/Kern areas, which had total 1,870 GWh of curtailment reduction. It is worth noting that the renewable curtailment reduction with the battery remapped is not as significant as the transmission congestion reduction since other system constraints that impact generation dispatch can also cause renewable curtailment.

Table 3.8-3: Comparison of renewable curtailment before and after battery re-mapping in Sensitivity 2 Portfolio

	Sensitivity 2			Sensitivity 2-Remapping batteries		
Zone	**Generation (GWh)**	**Curtailment (GWh)**	**Ratio**	**Generation (GWh)**	**Curtailment (GWh)**	**Ratio**
SCE Tehachapi	26,838	7,447	22%	27,994	6,290	18%
PG&E Carrizo	7,206	3,971	36%	7,808	3,368	30%
PG&E Fresno-Kern	11,294	2,692	19%	11,406	2,580	18%
SCE EOL	16,052	2,527	14%	16,370	2,209	12%
VEA	4,319	1,884	30%	4,397	1,806	29%
NM	5,877	1,551	21%	5,874	1,554	21%
AZ	4,311	1,342	24%	4,304	1,349	24%
NW	10,593	834	7%	10,465	962	8%
SCE Vestal	683	142	17%	705	121	15%
SCE NOL	2,579	383	13%	2,607	355	12%
SCE Eastern	8,182	369	4%	8,171	379	4%
SDGE IV	7,818	249	3%	7,824	244	3%
ID	336	62	16%	333	65	16%
PG&E Solano	4,903	54	1%	4,888	69	1%
PG&E N. CA	3,163	43	1%	3,151	55	2%
CO	180	39	18%	179	39	18%
IID	747	34	4%	753	29	4%
SCE Others	289	29	9%	292	26	8%
SDGE San Diego	263	17	6%	264	16	6%
AB	473	11	2%	470	14	3%
SCE Ventura	28	5	15%	29	4	13%
Total	**116,133**	**23,686**	**17%**	**118,286**	**21,534**	**15%**

3.8.3 Transmission alternatives to battery re-mapping

Incremental battery storages in the sensitivity portfolio cases helped to mitigate transmission congestion and renewable curtailment in local areas and across the system as well. Battery remapping based on the on-peak deliverability assessment and the production cost simulation results was conducted on the Sensitivity 2 portfolio PCM case. The results indicate that transmission congestion and renewable curtailment can be further reduced by allocating battery storages appropriately. Some areas, primarily the GridLiance and VEA area, however, may not be able to accommodate additional battery storage due to the limit of on-peak deliverability. Therefore, a transmission solution was considered to mitigate congestion and curtailment in the GridLiance and VEA area. A transmission solution was also considered for the SCE Whirlwind transformer congestion. The total capacity of renewable generators that were modeled at the Whirlwind 230 kV is relatively large, compared with the total capacity of the three transformers at the Whirlwind substation. The maximum capacity of additional battery storage at the Whirlwind 230 kV bus on top of the renewable and battery that are already modeled in the Sensitivity 2 PCM case is constrained by the on-peak deliverability limit due to the Whirlwind transformer constraint.

3.1.1.1 GridLiance West Conversion Project

It was observed that there was significant congestion and renewable curtailment in the GridLiance West and VEA area in the Sensitivity 2 PCM simulation results, as shown in Table 3.7-1 and Table 3.7-2, respectively. However, the battery remapping study can only add 60 MW of battery in the GridLiance West and VEA area due to the limit of on-peak deliverability, as shown in Table 3.8-2. Therefore, the Conversion project proposed by GridLiance West was studied as a transmission alternative to the battery remapping, and the results were compared with the ones with the battery remapped, especially for the GridLiance West and VEA area. The Conversion project was proposed to build a new inter-tie between the GridLiance West and VEA system and the NVE system, which is expected to mitigate congestion and curtailment in the GridLiance and VEA system. Details of the Conversion Project can be found in section 3.6.4.

Figure 3.8-2 shows the changes in congestion as a result of modeling the Conversion project. The Conversion project is effective to mitigate congestion in the GridLiance West and VEA area. The Path 26 corridor congestion reduced, while the PDCI congestion and the SCE's Vincent transformer congestion increased. This is an indication that the Conversion project not only impacts the generation dispatch and flow pattern in the GridLiance and VEA area, but also impacts the generation dispatch in southern California areas including SCE's Tehachapi area. The Conversion project also has minor impacts on congestion in other areas, mainly due to the changes in generation dispatch and loop flow.

Figure 3.8-2: Changes in congestion with modeling GridLiance West Conversion Project in Sensitivity 2 Portfolio PCM

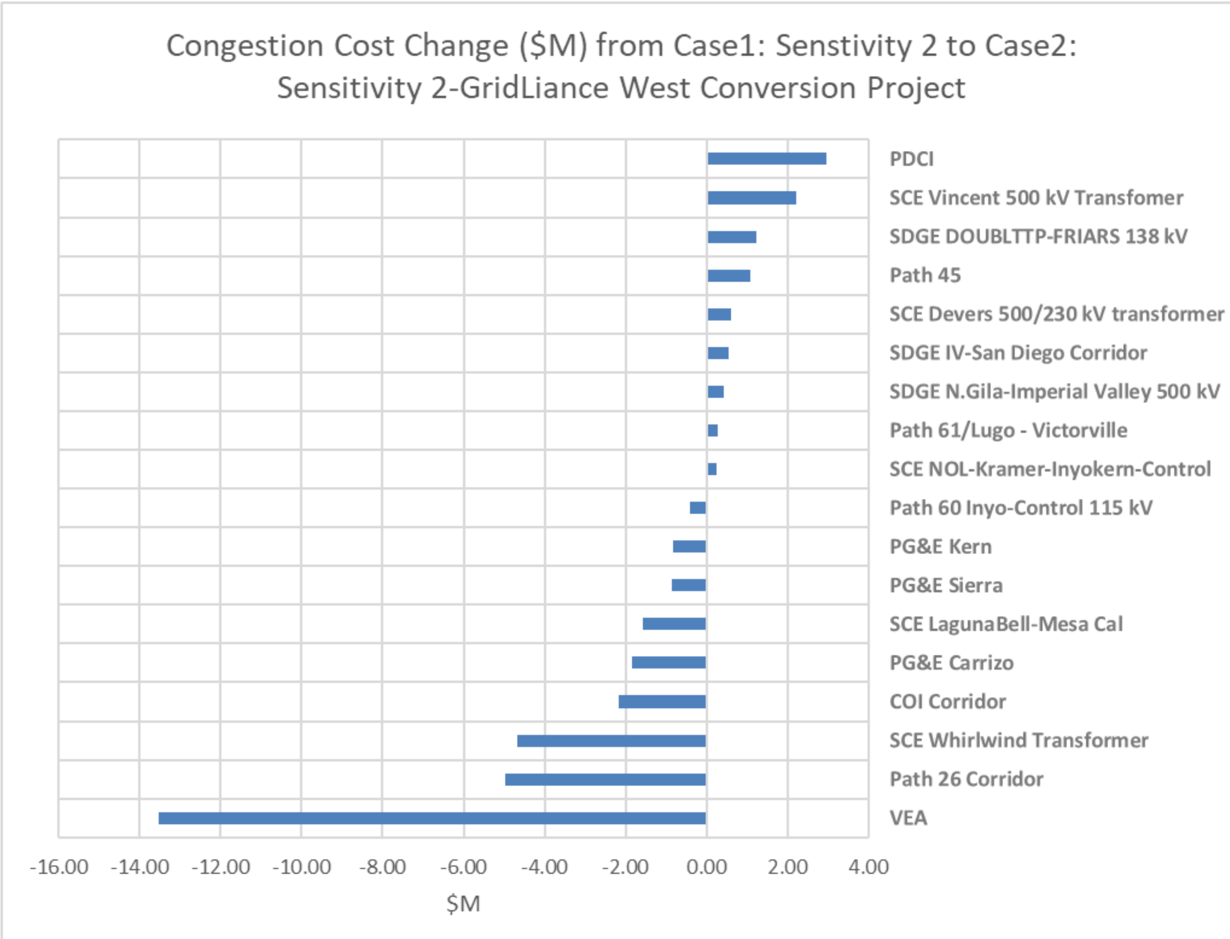


Table 3.8-4 compares the renewable curtailment in the Sensitivity 2 PCM cases with and without the Conversion project. The Conversion project is effective to mitigate the curtailment in the GridLiance and VEA area. The renewable curtailment in this area reduced by 1,315 GWh. The Conversion project caused changes in renewable curtailment in other areas as well. The second largest change in renewable curtailment was in the SCE's East of Lugo area, including the SCE's Eldorado/Mohave area and the Mountain Pass/Ivanpah area, with a 751 GWh increase. Smaller changes, increase or decrease, in renewable curtailment were observed in the remaining areas. As a result, the total curtailment reduction because of the Conversion project is 939 GWh.

Table 3.8-4: Comparison of renewable curtailment before and after modeling GridLiance West Conversion Project in Sensitivity 2 Portfolio PCM

	Sensitivity 2			Sensitivity 2-Conversion project		
Zone	Generation (GWh)	Curtailment (GWh)	Ratio	Generation (GWh)	Curtailment (GWh)	Ratio
SCE Tehachapi	26,838	7,447	22%	26,834	7,450	22%
PG&E Carrizo	7,206	3,971	36%	7,273	3,904	35%
PG&E Fresno-Kern	11,294	2,692	19%	11,372	2,614	19%
SCE EOL	16,052	2,527	14%	15,300	3,278	18%
VEA	4,319	1,884	30%	5,635	568	9%
NM	5,877	1,551	21%	5,893	1,535	21%
AZ	4,311	1,342	24%	4,434	1,219	22%
NW	10,593	834	7%	10,649	778	7%
SCE Vestal	683	142	17%	682	143	17%
SCE NOL	2,579	383	13%	2,497	465	16%
SCE Eastern	8,182	369	4%	8,237	314	4%
SDGE IV	7,818	249	3%	7,862	206	3%
ID	336	62	16%	339	59	15%
PG&E Solano	4,903	54	1%	4,909	47	1%
PG&E N. CA	3,163	43	1%	3,167	39	1%
CO	180	39	18%	182	36	17%
IID	747	34	4%	749	32	4%
SCE Others	289	29	9%	289	29	9%
SDGE San Diego	263	17	6%	264	15	5%
AB	473	11	2%	475	9	2%
SCE Ventura	28	5	15%	28	5	15%
Total	**116,133**	**23,686**	**17%**	**117,072**	**22,747**	**16%**

3.1.1.2 Whirlwind 500/230 kV transformer No. 4

As described in section 3.8.2, with relocating 1,170 MW of battery to the Whirlwind 230 kV bus, the congestion cost of the SCE Whirlwind transformers was reduced by about $21 million per year from $38.72 million per year before the battery remapping. There are still about $17 million of congestion cost on the Whirlwind transformers after the battery remapping. Adding the fourth transformer in the Whirlwind substation was considered as a transmission alternative to mitigate the Whirlwind transformer congestion and the associated renewable curtailment.

Figure 3.8-3 shows the changes in congestion because of modeling the fourth Whirlwind transformer. The Whirlwind transformer congestion cost was reduced by about $35 million per year, which demonstrated that adding a new transformer at the Whirlwind substation is more effective in mitigating the congestion on Whirlwind transformers than relocating 1,170 MW of battery to the Whirlwind 230 V bus. However, as the Whirlwind transformer congestion was mitigated, the previously curtailed renewable generation at the Whirlwind 230 kV system can be delivered to the system and may cause congestion in other areas, for example, it was observed in Figure 3.8-3 that the SCE Vincent transformer congestion increased after modeling the fourth Whirlwind transformer. As a result, curtailment in those areas may increase.

Figure 3.8-3: Changes in congestion with modeling the fourth Whirlwind transformer in Sensitivity 2 Portfolio PCM

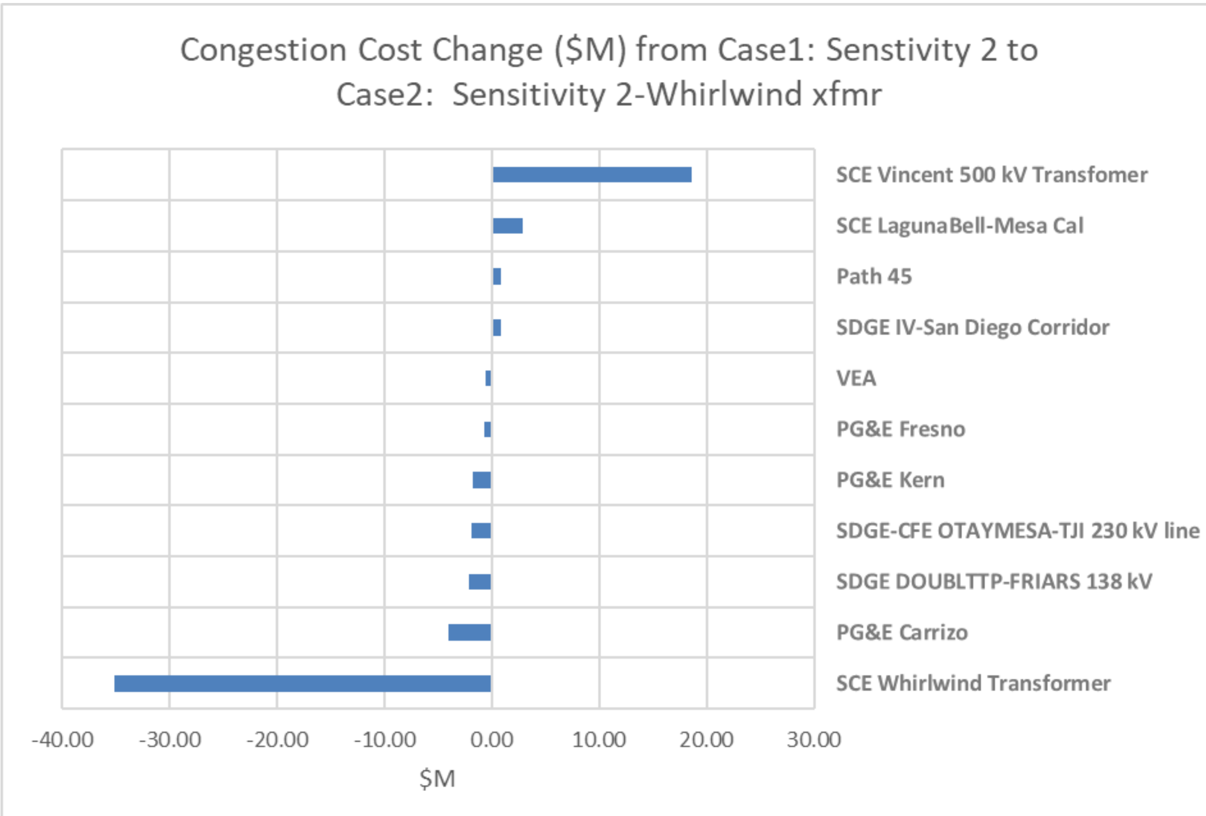


Table 3.8-5 compared the renewable curtailments in the Sensitivity 2 PCM cases with and without the fourth Whirlwind transformer. The total curtailment remains almost the same, as well as the SCE Tehachapi area curtailment. A closer look showed that the renewable curtailment at the Whirlwind 230 kV system reduced, which was aggregated into the SCE Tehachapi zone curtailment and not shown in this table. This indicated that other renewable generation in the SCE Tehachapi area was curtailed more than before the fourth Whirlwind transformer was modeled. In addition to the increase in transmission congestion in other areas, system constraints are also a factor for the total curtailment to remain almost the same.

Table 3.8-5: Comparison of renewable curtailment before and after modeling the fourth Whirlwind transformer in Sensitivity 2 Portfolio PCM

	Sensitivity 2			Sensitivity 2 – Whirlwind transformer		
Zone	**Generation (GWh)**	**Curtailment (GWh)**	**Ratio**	**Generation (GWh)**	**Curtailment (GWh)**	**Ratio**
SCE Tehachapi	26,838	7,447	22%	26,834	7,450	22%
PG&E Carrizo	7,206	3,971	36%	7,273	3,904	35%
PG&E Fresno-Kern	11,294	2,692	19%	11,372	2,614	19%
SCE EOL	16,052	2,527	14%	27,187	7,098	21%
VEA	4,319	1,884	30%	7,161	4,016	36%
NM	5,877	1,551	21%	11,278	2,708	19%
AZ	4,311	1,342	24%	16,021	2,557	14%
NW	10,593	834	7%	4,315	1,888	30%
SCE Vestal	683	142	17%	5,853	1,575	21%
SCE NOL	2,579	383	13%	4,295	1,359	24%
SCE Eastern	8,182	369	4%	10,577	850	7%
SDGE IV	7,818	249	3%	682	143	17%
ID	336	62	16%	2,576	385	13%
PG&E Solano	4,903	54	1%	8,179	372	4%
PG&E N. CA	3,163	43	1%	7,812	256	3%
CO	180	39	18%	336	62	16%
IID	747	34	4%	4,905	52	1%
SCE Others	289	29	9%	3,163	43	1%
SDGE San Diego	263	17	6%	179	39	18%
AB	473	11	2%	746	36	5%
SCE Ventura	28	5	15%	289	30	9%
Total	**116,133**	**23,686**	**17%**	**116,318**	**23,501**	**17%**

3.9 Transmission Plan Deliverability with Recommended Transmission Upgrades

As part of the coordination with other CAISO processes and as set out in Appendix DD (GIDAP) of the CAISO tariff, the CAISO calculates the available transmission plan deliverability (TPD) in each year's transmission planning process in areas where the amount of generation in the interconnection queue exceeds the available deliverability, as identified in the generator interconnection cluster studies. In areas where the amount of generation in the interconnection queue is less than the available deliverability, the transmission plan deliverability is sufficient. In this year's transmission planning process, the CAISO considered queue clusters up to and including queue cluster 13. An estimate of the generation deliverability supported by the existing system and approved upgrades is listed in Table 3.9-1 and Table 3.9-2[118]. The transmission plan deliverability is estimated based on the area deliverability constraints identified in recent generation interconnection studies without considering local deliverability constraints. Table 3.55 provides the deliverable study amount beyond the existing and contracted resources. The deliverable generation interconnection service capacity depends on the mix of the resource technology. The relationship between the generation interconnection service capacity and the study amount is discussed in Section 3.5.2. The deliverable interconnection service capacity in Table 3.55 is based on the resource mix in the current generation interconnection queue. For study areas not listed, the transmission plan deliverability is greater than the MW amount of generation in the CAISO interconnection queue up to and including queue cluster 13.

Table 3.9-1: Deliverability for area deliverability constraints in Southern CA area

Area Deliverability Constraint	Renewable Zones	Deliverable Study Amount (MW)	Deliverable Interconnection Service Capacity (MW)
GLW-VEA Area Constraint	Southern_Nevada	500	790
Eldorado transformer constraint	Southern_Nevada Eldorado/Mountain Pass (230kV)	3,360	3700
Colorado River transformer constraint	Riverside_Palm_Springs	1,490	1,620
Devers – Red Bluff constraint	Riverside_Palm_Springs	5,400	7,808
	Arizona		
Serrano – Alberhill – Valley constraint	Riverside_Palm_Springs	7,110	10,342
	Arizona		
	Imperial		
Lugo transformer constraint	Inyokern_North_Kramer	950	1,250
Kramer-Victor/Roadway - Victor South of Kramer flow limit	Inyokern_North_Kramer	200	325
Victor-Lugo South of Kramer flow limit	Inyokern_North_Kramer	530	980
Windhub transformer constraint	Tehachapi	3,080	3,970
Antelope – Vincent flow limit	Tehachapi	4,040	4,950
	Non-CREZ – Big Creek		
Laguna Bell – Mesa flow limit	Non-CREZ – Ventura	1,208	1208

118 The transmission plan deliverability is estimated relative to the latest official renewable portfolio provided for transmission planning process policy driven transmission need analysis. This portfolio was provided in 2019, so some amount of deliverability may have been utilized by renewable generation that has become operational.

Area Deliverability Constraint	Renewable Zones	Deliverable Study Amount (MW)	Deliverable Interconnection Service Capacity (MW)
South of Magunden flow limit	Non-CREZ – Big Creek	670	710
East of Miguel constraint	Arizona	1,335	1,969
	Imperial		
	Baja		
	Riverside		
Encina-San Luis Rey constraint	Arizona	2,901	3,479
	Imperial		
	Baja		
	Non-CREZ		
Imperial Valley transformer constraint	Imperial	1,959	2,106
San Luis Rey-San Onofre constraint	Arizona	1,748	1,886
	Imperial		
	Baja		
	Non-CREZ		
SDGE – Internal Area constraint	Imperial	968	968
	Non-CREZ		
Silvergate-Bay Boulevard constraint	Imperial	1,202	1,438
	Baja		
	Non-CREZ		
Oceanside constraint	Non-CREZ	280	280

Table 3.9-2: Deliverability for area deliverability constraints in PG&E area

Area Deliverability Constraint	Renewable Zones	Deliverable Study Amount (MW)	Deliverable Interconnection Service Capacity (MW)
Gates Bank 500/230kV #13	Carrizo	3,151MW	4,220W
Wilson-Storey-Borden #1 & #2 Lines 230kV lines	Westlands	113MW	200MW
Tesla-Westley 230kV line	Westlands and Carrizo	1,098.37MW	1,381.1MW
GWF Hanford Sw Sta-Contadina-Jackson Sw Sta 115kV lines	Westlands	145.8MW	152.9MW
New Diablo-Midway #4 500 kV Line	Westlands and Carrizo	13,887.9MW	19,258MW
Gates-Panoche #1 and #2 230kV lines	Westlands	8,850.5MW	11,011MW
Vierra-Tracy-Kasson 230kV line	Northern California	149.21MW	150.76MW
Melones-Tulloch 230kV line	Non-CREZ	126.3MW	128.7MW
Rio Oso-SPI-Lincoln 230V line	Non-CREZ	41.96MW	45.8MW
Q653F-Davis 230kV lines	Northern California	63.5MW	64.2MW
Los Banos 500/230kV TB	Westlands	2,356MW	3,103MW
Gates-Midway 500kV Line	Westlands and Carrizo	4,687 MW	5,413 MW
Contra Costa-Delta Switchyard 230kV line	Non-CREZ	2,996 MW	3,334 MW
Morro Bay-Templeton 230kV Line	Carrizo	6,778 MW	7,825 MW
Delevan-Cortina 230kV line	Northern California	4,564 MW	5,104 MW

3.10 Summary of findings

3.10.1 Summary of on-peak deliverability assessment results

The on-peak deliverability assessment identified several constraints in the base and sensitivity portfolios. Remedial Action Schemes (RAS), reduction of energy storage behind the constraints and transmission upgrades were considered to mitigate the constraints.

Base Portfolio

- All FCDS resources are expected to be deliverable with Remedial Action Schemes (RAS), as needed. As a result, no policy-driven transmission upgrades are identified.

Sensitivity Portfolios

- FCDS resources in several renewable transmission zones are not deliverable without a reduction in the amount of portfolio battery storage or transmission upgrades. Table 3.11-1 provides a description of the constraints, the sensitivity portfolio resources affected and the amount of energy storage reduction that is needed to avoid each constraint.

Table 3.10-1: Summary of on-peak deliverability constraints identified in sensitivity portfolios that require reduction in mapped battery storage or transmission upgrades

Renewable Transmission Zone	Constraint	Portfolio Resources Behind Constraint (MW)		Portfolio for which Mitigation is needed		Amount of generic battery storage that need to be curtailed to make portfolio On-Peak deliverable (MW) (Sens-1/Sens-2)
		Renewables (Base/Sens-1/Sens-2)	Battery Storage (Base/Sens-1/Sens-2)	Sens-01	Sens-02	
Inyokern_North_Kramer	Kramer to Victor	100/97/97	0/918/1105	✓	✓	438 / 625
Inyokern_North_Kramer	Victor to Lugo	363/397/397	0/1026/1237	✓	✓	197 / 408
Inyokern_North_Kramer	Lugo 500/230 kV Bank	554/397/397	0/1126/1341	-	✓	0 / 141
Riverside_Palm_Springs	Colorado River 500/230 kV Bank	65/0/0	0/2091/1322	✓	-	507/0
None (San Diego Area)	Otay Constraint	0	0/148/280	-	✓	0/10
Westlands, Central Valley, Los Banos, Northern California and Solano	Gates-Midway 500kV Line	0/3726/4043	0/2793/5592	✓	✓	203/2117
Solano and Northern California	Cayetano – North Dublin 230 kV	0/121/104	0/316/810	✓	✓	316/535
Solano and Northern California	Las Positas – Newark 230 kV	0/121/104	0/316/810	✓	✓	316/432

- Only about 50 MW out of 60 MW FCDS wind mapped to Cholame 70 kV bus in Greater Carrizo in the sensitivity portfolios is deliverable without transmission upgrades. Reducing the amount battery storage is not an option as none is mapped behind the constraint in either portfolio.

- FCDS resources including energy storage in other renewable transmission zones are expected to be deliverable with RAS where needed.

3.10.2 Summary of Off-peak deliverability assessment results

The off-peak deliverability assessment identified several constraints in the base and sensitivity portfolios. Remedial Action Schemes (RAS), dispatching available battery storage behind the constraints, adding energy storage behind the constraints and transmission upgrades were considered to mitigate the constraints.

Base Portfolio

- Three minor off-peak deliverability constraints were identified in the Westlands zone. Two of the constraints can be mitigated using RAS. Adding a 10 MW storage will mitigate the third constraint; namely, the Kettleman–Gates 70 kV constraint.

Sensitivity Portfolios

In addition to the constraints identified with the Base Portfolio, the following are the constraints identified in the sensitivity portfolios.

- In both Sensitivity-1 and Sensitivity-2, the Whirlwind 500/230 kV transformer was found to constrain renewable resources in the Tehachapi zone. Dispatching 120 MW of portfolio battery storage in Sensitivity 1 and 240 MW in Sensitivity 2 addressed the constraint.
- In sensitivity-2, off-peak deliverability constraints in the GLW/VEA area were found to cause 830 MW in renewable curtailments in Southern NV (CAISO) Zone. RAS is not considered a mitigation given the constraints occur under system normal conditions with all elements in service. Adding battery storage is also not considered a potential mitigation due to on-peak deliverability constraints. This leaves transmission upgrades or reducing the amount of renewables in the area as the only options. The preferred transmission development has a cost of $90 million and consists of a new Innovation–Desert View 230kV No.2 line, a new Desert View–Northwest 230kV No.2 line, converting the existing Gamebird–Amargosa 138 kV line to a 230 kV and terminating at Arden 230 kV substation and RAS.
- In Sensitivity-2, Midway–Renfro–Tupman 115 kV constraint in the Greater Carrizo zone causes 378 MW of renewable curtailment. This is considered a mapping issue as a 615 MW solar resource is mapped to a radial 115 kV line with a normal rating of 224 MVA. Re-conductoring Tupman Jct 1-Tupman and Tupman Jct 2-Tupman 115kV line sections (~$22M) and RAS will be needed to mitigate the off-peak deliverability constraint. Adding battery storage is not considered a potential mitigation due to on-peak deliverability constraints.
- Renewable resources in other renewable transmission zones are expected to be off-peak deliverable with RAS where needed.

3.10.3 Summary of production simulation results

The production cost simulation results for all three portfolios indicate that the assumption of renewable resource capacity and location continue to be the main driver of the changes in transmission congestion and renewable curtailment among the three portfolio PCM cases.

- The aforementioned observations regarding curtailment ratios point to zones in which resource build beyond a certain amount starts to increase the risk of significant renewable curtailment.
- Incremental battery storage in the sensitivity portfolio cases helped to mitigate transmission congestion and renewable curtailment in areas and across the system as well. Battery remapping based on the on-peak deliverability assessment and the production cost simulation results was conducted on the Sensitivity 2 portfolio PCM case. The results indicate that transmission congestion and renewable curtailment can be further reduced by allocating battery storage to locations with high curtailment. Some areas such as the GridLiance and VEA area, however, may not be able to accommodate additional battery storage due on-peak deliverability constraints. Transmission solution may be needed to mitigate congestion and curtailment in such areas.

3.11 Conclusion

The policy-driven assessment did not demonstrate a need for new policy-driven transmission upgrades. Therefore, the CAISO is not recommending approval of policy-driven transmission upgrades as part of the 2020-2021 transmission planning process. The CAISO reiterates that transmission projects previously approved would be needed to support the base portfolio officially transmitted by the CPUC as part of the 2020-2021 transmission planning process.

Chapter 4

4 Economic Planning Study

4.1 Introduction

The CAISO's economic planning study is an integral part of the CAISO's transmission planning process and is performed on an annual basis as part of the transmission plan. The economic planning study complements the reliability-driven and policy-driven analysis documented in this transmission plan, exploring economic-driven transmission solutions that may create opportunities to reduce ratepayer costs within the CAISO.

Each cycle's study is performed after the completion of the reliability-driven and policy-driven transmission studies performed as part of this transmission plan. The studies used a production cost simulation as the primary tool to identify potential study areas, prioritize study efforts, and to assess benefits by identifying grid congestion and assessing economic benefits created by congestion mitigation measures. This type of economic benefit is normally categorized as an energy benefit or production benefit. The production simulation is a computationally intensive application based on security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) algorithms. The production cost simulation is conducted for all hours for each study year.

Economic study requirements are being driven from a growing number of sources and needs, including:

- The CAISO's traditional economic evaluation process and vetting of economic study requests focusing on production cost modeling,
- An increasing number of reliability request window submissions citing potential broader economic benefits as the reason to "upscale" reliability solutions initially identified in reliability analysis or to meet local capacity deficiencies,
- An "economic driven" transmission solution may be upsizing a previously identified reliability solution, or replacing that solution with a different project,
- Opportunities to reduce the cost of local capacity requirements (LCR) – considering capacity costs in particular, and,
- Considering interregional transmission projects as potential alternatives to regional solutions to regional needs.

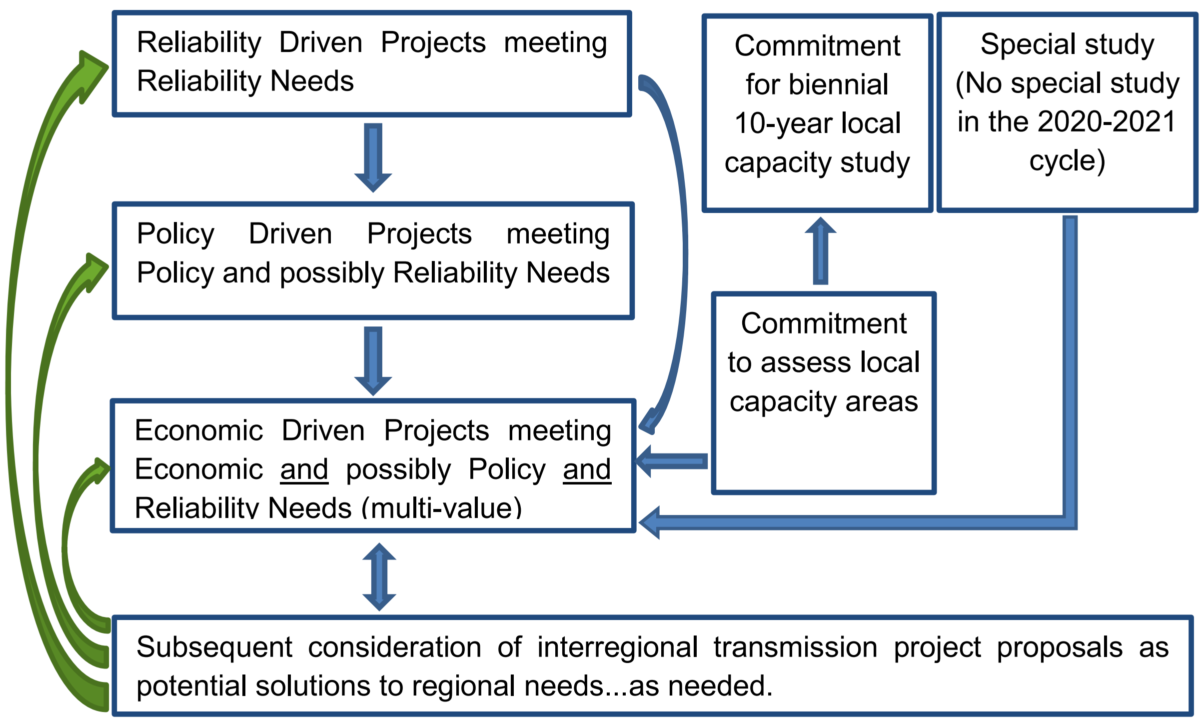
These more diverse drivers require a broader view of economic study methodologies and coordination between study efforts than in the past. As well, the economic assessment of the reduction or elimination of gas-fired generation in local capacity areas was conducted using the assumptions, criteria and models consistent with the 2019-2020 planning cycle. The local capacity requirements technical study criteria in the CAISO tariff, approved by FERC on January 17, 2020, were applied to the LCR reduction assessment in this planning cycle.

All transmission solutions identified in this transmission plan as needed for grid reliability and renewable integration were modeled in the production cost simulation database. This ensured that all economic planning studies would be based on a transmission configuration consistent with the reliability and public policy results documented in this transmission plan. The CAISO then performed the economic planning study to identify additional cost-effective transmission solutions to mitigate grid congestion and increase production efficiency within the CAISO. Selection of preferred solutions at “reliability” and “policy” stages are initially based on more conventional cost comparisons to meet reliability needs, *e.g*. capital and operating costs, transmission line loss savings, etc. As consideration of more comprehensive benefits, *e.g*. broader application of the TEAM, are conducted at the economic study stage, this can lead to replacing or upscaling a solution initially identified at the reliability or policy stage. The potential economic benefits are quantified as reductions of ratepayer costs based on the CAISO Transmission Economic Analysis Methodology (TEAM).[119]

The above issues resulted in stronger interrelationships between studies conducted under different aspects of the transmission planning process. As a result, there are strong linkages and cross-references between different chapters, with the economic study process becoming somewhat of a central or core feature to the overall analysis. These interrelationships are captured to some extent in Figure 4.1-1.

[119] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Figure 4.1-1: Interrelationship of Transmission Planning Studies



The production cost modeling simulations discussed thus far focus primarily on the benefits of alleviating transmission congestion to reduce energy costs. Other benefits are also taken into account where warranted, both to augment congestion-driven analysis and to assess other economic opportunities that are not necessarily congestion-driven. Local capacity benefits, *e.g.* reducing the requirement for local – and often gas-fired – generation capacity due to limited transmission capacity into an area can also be assessed and generally rely on power flow analysis. This is discussed in section 4.2 below.

The more localized benefits discussed above were largely conceptualized around conventional transmission upgrades, with preferred resource procurement explored as an option where viable. With higher levels of renewable resource development and with the decline in the size of the gas-fired generation fleet, increased value is emerging for preferred resources, including storage, on a system basis regardless of local capacity and transmission congestion needs.

4.2 Technical Study Approach and Process

Different components of CAISO ratepayer benefits are assessed and quantified under the economic planning study. First, production benefits are quantified by the production cost simulation that computes unit commitment, generator dispatch, locational marginal prices and transmission line flows over 8,760 hours in a study year. With the objective to minimize production costs, the computation balances supply and demand by dispatching economic generation while accommodating transmission constraints. The study identifies transmission congestion over the entire study period. In comparison of the “pre-project” and “post-project” study results, production benefits can be calculated from savings of production costs or ratepayer payments.

The production benefit relied upon by the CAISO includes three components of CAISO ratepayer benefits: consumer energy cost decreases; increased load serving entity owned generation revenues; and increased transmission congestion revenues. Second, other benefits including capacity benefits are also assessed. Capacity benefits may include system and flexible resource adequacy (RA) savings and local capacity savings. The system RA benefit corresponds to a situation where a transmission solution for importing energy leads to a reduction of CAISO system resource requirements, provided that out-of-state resources are less expensive to procure than in-state resources. The local capacity benefit corresponds to a situation where a transmission solution leads to a reduction of local capacity requirement in a load area or accessing an otherwise inaccessible resource.

The production cost simulation plays a major role in quantifying the production cost reductions that are often associated with congestion relief. Traditional power flow analysis is also used in quantifying other economic benefits such as system and local capacity savings.

Such an approach is consistent with the requirements of tariff section 24.4.6.7 and TEAM principles. The calculation of these benefits is discussed in more detail below.

In the production benefit assessments, the CAISO calculates CAISO ratepayer's benefits[120] as follows:

- *ISO ratepayer's production benefit = (ISO Net Payment of the pre-upgrade case) – (the ISO Net Payment of the post-upgrade case)*
- *ISO Net Payment = ISO load payment - ISO generator net revenue benefiting ratepayer - ISO transmission revenue benefiting ratepayer*

The above calculation reflects the benefits to CAISO ratepayers – offsetting other CAISO ratepayer costs – of transmission revenues or generation profits from certain assets whose benefits accrue to CAISO ratepayers. These include:

- PTO owned transmission;
- Generators owned by the utilities serving CAISO's load;
- Wind and solar generation or other resources under contract with an CAISO load serving entity to meet the state renewable energy goal; and,
- Other generators under contracts of which the information is available for public may be reviewed for consideration of the type and the length of contract.

How CAISO ratepayer benefits relate to (and differ from) CAISO production cost benefits are shown in Figure 4.2-1.

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[120] WECC-wide societal benefits are also calculated to assess the overall reasonableness of the results and to assess the impact of the project being studied on the rest of the WECC-wide system, but not as the basis for determining whether the proejct is in the interests of the ISO ratepayer to proceed with. The WECC-wide societal benefits are assessed according to the following formula: *WECC society production benefit = (WECC Production Cost of the pre-upgrade case) – (the WECC Production Cost of the post-upgrade case)*

Figure 4.2-1: Ratepayer Benefits vs. Production Cost Savings

ISO Net Ratepayer Benefits from Production Cost Simulations are the sum of:	Types of Revenues and Costs calculated in Production Cost Studies	ISO "Production Cost" Savings are the sum of:
	Load Payments at Market Prices for Energy	
Yes	Reductions in CAISO Ratepayer Gross Load Payments	
	Generation Revenues and Costs	
Yes	Increases in generator profits inside CAISO for generators owned by or under contract with utilities or load serving entities, being the sum of:	
	Increases in these generators' revenues	
	Decreases in these generators' costs	Yes
	Increases in merchant (benefits do not accrue to ratepayers) generator profits inside CAISO, being the sum of:	
	Increases in these generators' revenues	
	Decreases in these generators' costs	Yes
Yes	Increases in profits of dynamic scheduled resources under contract with or owned by utilities or load serving entities, being the sum of:	
	Increases in these dynamic scheduled resource revenues	
	Decreases in these dynamic scheduled resource costs	
	Transmission-related Revenues	
Yes	Increases in transmission revenues that accrue to CAISO ratepayers	
	Increases in transmission revenue for merchant (e.g. non-utility owned but under CAISO operational control) transmission	

In addition to the production and capacity benefits, any other benefits under TEAM— where applicable and quantifiable — can also be included. All categories of benefits identified in the TEAM document[121] and how they are addressed in the economic study process are summarized and set out in detail in Table 4.2-2.

[121] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Table 4.2-1: Summary of TEAM Benefit Categories

Categorization of Benefits	Individual sections in TEAM describing each potential benefit.	How are benefits assessed in TPP?
Production benefits: Benefits resulting from changes in the net ratepayer payment based on production cost simulation as a consequence of the proposed transmission upgrade.	In addition to production cost benefits themselves, focusing on CAISO net ratepayer benefits;	Benefits focused on CAISO net ratepayer benefits through production cost modeling.
	2.5.2 Transmission loss saving benefit (AND IN CAPACITY BENEFITS FOR CAPACITY) Transmission upgrade may reduce transmission losses. The reduction of transmission losses will save energy hence increase the production benefit for the upgrade, which is incorporated into the production cost simulation with full network model. In the meantime, the reduction of transmission losses may also introduce capacity benefit in a system that potentially has capacity deficit.	Energy-related savings are reflected in production cost modeling results.
Capacity benefits: Benefits resulting from increased importing capability into the CAISO BAA or into an LCR area. Decreased transmission losses and increased generator deliverability contribute to capacity benefits as well.	2.5.1 Resource adequacy benefit from incremental importing capability A transmission upgrade can provide RA benefit when the following four conditions are satisfied simultaneously: • The upgrade increases the import capability into the CAISO's controlled grid in the study years. • There is capacity shortfall from RA perspective in CAISO BAA in the study years and beyond. • The existing import capability has been fully utilized to meet RA requirement in the CAISO BAA in the study years. • The capacity cost in the CAISO BAA is greater than in other BAAs to which the new transmission connects.	These benefits are considered where applicable; note that local capacity reduction benefits are discussed below. .
	2.5.2 Transmission loss saving benefit (AND IN PRODUCTION BENEFITS FOR ENERGY) Transmission upgrade may reduce transmission losses. The reduction of transmission losses will save energy hence increase the production benefit for the upgrade, which is incorporated into the production cost simulation with full network model. In the meantime, the reduction of transmission losses may also introduce capacity benefit in a system that potentially has capacity deficit.	These benefits are considered, where applicable.
	2.5.3 Deliverability benefit Transmission upgrade can potentially increase generator deliverability to the region	This is primarily considered if the renewables portfolios identify the need for additional deliverability (as deliverability is

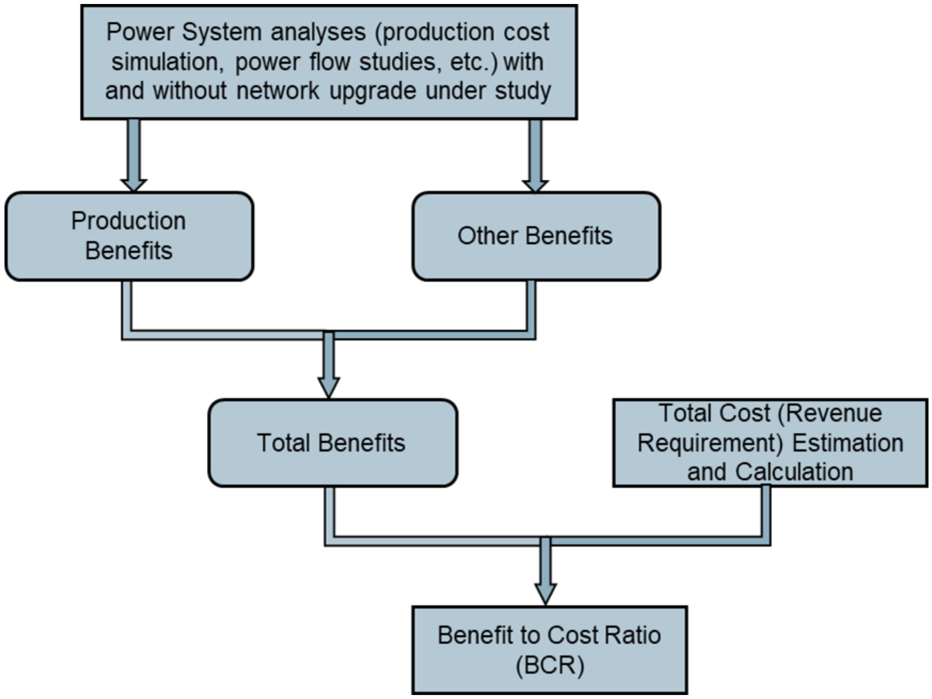
	under study through the directly increased transmission capacity or the transmission loss saving. Similarly to the resource adequacy benefit as described in section 3.5.1, such deliverability benefit can only be materialized when there will be capacity deficit in the region under study. Full assessment for assessing the deliverability benefit will be on case by case basis.	used in TEAM and in CAISO planning and generator interconnection studies) in which case the benefits may be policy benefits that have already been addressed in the development of portfolios, and further project development for this purpose for reducing local needs at this time is considered separately below.
	2.5.4 LCR benefit Some projects would provide local reliability benefits that otherwise would have to be purchased through LCR contracts. The Load Serving Entities (LSE) in the CAISO controlled grid pay an annual fixed payment to the unit owner in exchange for the option to call upon the unit (if it is available) to meet local reliability needs. LCR units are used for both local reliability and local market power mitigation. LCR benefit is assessed outside the production cost simulation. This assessment requires LCR studies for scenarios with and without the transmission upgrades in order to compare the LCR costs. It needs to consider the difference between the worst constraint without the upgrade and the next worst constraint with the upgrade. The benefit of the proposed transmission upgrade is the difference between the LCR requirement with and without the upgrade.	LCR benefits are assessed, and valued according to prudent assumptions at this time given the state of the IRP resource planning at the time – and supported by the CPUC.
Public-policy benefit: Transmission projects can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower cost renewable resources located in remote area, or by avoiding over-build.	2.5.5 Public-policy benefit If a transmission project increases the importing capability into the CAISO controlled grid, it potentially can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower cost renewable resources located in remote areas. When there is a lot of curtailment of renewable generation, extra renewable generators would be built or procured to meet the goal of renewable portfolio standards (RPS). The cost of meeting the RPS goal will increase because of that. By reducing the curtailment of renewable generation, the cost of meeting the RPS goal will be reduced. This part of cost saving from avoiding over-build can be categorized as public-policy benefit.	With the current coordination of resource portfolios with the CPUC and CEC in place, these issues are addressed in the course of the portfolio development process.
Renewable integration benefit: Interregional transmission upgrades help mitigate integration challenges, such as over-supply and curtailment, by allowing sharing energy and ancillary services (A/S) among multiple BAAs.	2.5.6 Renewable integration benefit As the renewable penetration increases, it becomes challenging to integrate renewable generation. Interregional coordination would help mitigating integration problems, such as over-supply and curtailment, by allowing	This can be considered as applicable, particularly for interregional transmission projects. Re-dispatch benefits would be included in the production cost savings in any event.

	sharing energy and ancillary services (A/S) among multiple BAAs. A transmission upgrade that increases the importing and exporting capability of BAAs will facilitate sharing energy among BAAs, so that the potential over-supply and renewable curtailment problems within a single BAA can be relieved by exporting energy to other BAAs, whichever can or need to import energy. A transmission upgrade that creates a new tie or increases the capacity of the existing tie between two areas will also facilitate sharing A/S Sharing between the areas, if the market design allow sharing A/S. The total A/S requirement for the combined areas may reduce when it is allowed to share A/S. The lower the A/S requirement may help relieving over-supply issue and curtailment of renewable resources. It is worth noting that allowing exporting energy, sharing A/S, and reduced amount of A/S requirement will change the unit commitment and economic dispatch. The net payment of the CAISO's ratepayers and the benefit because of a transmission upgrade will be changed thereafter. However, such type of benefit can be captured by the production cost simulation and will not be considered as a part of renewable integration benefit.	
Avoided cost of other projects: If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contribute to the benefit of the economic project.	2.5.7 Avoided cost of other projects If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contribute to the benefit of the economic project. Full assessment of the benefit from avoided cost is on a case-by-case basis.	This can be considered on a case by case basis, where applicable.

Once the total economic benefit is calculated, the benefit is weighed against the cost, which is the total revenue requirement, as described in the TEAM document, of the project under study. To justify a proposed transmission solution, the CAISO ratepayer benefit must be considered relative to the cost of the network upgrade. If the justification is successful, the proposed transmission solution may qualify as an economic-driven transmission solution. Note that other benefits and risks are taken into account – which cannot always be quantified – in the ultimate decision to proceed with an economic-driven transmission solution.

The technical approach of economic planning study is depicted in Figure 4.2-2. The economic planning study starts from an engineering analysis with power system simulations (using production cost simulation and snapshot power flow analysis). Based on results of the engineering analysis, the study enters the economic evaluation phase with a cost-benefit analysis, which is a financial calculation that is generally conducted in spreadsheets.

Figure 4.2-2: Technical approach of economic planning study



4.3 Financial Parameters Used in Cost-Benefit Analysis

A cost-benefit analysis is made for each economic planning study performed where the total costs are weighed against the total benefits of the potential transmission solutions. In these studies, all costs and benefits are expressed in 2020 U.S. dollars and discounted to the assumed operation year of the studied solution to calculate the net present values.

4.3.1 Cost analysis

In these studies, the "total cost" is considered to be the present value of the annualized revenue requirement in the proposed operation year. The total revenue requirement includes impacts of capital cost, tax expenses, O&M expenses and other relevant costs.

In calculating the total cost of a potential economic-driven transmission solution, when necessary, the financial parameters listed in Table 4.3-1 are used. The net present value of the costs (and benefits) are calculated using a social discount rate of 7 percent (real) with sensitivities at 5 percent as needed.

Table 4.3-1: Parameters for Revenue Requirement Calculation

Parameter	Value in TAC model
Debt Amount	50%
Equity Amount	50%
Debt Cost	6.0%
Equity Cost	11.0%
Federal Income Tax Rate	21.00%
State Income Tax Rate	8.84%
O&M	2.0%
O&M Escalation	2.0%
Depreciation Tax Treatment	15 year MACRS
Depreciation Rate	2% and 2.5%

In the initial planning stage, detailed cash flow information is typically not provided with the proposed network upgrade to be studied. Instead, lump sum capital cost estimates are provided. The CAISO then uses typical financial information to convert them into annual revenue requirements, and from there to calculate the present value of the annual revenue requirements stream. As an approximation, the present value of the utility's revenue requirement is calculated as the capital cost multiplied by a "CC-to-RR multiplier". For screening purposes, the multiplier used in this study is 1.3, reflective of a 7% real discount rate. This is an update to the 1.45 ratio set out in the CAISO's TEAM documentation[122] that was based on prior experiences of the utilities in the CAISO. The update reflects changes in federal income tax rates and more current rate of return inputs. It should be noted that this screening approximation is generally replaced on a case by case basis with more detailed modeling as needed if the screening results indicate the upgrades may be found to be needed.

As the "capital cost to revenue requirement" multiplier was developed on the basis of the long lives associated with transmission line, the multiplier is not appropriate for shorter lifespans expected for current battery technologies. Accordingly, levelized annual revenue requirement values can be developed for battery storage capital costs and those levelized annual revenue requirements can be then compared to the annual benefits identified for those projects. This has the effect of the same comparative outcome, but adapts to both the shorter lifespans of battery storage and the varying lifespans of different major equipment within a battery storage facility that impact the levelized cost of the facility. This approach has been applied to the battery storage projects that received detailed analysis set out section 4.10.

[122] The ISO expects to update the TEAM documentation dated November 2, 2017 to reflect this change.

4.3.2 Benefit analysis

In the CAISO's benefit analysis, total benefit refers to the present value of the accumulated yearly benefits over the economic life of the transmission solution. The yearly benefits are discounted to the present value in the proposed operation year before the dollar value is accumulated towards the total economic benefit. Because of the discount, the present worth of yearly benefits diminishes very quickly in future years.[123]

When detailed analysis of a high priority study area is required, production cost simulation and subsequent benefits calculations are conducted for the 10th planning year - in this case, for 2030. For years beyond 2030 the benefits are estimated by extending the 2030 year benefit with an assumed escalation rate.

The following financial parameters for calculating yearly benefits for use in determining the total benefit in this year's transmission planning cycle are:

- Economic life of new transmission facilities = 50 years;
- Economic life of upgraded transmission facilities = 40 years;
- Benefits escalation rate beyond year 2030 = 0 percent (real); and.
- Benefits discount rate = 7 percent (real) with sensitivities at 5 percent as needed.

4.3.3 Cost-benefit analysis

Once the total cost and benefit of a transmission solution is determined a cost-benefit comparison is made. For a solution to qualify as an economic transmission solution under the tariff, the benefit has to be greater than the cost or the net benefit (calculated as gross benefit minus cost) has to be positive. If there are multiple alternatives, the alternative that has the largest net benefit is considered the most economical solution. As discussed above, the traditional CAISO approach is to compare the present value of annualized revenue requirements and benefits over the life of a project using standardized capital cost-to-revenue requirement ratios based on lifespans of conventional transmission. Given the relatively shorter lifespans anticipated for battery storage projects, battery storage projects can be assessed by comparing levelized annual revenue requirements to annual benefits. As indicated above, the CAISO must also assess any other risks, impacts, or issues.

4.3.4 Valuing Local Capacity Requirement Reductions

As noted in chapter 1 and earlier in this chapter, the CAISO recognizes that additional coordination on the long term resource requirements for gas-fired generation for system capacity and flexibility requirements will need to take place with the CPUC through future integrated resource planning processes. This is particularly important in considering how to

[123] Discount of yearly benefit into the present worth is calculated by bi = Bi / (1 + d)i, where bi and Bi are the present and future worth respectively; d is the discount rate; and i is the number of years into the future. For example, given a yearly economic benefit of $10 million, if the benefit is in the 30th year, its present worth is $1.3 million based a discount rate of 7 percent. Likewise, if the benefit is in the 40th or 50th years, its present worth is $0.7 million or $0.3 million, respectively. In essence, going into future years the yearly economic benefit worth becomes very small.

assess the value to ratepayers of proposals to reduce gas-fired generation local capacity requirements in areas where, based on current planning assumptions, the gas-fired generation is sufficient to meet the local capacity needs. If there are sufficient gas-fired generation resources to meet the local capacity needs over the planning horizon, there is not a need for reliability-driven reinforcement; rather, the question shifts to the economic value provided by the reduction in local capacity requirement for the gas-fired generation. However, it cannot be assumed that gas-fired generation no longer required for local capacity purposes will not continue to be needed for system or flexible capacity reasons, albeit through competition with other system resources. While future IRP efforts are expected to provide more guidance and direction regarding expectations for the gas-fired generation fleet at a policy level, without that broader system perspective available at this time, the CAISO has taken a conservative approach in assessing the value of a local capacity reduction benefit when considering a transmission reinforcement or other alternatives that could reduce the need for existing gas-fired generation providing local capacity. In this planning cycle, the CAISO therefore applied the differential between the local capacity price and system capacity price to assess the economic benefits of reducing the need for gas-fired generation when considering both transmission and other alternatives.

It was also recognized that the basis for the local price may depend on the circumstances within the local capacity area, with several scenarios set out in Table 4.3-2.

Table 4.3-2: Scenarios for Consideration of Local Capacity Price Differentials

Scenario	Methodology (for this cycle)
If the local capacity area has a surplus of resources in the area and there is a reasonable level of competition in selling local RA capacity	The price differential between system and local capacity.
If there is only one (newer) generator in the area, and essentially no competition (or if all the units are needed and the oldest is still relatively new)	The price differential between system capacity and the full cost of service of the least expensive resource(s) may be the appropriate metric.
If there is only one older unit in the area that is heavily depreciated (or all the units are needed and if the newest is still relatively old)	Consider price the differential between the CPM soft offer cap and system capacity.*

Note *: If there is generation in an area or sub-area under an existing reliability must-run (RMR) contract, a sensitivity may be performed considering the difference between the cost of the RMR contract and the cost of system capacity.

These options are considered when needed on a case-by-case basis below and in the subsequent detailed analysis set out in section 4.10.

Northern California

For considering the benefits of local capacity requirement reductions in northern California, the differential between capacity north of Path 26 and local capacity was considered. The price of Greater Bay area generation local capacity based on the CPUC's most recent 2018 Resource Adequacy Report[124], which was published in August 2019, included a weighted average

124 https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/2018 RA Report rev.pdf

$2.77/kW-month for Greater Bay and $3.11/kW-month for the other PG&E areas. This results in a $33,240/MW-Year and $37,320/MW-year price, respectively, for this capacity. Recognizing that local capacity in the Greater Bay area or the other PG&E local areas could also provide other benefits such as flexible and/or system capacity need, the net capacity values would be the difference between the local and system capacity price. The system weighted average is $2.76/kW-month, or $33,120/MW-year. Additionally, the CPUC also provided a system weighted average if the system resources are located in northern California (i.e., NP 26). The weighted average for system capacity value that is located in NP 26 is $2.87/kW-month, or $34,440/MW-year. The net capacity values for the Greater Bay and Other PG&E areas versus system or NP 26 resources are set out in Table 4.3-3 below.

Table 4.3-3: Net capacity values for the Greater Bay and Other PG&E areas versus system or NP 26 resources

	Net capacity values (local – system)	**Net capacity values (local – NP 26 system resources)**
Greater Bay Area	$120/MW-year	$1200/MW-year
Other PG&E Areas	$4,200/MW-year	$2,880/MW-year

Southern California

For considering the benefits of local capacity requirement reductions in southern California, the differential between capacity south of Path 26 and local capacity was considered. The price of San Diego area generation local capacity based on the CPUC's most recent 2018 Resource Adequacy Report, which was published in August 2019[125], included a weighted average $3.07/kW-month for San Diego, $3.66/kW-month for the LA Basin area and $3.19/kW-month for Big Creek-Ventura. This results in a $36,840/MW-Year, $43,920/MW-year and $38,280/MW-year price, respectively, for this capacity. Recognizing that local capacity in these areas could also provide other benefits such as flexible and/or system capacity need, the net capacity values would be the difference between the local and system capacity price. The system weighted average is $2.76/kW-month, or $33,120/MW-year. Additionally, the CPUC also provided a system weighted average if the system resources are located in southern California (i.e., SP 26). The weighted average for system capacity value that is located in SP 26 is $2.38/kW-month, or $28,560/MW-year. The net capacity values for the Big Creek–Ventura, LA Basin and San Diego areas versus system or SP 26 resources are set out in Table 4.3-4 below.

125 https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/2018%20RA%20Report.pdf

Table 4.3-4: Net capacity values for the Southern California areas versus system or SP 26 resources

	Net capacity values (local – system)	Net capacity values (local – SP 26 system resources)
LA Basin	$10,800/MW-year	$15,360/MW-year
Big Creek–Ventura	$5,160/MW-year	$9,720/MW-year
San Diego	$3,720/MW-year	$8,280/MW-year

4.4 Study Steps of Production Cost Simulation in Economic Planning

While the assessment of capacity benefits normally uses the results from other study processes, such as resource adequacy and local capacity assessment, production benefits are assessed through production cost simulation. The study steps and the timelines of production cost simulation in economic planning are later than the other transmission planning studies within the same planning cycle. This is because the production cost simulation needs to consider upgrades identified in the reliability and policy assessments, and the production cost model development needs coordination with the entire WECC and management of a large volume of data. In general, production cost simulation in economic planning has three components, which interact with each other: production cost simulation database (also called production cost model or PCM) development and validation, simulation and congestion analysis, and production benefit assessment for congestion mitigation.

PCM development and validation mainly include the following modeling components:

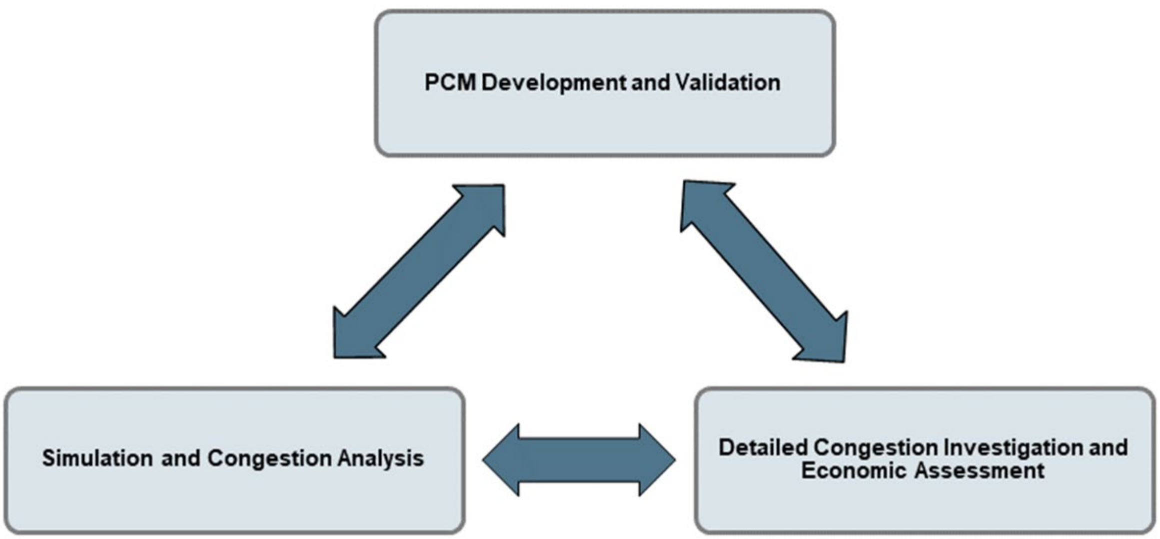
9. Network model (transmission topology, generator location, and load distribution)
10. Transmission constraint model, such as transmission contingencies, interfaces, and nomograms, etc.
11. Generator operation model, such as heat rate and ramp rate for thermal units, hydro profiles and energy limits, energy storage model, renewable profiles, and renewable curtailment and price model.
12. Load model, including load profiles, annual and monthly energy and peak demand, and load modifiers such as DG, DR, and EE.
13. Market and system operation model, and other models as needed, such as ancillary service requirements, wheeling rate, emission cost and assignment, fuel price and assignment, etc.

Congestion analysis is based on production cost simulation that is conducted for each hour of the study year. Congestion can be observed on transmission line or transformers, or on interfaces or nomograms, and can be under normal or contingency conditions. In congestion analysis, all aspects of results may need to be investigated, such as locational marginal price (LMP), unit commitment and dispatch, renewable curtailment, and the hourly power flow results under normal or contingency conditions. Through these investigations, congestion can be validated, or some data or modeling issues can be identified. In either situation, congestion analysis is used for database validation. The simulated power flow pattern is also compared with the historical data for validation purpose, although it is not necessary to have identical flow pattern between the simulation results and the historical data. There are normally many iterations between congestion analysis and PCM development.

In the detailed congestion investigation and economic assessment step, the CAISO quantifies economic benefits for each identified transmission solution alternative using the production cost simulation and other means. From the economic benefit information a cost-benefit analysis is conducted to determine if the identified transmission solution provide sufficient economic benefits to be found to be needed. Net benefits are compared with each other where the net benefits are calculated as the gross benefits minus the costs to compare multiple alternatives that would address identified congestion issues. The most economical solution is the alternative that has the largest net benefit. In this step, the PCM and the congestion results are further validated.

Normally there are a number of iterations among these three steps through the entire economic planning study process. Figure 4.4-1 shows these components and their interaction.

Figure 4.4-1: Steps of production cost simulation in Economic planning



4.5 Production cost simulation tools and database

The CAISO primarily used the software tools listed in Table 4.5-1 for this economic planning study.

Table 4.5-1: Economic Planning Study Tools

Program name	Version	Functionality
Hitachi ABB GridView™	10.3.1	The software program is a production cost simulation tool with DC power flow to simulate system operations in a continuous time period, e.g., 8,760 hours in a study year (8784 hours for leap year)

The CAISO normally develops a database for the 10-year case as the primary case for congestion analysis and benefit calculation. The CAISO may also develop an optional 5-year case for providing a data point in validating the benefit calculation of transmission upgrades by assessing a five year period of benefits before the 10-year case becomes relevant.

4.6 ISO GridView Production Cost Model Development

This section summarizes the major assumptions of system modeling used in the GridView PCM development for the economic planning study. The section also highlights the major CAISO enhancements and modifications to the Western Interconnection Anchor Data Set production cost simulation model (ADS PCM) database that were incorporated into the CAISO's database. It is noted that details of the modeling assumptions and the model itself are not itemized in this document, but the final PCM is posted on the CAISO's market participant portal once the study is finalized.

4.6.1 Starting database

The 2020-2021 TPP PCM development started from the ADS PCM 2030 version 1.0, which was released by WECC on June 30, 2020. The validated changes in the ADS PCM up to version 1.4.8 were incorporated into the CAISO planning PCM in 2020-2021 cycle. Using this database the CAISO developed the base cases for the CAISO TPP production cost simulation. These base cases included the modeling updates and additions, which followed the CAISO unified planning assumptions and are described in this section.

4.6.2 Network modeling

The ADS PCM uses a nodal model to represent the entire WECC transmission network. However, the network model in the ADS PCM is based on a power flow case that is different from the CAISO's reliability power flow cases developed in the current planning cycle. The CAISO took a more comprehensive approach and modified the network model for the CAISO's system to exactly match the reliability assessment power flow cases for the entire CAISO planning area. The transmission topology, transmission line and transformer ratings, generator location, and load distribution are identical between the PCM and reliability assessment power flow cases. In conjunction with modeling local transmission constraints and nomograms, unit commitment and dispatch can accurately respond to transmission limitations identified in reliability assessment. This enables the production cost simulation to capture potential congestion at any voltage level and in any local area.

4.6.3 Load

As a norm for economic planning studies, the production cost simulation models 1-in-2 weather conditions load in the system to represent typical or average load condition across the CAISO transmission network. The California load data was drawn from the California Energy Demand Forecast 2020-2030 adopted by California Energy Commission (CEC) on January 22, 2020[126],

[126] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report/2019-iepr

which is consistent with the demand forecast in the reliability assessment as described in Chapter 2.

Load modifiers, including DR, DG, and AAEE, were modeled as generators with hourly output profiles. The locations of the load modifiers were consistent with the reliability power flow cases.

4.6.4 Generation resources

Generator locations and installed capacities in the PCM are consistent with the 2020-2021 reliability assessment power flow case for 2030, including both conventional and renewable generators. Chapter 3 provides more details about the renewables portfolio.

4.6.5 Transmission constraints

As noted earlier, the production cost database reflects a nodal network representation of the western interconnection. Transmission limits were enforced on individual transmission lines, paths (*i.e.*, flowgates) and nomograms. However, the original ADS PCM database only enforced transmission limits under normal condition for transmission lines at 230 kV and above, and for transformers at 345 kV and above.

The CAISO made an important enhancement in expanding the modeling of transmission contingency constraints, which the original ADS PCM database did not model. In the updated database, the CAISO modeled contingencies on multiple voltage levels (including voltage levels lower than 230 kV) in the CAISO transmission grid to make sure that in the event of losing one transmission facility (and sometimes multiple transmission facilities), the remaining transmission facilities would stay within their emergency limits. The contingencies that were modeled in the CAISO's database mainly are the ones that identified as critical in the CAISO's reliability assessments, local capacity requirement (LCR) studies, and generation interconnection (GIP) studies. While all N-1 and N-2 (common mode) contingencies were modeled to be enforced in both unit commitment and economic dispatch stages in production cost simulation, N-1-1 contingencies that included multiple transmission facilities that were not in common mode, were normally modeled to be enforced in the unit commitment stage only. This modeling approach reflected the system reliability need identified in the other planning studies in production cost simulation, and also considered the fact that the N-1-1 contingencies normally had lower probability to happen than other contingencies and that system adjustment is allowed between the two N-1 contingencies. In addition, transmission limits for some transmission lines in the CAISO transmission grid at lower voltage than 230 kV are enforced.

Another critical enhancement to the production simulation model is that nomograms on major transmission paths that are operated by the CAISO were modeled. These nomograms were developed in CAISO's reliability assessments or identified in the operating procedures. In this planning cycle, the planning PCM continue to model critical credible contingencies in the COI corridor that were identified in the reliability assessment in lieu of COI nomograms, which is consistent with the planning PCM in the last planning cycle..

Scheduled maintenance of transmission lines was modeled based on historical data. Only the repeatable maintenances were considered. The corresponding derates on transmission capability were also modeled.

PDCI (Path 65) south to north rating was modeled at 1050 MW to be consistent with the operation limit of this path identified by LADWP, which is the operator of PDCI within California.

4.6.6 Fuel price and CO2 price

The forecasts of Natural Gas price, Coal prices, and CO2 prices were the same as in the ADS PCM 2030. All prices are in 2020 real dollar.

4.6.7 Renewable curtailment price model

The 2020-2021 planning PCM continued to use the multi-block renewable generator model that was first developed and used in the 2019~2019 planning cycle PCM. This model was applied to all CAISO wind and solar generators. Each generator was modeled as five equal and separate generators (blocks) with identical hourly profiles, and each block's Pmax was 20% of the Pmax of the actual generator. Each block had a different curtailment price around $-25/MWh, as shown in Table 4.6-1.

Table 4.6-1: Multi-blocks renewable model

Block	Price ($/MWh)
1	-23
2	-24
3	-25
4	-26
5	-27

4.6.8 Battery cost model and depth of discharge

The CAISO also refined its modeling of battery storage through the course of the 2019-2020 planning cycle, to reflect limitations associated with the depth of discharge of battery usage cycles (DoD or cycle depth) and replacement costs associated with the number of cycles and depth of discharge the battery is subjected to. In this refined battery model, the battery's operation cost was modeled as a flat average cost:

$$Average\ Cost = \frac{Per\ unit\ replacement\ cost}{Cycle\ life * DoD * 2}$$

The 2025 forecast obtained from the DOE (DOE/Hydro Wires report, July 2019[127]) was used as the baseline assumptions for battery parameters:

- DoD: 80%
- Cycle life: 3500 cycles
- Per unit replacement cost: $189,000/MWh

[127] https://www.sandia.gov/ess-ssl/wp-content/uploads/2019/07/PNNL_mjp_Storage-Cost-and-Performance-Characterization-Report_Final.pdf

With the above parameters, the average cost was $33.75/MWh. The same average cost was used in the PCM of the 2020-2021 planning cycle

4.7 Production Cost Simulation Results

Based on the economic planning study methodology presented in the previous sections, a congestion simulation of CAISO transmission network was performed to identify which facilities in the CAISO controlled grid were congested.

The results of the congestion assessment are listed in Table 4.7-1. Columns "Cost_F" and "Duration_F" were the cost and duration of congestion in the forward direction as indicated in the constraint name. Columns "Cost_B" and "Duration_B" were the cost and duration of congestion in the backward direction. The last two columns were the total cost and total duration, respectively.

Table 4.7-1: Potential congestion in the CAISO-controlled grid in 2030

No.	Area or Branch Group	Constraints Name	Costs_F ($K)	Duration_F (Hrs)	Costs_B ($K)	Duration_B (Hrs)	Costs T ($K)	Duration_T (Hrs)
1	SDGE DOUBLTTP-FRIARS 138 kV	DOUBLTTP-FRIARS 138 kV line, subject to SDGE N-2 SX-PQ + PQ-OT 230 kV with RAS	0	0	52,736	2,749	52,736	2,749
2	SCE Whirlwind Transformer	WIRLWIND 500/13.8 kV transformer #1	0	0	22,909	295	22,909	295
3	PDCI	P65 WECC Pacific DC Intertie (PDCI)	0	0	8,954	562	8,954	562
4	COI Corridor	P66 WECC COI	8,852	259	0	0	8,852	259
5	Path 45	P45 WECC SDG&E-CFE	669	130	7,130	1,323	7,798	1,453
6	PG&E Sierra	DRUM-BRNSWCKP 115 kV line #2	5,532	372	0	0	5,532	372
7	PG&E Fresno	LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	0	0	4,831	1,365	4,831	1,365
8	Path 26 Corridor	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	3,810	77	3,810	77
9	SCE LCIENEGA-LA FRESA 230 kV line	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	0	0	3,592	84	3,592	84
10	Path 60 Inyo-Control 115 kV	P60 WECC Inyo-Control 115 kV Tie	3,282	1,433	72	233	3,354	1,666
11	Path 26 Corridor	P26 WECC Northern-Southern California	0	0	2,870	154	2,870	154
12	Path 25 PACW-PG&E 115 kV	P25 WECC PacifiCorp/PG&E 115 kV Interconnection	0	0	2,815	486	2,815	486
13	SCE Antelope 66 kV system	NEENACH-TAP 85 66.0 kV line #1	2,421	888	0	0	2,421	888

No.	Area or Branch Group	Constraints Name	Costs_F ($K)	Duration_F (Hrs)	Costs_B ($K)	Duration_B (Hrs)	Costs T ($K)	Duration_T (Hrs)
14	Path 42 IID-SCE	P42 WECC IID-SCE	2,261	71	0	0	2,261	71
15	SCE RedBluff-Devers 500 kV	DEVERS-DVRS_RB_21 500 kV line #2	0	0	2,129	22	2,129	22
16	SCE NOL-Kramer-Inyokern-Control	VICTOR-LUGO 230 kV line #1	1,914	58	0	0	1,914	58
17	COI Corridor	TABLE MT-TM_TS_11 500 kV line #1	1,583	18	0	0	1,583	18
18	PG&E Fresno	Q526TP-PLSNTVLY 70 kV line, subject to PG&E N-2 Panoche-Schindler and Panoche-Excelsesiorss 115 kV	1,469	634	0	0	1,469	634
19	SCE RedBluff-Devers 500 kV	DVRS_RB_22-REDBLUFF 500 kV line #2	0	0	1,286	11	1,286	11
20	PG&E Fresno	KETLMN T-GATES 70.0 kV line #1	1,056	1,354	0	0	1,056	1,354
21	COI Corridor	TM_TS_12-TESLA 500 kV line #1	976	9	0	0	976	9
22	PG&E Fresno	FIVEPOINTSSS-CALFLAX 70 kV line, subject to PG&E N-2 Panoche-Schindler and Panoche-Excelsesiorss 115 kV	842	863	34	1	876	864
23	SCE NOL-Kramer-Inyokern-Control	VICTOR-LUGO 230 kV line #2	812	13	0	0	812	13
24	SDGE IV-San Diego Corridor	SUNCREST-SUNCREST TP2 230 kV line, subject to SDGE N-1 Sycamore-Suncrest 230 kV #1 with RAS	703	24	0	0	703	24
25	SCE LagunaBell-Mesa Cal	LAGUBELL-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV #2 and Mesa-Lighthipe 230 kV	0	0	642	21	642	21
26	SCE J.HINDS-MIRAGE 230 kV line	J.HINDS-MIRAGE 230 kV line #1	640	77	0	0	640	77
27	COI Corridor	TM_VD_11-TM_VD_12 500 kV line #1	587	7	0	0	587	7
28	COI Corridor	RM_TM_21-RM_DRS 500 kV line #2	545	20	0	0	545	20
29	PG&E Sierra	CHCGO PK-HIGGINS 115 kV line #1	510	35	0	0	510	35
30	SDGE-CFE OTAYMESA-TJI 230 kV line	OTAYMESA-TJI-230 230 kV line #1	0	0	453	107	453	107
31	COI Corridor	RM_TM_11-RM_DRS 500 kV line #1	420	16	0	0	420	16
32	Path 61/Lugo - Victorville	P61 WECC Lugo-Victorville 500 kV Line	0	0	381	41	381	41

No.	Area or Branch Group	Constraints Name	Costs_F ($K)	Duration_F (Hrs)	Costs_B ($K)	Duration_B (Hrs)	Costs T ($K)	Duration_T (Hrs)
33	San Diego	MELRSETP-SANMRCOS 69 kV line, subject to SDGE N-2 EN-SLR and EN-SLR-PEN 230 kV with RAS	0	0	352	155	352	155
34	SCE Antelope 66 kV system	ANTELOPE-NEENACH 66 kV line, subject to SCE N-1 Neenach-Bailey-WestPack 66kV N-1	0	0	346	120	346	120
35	PG&E Fresno	HELM 70.0/230 kV transformer #1	339	294	0	0	339	294
36	SCE NOL-Kramer-Inyokern-Control	VICTOR-LUGO 230 kV line #3	289	11	0	0	289	11
37	San Diego Silver Gate-Bay Boulervard	SILVERGT-BAY BLVD 230 kV line #1	0	0	276	20	276	20
38	PG&E Sierra	DRUM-DTCH FL1 115 kV line #1	258	32	0	0	258	32
39	SDGE IV-San Diego Corridor	SUNCREST-SUNCREST TP1 230 kV line, subject to SDGE N-1 Eco-Miguel 500 kV with RAS	212	17	0	0	212	17
40	SCE Lugo 500 kV Transformer	LUGO 500/13.8 kV transformer #2	0	0	176	5	176	5
41	SCE Devers 500/230 kV transformer	DEVERS 500/13.8 kV transformer #1	126	2	0	0	126	2
42	SCE NOL-Kramer-Inyokern-Control	VICTOR-LUGO 230 kV line #4	110	9	0	0	110	9
43	PG&E Mosslanding - Lasguilass 230 kV	MOSSLNSW-LASAGUILASS 230 kV line, subject to PG&E N-1 Mosslanding-LosBanos 500 kV	0	0	99	7	99	7
44	Path 15/CC	GT_MW_11-MIDWAY 500 kV line #1	0	0	84	4	84	4
45	SCE NOL-Kramer-Inyokern-Control	VICTOR 230/115 kV transformer #2	0	0	82	165	82	165
46	PG&E Fresno	ORO LOMA-EL NIDO 115 kV line #1	71	9	0	0	71	9
47	PG&E Cottle - Melones 230 kV	COTTLE-MELONES 230 kV line #1	0	0	64	9	64	9
48	Path 26 Corridor	MW_VINCNT_11-MW_VINCNT_12 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	55	6	0	0	55	6
49	PG&E Gates-CAIFLATSSS 230 kV	GATES D-CALFLATSSS 230 kV line #1	0	0	53	3	53	3
50	PG&E USWP JRW-Cayetano 230 kV	USWP-JRW-CAYETANO 230 kV line, subject to PG&E N-2 C.Costa-Moraga 230 kV	46	4	0	0	46	4
51	PG&E/Sierra MARBLE transformer	MARBLE 63.0/69.0 kV transformer #1	40	6	0	0	40	6

No.	Area or Branch Group	Constraints Name	Costs_F ($K)	Duration_F (Hrs)	Costs_B ($K)	Duration_B (Hrs)	Costs T ($K)	Duration_T (Hrs)
52	SDGE IV-San Diego Corridor	MIGUEL-MIGUEL 230 kV line, subject to SDGE T-1 Miguel 500-230 kV #1 with RAS	0	0	34	4	34	4
53	PG&E POE-RIO OSO	POE-RIO OSO 230 kV line #1	32	17	0	0	32	17
54	VEA Jackass Flats - Mercury 138 kV	JACKASSF-MERCRYSW 138 kV line #1	29	66	0	0	29	66
55	SCE Serrano-Villa PK 230 kV	SERRANO-VILLA PK 230 kV line, subject to SCE N-2 Serrano-Lewis #1 and Serrano-Villa PK #2 230 kV	28	1	0	0	28	1
56	SCE NOL-Kramer-Inyokern-Control	INYOKERN-KRAMER 115 kV line #1	18	10	0	0	18	10
57	Path 15/CC	GATES-GT_MW_11 500 kV line #1	0	0	13	2	13	2
58	SDGE N.Gila-Imperial Valley 500 kV	N.GILA-IMPRLVLY 500 kV line #1	12	1	0	0	12	1
59	SCE J.HINDS-MIRAGE 230 kV line	JHINDMWD-J.HINDS 230 kV line #r1	0	0	10	3	10	3
60	PG&E Solano	WND MSTR-DELTAPMP 230 kV line #1	10	2	0	0	10	2
61	PG&E North Valley	PEASE-HONC JT1 115 kV line #1	0	0	6	1	6	1
62	SDGE-CFE IV-ROA 230 kV line and IV PFC	IV PFC1 230/230 kV transformer #1	5	2	0	0	5	2
63	Path 15/CC	P15 WECC Midway-LosBanos	0	0	5	2	5	2
64	SCE Sylmar - Pardee 230 kV	PARDEE-SYLMAR S 230 kV line, subject to SCE N-1 Sylmar-Pardee 230kV	0	0	1	1	1	1
65	PG&E Delevn-Cortina 230 kV	DELEVAN-CORTINA 230 kV line, subject to PG&E-BANC N-1 Maxwell-Tracy 500kV	1	1	0	0	1	1

The branch group or local area information was provided in the first column in Table 4.7-1. The branch groups were identified by aggregating congestion costs and hours of congested facilities to an associated branch or branch group for normal or contingency conditions. The congestions subject to contingencies associated with local capacity requirements were aggregated by PTO service area based on where the congestion was located. The results were ranked based on the 2030 congestion cost. The potential congestion across specific branch groups and local capacity areas is summarized in Table 4.7-2.

Table 4.7-2: Aggregated potential congestion in the CAISO-controlled grid in 2030

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
1	SDGE DOUBLTTP-FRIARS 138 kV	52.74	2,749
2	SCE Whirlwind Transformer	22.91	295
3	COI Corridor	12.96	329
4	PDCI	8.95	562
5	PG&E Fresno	8.64	4,520
6	Path 45	7.80	1,453
7	Path 26 Corridor	6.74	237
8	PG&E Sierra	6.30	439
9	SCE LCIENEGA-LA FRESA 230 kV line	3.59	84
10	SCE RedBluff-Devers 500 kV	3.42	33
11	Path 60 Inyo-Control 115 kV	3.35	1,666
12	SCE NOL-Kramer-Inyokern-Control	3.23	266
13	Path 25 PACW-PG&E 115 kV	2.81	486
14	SCE Antelope 66 kV system	2.77	1,008
15	Path 42 IID-SCE	2.26	71
16	SDGE IV-San Diego Corridor	0.95	45
17	SCE J.HINDS-MIRAGE 230 kV line	0.65	80
18	SCE LagunaBell-Mesa Cal	0.64	21
19	SDGE-CFE OTAYMESA-TJI 230 kV line	0.45	107
20	Path 61/Lugo - Victorville	0.38	41
21	San Diego	0.35	155
22	San Diego Silver Gate-Bay Boulervard	0.28	20
23	SCE Lugo 500 kV Transformer	0.18	5
24	SCE Devers 500/230 kV transformer	0.13	2
25	Path 15/CC	0.10	8
26	PG&E Mosslanding -Lasguilass 230 kV	0.10	7
27	PG&E Cottle - Melones 230 kV	0.06	9
28	PG&E Gates-CAIFLATSSS 230 kV	0.05	3
29	PG&E USWP JRW-Cayetano 230 kV	0.05	4
30	PG&E/Sierra MARBLE transformer	0.04	6
31	PG&E POE-RIO OSO	0.03	17
32	VEA Jackass Flats - Mercury 138 kV	0.03	66
33	SCE Serrano-Villa PK 230 kV	0.03	1
34	SDGE N.Gila-Imperial Valley 500 kV	0.01	1
35	PG&E Solano	0.01	2
36	PG&E North Valley	0.01	1

No.	Aggregated congestion	Cost ($M)	Duration (Hr)
37	SDGE-CFE IV-ROA 230 kV line and IV PFC	0.01	2
38	SCE Sylmar - Pardee 230 kV	0.00	1
39	PG&E Delevn-Cortina 230 kV	0.00	1

In this planning cycle, investigations were conducted on the constraints that may have a large impact on the bulk system or the heavily congested areas, and showed recurring congestion. Specifically, these constraints selected for further analysis are shown in Table 4.7-3. The detailed analysis results are in section 4.10.

Table 4.7-3: Constraints selected for Detailed Investigation

Constraints	Cost (M$)	Duration (Hours)	Overview of congestion investigation
SDG&E DOUBLTTP-FRIARS 138 kV line	52.74	2,749	SDG&E Doublet Tap – Friars 138 kV line congestion has the largest congestion cost among congestions identified in this planning cycle. Both San Diego generators and IV/ECO generators may contribute to the congestion, including solar generators since congestion was observed during solar hours.
SCE Whirlwind 500/230 kV Transformers	22.91	295	About 4000 MW of renewable generators were modeled behind the Whirlwind 500/230 kV transformers constraint in the base portfolio PCM, including about 3000 MW existing or under construction generators, and the rest generators are under contract as shown in the CPUC's base portfolio.
COI Corridor	12.96	329	COI congestion slightly increased in this planning cycle compared with the congestion in the last planning cycle. The changes in transmission and renewable assumptions in the Northern Grid territory contributed to the COI congestion.
PG&E Fresno area constraints	8.64	4,520	Congestions were observed on multiple lines in the PG&E Fresno area, with relatively high congestion cost and duration. Some are recurring congestions.
Path 26 corridor south to north congestion	6.74	273	Path 26 congestion was mostly caused by the large amount of renewable generation in Southern CA identified in the CPUC portfolio

Congestions were selected not solely based on congestion cost or duration, but by taking other considerations into account. Comparing the congestion and curtailment results, it was observed that some congestions with large cost or duration were driven by local renewable generators identified in the CPUC default renewable portfolio. Congestions in these areas were subject to change with further clarity of the interconnection plans of the future resources. Therefore, the congestions in these areas or zones were not selected for detail analysis in this planning cycle, particularly, the SCE NOL area and the Red Bluff to Devers congestions, and the Path 42 congestion.

Other constraints were also analyzed, but not at the same detailed level for different reasons as discussed below.

Most of the observed Path 45 congestion was in the direction from CFE to CAISO, which is mainly due to the natural gas price difference across the border. Other factors that may impact the congestion include the renewable generation development in Imperial Valley area and its representation in the future 50% renewable portfolio, and the CFE's generation and load modeling. Further clarity of such factors will be required before detailed investigations need to be conducted. The CAISO will continue to monitor the congestion on Path 45 in future planning cycles.

Congestions were observed in the SCE's Western LA Basin area, including the La Cienega – La Fresa 230 kV line and the Laguna Bell – Mesa Cal 230 kV line. Potential mitigations were studied in the last planning cycle as part of the LCR reduction study. The Western LA Basin area is evaluated again in the LCR reduction study in this planning cycle.

PG&E Sierra area's congestion increased since the previous cycle. This is mainly because more solar and wind generators were modeled in the Nevada Energy's Sierra area in the ADS PCM 2030, compared with the previous ADS PCM. The renewable energy surplus in the Nevada's Sierra area potentially increased the flow from Nevada to California on the path through the PG&E's Sierra area, which caused the increase in the congestion in the PG&E Sierra area.

No detailed analyses on other congestions in Table 4.7-1 and were conducted as the congestions were not sufficient for justifying upgrades, based on either the studies in previous planning cycles or engineering judgement. They will be monitored in future planning cycles and will be studied as needed.

4.8 Economic Planning Study Requests

As part of the economic planning study process, economic planning study requests are accepted by the CAISO, to be considered in addition to the congestion areas identified by the CAISO. These study requests are individually considered for designation as a High Priority Economic Planning Study for consideration in the development of the transmission plan. These economic study requests are distinct from the interregional transmission projects discussed in Chapter 5, but the interregional transmission projects discussed in Chapter 5 may be considered as options to meeting the needs identified though the economic planning studies.

Other economic study needs driven by stakeholder input have also been identified through other aspects of the planning process as well – those are also set out here, with the rationale for proceeding to detailed analysis where warranted.

The CAISO's tariff and Business Practice Manual allows the CAISO to select from economic study requests and other sources the high priority areas that will receive detailed study while developing the Study Plan, based on the previous year's congestion analysis. Recognizing that changing circumstances may lead to more favorable results in the current year's study cycle, the CAISO has over the past number of planning cycles carried all study requests forward as potential high priority study requests, until the current year's congestion analysis is also available for consideration in finalizing the high priority areas that will receive detailed study. This additional review gives more opportunity for the study requests to be considered, that can take into account on case by case basis the latest and most relevant information available.

Accordingly, the CAISO reviewed each regional study or project being considered for detailed analysis, and the basis for carrying the project forward for detailed analysis as high priority economic planning studies – or not – is set out in this section. The section also describes how the study requests or projects selected for detailed analysis were studied, e.g. on a standalone basis or as one of several options of a broader area study. The received study requests are summarized in Table 4.8-1. Evaluations for the study requests for purposes of selecting the final list of high priority economic planning studies are included in the following subsections.

Table 4.8-1: Economic study requests

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

4.8.1 Congestion on Doublet Tap to Friars 138 kV in SDG&E area

Study request overview

Calpine Corporation submitted a study request to conduct an economic study to identify cost effective solutions to relieve the transmission congestion on Doublet Tap – Friars 138kV line in the SDG&E area.

Evaluation

The benefits described in the submission and CAISO's evaluation of the economic study request are summarized in Table 4.8-2.

Table 4.8-2: Evaluating study request – Congestion on Doublet Tab to Friars 138 kV in SDG&E area

Study Request: Congestion on Doublet Tap to Friars 138 kV in SDG&E area		
Benefits category	**Benefits stated in submission**	**CAISO evaluation**
Identified Congestion	Calpine states that the transmission congestion of Doublet Tap – Friars 138kV line is one of the top constraints in the SDG&E area	Congestion was identified on the Doublet Tap – Friars 138 kV line. The proposed upgrade can mitigate the congestion.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Not addressed in submission	No benefits identified by CAISO
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by CAISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by CAISO
Integrate New Generation Resources or Loads	Not addressed in submission	No benefits identified by CAISO
Other	None	No benefits identified by CAISO

Conclusion

Based on the congestion analysis results and comments provided, the Doublet Tap to Friars 138 kV area congestion was selected for detailed analysis in this planning cycle. Please refer to section 4.10.1.

4.8.2 Congestion on Gates to Tulare Lake 70 kV in PG&E Fresno area

Study request overview

ConEdison submitted a study request to conduct an economic study for the Fresno Avenal area for the purpose of minimizing congestion on the Gates-Tulare Lake 70 kV line, and delivery of a Location Constrained Resource.

Evaluation

The benefits described in the submission and CAISO's evaluation of the economic study request are summarized in **Table 4.8-3**.

Table 4.8-3: Evaluating study request – Congestion on Gates to Tulare Lake 70 kV in PG&E Fresno area

Study Request: Congestion on Gates to Tulare Lake 70 kV in PG&E Fresno area		
Benefits category	**Benefits stated in submission**	**CAISO evaluation**
Identified Congestion	ConEdison states that there is congestion identified by the CAISO on the Gates-Tulare Lake 70 kV line	Congestion was identified on the Kettleman Hills Tap – Gates 70 kV line. The proposed upgrade was selected as a mitigation alternative.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	ConEdison refers to the need for delivery of a Location Constrained Resource in the study area	No benefit identified by CAISO
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by CAISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by CAISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	No benefits identified by CAISO
Other	ConEdison requests to discuss with CAISO the use of a private discount factor for this project	No benefits identified by CAISO

Conclusion

Based on the congestion analysis results and comments provided, the Gates to Tulare Lake 70 kV area congestion was selected for detailed analysis in this planning cycle. Please refer to section 4.10.4.

4.8.3 Gridliance West/VEA system upgrades

Study request overview

The proposed Gridliance West (GLW)/VEA system upgrades are summarized below:

14. Pahrump – Sloan Canyon: Upgrade the existing Pahrump – Sloan Canyon 230 kV line to 926/1195 normal/emergency rating and connect to the new Gamebird 230 kV bus and Trout Canyon 230 kV switching station;
15. Innovation – Desert View: Add second Innovation – Desert View 230 kV circuit;
16. Desert View – Northwest: Add a second 230 kV circuit Desert View – Northwest at 926/1195 normal/emergency rating;
17. Pahrump – Innovation: Upgrade Pahrump – Innovation 230 kV to 926/1195 normal/emergency rating.

In addition to the upgrades above, GLW upgrades include the following project and alternatives as a reliability upgrade:

18. Innovation and Lathrop Wells Phase Shifting Transformers: Add 138 kV phase shifting transformers at Innovation and Lathrop Wells stations.

The following alternatives to the phase shifting transformers are requested to be considered:

a. Jackass Flats – Mercury – Northwest: Rebuild the Jackass Flats – Mercury (DOE) and Mercury – Northwest (NVE) 138 kV lines at 207/285 normal/emergency rating
b. Innovation and Lathrop Wells Line Reactors: Add 138 kV line reactors at Innovation and Mercury Switch
c. 138 kV Line Reconfiguration: previously proposed line reconfiguration included the following:
    i. Jackass Flats – Mercury taken out of service
    ii. Mercury Switch – Indian Springs and Lathrop Wells – Jackass Flats operating normally open. These lines could be closed for emergencies.

Evaluation

The benefits described in the submission and CAISO's evaluation of the study request are summarized in Table 4.8-4.

Table 4.8-4: Evaluating study request – Gridliance West/VEA system upgrades

Study Request: Gridliance West/VEA system upgrades		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	GridLiance refers to CAISO identified congestion on the Pahrump – Sloan Canyon 230 kV line. Reconductoring the Pahrump – Sloan Canyon 230 kV line to mitigate the identified congestions increases congestion on the neighboring NVE system.	Minor congestion was observed in the GridLiance/VEA 138 kV system in this planning cycle. The proposed upgrade on the 230 kV system is not expected to mitigate the 138 kV system congestion
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	A RESOLVE analysis conducted by GridLiance on the expanded energy-only case identified 1462 MW of solar generation sited to the GLW footprint. GridLiance requests CAISO to consider siting these additional MW's to GLW's system and to conduct a detailed study of the need for transmission upgrades on the system as a result of the modification.	Pursuant to the study plan, the CAISO studied only the CPUC provided resource portfolios.
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by CAISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by CAISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	No benefits identified by CAISO
Other	GridLiance states that the proposed upgrades will: (1) enable CAISO-connected renewable generation in Southern Nevada to meet California carbon goals, (2) mitigate thermal overloading, (3) improve reliability, and (4) improve the resiliency of GLW's system.	No benefits identified by CAISO

Conclusion

No detailed economic assessment was conducted for this study request in this planning cycle.

4.8.4 COI congestion and SWIP-North project

Study request overview

LS Power Development, LLC submitted an economic study request to study congestion on California-Oregon Intertie (COI), Pacific AC Intertie (PACI) and Nevada-Oregon Border (NOB). In addition, the study requests to study the Southwest Intertie Project – North (SWIP-North) project as an economic project.

LS Power requests the CAISO to quantify financial congestion on the PACI, NOB, and COI paths in addition to the physical congestion that it has been quantified over the last few planning cycles.

The Southwest Intertie Project - North (SWIP - North) project is comprised of a single circuit 500 kV transmission line from Midpoint substation (in Idaho) to Robinson Summit substation (in Nevada). The project will provide approximately 1000 MW of bidirectional transmission capacity between Midpoint and Harry Allen.

Evaluation

The benefits described in the submission and CAISO's evaluation of the study request are summarized in Table 4/8-5.

Table 4.8-5: Evaluating study request – COI congestion and SWIP-North project

Study Request: COI congestion and SWIP-North project		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	Request is for CAISO to study congestion on California Oregon Intertie (COI), Pacific AC Intertie (PACI) and Nevada-Oregon Border (NOB)	Economic studies performed by the CAISO have identified congestion on COI; these congestion costs did not change significantly from previous transmission plans; and were previously found not to be sufficient to warrant transmission solutions in previous transmission plans. However, the CAISO selected to reevaluate COI congestion in this planning cycle because of the changes in transmission and resource assumptions in the ADS PCM for the systems outside California, especially the Northwest and PacifiCorp East systems. SWIP-North project will be assessed as an alternative of mitigation for COI congestion.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Request refers to several large solar, wind and bulk storage projects in the Idaho Power interconnection queue at/near Midpoint and states that a new transmission line such as SWIP-North can provide these projects direct access to CAISO market, by virtue of a Pseudo Tie Agreement with CAISO	The CAISO's transmission planning studies use CPUC's assumption for out of state resources
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by CAISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by CAISO
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	See "Delivery of Location Constrained Resource Interconnection Generators" above
Other	Study request recommends that CAISO improve the study model and/or study tools to capture financial congestion and to consider the 1000 MW of bidirectional transmission right that the project can provide to the CAISO market. Study request references policy benefits from the proposed project for reducing GHG emissions and renewable curtailment reductions. Study request suggests that the CAISO should not limit exports to 2000 MW as in previous cycles, but should consider using higher limits such as 5000 MW to 7000 MW as utilized in Extended Day Ahead Market Feasibility Assessments Study. Study request states that the proposed project will create a new 2000 MW path from Midpoint to Robinson Summit and will effectively move CAISO's BAA boundary station to Midpoint.	Study scenarios of out of state projects, including SWIP-North, need to be developed in the Inter-regional planning (ITP) process. The transmission right model needs to be coordinated with the ADS PCM process to collectively and consistently consider the impact of modeling changes on the existing transmission right in the system and in the ADS PCM.

Conclusion

A detailed economic assessment was conducted for this submitted study request in this planning cycle, as set out in section 4.10.3.

The CAISO considers the submitted project to be an interregional transmission project (ITP) due to the physical interconnections at Robinson Summit, Nevada and Midpoint, Idaho, within the WestConnect and Northern Grid (NG) planning regions, respectively. Please refer to chapter 5 regarding the ITP process.

4.8.5 Flow Control for Congestion Reduction on the California-Oregon Intertie (COI)

Study request overview

Smart Wires submitted a request for the CAISO to study all options to relieve COI congestion and the previously reported reliability constraints, including Smart Wires' COI submission during the 2019-2020 TPP reliability window. The project submitted in the 2019-2020 TPP reliability window consisted of the following:

- SmartValve installations on:
    a. Round Mountain – Table Mountain 500 kV Lines #1 and #2,
    b. Cottonwood E – Round Mountain 230 kV line #3, and
    c. Delevan – Cortina 230 kV
- An alternative is to deploy a hybrid solution to include:
    a. SmartValve deployments on Round Mountain – Table Mountain 500 kV Lines #1 and #2, and
    b. Reduced COI flow for the remaining constrains on the Cottonwood E – Table Mountain 230 kV line #3 and Delevan – Cortina 230 kV line.

Evaluation

The benefits described in the submission and CAISO's evaluation of the study request are summarized in Table 4.8-6.

Table 4.8-6: Evaluating study request – Flow Control for Congestion Reduction on the California-Oregon Intertie (COI)

Study Request: Flow Control for Congestion Reduction on the California-Oregon Intertie (COI)		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Submission refers to congestion on COI	Minor congestion on the Delevan - Cortina 230 kV line was identified in this planning cycle. The proposed project potentially help to reduce the congestion. However, the limiting component for the COI corridor congestion was mainly the COI path limit.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Not addressed in submission	No benefits identified by CAISO
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by CAISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by CAISO
Integrate New Generation Resources or Loads	Not addressed in submission	No benefits identified by CAISO
Other	Smart Wires states that relying on congestion management for a reliability need indicates that the need is purely economic. While Smart Wires supports using "congestion management" as a mitigation measure, the request states that given that there is always a viable generation dispatch to resolve these overloads, such constraints then become an economic problem.	No benefits identified by CAISO

Conclusion

The Smart Wires devices as proposed in this economic study request may help to mitigate some congestions on individual branches. However, those congestions were not significant and not selected for detailed analysis in this planning cycle. The devices may help to improve COI transmission capability, but this is subject to further reliability assessment. Production cost simulation studies can be conducted in the future planning cycles when the COI transmission limit associated with the Smart Wires devices as proposed is assessed.

No detailed economic assessment for this study request was conducted in this planning cycle.

4.8.6 Economic Study Requests to Reduce Local Capacity Requirements (LCR) Using Power Flow Control

Study request overview

Smart Wires submitted a request for the CAISO to study a proposed Contra Costa Sub-Area solution to cost effectively reduce the LCR requirements in the Contra Costa sub-area by impeding flow on the Tesla – Delta Switchyard 230 kV constraint. This project was previously submitted in the 2019-2020 TPP cycle by Smart Wires.

In addition, Smart Wires requested to study the following power flow control solutions to mitigate LCR constraints via power flow control:

a. Power Flow Control for LCR reduction in the South Bay - Moss Landing Sub-Area

   Power flow control solution to optimally divert power away from the Moss Landing – Las Aguilas 230 kV constraint.

b. Power Flow Control for LCR reduction in the Ames – Pittsburg – Oakland – Sub-Area

   Power flow control solution to optimally divert power away from the Ames-Ravenswood 115 kV and Moraga-Claremont 115 kV transmission constraints.

c. Power Flow Control for LCR reduction in the Fresno Area

   Power flow control solution to optimally divert power away from the Gates - Mustang 230 kV constraint.

d. Power Flow Control for LCR reduction in the Western LA Basic Sub-Area

   Power flow control solution to optimally divert power away from the Mesa - Laguna Bell 230 kV constraint.

Evaluation

The benefits described in the submission and CAISO's evaluation of the study request are summarized in Table 4.8-7.

Table 4.8-7: Economic Study Requests to Reduce Local Capacity Requirements (LCR) Using Power Flow Control

Study Request: Economic Study Requests to Reduce Local Capacity Requirements (LCR) Using Power Flow Control		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	Not addressed in submission	No benefit identified by CAISO
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Not addressed in submission	No benefit identified by CAISO
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by CAISO
Increase in Identified Congestion	Not addressed in submission	No benefits identified by CAISO
Integrate New Generation Resources or Loads	Not addressed in submission	No benefits identified by CAISO
Other	Smart Wires states that the purpose of the proposed projects is to reduce local capacity costs. The proposed projects may provide potential to increase network efficiency and deliver additional benefits for California's ratepayers	No benefits identified by CAISO

Conclusion

No detailed economic assessment for this study request was conducted in this planning cycle.

4.8.7 Path 26 congestion study

Study request overview

Southwestern Power Group (SWPG) submitted a request for the CAISO to study Path 26 congestion, which may be aggravated by resources in Southern California and out of state. SWPG also request to study potential upgrades for Path 26.

Evaluation

The benefits described in the submission and CAISO's evaluation of the study request are summarized in Table 4.8-8.

Table 4.8-8: Path 26 congestion study

Study Request: Path 26 congestion study		
Benefits category	Benefits stated in submission	ISO evaluation
Identified Congestion	SWPG refers to congestion identified by the CAISO on Path 26, which may be aggravated by the resources in Southern California and out of state.	The Path 26 congestion was identified in this planning cycle, and was selected to receive detailed analysis.
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	SWPG expects that the CAISO will study new wind resources in the New Mexico area. The request also refers to renewable resources in the Riverside East/Palm Springs transmission zone as well as projects to be built elsewhere in the greater Southern California region	No benefits identified by CAISO
Local Capacity Area Resource requirements	Not addressed in submission	No benefits identified by CAISO
Increase in Identified Congestion	SWPG states that Path 26 is expected to be more constrained in the future as more renewables are built out in the Southern California area and adjacent import points.	No benefits identified by CAISO
Integrate New Generation Resources or Loads	Not addressed in submission	Resources in Southern California and in the southwest states contribute to congestion on Path 26. Mitigating Path 26 congestion potentially help to integrate new resources in these areas.
Other	SWPG request that the CAISO study a high wind export case which includes 4,000 MWs of wind exported from New Mexico. SWPG requests that the CAISO clarify whether this case will be studied as part of the 2020/21 TPP or as part of the CAISO's Inter-regional study process.	No benefits identified by CAISO

Conclusion

Path 26 congestion was selected to receive detailed analysis in this planning cycle.

4.8.8 Pacific Transmission Expansion (PTE) HVDC Project[128]

Study request overview

Western Grid Development LLC (Western Grid) submitted the PTE project which consists of a 2,000 MW controllable HVDC subsea transmission cable that connects northern and southern California via submarine cables to be located in the Pacific Ocean off the coast of California. The project was previously submitted in the 2019-2020 TPP cycle and was resubmitted with an additional study scope in the comments to the CAISO 2020-2021 Transmission Planning Process Stakeholder Meeting on September 23~24, 2020. The project, as proposed, will have one northern point of interconnection in the PG&E area and three points of interconnection in the SCE area for its southern terminals. The proposed project includes the Voltage Source Converter (VSC) stations as in the followings:

Option 1:

- one 2,000 MW, 500 kV DC/500 kV AC converter station located at the northern terminus of the project at Diablo Canyon 500 kV switchyard,
- one 500 MW, 500 kV DC/220 kV AC converter station connected to SCE Goleta substation via a 3 mile underground AC cable,
- one 1,000 MW, 500 kV DC/220 kV AC converter station connected at Redondo Beach, and
- one 500 MW, 500 kV DC/220 kV AC converter station connected at Huntington Beach.

Option 2:

- one 2,000 MW, 500 kV DC/500 kV AC converter station located at the northern terminus of the project at Diablo Canyon 500 kV switchyard,
- one 500 MW, 500 kV DC/220 kV AC converter station connected to SCE Goleta substation via a 3 mile underground AC cable,
- one 500 MW, 500 kV DC/220 kV AC converter station connected at El Segundo substation,
- one 500 MW, 500 kV DC/220 kV AC converter station connected at Huntington Beach
- one 500 MW, 500 kV DC/220 kV AC converter station connected at San Onofre substation.

The project will have a total transfer capacity of 2,000 MW from the PG&E area into the SCE/SDG&E area or vice versa.

Evaluation

The benefits described in the submission and CAISO's evaluation of the study request are summarized in Table 4.8-9.

[128] PTE was formerly submitted as California Transmission Project (CTP) with a different scope.

Table 4.8-9: Evaluating study request – Pacific Transmission Expansion (PTE) HVDC Project

Study Request: Pacific Transmission Expansion HVDC Project		
Benefits category	**Benefits stated in submission**	**ISO evaluation**
Identified Congestion	Not addressed in submission	The PTE project can create a path parallel to Path 26. The Path 26 congestion was identified in this planning cycle, and was selected to receive detailed analysis
Delivery of Location Constrained Resource Interconnection Generators or similar high priority generators	Western Grid states that the proposed project's location off shore offers California an option to interconnect and deliver up to 2,000 MW of economic offshore wind energy as well as support delivery of renewable energy between northern and southern California.	No benefits identified by CAISO
Local Capacity Area Resource requirements	Western Grid states that the proposed project would reduce local capacity requirements in the Western LA Basin thereby allowing 1,993 MWs of gas plant generating capacity to retire.	LCR reduction study for the Western LA Basin and SDG&E areas were conducted in this planning cycle
Increase in Identified Congestion	Not addressed in submission	Detailed congestion analysis was conducted for the PTE project
Integrate New Generation Resources or Loads	See "Delivery of Location Constrained Resource Interconnection" above	No benefits identified by CAISO
Other	Western Grid states the following benefits of the proposed project: • Converters with their grid forming attributes can respond much faster than the synchronous generators used on gas fired units. The faster response applies both in reaction time and impact for AC voltage control and frequency stabilization while providing effective short circuit capacity and system damping requirements. • Project can deliver system flexibility to the locally constrained area. • Project is a transmission alternative which can support renewable integration by reducing expected curtailment of renewables in the CPUC portfolios and that will allow sharing of energy and ancillary services among multiple Balancing Area Authorities (BAAs). • Project will improve air quality particularly in the LA area • Project will provide reliability support to the Big Creek/Ventura Area of SCE, specifically within the Goleta area, where it will mitigate the voltage collapse issues under N-2 outages by providing up to 500 MW into Goleta in the event of an outage. • Project reduces the risk of another wildfire cutting off electric service to the LA coastal area due to the use of subsea cables that can be used when local gas plants are cut off due to wild fires.	No benefits identified by CAISO

Conclusion

The PTE project is an alternative for reducing Big Creek/Ventura area and the Western LA Basin sub-area local capacity requirements, as well as potential Path 26 congestion mitigation.

Production benefits of the PTE project were assessed in section 4.10.5. The Big Creek/Ventura area and the overall LA Basin and San Diego-Imperial Valley area local capacity gas-fired generation reduction benefits were assessed in section 4.10.7 and section 4.10.7, respectively.

4.9 Local Capacity Requirement Reduction Benefit Evaluation

Study requirement

In the 2018-2019 and 2019-2020 planning cycles, the ISO undertook analysis of local capacity requirements, including consideration of potential alternatives to eliminate or materially reduce local capacity requirement needs. In the ISO's annual local capacity technical study process conducted in early 2020, the ISO also examined charging capabilities in local capacity areas, to explore the possibility of using energy storage to reduce reliance on gas-fired generation to meet local capacity requirements. Building on both of those efforts, the ISO undertook in this planning cycle a more comprehensive analysis to assess the alternatives to materially reduce or eliminate reliance on gas-fired generation considering both transmission and storage opportunities. This review went beyond the traditional local capacity technical studies, including the biennial 10 year local capacity technical studies that are part of the CAISO's ongoing study process, by examining characteristics of requirements in more detail, and examining possible mitigations. These studies were conducted under the economic analysis framework, as there is currently not a basis for identifying solutions on a reliability basis or policy basis. If there are sufficient local resources to maintain reliability, reducing the use of those resources is not necessary to meet NERC or CAISO planning standards. Further, there are no applicable federal or state policies at this time that necessitate planning for reduced local capacity levels beyond state policies for generation relying on coastal waters for once-through-cooling, and those needs have been addressed in previous transmission plans.

It was recognized that actual viable economic-driven opportunities may be unlikely, but that even if that was the case, examining and understanding the needs – and the load, generation and system characteristics driving those needs, could be valuable in future resource procurement processes outside of the CAISO's transmission planning process. In particular, the information regarding local requirement characteristics in all areas, and the scope of upgrades necessary to effect reductions in the areas selected for detailed studies - even if not currently economic - would be helpful to state policy makers and regulatory agencies in considering future policy direction or resource planning decisions.

Recognizing that a thorough and comprehensive review of transmission and hybrid alternatives for all local capacity areas in a single planning cycle was unrealistic, the CAISO targeted this expanded study on exploring and assessing alternatives to eliminate or materially reduce requirements in "at least half" of the existing areas and sub-areas in the first year (the 2018-2019 transmission planning cycle) and completing the analysis in the subsequent 2019-2020 planning cycle. A comprehensive review in this 2020-2021 planning cycle was performed building on the review conducted over the two previous years with considering in more depth the potential for both transmission and preferred resources working together to reduce local requirements for gas-fired generation.

In this planning cycle, the following economic analysis was performed for the local capacity areas:

- Identify potential transmission upgrades that would economically lower gas-fired generation capacity requirements in local capacity areas or sub-areas

  - Retirement of gas-fired generation in the IRP has not identified significant retirement, as such methodology for economic assessment will be the same as in the 2018-2019 and 2019-2020 transmission planning process

- Explore and assess alternatives – conventional transmission and preferred resources - to reduce or eliminate need for gas-fired generation in local capacity areas and sub-areas.

This analysis therefore provided an overview of the local capacity requirements on the CAISO system in greater depth than traditional local capacity requirements technical studies.

As discussed in Chapter 6, alternatives to eliminate or materially reduce local capacity requirements in the selected areas and sub-areas were developed, exploring not only the most limiting conditions and issues, but often exploring the “next level” of limitation that would be binding once the most limiting conditions were addressed.

Many of those alternatives are quite complex, relatively costly, and require further coordination with the CPUC’s integrated resource planning framework and the longer term needs for gas-fired generation for system purposes before recommendations could be seriously considered. However, some of the less expensive and more modest upgrades identified do warrant further consideration as potential economic-driven transmission projects in this planning cycle, as well as other upgrades proposed by stakeholders that warrant detailed analysis.

The review described in Chapter 6 was conducted as an extension of the previous years’ efforts, and relied on the information and base cases developed in that cycle and based on the local capacity technical study criteria in effect at the time. Any areas that were considered potential economic study requests deserving detailed study as potential high priority study requests were then considered below, using the current planning cycle’s study assumptions.

Evaluation and Conclusions

The differential in Resource Adequacy capacity cost between all local areas and CAISO system (including NP26 and SP26) has declined from previous years, therefore there is no need to reassess projects assessed in past planning cycles that were not found to be economic. The CAISO is using public cost information, from the latest RA reports provided by CPUC.[129]

The current studies have concentrated only on new projects more recently proposed by stakeholders or that were previously found to close to being economically feasible in the last 2 years’ studies, located in these areas:

- Bay Area
- LA Basin
- San Diego/Imperial Valley

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https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/2018%20RA%20Report%20rev.pdf

4.10 Detailed Investigation of Congestion and Economic Benefit Assessment

The CAISO selected the branch groups and study areas listed in Table 4.10-1 for further assessment as high priority studies after evaluating identified congestion, considering potential local capacity reduction opportunities and stakeholder-proposed reliability projects citing material economic benefits, and reviewing stakeholders' study requests, consistent with tariff section 24.3.4.2.

Facilities identified as potential mitigations in those study areas include stakeholder proposals from a number of sources; request window submissions citing economic benefits, economic study requests, and comments in various stakeholder sessions suggesting alternatives for reducing local capacity requirements.

The stakeholder-proposed mitigations being carried forward for detailed analysis are set out in Table 4.10-1 for ease of tracking where and how these stakeholder proposals were addressed.

The detailed analysis also considers other CAISO-identified potential mitigations which have been listed in Table 4.10-1 as well.

Table 4.10-1: Detailed Economic Benefit Investigation

Detailed investigation	Alternative	Proposed by	Reason
Congestion			
SDG&E Doublet tap – Friars 138 kV line under the N-2 contingency of Sycamore-Penasquitos and Penasquitos – Old Town 230 kV lines	Expand the SPS to include ECO and IV generators	ISO/ Calpine/SDG&E	The mitigation alternatives are expected to reduce or eliminate the congestion
	Reconductoring the congested line		
	Rearrange Penasquitos – Old Town line to eliminate the N-2 contingency		
SCE Wirlwind 500/230 kV Transformers	Add the fourth transformer at Whirlwind substation	ISO	The mitigation alternatives are expected to reduce or eliminate the congestion and reduce renewable curtailment
	Add battery storage at Whirlwind 230 kV bus		
COI corridor	SWIP-North Project	LS Power	SWIP-North Project potentially provides a parallel path to the COI corridor.
PG&E Fresno area	Reconductoring Kettleman Hills Tap to Gates 70 kV line	PG&E	Potentially mitigate or reduce the identified congestion
	Rerating Helm 230/70 kV transformer with higher rating	ISO	Potentially mitigate or reduce the identified congestion
	SPS of tripping generators for the N-1 contingency of Penoche – Mendota 115 kV line	ISO	Potentially mitigate or reduce the identified congestion
	SPS of tripping generators for the N-2 contingency of Panoche-Schindler and Panoche – Exelesesissio 115 kV lines	ISO	Potentially mitigate or reduce the identified congestion

Detailed investigation	Alternative	Proposed by	Reason
Path 26 Corridor in south to north direction	PTE HVDC (Multi-terminals DC between Diablo Canyon, Goleta, Redondo Beach, and Huntington Beach)	PTE	The PTE Project provides a parallel path to Path 26 and can potentially reduce congestion on Path 26 corridor
Local Capacity Reduction Study Areas			
PG&E Greater Bay Area	Metcalf 500-230 kV Transformers Dynamic Series Reactor Project	PG&E	Potentially reduce local capacity requirements
PG&E Greater Bay Area-San Jose sub-area	Metcalf 230 kV substation	Horizon West	Potentially reduce local capacity requirements
PG&E Greater Bay Area Contra Costa sub-area	Contra Costa – Pittsburg 230 kV Reliability Project	Horizon West	Potentially reduce local capacity requirements
	Smart valve in series with Tesla – Delta Switchyard 230 kV line	Smart Wire	Potentially reduce local capacity requirements
Big Creek–Ventura area	Option 1: PTE HVDC (Multi-terminals DC between Diablo Canyon, Goleta, Redondo Beach, and Huntington Beach) Option 2: PTE HVDC (Multi-terminals DC between Diablo Canyon, Goleta, El Segundo, Huntington Beach and San Onofre)	Western Grid Development, LLC (WGD)	Potentially reduce local capacity requirements
Western sub-area (LA Basin) El Nido sub-area (LA Basin) Overall LA Basin	Option 1: PTE HVDC (Multi-terminals DC between Diablo Canyon, Goleta, Redondo Beach, and Huntington Beach) Option 2: PTE HVDC (Multi-terminals DC between Diablo Canyon, Goleta, El Segundo, Huntington Beach and San Onofre)	WGD	Potentially reduce local capacity requirements
	Upgrade La Fresa - La Cienega 230kV Line & Install Series Reactor on the Mesa - Laguna Bell and Mesa - Lighthipe 230kV Lines	ISO	Potentially reduce local capacity requirements
	Lugo Area – LA Basin HVDC Line with underground AC cable connections to Lighthipe & La Cienega	ISO	Potentially reduce local capacity requirements
Western sub-area (LA Basin) Overall LA Basin	Devers – Lighthipe DC Line	ISO	Potentially reduce local capacity requirements
Overall LA Basin San Diego-Imperial Valley	Lake Elsinore Advanced Pump Storage (LEAPS) Project: Option 1 – SCE/SDG&E connection with no pump storage Option 2 – Option 1 with 500 MW pump storage Option 3 – SDG&E connection only	Nevada Hydro	Potentially reduce local capacity requirements

This study step consists of conducting detailed investigations and modeling enhancements as needed. To the extent that economic assessments for potential transmission solutions are needed, the production benefits and other benefits of potential transmission solutions are based on the CAISO's Transmission Economic Analysis Methodology (TEAM)[130], and potential economic benefits are quantified as reductions of ratepayer costs.

In addition to the production benefit, other benefits were also evaluated as needed. As discussed in section 4.2, other benefits are also taken into account on a case by case basis, both to augment congestion-driven analysis and to assess other economic opportunities that are not necessarily congestion-driven.

All costs and payments provided in this section are in 2020 real dollars.

Finally, it is important to reiterate that all regional transmission solutions – other than modifications to existing facilities, are subject to the CAISO's competitive solicitation process as set out in the CAISO's tariff. So, while many projects have been submitted with narrowly defined project scopes, the CAISO is not constrained to only study those scopes without modification, or to study the projects exclusively on the basis under which the proponent suggested.

4.10.1 SDG&E Doublet Tap – Friars 138 kV Congestion and Mitigations

Congestion analysis

Congestion on the SDG&E Doublet Tap – Friars 138 kV line was observed in this planning cycle when the flow was from Friars to Doublet Tap under contingency condition. The critical contingency was the N-2 contingency of the SDG&E Sycamore – Penasquitos and Penasquitos – Old Town 230 kV lines.

As the baseline assumption in the planning PCM, SPS of tripping generators in the Otay Mesa area was modeled associated with the N-2 contingency of the Sycamore – Penasquitos and Penasquitos – Old Town 230 kV lines. This SPS was proposed in Chapter 2, section 2.9.3 and in the CAISO's generation interconnection process. The congestion cost and hours are $52.74 million per year and 2,749 hours, respectively.

Table 4.10-2 shows the heat map of the occurrences of the Doublet Tap – Friars congestion at each hour of the day in each month in the simulation results of the base portfolio PCM. The numbers in the table are the total occurrences of the congestion at each hour in a month. For example, congestion occurred total 22 times at the first hour of the days in January. It was observed that majority of the congestion on the Doublet Tap – Friars line was observed outside the solar hours. Congestion on this line is relatively light in April and May compared with other months.

[130] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

Table 4.10-2: Occurrences of Doublet Tap – Friars congestion

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	22	20	9	7	2	13	21	21	21	16	23	22
2	21	19	5	5	2	4	14	21	12	13	18	26
3	14	15	4	5	0	2	10	17	11	9	9	25
4	13	12	4	4	0	1	6	17	12	8	8	20
5	10	13	4	4	0	1	7	17	14	10	7	19
6	9	13	10	5	2	7	14	21	18	14	10	17
7	10	15	8	11	6	14	14	24	23	22	16	19
8	11	20	18	6	3	17	15	23	20	25	19	21
9	24	26	7	1	0	2	10	18	10	19	8	27
10	12	8	3	0	0	2	3	4	2	5	1	15
11	3	6	2	0	0	1	3	3	2	2	0	3
12	2	5	2	0	0	1	4	2	3	1	0	3
13	1	4	1	0	0	2	10	3	2	1	0	3
14	1	4	2	0	0	6	10	6	7	1	0	2
15	1	4	2	0	0	8	12	5	11	1	0	1
16	1	2	0	0	1	1	6	5	15	3	0	1
17	3	4	0	0	1	2	5	9	19	6	2	3
18	7	9	1	0	1	6	14	11	16	13	13	14
19	9	15	5	2	3	9	11	6	7	14	20	21
20	13	12	14	5	2	3	5	3	6	20	18	22
21	13	15	17	9	15	16	9	9	12	21	13	22
22	9	17	19	7	10	23	15	16	16	18	17	25
23	13	16	14	8	7	23	17	11	19	19	21	26
24	11	20	13	6	4	13	16	17	19	19	17	23

In order to investigate the driver of the congestion, heat maps were created for the generation output of the generators in the SDG&E Otay Mesa area and the total flow importing to San Diego from east to west. The SDG&E Otay Mesa area generators include a combined cycle generator, three combustion turbine generators, and a battery storage. San Diego import flow from east to west includes flows on Eco – Miguel 500 kV line, Ocotillo – Suncrest 500 kV line, and TJI230 – Otay Mesa 230 kV line. Generation output in the SDG&E ECO, Ocotillo, and Imperial Valley areas, and the flow along East of River (Path 49) and West of River (Path 46), impact the San Diego importing flow from east to west.

Table 4.10-3 shows the heat map of the average hourly generation output of the SDG&E Otay Mesa area in the base portfolio PCM simulation results. The negative generation output indicates that the battery storage in this area is in charging mode and the charging flow is greater than the generation output of the thermal generation in the same area. Table 4.10-4 shows the heat map of the average hourly flow of the San Diego import from east to west in the base portfolio PCM simulation results. Comparing the three heat maps in Table 4.10-2, Table 4.10-3, and Table 4.10-4, it was observed that the congestion from Friars to Doublet Tap is more correlated with the San Diego importing flow than with the generation output in the Otay Mesa area over the year. The Otay Mesa area generation contributes to the Friars to Doublet Tap flow mainly in the evening.

Table 4.10-3: Average hourly generation output (MW) of generators in Otay Mesa area in each month

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0	0	0	0	0	0	0	10	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	-3	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	4	0	0	0	0	0
7	0	0	13	0	0	0	18	31	0	0	0	0
8	0	24	16	0	0	0	16	28	0	0	0	7
9	0	25	0	0	0	0	16	7	0	0	0	8
10	0	0	0	-4	-1	0	5	0	-5	-3	-3	0
11	-19	-18	-46	-97	-149	-71	-60	-54	-113	-96	-154	-23
12	-154	-172	-250	-250	-257	-214	-138	-173	-193	-225	-230	-139
13	-218	-194	-261	-269	-265	-229	-143	-211	-182	-236	-226	-195
14	-209	-199	-256	-269	-254	-215	-125	-181	-141	-214	-226	-177
15	-179	-164	-259	-261	-215	-183	-97	-139	-87	-157	-192	-134
16	-100	-105	-152	-129	-62	-104	-41	-42	-18	-56	-13	-21
17	21	-3	-2	-5	0	-10	-8	33	80	62	103	99
18	188	98	85	28	111	46	37	151	240	190	199	171
19	227	192	237	247	225	181	192	366	622	376	193	254
20	224	214	254	303	256	251	492	666	702	421	237	209
21	158	215	206	268	241	403	575	695	626	359	202	157
22	95	132	174	267	164	333	503	567	495	277	95	119
23	25	84	83	92	44	179	383	508	182	56	10	91
24	5	17	2	23	23	92	38	65	21	16	0	34

Table 4.10-4: Average flow (MW) of San Diego import from east to west in each month

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	88,807	79,808	81,406	79,290	75,394	78,009	86,922	88,994	83,335	81,409	84,433	89,085
2	85,273	76,841	75,936	76,615	68,754	70,208	82,333	86,072	78,263	76,004	79,799	86,462
3	81,103	73,429	70,769	73,523	61,369	63,637	78,523	82,944	74,679	71,055	73,864	82,336
4	78,039	71,135	68,595	72,108	59,658	60,400	75,433	81,279	72,742	69,391	69,908	80,026
5	76,354	69,911	68,418	71,909	61,110	61,578	75,565	81,007	72,631	70,650	68,514	78,603
6	76,201	70,701	73,572	75,898	66,523	68,187	78,266	83,555	76,183	76,050	70,062	78,145
7	78,907	73,315	78,729	78,543	72,392	73,088	80,324	85,387	81,062	82,084	74,346	80,328
8	83,570	76,058	82,363	76,212	71,770	76,979	81,196	86,947	82,426	86,121	78,222	83,839
9	88,171	76,835	75,649	64,415	66,044	75,020	78,246	84,208	76,433	81,595	70,979	85,905
10	74,075	66,160	64,393	54,684	57,925	72,170	70,095	74,787	67,291	70,772	60,663	76,515
11	62,208	55,493	54,390	48,033	52,133	67,773	67,025	65,996	61,477	62,827	52,815	62,449
12	55,369	54,046	52,419	44,021	47,710	65,346	66,871	63,058	60,149	60,142	50,322	56,735
13	51,322	49,124	45,519	39,018	44,518	62,123	67,323	62,441	60,320	55,426	46,605	54,496
14	48,368	47,830	42,255	36,643	44,778	61,027	66,903	63,976	63,532	54,580	44,965	52,669
15	48,335	45,101	42,545	37,174	45,665	61,679	67,757	65,442	67,486	55,526	45,634	52,783
16	50,225	46,774	40,416	36,062	45,169	60,311	66,849	66,730	71,473	59,048	44,392	52,408
17	53,767	49,625	41,860	39,655	51,944	61,592	69,981	70,241	76,434	66,324	55,251	62,747
18	65,976	61,459	52,426	50,819	61,221	66,816	76,055	75,612	78,830	76,022	73,111	78,418
19	87,692	76,018	72,689	61,416	73,110	72,931	78,681	76,334	76,341	86,849	88,934	90,182
20	90,517	80,903	87,671	76,032	82,425	78,326	77,841	75,655	81,679	91,121	88,188	92,680
21	90,793	81,124	89,041	79,652	87,439	87,503	83,039	83,114	86,297	92,391	87,849	92,827
22	90,806	81,438	87,712	77,819	84,644	87,441	85,151	85,810	85,559	89,905	88,396	92,445
23	91,133	80,763	86,169	79,646	84,537	84,389	86,182	85,698	87,895	89,164	87,819	91,361
24	90,536	80,855	84,023	78,288	77,239	78,377	89,517	91,274	86,170	86,270	86,190	90,875

Congestion mitigation alternatives

Based on the congestion analysis and the economic study request evaluation, three mitigation alternatives were studied for the Doublet Tap – Friars congestion in this planning cycle.

1. Expand the SPS proposed Chapter 2, section 2.9.3 to trip generation in the Otay Mesa area, to also trip generators in the SDG&E's ECO and Imperial Valley areas. The total tripped generation by the expanded SPS in the planning PCM was capped at 1400 MW, which is consistent with the SPS limitation for N-2 contingencies as required by the CAISO's Planning Standard[131].
2. Reconductoring the Doublet Tap – Friars 138 kV line with increased rating of 320 MVA, which was proposed in the CAISO's generation interconnection study.
3. Rearrange the Penasquitios – Old Town 230 kV line to make the N-2 contingency of the Sycamore – Penasquitos and Penasquitos – Old Town 230 kV lines not a credible N-2 contingency so that the planning PCM does not need to model this N-2 contingency.

Table 4.10-5 shows the Doublet Tap – Friars congestion with and without mitigations, and the changes of renewable curtailment as well. The expanded SPS can significantly reduce congestion, while the other two alternatives can completely mitigate the congestion. The total renewable curtailment slightly reduced in the cases with the mitigation alternatives modeled.

Table 4.10-5: Doublet Tap – Friars Congestion and Renewable Curtailment

	Base case		Alternative 1 – Expended SPS		Alternative 2 - Reconductoring		Alternative 3 – Rearrangement	
Congestion	**$M**	**Hours**	**$M**	**Hours**	**$M**	**Hours**	**$M**	**Hours**
Doublet Tap - Friars 138 kV	52.74	2,749	5.47	378	0	0	0	0
Wind and Solar	**Output (GWh)**	**Curtail (GWh)**	**Output (GWh)**	**Curtail (GWh)**	**Output (GWh)**	**Curtail (GWh)**	**Output (GWh)**	**Curtail (GWh)**
ISO Total	75,051	13,595	75,072	13,575	75,072	13,575	75,066	13,581

Production benefits

The production benefit for CAISO's ratepayers and the production cost savings of all three mitigation alternatives for the Doublet Tap – Friars congestion are shown in Table 4.10-6.

131 http://www.caiso.com/Documents/ISOPlanningStandards-September62018.pdf

Table 4.10-6: Production Benefits of Mitigating Doublet Tap – Friars Congestion

	Base case	Alternative 1 – Expanded SPS		Alternative 2 - Reconductoring		Alternative 3 – Rearrangement	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	7,954	7,961	-6	7,949	6	7,944	10
ISO generator net revenue benefiting ratepayers	3,554	3,583	29	3,579	26	3,579	25
ISO transmission revenue benefiting ratepayers	268	230	-39	226	-42	227	-42
ISO Net payment	4,132	4,148	-16	4,143	-11	4,139	-7
WECC Production cost	13,213	13,169	44	13,157	56	13,153	60

Note that CAISO ratepayer "savings" are a decrease in load payment, but an increase in CAISO generator net revenue benefiting ratepayers and an increase in CAISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

The Alternative 1 Expanded SPS increased the CAISO load payment, while the other two alternatives reduced the load payment. All three alternatives increased CAISO generator net revenue or profit, attributed to the increase of renewable generation and the increase of LMP in some areas as the renewable curtailment reduced. However, the load payment savings and the generator profit savings cannot offset the decrease in the transmission revenue due to the reduction of the congestion cost on the Doublet Tap – Friars 138 kV line. This resulted in negative benefit to the CAISO ratepayers for all three alternatives, although they can help to reduce WECC wide production cost.

Considering the uncertainty of the future renewable development in the SDG&E area and the implementation of the SPS associated with the N-2 contingency, the proposed alternatives were assessed against the case without SPS, or the "No SPS" case. The congestion and curtailment results are shown in Table 4.10-7. The results of the base case and the Alternative 3 case are the same as in the earlier discussion, but are listed here for comparison purpose. As shown in Table 4.10-7, the "No SPS" case has the worst congestion on the Doublet Tap – Friars 138 kV line among all studied cases. Without SPS, the Alternative 2 to reconductoring the Doublet Tap –Friars 138 kV line cannot completely mitigate the congestion. The renewable generation and curtailment did not change much across all studied cases.

Table 4.10-7: Doublet Tap – Friars Congestion and Renewable Curtailment compared with "No SPS" case

	"No SPS" case		Base case (SPS to trip Otay Mesa area generators)		Alternative 2 – Reconductoring (No SPS)		Alternative 3 – Rearrangement	
Congestion	**$M**	**Hours**	**$M**	**Hours**	**$M**	**Hours**	**$M**	**Hours**
Doublet Tap - Friars 138 kV	78.59	3,728	52.74	2,749	2.879	173	0	0
Wind and Solar	**Output (GWh)**	**Curtail (GWh)**	**Output (GWh)**	**Curtail (GWh)**	**Output (GWh)**	**Curtail (GWh)**	**Output (GWh)**	**Curtail (GWh)**
ISO Total	75,067	13,580	75,051	13,595	75,075	13,571	75,066	13,581

Table 4.10-8 demonstrated that both the Reconductoring and Rearrangement alternatives showed about $2 million of benefit per year to the CAISO ratepayers. Depending on the cost of the alternatives, they may become economically effective. However, from the economic perspective, using SPS to trip generators in the Otay Mesa area is still the most economically effective option, which has about $13 million of benefit per year.

Table 4.10-8: Production Benefits of Mitigating Doublet Tap – Friars Congestion compared with "No SPS" case

	"No SPS" case	Base case (SPS to trip Otay Mesa area generators)		Alternative 2 – Reconductoring (No SPS)		Alternative 3 – Rearrangement (No SPS)	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	8,032	7,954	78	7,955	78	7,949	84
ISO generator net revenue benefiting ratepayers	3,590	3,554	-37	3,581	-9	3,579	-11
ISO transmission revenue benefiting ratepayers	297	268	-28	230	-66	226	-71
ISO Net payment	4,145	4,132	13	4,143	2	4,143	2
WECC Production cost	13,215	13,213	2	13,155	59	13,157	58

Note that CAISO ratepayer "savings" are a decrease in load payment, but an increase in CAISO generator net revenue benefiting ratepayers and an increase in CAISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Conclusions

All three alternatives can mitigate the Doublet Tap – Friars 138 kV congestion, but none shows benefit to the CAISO's ratepayers, with assuming the SPS of tripping Otay Mesa area generators in place which is the baseline assumption in this planning cycle. Therefore, the CAISO does not recommend these alternatives for approval as economic-drive projects in this planning cycle. Further evaluation, including benefit to cost ratio assessment, may be conducted in future planning cycles with additional clarity of renewable development and SPS implementation in the SDG&E area.

4.10.2 SCE Whirlwind 500/230 kV Transformer Congestion and Mitigations

Congestion analysis

In the planning PCM for the base portfolio, there are about total 4000 MW of generators connected to the Whirlwind 230 kV bus. There are three transformers in the Whirlwind substation in the planning PCM, each with a 1120 MVA normal rating. The total capacity of these three transformers is less than the total capacity of generators connected to the Whirlwind 230 kV bus. Congestion on the Whirlwind transformers under normal conditions was observed in this planning cycle in the hours when the renewable generation output was high. Table 4.10-9 summarized the SCE Whirlwind generator capacity by generator type.

Table 4.10-9: SCE Whirlwind Generator Summary (base portfolio)

Generator Type	Capacity (MW)
Battery Storage	10
Wind	333
Solar	3,715
Total	**4,058**

Congestion mitigation alternatives

Based on the congestion analysis and the generation deliverability assessments, two mitigation alternatives were studied for the Whirlwind transformer congestion in this planning cycle.

4. Add 1170 MW of battery storage at Whirlwind 230 kV bus. The 1170 MW is the maximum available deliverability at Whirlwind 230 kV, considering the generators that were already modeled in the base portfolio case. This alternative is consistent with the battery remapping evaluation for the Sensitivity 2 portfolio as set out in section 3.8.
5. Add the fourth transformer in the Whirlwind substation, with the same rating and impedance as of the other three Whirlwind transformers.

Table 4.10-10 shows the SCE Whirlwind transformer congestion and the renewable curtailment with and without the mitigations. Adding 1170 MW of battery at the Whirlwind 230 kV bus can absorb the surplus of the renewables generation that are delivered to the Whirlwind 230 kV bus thereby can reduce the congestion on the Whirlwind 500/230 kV transformers. However, the 1170 MW of battery is not sufficient to completely mitigate the congestion. Adding more battery capacity may be helpful to further reduce congestion, but it is not an option since the total generation capacity at Whirlwind 230 kV is limited by the on-peak deliverability. Adding a fourth Whirlwind transformer is sufficient to mitigate the congestion.

Adding battery capacity is more effective in reducing renewable curtailment than adding a new transformer. This is because batteries can help to shift the surplus energy to other hours when the energy is needed, but adding a transformer can only reduce the curtailment locally and may increase curtailment at other places within the CAISO system. This observation is consistent with the results in the battery remapping evaluation for the Sensitivity 2 portfolio as set out in section 3.8.

Table 4.10-10: SCE Whirlwind Transformer Congestion and Renewable Curtailment

	Base case		Alternative 1 – 1170 MW battery at Whirlwind 230 kV		Alternative 2 – The Fourth Whirlwind transformer	
Congestion	**$M**	**Hours**	**$M**	**Hours**	**$M**	**Hours**
Whirlwind	22.91	295	9.35	165	0	0
Wind and Solar	**Output (GWh)**	**Curtail (GWh)**	**Output (GWh)**	**Curtail (GWh)**	**Output (GWh)**	**Curtail (GWh)**
ISO Total	75,051	13,595	76,633	12,014	75,108	13,538

Production benefits

The production benefit for the CAISO's ratepayers and the production cost savings of the two alternatives to mitigate the Whirlwind 500/230 kV transformer congestion are shown in Table 4.10-11. Neither alternative shows benefit to the CAISO's ratepayers.

Table 4.10-11: Production Benefits of Mitigating Whirlwind 500/230 kV Transformer Congestion

	Base case	Alternative 1 – 1170 MW battery at Whirlwind 230 kV		Alternative 2 – The Fourth Whirlwind transformer	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	7,954	8,049	-94	7,962	-8
ISO generator net revenue benefiting ratepayers	3,554	3,611	57	3,571	17
ISO transmission revenue benefiting ratepayers	268	261	-7	253	-15
ISO Net payment	4,132	4,177	-45	4,138	-6
WECC Production cost	13,213	13,223	-10	13,220	-7

Note that CAISO ratepayer "savings" are a decrease in load payment, but an increase in CAISO generator net revenue benefiting ratepayers and an increase in CAISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

It was observed that the load payment increased. This is attributed to the renewable curtailment reduction as the congestion was mitigated. Since renewable curtailment triggered negative LMP, the system LMP increased as the renewable curtailment reduced. Both alternatives reduced the transmission revenue benefitting the CAISO's ratepayers mainly because the Whirlwind transformer congestion cost reduced after the congestion was reduced or mitigated. Generator net revenue benefitting the CAISO's ratepayers increased in both cases with mitigations, mainly due to the decrease of the renewable curtailment and the increase of the LMP.

WECC production cost increased, but the reasons are slightly different for these two alternatives. In the case with 1170 MW of battery, the WECC production cost increase is mainly due to the operation cost for the battery, as described in section 4.6.8. In the Alternative 2 case, adding the fourth transformer at Whirlwind substation resulted in the change of thermal generation dispatch across the system to respond the incremental renewable generation. Increases in the fuel cost, the variable operation and maintenance cost, and the startup cost in the Alternative 2 PCM simulation results were observed.

The Alternative 1 case was also assessed against a reference case that has the additional 1170 MW of battery capacity modeled at the Lugo 500 kV bus. The battery storage at the Lugo 500 kV bus mainly helps to mitigate system constraint-related renewable curtailment since the Lugo 500 kV bus is not in any congested areas. In this assessment, essentially, the potential benefits of remapping battery storage from other unconstrained locations to the Whirlwind 230 kV bus were assessed.

The curtailment results are shown in Table 4.10-12. The results of the base case and the Alternative 1 case are the same as in the earlier discussion, but are listed here for comparison purposes. It was observed that battery storage can help to reduce renewable curtailment regardless the location of the battery storage. The Alternative 1 case has less renewable curtailment than the reference case because it has the battery storage modeled at the Whirlwind 230 kV bus, which directly mitigated the Whirlwind transformer congestion and is effective to mitigate renewable curtailment at the Whirlwind area.

Table 4.10-12: Whirlwind Congestion - Renewable Curtailment Comparison between the Alternative 1 and Reference case

	Base case		Reference Case - 1170 MW battery at Lugo 500 kV		Alternative 1 – 1170 MW battery at Whirlwind 230 kV	
Wind and Solar	Output (GWh)	Curtail (GWh)	Output (GWh)	Curtail (GWh)	Output (GWh)	Curtail (GWh)
ISO Total	75,051	13,595	76,563	12,084	76,633	12,014

Table 4.10-13 shows the production benefits for CAISO ratepayers from the Alternative 1 compared with the reference case. The load payment and generator profit benefitting ratepayers in the Alternative 1 case reduced compared with the reference case, which was mainly because overall the LMP in the CAISO controlled grid reduced as congestion relieved on the Whirlwind transformer. It is worth noting that the LMP in the Whirlwind 230 kV system may increase as the renewable curtailment in the Whirlwind area and the Whirlwind transformer congestion were mitigated by the battery storage. The transmission revenue reduction in the Alternative 1 case was also because of the Whirlwind transformer congestion mitigation. It was observed that compared with the reference case, remapping battery storage to the Whirlwind 230 kV bus in the Alternative 1 case did not show benefit to the CAISO ratepayers. This indicated that remapping battery storage to a highly congested area with high renewable curtailment can help to reduce congestion and renewable curtailment, which is consistent with the battery remapping analysis results in section 3.8.2. However, there were still no production benefits for CAISO ratepayers found with the batteries remapped to the Whirlwind 230 kV bus.

Table 4.10-13: Production Benefits of Alternative 1 compared with the Reference case

	Reference Case - 1170 MW battery at Lugo 500 kV	Alternative 1 - 1170 MW battery at Whirlwind	Alternative 1 Savings compared with Reference Case 1
	$M	$M	$M
ISO load payment	8,066	8,049	18
ISO generator net revenue benefiting ratepayers	3,612	3,611	-1
ISO transmission revenue benefiting ratepayers	280	261	-19
ISO Net payment	4,174	4,177	-3
WECC Production cost	13,225	13,223	3

Note that CAISO ratepayer "savings" are a decrease in load payment, but an increase in CAISO generator net revenue benefiting ratepayers and an increase in CAISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Conclusions

Both alternatives, adding 1170 MW of battery and adding a transformer, can mitigate the congestion on the Whirlwind transformers, but they don't have economic benefit to the CAISO's ratepayers based on the TEAM perspective. Therefore, the CAISO does not recommend either of these alternatives for approval as economic-driven projects in this planning cycle. Further evaluation will be conducted in a future planning cycle once there is more clarity in the battery storage development picture in the CAISO controlled grid from the CPUC's IRP.

4.10.3 COI Corridor Congestion and SWIP-North Project assessment

Congestion analysis

Congestion was observed in this planning cycle on the COI corridor that includes Path 66 (COI) and its downstream lines, when the power flow on this corridor was from north to south. Table 4.10-14 shows the COI corridor congestion cost and duration. Path 66 is the most congested component in the COI corridor, followed by the Table Mountain – Tesla 500 kV line.

Table 4.10-14: COI Corridor Congestion

Constraints	Costs ($M)	Duration (Hrs)
P66 WECC COI	8.85	259
Table Mountain – Tesla 500 kV line	2.56	27
Table Mountain – Vaca Dixon 500 kV line	0.59	7
Round Mountain – Table Mountain 500 kV line	0.97	38

Path 66 is an inter-tie between the Northwest and the California systems. The load and resource assumptions in the Northwest and the adjacent areas have a large impact on Path 66 congestion. The ADS PCM 2030 modeled more future renewable resources than the ADS PCM 2028 in the areas outside the CAISO system, consistent with the Load & Resource submittals and Integrated Resource Plans of the utilities. These resources, especially those in the PacifiCorp East areas and in the Nevada Energy's Sierra area, aggravated the flow coming into the Malin 500 kV bus. Further, changes in the ADS PCM 2030 transmission model also impacted the congestion on Path 66. The significant transmission model changes include the addition of the Boardman to Hemingway 500 kV line as well as additional 500 kV segments of the Gateway West project between the Anticline and Hemingway 500 kV buses, which are also adopted in the CAISO's planning PCM. The COI corridor congestion observed in this planning cycle did not significantly increase compared with the congestion in the previous planning cycles. However, due to the modeling changes in the ADS PCM 2030 as described above, it is worth reinvestigating the COI corridor congestion in this planning cycle and the potential mitigations.

Figure 4.10-1 shows the hourly flow of COI and the COI limits with derates due to the scheduled maintenances that were modeled in the planning PCM. Both the COI scheduled maintenances and derates were modeled the same as in the previous planning cycles, which were provided by the COI facility owners. Further investigating the COI congestion identified that the COI flows were binding at the 4800 MW COI path rating in 65 hours out of the total 259 congestion hours. In the rest hours of the congestion, the COI flows were binding at the reduced COI limits due to scheduled maintenances.

Figure 4.10-1: Path 66 (COI) Limit and Flow (positive direction is from north to south)

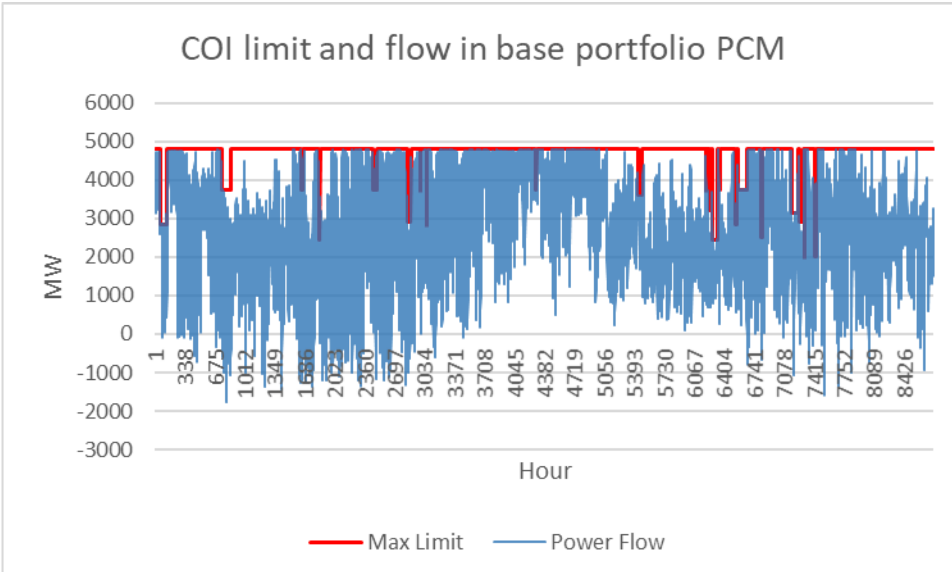


Table 4.10-15 shows the occurrences of Path 26 congestion at the hours of the day in each month in the base portfolio PCM simulation results.

Table 4.10-15: Occurrences of Path 66 Congestion

Hour of the day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	2	1	2	1	0	0	1	0	1	5	6	0
2	3	1	2	2	0	0	1	1	1	5	7	0
3	3	0	1	0	0	0	2	2	1	3	4	0
4	1	0	1	1	0	0	1	0	1	3	2	0
5	1	0	1	0	0	0	1	1	1	3	3	0
6	1	0	2	0	0	0	1	1	1	5	0	0
7	1	0	2	1	2	0	3	0	4	6	1	0
8	2	0	1	0	1	2	4	0	2	7	3	0
9	1	0	0	0	1	2	0	0	1	5	1	0
10	1	0	0	0	0	2	0	0	2	1	1	0
11	1	0	0	0	0	0	0	1	0	0	1	0
12	2	0	0	0	0	0	0	1	0	0	0	0
13	2	0	0	0	0	1	0	0	0	0	0	0
14	1	0	0	0	0	1	0	0	0	0	0	0
15	1	0	0	0	0	1	1	0	1	0	0	0
16	2	0	0	0	0	1	0	0	1	1	0	0
17	2	0	0	0	0	1	1	0	1	3	0	0
18	2	0	0	0	0	1	1	1	1	5	0	0
19	2	0	0	1	0	0	0	1	0	5	1	0
20	2	0	0	1	0	0	0	0	1	5	0	0
21	2	1	0	1	0	0	0	1	1	5	0	0
22	2	1	0	1	0	0	0	2	1	5	1	0
23	2	1	0	1	0	0	0	2	0	6	2	0
24	2	1	0	1	0	0	1	1	0	6	1	0

It was observed that most of the COI congestion occurred outside the solar hours, which indicates that the solar generation in the California areas can push flow to COI from south to north hence reduce COI congestion in north to south direction. There are total 118 hours in October and November when COI congestion was observed, which is partially attributed to the PDCI scheduled maintenance that was modeled in the planning PCM, and in the ADS PCM 2030 as well.

Congestion mitigation alternatives

The SWIP-North project was studied as a mitigation alternative for the COI corridor congestion. This project was proposed to build a new 500 kV line between the Idaho Power's Midpoint 500 kV bus and the Nevada Energy's Robinson Submit 500 kV bus. The SWIP-North project was submitted as an economic study request and an Interregional Transmission Process (ITP) project in this planning cycle.

First, the impacts of modeling the SWIP-North project on the power flow solution and congestion were analyzed. Figure 4.10-2 shows the hourly flow on the Midpoint – Robinson Summit 500 kV line of the SWIP-North project, and its duration curve. The positive direction is from Midpoint to Robinson Summit, or from north to south. It was observed that in more hours in the year the flow on this line was from south to north than from north to south. The north to south flow can be as high as 1500 MW, which is also higher than the maximum flow from south to north, which is less than 600 MW. Given the flow pattern and the magnitude of the Midpoint – Robinson Summit flow, it is not expected that the SWIP-North project would impact the COI flow too much. Figure 4.10-3 shows the COI flow duration curves with and without SWIP-North project. The two curves are very close to each other.

Figure 4.10-2: SWIP-North Flow (positive direction is from north to south)

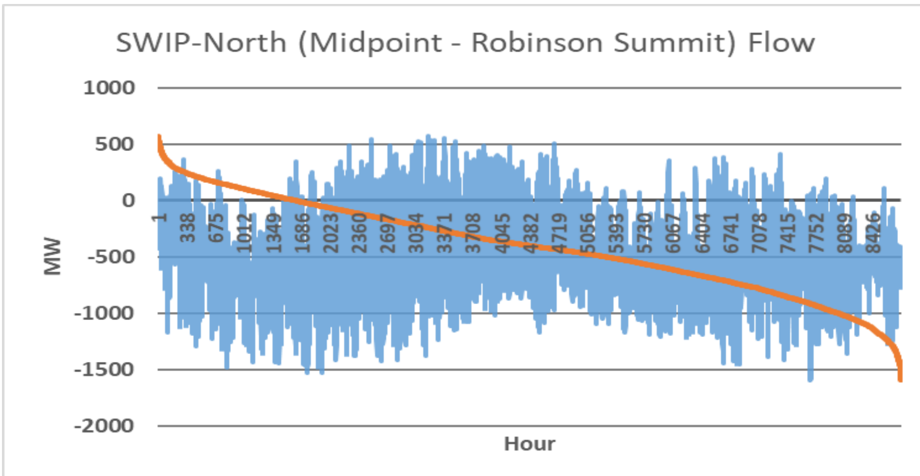
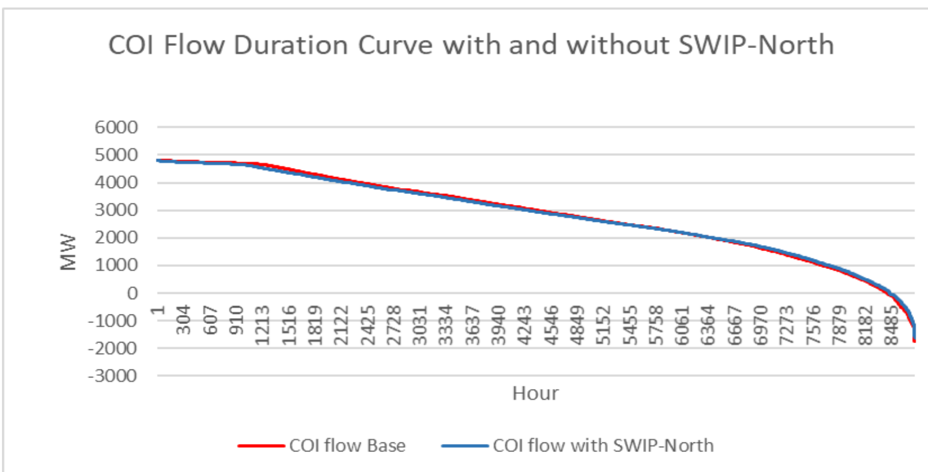
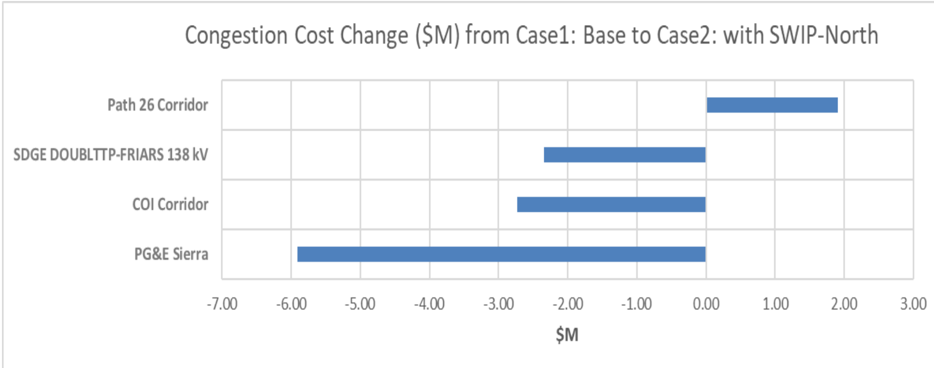


Figure 4.10-3: COI flow duration curve in the base case and in the case with SWIP-North



The SWIP-North project helps to mitigate the COI corridor congestion when both have flow from north to south. Figure 4.10-4 shows the major congestion changes due to modeling the SWIP-North project. The reduction of COI corridor congestion cost by about $2.7M per year.

Figure 4.10-4: Changes in Congestion with SWIP-North Project modeled



The largest congestion reduction with the SWIP-North project modeled was observed in the PG&E Sierra area, which is on the path connecting the PG&E Valley area and the Nevada's Sierra area. The congestion reduced because the loop flow through the NVE's Sierra area to the PG&E Valley area was mitigated by the SWIP-North project. The Path 26 congestion increased because the Path 26 flow from south to north was aggravated when the SWIP-North flow was from Midpoint to Robinson Summit. On the other hand, the increased flow injection into southern California by the SWIP-North project can provide counter flow to mitigate the congestion on the SDG&E's Doublet Tap – Friars 138 kV line.

The impacts of the SWIP-North project on generation dispatch and renewable curtailment were investigated in this planning cycle. First, the generation changes in regions, which generally match the Balancing Authority Area (BAA) footprints, are shown in Figure 4.10-5. The generation changes by generator type are represented in different color in the chart. The largest generation increase was observed in the SW_NVE region, which is the Nevada Energy BAA (NVE). The generation outputs in the CAISO region (CA_CISO) and the PacifiCorp East region (BS_PACE) had the largest decrease. While majority of generation changes in these regions were from thermal generators, renewable generation in the NVE region increased significantly as the SWIP-North project modeled. Noticeable generation changes were also observed in other BAAs or regions, such as BANC (CA_BANC), APS (SW_AZPS), SRP (SW_SRP), WAPA Rocky Mountain (RM_WACM), etc. The output of CAISO's solar generation increased slightly. The pattern of the generation changes indicated that the SWIP-North project impacts the generation dispatch across all three planning regions in the Western Interconnection.

Figure 4.10-5: Generation Changes by Region by Generator Type with SWIP-North Project modeled

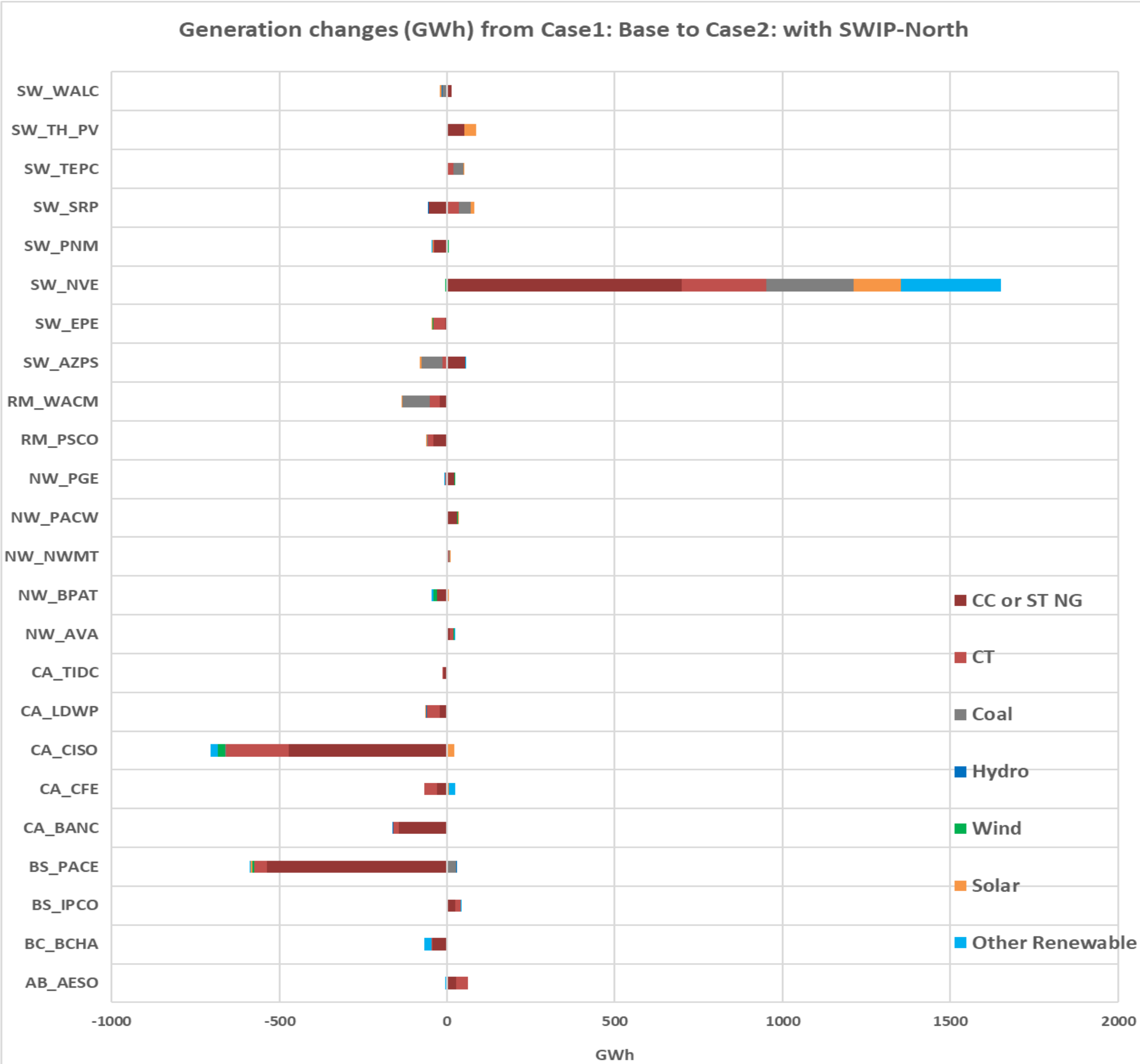
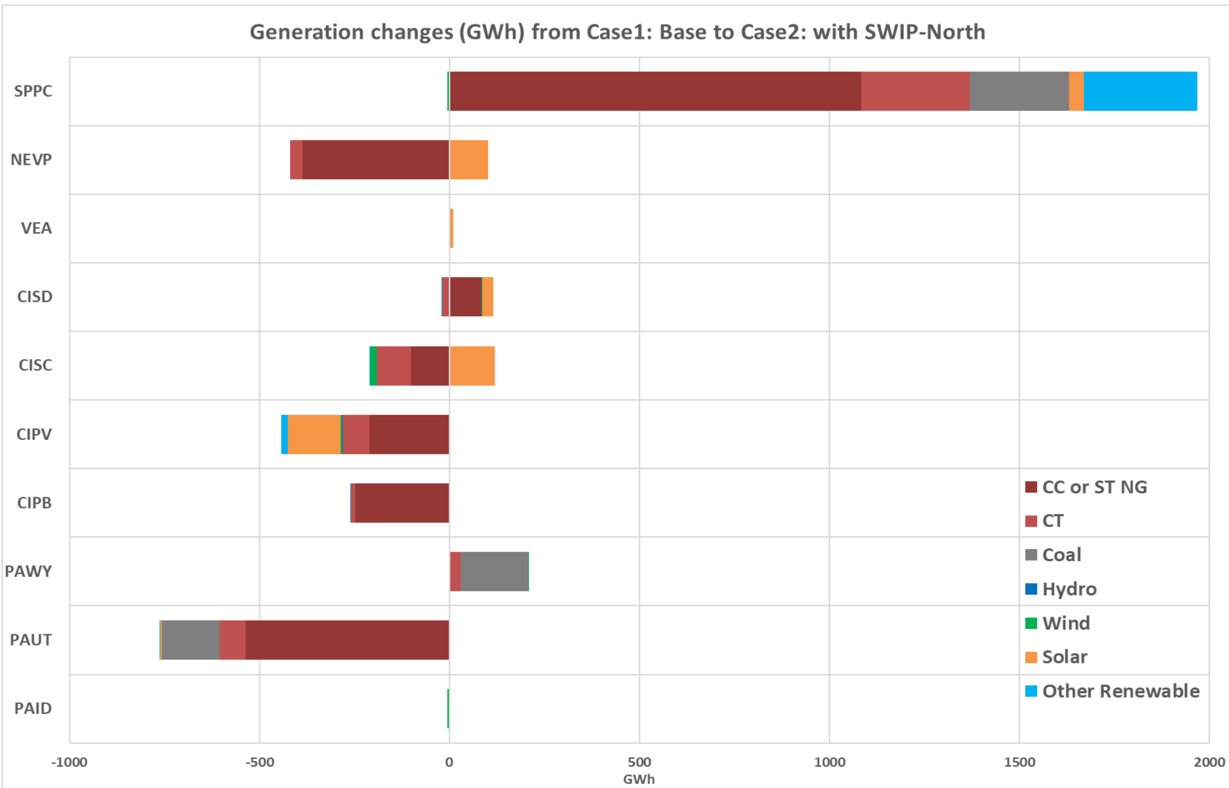


Figure 4.10-6 shows generation changes by load area in the BS_PACE, CA_CISO, and SW_NVE regions, which have the largest generation changes by region with the SWIP-North project modeled. In Figure 4.10-6, SPPC and NEVP are the NVE's Sierra area and Southern Nevada area, respectively. VEA, CISD, CISC, CIPB, CIPV are the CAISO's VEA area, SDG&E area, SCE area, and PG&E's Bay and PG&E's Valley areas, respectively. PAWY, PAUT, PAID are the PacifiCorp East region's load areas in Wyoming, Utah, and Idaho, respectively. Figure 4.10-6 demonstrated that the largest generation increase by load area occurred in the NVE's Sierra area (SPPC), but generation in the southern NV area (NEVP) decreased. The largest generation decrease was observed in the PACE's Utah area. The largest generation decrease within the CAISO's system was observed in the PG&E Valley area, followed by the PG&E Bay area and the SCE area. The SDG&E area generation increased mainly because the renewable

curtailment reduced in the SDG&E area due to the reduction of the Doublet Tap – Friars 138 kV line congestion. The increase of SCE area solar generation output and the decrease of the PG&E Valley area solar generation output are the results of generation dispatch change mainly attributed to the transmission topology change with the SWIP-North project modeled. The changes of the solar generation output in the SCE and SDG&E areas and in the PG&E Valley area aggravated the Path 26 congestion when its flow was from south to north.

Figure 4.10-6: Generation Changes by Load Area by Generator Type with SWIP-North Project modeled in Selected Regions



Finally, Table 4.10-16 shows the total wind and solar generation and curtailment in the CAISO controlled grid with and without the SWIP-North project modeled. The renewable curtailment reduced in the case with SWIP-North modeled, but the change is not significant.

Table 4.10-16: Wind and Solar Generation and Curtailment in the CAISO controlled grid

ISO Wind and Solar in the Base case			ISO Wind and Sola in the SWIP-North case		
Generation (GWh)	Curtailment (GWh)	Ratio	Generation (GWh)	Curtailment (GWh)	Ratio
75,051	13,595	15%	75,075	13,572	15%

Production benefits

The production benefit of the SWIP-North project for CAISO's ratepayers and the WECC production cost savings are shown in Table 4.10-17. The annual production benefit of the

SWIP-North project to the CAISO ratepayers is $10.1 million per year, which increased from the economic assessment result in the 2018~2019 planning cycle, in which the SWIP-North project did not provide positive benefit to the CAISO ratepayers.

Table 4.10-17: Production Benefits of SWIP-North Project

	Pre project ($M)	Post project ($M)	Savings ($M)
ISO load payment	7,954	7,904	51
ISO generator net revenue benefiting ratepayers	3,554	3,520	-34
ISO transmission revenue benefiting ratepayers	268	262	-6
ISO Net payment	4,132	4,122	10
WECC Production cost	13,213	13,178	35

Note that CAISO ratepayer "savings" are a decrease in load payment, but an increase in CAISO generator net revenue benefiting ratepayers and an increase in CAISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Cost estimates

The capital cost of the SWIP-North project was estimated at about $525 million in 2018 real dollar based on the economic study request submittal in the 2018~2019 planning cycle. The estimated cost was escalated to $543 million in 2020 real dollar based on the inflation factor provided in the CEC 2019 IEPR[132]. Applying the CAISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $543 million capital translates to a total cost of $706 million.

Benefit to Cost Ratio

The present value of the production benefit are shown in Table 4.10-18 and were calculated on a 50 year project life followed by the calculation of the benefit to cost ratio. The economic assessment for the SWIP-North project in this planning cycle identified that its benefit to cost ratio is 0.21, which indicates that the production cost benefit of this project likely cannot cover its total cost over its economic life. No other benefit was assessed for the SWIP-North project in this planning cycle, such as capacity benefit. To assess capacity benefit of the SWIP-North project requires further clarity of the CPUC's base renewable portfolio assumption for out of state resources. It also requires additional coordination with other planning regions to identify potential impacts of the SWIP-North project on the CAISO's import capability.

[132] https://efiling.energy.ca.gov/GetDocument.aspx?tn=231777&DocumentContentId=63623

Table 4.10-18: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

SWIP-North project	
Production cost savings ($million/year)	10.10
Capacity saving ($million/year)	0
Capital cost ($million)	543
Discount Rate	7%
PV of Production cost savings ($million)	149
PV of Capacity saving ($million)	0
Total benefit ($million)	149
Total cost (Revenue requirement) ($million)	706
Benefit to cost ratio (BCR)	0.21

Conclusions

Based on the CAISO's analysis, consistent with its Transmission Economic Analysis Methodology, the benefit to cost ratio was not sufficient for the CAISO to find the need for funding the SWIP-North project as an economic-driven project. It should be noted that the SWIP-North project was also submitted as an ITP project, and is under assessment in the ITP by the CAISO and other planning regions. The CAISO will coordinate with other planning regions through the ITP to further evaluate this project. In addition, COI congestion mitigation and the SWIP-North project may be reevaluated in future planning cycle with considering stakeholder comment regarding potentially extending the scope of the SWIP-North project to include series compensation on the Robinson to Harry Allen 500 kV line.

4.10.4 PG&E Fresno Congestions and Mitigations

Congestion analysis

Table 4.10-19 is a subset of Table 4.7-1 with only showing the congestions in the PG&E's Fresno area that were observed in this planning cycle.

Table 4.10-19: Top Five PG&E Fresno Area Congestions

Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	0	0	4,831	1,365	4,831	1,365
Q526TP-PLSNTVLY 70 kV line, subject to PG&E N-2 Panoche-Schindler and Panoche-Excelsesiorss 115 kV	1,469	634	0	0	1,469	634
KETLMN T-GATES 70.0 kV line #1	1,056	1,354	0	0	1,056	1,354
FIVEPOINTSSS-CALFLAX 70 kV line, subject to PG&E N-2 Panoche-Schindler and Panoche-Excelsesiorss 115 kV	842	863	34	1	876	864
HELM 70.0/230 kV transformer #1	339	294	0	0	339	294

Table 4.10-20, Table 4.10-21, Table 4.10-22, Table 4.10-23, and Table 4.10-24 show the occurrences of the Fresno area congestions in the hours of the day in each month. The hours of the day were not shown in the tables if there were no congestion observed in those hours in any month. Most of the congestions in the PG&E Fresno area were observed during the daytime, especially during the solar hours, which indicates that the Fresno area congestions are highly correlated with the solar generation in the Fresno area. In addition, congestions were observed more frequently in the summer months than in the winter months, which indicates the correlation between the local load and congestions in the Fresno area. Another factor that may impact the Fresno area congestions is the summer ratings of the congested transmission lines. Summer ratings are normally less than the winter ratings and are applied from April to October. The Helms transformer has the same rating through the year.

Table 4.10-20: Occurrences of Le Grand – Chowchilla 115 kV Congestion

Hour of the day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
10	0	0	0	19	28	22	21	9	3	0	0	0
11	0	0	4	18	28	29	30	29	28	23	0	0
12	0	0	12	16	27	30	31	30	30	27	5	0
13	3	11	8	11	25	29	31	31	29	28	13	0
14	4	10	4	9	22	28	31	29	29	25	7	0
15	0	8	3	8	21	26	31	30	29	20	0	0
16	0	0	0	8	25	28	31	30	29	13	0	0
17	0	0	0	11	21	21	27	24	5	0	0	0

Table 4.10-21: Occurrences of Q526 Tap (Schindler) – Pleasanton Valley 70 kV Congestion

Hour of the day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
10	0	0	0	11	15	3	4	4	6	5	0	0
11	0	0	0	4	16	23	29	27	28	22	0	0
12	0	1	1	5	11	20	24	25	21	15	0	0
13	0	1	0	2	7	14	18	14	8	4	2	0
14	0	0	0	3	2	10	19	11	8	4	1	0
15	0	0	0	2	4	12	21	10	15	7	0	0
16	0	0	0	1	6	17	22	22	22	10	0	0
17	0	0	0	2	5	1	4	3	0	0	0	0

Table 4.10-22: Occurrences of Kettleman Hills Tap - Gates 70 kV Congestion

Hour of the day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
10	0	0	0	18	25	22	20	20	23	15	0	0
11	0	0	2	11	22	27	31	31	28	23	6	0
12	7	6	0	9	20	29	31	29	29	18	5	7
13	4	4	0	5	22	29	31	28	28	15	4	7
14	1	5	0	6	25	30	31	29	28	19	1	4
15	1	5	0	9	23	25	31	29	30	17	3	2
16	5	1	0	10	21	25	31	29	30	24	0	0
17	0	0	0	9	18	21	31	27	18	9	0	0

Table 4.10-23: Occurrences of Fivepoints – Calflax 70 kV Congestion

Hour of the day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
11	0	0	6	6	4	3	3	3	9	5	3	0
12	14	11	9	6	13	15	22	19	24	13	18	10
13	12	10	5	4	17	22	27	27	27	19	17	10
14	9	7	2	5	19	22	29	28	27	19	15	9
15	2	6	2	5	17	20	27	28	26	19	10	6
16	0	2	0	4	12	9	9	21	17	15	0	0
17	0	0	0	1	0	0	0	1	0	0	0	0
21	0	0	0	0	0	0	1	0	0	0	0	0

Table 4.10-24: Occurrences of Helm 70/230 kV Congestion

Hour of the day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12	0	0	3	1	2	1	2	2	4	5	3	0
13	10	9	6	2	4	6	8	21	18	13	14	6
14	9	7	1	1	6	7	12	21	20	13	12	4
15	1	4	0	0	2	4	8	10	5	6	0	1

Congestion mitigation alternatives

Table 4.10-25 summarized the potential mitigations for the congestions in the PG&E Fresno area.

Table 4.10-25: Summary of Mitigation Alternatatives for PG&E Fresno Congestions

Constraints Name	Mitigation
LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	SPS
Q526TP-PLSNTVLY 70 kV line, subject to PG&E N-2 Panoche-Schindler and Panoche-Excelsesiorss 115 kV	SPS
KETLMN T-GATES 70.0 kV line #1	Reconductoring
FIVEPOINTSSS-CALFLAX 70 kV line, subject to PG&E N-2 Panoche-Schindler and Panoche-Excelsesiorss 115 kV	SPS
HELM 70.0/230 kV transformer #1	Transformer upgrade

These mitigations were studied one by one, since each of them was designed for mitigating specific congestion. The study results showed that reconductoring the Kettleman Hills Tap – Gates 70 kV line and upgrading the Helm transformer can completely mitigate the respective congestions, but the SPS alternatives can only partially mitigate the respective congestions. It is worth noting that these SPS alternatives only considered to trip the generators most effective to the congestions. Tripping additional generators in the adjacent areas may further reduce the congestions. To expand these SPS however requires to evaluate the feasibility of SPS implementation and potential impact on the reliability of the adjacent areas. Therefore, no further economic assessment was conducted for the SPS alternatives in this planning cycle. The CAISO will coordinate with PG&E for the scope of these SPS in future planning cycles.

Production benefits

The production benefits for CAISO ratepayers and the production cost savings of reconductoring the Kettleman Hills Tap to Gates 70 kV line and upgrading the Helm transformer for CAISO's ratepayers, respectively, are shown in Table 4.10-26.

Table 4.10-26: Production Benefits for Reconductoring Kettleman Hills Tap to Gates 70 kV line and Helm transformer

	Base case	Reconductoring Kettleman Hills Tap to Gates		Upgrading Helm transformer	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	7,954	7,957	-2	7,953	1
ISO generator net revenue benefiting ratepayers	3,554	3,555	1	3,554	0
ISO transmission revenue benefiting ratepayers	268	268	0	268	0
ISO Net payment	4,132	4,133	-1.04	4,131	0.82
WECC Production cost	13,213	13,214	-1	13,217	-4

Note that CAISO ratepayer "savings" are a decrease in load payment, but an increase in CAISO generator net revenue benefiting ratepayers and an increase in CAISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Cost estimates

The estimated capital cost for reconductoring the Kettleman Hills Tap – Gates 70 kV line is about $13.2 million based on the PG&E's per unit cost[133]. However, no further cost estimates and benefit to cost ratio calculation for this alternative were conducted in this planning cycle, since the reconductoring does not show a benefit to the CAISO's ratepayers.

The capital cost of upgrading the Helm transformer was estimated at about $10 million based on the PG&E's per unit cost that has been derived for generation interconnection study. Applying the CAISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $10 million capital cost translates to a total cost of $13 million.

Benefit to Cost Ratio

The present value of the sum of the production cost of the Helm transformer upgrade is shown in Table 4.10-27 and were calculated on a 40 year project life followed by the calculation of the benefit to cost ratio. No capacity saving was identified in this planning cycle.

[133] http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx

Table 4.10-27: Benefit to Cost Ratios (Ratepayer Benefits per TEAM) of Helm 70/230 kV Transformer Upgrade

PG&E Fresno Helm 70/230 kV transformer Upgrade	
Production cost savings ($million/year)	0.82
Capacity saving ($million/year)	0
Capital cost ($million)	10
Discount Rate	7%
PV of Production cost savings ($million)	12
PV of Capacity saving ($million)	0
Total benefit ($million)	12
Total cost (Revenue requirement) ($million)	13
Benefit to cost ratio (BCR)	0.90

Conclusions

Based on the CAISO's analysis, consistent with its Transmission Economic Analysis Methodology, the benefit to cost ratio was not sufficient for the CAISO to find the economic need to upgrade the Helm 70/230 kV transformer. The other mitigation alternatives for the PG&E Fresno area congestions did not show benefit to the CAISO's ratepayers in this planning cycle or required further evaluate in future planning cycle.

It should be noted that the congestion on this line is related to several key factors including the local load profile and the local solar generator output. The CAISO will coordinate with PG&E to investigate these key factors in future planning cycles.

4.10.5 Path 26 corridor congestion and the PTE project

Congestion analysis

The production cost simulation results demonstrated congestion occurring on the Path 26 corridor mainly when the flow was from south to north, except for the congestion on the Midway – Vincent 500 kV line, which was observed when the flow was from Midway to Vincent. Renewable generators in southern California identified in the CPUC renewable portfolio were the main driver of the Path 26 corridor congestion. The congestion cost and hours of the Path 26 corridor congestion are shown in Table 4.10-28.

Table 4.10-28: Path 26 corridor congestion

Constraints Name	Congestion Costs ($M)	Congestion Duration (Hrs)
MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	3.81	77
P26 WECC Northern-Southern California	2.87	154
MW_VINCNT_11-MW_VINCNT_12 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	0.055	6

It was observed in Table 4.10-28 that the majority of the congestion on the Path 26 corridor occurred on the Midway to Whirlwind 500 kV line and the Path 26 WECC path. The congestion analysis in this section was focused on these two congested components. Table 4.10-29 shows the occurrences of the Midway – Whirlwind 500 kV line congestion, which was observed between April and October and during the solar hours. Table 4.10-29 only shows the hours of the day when the Midway – Whirlwind 500 kV line was congested in at least one month. The congestion on this 500 kV line is mainly attributed to the high solar generation output in the southern California areas and the low summer line ratings. The summer line ratings were enforced from April to October in the planning PCM, which is consistent with the CAISO's grid operation.

Table 4.10-29: Occurrences of Midway – Whirlwind 500 kV Line Congestion

Hour of the day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
9	0	0	0	4	10	9	2	3	0	0	0	0
10	0	0	0	0	3	5	4	5	1	0	0	0
11	0	0	0	0	0	5	0	1	1	1	0	0
12	0	0	0	0	0	3	0	0	0	1	0	0
13	0	0	0	0	0	1	0	0	0	0	0	0
15	0	0	0	0	1	0	0	0	0	1	0	0
16	0	0	0	0	2	1	1	2	0	1	0	0
17	0	0	0	0	2	3	0	2	0	0	0	0
18	0	0	0	0	0	2	0	0	0	0	0	0

Table 4.10-30 shows the occurrences of the Path 26 congestion. The congestion was also observed mainly during the solar hours, which indicates that the high solar generation output in the southern California areas was the main driver of the Path 26 congestion. Path 26 was less congested in the summer months than in the other months of the year, because the load is also high in summer in southern California.

Table 4.10-30: Occurrences of Path 26 Congestion

Hour of the day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0	0	0	0	0	0	0	1	0	0	0	0
2	0	0	0	0	0	0	0	1	0	0	0	1
3	0	0	0	0	0	0	0	0	0	0	0	1
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	1	0	0	0
8	0	0	0	0	5	1	0	0	5	4	0	0
9	0	3	3	2	4	1	2	2	6	2	4	1
10	2	2	1	1	1	0	0	0	1	0	3	1
11	3	4	5	2	0	0	0	0	0	1	0	1
12	3	6	4	2	0	0	0	0	0	2	2	2
13	3	3	2	2	0	0	0	0	0	2	3	3
14	4	2	2	2	0	0	0	0	0	1	0	0
15	1	1	2	2	0	0	0	0	0	0	0	1
16	2	0	1	1	0	0	0	0	0	0	0	2
17	0	0	0	0	0	0	0	0	0	0	0	1
18	0	0	0	1	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	2	0
22	0	0	0	0	0	0	0	0	1	0	1	0
23	0	0	0	0	0	0	0	2	1	0	0	0
24	0	0	0	0	0	0	0	4	0	0	0	0

Congestion mitigation alternatives

The Pacific Transmission Expansion (PTE) project, a stakeholder-submitted economic study request with multi-terminals offshore HVDC lines between the northern and southern California systems, was considered as an alternative to mitigating the Path 26 corridor congestion in this planning cycle. Figure 4.10-7 and Figure 4.10-8 show the two options of the PTE project, which were submitted by stakeholder to the CAISO's reliability request window. Detailed information of the PTE project can be found in section 4.8.8.

Figure 4.10-7: PTE project – Option 1

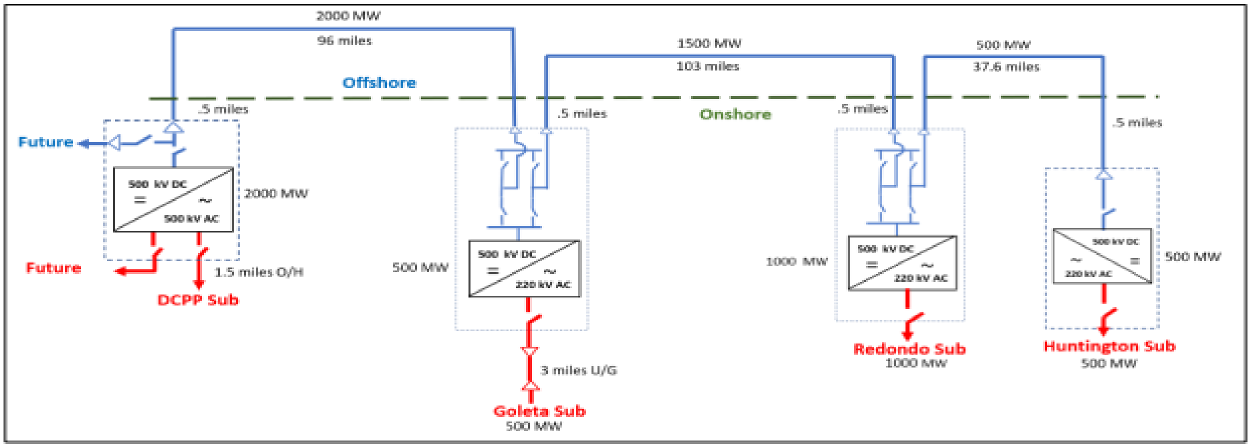
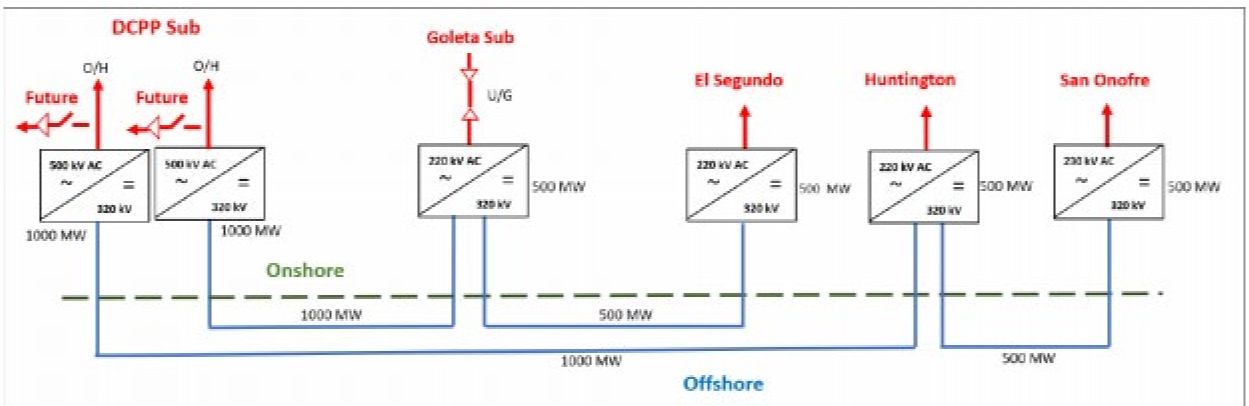
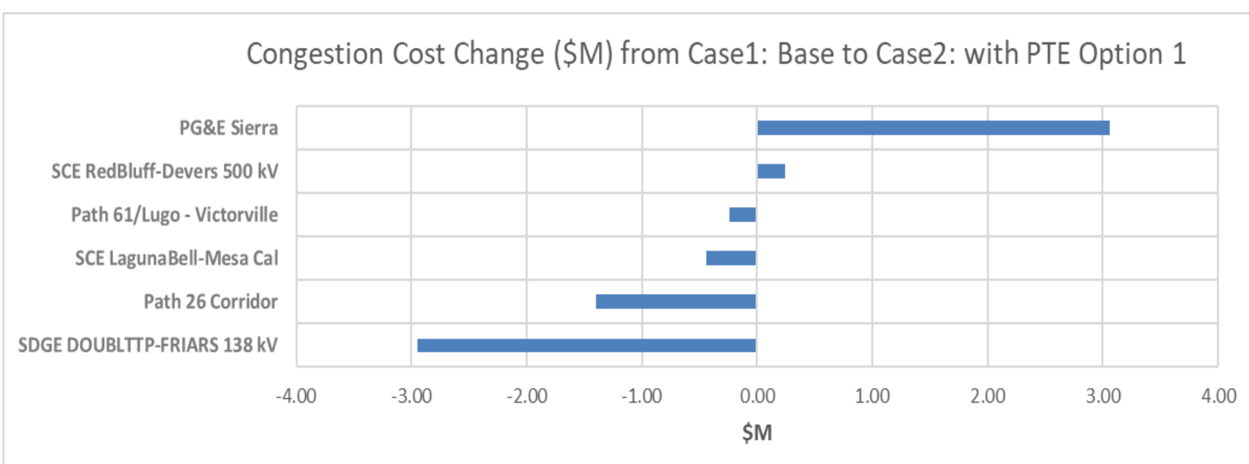


Figure 4.10-8: PTE project – Option 2



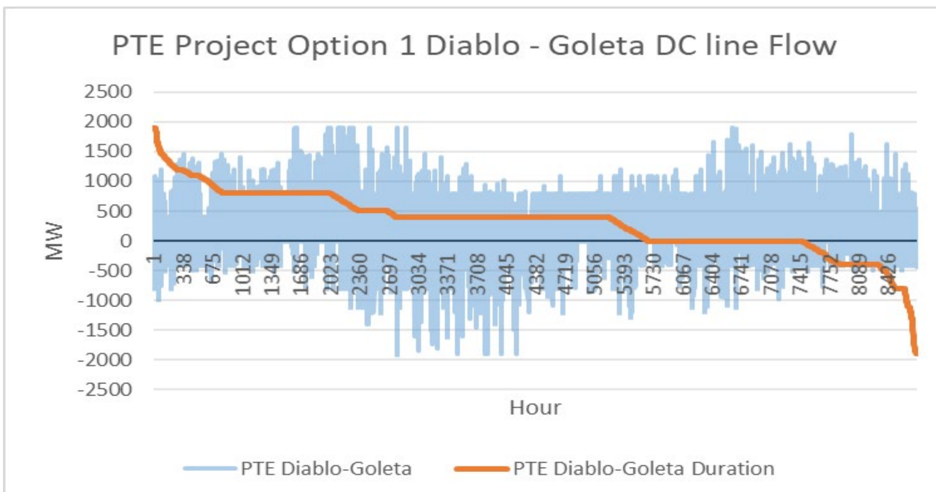
The noticeable congestion changes resulted from modeling the PTE project Option 1 is shown in Figure 4.10-9.

Figure 4.10-9: Congestion changes with PTE project Option 1 modeled



The change of the Path 26 corridor congestion with the PTE project Option 1 modeled in this planning cycle was not as significant as in the study results in the last planning cycle. This is mainly because of the changes of renewable resource assumptions in the planning PCM, which resulted in the PTE HVDC line flow were from north to south in many hours of the year in the simulation results and potentially creating loop flow between the PTE HVDC lines and the Path 26 corridor. Figure 4.10-10 shows the Diablo – Goleta HVDC line hourly flow and duration in the PTE Option 1 PCM case. The positive direction is from Diablo to Goleta. It was observed that there were more hours when the HVDC flow was from north to south than from south to north. Consequently, the total congestion hours of the Path 26 corridor congestion increased to 1228 hours in the PTE Option 1 PCM from the 237 congestion hours in the base planning PCM.

Figure 4.10-10: PTE project Option 1 Diablo – Goleta HVDC line flow



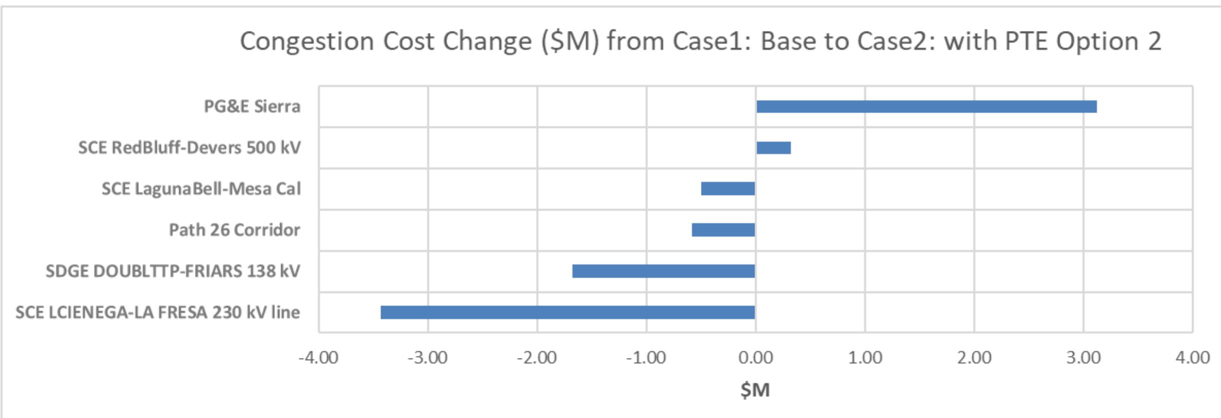
The increase of the PG&E Sierra area congestion, mainly on the Drum – Brunswick 115 kV line, was observed when the flow was from the NVE's Sierra area to the PG&E Valley area. This is partially because the loop flow through the NVE's Sierra area to the PG&E Valley area increased when the PTE HVDC line flow was from north to south. In the meantime, it was observed that the LMP in the PG&E Valley area increase in many hours when the flow from northern California to southern California increased. As a result, the price difference between the NVE's Sierra area and the PG&E Valley area increased, which also contributed to the increase of the PG&E Sierra area congestion cost.

The congestion cost decrease on the SCE Laguna Bell – Mesa Cal 230 kV line and the SDG&E Doublet Tap – Friars 138 kV line are also related to the PTE HVDC flow from north to south. The HVDC line terminated at the Redondo Beach substation can provide counter flow to the Laguna Bell – Mesa Cal 230 kV line. Similarly, the HVDC line terminated at the Huntington Beach can help to mitigate the congestion on the Doublet Tap – Friars 138 kV line.

The south to north flow on the PTE Diablo – Goleta HVDC line, on the other hand, helped to mitigate the Path 26 congestion and the Path 61 congestion when the flows on these two WECC paths were from south to north. The congestion on the SCE Red Bluff – Devers 500 kV line slightly increased due to generation dispatch change. Specifically, the relief of the Path 26 and Path 61 congestion helped to reduce the renewable curtailment, or increase the renewable generation, in the SCE Riverside East area. As a result, the flow from the Red Bluff 500 kV bus to the Devers 500 kV bus and the congestion on the line increased.

Figure 4.10-11 shows the impact of the PTE project Option 2 on congestion. In general, the impact of the two options of the PTE project on the congestion in the CAISO's controlled grid are similar. The changes in individual congestions may vary due to the configuration differences between these two options.

Figure 4.10-11: Congestion changes with PTE project Option 2 modeled



The PTE Option 2 has less impact on the Path 26 corridor congestion than the Option 1 does because the Option 2 has a 1000 MW HVDC line between the PG&E's Diablo and the SCE's Goleta substations, compared to the 2000 MW HVDC line between the Diablo and Goleta substations in the Option 1. The SCE La Cienega – La Fresa 230 kV line congestion reduced more in the Option 2 case than in the Option 1 case. This is because the HVDC line terminated at the El Segundo substation in the Option 2 is more effective to mitigate the congestion on the La Cienega – La Fresa 230 kV line than the HVDC line terminated at the Redondo Beach substation in the Option 1.

Production benefits

The production benefit of the PTE project for CAISO's ratepayers and the production cost savings are shown in Table 4.10-31.

Table 4.10-31: Production Benefits for the PTE HVDC project

	Base case	Option 1		Option 2	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	7,954	7,986	-32	7,988	-33
ISO generator net revenue benefiting ratepayers	3,554	3,572	18	3,574	20
ISO transmission revenue benefiting ratepayers	268	267	-1	267	-1
ISO Net payment	4,132	4,147	-15	4,147	-15
WECC Production cost	13,213	13,219	-6	13,210	3

Note that CAISO ratepayer "savings" are a decrease in load payment, but an increase in CAISO generator net revenue benefiting ratepayers and an increase in CAISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

The total production cost benefit of the PTE project Option 1 to the CAISO ratepayers is -$15 million per year based on the production cost simulation results in this planning cycle, which is the summation of the changes of load payment, generator net revenue, and transmission revenue. The production cost simulation results showed that modeling the PTE project results in an increase in load payment and an increase in generator net revenue. Transmission revenue benefiting ratepayers reduced because congestion cost reduced with the PTE project modeled. The Option 2 has the same production cost benefit to the CAISO ratepayers at -$15 million per year, although the savings of load payment, generator profile, and transmission revenue are different from the Option 1 results. The WECC production cost saving with the PTE Option 1 is also negative, which indicated that this option does not help to reduce the system overall production cost. The PTE Option 2 can reduce the system overall production cost.

The PTE project was identified as an alternative to reducing LCR in some local areas in the SCE's and SDG&E's systems. The detailed LCR reduction assessment for the PTE project can be found in section 4.10.7 and 4.10.8, where the cost estimation and the benefit to cost ratio calculation for the PTE project are also described.

4.10.6 Greater Bay Area Local Capacity Reduction Study

Greater Bay Area Contra Costa Sub-area Local Capacity Reduction Study

The CAISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the Greater Bay Area Contra costa sub-area that the CAISO considered to potentially have minimal environmental impact and be cost-effective given the economic study parameters relied upon in this 2020-2021 planning cycle. The assessment of alternatives to reduce and eliminate the LCR requirement in the Contra Costa sub-area is in Appendix G, section 3.2.5.2. The alternatives would consist of the following:

- Alternative 1: Horizon's West connecting the existing PG&E's Contra Costa PP 230 kV substation, via a new 230 kV line (Option1-submarine & Option 2-underground) and switchyard, to the existing PG&E's Pittsburg 230 kV substation
- Alternative 2: Smart Wire's (SW) Tesla-Delta Switchyard 230 kV line reactance project with Smart Wires device.

Production benefits

This alternative is not expected to provide production benefits. Only minor congestion was identified in the Contra Costa sub-area in this planning cycle, as shown in Table 4.7-1.

Local Capacity Benefits:

The primary benefit to CAISO ratepayers would be a reduction in local capacity requirements in the Greater Bay Area. Alternative 1 does not mitigate or reduce the original LCR requirement for this area and will not be discussed further in this section. Alternative 2 eliminates the requirement for gas-fired generation in the Contra Costa by approximately 576 MW[134].

As discussed in section 4.3.4, local capacity requirement reductions in northern California were valued in this planning cycle at the difference between local and system and between local and "north of path 26 system" resources. For the Contra Costa sub-area, these translated to values of $120/MW-year and ($1200)/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2020-2021 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

The benefit of local capacity reductions in the Contra Costa sub-area are shown in Table 4.10-32 . The benefit of local capacity reductions in the Contra Costa sub-area is valued based on the cost range for the Contra Costa sub-area.

Table 4.10-32: Contra Costa LCR Sub-area Reduction Benefits

SW(Tesla-Delta Switchyard 230 kV line reactance project)		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (MW)	576	
Capacity value (per MW-year)	$120	($1,200)
LCR Reduction Benefit ($million)	$0.07	-$0.69

Cost estimates:

[134] The actual LCR reduction is 1334 MW which includes the NQC of Marsh landing units. These units are also black start units and so the NQC of these units are not considered in calculating the LCR benefit.

The planning estimate cost for the alternative 2 transmission project is $5.4 million, based on the request window submittal in 2019-2020 transmission planning process. These are estimated costs at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Applying the CAISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", for a total of $7 million for the Tesla-Delta Switchyard 230 kV line reactance project.

Benefit to Cost Ratio

The present value of the capacity benefit and the benefit to cost ratio for the Tesla-Delta Switchyard 230 kV line reactance project is shown in Table 4.10-33. These values were calculated based on a 40 year project life.

Table 4.10-33 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

SW(Tesla-Delta Switchyard 230 kV line reactance project)		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.07	-$0.69
Capital Cost Estimate ($ million)	$5.4	
Benefit to Cost		
PV of Savings ($million)	$0.95	($9.54)
Estimated "Total" Cost (screening) ($million)	$7.02	
Benefit to Cost	0.14	-1.36

The differential between the PG&E local resource adequacy capacity costs and system capacity costs provide only marginal benefits for the project.

Conclusions

Horizon West's alternative 1 does not mitigate and or reduce the original LCR requirement for the area. Hence, it was not considered for the economic evaluation in this cycle. Smart Wire's alternative 2 eliminates the LCR requirement for the Contra costa sub pocket. However, based on the latest publically available 2018 RA prices this project only provides marginal benefits for this area. For this reason, the alternative is not recommended for approval at this time. The benefit to cost ratio for this project can be reassessed in future cycles based on the latest available CPUC RA data.

Greater Bay Area San Jose Sub-area Local Capacity Reduction Study

The CAISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the Greater Bay Area San Jose sub-area that the CAISO considered to potentially have minimal environmental impact and be cost-effective given the economic study parameters relied upon in this 2020-2021 planning cycle. The assessment of alternatives to reduce and eliminate the LRC requirement in the San Jose sub-area is in Appendix G, section 3.2.5.7. The alternatives would consist of the following:

- Alternative 1: Horizon West's Metcalf 230 kV substation.

Production benefits

The alternatives are not expected to provide production benefits. No congestion was identified in the San Jose sub-area in this planning cycle.

Local Capacity Benefits:

The primary benefit to CAISO ratepayers would be a reduction in local capacity requirements in the San Jose sub area. The local capacity requirement for generation in the San Jose sub-area was reduced or mitigated resulting in a reduction of approximately 162 MW with this alternative.

As discussed in section 4.3.4, local capacity requirement reductions in northern California were valued in this planning cycle at the difference between local and system and between local and "north of path 26 system" resources. For the San Jose sub-area, these translated to values of $120/MW-year and ($1200)/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2020-2021 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC's Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

The benefit of local capacity reductions in the San Jose sub-area are valued based on the cost range for the sub-area as shown in Table 4.10-34.

Table 4.10-34: San Jose LCR Sub-area Reduction Benefits – Alternative 1

Alternative 1: Horizon West's Metcalf 230 kV substation		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (MW)	162	
Capacity value (per MW-year)	$120	($1,200)
LCR Reduction Benefit ($million)	$0.02	-$0.19

Cost estimates:

The planning estimate cost for the Metcalf 230 kV substation is $80 million, based on the request window submittal. These are estimated costs at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Applying the CAISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", for a total of $104 million for the Metcalf 230 kV substation project.

Benefit to Cost Ratio

The present value of the capacity benefit and the benefit to cost ratio for the Metcalf 230 kV substation project is shown in Table 4.10-35. These values were calculated based on a 40 year project life.

Table 4.10-35 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 1: Metcalf 230 kV substation		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.02	-$0.19
Capital Cost Estimate ($ million)	$80	
Benefit to Cost		
PV of Savings ($million)	$0.27	($2.68)
Estimated "Total" Cost (screening) ($million)	$104	
Benefit to Cost	0.00	-0.03

The differential between the PG&E local resource adequacy capacity costs and system capacity costs provide almost negligible benefits for the project.

Conclusions

The Metcalf 230 kV substation project provides some reduction in the San Jose sub area requirement. However, based on the latest publically available 2018 RA prices this project only provides marginal benefit for this area. For this reason, the alternative is not recommended for approval at this time. The benefit to cost ratio for this project can be reassessed in future cycles based on the latest available CPUC RA data.

Greater Bay Area Local Capacity Reduction Study

The CAISO examined a potential transmission option for reducing and eliminating the gas-fired generation requirements in the Greater Bay LCR area that the CAISO considered to potentially have minimal environmental impact and be cost-effective given the economic study parameters relied upon in this 2020-2021 planning cycle. The assessment of alternatives to reduce and eliminate the LCR requirement in the Contra Costa sub-area is in Appendix G, section 3.2.5.7. The alternatives would consist of the following:

- PG&E's Metcalf 500-230 kV Transformers Dynamic Series Reactor Project

Production benefits

The alternatives are not expected to provide production benefits. Only minor congestion was identified in the Great Bay Area in this planning cycle, as shown in Table 4.7-1.

Local Capacity Benefits:

The primary benefit to CAISO ratepayers would be a reduction in local capacity requirements in the greater bay area. The local capacity requirement for generation in the greater bay area was reduced or mitigated resulting in a reduction of approximately 1342 MW with this alternative.

As discussed in section 4.3.4, local capacity requirement reductions in northern California were valued in this planning cycle at the difference between local and system and between local and “north of path 26 system” resources. For the greater bay area, these translated to values of $120/MW-year and ($1200)/MW-year respectively. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources, and is also being applied in the 2020-2021 transmission planning cycle to resources such as storage recognizing the need for further coordination with the CPUC’s Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

The benefit of local capacity reductions in the greater bay area are shown in Table 4.10-36. The benefit of local capacity reductions in the area is valued based on the cost range for the sub-area.

Table 4.10-36: Greater Bay area Reduction Benefits – Alternative 1

Alternative 1: Metcalf 500-230 kV Transformers Dynamic Series Reactor Project		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (MW)	1342	
Capacity value (per MW-year)	$120	($1,200)
LCR Reduction Benefit ($million)	$0.16	-$1.61

Cost estimates:

The planning estimate cost for the Metcalf 500-230 kV Transformers Dynamic Series Reactor Project is $22-32 million, based on the request window submittal. These are estimated costs at this time and would need to be refined further with engineering estimate if there is further interest and consideration.

Applying the CAISO’s screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the “total” cost”, for a total of $29- 42 million for the Metcalf 500-230 kV Transformers Dynamic Series Reactor project.

Benefit to Cost Ratio

The present value of the capacity benefit and the benefit to cost ratio for the Metcalf 500-230 kV Transformers Dynamic Series Reactor project is shown in Table 4.10-37. These values were calculated based on a 40 year project life.

Table 4.10-37 : Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 1: Metcalf 500-230 kV Transformers Dynamic Series Reactor Project Metcalf 230 kV substation		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.16	-$1.61
Capital Cost Estimate ($ million)	$22-32	
Benefit to Cost		
PV of Savings ($million)	$2.22	($22.22)
Estimated "Total" Cost (screening) ($million)	$29-42	
Benefit to Cost	0.00 to 0.08	-0.78 to-0.03

The differential between the PG&E local resource adequacy capacity costs and system capacity costs provide almost negligible benefits for the project.

Conclusions

The Metcalf 500-230 kV Transformers Dynamic Series Reactor Project provides some significant reduction in the bay area requirement. However, based on the latest publically available 2018 RA prices, this project provides almost negligible benefit for this area. For this reason, the alternative is not recommended for approval at this time. The benefit to cost ratio for this project can be reassessed in future cycles based on the latest available CPUC RA data.

4.10.7 Big Creek-Ventura Area Local Capacity Reduction Study

As a part of the 2019-2020 transmission planning process the CAISO undertook an assessment of the Big Creek/Ventura LCR Area to determine potential transmission alternatives to reduce or eliminate the need for gas-fired generation to meet the LCR requirement. The following alternatives were considered:

- Pardee-Sylmar lines rating increase
- Pacific Transmission Expansion (PTE) HVDC

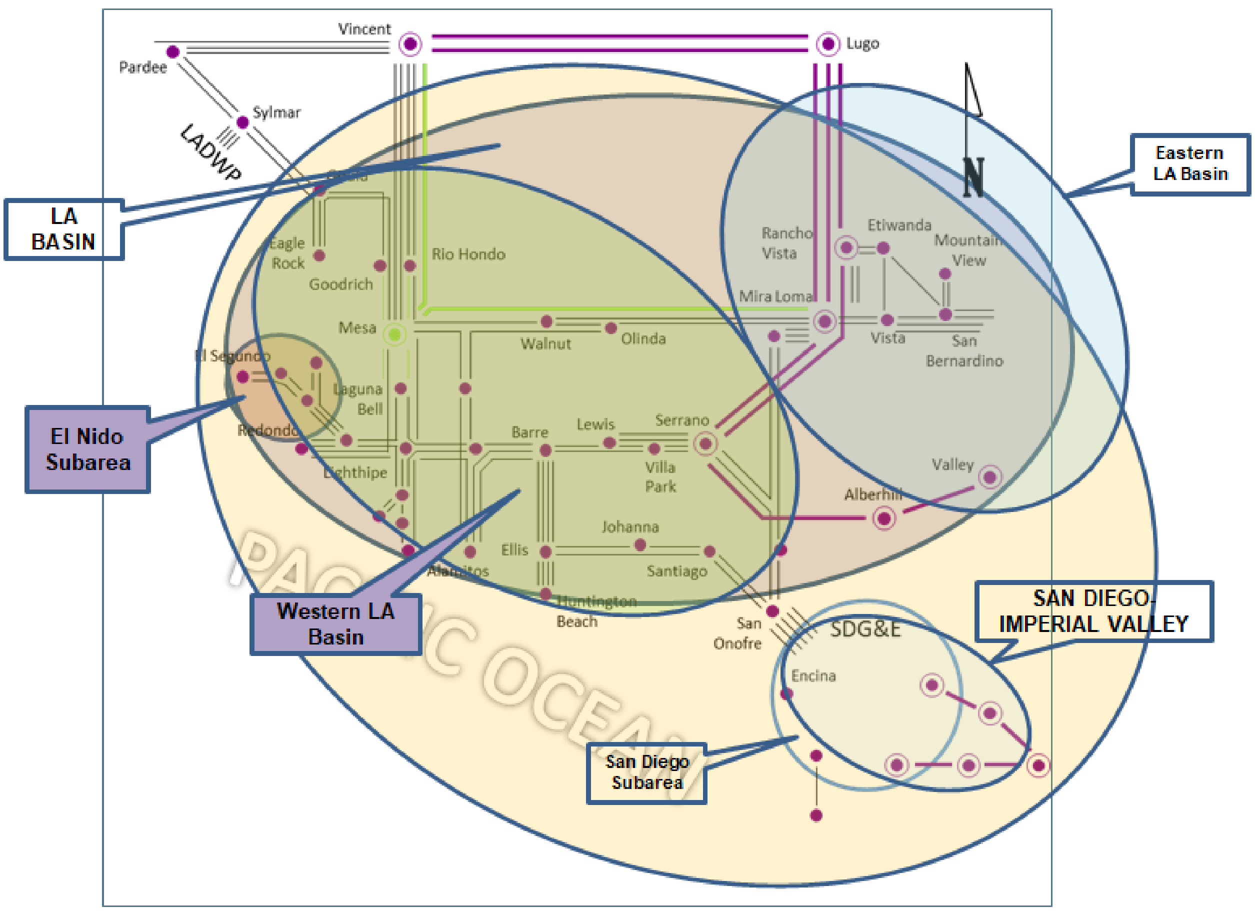
The Pardee-Sylmar Line rating increase project was approved as a reliability project with economic benefits derived from LCR and production cost reduction in the previous 2019-2020 Transmission Plan. The PTE Project was found to reduce the Big Creek/Ventura LCR requirement by approximately 393 MW due to its 500 MW terminal at Goleta. The PTE project with some configuration alternatives is assessed in the current planning cycle as part of the LA Basin area assessment in section 4.10.8. Since the configuration of the project in the Big Creeck/Ventura area has not changed from last year, its LCR reduction benefit in the area is not expected to materially change. As a result, the project's LCR reduction benefit with respect to the Big Creek/Ventura area determined in the previous planning cycle will be used as an input in the assessment performed as part of the LA Basin local capacity area.

No new alternatives are considered for the Big Creek/Ventura area in the current planning cycle.

4.10.8 El Nido, Western LA Basin Sub-areas, overall LA Basin and San Diego-Imperial Valley Areas Local Capacity Reduction Study

El Nido, shown in Figure 4.10-12, is a sub-area within the Western LA Basin. Western LA Basin is a sub-area within the LA Basin LCR area. The following diagram provides the context of these two sub-areas within the overall LA Basin area.

Figure 4.10-12 Single line diagram of the LA Basin and San Diego-Imperial Valley LCR and sub LCR areas



Recap of El Nido sub-area local capacity requirement (2030)

The results for this assessment are summarized in Table 4.10-38. For further details, please refer to Appendix G of this 2020-2021 Transmission Plan.

Table 4.10-38: 2030 LCR Need and Transmission Constraint in the El Nido sub-area

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2030	First Limit	P7	Thermal loading on La Fresa-La Cienega 230 kV line	La Fresa – El Nido #3 & 4 230 kV lines	355 MW

Recap of the Western LA Basin sub-area local capacity requirement (2030)

The results for this assessment are summarized in Table 4.10-39. For further details, please refer to Appendix G of the Transmission Plan.

Table 4.10-39: 2030 LCR Need and Transmission Constraint in the Western LA Basin sub-area

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2030	First Limit	P6	Thermal loading on the Mesa-Laguna Bell #1 230 kV line	Mesa – Redondo #1 230 kV line, followed by Mesa - Lighthipe 230 kV line, or vice versa	3,924

Recap of the Eastern LA Basin sub-area local capacity requirement (2030)

For further details, please refer to Appendix G of the Transmission Plan. The results are shown in Table 4.10-40.

Table 4.10-40: 2030 LCR Need and Transmission Constraint in the Eastern LA Basin sub-area

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2030	First Limit	Extreme (N-1-2)	Post-transient voltage stability	Serrano-Valley 500 kV line, followed by Devers – Red Bluff 500 kV #1 and 2 lines	2,270

Recap of the overall LA Basin sub-area local capacity requirement (2030)

For further details, please refer to Appendix G of the Transmission Plan. The results are shown in Table 4.10-41.

Table 4.10-41: 2030 LCR Need and Transmission Constraint for the overall LA Basin sub-area

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2030	Sum of Western & Eastern LA Basin Needs	See study results	See Western and Eastern LA Basin LCR results	See Western and Eastern LA Basin LCR results	6,194
2030	N/A	P3	Yucca-Pilot Knob 161kV Line	TDM generation, system readjustment, followed by Imperial Valley-North Gila 500kV line	6,194

Recap of the overall San Diego – Imperial Valley local capacity requirement (2030)

For further details, please refer to Appendix G of the Transmission Plan. These result are shown in Table 4.10-42.

Table 4.10-42: 2030 LCR Need and Transmission Constraint in the San Diego – Imperial Valley Area

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2030	First Limit (No Solar Generation Due to Load Peaking at 8 p.m.)	P3	Yucca-Pilot Knob 161kV line	G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500 kV line (N-1)	3,718 MW

<u>CAISO-considered LCR reduction solutions and proposed project submittals through stakeholder comments</u>

The CAISO examined a number of potential transmission options for reducing the gas-fired generation requirements in the El Nido, Western LA Basin sub-areas, overall LA Basin and San Diego-Imperial Valley areas. The transmission options identified by the CAISO would be expected to have minimal environmental impact and be relatively low cost given the economic study parameters relied upon in this 2020-2021 planning cycle. The following table provides a list of potential solutions that the CAISO evaluated to further reduce the local gas-fired generation need in the El Nido, Western LA Basin sub-areas, overall LA Basin and San Diego-Imperial Valley areas. The alternatives are summarized in Table 4.10-43.

Table 4.10-43: Study Alternatives for Reducing Local Gas-Fired Generation in the El Nido, Western LA Basin sub-areas, overall LA Basin and San Diego-Imperial Valley areas

	Name of Solutions	Submitter	Prior transmission planning process submittal	Target LCR reduction areas	500kV Voltage	230kV Voltage	DC	Estimated costs ($ million)
1	Upgrade La Fresa - La Cienega 230kV Line & Install Series Reactor on the Mesa - Laguna Bell and Mesa - Lighthipe 230kV Lines	CAISO	2019-2020	El Nido, Western LA Basin, overall LA Basin		√		$ 119
2a & 2b	Pacific Transmission Expansion (PTE) VSC DC Project – Options 1 & 2	Western Grid Developer	2019-2020	Big Creek/Ventura, El Nido Subarea, Western LA Basin Subarea, overall LA Basin, San Diego-Imperial Valley			√	$ 1,850
3	Devers – Lighthipe DC Line	CAISO	N/A	El Nido, Western LA Basin, overall LA Basin			√	$ 1,100
4	Lugo Area – LA Basin HVDC Line with underground AC cable connections to Lighthipe & La Cienega	CAISO	N/A	El Nido, Western LA Basin, overall LA Basin			√	$ 1,100

	Name of Solutions	Submitter	Prior transmission planning process submittal	Target LCR reduction areas	500kV Voltage	230kV Voltage	DC	Estimated costs ($ million)
5a 5b 5c	Lake Elsinore Advanced Pumped Storage (LEAPS) Project – Options 1 and 2	Nevada Hydro	2018-2019 and prior transmission planning processes	Overall LA Basin, San Diego-Imperial Valley	√	√		Option 5a: $829 Option 5b: $ 2,040 Option 5c: $ 1,760

Local Capacity Benefits:

The following are assessments to determine benefits associated with seven alternatives listed in the table above.

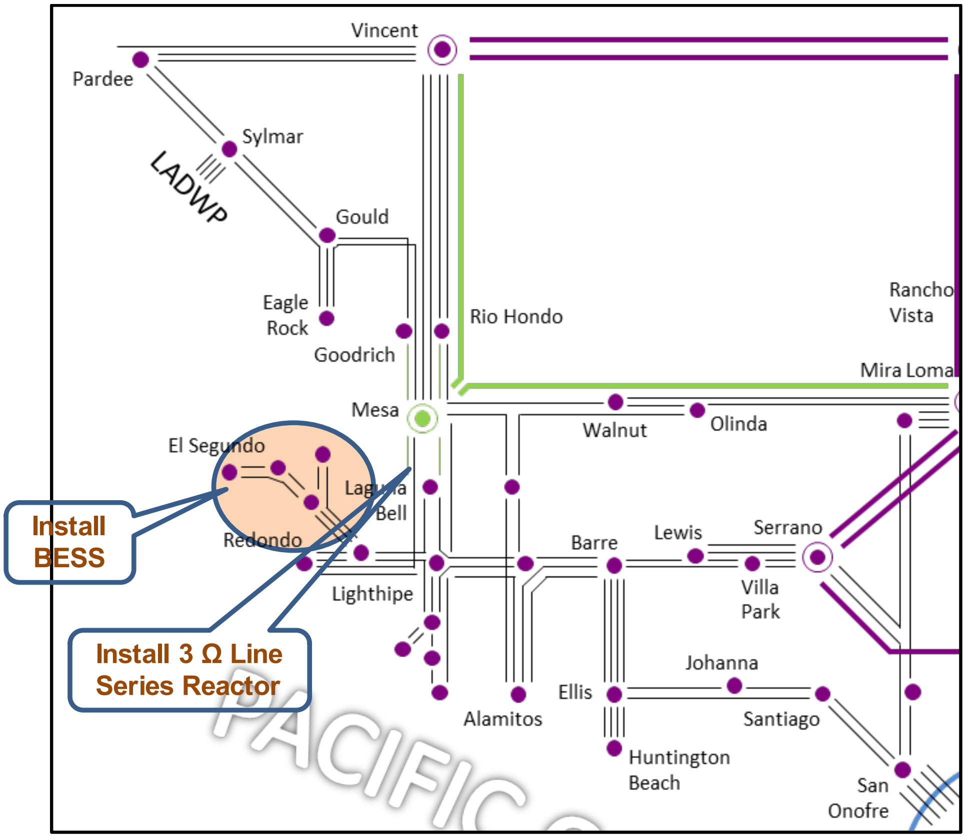
Alternative 1 – Upgrade La Fresa-La Cienega 230 kV line and Install Series Reactors on the Mesa-Laguna Bell and Mesa-Lighthipe 230 kV lines

A single line diagram of the vicinity of Alternative 1 is shown in Figure 4.10-13.

The primary benefit to CAISO ratepayers would be a reduction in local capacity requirements in the El Nido and Western LA Basin sub-areas. The local capacity requirement for gas-fired generation in the El Nido sub area was reduced resulting in a reduction of approximately 355 MW. Additionally, approximately 1,137 MW of local capacity requirement for gas-fired generation was reduced for the Western LA Basin sub-area and the overall LA Basin. Reducing local capacity requirements in the overall LA Basin causes an adverse impact of 465 MW to the San Diego-Imperial Valley LCR area (i.e., increasing the LCR need by 465 MW).

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the El Nido, Western LA Basin, Eastern LA Basin sub-areas and the overall LA Basin, these translated to values of $10,800/MW-year and $15,360/MW-year respectively. For the San Diego-Imperial Valley LCR area, these translated to values of $3,720/MW-year and $8,280/MW-year. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources. It is also recognized of the need for further coordination with the CPUC's Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

Figure 4.10-13: Single line diagram of the vicinity of Alternative 1



<u>Description of Alternative 1 and determination of local capacity benefits:</u>

- Reconductor 12-mile La Fresa – La Cienega 230 kV line
- Install 3 Ω line series reactors on the Mesa-Laguna Bell and Mesa-Lighthipe 230kV lines
- Amount of gas-fired generation capacity reduction in El Nido sub-area : 355 MW
- Net amount of gas-fired generation reduction in the in the Western LA Basin and overall LA Basin: 1137 MW
- Adverse impact to the San Diego – Imperial Valley LCR: - 465 MW

The net benefit of local capacity reductions of the Alternative 1 in the overall LA Basin is shown in Table 4.10-44. These values are based on the cost range for southern California area.

Table 4.10-44: El Nido and Western LA Basin sub-areas Net LCR Reduction Benefits for Alternative 1

	Alternative 1: Reconductor 230 kV Line in El Nido Sub-area and Install Line Series Reactors on 230 kV Lines in Western LA Basin	
	Local versus System Capacity	Local versus SP 26
LCR reduction (overall LA Basin) (MW)	1137	
Capacity value (per MW-year)	$10,800	$15,360
LCR increase cost ($million)	$12.3	$17.5
LCR increase (San Diego-Imperial Valley) (MW)	-465	
Capacity value (per MW-year)	$3,720	$8,280
LCR increase cost ($million)	-$1.7	-$3.9
Net LCR Saving ($million/year)	$10.5	$13.6

Cost estimates:

The planning estimate cost for the Alternative 1 includes the following:

- $104 million, using SCE transmission unit cost, for reconductoring La Fresa-La Cienega 230kV line in the El Nido sub-area
- $15 million for installing 3 Ω line series reactors on the Mesa-Laguna Bell 230kV and Mesa-Lighthipe 230kV lines
- The total cost for installing the BESS and reconductoring line is $119 million.

This estimated cost would need to be refined further if there is further interest and consideration of this alternative.

Benefit to Cost Ratio

The present value of the capacity benefits is shown in Table 4.10-45. These values are based on a 40-year[135] project life.

[135] Upgrades on existing transmission facilities are assumed to have 40-year project life in the economic evaluation.

Table 4.10-45: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 1: Reconductor 230kV Line in El Nido Subarea and Install Line Series Reactors on 230kV Line in Western LA Basin		
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$10.5	$13.6
PV of LCR Savings ($million)	$140.65	$181.50
Capital Cost		
Capital Cost Estimate ($ million)	$119	
Estimated "Total" Cost (screening) ($million)	$155	
Benefit to Cost		
PV of Savings ($million)	$140.65	$181.50
Estimated "Total" Cost (screening) ($million)	$154.70	
Benefit to Cost	0.91	1.17

The differential between the local resource adequacy capacity costs vs. system capacity costs and local resource adequacy capacity costs vs. SP26 system capacity costs provide only marginal benefits for the project. As discussed earlier, the CAISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

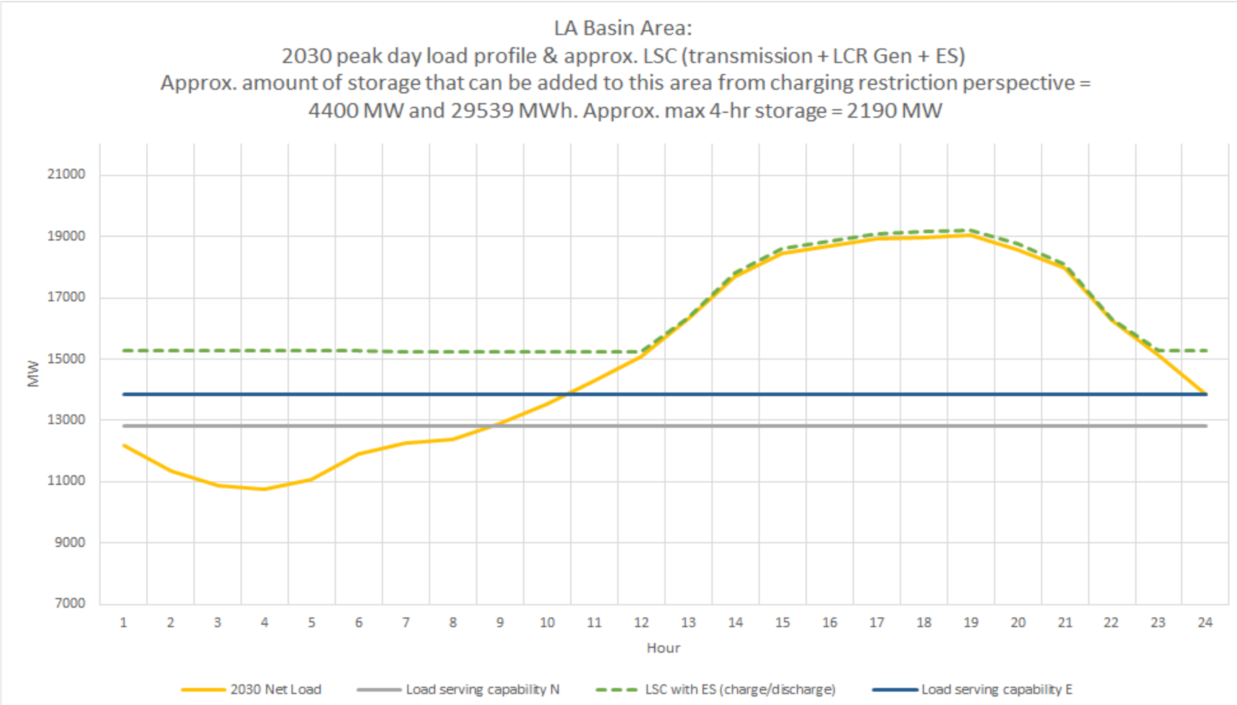
Energy storage addition based on charging capability

The estimated amount of energy storage that can potentially be implemented in the LA Basin LCR area based on charging capability is 4,400 MW, with a total energy of 29,539 MWh. The amount of 4-hour energy storage that can potentially be added is 2,190 MW. Figure 4.10-14 includes a 24-hour plot for the total potential energy storage addition in the LA Basin LCR area.

Because of the potential impact to the LCR needs described above in the San Diego-Imperial Valley area due to the addition of Alternative 1, the total estimated amount of energy storage charging capability of 1,187 MW capacity and 6,994 MWh of energy for the base case scenario (i.e., no transmission additions)[136] cannot be maintained until the LCR deficiency described above is cured for the San Diego-Imperial Valley area.

[136] See Appendix G for the San Diego-Imperial Valley area

Figure 4.10-14: Plot of total potential energy storage addition in the LA Basin with Alternative 1



Conclusions

Further consideration will be given in future planning cycles once cost estimates are better refined, and greater clarity on the need to retain gas-fired generation in the Western LA Basin sub-area and the overall LA Basin area for system reasons is achieved.

Alternative 2 - Proposed Pacific Transmission Expansion HVDC Project

A single line diagram of the proposed Pacific Transmission Expansion HVDC Project is shown in Figure 4.10-15 and Figure 4.10-16. There are two options with this proposed project:

- Option 2A: this option is the same option that was evaluated in the 2019-2020 transmission planning process, with four converters at Diablo Canyon (-2000 MW), Goleta (+500 MW), Redondo Beach (+1000 MW) and Huntington Beach (+500 MW). Submarine cables are proposed to connect these converter stations.
- Option 2B: this option is similar to the above option, with the exception for the locations of the converters in the LA Basin. This option has the locations for the converter stations: Diablo Canyon (-2000 MW), Goleta (+500 MW), El Segundo (+500 MW), Huntington Beach (+500 MW) and San Onofre (+500 MW).

The primary benefit to CAISO ratepayers would be a reduction in local capacity requirements in the Big Creek-Ventura LCR area and the Western LA Basin sub-area. The local capacity requirement for gas-fired generation in the Big Creek-Ventura area was reduced by 393 MW, and 1,889 MW for the Western LA Basin sub-area. Table 4.10-46 summarizes the LCR reduction benefits as well as adverse impact. Negative values denote adverse impact to the LCR requirements in an LCR area (i.e., LCR need is increased).

Figure 4.10-15: Proposed Pacific Transmission Expansion HVDC Project Option 1

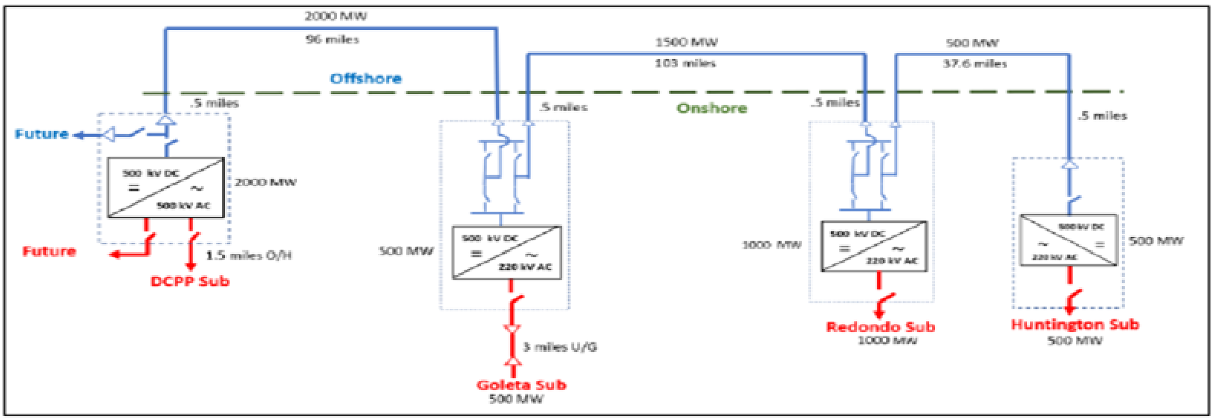


Figure 4.10-16: Proposed Pacific Transmission Expansion HVDC Project Option 2

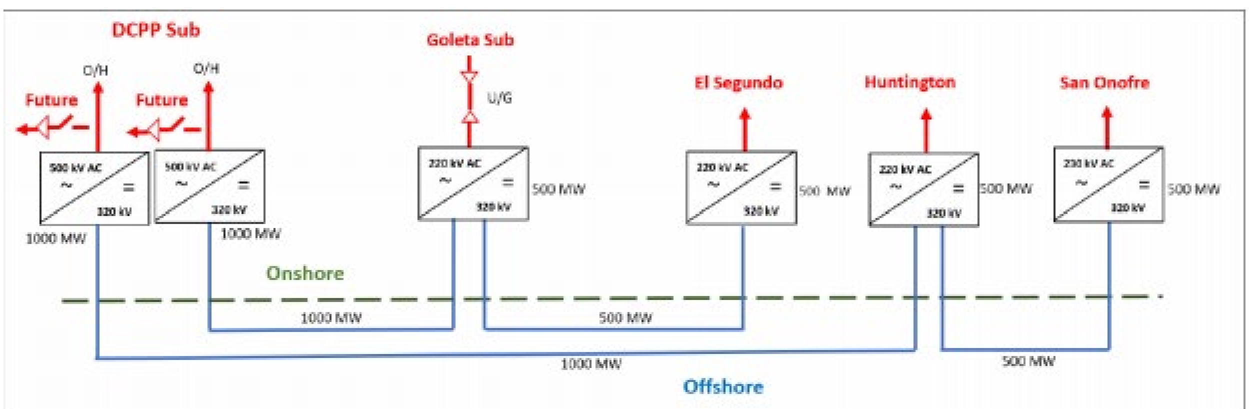


Table 4.10-46: Summary of LCR Benefits or Adverse Impacts for Each of the Major Southern LCR Areas

	Option 1 (MW)	Option 2 (MW)
Amount of gas-fired generation reduction in the Big Creek-Ventura area	393	393
Total amount of gas-fired generation reduction in the overall LA Basin	1,740	655
Adverse impact to the San Diego – Imperial Valley LCR	-140	0

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and “south of path 26 system” resources. For the El Nido, Western LA Basin, Eastern LA Basin sub-areas and the overall LA Basin, these translated to values of $10,800/MW-year and $15,360/MW-year respectively. For the Big Creek/Ventura LCR area, these translated to values of $5,160/MW-year and $9,720/MW-year. For the San Diego-Imperial Valley LCR area, these translated to values of $3,720/MW-year and $8,280/MW-year. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources. It is also recognized of the need for further coordination with the CPUC's Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

<u>Description of Alternative 1 and determination of local capacity benefits:</u>

- This option is proposed by the Western Grid Development, LLC
- Scope of proposed project:
    - Option 2A - Install four Voltage Source Converter stations, rated 2000 MW (500 kV DC/AC) at Diablo Canyon, 1000 MW (500 kV DC / 230 kV AC) at Redondo Beach, two 500 MW (500 kV DC / 230 kV AC) at Goleta and Huntington Beach, respectively
    - Option 2B - Install four Voltage Source Converter stations, rated 2000 MW (500 kV DC/AC) at Diablo Canyon, four 500 MW (500 kV DC / 230 kV AC) at Goleta, El Segundo, Huntington Beach, and San Onofre, respectively
    - Install 500 kV DC submarine cables connecting Diablo Canyon switchyard to Goleta, Redondo Beach and Huntington Beach substations (Option 2A) or to Goleta, El Segundo, Huntington Beach and San Onofre substations (Option 2B)
- Amount of gas-fired generation reduction in the Big Creek-Ventura area: 393 MW
- Amount of gas-fired generation reduction for the overall LA Basin area: 1,740 MW (Option 2A), or 655 MW (Option 2B)
- Adverse impact to the San Diego – Imperial Valley LCR: - 140 MW (Option 2A), or 0 MW (Option 2B)

The net benefit of local capacity reductions of the Alternatives 2A and 2B in the Big Creek/Ventura area and Western LA Basin sub-area is shown in Table 4.10-47 and Table 4.10-48. These values are based on the cost range for southern California area.

Table 4.10-47: Big Creek/Ventura area and overall LA Basin Net LCR Reduction Benefits for Alternative 2A

	Pacific Transmission Expansion Project (PTEP Option 2A)	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Big Creek-Ventura Area) (MW)	393	
Capacity value (per MW-year)	$5,160	$9,720
LCR Reduction Benefit ($million)	$2.0	$3.8
LCR reduction benefit (LA Basin) (MW)	1740	
Capacity value (per MW-year)	$10,800	$15,360
LCR Reduction Benefit ($million)	$18.8	$26.7
LCR increase (San Diego-Imperial Valley) (MW)	-140	
Capacity value (per MW-year)	$3,720	$8,280
LCR increase cost ($million)	-$0.5	-$1.2
Net Total LCR Saving ($million/year)	$20.3	$29.4

Table 4.10-48: Big Creek/Ventura area and overall LA Basin Net LCR Reduction Benefits for Alternative 2B

	Pacific Transmission Expansion Project (PTEP Option 2B)	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Big Creek-Ventura Area) (MW)	393	
Capacity value (per MW-year)	$5,160	$9,720
LCR Reduction Benefit ($million)	$2.0	$3.8
LCR reduction benefit (LA Basin) (MW)	655	
Capacity value (per MW-year)	$10,800	$15,360
LCR Reduction Benefit ($million)	$7.1	$10.1
LCR increase (San Diego-Imperial Valley) (MW)	0	
Capacity value (per MW-year)	$3,720	$8,280
LCR increase cost ($million)	$0.0	$0.0
Net Total LCR Saving ($million/year)	$9.1	$13.9

Production benefits

Please see section 4.10.5 for the production benefit analysis for the proposed PTE Project above.

Cost estimates

The cost estimate provided by the project sponsor is $1,850 million for the proposed project. Applying the CAISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", translates to a total cost of $2,405 million.

Benefit to Cost Ratio

The present value of the sum of the production cost and capacity benefits are shown in Table 4.10-49 and Table 4.10-50. These values are based on a 50 year project life[137].

Table 4.10-49: Benefit to Cost Ratios (Ratepayer Benefits per TEAM) for Option 2A

PTE Option 2A		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/ year)	-$15	
Total PCM Benefits ($million/ year)	-$15	
PV of Prod Cost Savings ($million)	($207.01)	
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$20.3	$29.4
PV of LCR Savings ($million)	$280.14	$405.56
Capital Cost Estimate ($ million)	$1,850	
Estimated "Total" Cost (screening) ($million)	$2,405	
Benefit to Cost Ratio		
Benefit to Cost		
PV of Savings ($million)	$73.13	$198.55
Estimated "Total" Cost (screening) ($million)	$2,405.00	
Benefit to Cost	0.03	0.08

137 For new transmission projects, the project life is assumed to be 50-year in the economic evaluation.

Table 4.10-50: Benefit to Cost Ratios (Ratepayer Benefits per TEAM) for Option 2B

PTE Option 2B		
Production Cost Modeling Benefits		
Ratepayer Benefits ($million/ year)	-$15	
Total PCM Benefits ($million/ year)	-$15	
PV of Prod Cost Savings ($million)	($207.01)	
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$9.1	$13.9
PV of LCR Savings ($million)	$125.61	$191.56
Capital Cost Estimate ($ million)	$1,850	
Estimated “Total” Cost (screening) ($million)	$2,405	
Benefit to Cost Ratio		
Benefit to Cost		
PV of Savings ($million)	($81.40)	($15.45)
Estimated “Total” Cost (screening) ($million)	$2,405.00	
Benefit to Cost	-0.03	-0.01

The differential between the local resource adequacy capacity costs vs. system capacity costs and local resource adequacy capacity costs vs. SP26 system capacity costs provide only marginal benefits for the project. As discussed earlier, the CAISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

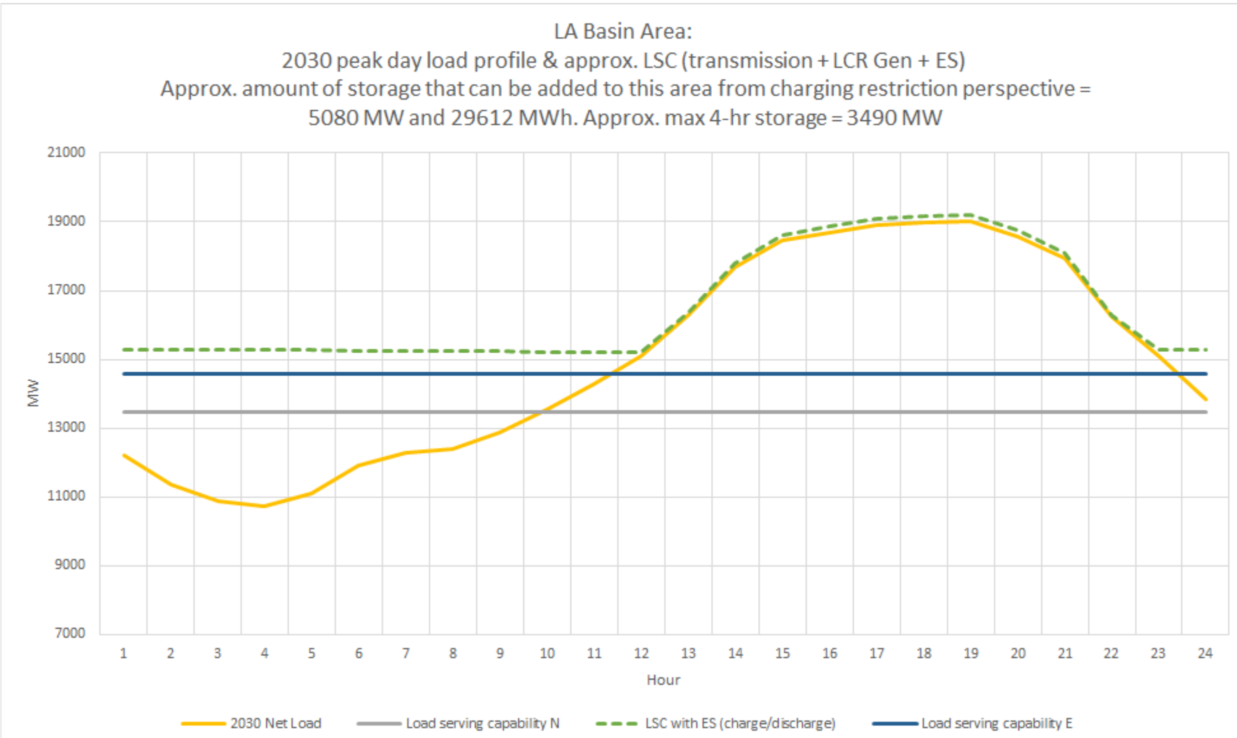
Energy storage addition based on charging capability

Alternative 2A

The estimated amount of energy storage that can potentially be implemented in the LA Basin LCR area based on charging capability with Alternative 2A is 5,080 MW, with a total energy of 29,612 MWh. The amount of 4-hour energy storage that can potentially be added is 3,490 MW. Figure 4.10-17 includes a 24-hour plot for the total potential energy storage addition in the LA Basin LCR area with Alternative 2A.

Because of the potential impact described above to the LCR needs in the San Diego-Imperial Valley area due to the addition of Alternative 2A, the total estimated amount of energy storage charging capability of 1,187 MW capacity and 6,994 MWh of energy for the base case scenario (i.e., no transmission additions)[138] cannot be maintained until the LCR deficiency described above is cured for the San Diego-Imperial Valley area.

Figure 4.10-17: Plot of total potential energy storage addition in the LA Basin with Alternative 2A



Alternative 2B

The estimated amount of energy storage that can potentially be implemented in the LA Basin LCR area based on charging capability with Alternative 2B is 3,936 MW, with a total energy of 29,350 MWh. The amount of 4-hour energy storage that can potentially be added is 1,250 MW. Figure 4.10-18 includes a 24-hour plot for the total potential energy storage addition in the LA Basin LCR area with Alternative 2B.

The estimated amount of energy storage that can potentially be implemented in the San Diego-Imperial Valley LCR area based on charging capability with Alternative 2B is 1,187 MW, with a total energy of 6,994 MWh. The amount of 4-hour energy storage that can potentially be added is 680 MW. Figure 4.10-19 includes a 24-hour plot for the total potential energy storage addition in the San Diego-Imperial Valley LCR area with Alternative 2B.

[138] See Appendix G for the San Diego-Imperial Valley area

Figure 4.10-18: Plot of total potential energy storage addition in the LA Basin with Alternative 2B

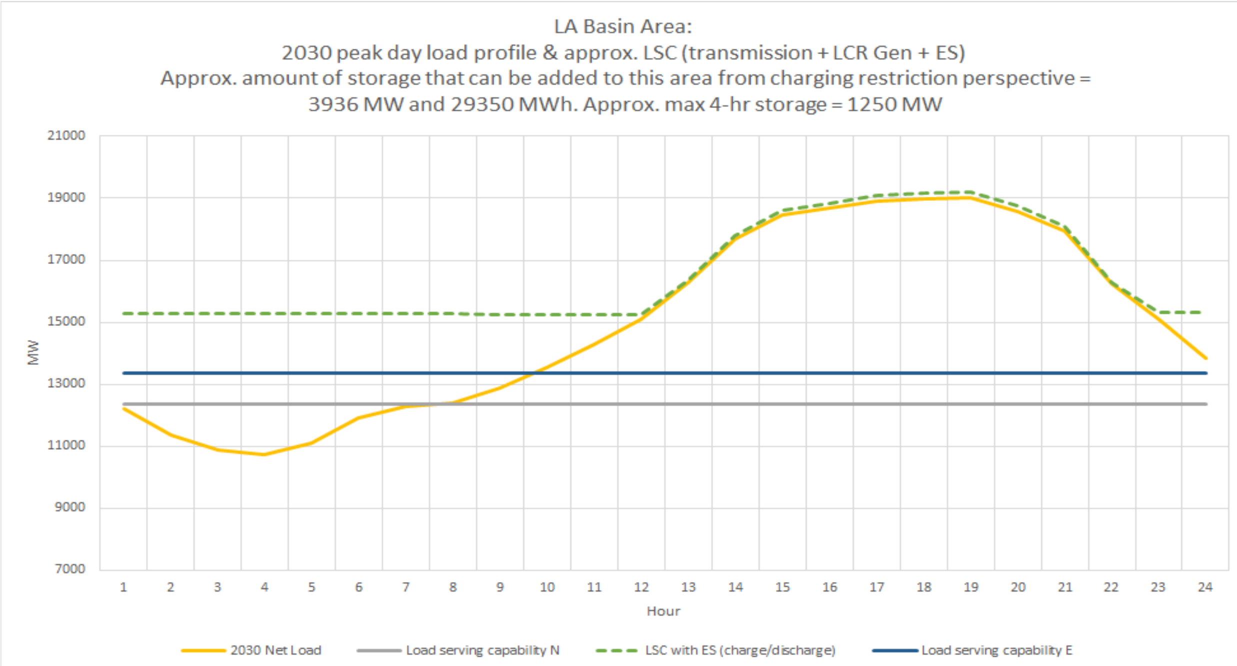
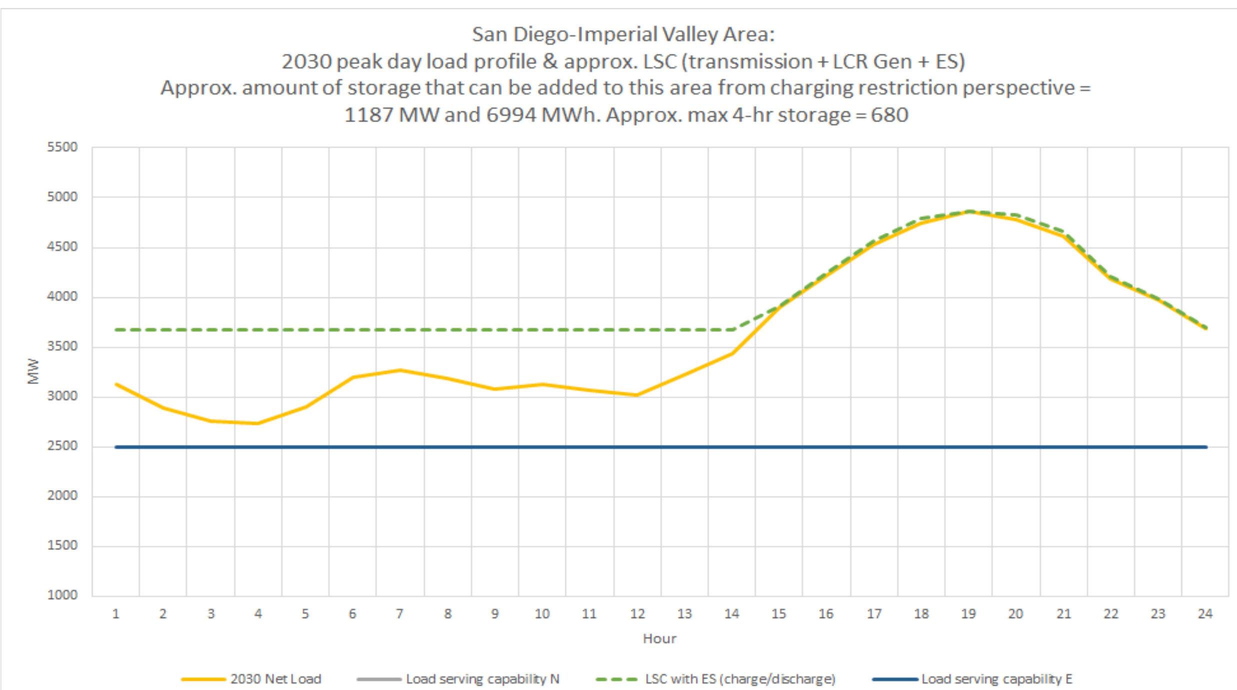


Figure 4.10-19. Plot of total potential energy storage addition in the San Diego-Imperial Valley area with Alternative 2B



Conclusions

The economic benefits of the Pacific Transmission Expansion project's two options are not sufficient on a standalone basis to support the project as an economic-driven transmission project based on the findings in the 2020-2021 transmission planning studies. The project provides benefits for which the CAISO is valuing with conservative assumptions at this time, due to uncertainty regarding the future reliance on gas-fired generation for system and flexible needs. The CAISO expects that dialogue will continue as the CPUC's integrated resource planning processes provide further direction on longer term capacity and energy procurement, and as system needs for other attributes the project may provide are further assessed.

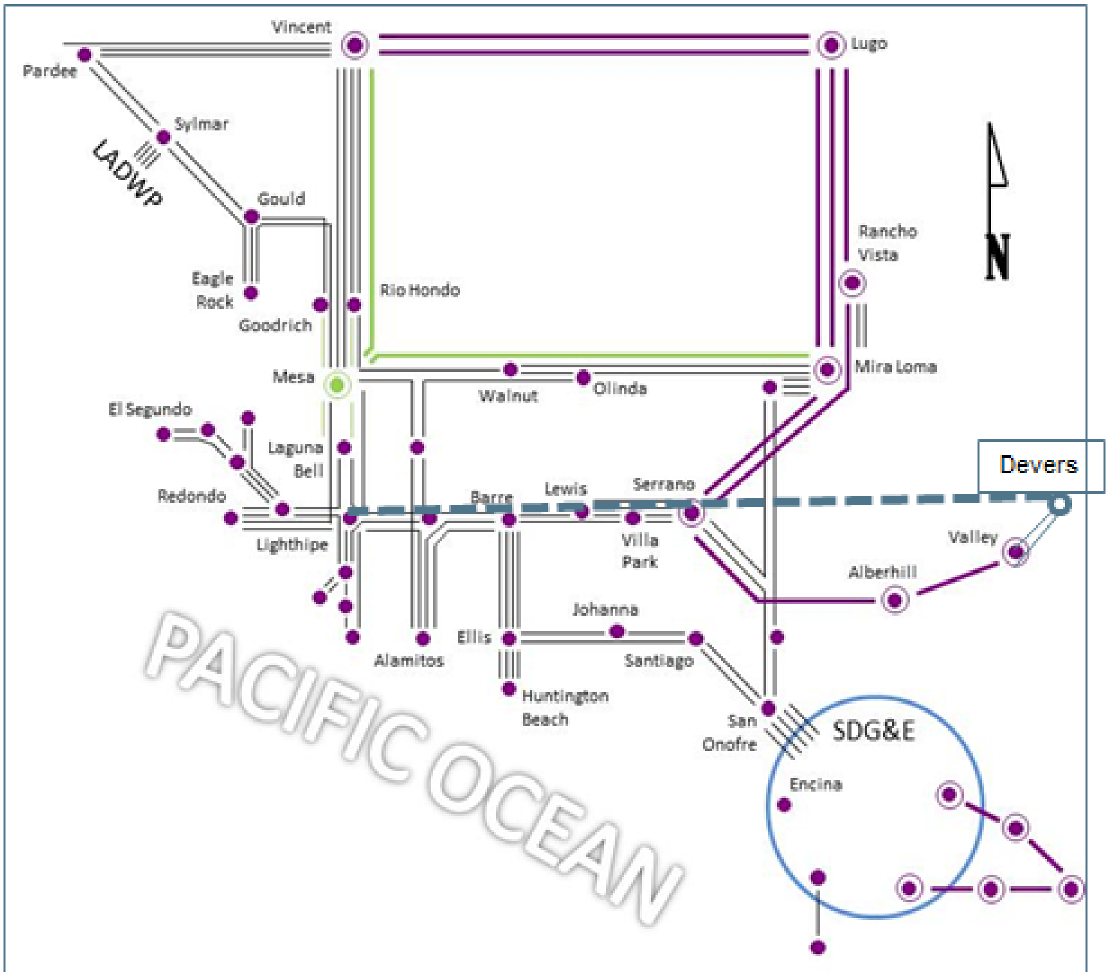
Alternative 3 - Install a new Devers – Lighthipe HVDC line

A single line diagram of the vicinity of Alternative 3 is shown in Figure 4.10-20.

The primary benefit to CAISO ratepayers would be a reduction in local capacity requirements in the Western LA Basin sub-area and the overall LA Basin. The local capacity requirement for gas-fired generation in the Western LA Basin sub area and thus the overall LA Basin area was reduced resulting in a reduction of approximately 849 MW. However, reducing local capacity requirements in the Western LA Basin causes an adverse impact of 211 MW to the San Diego-Imperial Valley LCR area (i.e., increasing the LCR need by 211 MW).

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the El Nido, Western LA Basin, Eastern LA Basin sub-areas and the overall LA Basin, these translated to values of $10,800/MW-year and $15,360/MW-year respectively. For the San Diego-Imperial Valley LCR area, these translated to values of $3,720/MW-year and $8,280/MW-year. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources. It is also recognized of the need for further coordination with the CPUC's Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

Figure 4.10-20: Single line diagram of the vicinity of Alternative 3



Description of Alternative 3 and determination of local capacity benefits:

- Install approximately 100 mi. of +/- 320 kV between Devers and Lighthipe Substations
- Install RAS to trip the bipole DC line under N-2 contingency of Devers – Red Bluff 500kV lines
- Estimated Total Cost: $1.1 billion
- Amount of gas-fired generation capacity reduction in the LA Basin: 849 MW
- Adverse impact to the San Diego – Imperial Valley LCR: - 211 MW

The net benefit of local capacity reductions of the Alternative 3 in the overall LA Basin is shown in Table 4.10-51. These values are based on the cost range for southern California area.

Table 4.10-51: Overall LA Basin area Net LCR Reduction Benefits for Alternative 3

	Alternative 3: Devers - Lighthipe DC Line	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (LA Basin) (MW)	849	
Capacity value (per MW-year)	$10,800	$15,360
LCR Reduction Benefit ($million)	$9.2	$13.0
LCR increase (San Diego-Imperial Valley) (MW)	-211	
Capacity value (per MW-year)	$3,720	$8,280
LCR increase cost ($million)	-$0.8	-$1.7
Net Total LCR Saving ($million/year)	$8.4	$11.3

Cost estimates

The planning estimate cost for the Alternative 3 is $1,100 million. The cost estimate is estimated to be $1,100 million for the proposed project based on industry cost for voltage-sourced HVDC converter stations and other related AC connections. Applying the CAISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", translates to a total cost of $1,430 million.

Benefit to Cost Ratio

The levelized fixed cost as compared to the savings associated with the capacity benefits are shown in Table 4.10-52. The benefit to cost ratios were calculated for the range of the local capacity benefits.

Table 4.10-52: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 3: Devers - Lighthipe DC Line		
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$8.4	$11.3
PV of LCR Savings ($million)	$115.71	$155.86
Capital Cost		
Capital Cost Estimate ($ million)	$1,100	
Estimated "Total" Cost (screening) ($million)	$1,430	
Benefit to Cost		
PV of Savings ($million)	$115.71	$155.86
Estimated "Total" Cost (screening) ($million)	$1,430.00	
Benefit to Cost	0.08	0.11

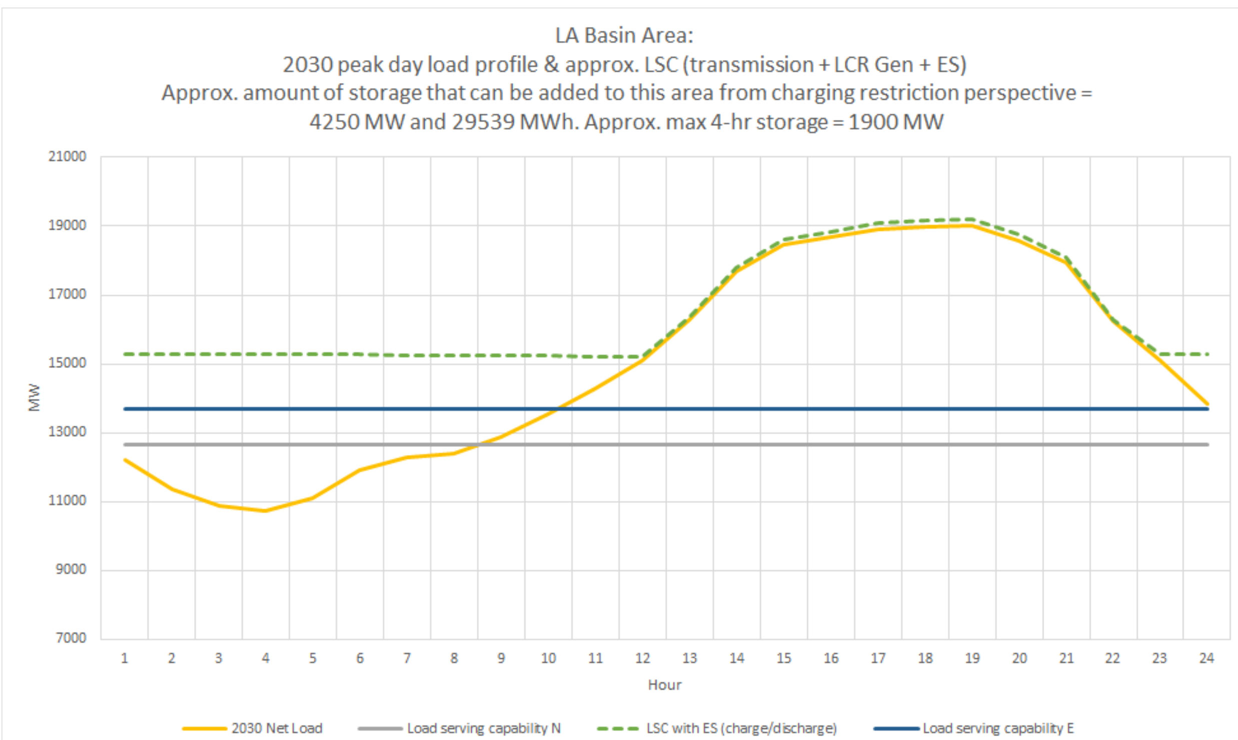
The differential between the local resource adequacy capacity costs vs. system capacity costs and local resource adequacy capacity costs vs. SP26 system capacity costs provide only marginal benefits for the project. As discussed earlier, the CAISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

Energy storage addition based on charging capability

The estimated amount of energy storage that can potentially be implemented in the LA Basin LCR area based on charging capability with Alternative 3 is 4,250 MW, with a total energy of 29,539 MWh. The amount of 4-hour energy storage that can potentially be added is 1,900 MW. Figure 4.10-21 includes a 24-hour plot for the total potential energy storage addition in the LA Basin LCR area with Alternative 3.

Because of the potential impact described above to the LCR needs in the San Diego-Imperial Valley area due to the addition of Alternative 3, the total estimated amount of energy storage charging capability of 1,187 MW capacity and 6,994 MWh of energy for the base case scenario (i.e., no transmission additions)[139] cannot be maintained until the LCR deficiency described above is cured for the San Diego-Imperial Valley area.

Figure 4.10-21: Plot of total potential energy storage addition in the LA Basin area with Alternative 3



Conclusions

The economic benefits of the proposed Devers-Lighthipe HVDC project are not sufficient on a standalone basis to support the project as an economic-driven transmission project based on

[139] See Appendix G for the San Diego-Imperial Valley area

the findings in the 2020-2021 transmission planning studies. The project provides benefits for which the CAISO is valuing with conservative assumptions at this time, due to uncertainty regarding the future reliance on gas-fired generation for system and flexible needs. The CAISO expects that dialogue will continue as the CPUC's integrated resource planning processes provide further direction on longer term capacity and energy procurement, and as system needs for other attributes the project may provide are further assessed.

<u>Alternative 4 – Install a new Lugo area to LA Basin HVDC line with underground AC cable connections to Lighthipe and La Cienega substations</u>

The primary benefit to CAISO ratepayers would be a reduction in local capacity requirements in the El Nido and Western LA Basin sub-areas as well as the overall LA Basin. The local capacity requirement for gas-fired generation in the overall LA Basin was reduced resulting in a reduction of approximately 618 MW, all of which in the Western LA Basin. However, reducing local capacity requirements in the Western LA Basin causes an adverse impact of 75 MW to the San Diego-Imperial Valley LCR area (i.e., increasing the LCR need by 75 MW).

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the El Nido, Western LA Basin, Eastern LA Basin sub-areas and the overall LA Basin, these translated to values of $10,800/MW-year and $15,360/MW-year respectively. For the San Diego-Imperial Valley LCR area, these translated to values of $3,720/MW-year and $8,280/MW-year. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources. It is also recognized of the need for further coordination with the CPUC's Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

<u>Description of Alternative 4 and determination of local capacity benefits:</u>

- Install approximately 80 - 100 mi. of +/- 320 kV DC line from the Lugo area to the LA Basin
- Amount of gas-fired generation capacity reduction in the LA Basin: <u>618 MW</u>
- Adverse impact to the San Diego – Imperial Valley LCR: - <u>75 MW</u>

The net benefit of local capacity reductions of the Alternative 4 in the Western LA Basin sub-area, and hence overall LA Basin, is shown in Table 4.10-53. These values are based on the cost range for the southern California area.

Table 4.10-53: Overall LA Basin Net LCR Reduction Benefits for Alternative 4

	Alternative 4: Lugo area to the LA Basin DC line	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (LA Basin) (MW)	618	
Capacity value (per MW-year)	$10,800	$15,360
LCR Reduction Benefit ($million)	$6.7	$9.5
LCR increase (San Diego-Imperial Valley) (MW)	-75	
Capacity value (per MW-year)	$3,720	$8,280
LCR increase cost ($million)	-$0.3	-$0.6
Net Total LCR Saving ($million/year)	$6.4	$8.9

Cost estimates:

The cost estimate is estimated to be $1,100 million for the proposed project based on industry cost for voltage-sourced converter stations and estimated cost for underground AC cables. Applying the CAISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", translates to a total cost of $1,430 million.

Benefit to Cost Ratio

The levelized fixed cost as compared to the savings associated with the capacity benefits are shown in Table 4.10-54. The benefit to cost ratios were calculated for the range of the local capacity benefits.

Table 4.10-54: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

Alternative 4: Lugo area to LA Basin HVDC Line		
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$6.4	$8.9
PV of LCR Savings ($million)	$88.26	$122.43
Capital Cost		
Capital Cost Estimate ($ million)	$1,100	
Estimated "Total" Cost (screening) ($million)	$1,430	
Benefit to Cost		
PV of Savings ($million)	$88.26	$122.43
Estimated "Total" Cost (screening) ($million)	$1,430.00	
Benefit to Cost	0.06	0.09

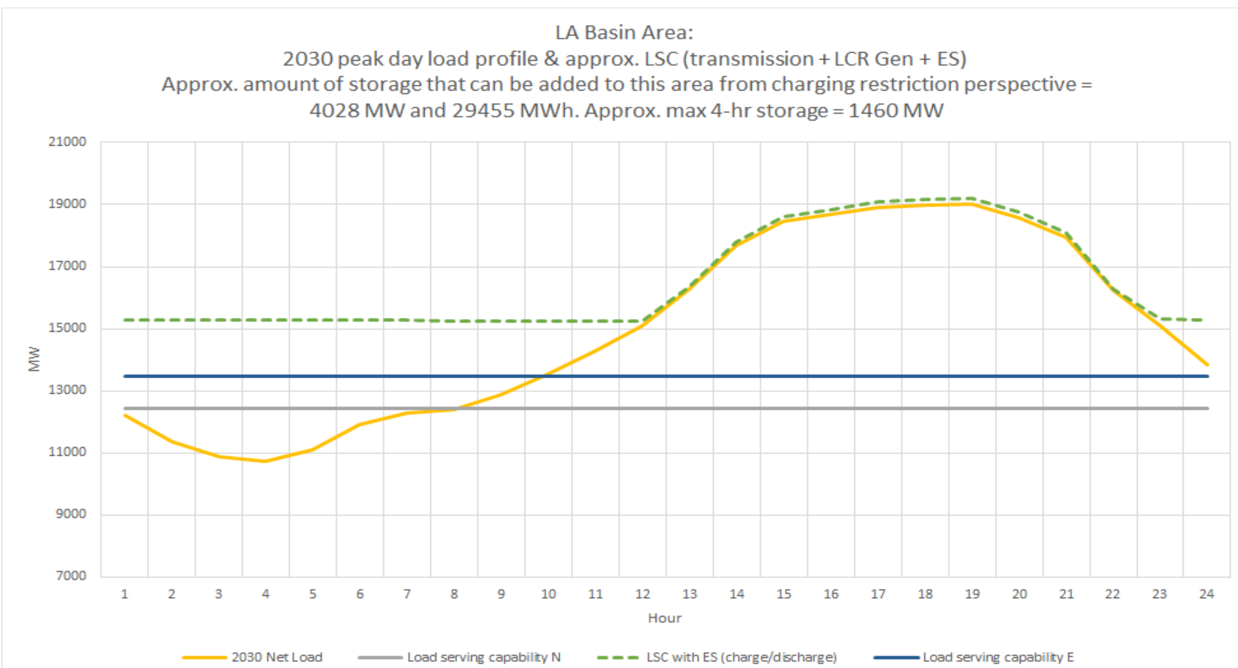
The differential between the local resource adequacy capacity costs vs. system capacity costs and local resource adequacy capacity costs vs. SP26 system capacity costs provide only marginal benefits for the project. As discussed earlier, the CAISO needs to be conservative at this point in considering expenditures based on the benefits of reducing local capacity resources.

Energy storage addition based on charging capability

The estimated amount of energy storage that can potentially be implemented in the LA Basin LCR area based on charging capability with Alternative 4 is 4,028 MW, with a total energy of 29,455 MWh. The amount of 4-hour energy storage that can potentially be added is 1,460 MW. Figure 4.10-22 includes a 24-hour plot for the total potential energy storage addition in the LA Basin LCR area with Alternative 4.

Because of the potential impact described above to the LCR needs in the San Diego-Imperial Valley area due to the addition of Alternative 4, the total estimated amount of energy storage charging capability of 1,187 MW capacity and 6,994 MWh of energy for the base case scenario (i.e., no transmission additions)[140] cannot be maintained until the LCR deficiency described above is cured for the San Diego-Imperial Valley area.

Figure 4.10-22: Plot of total potential energy storage addition in the LA Basin area with Alternative 4



Conclusions

The economic benefits of the proposed Lugo area to LA Basin HVDC project are not sufficient on a standalone basis to support the project as an economic-driven transmission project based on the findings in the 2020-2021 transmission planning studies. The project provides benefits for which the CAISO is valuing with conservative assumptions at this time, due to uncertainty regarding the future reliance on gas-fired generation for system and flexible needs. The CAISO expects that dialogue will continue as the CPUC's integrated resource planning processes

[140] See Appendix G for the San Diego-Imperial Valley area

provide further direction on longer term capacity and energy procurement, and as system needs for other attributes the project may provide are further assessed.

Alternative 5 – Lake Elsinore Advanced Pumped Storage (LEAPS) Project

The Lake Elsinore Advanced Pumped Storage (LEAPS) Project was submitted by Nevada Hydro on February 14, 2018 on the basis of section 24.3.3 of the CAISO's tariff, which the CAISO indicated would be considered an economic study request,[141] and into the 2018 Request Window on October 1, 2018 to address reliability needs in addition to providing other benefits. As set out in chapter 2 of the 2018-2019 Transmission Plan, the CAISO did not identify a reliability need for this project, as the power flow concerns identified in the SDG&E main system can be eliminated by operational measures. For this reason, the project was not found to be needed as a reliability-driven project. The CAISO subsequently examined the project for further benefits, as an economic study request as stated in the final Unified Planning Assumptions and Study Plan[142]. In the 2020-2021 transmission planning cycle, the Nevada Hydro Company submitted comments requesting the CAISO to re-study the proposed project as part of the long-term 2030 LCR gas-fired generation reduction assessment.

The LEAPS Project ("Project") scope of work includes the following:

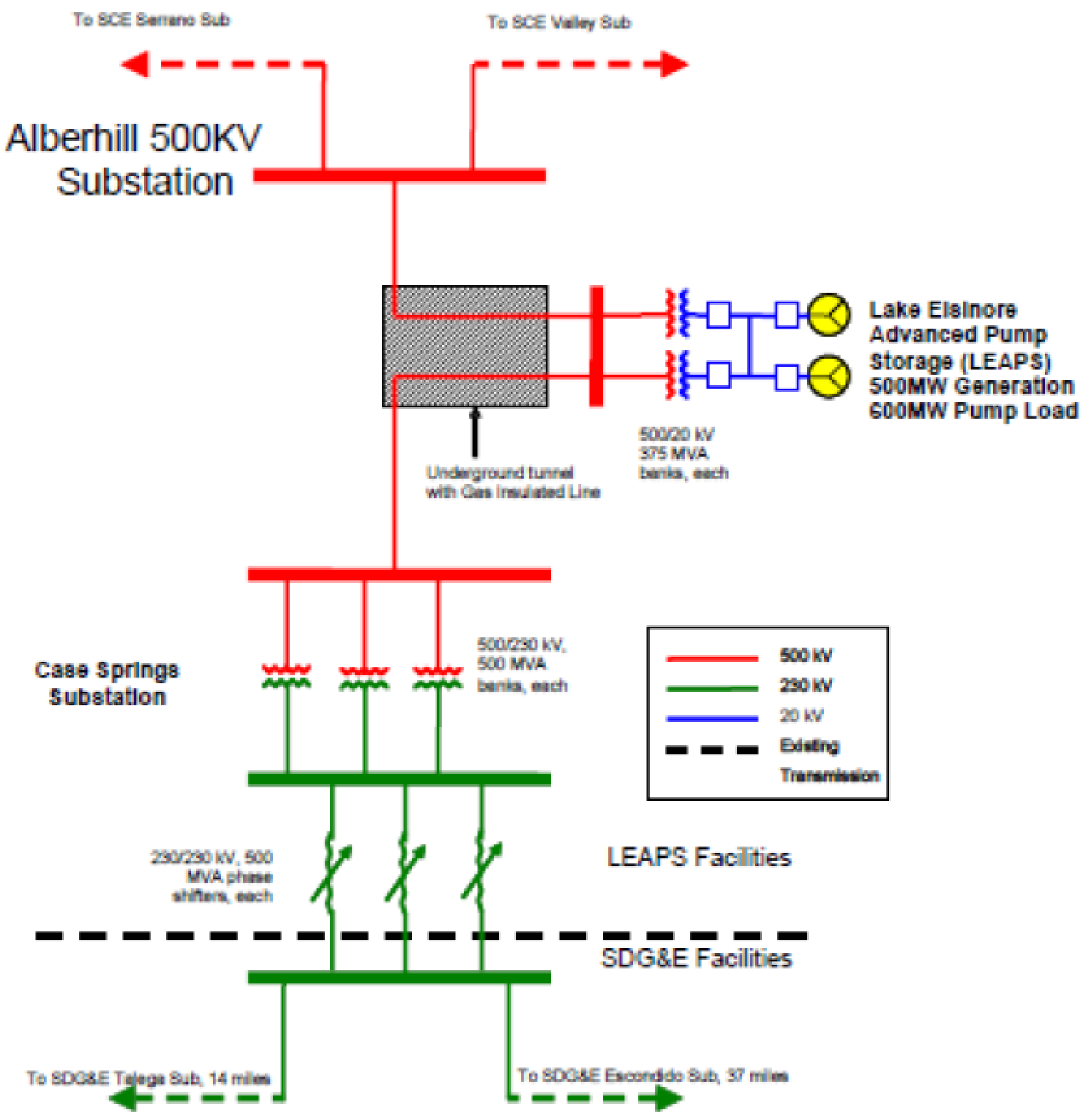
Option 1: Connection to both SCE and SDG&E

- This option, shown in Figure 4.10-23, interconnects the project at two points: (i) to SCE's transmission system at the proposed Alberhill 500 kV substation (if approved by the CPUC) and (ii) to SDG&E's transmission system by looping in the Talega – Escondido 230 kV line via the proposed Case Springs 230 kV substation. If Alberhill is not approved, the connection point will be roughly one mile to the north-west at the proposed Lake Switchyard location. The following figure includes the transmission configuration for the proposed project.
- Approximate Project Cost = $2.04 billion

[141] Page 26, Section 3.8, California ISO 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, Draft, February 22, 2018.

[142] Page 26, Section 3.8, California ISO 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, Final, March 30, 2018.

Figure 4.10-23: LEAPS Option 1 Configuration



Although the Nevada Hydro proposal does not propose an option of only the transmission development, considering the benefits provided by the transmission lines and phase shifters, and then the incremental benefits of the pumped hydro storage facility also enables a determination of the services being provided by each component of the proposed project. Accordingly, the CAISO's analysis of the benefits was based on a phased approach:

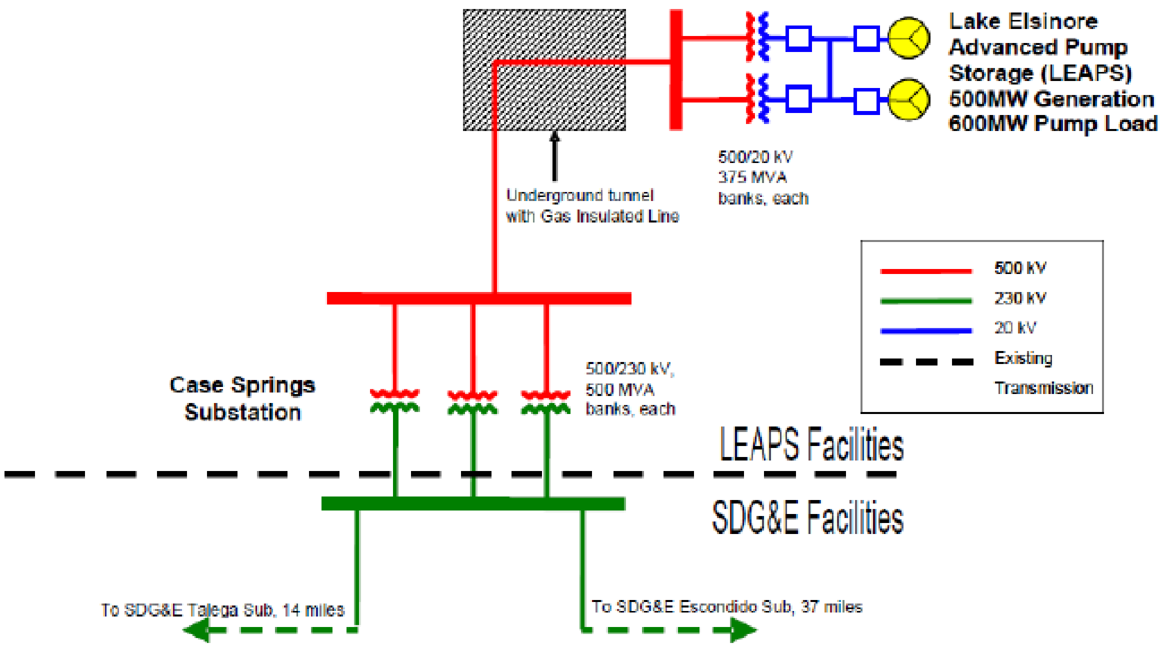
- Option 1a – the transmission development without the hydro pumped storage; and,
- Option 1b – the complete proposal, reflecting the addition of the hydro pumped storage facility to the transmission development.

Option 2: Connection to SDG&E only

- This option, shown in Figure 4.10-24, Interconnects to SDG&E's transmission by looping in the Talega – Escondido 230 kV line via the Case Springs 230 kV substation.

- Approximate Project Cost = $1.76 billion

Figure 4.10-24: LEAPS Option 2 Configuration



A preliminary target in-service date of 2025 has been proposed, and additional siting, permitting and design activities will be necessary to establish the feasibility of that target date.

The proponent stated that the proposed project would provide congestion mitigation benefits under various N-1 contingencies, economic benefits associated with reducing local capacity requirements, and renewable integration via the use of the pumped storage.

In the course of the reliability assessment set out in chapter 2, the CAISO did not identify a reliability need for which a reinforcement in this area would be necessary. Although the pumped storage would be expected to provide reactive power in keeping with the CAISO's reactive power requirements set out in the CAISO's tariff, the CAISO has not identified this as a specific need. Therefore, the analysis centered on the economic benefits LEAPS could provide.

The CAISO's evaluation of economic study requests for potential approval of transmission solutions is based on the most current version of the CAISO Transmission Economic Evaluation Methodology (TEAM)[143], which emphasizes the ratepayer perspective. That perspective was maintained in this analysis for purposes of approval recommendations. The CAISO has also recognized the value storage projects could provide from a system perspective, and has conducted a number of informational special studies in past transmission planning cycles to

[143] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

help inform industry of the potential benefits large (hydro) storage resources may be able to provide. (Those past studies relied primarily on zonal PLEXOS analysis, and updates to those studies are provided on that basis in chapter 7 addressing storage benefits more generally.) To provide a comprehensive overview of the potential benefits of this project, the CAISO conducted this economic analysis assessing both the benefits from a ratepayer perspective for purposes of forming recommendations in the transmission approval process, and also from a total societal perspective for purposes of informing resource procurement processes such as the CPUC's integrated resource planning processes. Both sets of results are provided below.

LEAPS Project's Production Benefit

The CAISO conducted detailed production benefit analysis for LEAPS Project in the 2018-2019 planning cycle. The modeling assumptions for transmission, resource, and load for the SCE and SDG&E systems did not change significantly since then. Therefore, production benefit was not reassessed for the LEAPS project in this planning cycle, since the changes in the study assumptions in this planning cycle were not expected to have material impact on the production benefit of the LEAPS Project.

Local Capacity Benefits:

A benefit to CAISO ratepayers would be a reduction in local capacity requirements in the San Diego-Imperial Valley area. These benefits are analyzed and considered exclusively as a ratepayer benefit.

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and "south of path 26 system" resources. For the El Nido, Western LA Basin, Eastern LA Basin sub-areas and the overall LA Basin, these translated to values of $10,800/MW-year and $15,360/MW-year respectively. For the San Diego-Imperial Valley LCR area, these translated to values of $3,720/MW-year and $8,280/MW-year. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources. It is also recognized of the need for further coordination with the CPUC's Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

Option 1 – Connecting to both SCE and SDG&E

Modeling the LEAPS (Option 1) in the long-term local capacity requirement study case for the San Diego-Imperial Valley Area resulted in the following:

- ***Option 1a*** – the transmission development alone, without the LEAPS pumped storage, provides about 443 MW of local (gas-fired) capacity requirement reduction benefits for the San Diego – Imperial Valley LCR area under the critical G-1/N-1 contingency of the TDM power plant (593 MW) and the Imperial Valley – North Gila 500 kV line.
- However, removing 443 MW of local gas-fired resources in the San Diego-Imperial Valley area without local capacity replacement would adversely impact the local capacity need in the Western LA Basin sub-area. Modeling the study case without the pumped storage and removing 443 MW of local capacity (gas-fired) resources in the San Diego-

Imperial Valley area resulted in the need for an additional 150 MW of local capacity resources in the Western LA Basin sub-area to mitigate the overloading concern on the Mesa-Laguna Bell #1 230 kV line under an overlapping N-1-1 contingency of the Mesa-Redondo 230 kV line and the Mesa-Lighthipe 230 kV line.

- ***Option 1b*** – the pumped storage with the transmission development could reduce the gas-fired local capacity resource requirement for the San Diego – Imperial Valley area by approximately 514 MW in the San Diego area. The LEAPS pumped storage provides local capacity to the San Diego and San Diego-Imperial Valley area and can act to replace capacity otherwise provided by gas-fired generation in the area. The limiting contingency is the overlapping G-1 of the TDM generation (593 MW), system readjusted, followed by the North Gila – Imperial Valley 500 kV line, or vice versa. The limiting element is the El Centro 230/92 kV transformer.
- Since local capacity could be reduced in the San Diego-Imperial Valley area with the project modeled, the CAISO evaluated for potential local capacity impact to the Western LA Basin sub-area. The study case was restored to normal condition, then studied with an overlapping N-1 of Mesa – Redondo 230 kV line, system readjusted, the followed by an N-1 contingency Mesa – Lighthipe 230 kV line. The Mesa – Laguna Bell 230 kV line #1 flow was within its emergency rating. The Western LA Basin sub-area, and the overall LA Basin area local capacity need was not impacted by the proposed LEAPS project with transmission (Option 1b).

Option 2 - Connecting to SDG&E Only

- By modeling the LEAPS (Option 2) in the long-term local capacity requirement study case, the gas-fired local capacity resources for the San Diego – Imperial Valley area could be reduced by approximately 533 MW in the San Diego area. The LEAPS pumped storage provides local capacity to the San Diego and San Diego-Imperial Valley area and replaces the gas-fired generation in the area. The limiting contingency is the overlapping G-1 of the TDM generation (593 MW), system readjusted, followed by the North Gila – Imperial Valley 500 kV line, or vice versa. The limiting element is the El Centro 230/92 kV transformer. The potential reduction in gas-fired generation local capacity requirement is larger than the capacity of the pumped hydro storage, and also larger than the benefit from Option 1, again supporting the increased effectiveness of the interconnection point in San Diego.
- Because local capacity is reduced in the San Diego-Imperial Valley area with the project modeled, the CAISO evaluated for potential local capacity impact to the Western LA Basin sub-area. The study case was restored to normal condition, then studied with an overlapping N-1 of Mesa – Redondo 230 kV line, system readjusted, the followed by an N-1 contingency Mesa – Lighthipe 230 kV line. The Mesa – Laguna Bell 230 kV line #1 flow was within its emergency rating. The Western LA Basin sub-area, and the overall LA Basin area local capacity need was not impacted by the proposed LEAPS (Option 2).

The CAISO notes that the local capacity benefits are a function of the amount of generating capacity of the pumped storage and the effectiveness of the interconnection point. While there are variations depending on relative effectiveness[144] of the configuration of the interconnection to the grid and the location of the gas-fired resources being displaced as providers of local capacity, this is consistent with variations seen in the effectiveness of the resources currently providing the local capacity requirements in the San Diego/Imperial Valley area. The benefits therefore relate to substituting one type of local capacity resource – gas-fired generation – with another – the generating capacity of the pumped storage.

Valuing Local Capacity Requirement Reduction Benefits for Options 1a, 1b, and 2

As discussed in section 4.3.4, local capacity requirement reductions in southern California were valued in this planning cycle at the difference between local and system and between local and “south of path 26 system” resources. For the El Nido, Western LA Basin, Eastern LA Basin sub-areas and the overall LA Basin, these translated to values of $10,800/MW-year and $15,360/MW-year respectively. For the San Diego-Imperial Valley LCR area, these translated to values of $3,720/MW-year and $8,280/MW-year. This differential methodology is generally applied in considering the benefit of transmission projects that can reduce local capacity requirements but do not provide additional system resources. It is also recognized of the need for further coordination with the CPUC’s Integrated Resource Planning processes regarding the long term direction for the gas-fired generation fleet.

In Table 4.10-55 the benefit of local capacity reductions in the San Diego-Imperial Valley area for each of the three options are valued based on the ranges for San Diego, and the impact for option 1a on the Western LA Basin sub-area is based on the cost range for the LA Basin.

[144] Note that the effectiveness factors listed in the 2028 Local Capacity Technical Study described in section 6.1 and provided in Appendix G show a range for generation in the San Diego and Imperial Valley combined area of 11.88% to 25.42%. Effectiveness was measured as the impact on the flow on the constrained transmission facility as a percent of output from the local capacity resource. In other words, some existing resources are more than twice as effective as others at addressing the limiting constraint, due to the physical location of the resources.

Table 4.10-55: LCR Reduction Benefits for all Options

	Option 1a		Option 1b		Option 2	
	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	443		514		533	
Capacity value (per MW-year)	$3,720	$8,280	$3,720	$8,280	$3,720	$8,280
LCR Reduction Benefit ($million)	$1.6	$3.7	$1.9	$4.3	$2.0	$4.4
LCR increase (LA Basin) (MW)	150		0		0	
Capacity value (per MW-year)	$10,800	$15,360	N/A	N/A	N/A	N/A
LCR increase cost ($million)	$1.6	$2.3	0	0	0	0
Net LCR Saving ($million/year)	$0.0	$1.4	$1.9	$4.3	$2.0	$4.4

The CAISO has not identified a difference in the function being provided in providing local capacity in the San Diego area compared to other resources, including the gas-fired generation currently providing the local capacity in the area, other than typical variations in effectiveness based on different interconnection points inside the San Diego area.

Cost estimates:

Option 1a: Nevada Hydro did not provide a separate cost estimate for the development of the transmission line project with associated switching substation cost without the LEAPS pumped storage. However, the cost for the development of the line can be estimated by removing the cost for the pumped storage facility from the Nevada Hydro Company's website for the proposed project (http://leapshydro.com/wp-content/uploads/2017/10/Process-Costs-and-Financing.pdf). The cost estimate for the transmission facilities without the pumped storage is approximately $829 million. Applying the CAISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $829 million capital translates to a total cost of $1,078 million.

Option 1b: The current cost estimate from Nevada Hydro includes $2.04 billion for the proposed project Option 1. Applying the CAISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $2.04 billion capital translates to a total cost of $2.652 billion.

Option 2: The current cost estimate from Nevada Hydro includes $1.765 billion for the proposed project Option 2. Applying the CAISO's screening factor of 1.3 to convert the capital cost of a project to the present value of the annualized revenue requirement, referred to as the "total" cost", the $1.765 billion capital translates to a total cost of $2.295 billion.

Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

The net present values of those annual revenue streams were estimated over 50[145] years as set out in Table 4.10-56.

Table 4.10-56: Benefit to Cost Ratios (Ratepayer Benefits per TEAM)

	Option 1a		Option 1b		Option 2	
Production Cost Modeling Benefits (from 2018-2019 TPP)						
Total PCM Benefits ($million/ year)	$4		$42		$39	
PV of Prod Cost Savings ($million)	$55.20		$579.63		$538.23	
Local Capacity Benefits						
	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$0.0	$1.4	$1.9	$4.3	$2.0	$4.4
PV of LCR Savings ($million)	$0.39	$18.82	$26.39	$58.73	$27.36	$60.91
Capital Cost Estimate ($ million)	$829		$2,040		$1,765	
Estimated “Total” Cost (screening) ($million)	$1,078		$2,652		$2,295	
Benefit to Cost Ratio						
Benefit to Cost						
PV of Savings ($million)	$55.59	$74.03	$606.02	$638.37	$565.59	$599.14
Estimated “Total” Cost (screening) ($million)	$1,077.70		$2,652		$2,295	
Benefit to Cost	0.05	0.07	0.23	0.24	0.25	0.26

Energy storage addition based on charging capability

Alternative 5.1A

The estimated amount of energy storage that can potentially be implemented in the LA Basin LCR area based on charging capability with Alternative 5.1A is 3,444 MW, with a total energy of 26,595 MWh. The amount of 4-hour energy storage that can potentially be added is 1,040 MW. Figure 4.10-25 includes a 24-hour plot for the total potential energy storage addition in the LA Basin LCR area with Alternative 5.1A.

The estimated amount of energy storage that can potentially be implemented in the San Diego-Imperial Valley LCR area based on charging capability with Alternative 5.1A is 1,620 MW, with a

[145] 50-year life is used as this would have involved new construction for transmission project.

total energy of 6,941 MWh. The amount of 4-hour energy storage that can potentially be added is 1540 MW. Figure 4.10-26 includes a 24-hour plot for the total potential energy storage addition in the San Diego-Imperial Valley LCR area with Alternative 5.1A.

Figure 4.10-25. Plot of total potential energy storage addition in the LA Basin area with Alternative 5.1A

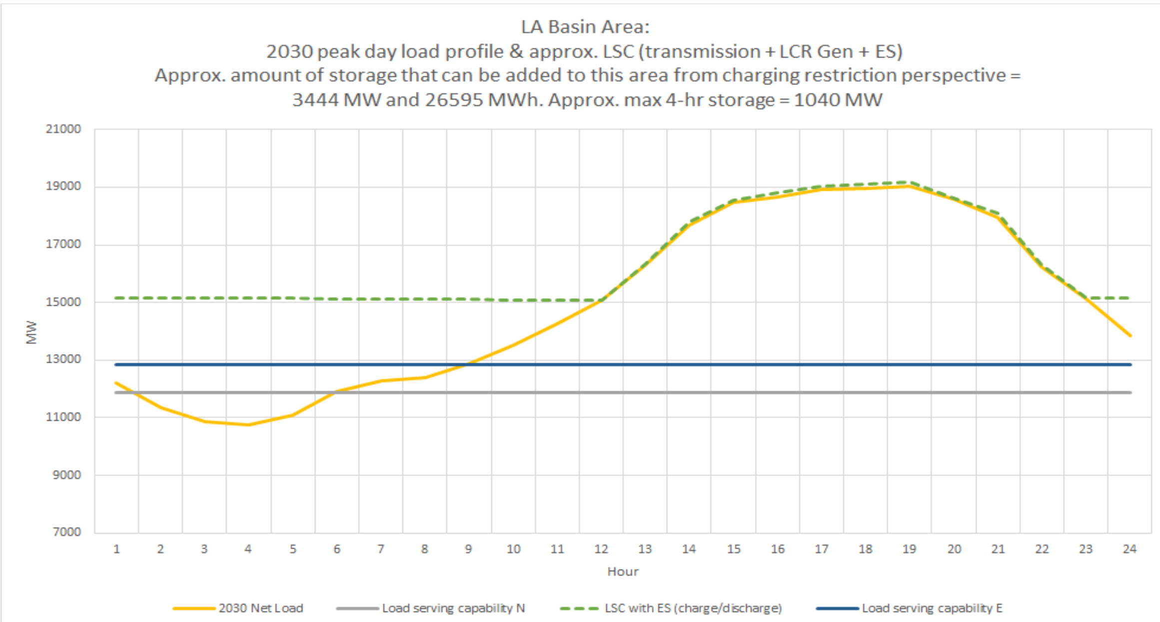
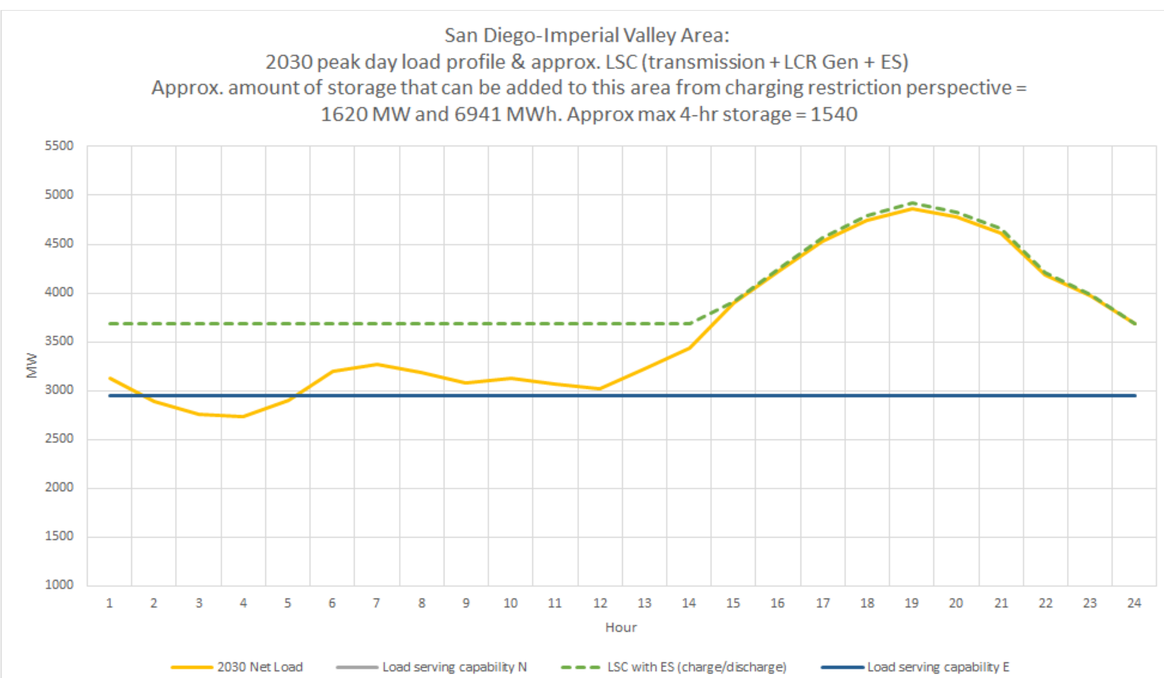


Figure 4.10-26. Plot of total potential energy storage addition in the San Diego-Imperial Valley area with Alternative 5.1A



Alternative 5.1B

The estimated amount of energy storage that can potentially be implemented in the LA Basin LCR area based on charging capability with Alternative 5.1B is 3,550 MW, with a total energy of 27,244 MWh. The amount of 4-hour energy storage that can potentially be added is 1,070 MW. Figure 4.10-27 includes a 24-hour plot for the total potential energy storage addition in the LA Basin LCR area with Alternative 5.1B.

The estimated amount of energy storage that can potentially be implemented in the San Diego-Imperial Valley LCR area based on charging capability with Alternative 5.1B is 1,665 MW, with a total energy of 7,417 MWh. The amount of 4-hour energy storage that can potentially be added is 1540 MW. Figure 4.10-28 includes a 24-hour plot for the total potential energy storage addition in the San Diego-Imperial Valley LCR area with Alternative 5.1B.

Figure 4.10-27: Plot of total potential energy storage addition in the LA Basin area with Alternative 5.1B

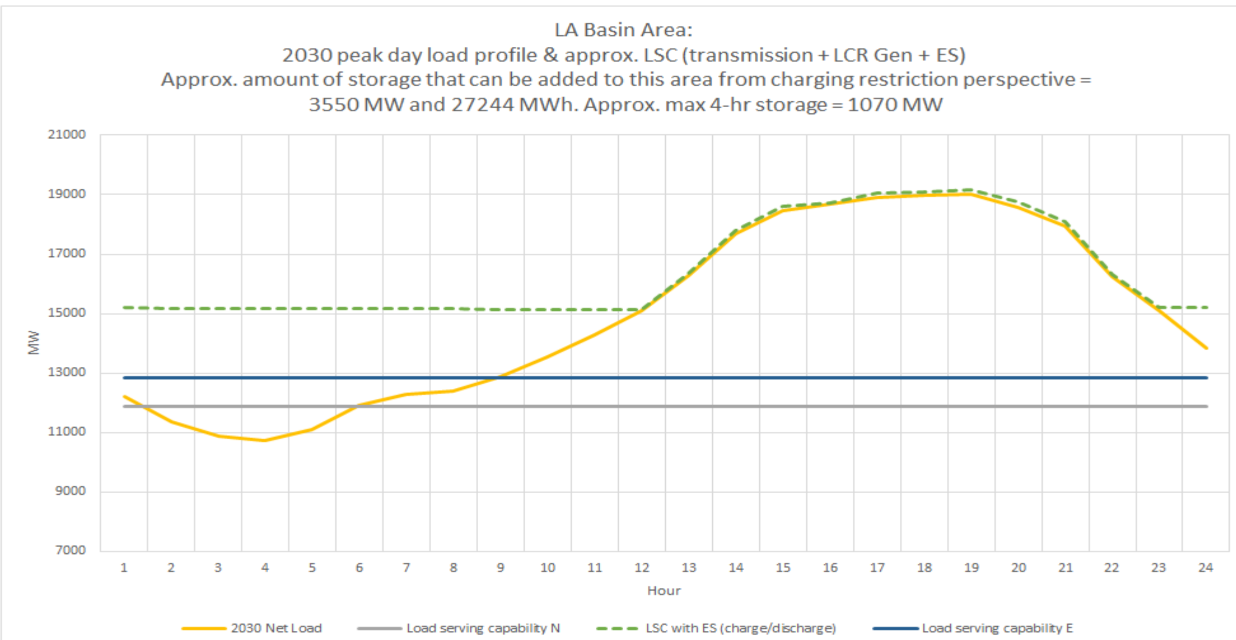
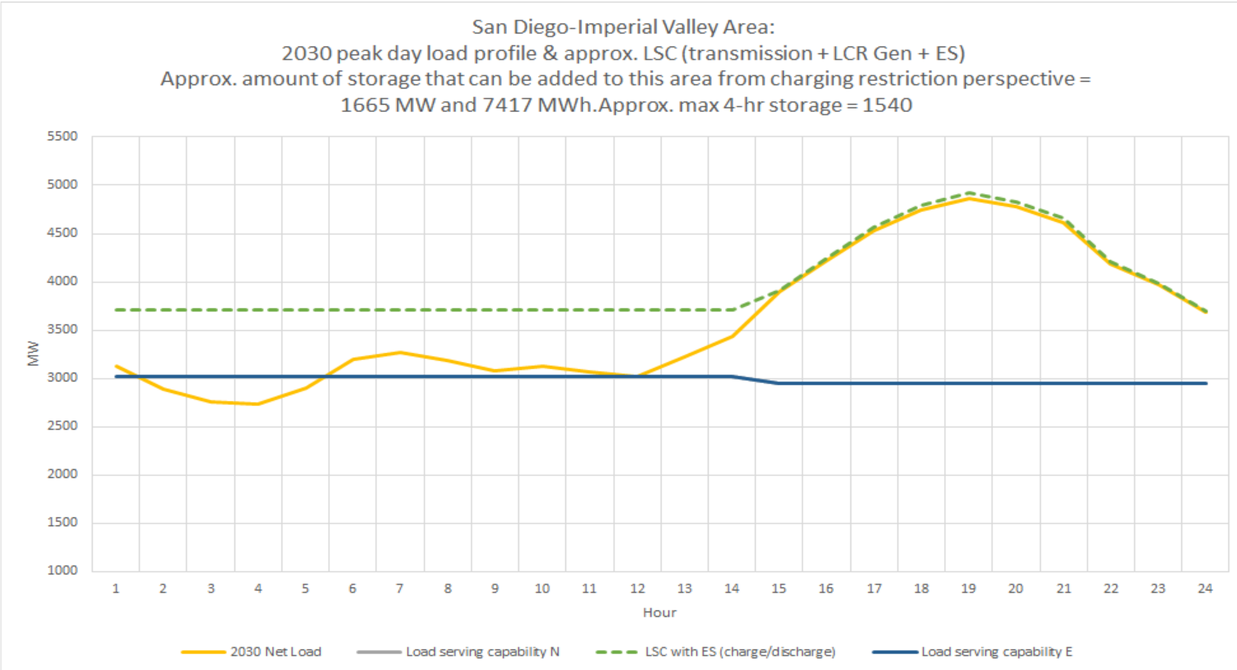


Figure 4.10-28: Plot of total potential energy storage addition in the San Diego-Imperial Valley area with Alternative 5.1B



Alternative 5.2

The estimated amount of energy storage that can potentially be implemented in the LA Basin LCR area based on charging capability with Alternative 5.2 is 3,550 MW, with a total energy of 27,244 MWh. The amount of 4-hour energy storage that can potentially be added is 1,070 MW. Figure 4.10-29 includes a 24-hour plot for the total potential energy storage addition in the LA Basin LCR area with Alternative 5.2.

The estimated amount of energy storage that can potentially be implemented in the San Diego-Imperial Valley LCR area based on charging capability with Alternative 5.2 is 1,430 MW, with a total energy of 4,376 MWh. The amount of 3.1-hour[146] energy storage that can potentially be added is 1430 MW. Figure 4.10-30 includes a 24-hour plot for the total potential energy storage addition in the San Diego-Imperial Valley LCR area with Alternative 5.2.

Figure 4.10-29: Plot of total potential energy storage addition in the LA Basin area with Alternative 5.2

[146] 3.1-hour is the maximum hours for charging capability associated with Alternative 5.2.

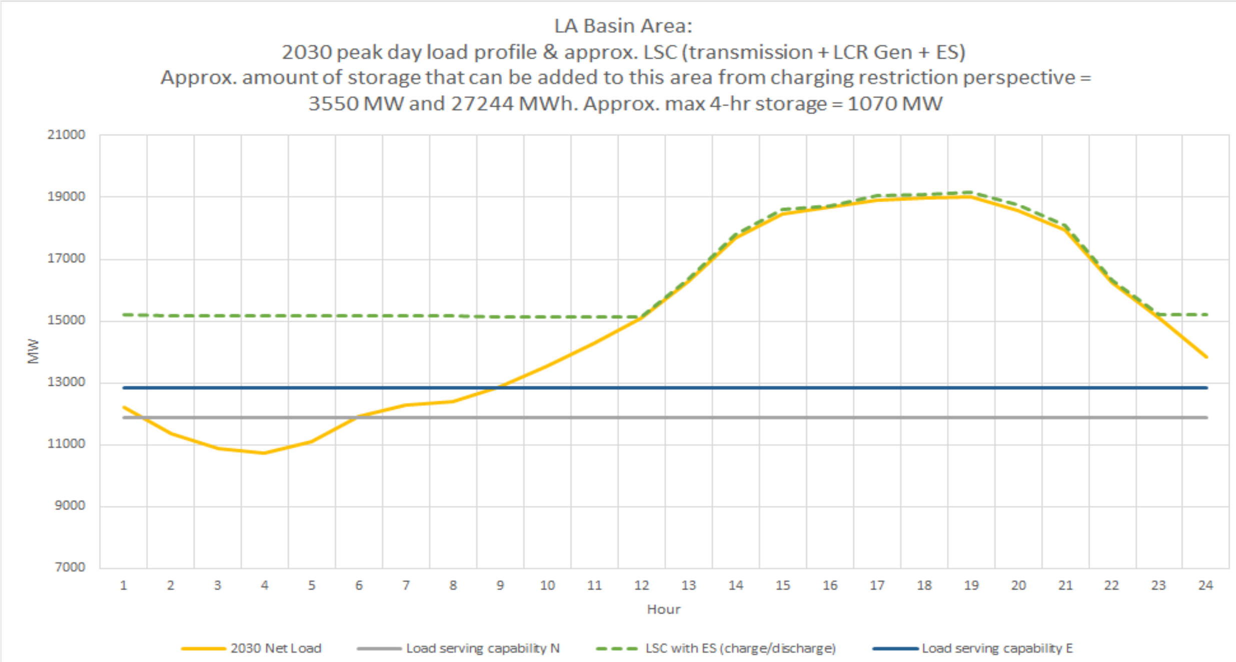
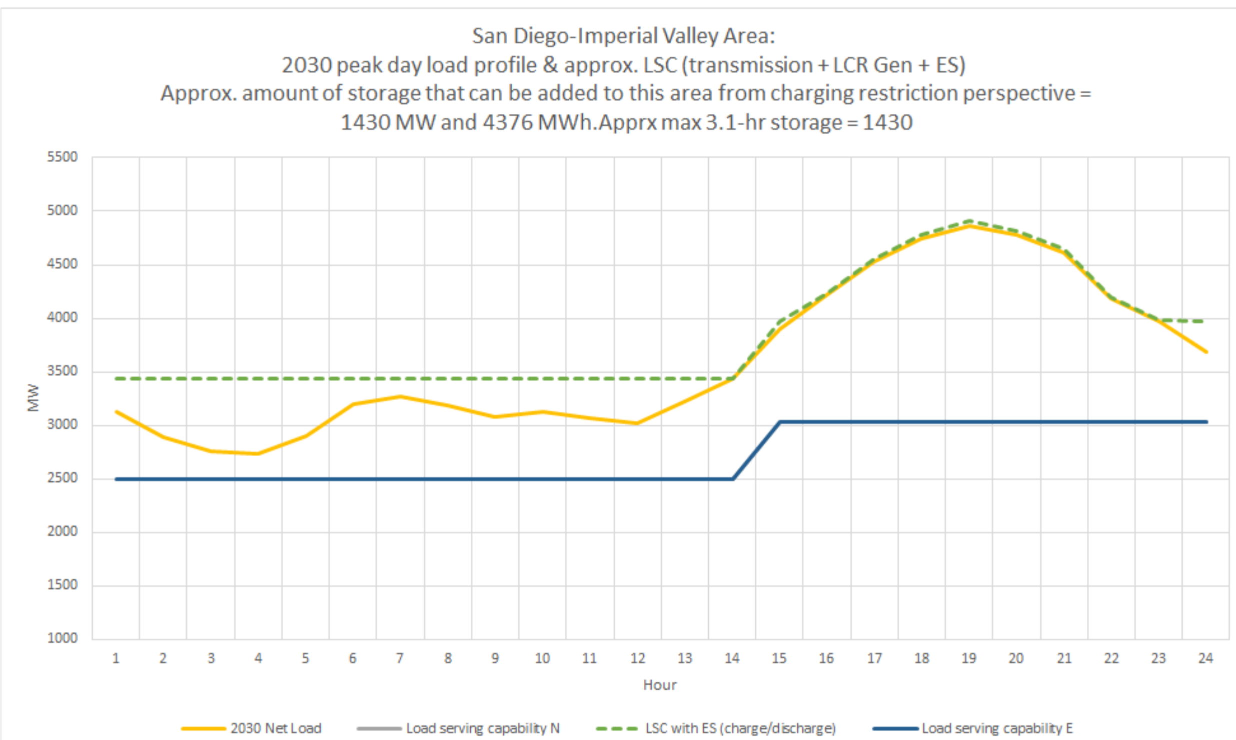


Figure 4.10-30: Plot of total potential energy storage addition in the San Diego-Imperial Valley area with Alternative 5.2



Conclusions

Based on the CAISO's analysis, consistent with its Transmission Economic Analysis Methodology, the following was observed:

- Based the TEAM ratepayer perspective, and assuming the LEAPS net revenue as a ratepayer benefit, the benefit to cost ratio was not sufficient for the CAISO to find the need for the LEAPS project.
- This result may need to be revisited in the future, as conservative values were applied for the local capacity in the San Diego/Imperial Valley area due to the uncertainty regarding future system requirements for the gas-fired generation fleet in the area, and the need for further coordination with the CPUC's IRP process and direction from that process. The CAISO notes that consideration of system capacity requirements - which would heavily influence the capacity benefits of LEAPS - is best addressed within the IRP process, where overall resource procurement considerations weigh the costs and benefits of alternative capacity and energy resources.
- The material difference between production cost savings and CAISO ratepayer benefits suggests that there are other non-transmission benefits that might be considered from a broader resource planning perspective and which are best addressed in the CPUC's IRP process where broader consideration of capacity procurement can be taken into account.
- The CAISO did not identify benefits that directly related to LEAPS performing a transmission function operating to meet an CAISO-identified transmission need:
    - There were no identified reliability needs in the planning horizon driving the need for the project;
    - The production cost benefits associated with the pumped storage facility arise from the resource functioning as a market resource and participating in the CAISO market; and,
    - The local capacity benefits associated with the pumped storage facility arise from the resource functioning as a local capacity resource based on its generating capacity.

4.11 Summary and Recommendations

The CAISO conducted production cost modeling simulations in this economic planning study and grid congestion was identified and evaluated; the congestion studies helped guide the specific study areas that were considered for further detailed analysis. Other factors, including the CAISO's commitment to consider potential options for reducing the requirements for local gas-fired generation capacity, and prior commitments to continue analysis from previous years' studies, also guided the selection of study areas.

The CAISO then conducted extensive assessments of potential economic transmission solutions consisting of production cost modeling and assessments of local capacity benefits. These potential transmission solutions included stakeholder proposals received from a number of sources; request window submissions citing economic benefits, economic study requests, and comments in various stakeholder sessions suggesting alternatives for reducing local capacity requirements. Alternatives also included interregional transmission projects as set out in chapter 5. Overall, 17 areas, sub-areas, and transmission paths were studied. This entailed consideration of 22 proposals and alternatives.

The study results in this planning cycle were heavily influenced by certain CAISO planning assumptions driven by overall industry conditions. In particular, the longer term requirements for gas-fired generation for system and flexible capacity requirements continue to be examined, in the CPUC's integrated resource planning process, but actionable direction regarding the need for these resources for those purposes is not yet available. The uncertainty regarding the extent to which gas-fired generation will be needed to meet those system and flexible capacity requirements necessitated taking a conservative approach in this planning cycle in assigning a value to upgrades potentially reducing local gas-fired generation capacity requirements. The CAISO accordingly placed values on benefits associated with reducing local gas-fired generation capacity requirements primarily on the difference between the relevant local area capacity price and system capacity prices. This conservative assumption was a key difference between the economic benefits calculated in this study, and the economic assessments stakeholders provided in support of their projects. The CAISO recognizes that the capacity value of many of these projects will need to be revised when actionable direction on the need for gas-fired generation for system and flexible needs is available.

The CAISO's focus on ratepayer benefits, rather than broader WECC-wide societal benefits, was another difference between a number of stakeholder proposals.

The overall economic planning study results in the 2020-2021 planning cycle are summarized in Table 4.11-1.

Table 4.11-1: Summary of economic assessment in the 2020-2021 planning cycle

Congestion or study area	Alternative	Benefits Consideration	Economic Justification
SDG&E Doublet Tap – Friars 138 kV line under the N-2 contingency of Sycamore – Penasquitos and Penasquitos – Old Town 230 kV lines	Expanded the previously proposed SPS in GIP to trip IV and ECO generators under the N-2 contingency; Reconductoring the congested line; Rearrange the Penasquitos – Old Town 230 kV line to make the N-2 contingency not a credible N-2	Production cost ratepayer benefits not sufficient	No
SCE Whirlwind 500/230 kV transformer	Add 1170 MW of battery storage at Whirlwind 230 kV; Add the fourth transformer in the Whirlwind substation	Production cost ratepayer benefits not sufficient	No
COI corridor	SWIP-North project	Production cost ratepayer benefits not sufficient	No
PG&E Fresno area	Kettleman Hills Tap to Gates 70 kV line reconductoring); Helm 70/230 kV transformer upgrade	Production cost ratepayer benefits not sufficient	No
Path 26 corridor, Big Creek/Ventura LCR area, Western LA Basin sub-area	PTE HVDC project Option 1 and Option 2	Production cost ratepayer benefits and local capacity benefits not sufficient	No
PG&E Greater Bay Area Contra Costa sub-area	Contra Costa – Pittsburg 230 kV Reliability Project	Local capacity benefits not sufficient	No
	Smart valve in series with Tesla – Delta Switchyard 230 kV line	Local capacity benefits not sufficient	No
PG&E Greater Bay Area-San Jose sub-area	Metcalf 230 kV substation	Local capacity benefits not sufficient	No
PG&E Greater Bay Area	Metcalf 500-230 kV Transformers Dynamic Series Reactor Project	Local capacity benefits not sufficient	No
Big Creek/Ventura Area and Santa Clara sub-area	Pacific Transmission Expansion Project (Option 1)	Production benefit and Local capacity benefits not sufficient	No
	Pacific Transmission Expansion Project (Option 2)	Production benefit and Local capacity benefits not sufficient	No
LA Basin Area	Reconductor 230kV line in El Nido subarea and install line series reactors on 230kV lines in western LA Basin subarea	Local capacity benefits marginal	No
	Pacific Transmission Expansion Project (Option 1)	Production benefit and Local capacity benefits not sufficient	No
	Pacific Transmission Expansion Project (Option 2)	Production benefit and Local capacity benefits not sufficient	No

Congestion or study area	Alternative	Benefits Consideration	Economic Justification
	Devers – Lighthipe HVDC Line	Local capacity benefits not sufficient	No
	Lugo Area – LA Basin HVDC Line and AC Cables to Lighthipe and La Cienega Substations	Local capacity benefits not sufficient	No
San Diego – Imperial Valley Area	Lake Elsinore Advanced Pumped Storage (LEAPS) Project – Option 1A	Production benefit and Local capacity benefits not sufficient	No
	Lake Elsinore Advanced Pumped Storage (LEAPS) Project – Option 1B	Production benefit and Local capacity benefits not sufficient	No
	Lake Elsinore Advanced Pumped Storage (LEAPS) Project – Option 2	Production benefit and Local capacity benefits not sufficient	No

In summary, no transmission solution was found to have sufficient economic benefits in this planning cycle. Several paths and related projects will be monitored in future planning cycles to take into account further consideration of suggested changes to CAISO economic modeling, and further clarity on renewable resources and gas-fired generation supporting California’s renewable energy goals.

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Chapter 5

5 Interregional Transmission Coordination

The CAISO conducts its coordination with neighboring planning regions through the biennial interregional transmission coordination framework established in compliance with FERC Order No. 1000. The CAISO's 2020-2021 transmission planning cycle was completed during the even-year portion of the 2020-2021 interregional transmission coordination cycle.

The CAISO hosted its 2020-2021 ITP submission period in the first quarter of 2020 in which proponents were able to submit ITP proposals to the CAISO and request their evaluation within the 2020-2021 transmission planning process. The submission period began on January 1st and closed March 31st where four interregional transmission projects and their documentation were submitted by their project sponsors for consideration by the CAISO. Of the four projects submitted, three projects were submitted into the 2018-2019 interregional transmission coordination cycle and resubmitted into the 2020-2021 cycle. Based on the study assumptions and the reliability, policy, and economic regional assessments documented in this 2020-2021 transmission plan, no further consideration of the submitted ITPs will be required in the 2021-2022 TPP. More information about the ITP submittals is provided in section 5.4.

5.1 Background on the Order No. 1000 Common Interregional Tariff

FERC Order No. 1000 broadly reformed the regional and interregional planning processes of public utility transmission providers. While instituting certain requirements to clearly establish regional transmission planning processes, Order No. 1000 also required improved coordination across neighboring regional transmission planning processes through procedures for joint evaluation and sharing of information among established transmission planning regions. Since the final rule was issued, the CAISO has continued to collaborate with neighboring transmission utility providers and Western Planning Regions (WPRs) across the Western Interconnection through a coordinated process for considering interregional projects.

Early on in the interregional transmission coordination process the WPRs developed certain business practices for the specific purpose of providing stakeholders visibility and clarity on how the WPRs would engage in interregional coordination activities among their respective regional planning processes. Commensurate with each WPR's regional arrangement with their members, these business practices were incorporated into their regional processes to be followed within the development of their regional plans. For the CAISO, these business practices have been incorporated into the CAISO's Business Practice Manual (BPM) for the Transmission Planning Process.

Commensurate with past interregional transmission coordination cycles, the CAISO continued to play a leadership role in Order 1000 processes within the CAISO's planning region, through direct coordination with the other WPRs and representing and supporting interregional coordination concepts and processes in public forums such as WECC. The WPRs have actively engaged to resolve conflicts and challenges that have arisen since the first coordination cycle was initiated in 2016. The CAISO and other WPRs have continued to consider and forge new opportunities to facilitate coordination among its stakeholders and neighboring planning regions for the benefit of interregional coordination.

5.2 Interregional Transmission Projects

Interregional Transmission Projects have been considered in this transmission planning process on the basis that:

- The ITP must electrically interconnect at least two Order 1000 planning regions;
- While an ITP may connect two Order 1000 planning regions outside of the CAISO, the ITP must be submitted to the CAISO before it can be considered in the CAISO's transmission planning process;
- When a sponsor submits an ITP into the regional process of an Order 1000 planning region it must indicate whether or not it is seeking cost allocation from that Order 1000 planning region; and,
- When a properly submitted ITP is successfully validated, the two or more Order 1000 planning regions that are identified as Relevant Planning Regions are then required to assess an ITP. This applies whether or not cost allocation is requested.

All WPRs are consistent in how they consider interregional transmission projects within their Order 1000 regional planning processes.

5.3 Interregional Transmission Coordination per Order No. 1000

Overall, the interregional coordination requirements established by Order No. 1000 are reasonably straight-forward. In general, the interregional coordination order requires that each WPR (1) commit to developing a procedure to coordinate and share the results of their planning region's regional transmission plans to provide greater opportunities for the WPRs to identify possible interregional transmission facilities that could address regional transmission needs more efficiently or cost effectively than separate regional transmission facilities; (2) develop a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions; (3) establish a formal agreement to exchange among the WPRs, at least annually, their planning data and information; and finally (4) develop and maintain a website or e-mail list for the communication of information related to the interregional transmission coordination process.

On balance, the CAISO fulfills these requirements by following the processes and guidelines documented in the BPM for the Transmission Planning Process and through its development and implementation of the TPP.

5.3.1 Procedure to Coordinate and Share CAISO Planning Results with other WPRs

During each planning cycle the CAISO predominately exchanges its interregional information with the other WPRs in two ways: (1) an annual coordination meeting hosted by the WPRs; and (2) a process by which ITPs can be submitted to the CAISO for consideration in its TPP. While the annual coordination meetings are organized by the WPRs, one WPR is designated as the host for a particular meeting and in turn, is responsible for facilitating the meeting. The annual coordination meetings are generally held in February of each year, but in no event later than March 31. Hosting responsibilities are shared by the WPRs in a rotational arrangement that has been agreed to by the WPRs. WestConnect hosted the 2020 meeting and NorthernGrid is hosting the 2021 meeting.

In general, the purpose of the coordination meeting is to provide a forum for stakeholders to discuss planning activities of the west, including a review of each region's planning process, its needs and potential interregional solutions, update on Interregional Transmission Project (ITP) evaluation activities, and other related issues. It is important to note that the CAISO's planning processes is annual while the planning processes of NorthernGrid and WestConnect are biennial. To address this difference in planning cycles, the WPRs have agreed to annually share the planning data and information that is available at the time the annual interregional coordination meeting is held; divided into an "even" and "odd" year framework. Specifically, the information which the CAISO shares is shown in Table 5.3-1.

Table 5.3-1: Annual Interregional Coordination Information

Even Year	Odd Year
Most recent draft transmission plan	Most recent draft transmission plan
ITPs that: Were being considered within the previous odd year draft transmission plan; That are being considered within the previous odd year draft transmission plan for approval and/or awaiting "final approval" from the relevant planning regions; and, That have been submitted for consideration in the even year transmission plan.	ITPs that: Were being considered within the previous even year draft transmission plan; and, That were considered in the even year draft transmission plan and approved by the CAISO Board for further consideration within the odd year draft transmission plan.

5.3.2 Submission of Interregional Transmission Projects to the CAISO

As part of its TPP the CAISO provides a submission window during which proponents may submit their ITPs into the CAISO's annual planning process within the current interregional coordination cycle. The submission window is open from January 1st through March 31st of every even numbered year. Interregional Transmission Projects will be considered by the WPRs on the basis that:

- The ITP must electrically interconnect at least two Order 1000 planning regions;
- While an ITP may connect two Order 1000 planning regions outside of the CAISO, the ITP must be submitted to the CAISO before it can be considered in the CAISO's transmission planning process;

- When a sponsor submits an ITP into the regional process of an Order 1000 planning region it must indicate whether or not it is seeking cost allocation from that Order 1000 planning region; and,
- When a properly submitted ITP is successfully validated, the two or more Order 1000 planning regions that are identified as Relevant Planning Regions are then required to assess an ITP. This applies whether or not cost allocation is requested.

An ITP submittal must include specific technical and cost information for the CAISO to consider during its validation/selection process of the ITP. In order for the CAISO to consider a proponent's project as an ITP, it must have been submitted to and validated by at least one other WPR. Once the validation process has been completed, each WPR is then considered to be a Relevant Planning Region. All Relevant Planning Regions consider the proposed ITP in their regional process. For the CAISO, validated ITPs will be included in the CAISO's Transmission Planning Process Unified Planning Assumptions and Study Plan for the current planning cycle and evaluated in that year's transmission planning process.

All WPRs are consistent in how they consider interregional transmission projects within their Order 1000 regional planning processes.

5.3.3 Evaluation of Interregional Transmission Projects by the CAISO

Once the submittal and validation process has been completed, the CAISO shares its planning data and information with the other Relevant Planning Regions and develops a coordinated evaluation plan for each ITP to be considered in its regional planning process. The process to evaluate an ITP can take up to two years where an "initial" assessment is completed in the first or even year and, if appropriate, a final assessment is completed in the second or odd year. The assessment of an ITP in a WPR's regional process continues until a determination is made as to whether the ITP will/will not meet a regional need within that Relevant Planning Region. If a WPR determines that an ITP will not meet a regional need within its planning region, no further assessment of the ITP by that WPR is required. Throughout this process, as long as an ITP is being considered by at least two Relevant Planning Regions, it will continue to be assessed as an ITP for cost allocation purposes; otherwise, the ITP will no longer be considered within the context of Order No. 1000 interregional cost allocation. However, if one or more planning regions remain interested in considering the ITP within its regional process even though it is not on the path of cost allocation, it may do so with the expectation that the planning region(s) will continue some level of continued cooperation with other planning regions and with WECC and other WECC processes to ensure all regional impacts are considered.

5.3.3.1 Even Year ITP Assessment

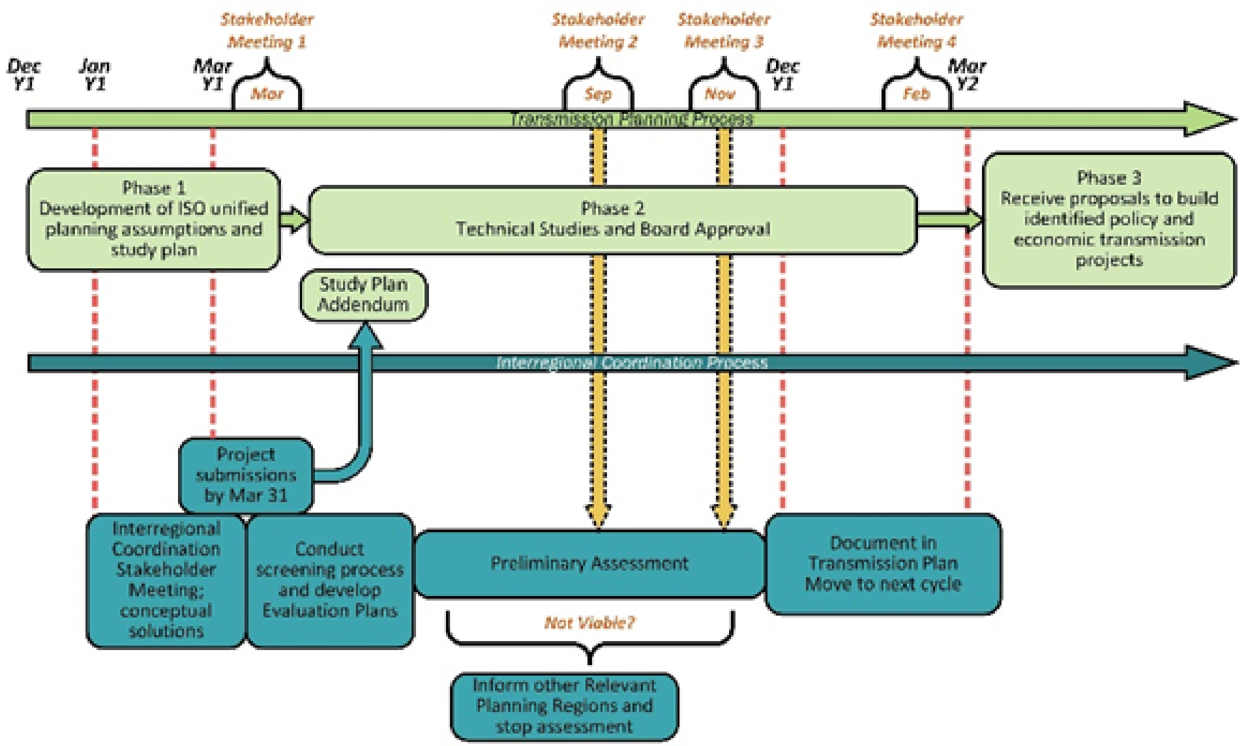
The even year ITP assessment begins when the relevant planning regions initiate the coordinated ITP evaluation process. This evaluation process constitutes the relevant planning regions' formal process to identify and jointly evaluate transmission facilities that are proposed to be located in planning regions in which the ITP was submitted. The goal of the coordinated ITP evaluation process is to achieve consistent planning assumptions and technical data of an ITP that will be used by all relevant planning region(s) in their individual evaluations of the

ITP(s). The relevant planning regions are required to complete the ITP evaluation process within 75 days after the ITP submittal deadline of March 31 during which a lead planning region is selected for each ITP proposal to develop and post for CAISO stakeholder review, a coordinated ITP evaluation process plan for each ITP. Once the ITP evaluation plans are finalized, each relevant planning region independently considers the ITPs that have been submitted into its regional planning process.

As with the other relevant planning regions, the CAISO assesses the ITP proposals under the CAISO tariff. As illustrated in the CAISO shares this information with stakeholders through its regularly scheduled stakeholder meetings, as applicable.

It is important to note that the CAISO manages its assessment of an ITP proposal across the two year interregional coordination cycle in two steps. During the even year, the CAISO makes a preliminary assessment of the ITP and once it completes that task, CAISO must consider whether or not consideration of the ITP should continue into the next CAISO planning cycle (odd year interregional coordination process). That determination can be made based on a number of factors including economic, reliability, and public policy considerations.

Figure 5.3-1: Even Year Interregional Coordination Process

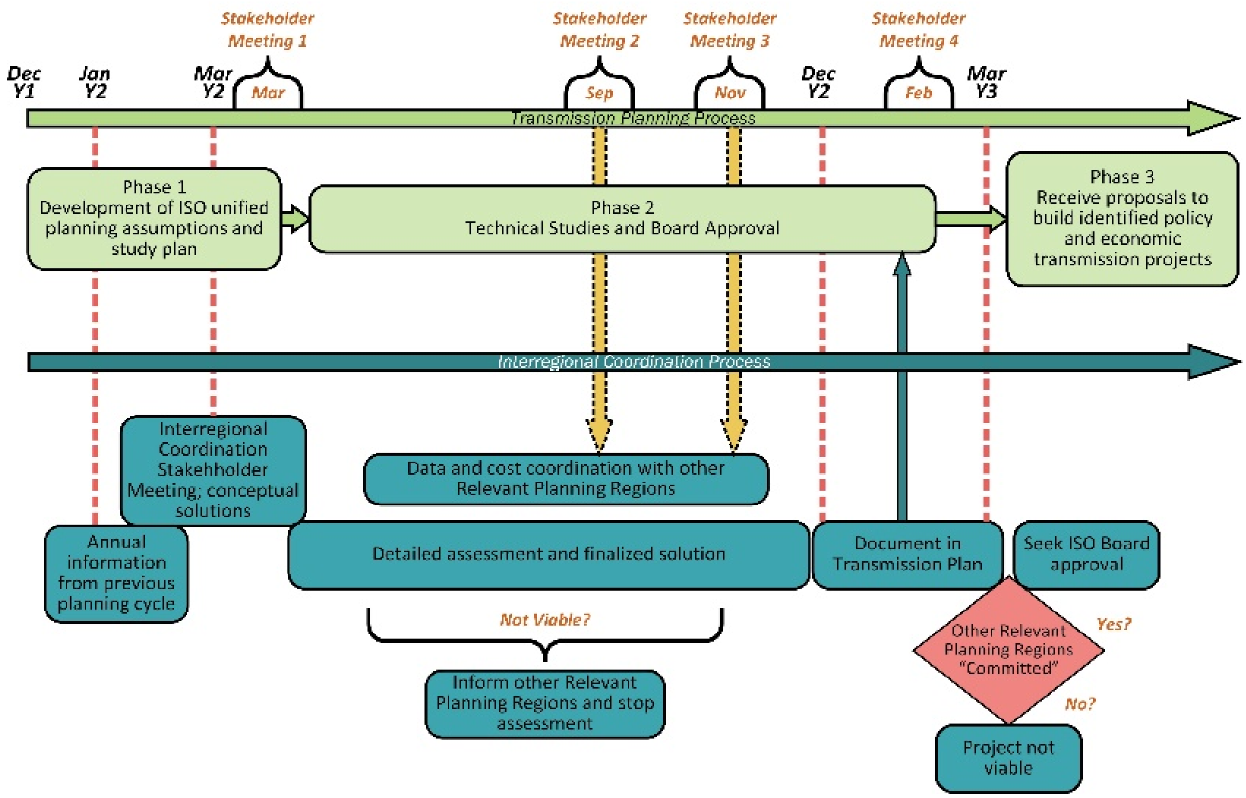


The CAISO will document the results of its initial assessment of the ITP in its transmission plan including a recommendation to continue or not continue assessment of the ITP in the odd year. The CAISO Board's approval of the transmission plan is sufficient to enact the recommendations of the transmission plan.

5.3.3.2 Odd Year ITP Assessment

A recommendation in the even year transmission plan to continue assessing an ITP will initiate consideration of the ITP in the following, or odd year transmission planning cycle and as such, will be documented in the odd year transmission planning process, unified planning assumptions, and study plan. Similar to the even year coordination process shown in Figure 5.3-1, the CAISO will follow the odd year interregional coordination process shown in Figure 5.3-2.

Figure 5.3-2: Odd Year Interregional Coordination Process



During the odd year planning cycle the CAISO will conduct a more in-depth analysis of the project proposal, which will include consideration of the timing in which the regional solution is needed and the likelihood that the proposed interregional transmission project will be constructed and operational in the same timeframe as the regional solution(s) it is replacing. The CAISO may also determine the regional benefits of the interregional transmission project to the CAISO that will be used for purposes of allocating any costs of the ITP to the CAISO.

If the CAISO determines that the proposed ITP is a more efficient or cost effective solution to meet a CAISO-identified regional need and the ITP can be constructed and operational in the same timeframe as the regional solution, the CAISO will then consider the ITP as the preferred solution in the CAISO transmission plan. The CAISO will document its analysis of the ITP and the other regional transmission solutions.

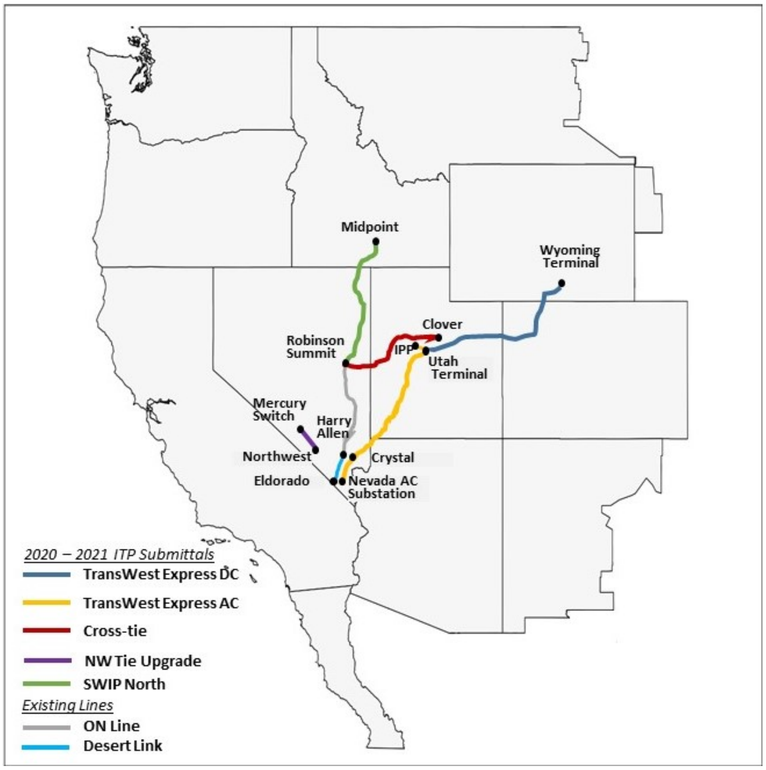
Once the CAISO selects an ITP in the CAISO transmission plan the CAISO will coordinate with the other relevant planning regions to determine if the ITP will be selected in their regional plans and whether or not a project sponsor has committed to pursue or build the project. Based on the information available, the CAISO may inform the CAISO Board on the status of the ITP proposal and if appropriate, seek approval from the board to continue working with all relevant parties associated with the ITP to determine if the ITP can viably be constructed. Determining viability may take several years during which time the CAISO will continue to consider the ITP it its transmission planning process and if appropriate, select it as the preferred solution. The CAISO may seek CAISO Board approval to build the ITP once the CAISO receives a firm commitment to construct the ITP.

5.4 2020-2021 Interregional Transmission Coordination ITP Submittals to the CAISO

The CAISO hosted its 2020-2021 ITP submission period in the first quarter of 2020 in which proponents were able to submit ITP proposals to the CAISO and request their evaluation within the 2020-2021 transmission planning process. The submission period began on January 1st and closed March 31st where four interregional transmission projects and their documentation[147] were submitted by their project sponsors for consideration by the CAISO. Of the four projects submitted, three projects were submitted into the 2018-2019 interregional transmission coordination cycle and resubmitted into the 2020-2021 cycle. The submitted projects are shown in Figure 5.4-1.

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

Figure 5.4-1 Interregional Transmission Project Submitted to the CAISO



Following the submission and successful screening of the ITP submittals, the CAISO coordinated its ITP evaluation with the other relevant planning regions a result of which was the coordinated development of “ITP Evaluation Process Plan(s)” for each of the ITPs submitted to the CAISO. Given the intent of the coordinated ITP evaluation process is to achieve consistent planning assumptions and technical data of an ITP to be used in the individual regional evaluations of an ITP, these evaluation plans satisfy that intent and as such, fulfills Order 1000’s requirement of the relevant planning regions to jointly coordinate regional planning processes that evaluate an ITP. In doing so, the evaluation plans document a common framework, coordinated by the WPRs, to provide basic descriptions, major assumptions, milestones, and key participants in the ITP evaluation process. The CAISO then utilizes this information in its development of all planning data and information that is required for the CAISO to assess the ITP in its transmission planning process. Specifically, the information in the evaluation plans is considered an addendum to the approved Transmission Planning Process Unified Planning Assumptions and Study Plan[148].

5.4.1 2020-2021 Interregional Transmission Coordination ITP Submittals

During the course of this year’s planning cycle, the CAISO considered all four ITPs that were submitted during the ITP submission period. The proposed ITPs, their sponsor’s identified need, and the CAISO’s identified need as determined by the CAISO’s assessment are summarized in

148 http://www.caiso.com/Documents/FinalStudyPlan_2020-2021TPP_Revised.pdf

Table 5.4-1. Where appropriate, additional assessment information in provided in section 5.4.1.1 through section 5.4.1.4.

Table 5.4-1: ITPs Submitted into the 2020-2021 Submission Period

Project Name	Sgmts	Company	CEII or Confidential Data Submitted	Project Submitted to	Relevant Planning Regions	Cost Allocation Requested From	Termination From	Termination to	In Service Date
Cross-Tie Transmission Project		TransCanyon, LLC	Yes	CAISO, NTTG, NG, WC	NG and WC	CAISO, NTTG and WC	Clover, UT (PacifiCorp)	Robinson Summit, NV (NV Energy)	2024
Northwest Tie Upgrade		GridLiance West	No	CAISO, WC	CAISO and WC	CAISO, WC	Innovation (VEA, GLW, CAISO)	Northwest, NV (NVE)	2024
SWIP-North`		Great Basin Transmission LLC	Yes	CAISO, NTTG and WC	NG, WC and CAISO	CAISO, NTTG and WC	Midpoint. ID (IPCO, PAC)	Robinson Summit, NV (NV Energy)	2023
TWE WY-IPP DC Project[149]	1	TransWest Express, LLC	No	CAISO and NTTG	Not an ITP	CAISO	Sinclair, WY (PAC)	Delta, UT (PAC)	2025
TWE WY-IPP DC + IPP-Crystal 500 kV AC Project	1+2	TransWest Express, LLC	No	CAISO and NTTG	NG + (WC)	CAISO	Sinclair, WY (PAC)	No. Vegas (NV Energy)	2025
TWE WY-IPP DC + Crystal - Eldorado 500 kV AC Project	1+3	TransWest Express, LLC	No	CAISO and NTTG	NA – segments not contiguous	CAISO			2025

5.4.1.1 Cross-Tie Transmission Project

A summary of the ITP information submitted to the CAISO is shown in Table 5.4-2.

Table 5.4-2: ITP Submittal Information for the Cross-Tie Transmission Project

Project Submitted To:	**California ISO, Northern Tier Transmission Group ("NTTG") and WestConnect**
Relevant Planning Regions:	NTTG and WestConnect
Cost Allocation Requested From:	California ISO, NTTG and WestConnect

Stated Purpose of the Project

The stated purpose of the Cross-Tie Project is that it would couple with the planned Gateway South Project (Aeolus – Clover), the existing One Nevada Line (Robinson Summit – Harry Allen) and the currently under construction Harry Allen – Eldorado 500 kV transmission project and would provide needed transmission capacity between the Intermountain West (Utah/Wyoming) region of NTTG and the Desert Southwest portion of WestConnect. The project

[149] The TWE WY-IPP DC Project, the TWE IPP-Crystal 500 kV AC Project, and the TWE Crystal-Eldorado 500 kV AC Project are three separate ITP submittals that can be evaluated as both individual ITPs and as a unified ITP, including either two or three segments

proponent states that this additional transmission capacity would facilitate access between the significant renewable resources in Wyoming/Utah and diverse utility load profiles in Desert Southwest/California. Also, this interregional project would result in lowering the cost of RPS compliance for the Desert Southwest and California while enhancing opportunities to balance the renewable resource mix between the Desert Southwest, California and the Intermountain West. The project would also facilitate the CAISO in meeting California's RPS and GHG requirements by providing transmission access to high capacity wind resources in Utah and Wyoming.

Project Description

TransCanyon, LLC (TransCanyon) submitted the 213-mile Cross-Tie Transmission Project (Cross-Tie Project) for consideration as an ITP. The Cross-Tie project is a proposed 1500 MW, 500 kV HVAC transmission project that would be constructed between central Utah and east-central Nevada (see Figure 5.4-2), connecting PacifiCorp's proposed 500 kV Clover substation (in the NTTG planning region) with NV Energy's existing 500 kV Robinson Summit substation (in the WestConnect planning region). The proposed project would include series compensation at both ends of the Cross-Tie transmission line. In addition, series compensation would be needed on the existing Robinson Summit to Harry Allen 500-kV line along with phase shifting transformers at Robinson Summit 345-kV.

The project would be required to satisfy the requirements of the National Environmental Policy Act (NEPA) and the Bureau of Land Management (BLM). A significant portion of the routing of the line has been previously studied under the Southwest Intertie Project Environmental Impact Statement, which received federal approval in a Record of Decision published in 1994 but was not constructed. Further, the project would be subject to the state approval processes applicable for Nevada and Utah. According to TransCanyon, the project could be in-service as early December 2024.

Figure 5.4-2: Cross-Tie Project Overview

Reliability Assessment

None performed

Economic Assessment

None Performed

Conclusions

The stated purpose of the Cross-Tie Project is a transmission solution that would "provide needed transmission capacity between the Intermountain West (Utah/Wyoming) region of NTTG and the Desert Southwest portion of WestConnect" and "facilitate access between the significant renewable resources in Wyoming/Utah and diverse utility load profiles in Desert Southwest/California." However, the study assumptions and the reliability, policy, and economic regional assessments documented in this study do not support finding this project needed in this planning cycle.

5.4.1.2 Northwest Tie Upgrade Project

A summary of the ITP information submitted to the CAISO for the Northwest Tie Upgrade Project is shown in Table 5.4-3.

Table 5.4-3: ITP Submittal Information for the Northwest Tie Upgrade Project

Project Submitted To:	**California ISO and WestConnect**
Relevant Planning Regions:	California ISO and WestConnect
Cost Allocation Requested From:	California ISO and WestConnect

Stated Purpose of the Project

The stated purpose of the Northwest Tie Upgrade project is to allow additional flow bi-directionally on the current Innovation-to-Northwest 138 kV system.

Project Description

GridLiance West (GLW) submitted the 47-mile Northwest Tie Upgrade Project (Northwest Tie) for consideration as an Interregional Transmission Project. Northwest Tie is a proposed upgrade of an existing 138 kV transmission line located in southern Nevada (see Figure 5.4-3), connecting the GLW/Valley Electric Association (VEA) system (in the CAISO planning region) with NV Energy's existing 230/138 kV transformer bank at Northwest substation (in the WestConnect planning region). The Indian Springs – Mercury 138 kV segment of this project is a part of Western Electricity Coordinating Council (WECC) Path 81 – Southern Nevada Transmission Interface (SNTI). According to GLW, the project is expected to be in-service by 05/31/2024.

Figure 5.4-3: Northwest Tie Upgrade Project Overview

Reliability Assessment

None performed.

Economic Assessment

None performed

Conclusions

The stated purpose of the Northwest Tie Upgrade Project is to allow additional flow bi-directionally on the current Innovation-to-Northwest 138 kV system. However, the study assumptions and the reliability, policy, and economic regional assessments documented in this study do not support finding this project needed in this planning cycle.

5.4.1.3 SWIP – North Project

A summary of the ITP information submitted to the CAISO for the SWIP – North Project is shown in Table 5.4-4.

Table 5.4-4: ITP Submittal Information for the SWIP - North Project

Project Submitted To:	**California Independent System Operator ("California ISO"), Northern Tier Transmission Group ("NTTG") and WestConnect**
Relevant Planning Regions:	California ISO, NTTG and WestConnect
Cost Allocation Requested From:	California ISO, NTTG and WestConnect

It is noted that LS Power also requested the CAISO to quantify financial congestion on the PACI, NOB, and COI paths in addition to the physical congestion that it has been quantified over the last few planning cycles. The detailed results of this assessment are documented in Chapter 4.

Stated Purpose of the Project

The stated purpose of the SWIP - North Project is that it would provide a new backbone for the western grid that would provide not only economic benefits, but additional reliability benefits and insurance against emergency outage scenarios. The proponent also states that the project would provide benefits related to congestion relief on COI, energy market value, integrating renewables that support GHG and RPS policy goals, EIM benefits, increased capacity benefits, increased load diversity, wheeling revenues, insurance value and reliability benefits.

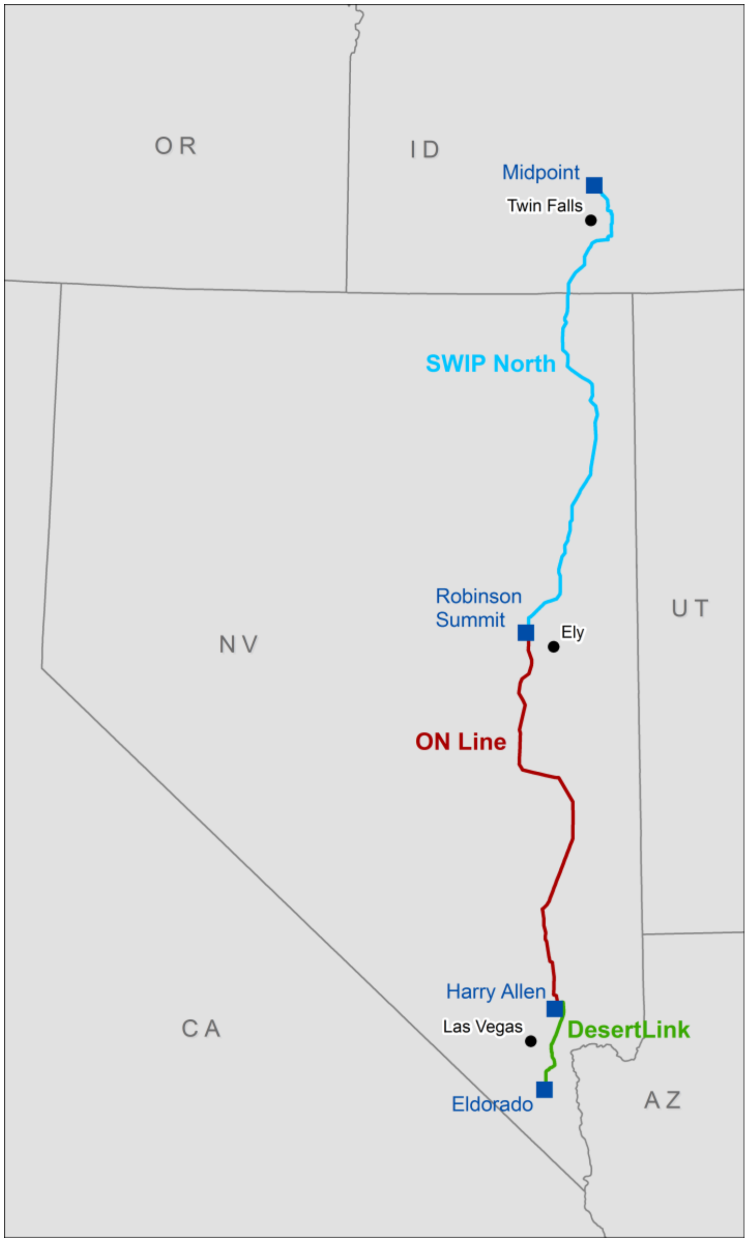
Project Description

As set out in Chapter 2, the SWIP - North Project was submitted in the 2018 Request Window as a transmission solution to address thermal overloads on the 500 kV and 230 kV systems in northern California and to improve low voltage issues in northern California during summer peak conditions with high COI N-S flows. The project was also proposed by a non-PTO, Great Basin Transmission (GBT), LLC, an affiliate of LS Power, as a Reliability Transmission Project discussed in chapter 2 and as part of an economic study request discussed in chapter 4.

The SWIP - North Project connects the Midpoint 500 kV substation (in NTTG) to the Robinson Summit 500 kV substation (in WestConnect) via a 275-mile, 500kV single circuit AC transmission line (see Figure 5.4-4). The project is expected to have a bi-directional WECC-approved path rating of approximately 2000 MW. Upon completing a new physical connection at Robinson Summit a capacity sharing arrangement would be triggered between GBT and NV Energy across the already in-service ON-Line Project and SWIP-N that would provide GBT with control of ~1,000 MW bi-directional capacity between Midway and Harry Allen.

The project also includes an optional 500 MW, 6-hour battery storage project located at either the Midpoint substation, Eldorado substation, or both and is proposed to be operated by CAISO as a Transmission Asset. The project proponents claim that the addition of battery storage further enhances benefits of the project, which will include allowing delivery of renewables from diverse out of state locations such as Idaho and Northern Nevada and providing certainty that firm, GHG-free energy will be deliverable during the evening peak hours.

Figure 5.4-4: SWIP - North Map of the Preliminary Route



Reliability Assessment

The bulk system assessment identified a number contingencies that result in transmission constraints. The recommended solutions to mitigate the identified reliability concerns include, among others, managing COI flow and installing dynamic reactive support at the Round Mountain and Gates 500kV switchyards:

Economic Assessment

A more detailed discussion of the CAISO's economic assessment of the SWIP North Project is presented in Section 4.10.3.

Production Benefits

The annual production cost benefit to the CAISO ratepayers is $10.1 million/per year as identified in this planning cycle, which increased from the economic assessment result of this project in the 2018~2019 planning cycle, which did not show benefit to the CAISO ratepayers.

Benefit to Cost Ratio

The present value of the sum of the production cost was calculated on a 50 year project life followed by the calculation of the benefit to cost ratio. The economic assessment for the SWIP-North project in this planning cycle identified that its benefit to cost ratio is 0.21, which indicates that the production cost benefit of this project likely cannot cover its total cost over its economic life. No other benefit was assessed for the SWIP-North project in this planning cycle.

Conclusions

Based on the CAISO's analysis, consistent with its Transmission Economic Analysis Methodology, the benefit to cost ratio was not sufficient for the CAISO to find the need for funding the SWIP-North project as an economic-driven project.

5.4.1.4 TransWest Express Transmission Project

A summary of the ITP information submitted to the CAISO for the TransWest Express Transmission Project is shown in Table 5.4-5.

Table 5.4-5: ITP Submittal Information for the TransWest Express Transmission Project

Project Submitted To:	**California Independent System Operator ("California ISO"), Northern Tier Transmission Group ("NTTG")**
Relevant Planning Regions:	California ISO and NTTG
Cost Allocation Requested From:	California ISO

Stated Purpose of the Project

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

Project Description

The TransWest Express (TWE) Transmission Project consists of three discrete interconnected transmission segments that, when considered together, will interconnect transmission infrastructure in Wyoming, Utah, and southern Nevada. TransWest submitted their project as three separate ITP submittals:

1. TWE WY-IPP DC Project;

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

3. TWE Crystal-Eldorado 500 kV AC Project.

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

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

The TWE Project will interconnect with facilities owned and/or operated by some WestConnect Transmission Owners with Load Serving Obligations (TOLSOs); however, TransWest did not submit the TWE Project to WestConnect. As stated by the project sponsor, the TWE Project will meet local needs and does not anticipate meeting any regional needs within WestConnect. As such, TransWest is working directly with certain WestConnect members and has encouraged the California ISO and NorthernGrid to do the same during the 2020-2021 regional planning cycle.

Reliability Assessment

None performed.

Economic Assessment

None performed.

Conclusions

The stated purpose of the TWE Project is that it will provide needed transmission capacity between the Rocky Mountain region and the Desert Southwest and CAISO regions. This additional transmission capacity will provide load serving entities with access to high quality wind generation resources and enhanced market efficiency through broader interregional integration. Moreover, the TWE Project can contribute significantly to the Desert Southwest states meeting statutory and public policy goals to obtain a large percentage of electricity from renewable energy resources, to decrease greenhouse gas emissions, and to move to 100% carbon-free electricity. However, the study assumptions and the reliability, policy, and economic regional assessments documented in this transmission plan do not support finding this project needed in this planning cycle.

5.5 Formation of Northern Grid

Since the first interregional transmission coordination cycle was initiated, four WPRs closely coordinated the development of the necessary processes, protocols, and guidelines that were required to fully implement the requirements of Order No. 1000 and the Order No. 1000 Common Interregional Tariff. During 2019 two WPRs, the Northern Tier Transmission Group and ColumbiaGrid, merged into a single transmission planning region in order to facilitate regional transmission planning, enable one common set of data and assumptions, identify regional transmission projects through a single stakeholder forum, and eliminate duplicative administrative processes. The Federal Energy Regulatory Commission accepted tariff modifications filed by the FERC-jurisdictional members of NorthernGrid — Avista Corporation, Idaho Power Company, MATL, NorthWestern Energy, PacifiCorp, Portland General Electric Company, and Puget Sound Energy. The filings asked FERC to accept modifications to each filing party's Open Access Transmission Tariff transmission planning section to reflect the new NorthernGrid regional transmission planning process.

It is important to note that the coordination guides and protocols that were developed over the last two interregional coordination cycles that have been effective in ensuring transparency and comparability of the existing ITP coordination process remain in place and will continue forward to future interregional transmission coordination cycles. Beginning in 2020 the CAISO and WestConnect engaged with NorthernGrid representatives to continue to engaging in interregional transmission coordination activities.

5.6 Development of the ADS

Developing and implementing the ADS is a significant undertaking for WECC as its intended objective is to "re-write" its data collection process to include production cost information and clearly link power flow and load and resource information with the production cost information. In 2017 the WECC Reliability Assessment Committee (RAC) formed the ADS Task Force which was actively engaged in implementation of the ADS and was charged with considering and proposing any recommended changes needed to facilitate the successful implementation of the ADS.

The ADS Task Force completed its work in late 2019 and reported its findings to the RAC[150]. As a result of the ADSTF's findings, RAC formed the Loads and Resources Task Force (LRTF) to identify and reconcile resource and load inconsistencies between information submitted to NERC as part of their Loads and Resources (LAR) process and information included in WECC power flow cases. The LRTF completed its work in late 2020 and in general, has recommended that WECC further refine its existing resource and load collection processes to ensure that the appropriate data is collected and available to the ADS development processes.

The 2030 ADS was made available to WECC members on June 30, 2020. While WECC delivered the ADS on schedule, it was generally considered incomplete as it included data and representation errors. Since its release, several updates have been made available, all of which

[150] https://www.wecc.org/Administrative/DeShazo%20-%20ADSTF%20Transmittal%20Letter_October%202019.pdf?Web=1

have considerably improved the data integrity of the ADS. Equally important is WECC's commitment to continue to improve the overall ADS process through their commitment of a single WECC staff member who is charged with oversight of the ADS process and the development of the 2032 ADS.

The CAISO continues to support WECC's ADS activities and remains engaged in the ADS development process through standing WECC subcommittees and workgroups. The ADS remains the best representative approach to addressing existing and ongoing data inconsistencies and applications, while facilitating a common dataset that accurately represents the regional plans of the WPRs. Each year the CAISO builds over 100 power flow cases to perform its reliability assessment of the CAISO controlled grid as well as a detailed production cost model dataset from which it performs economic, policy, and other "special studies". Clearly, significant CAISO resources are committed to developing these study models during each planning cycle and, as such, their accuracy is of paramount importance to that process. The CAISO believes that the successful development and implementation of the ADS will yield, through a consistent and repeatable process, better coordinated and more accurate datasets that will maximize their use and minimize errors in WPR regional and WECC assessments.

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Chapter 6

6 Other Studies and Results

The studies discussed in this chapter focus on other recurring study needs not previously addressed in preceding sections of the transmission plan and are either set out in the CAISO tariff or forming part of the ongoing collaborative study efforts taken on by the CAISO to assist the CPUC with state regulatory needs. The studies have not been addressed elsewhere in the transmission plan. These presently include the reliability requirements for resource adequacy, simultaneous feasibility test studies, a system frequency response assessment, and a flexible capacity deliverability assessment.

6.1 Reliability Requirement for Resource Adequacy

Section 6.1.1 summarize the technical studies conducted by the CAISO to comply with the reliability requirements initiative in the resource adequacy provisions under section 40 of the CAISO tariff as well as additional analysis supporting long term planning processes, being the local capacity technical analysis and the resource adequacy import allocation study. The local capacity technical analysis addressed the minimum local capacity area requirements (LCR) on the CAISO grid. The resource adequacy import allocation study established the maximum resource adequacy import capability to be used in 2021. Upgrades that are being recommended for approval in this transmission plan have therefore not been taken into account in these studies.

6.1.1 Local Capacity Requirements

The CAISO conducted short- and long-term local capacity technical (LCT) analysis studies in 2020. A short-term analysis was conducted for the 2021 system configuration to determine the minimum local capacity requirements for the 2021 resource procurement process. The results were used to assess compliance with the local capacity technical study criteria as required by the CAISO tariff section 40.3. This study was conducted in January through April through a transparent stakeholder process with a final report published on May 1, 2020. For detailed information on the 2021 LCT Study Report please visit:

http://www.caiso.com/Documents/Final2021LocalCapacityTechnicalReport.pdf

One long-term analysis was also performed identifying the local capacity needs in the 2025 period. The long-term analyses provide participants in the transmission planning process with future trends in LCR needs for up to five years respectively. The 2025 LCT Study Report was published on May 1, 2020 and for detailed information please visit:

http://www.caiso.com/Documents/Final2025Long-TermLocalCapacityTechnicalReport.pdf

The CAISO also conducts a ten-year local capacity technical study every second year, as part of the annual transmission planning process. The ten-year LCT studies are intended to synergize with the CPUC long-term procurement plan (LTPP) process and to provide an indication of whether there are any potential deficiencies of local capacity requirements that need to trigger a new LTPP proceeding and, per agreement between state agencies, they are done on every other year cycle.

The most recent ten-year LCR study was initiated in the current 2020-2021 transmission planning process. The CAISO undertook a comprehensive study of local capacity areas, examining both the load shapes and new battery charging and discharging characteristics underpinning local capacity requirements, and evaluating reduction alternatives, mostly proposed by stakeholders, even if it is unlikely that the economic benefits alone would outweigh the costs. A number of these alternatives received detailed economic evaluations in this planning cycle, as set out in chapter 4, to assess if they should be approved as economic-driven transmission solutions.

For detailed information about the 2030 long-term LCT study results, please refer to the stand-alone report in the Appendix G.

As shown in the LCT study reports and indicated in the LCT study manual, that the CAISO prepares each year setting out how that year's LCT studies will be performed, 12 load pockets are located throughout the CAISO-controlled grid as shown in Table 6.1-1; however only 10 of them have local capacity area requirements as illustrated in Figure 6.1-1.

Table 6.1-1: List of Local Capacity Areas and the corresponding service territories within the CAISO Balancing Authority Area

No	LCR Area	Service Territory
1	Humboldt	PG&E
2	North Coast/North Bay	
3	Sierra	
4	Stockton	
5	Greater Bay Area	
6	Greater Fresno	
7	Kern	
8	Los Angeles Basin	SCE
9	Big Creek/Ventura	
10	Greater San Diego/Imperial Valley	SDG&E
11	Valley Electric	VEA
12	Metropolitan Water District	MWD

Figure 6.1-1: Approximate geographical locations of LCR areas

Each load pocket is unique and varies in its capacity requirements because of different system configurations. For example, the Humboldt area is a small pocket with total capacity requirements of approximately 130 MW. In contrast, the requirements of the Los Angeles Basin are approximately 7,000 MW. The short-term and long-term LCR needs from this year's studies are shown in Table 6.1-2.

Table 6.1-2: Local capacity areas and requirements for 2021, 2025 and 2030

LCR Area	LCR Capacity Need (MW)		
	2021	2025	2030
Humboldt	130	132	135
North Coast/North Bay	842	837	842
Sierra	1,821	1,367	1,518
Stockton	596	619	619
Greater Bay Area	6,353	6,110	7,344
Greater Fresno	1,694	1,971	2,296
Kern	413	186	413
Big Creek/Ventura	2,296	1,002	1,151
Los Angeles Basin	6,127	6,309	6,194
Greater San Diego/Imperial Valley	3,888	3,557	3,718
Valley Electric	0	0	0
Metropolitan Water District	0	0	0
Total	24,160	22,090	24,230

Notes:
For more information about the LCR criteria, methodology and assumptions please refer to the CAISO LCR manual.[151]
For more information about the 2021 LCT study results, please refer to the report posted on the CAISO website.
For more information about the 2025 LCT study results, please refer to the report posted on the CAISO website.

[151] "Final Manual 2021 Local Capacity Area Technical Study," December 23, 2019, http://www.caiso.com/Documents/2021LocalCapacityRequirementsFinalStudyManual.pdf .

6.1.2 Resource adequacy import capability

The CAISO has established the maximum resource adequacy (RA) import capability to be used in year 2021 in accordance with CAISO tariff section 40.4.6.2.1. These data can be found on the CAISO website[152]. The entire import allocation process[153] is posted on the CAISO website.

The CAISO also confirms that all import branch groups or sum of branch groups have enough maximum import capability (MIC) to achieve deliverability for all external renewable resources in the base portfolio along with existing contracts, transmission ownership rights and pre-RA import commitments under contract in 2030.

The future outlook for all remaining branch groups can be accessed at the following link:

http://www.caiso.com/Documents/AdvisoryestimatesoffutureResourceAdequacyImportCapabilityforyears2021-2030.pdf

The advisory estimates reflect the target maximum import capability (MIC) from the Imperial Irrigation District (IID) to be 702 MW in year 2022 to accommodate renewable resources development in this area that CAISO has established in accordance with Reliability Requirements BPM section 5.1.3.5. The import capability from IID to the CAISO is the combined amount from the IID-SCE_BG and the IID-SDGE_BG.

The 10-year increase in MIC from current levels out of the IID area is dependent on transmission upgrades in both the CAISO and IID areas as well as new resource development within the IID and CAISO systems, and, for the CAISO system, on the West of Devers upgrades in particular. The increase to the target level is expected to take place when the West of Devers upgrades are completed and depends on all necessary upgrades being completed in both the CAISO and IID areas. The CAISO also notes that upgrades proposed to the IID-owned 230 kV S Line will increase deliverability out of the Imperial area overall and including from IID. The allocation of that deliverability in the future will be available to support deliverability of generation connecting either to the CAISO controlled grid or the IID system based on the application of the CAISO's tariff and business practices.

[152] "California ISO Maximum RA Import Capability for year 2021," available on the ISO's website at http://www.caiso.com/Documents/ISOMaximumResourceAdequacyImportCapabilityforYear2021.pdf .

[153] See general the Reliability Requirements page on the ISO website http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx .

6.2 Long-Term Congestion Revenue Rights Simultaneous Feasibility Test Studies

The Long-term Congestion Revenue Rights (LT CRR) Simultaneous Feasibility Test studies evaluate the feasibility of the fixed LT CRRs previously released through the CRR annual allocation process under seasonal, on-peak and off-peak conditions, consistent with section 4.2.2 of the Business Practice Manual for Transmission Planning Process and tariff sections 24.1 and 24.4.6.4

6.2.1 Objective

The primary objective of the LT CRR feasibility study is to ensure that fixed LT CRRs released as part of the annual allocation process remain feasible over their entire 10-year term, even as new and approved transmission infrastructure is added to the CAISO-controlled grid.

6.2.2 Data Preparation and Assumptions

The 2020 LT CRR study leveraged the base case network topology used for the annual 2021 CRR allocation and auction process. Regional transmission engineers responsible for long-term grid planning incorporated all the new and CAISO approved transmission projects into the base case and a full alternating current (AC) power flow analysis to validate acceptable system performance. These projects and system additions were then added to the base case network model for CRR applications. The modified base case was then used to perform the market run, CRR simultaneous feasibility test (SFT), to ascertain feasibility of the fixed CRRs. A list of the approved projects can be found in the 2020-2021 Transmission Plan. In the SFT-based market run, all CRR sources and sinks from the released CRR nominations were applied to the full network model (FNM). All applicable constraints that were applied during the running of the original LT CRR market were considered to determine flows as well as to identify the existence of any constraint violations. In the long-term CRR market run setup, the network was limited to 60 percent of available transmission capacity. The fixed CRR representing the transmission ownership rights and merchant transmission were also set to 60 percent. All earlier LT CRR market awards were set to 100 percent, since they were awarded with the system capacity already reduced to 60 percent. For the study year, the market run was set up for two seasons (with season 1 being January through March and season 3 July through September) and two time-of-use periods (reflecting on-peak and off-peak system conditions). The study setup and market run are conducted in the CRR study system. This system provides a reliable and convenient user interface for data setup and results display. It also provides the capability to archive results as save cases for further review and record-keeping.

- The CAISO regional transmission engineering group and CRR team must closely collaborate to ensure that all data used were validated and formatted correctly. The following criteria were used to verify that the long-term planning study results maintain the feasibility of the fixed LT CRRs:SFT is completed successfully;
- the worst case base loading in each market run does not exceed 60 percent of enforced branch rating; and,

- there are overall improvements on the flow of the monitored transmission elements.

6.2.3 Study Process, Data and Results Maintenance

A brief outline of the current process is as follows:

- The base case network model data for long-term grid planning is prepared by the regional transmission engineering (RTE) group. The data preparation may involve using one or more of these applications: PTI PSS/E, GE PSLF and MS Excel;
- RTE models new and approved projects and perform the AC power flow analysis to ensure power flow convergence;
- RTE reviews all new and approved projects for the transmission planning cycle;
- applicable projects are modeled into the base case network model for the CRR allocation and auction in collaboration with the CRR team, consistent with the BPM for Transmission Planning Process section 4.2.2;
- CRR team sets up and performs market runs in the CRR study system environment in consultation with the RTE group;
- CRR team reviews the results using user interfaces and displays, in close collaboration with the RTE group; and
- The input data and results are archived to a secured location as saved cases.

6.2.4 Conclusions

The SFT studies involved four market runs that reflected two three-month seasonal periods (January through March and July through September) and two time-of-use (on-peak and off-peak) conditions.

The results indicated that all existing fixed LT CRRs remained feasible over their entire 10-year term as planned. In compliance with section 24.4.6.4 of the CAISO tariff, the CAISO followed the LTCRR SFT study steps outlined in section 4.2.2 of the BPM for the Transmission Planning Process to determine whether there are any existing released LT CRRs that could be at risk and for which mitigation measures should be developed. Based on the results of this analysis, the CAISO determined in Dec 2020 that there are no existing released LT CRRs at-risk" that require further analysis. Thus, the transmission projects and elements approved in the 2020-2021 Transmission Plan did not adversely impact feasibility of the existing released LT CRRs. Hence, the CAISO did not evaluate the need for additional mitigation solutions.

6.3 Frequency Response Assessment and Data Requirements

As penetration of renewable resources increases, conventional generators are being displaced with renewable resources. Given the materially different operating characteristics of renewable generation, this necessitates broader consideration of a range of issues in managing system dispatch and maintaining reliable service across the range of operating conditions. Many of these concerns relate directly or indirectly to the “duck curve”, highlighting the need for flexible ramping generation but also for adequate frequency response to maintain the capability to respond to unplanned contingencies as the percentage of renewable generation online at any time climbs and the percentage of conventional generation drops.

Over past planning cycles, the CAISO conducted a number of studies to assess the adequacy of forecast frequency response capabilities, and those studies also raised broader concerns with the accuracy of the generation models used in our analysis. Inadequate modeling not only impacts frequency response analysis, but can also impact dynamic and voltage stability analysis as well.

The CAISO has therefore been conducting studies and model collection and validation efforts over the past several years to identify priority areas for improving generation modeling in power flow and stability analysis. This effort is critical both due to identified areas of concern with the models and data presently available, as well as the increasing requirements in NERC mandatory standards.

The work conducted in the time frame of the 2017-2018 planning cycle have focused primarily on data collection and model validation. During 2018, the CAISO undertook an effort to collect accurate modeling data from the generation owners. In response to the CAISO requests, numerous data was received and many generation models were updated. These updates were reported to WECC and were included in the WECC Dynamic Master File. The frequency response study was performed with the use of the updated generation models for the units for which the updated models were received.

In addition, the CAISO Business Practice Manual (BPM) has been updated to include requirements to generation modeling data submittals. The CAISO Tariff Section 24.8.2 requires “Participating Generators [to] provide the CAISO on an annual or periodic basis in accordance with the schedule, procedures and in the form required by the Business Practice Manual any information and data reasonably required by the CAISO to perform the Transmission Planning Process. . . .” Section 10 of the BPM establishes both: (1) what information and data must be submitted; and (2) the schedule, procedures, and format for submitting that information and data.

The CAISO requires generating unit models in the GE-PSLF format and other technical information from participating generators, as identified in the generator data template that was developed by the CAISO in 2018. Generator data templates for different categories of participating generators will be posted on the CAISO website. The generator resource list identifying all participating generators by data category and submission phase also can be accessed on the CAISO website. The BPM includes sanctions to the Generation Owners for not providing the requested data in time.

In the subsections below, the progress achieved and issues to be considered going forward has been summarized, as well as the background setting the context for these efforts and the study results.

6.3.1 Frequency Response and Over generation issues

The CAISO's most recent concerted study efforts in forecasting frequency response performance commenced in the 2014-2015 transmission planning cycle and continued on in subsequent years, using the latest dynamic stability models. In the 2019-2020 transmission planning cycle the potential impact of inverter-based resources (IBR) providing frequency response was also studied.

Reliability Standard BAL-003-2 (Frequency Response and Frequency Bias Setting)

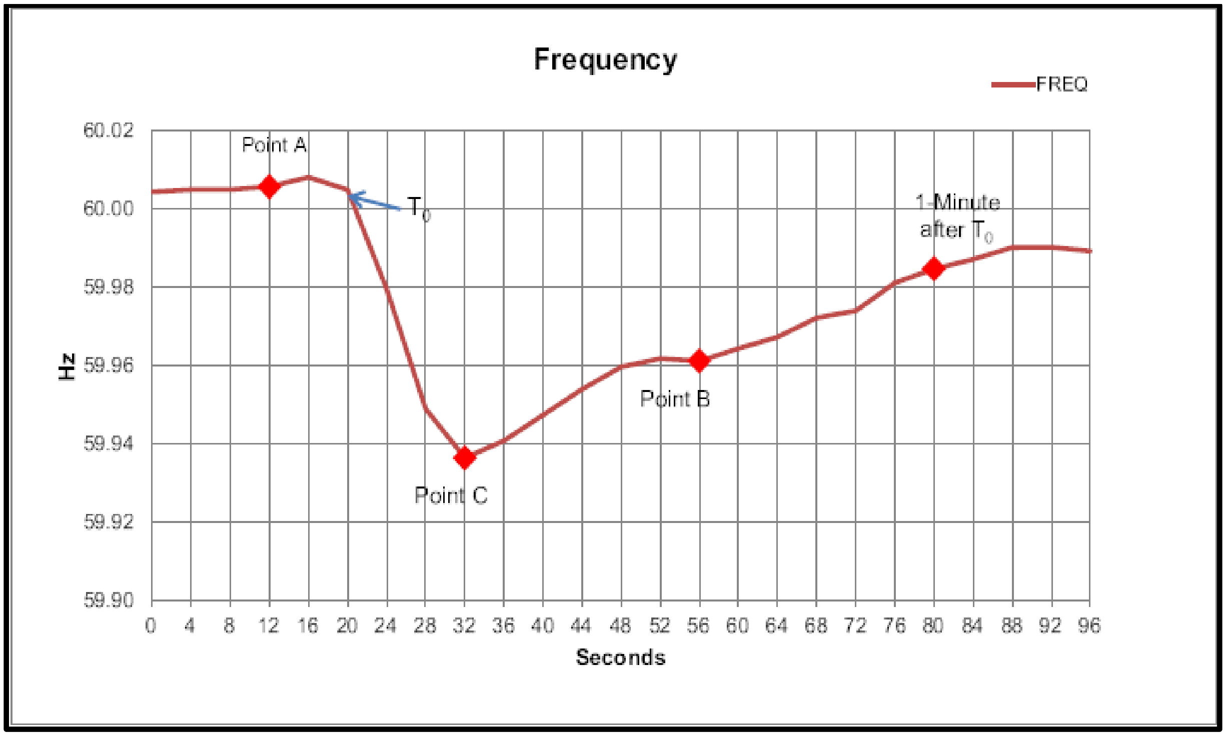
On July 15, 2020 FERC approved Reliability Standard BAL-003-2 (Frequency Response and Frequency Bias Setting), as submitted by North American Reliability Corporation (NERC). This standard was an update of the Standard BAL-003-1 and the Standard BAL-003-1.1 that created an obligation for balancing authorities, including the CAISO, to demonstrate sufficient frequency response to disturbances that result in decline of the system frequency by measuring actual performance against a predetermined frequency response obligation.

NERC has established the methodology for calculating frequency response obligations (FRO). A balancing authority's FRO is determined by first defining the FRO of the interconnection as a whole, which is referred to as the Interconnection Frequency Response Obligation (IFRO). The methodology then assigns a share of the total IFRO to each balancing authority based on its share of the total generation and load of the interconnection. The IFRO of the WECC Interconnection is determined annually based on the largest potential generation loss, which is the loss of two units of the Palo Verde Nuclear Generation Station (2,740 MW). This is a credible outage that results in the most severe frequency excursion post-contingency.

To assess each balancing authority's frequency performance, NERC selects at least 20 actual disturbances involving a drop in frequency each year, and measures frequency response of each balancing authority to each of these disturbances. Frequency response is measured in MW per 0.1 Hz of deviation in frequency. The median of these responses is the balancing authority's Frequency Response Measure (FRM) for the year. It is compared with the balancing authority's FRO to determine if the balancing authority is compliant with the standard. Thus, the BAL-003-2 standard requires the CAISO to demonstrate that its system provides sufficient frequency response during disturbances that affected the system frequency. To provide the required frequency response, the CAISO needs to have sufficient amount of frequency-responsive units online, and these units need to have enough headroom to provide such a response. Even though the operating standard measures the median performance, at this time planners assume that the performance should be targeted at meeting the standard at all times, and that unforeseen circumstances will inevitably lead to a range of outcomes in real time distributed around the simulated performance.

A generic system disturbance that results in frequency decline, such as a loss of a large generating facility is illustrated in Figure 6.3-1. Pre-event period (Point A) represents the system frequency prior to the disturbance with T_0 as the time when the disturbance occurs. Point C (frequency nadir) is the lowest level to which the system frequency drops, and Point B (settling frequency) is the level to which system frequency recovers in less than a minute as a result of the primary frequency response action. Primary frequency response is automatic and is provided by frequency responsive load and resources equipped with governors or with equivalent control systems that respond to changes in frequency. Secondary frequency response (past Point B) is provided by automatic generation control (AGC), and tertiary frequency response is provided by operator's actions.

Figure 6.3-1: Illustration of Primary Frequency Response



The system frequency performance is acceptable when the frequency nadir post-contingency is above the set point for the first block of the under-frequency load shedding relays, which is set at 59.5 Hz.

Where ΔP is the difference in the generation output before and after the contingency, and Δf is the difference between the system frequency just prior to the contingency and the settling frequency. For each balancing authority within an interconnection to meet the BAL-003-2 standard, the actual Frequency Response Measure should exceed the FRO of the balancing authority. FRO is allocated to each balancing authority and is calculated using the formula below.

$$FRO_{BA} = FRO_{Int} \frac{Pgen_{BA} + Pload_{BA}}{Pgen_{Int} + Pload_{Int}}$$

The Interconnection Frequency Response Obligation changes from year to year primarily as the result of the changes in the statistical frequency variability during actual disturbances, and statistical values of the frequency nadir and settling frequency observed in the actual system events. Allocation of the Interconnection FRO to each balancing authority also changes from year to year depending on the balancing authority's portion of the interconnection's annual generation and load. The studies performed by the CAISO in 2015 used the WECC FRO for 2016 that was determined as 858 MW/0.1 Hz and being on a conservative side, assumed that the CAISO's share is approximately 30 percent of WECC, which is 257.4 MW/0.1 Hz. It remained the same for 2017. For 2019, the Western Interconnection FRO was also calculated as 858 MW/0.1 Hz, according to the NERC 2018 Frequency Response Annual Analysis. Maximum delta frequency for the Western Interconnection for 2019 was calculated by NERC as 0.248 Hz. For 2018, it was calculated as 0.280 Hz.

The latest NERC BAL-003-2 Standard shows that for 2020, the Western Interconnection FRO was also calculated as 858 MW/0.1 Hz. Maximum delta frequency for the Western Interconnection for 2020 was calculated as 0.280 Hz. Thus, CAISO share of the Western Interconnection Frequency Response Obligation remains at 257.4 MW/0.1 Hz.

The NERC frequency response annual analysis report that specifies Frequency Response Obligations of each interconnection can be found on the NERC website[154].

The transition to increased penetration of renewable resources and more conventional generators being displaced with renewable resources does affect the consideration of frequency response issues. Most of the renewable resources coming online are wind and solar photovoltaic (PV) units that are inverter-based and do not have the same inherent capability to provide inertia response or frequency response to frequency changes as conventional rotating generators. Unlike conventional generation, inverter-based renewable resources must be specifically designed to provide inertia response to arrest frequency decline following the loss of a generating resource and to increase their output in response to a decline in frequency. While a frequency response characteristic can be incorporated into many inverter-based generator designs, the upward ramping control characteristic is only helpful if the generator is dispatched at a level that has upward ramping headroom remaining. To provide this inertia-like frequency response, wind and solar resources would have to have the necessary controls incorporated into their designs, and also have to operate below their maximum capability for a certain wind speed or irradiance level, respectively, to provide frequency response following the loss of a

[154] "2018 Frequency Response Annual Analysis," November 2018, https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/2018%20Frequency%20Reponse%20Annual%20Analysis%20Info%20Filing.pdf#search=Frequency%20Response%20annual%20analysis

large generator. As more wind and solar resources displace conventional synchronous generation, the mix of the remaining synchronous generators may not be able to adequately meet the CAISO's FRO under BAL-003-2 for all operating conditions.

The most critical conditions when frequency response may not be sufficient is when a large amount of renewable resources is online with high output and the load is relatively low, therefore many of conventional resources that otherwise would provide frequency response are not committed. Curtailment of renewable resources either to create headroom for their own governor response, or to allow conventional resources to be committed at a minimum output level is a potential solution but undesirable from an emissions and cost perspective.

Generation Headroom

Another metric that was evaluated in the CAISO studies was the headroom of the units with responsive governors. The headroom is defined as a difference between the maximum capacity of the unit and the unit's output. For a system to react most effectively to changes in frequency, enough total headroom must be available. Block loaded units and units that don't respond to changes in frequency (for example, inverter-based or asynchronous renewable units) have no headroom.

The ratio of generation capacity that provides governor response to all generation running on the system is used to quantify overall system readiness to provide frequency response. This ratio is introduced as the metric Kt; the lower the Kt, the smaller the fraction of generation that will respond. The exact definition of Kt is not standardized.

For the CAISO studies, it was defined as the ratio of power generation capability of units with responsive governors to the MW capability of all generation units. For units that don't respond to frequency changes, power capability is defined as equal to the MW dispatch rather than the nameplate rating because these units will not contribute beyond their initial dispatch.

6.3.2 FERC Order 842

On February 15, 2018 FERC issued Order 842 that requires newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. Based on FERC Order 842, all generators including wind and solar generators that execute an LGIA on or after May 15, 2018 are required to provide frequency response. While FERC Order 842 doesn't specify any headroom requirement, it is expected that under spring off peak conditions with significant solar generation, the solar generation will be curtailed and therefore new solar units that are capable of frequency response will have the headroom to be able to change MW output upward as well as downward.

6.3.3 2019-2020 Transmission Plan Study

The primary focus of the studies conducted in the 2019-2020 transmission planning cycle was to assess the contribution that inverter-based resources could provide to frequency response. A number of existing IBRs connected to the CAISO footprint have primary frequency response

(PFR) capability but other than for a few units, the PFR capabilities of the IBRs are not enabled. There were around 18 GW of existing installed IBRs across the CAISO in 2019, which is forecasted to reach 26 GW by year 2024. Considering the subset of existing IBRs with frequency response required and enabled, and new IBRs which are required to provide primary frequency response per FERC Order 842, it is expected that the PFR capability of the IBRs would be beneficial to system recovery from frequency events and to meet the CAISO Frequency Response Obligation (FRO).

Both existing and future IBRs with primary frequency response obligations, at the CAISO's operation direction, could be curtailed such that headroom is available for upward PFR. The study of the 2019-2020 Transmission Plan assessed the impact of enabling the PFR capability of the IBRs on system frequency response, providing headroom is available.

In addition to enabling PFR capabilities, the CAISO was considering modifications to the interconnection requirements for IBR connected to the CAISO's footprint. Specifically, the CAISO was considering changing the frequency deadband and the droop settings requirements for IBRs to drive faster frequency response. A study was required to determine the impact of the above changes on system frequency response, with the test being the simulation of the tripping of two Palo Verde units. Given the size of these units, the trip causes sufficient frequency decline in the simulation and facilitates comparison of the output of different generating units. This is the test the CAISO performs to forecast compliance with the requirements of NERC's BAL-003 standard.

The scope of the 2019-2020 Transmission Plan study was to test the impact of enabling the IBR PFR capability. The study included a test where the response was calculated without enabling the PFR of any of the IBRs except those that currently are already enabled. It also included the simulation in an assumption that the PFR of all the new IBRs that coming online between now and year 2024 was enabled assuming 8% headroom is available on all solar units. The third simulation assumed that in addition to new units, the PFR of 60% of the existing IBRs was enabled and these units have the capability to provide primary frequency response even if these control features are not required under their generator interconnection agreements to be activated.

In addition to enabling PFR as described above, the CAISO also studied the impact of changing the droop and frequency deadband settings to achieve improved frequency response contributions and performance. The current droop and deadband requirements are 5% and ±0.036 Hz. The study assessed changes to the droop and deadband requirements for new IBRs to 4% and ±0.0167 Hz, for several study scenarios.

The study used the year 2024 spring off peak case that due to low load and high solar generation had majority of gas units in the CAISO offline and therefore not providing frequency response. The study scenarios are summarized in Table 6.3-1.

Table 6.3-1: Study Scenarios for Frequency Response Study in the 2019-2020 TPP

	Study Scenarios						
	Base	SC1	SC2	SC3	SC4	SC5	SC6
PFR enabled for existing IBRs?	Yes for a few units	Yes for a few units	Yes for a few units	Yes for a few units	Yes for a few units	**Yes for 60%**	**Yes for 60%**
Existing IBRs and other gens droop	5%	5%	5%	5%	5%	5%	5%
Existing IBRs and other gens deadband (Hz)	±0.036	±0.036	±0.036	±0.036	±0.036	±0.036	±0.036
PFR enabled for new IBRs?	No	Yes	Yes	Yes	Yes	Yes	Yes
New IBRs droop	n/a	**5%**	**4%**	5%	**4%**	5%	**4%**
New IBRs deadband (Hz)	n/a	**±0.036**	±0.036	**±0.0167**	**±0.0167**	±0.036	**±0.0167**

The analysis also included a sensitivity study with the CAISO export at the historical data. This was achieved by the solar generation curtailment. In this study, the headroom of the solar units was around 40% following the curtailments. Same scenarios as for the base case were studied for the sensitivity case.

The study results for the baseline scenarios and the sensitivity study scenarios are illustrated in Figures 6.3-2 through 6.3-5.

These results indicate that by just enabling the frequency response of the new units coming online between now and year 2024 (SC1 to SC4), the system recovers from frequency events faster and settles at higher frequencies. This is true even with 5% droop and ±0.036 Hz deadband, but the CAISO generation provides more support in scenarios with 4% droop and ±0.0167 Hz deadband.

Another major improvement in the frequency recovery occurs when the frequency response of around 60% of the existing units that have the capability, are enabled.

It should be noted that if the PFR of the existing capable units and all the future IBRs are activated, the CAISO's frequency response may far exceed the required FRO value which was assumed at around 250 MW/0.1 Hz. The exceedance will be higher with 4% droop and ±0.0167 Hz deadband.

Compared to the base study case, the total CAISO generation output for the sensitivity study almost doubles and therefore frequency recovery is faster and at higher value. The exceedance of the CAISO response compared to its FRO is higher in this sensitivity case.

Figure 6.3-2: System Frequency Response Under Baseline Case (8% headroom)

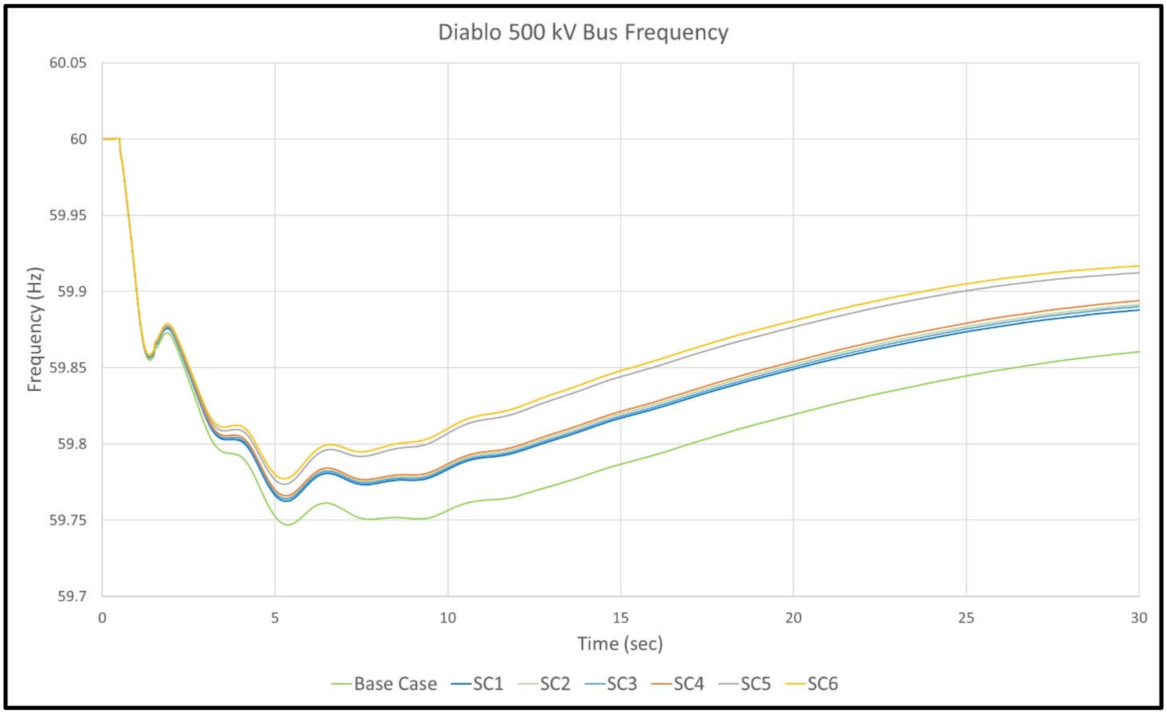


Figure 6.3-3: Total Output of CAISO Generators Under Baseline Case (8% headroom)

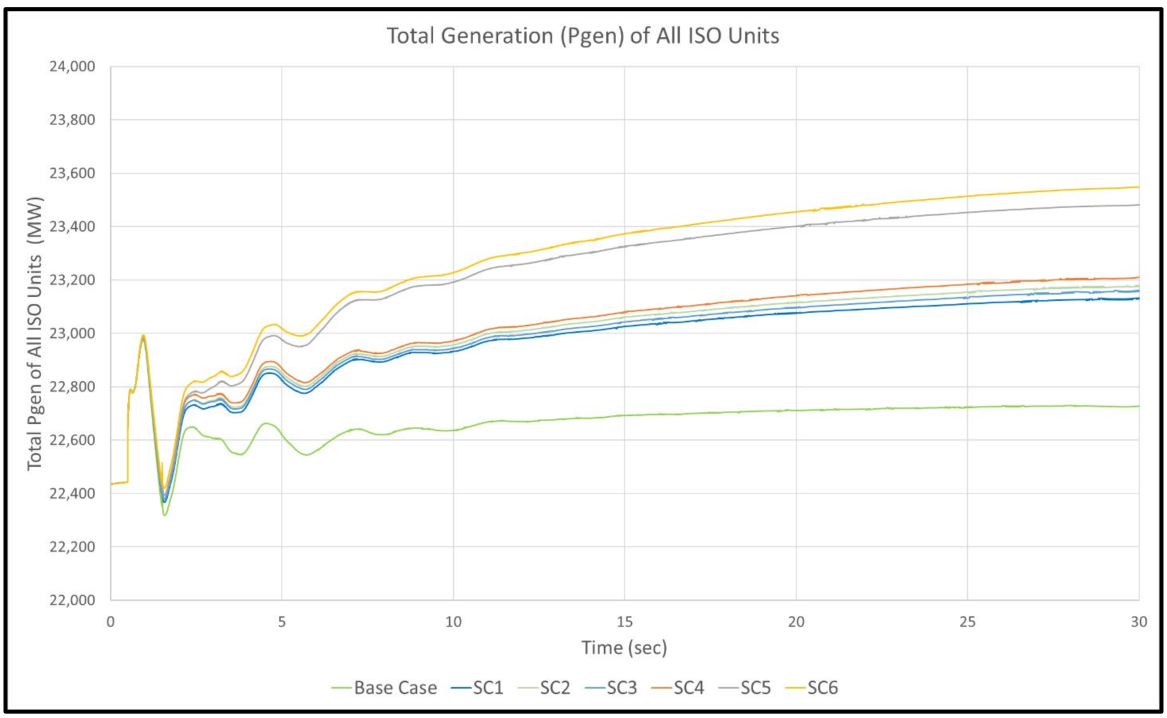


Figure 6.3-4: System Frequency Response under Sensitivity Case (~40% headroom)

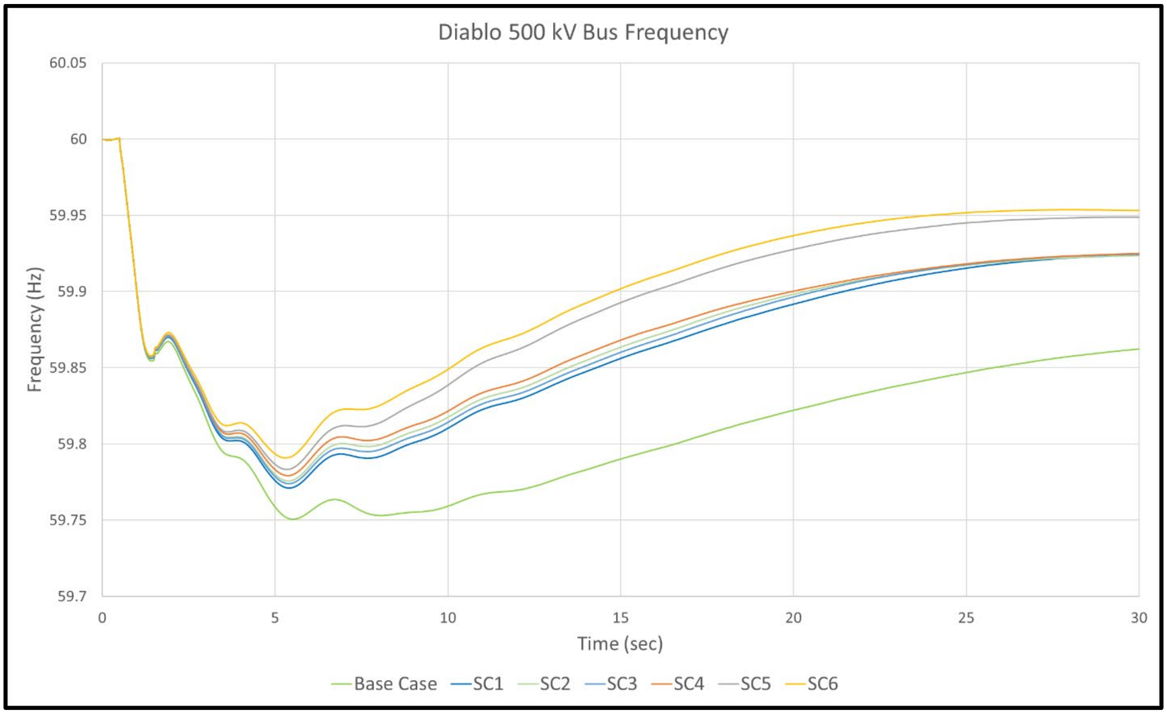
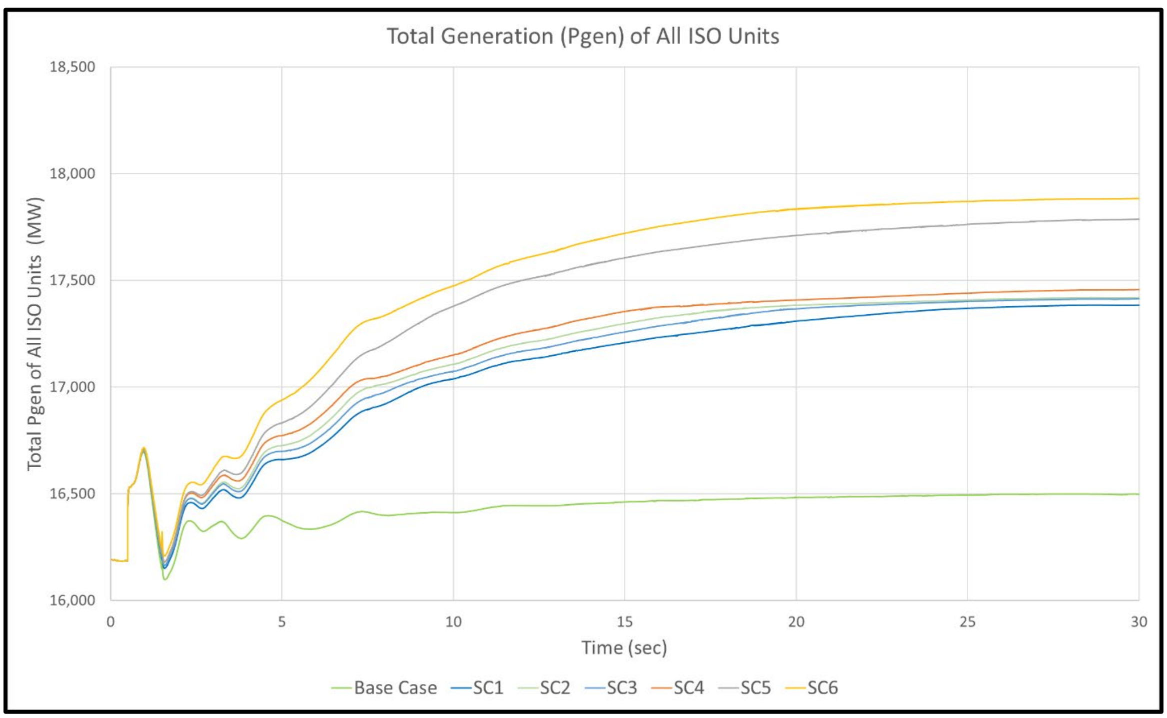


Figure 6.3-5: Total Output of CAISO Generators Under Sensitivity Case (~40% headroom)



Conclusions and Recommendations from the 2019-2020 TPP Study

This study indicated that CAISO system response to major frequency events such as two Palo Verde units improves when IBRs have headroom and their frequency response are enabled.

The studies illustrated that the CAISO is forecasted to meet and even exceed its Frequency Response Obligation (FRO) with the frequency response of new IBRs enabled per FERC Order 842 and would be further improved with approximate 60% of existing IBRs enabled while they have headroom due to curtailment. As illustrated above the changes to the deadband and droop settings have modest benefits for the frequency response.

With regards to the CAISO FRO requirements, it is sufficient to meet FRO just by enabling the PFR even with current values for droop and deadband however the CAISO generation output will increase with the proposed 4% droop and ±0.0167 Hz deadband.

6.3.3.1 Progress in Updating Models

The CAISO has continued to work with Transmission Owners to collect the needed information from generators, and this effort has raised a number of challenges. The various standards requirements obligating the provision of validated data are complex:

NERC requires all generators connected to the Bulk Electric System and greater than 20 MVA (single unit) or 75 MVA (generating plant) comply with NERC data standards, and provide updated data at least every 10 years. However the NERC dynamic data validation standards only apply to generating units that are greater than 75 MVA, which appears to capture about 80% of grid-connected generation in the CAISO footprint.

The WECC generating unit validation policy applies to generators greater than 10 MVA, which would address a further 17%.

The CAISO also has certain tariff rights to generator information. Under the CAISO Tariff Section 24.8.2, CAISO can request generator modeling data on an annual or periodic basis, as identified in the CAISO BPM for Transmission Planning Process. The CAISO has added a new Section 10 to the BPM describing the process which is set to receive, validate and update generator modeling data used in the CAISO transmission planning and reliability studies. This process addresses requirements for all CAISO participating generators. The new section of the BPM includes participating generators classification according to which the data is requested and provided.

Participating generator modeling requirements identify five different categories of operational generating units. Each operational generating unit is identified and categorized by their CAISO market Resource ID. Aggregate resources are identified and categorized by the parent market Resource ID. These categories are:

- <u>Category 1</u> - Participating generators connected to the Bulk Electric System (BES):
    - Individual generating unit with nameplate capacity greater than 20 MVA, or
    - Aggregate resource, i.e., the parent resource of multiple generating units with total aggregate nameplate capacity greater than 75 MVA.

- Category 2 – Participating generators connected to facilities 60 kV and above, and not covered in category 1:
    - Individual generating unit with nameplate capacity greater than 10 MVA, or
    - Aggregate resource, i.e., the parent resource of multiple generating units with total aggregate nameplate capacity greater than 20 MVA.
- Category 3 - Participating generators connected to BES or facilities above 60KV with generation output lower than the category 1 or 2 modeling requirement thresholds.
    - Individual generating unit with nameplate capacity less than 10 MVA, or
    - Aggregate resource, i.e., the parent resource of multiple generating units with total aggregate nameplate capacity less than 20 MVA.
- Category 4 - Non-Net Energy Metered (non-NEM) participating generator connected to non-BES facilities below 60KV, but explicitly modelled as an individual generating unit in transmission planning power flow and stability studies.
- Category 5 - Non-Net Energy Metered (non-NEM) participating generator connected to non-BES facilities below 60KV, modelled as an aggregate resource in transmission planning power flow and stability studies.

The CAISO and PTOs are actively pursuing validated modeling data from all generators. The CAISO has developed a data template that is being sent to the generation owners. The data templates have to be completed by generator owners for successful submission of data. They may also require submission of supporting documents. The data are submitted to the CAISO based on the instructions in the BPM. The data requirements to each category of the generators are also described in the BPM.

The CAISO continues to send a data request letter to the participating generators, as set out in the schedule within the BPM, identifying the specific data requirements for the generating unit. The data request letter contains instructions for the participating generator to identify the applicable category and phase of their resource, associated data requirements, compliance deadline, and process to submit data to the CAISO and applicable PTO.

The process of the data collection is on-going and is being implemented in several stages. It was started in May 2019 with the data requests for the Category 1 generation units with the completion of the process for all the units planned for September of 2022.

Generating units that achieve commercial operation after September 1, 2018, are to submit the required generator modeling data within one hundred and twenty calendar days of achieving commercial operation in the CAISO market. The required data is identified in the generator data template provided to the participating generator upon achieving commercial operation.

Under the CAISO Tariff section 37.6.2, the CAISO can apply penalty of $500/day for failure to submit requested data. The criteria for applying sanctions are listed in BPM. The penalty is to be applied to Scheduling Coordinator associated with resource ID of generating unit.

6.3.4 2020-2021 Transmission Plan Study

Historically the thermal, hydro and other synchronous generators would provide sufficient response to the CAISO system to be able to meet the applicable standards. As of 10/14/2020, a total of 20.3 GW of Inverter Based Resources (IBRs) (wind, solar, storage) are connected to the CAISO grid and the total installed capacity is expected to reach 33 GW by year 2030. The majority of the existing IBRs do not provide frequency response but, consistent with FERC Order 842, all IBRs that sign Large Generation Interconnection Agreements (LGIA) on or after 5/15/2018 will have frequency response capability. With high levels of IBRs it is critical to assess the frequency response of the system in future years and identify mitigation measures if there are any issues. In addition to transmission –connected IBRs, as of 4/30/2020, around 9.4 GW Behind the Meter Distributed Energy Resources (BTM DER) is installed in the system and the total installed BTM DER is expected to reach around 21 GW in 2030.

As in the previous CAISO frequency response studies, the 2020-2021 Transmission Plan study concentrated on the primary frequency response, which occurs automatically prior to the AGC or operator actions. The objective of this study was to assess the CAISO system frequency response in the year 2030 and identify any performance issues related to frequency response. The base case selected for the frequency response studies was the Spring off-Peak case for 2030. The cases studied had different assumptions on the generation dispatch and the headroom and on frequency response provided by IBRs and the battery energy storage devices.

The contingency studied was an outage of two Palo Verde nuclear units, which is the most critical credible contingency in regards to frequency deviation. This contingency was studied in dynamic stability simulations for 60 seconds for all PG&E Bulk system cases in the 2020-2021 planning process.

The base case had relatively low levels of conventional generation in the CAISO, which may present a challenge in meeting the FRO. Therefore, this case was selected for the studies and was analyzed in more detail.

Study Assumptions

In the 2030 Spring off-Peak case selected for the studies, base load flags for all generators but new IBRs in the CAISO system were set based on the WECC original case. Base load flags in the power flow cases indicate whether generators have primary frequency response. The base load flag may indicate that the unit does not have upward, but has downward frequency response, or it doesn't have any response to changes in frequency, or it is under frequency control and can respond both to downward or upward frequency deviations. The base load flag for new IBRs in CAISO system were set based on study scenarios discussed below.

Most of non-ISO generators were dispatched in the starting case based on the CAISO 2020-2021 TPP 2030 Spring off-peak case. Compared to the starting WECC case, generation output in some areas such as Northwest and Arizona was adjusted to set the path flows at the stressed level required for the TPP studies. The COI flow in the cases studied was close to its south to north limit.

The study used the latest WECC Master Dynamic File, which is the database of dynamic stability models of the WECC generators, HVDC lines, dynamic reactive support devices, relays and other equipment. The Masterfile is updated by WECC several times a year when the new or updated models become available. The Master Dynamic File that was used included updated models of the CAISO generators submitted by the Generation Owners up to date and verified by the CAISO.

Load models are not included in the WECC Master Dynamic File because the load depends on the season and the hour of the day and the load models are different for different cases. Load models are used as an addition to the Master Dynamic File. The latest composite load model was used in the dynamic model, which reflects the dependency of load from frequency and reflects the season and the hour that is studied. This load model includes behind the meter DERs. The study assumed that DERs do not respond to frequency variations. Tripping settings of DER on voltage and frequency variations were assumed based on the NERC SPIDER Work Group Guideline recommendations. The settings are such that the DER are not expected to trip in typical frequency events observed in this study.

In addition to the base case, the cases with reduced headroom on the units with responsive governors were studied to analyze the system with more conservative assumptions and to more clearly show the impact of the IBR when they have frequency regulation.

Study Methodology

The starting base case was the 2030 spring base case used in the 2020-2021 TPP which represents the system on April 7th at 1pm. Some of the system parameters in the base case are provided in the Table 6.3-2.

Table 6.3-2. Interface Flow Assumptions in the 2030 Spring off-Peak case

Parameter	Value (MW)
COI (N-S)	-3,609.6
PDCI (N-S)	-199.9
Path 15 (S-N)	499.5
Path 26 (N-S)	780.1
Path 46 (WOR) (E-W)	-2,052.3
Path 49 (EOR) (E-W)	-4,718.3
IPPDC (E-W)	403
SDG&E (area 22) Export	461.5
SCE (area 24) Export	5,199
PG&E (area 30) Export	4,475
LADWP (area 26) Export	1,360
ISO installed/dispatched solar	21,506 / 14,357
ISO installed/dispatched wind	7,600 / 2,307
ISO installed/dispatched BESS	2,593 / -2,568 (load)
ISO installed/dispatched BTM DER	21,189 / 17,127
ISO Inertia	94.6 GW.S
WECC Inertia	644.1 GW.S

If the inertia of wind generators, which are induction generators, is not included in the calculations, the WECC inertia is 614.5 GW.S and CAISO inertia is 83 GW.S.

The initial dynamic stability run showed several modeling errors in generators and inverter models which were corrected and the case updated. The contingency of the outage of two Palo Verde nuclear units was first simulated on the base case and then on three cases with reduced headroom to determine what would be critical, but still realistic conditions. In creation of the study cases, all limitations were considered, such as limits on the flow paths and capability of the governors. These starting cases assumed that IBR don't have primary frequency response.

One of the cases with the reduced headroom was selected to be used in the studies that examined the impact of inverter-based generation on frequency response in case when they have headroom and they respond to frequency deviations. This case had the lowest frequency response compared with the other cases, but it still had sufficient spinning reserve. In this case, the conventional units that had possible modeling errors were turned off and their output re-dispatched to other units in the area. Also, hydro units with low output were turned off and their output re-dispatched to the other units on the same river. It was done to reduce the headroom.

The following scenarios were considered.

Table 6.3-3. Scenarios Studied in the 2020-2021 TPP Frequency Response Study

Scenarios	SC1	SC2	SC3	SC4
PFR from IBR is switched off	✓	-	-	-
PFR from IBR is switched off and low overall generation headroom.	-	✓	-	-
PFR enabled for new BESS only and low overall generation headroom	-	-	✓	-
PFR enabled for all new IBRs assuming 10% headroom and low overall generation headroom	-	-	-	✓

For all the cases, Battery Energy Storage Systems (BESS) were charging in the starting cases. In the scenarios, where BESS had frequency response enabled, it was assumed that the BESS will reduce its charge in response to the frequency drop, but will not start to discharge. Thus, it was assumed that they will not supply real power to the grid. Although some BESS are capable of turning from charging to discharging in a matter of seconds, a conservative assumption is that they will not do that in the timeframe of the dynamic simulation. Parameters of the BESS and their controls were provided by the BESS owners, or if they were not provided, or if the provided parameters caused unreasonable performance and had errors, typical generic parameters were used. For the BESS that in the simulations showed that they went from charging to discharging, control parameters were adjusted so that they would not provide real power to the grid.

The contingency simulated for all the scenarios was an outage of two Palo Verde Nuclear units. Each stability simulation was run for 60 seconds.

The following values and measures were monitored:

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

ii. The total new IBR output

iii. The total output of all other CAISO generators

iv. The major path flows

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

vi. Frequency response from each unit in MW and in percent of the maximum output.

vii. Rate of Change of Frequency (ROCOF)

Study Results

Table 6.3-4 summarizes assumptions on load and generation from selected cases that were studied.

Table 6.3-4. Load and Generation in the Cases Studied

Case		2030 Spring off-Peak case	2030 Spring off-Peak case with reduced headroom	2030 Spring off-Peak case with reduced headroom and responsive BESS	2030 Spring off-Peak case with reduced headroom and responsive IBR
Gross Load, including pumps and motors, MW	ISO, incl. MUNI	**31,776**	**31,776**	**31,776**	**31,776**
	Total WECC	**146,098**	**146,098**	**146,098**	**146,098**
Generation total dispatch , incl. DER, not including batteries, MW	ISO, incl. MUNI	**45,112**	**45,078**	**45,078**	**45,078**
	Total WECC	**154,353**	**154,310**	**154,310**	**154,310**
Batteries total dispatch, MW (Negative sign means charging)	ISO, incl. MUNI	**-2,568**	**-2,568**	**-2,568**	**-2,568**
	Total WECC	**-2,699**	**-2,699**	**-2,699**	**-2,699**
Conventional Generation with responsive governors, MW	ISO, incl. MUNI, dispatch	**6,262**	**5,928**	**5,928**	**5,928**
	ISO, incl. MUNI, capacity	**9,190**	**8,329**	**8,329**	**8,329**
	Total WECC, dispacth	**67,689**	**59,252**	**59,252**	**59,252**
	Total WECC, capacity	**84,814**	**71,514**	**71,514**	**71,514**
Wind and solar, non responsive, including x-mission DER, dispatch MW	ISO, incl. MUNI	**16,664**	**16,664**	**16,664**	**10,112**
	Total WECC	**30,276**	**30,276**	**30,276**	**23,724**
Wind and solar, responsive, dispatch MW	ISO, incl. MUNI	**0**	**0**	**0**	**6,552**
	Total WECC	**0**	**0**	**0**	**6,552**
Batteries, non responsive, MW	ISO, incl. MUNI	**-2,568**	**-2,568**	**-258**	**-2,568**
	Total WECC	**-2,699**	**-2,699**	**-389**	**-2,699**
Batteries, responsive, MW	ISO, incl. MUNI	**0**	**0**	**-2,310**	**0**
	Total WECC	**0**	**0**	**-2,310**	**0**
Conventional non responsive, MW	ISO, incl. MUNI	**5,402**	**5,065**	**5,065**	**5,065**
	Total WECC	**47,565**	**47,170**	**47,170**	**47,170**
Dispatch of responsive generation, % of capacity	ISO, incl. MUNI	**68.1%**	**71.2%**	**43.4%**	**59.1%**
	Total WECC	**79.8%**	**82.9%**	**79.6%**	**78.1%**
Kt – ratio of number of responsive generation to number of total generation, %	ISO, incl. MUNI	**16.1%**	**15.2%**	**18.5%**	**21.5%**
	Total WECC	**34.2%**	**33.8%**	**34.9%**	**35.6%**

As can be seen from the table, in these cases, renewable (solar PV and wind) generation dispatch not including battery storage was 36.9% of the total generation dispatch in the CAISO and 19.6% of the total dispatch in WECC.

Table 6.3-5 summarizes the amount of frequency responsive and non-responsive generators on-line in the cases studied. Synchronous condensers and pumps are not included in the count of the units.

Table 6.3-5. Amount of Frequency Responsive and non-Frequency Responsive Units

Case		2030 Spring off-Peak case	2030 Spring off-Peak case with reduced headroom	2030 Spring off-Peak case with reduced headroom and responsive BESS	2030 Spring off-Peak case with reduced headroom and responsive IBR
Total generation units on-line, not including BESS	ISO, incl. MUNI	**875**	**863**	**863**	**863**
	Total WECC	**2,558**	**2,537**	**2,537**	**2,537**
Conventional Generation with responsive governors	ISO, incl. MUNI	**141**	**131**	**131**	**131**
	Total WECC	**875**	**858**	**858**	**858**
Conventional Generation with non- responsive governors	ISO, incl. MUNI	**258**	**256**	**256**	**256**
	Total WECC	**937**	**933**	**933**	**933**
Batteries, responsive	ISO, incl. MUNI	**0**	**0**	**30**	**0**
	Total WECC	**0**	**0**	**30**	**0**
Batteries, non- responsive	ISO, incl. MUNI	**37**	**37**	**7**	**37**
	Total WECC	**39**	**39**	**9**	**39**
Wind and solar responsive	**ISO, incl. MUNI**	**0**	**0**	**0**	**70**
	Total WECC	**0**	**0**	**0**	**70**
Wind and solar non-responsive	**ISO, incl. MUNI**	**476**	**476**	**476**	**406**
	Total WECC	**746**	**746**	**746**	**676**

The dynamic simulation results for an outage of two Palo Verde generation units for the 2030 Spring Off-Peak cases studies showed the following frequency nadir and settling frequencies.

Table 6.3-6. Frequency Nadir and Settling Frequency in the Cases Studied

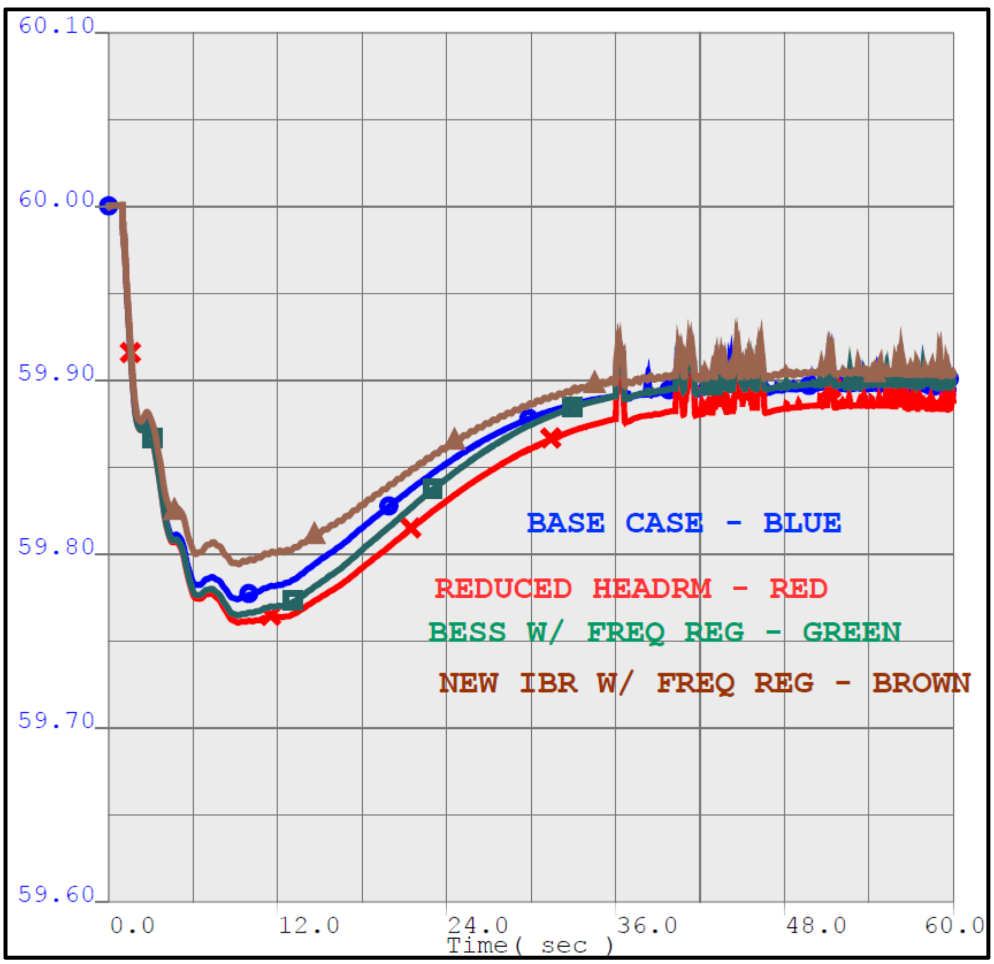
	2030 Spring off-Peak case	2030 Spring off-Peak case with reduced headroom	2030 Spring off-Peak case with reduced headroom and responsive BESS	2030 Spring off-Peak case with reduced headroom and responsive IBR
Settling Frequency, Hz	59.889	59.884	59.897	59.904
Frequency Nadir, Hz	59.776	59.744	59.767	59.795

It appeared that the frequency response is connected with the measure Kt - ratio of number of responsive generation to number of total generation. The higher is this ratio, the better is the system frequency response.

The frequency plot for the Midway 500 kV bus for the four cases studied is shown in Figure 6.3.6. As can be seen from the plot, the lower is the headroom on the frequency responsive units, the lower is the nadir and the settling frequency, and the frequency nadir occurs at the later time. The curves slope after the disturbance, which depends on the system inertia appeared to be the same for all three cases. Having frequency response from the BESS and IBR improved frequency performance, and the improvement from the IBR response was more than the improvement from the BESS response.

As can be seen from the plots, the frequency nadir was above the first block of under-frequency relay settings of 59.5 Hz for all four cases. For this contingency, voltages on all the buses were within the required limits in all the cases studied.

Figure 6.3-6: Frequency on the Midway 500 kV bus with an outage of two Palo Verde units in the 2030 Spring Off-Peak case with different headroom and frequency response from BESS and IBR



The study evaluated governor response of the units that had responsive governors. For the starting case, the highest response in MW was from large hydro units in Washington State, with the highest from Grand Coulee unit #22 at 33.8 MW and Grand Coulee unit #19 at 33.7 MW. These are large units (825 MW and 707 MW) that were loaded only to approximately 56-67% of their capacity in the base case. Other generation units that showed high governor response are Intermountain coal-fired power plant in Utah operated by LADWP; and Dry Fork coal-fired plant in Wyoming, as well as hydro power plants in Alberta and Washington State. If measured in percentage from the generator's capacity, an average response was 3.7 percent, but it varied from less than 1 percent for the units that were loaded up to their capacity to around 11-12 percent for the lightly loaded hydro units.

The following table summarizes the headroom and frequency response in MW and in MW/0.1 Hz, as well as Frequency Response Obligation.

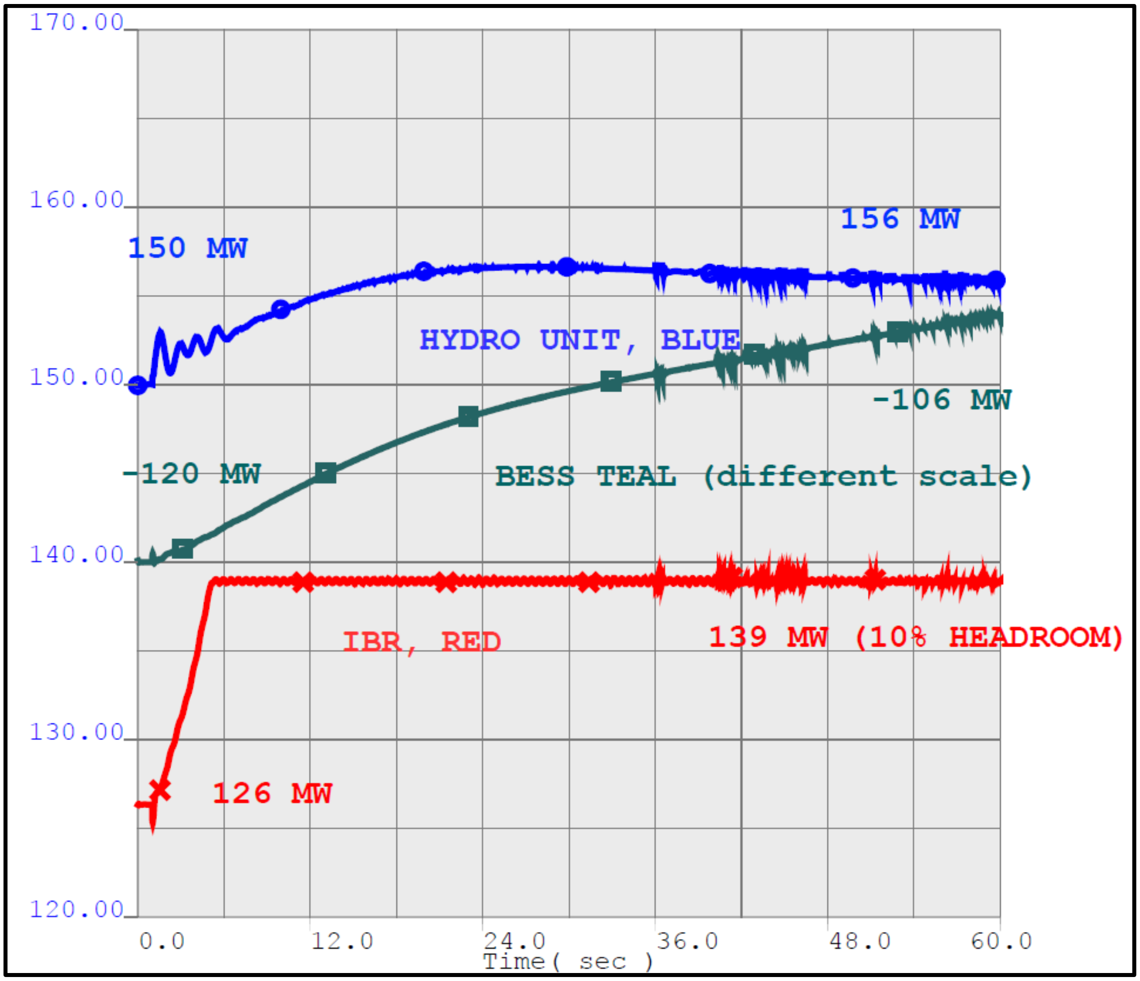
Table 6.3-7. Headroom and Frequency Response in the Cases Studied

Case		2030 Spring off-Peak case	2030 Spring off-Peak case with reduced headroom	2030 Spring off-Peak case with reduced headroom and responsive BESS	2030 Spring off-Peak case with reduced headroom and responsive IBR
Headroom, MW	ISO, incl. MUNI	**2,629**	**2,293**	**4,541**	**2,927**
	Total WECC	**15,021**	**11,641**	**13,722**	**12,351**
Responsive units	ISO, incl. MUNI	**141**	**131**	**161**	**201**
	Total WECC	**875**	**858**	**888**	**928**
Response, MW	ISO, incl. MUNI	**268**	**269**	**509**	**659**
	Total WECC	**2,607**	**2,438**	**2,535**	**2,533**
Response from Batteries, MW	WECC/ISO	**0**	**0**	**262**	**0**
Response from IBR, MW	WECC/ISO	**0**	**0**	**0**	**440**
Response, MW/0.1Hz	ISO, incl. MUNI	**241.5**	**231.7**	**494.4**	**686.0**
	Total WECC	**2,349**	**2,101**	**2,461**	**2,639**
FRO, MW/0.1 Hz	ISO, incl. MUNI	**257.4**			
	Total WECC	**858**			

As can be seen from the table, for the base case and for the case with reduced headroom, frequency response from the CAISO was below its Frequency Response Obligation. However, the response from WECC in general was significantly above its obligation. Such large response was thanks to large amount of hydro units on-line in the Northwest and Canada modeled in the case. It can be also seen that having frequency response from battery storage and from inverter-based resources, substantially improves the system frequency performance and allows the CAISO to fulfill its Frequency Response Obligation even if the performance was not meeting the BAL-003-2 requirements without response from the inverter-based resources.

Figure 6.3.7 shows an example of response to the frequency dip from a conventional hydro generator, a battery storage (BESS) and from inverter-based generator (IBR). It was assumed that both BESS and IBR had the droop of 5%.

Figure 6.3.7. Real power output from hydro unit, and BESS and IBR with frequency control. Outage of two Palo Verde Units.



As can be seen from the plots, the inverter-based generator provides the fastest response. Its real power output increases according to its frequency droop and stops when it reaches the maximum. In this case, 10% headroom was assumed and the output didn't increase after it reached 110% of the original output. In this plot, the BESS decreases its charge in response to the frequency dip, but doesn't completely discharge. The hydro unit responds, but doesn't reach its maximum capacity. This unit had capacity of 167 MW, and the initial output of 150 MW.

Figure 6.3.8 illustrates output of the BESS when they are under frequency control. As can be seen from the plots, large batteries can significantly help with frequency response. However, as the studies showed, it depends on the model parameters, and more work is needed to model the BESS more accurately.

Figure 6.3.8. Output of the BESS with an outage of two Palo Verde nuclear units when BESS are under frequency control

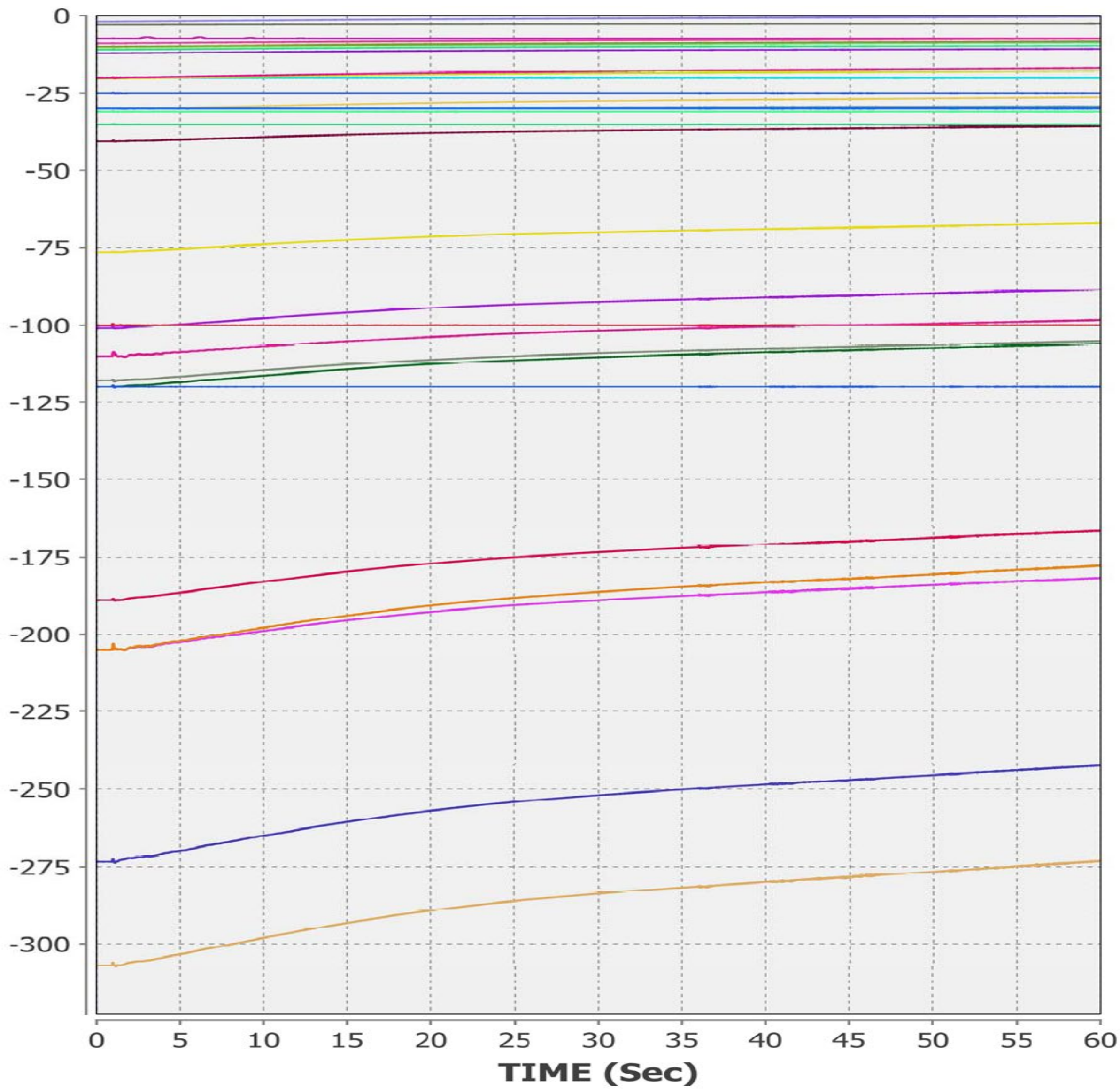
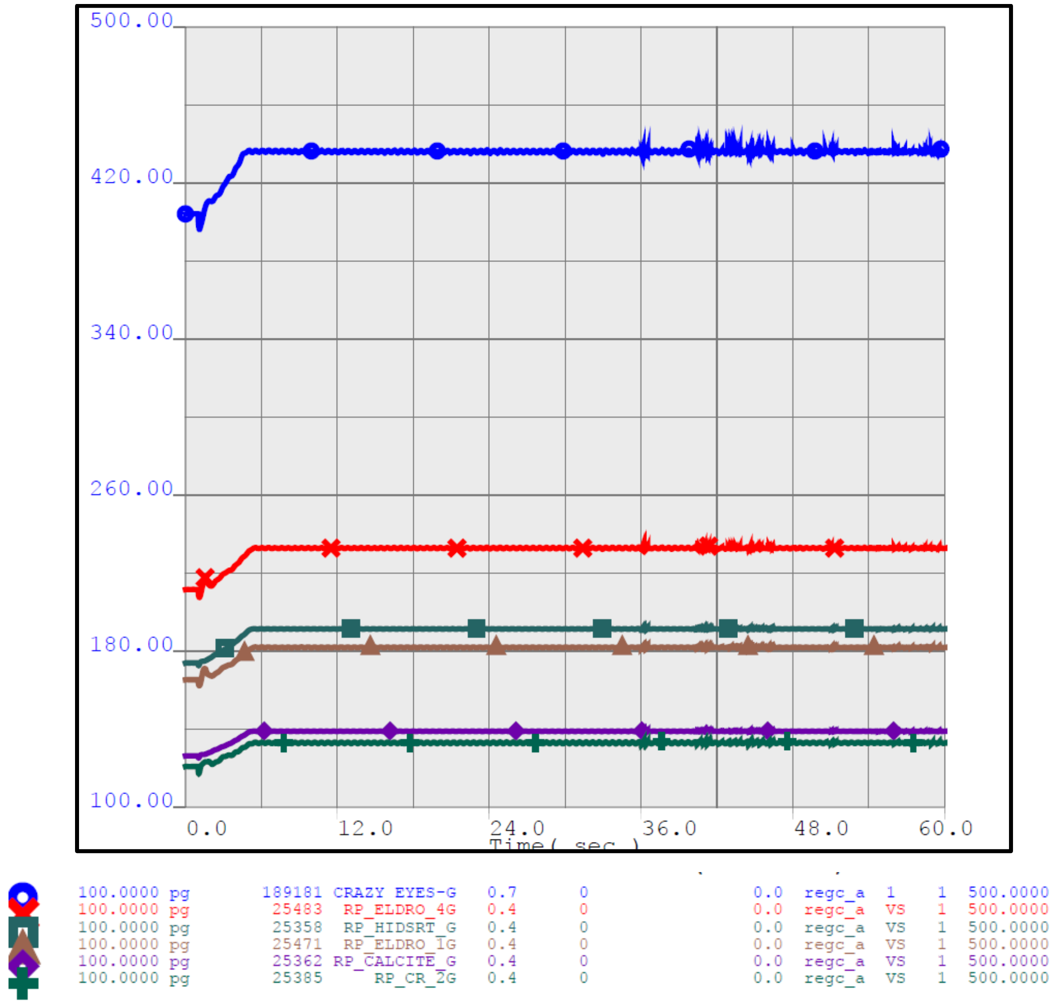


Figure 6.3.9 illustrates output of the IBR when they are under frequency control. The six largest units were selected as an example. As can be seen from the plot, all the units respond proportionally to their gain (reciprocate of the droop), until the unit reaches its maximum output. Since it was assumed that IBR have 10% headroom, their output increased by 10% and then stopped. From this plot, it is also seen that IBR can substantially improve the system response to frequency dips and will allow CAISO to fulfill its Frequency Response Obligation if they are capable of frequency control and have headroom.

Figure 6.3.9. Output of the large IBR units when they are under frequency control. Outage of two Palo Verde nuclear units.

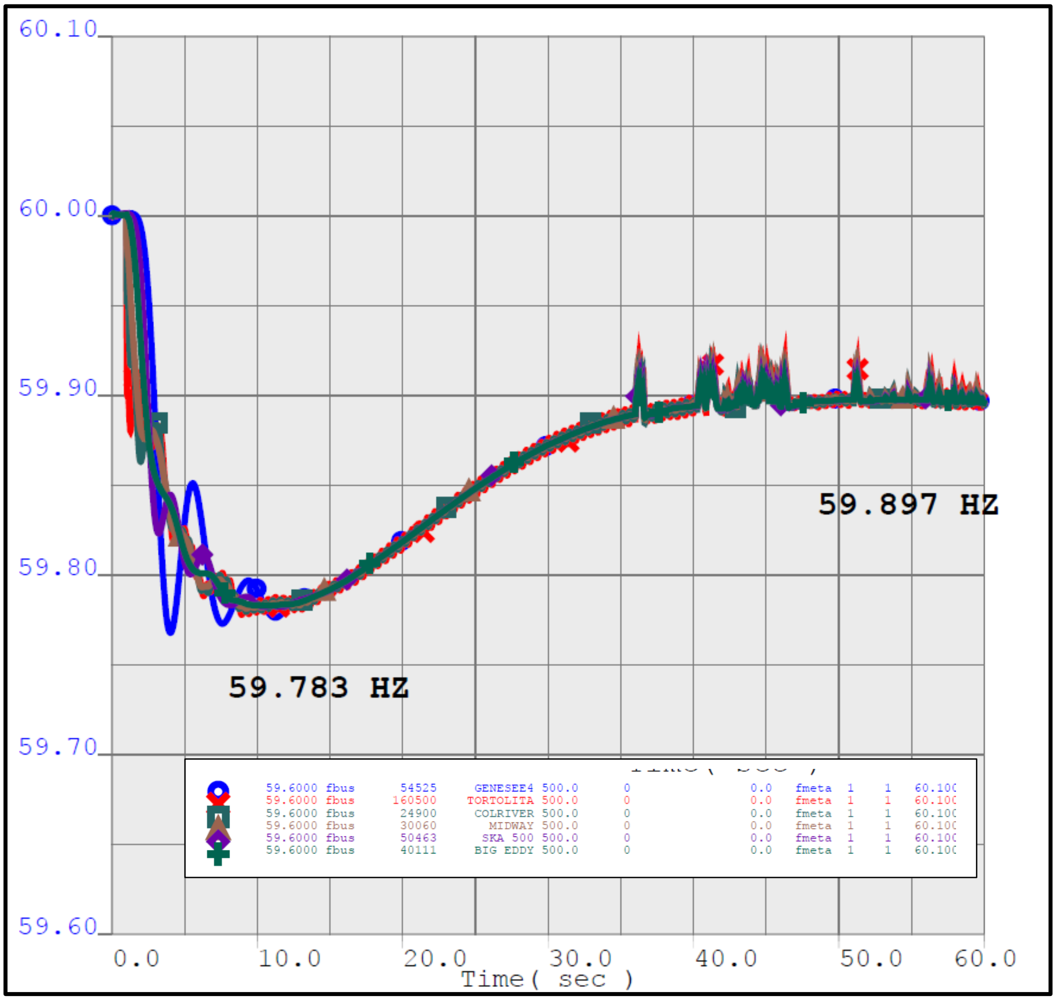


It should be also noted that even if the headroom in the case with responsive IBR and non-responsive BESS was lower than in the case with responsive BESS and non-responsive IBR, the Frequency Response Measure in this case was higher. This was due to the higher response from the IBR, than from BESS. Thus, the headroom appears to be a very approximate indicator of whether the frequency response will be within the requirements and the coefficient Kt appears to be a better indicator.

Additional sensitivity study was performed to determine if it is possible to have 100% generation from renewable energy resources within the CAISO and still be in compliance with the BAL-003-2 Standard. For this study, the case with frequency response from the new IBR and 10% headroom on the frequency responsive IBR was used. It was assumed that no other generation in the CAISO will respond to the frequency deviation. The same contingency, an outage of two Palo Verde units was simulated. The assumptions on the dispatch and frequency response settings for all generation in WECC were not changed.

The study results showed that the frequency response was sufficient both from WECC and from the CAISO. The Frequency Response Measure for WECC was 2507 MW/0.1 Hz and the Frequency Response Measure for the CAISO was 497 MW/0.1 Hz which is above the FRO. The plot of frequency on the selected 500 kV buses is shown in Figure 6.3.10.

Figure 6.3.10. Frequency on selected 500 kV buses in assumption of only new IBR in the CAISO are providing frequency response. Outage of two Palo Verde units.



In this case, the output from the frequency-responsive IBR was 6,552 MW, and at 10% headroom with 5% droop, the response was 447 MW, which was sufficient to fulfill the CAISO FRO.

2020-2021 Study Conclusions

- The initial study results indicated acceptable frequency performance within WECC but not acceptable frequency performance within the CAISO for the base case studied (Spring Off-Peak of 2030). WECC Frequency Response Measure (FRM) was above the Frequency Response Obligation (FRO) and the CAISO FRM was slightly below the obligation specified in BAL-003-2. The case with the reduced headroom had even lower CAISO FRM, but WECC FRM was still well above its obligation.

- With lower commitment of the frequency-responsive units, and no frequency response from inverter-based generation and battery storage, frequency response from the CAISO may be even lower and the deficiency in frequency response may be higher. However, in the assumptions studied, for WECC as a whole not meeting the standard is not likely, considering large amount of frequency responsive units available, especially in Canada and Northwest.
- Battery storage and inverter-based generation having frequency response will significantly improve the system frequency performance and will allow the CAISO to fulfill its Frequency Response Obligation, even if not all Inverter-Based Resources and batteries provide frequency response.
- The studies showed that although both battery storage and inverter-based generators may be very effective in enhancing frequency stability and providing compliance with the BAL-003-2 Standard, if they have frequency response, but the response from the inverter-based generators appears to be more effective than the response from the batteries. The reason may be different parameters of the IBR and batteries, but this needs to be explored further.
- Being in compliance with the BAL-003-2 Standard while having 100% of energy provided by renewable resources in the CAISO is possible if the new IBR resources have frequency response and have at least 10% headroom. Another condition is that generators in all other areas of WECC have sufficient frequency response. The most critical case is when Maximum Delta Frequency with contingency is 0.280 Hz according to the BAL-003-2 Standard. In this case, the CAISO should have frequency-responsive IBR on-line that have around 10,200 MW installed capacity and have at least 10% headroom. Considering the amount of IBR planned to be constructed in the next ten years, having 100% energy from renewable resources is possible from a frequency response perspective.

Compared to the CAISO's actual system performance during disturbances, the study results still seem optimistic because actual frequency responses for some contingencies were lower than the dynamic model indicated. Therefore, a thorough validation of the models needs to be performed to ensure that governor response in the simulations matches their response in the real life. The issue that was observed in real system operation was withdrawal of the governor response that was not observed in the simulations.

6.3.5 Next Steps

The current efforts on the collecting and improving modeling data will continue. The WECC dynamic modeling database is being updated and it will continue to be updated as the responses from the generation owners are received. The CAISO and the PTOs will continue to perform dynamic stability simulations to ensure that the updated models demonstrate adequate dynamic stability performance. After the models are validated, they are sent to WECC so that the WECC Dynamic Masterfile can be updated, and the updated models will be used in the future.

More work is needed on improving modeling of the battery energy storage. Some models received from the Generation Owners showed inadequate performance and were replaced in the studies by typical generic models. Also typical generic models were used for some future energy storage devices. The studies showed that the battery energy storage output and its frequency performance substantially depend on the parameters of the battery storage plant control and are very sensitive to its parameters. Therefore, getting accurate models of the battery storage controls is of utmost importance.

Opportunities may be considered to obtain frequency response from existing IBR that have capability to provide frequency response, but whose interconnection agreements predated the current requirement.

Future work will include validation of models based on real-time contingencies and studies with modeling of behind the meter generation. Further work will also investigate measures to improve the CAISO frequency response post contingency. Other contingencies may also need to be studied, as well as other cases that may be critical for frequency response.

6.4 Flexible Capacity Deliverability

6.4.1 Background

In conjunction with the CPUC annual Resource Adequacy proceeding (R.11-10-023), the CAISO developed the flexible resource adequacy criteria and must-offer obligation (FRACMOO) through a stakeholder process in 2014. The flexible capacity is the capacity that can be ramped to match net load ramping that becomes an operating challenge as more and more variable energy resources are added to the system. The CAISO determines annually the flexible capacity need of the CAISO system. The CAISO system need is then allocated to each of the local regulatory authorities (LRAs) responsible for load in the CAISO balancing authority area.

The capacity of resources that can be counted on to meet the flexibility need is called Effective Flexible Capacity (EFC). Currently, the deliverability of EFC is based on the resource's Net Qualifying Capacity (NQC). The deliverability test for determining NQC is under summer peak conditions and it provides enough assurance that flexible resources are deliverable at the end of the ramping during summer months. Initially, it was assumed that the summer peak condition reasonably represents the stressed operating scenario to deliver the full output of the flexible resources to the CAISO aggregate load. Therefore, the NQC could be counted as the upper limit of the EFC. With more and more renewable generation in operation, actual data reveals that the highest system ramping need occurs during weekend, non-summer months, instead of summer peak days. This trend raises a concern with the existing approach when resource ramping during the non-summer season is constrained by the transmission capability. As an initial effort to address this concern, the CAISO developed a methodology and tested the deliverability of flexible capacity in the 2019-2020 TPP cycle.

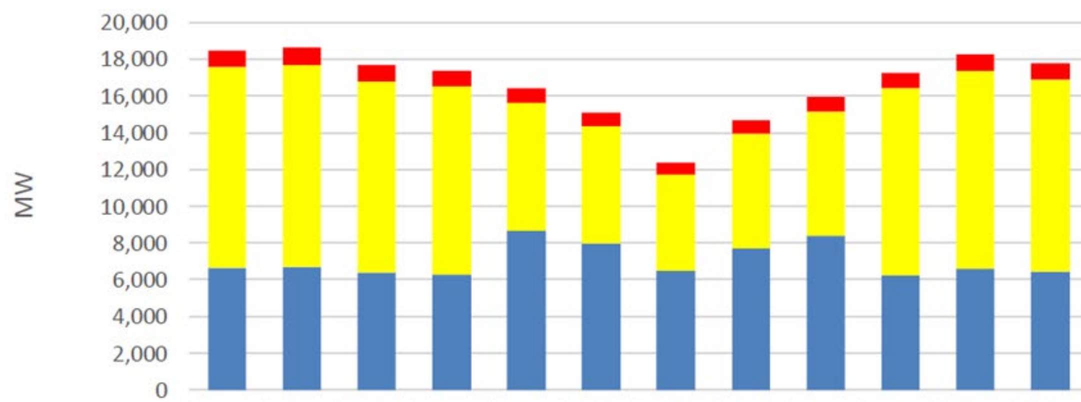
6.4.2 Deliverability Requirement for Flexible Capacity

The deliverability of flexible capacity shall mean that the output of a flexible resource could be ramped through its Effective Flexible Capacity range simultaneously with other flexible resources in the same generator pocket to meet the system net load ramping needs without being constrained by the transmission capability.

6.4.2.1 Seasonal Deliverability Requirement

The CAISO flexible capacity need assessment has shown that the system-wide total flexible capacity need is the highest in the non-summer months. The 2020 flexible capacity needs[155] are shown in Figure 6.4-1. The base flexible capacity need is 36 percent of the total system need for the non-summer months and 53 percent for the summer months. The time period for peak and super-peak flexible capacity is HE16 through HE20 for both summer and non-summer months. It has been observed that the increase in grid connected solar and incremental behind-the-meter solar will reduce the secondary net load ramp in the non-summer months, but will increase the primary net load ramp.

Figure 6.4-1: CAISO System-Wide Flexible Capacity Needs in Each Category for 2020



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	925	931	885	869	822	756	617	733	798	863	913	890
Peak Flexibility	10,900	10,974	10,428	10,240	6,970	6,406	5,230	6,218	6,766	10,174	10,758	10,493
Base Flexibility	6,675	6,721	6,387	6,271	8,652	7,951	6,491	7,718	8,398	6,231	6,589	6,426

The flexible capacity needs to be deliverable in all the months, especially the non-summer months to meet the highest system-wide need. The seasonal difference between non-summer and summer could drive quite different generation pockets from the transmission capacity perspective. Even for the same generation pockets, the transmission could be stressed more in the non-summer season than in the summer season.

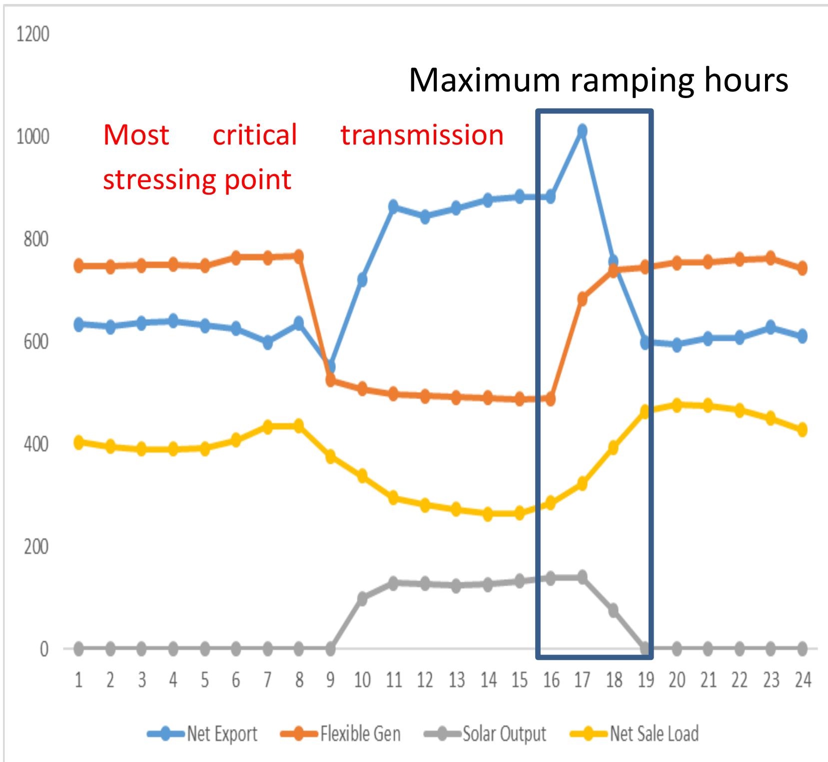
6.4.2.2 Deliverability along the Net Load Ramping Curve

Along the maximum net load ramping curve, the system condition transitions from low load and high renewable output to high load and low renewable output. The most stressed condition for the generation pocket, from a transmission capability perspective, varies depending on the mix

155 http://www.caiso.com/Documents/Final2020FlexibleCapacityNeedsAssessment.pdf

and profiles of the load and resources inside the pocket. The flexible capacity needs to be deliverable along the entire ramping curve, not only at the starting and ending points of the ramping curve. How the load, flexible generation and solar generation inside a generation pocket ramp on a spring afternoon is shown in Figure 6.4-2. The net export from the generation pocket peaks at HE17 and stresses the transmission system the most.

Figure 6.4-2: Illustration of Load and Resource Ramping and Impacts on Transmission



6.4.3 Flexible Capacity Deliverability Assessment Procedure

The CAISO has revised the on-peak and off-peak deliverability assessment methodologies. The scenarios assessed in the revised on-peak methodology align with the starting and ending conditions for the system ramping need in the summer months. The scenario assessed in the revised off-peak methodology aligns with the starting conditions for the system ramping need in the non-summer months. The flexible deliverability test would rely on the deliverability assessment and add new tests to address the scenario not already covered in the deliverability assessment. A testing procedure was developed to monitor the generation pockets for flexible deliverability. However, no study and requirements will be proposed to be considered for enforcement on new generators in the generation interconnection study procedure until 1) it becomes clear how the flexible capacity will be counted, especially for the wind and solar capacity through a FRACMOO follow-up initiative, 2) the revised on-peak and off-peak deliverability methodologies are approved and adopted, and 3) the TPP analysis identifies flexible deliverability constraints.

The proposed procedure to analyze flexible deliverability in the annual transmission planning process involves four major steps as described in the following sections.

6.4.3.1 Identify potential transmission constraints

Identify potential transmission constraints for flexible deliverability from planning studies and operational data. First, review the latest generation interconnection study reliability assessment. Select the overloads that were only identified under the off-peak condition. Then supplement the constraint list by examining congestions from the most recent transmission planning economic planning studies, and from real-time operation. If a congestion occurs during the high net load ramping hours, the binding constraint is selected for further analysis.

6.4.3.2 Define generation pockets (gen-pockets)

Group the potential constraints from Step 6.4.3.1 by the general electrical area. For each electrical area, select a proper off-peak power flow case in the current TPP cycle. Adjust the base case by the dispatch changes shown in Table 6.4-1 to represent the mid-day system condition on an off-peak season weekday.

Table 6.4-1: Base Case Dispatch Adjustment

Solar resources in the study area	Full output
Wind resources in the study area	Pgen = Historical minimum output; Pmax = historical maximum output
Other non-dispatchable resources in the study area	Full output
Flexible resources in the study area	Pgen = Minimum output (Pmin)
Load in the study area	Historical minimum
Imports that impact the study area	Historical minimum
Add a generator at tie-point for each import above	Status off; Pmax = historical maximum – historical minimum

Historical data from 3 pm to 8 pm on spring days are used to establish the dispatch condition because the highest system flexible need occurred in spring. If this changes in the future, the season and time period will be adjusted to ensure they align with the highest flexible need.

Use a power flow tool such as TARA to calculate distribution factors from each generator and load in the study area on each potential transmission constraint.

Define the gen-pocket as all generators that have 5% or greater distribution factor on the constraint and all loads that have -5% or less distribution factor.

6.4.3.3 Express transmission limits

For each potential transmission constraint and associated gen-pocket, express the constraint as

$$\sum_{\substack{w\in wind\\ resources}} d_w \Delta P_{gw} + \sum_{\substack{s\in solar\\ resources}} d_s \Delta P_{gs} + \sum_{\substack{f\in flexible\\ resources}} d_f \Delta P_{gf} + \sum_{\substack{i\in import\\ generators}} d_i \Delta P_{gi} + \sum_{l\in loads} d_l \Delta P_l$$

$$\leq Flow\ Limit - Flow\ in\ the\ Base\ Case \qquad (1)$$

$where$

$d_w, d_s, d_f, d_i, d_l\ are\ distribution\ factors\ of\ P_g\ and\ P_l$

$\Delta P_{gw} \leq Pmax_w - Pgen_w$

$-Pgen_s \leq \Delta P_{gs} \leq 0$

$\Delta P_{gf} \leq Pmax_f - Pgen_f$

$\Delta P_{gi} \leq Pmax_i - Pgen_i$

$\Delta P_l \leq Off\ peak\ season\ highest\ load - P_l$

$\sum \Delta P_{gf} \leq k\left(\sum \Delta P_l - \sum \Delta P_{gs}\right)$

In the expression, wind resource output is an independent variable bounded by the historical minimum and maximum outputs. Change of flexible resource output is bounded by the net change of load minus solar output multiplied by a factor of k.

6.4.3.4 Determine flexible deliverability margin

Use an optimization tool to find the maximum value of the left side expression of inequality equation (1). Factor k is the ratio of the total flexible generation change during the flexible capacity ramping period to the net load minus solar output change. The k factor is selected by observing production cost simulation or historical operation data for the generation pocket. The meaning of k factor in terms of defining the feasible region to solve the optimization problem is illustrated in Figure 6.4-3.

$$max \sum_{\substack{w\in wind\\ resources}} d_w \Delta P_{gw} + \sum_{\substack{s\in solar\\ resources}} d_s \Delta P_{gs} + \sum_{\substack{f\in flexible\\ resources}} d_f \Delta P_{gf} + \sum_{\substack{i\in import\\ generators}} d_i \Delta P_{gi} + \sum_{l\in loads} d_l \Delta P_l$$

$s.t.$

$\Delta P_{gw} \leq Pmax_w - Pgen_w$

$-Pgen_s \leq \Delta P_{gs} \leq 0$

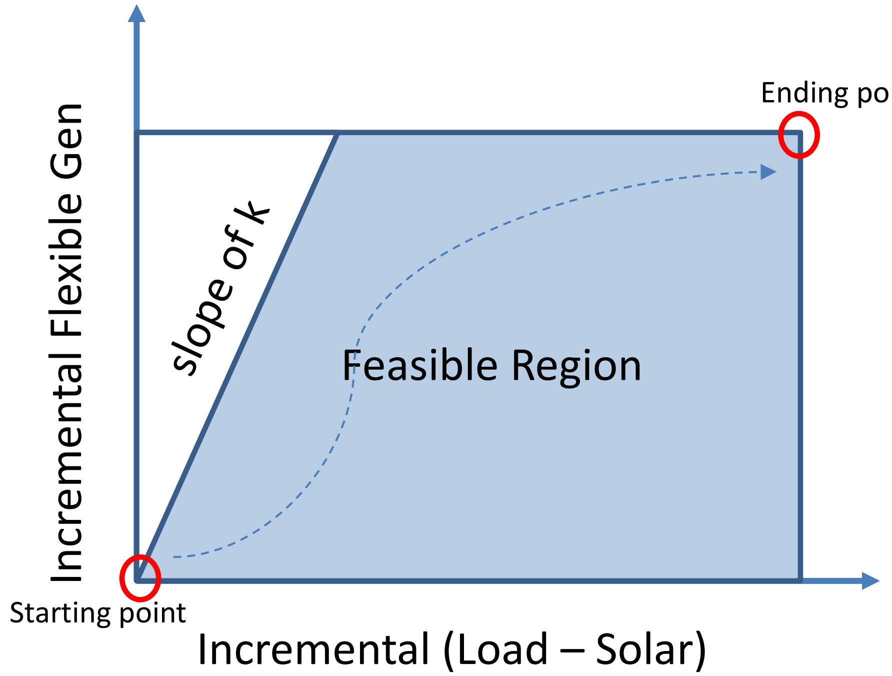
$\Delta P_{gf} \leq Pmax_f - Pgen_f$

$\Delta P_{gi} \leq Pmax_i - Pgen_i$

$\Delta P_l \leq Off\ peak\ season\ highest\ load - P_l$

$\sum \Delta P_{gf} \leq k\left(\sum \Delta P_l - \sum \Delta P_{gs}\right)$

Figure 6.4-3: Feasible Region for Optimization



The operating conditions, i.e. P_g and P_l, that achieve the maximum value in the optimization are considered the most stressed dispatch for the constraint and plugged into the base case. The rest of the system is adjusted to balance overall load and resources. The flexible deliverability margin is the difference between the applicable facility rating and the flow resulting from the most stressed dispatch. A positive margin means the constraint is not limiting the flexible deliverability while a negative margin means the transmission becomes the bottleneck.

6.4.4 Flexible Capacity Deliverability Assessment

The CAISO performed the 2019-2020 flexible capacity deliverability assessment using the procedure described above. The 2029 spring off-peak base scenario is used to establish the starting point of the analysis. The system condition of the scenario are summarized in Table 6.4-2.

Table 6.4-2: 2029 Spring Off-Peak Base Scenario

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
Spring Off Peak	4/7 HE 13	80%	81%	79%	100%	98%	98%	55%	54%	22%	21%	26%	17%

Potential generation pockets were selected by reviewing the real time congestion data from market operation, production cost simulation results and generation interconnection studies. Then separate base cases were created for each generation pocket according to Table 6.4-1. The sections below provide the details of the generation pocket analyses.

6.4.4.1 SCE area results

Three generation pockets were identified and analyzed in SCE area. See Table 6.3 below.

Table 6.4-3: SCE Potential Flexible Deliverability Constraints

Constraint Name	Monitored	Contingency	Source
North of Lugo	Lugo AA bank	base case	Cluster 11 Phase I RTM
North of Magunden	Vestal - Magunden No. 1	Vestal - Magunden No. 2	Cluster 11 Phase I RTM
Blythe	Julian Hinds - Mirage 230kV	base case	RTM

North of Lugo Constraint

The Lugo 500/230 kV transformer banks limit energy delivery from North of Lugo area to the rest of the CAISO system. The net export from the pocket is higher during off-peak period than the peak period. There are about 1153 MW of flexible capacity and 1427 MW of solar resources North of Lugo. During spring afternoons, the load seen at the transmission level is projected to be between 227 MW to 604 MW. The analysis results for this generation pocket are shown in Table 6.4-4. Different values of k were tested. The deliverability margin reduces as k increases. The historical value of k is about 2, corresponding to 25% margin. If more energy storage is added in North of Lugo, k would increase and the margin will reduce. It was estimated that about 280 MW energy storage could be added without hitting the transmission limitation.

Table 6.4-4: Analysis of North of Lugo Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=2)	Max Flow Point (k=3)	Max Flow Point (k=10)
Flexible Gen	52.82	0	1153	1153	1153	1153
Solar Gen	1427	0	1427	981	1130	1337
Load	227	227	604	332	297	248
Monitored Flow	583			840	918	1026
Flow Margin				25%	18%	8%

North of Magunden Constraint

The Vestal – Maguden 230kV line flows limit energy delivery from Big Creek, Rector, Springville and Vestal to the rest of the CAISO system. The net export from the pocket is higher during off-peak period than the peak period. There are about 1069 MW of flexible capacity and 157 MW of solar resources in the generation pocket. During spring afternoons, the load seen at the transmission level is projected to be between 244 MW to 678 MW. The analysis results for this generation pocket are shown in Table 6.4-5. Different values of k were tested. The deliverability margin reduces ask increases. The historical value of k is about 3, corresponding to 51% margin. If more energy storage is added in the pocket, k would increase and the margin will reduce. It was estimated that about 500 MW energy storage could be added without hitting the transmission limitation.

Table 6.4-5: Analysis of North of Magunden Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=2)	Max Flow Point (k=3)	Max Flow Point (k=10)
Flexible Gen	0	0	1069	1069	1069	1069
Solar Gen	157	0	157	15	62	129
Load	244	244	678	637	506	323
Monitored Flow	-21			210	299	424
Flow Margin				65%	51%	30%

Blythe Constraint

The Julian Hinds – Mirage 230kV line flow limits the energy delivery of Blythe generation to the rest of the CAISO system. This is a small generation pocket with 493 MW flexible capacity and negligible solar resources. The Blythe import is contained in the generation pocket. Blythe import ranges from 0 to 17 MW on a spring day. There is significant pumping load in the pocket. The pumping load ranges from 0 to 317 MW on a spring day. The Julian Hinds – Mirage line flow is stressed the most under low pumping load and high import condition. A deliverability margin of 12% under the most stressed condition is shown in Table 6.4-6. It was estimated that about 70 MW energy storage could be added without hitting the transmission limitation.

Table 6.4-6: Analysis of Blythe Constraint

Variable	Min	Max	Max Flow Point
Flexible Gen	0	493	493
Pump	0	317	0
Import	0	17	17
Monitored Flow			315
Flow Margin			12%

6.4.4.2 SDG&E area results

Three generation pockets were identified and analyzed in SDG&E area. The results are summarized in Table 6.4-7.

Table 6.4-7: SDG&E Potential Flexible Deliverability Constraints

Constraint Name	Monitored	Contingency	Source
Doublet Tap-Friars	Doublet Tap-Friars 138 kV	San Luis Rey-Encina 230 kV and San Luis Rey-Encina-Palomar 230 kV	RTM
San Luis Rey-San Onofre	San Luis Rey-San Onofre 230 kV #1	San Luis Rey-San Onofre 230 kV #2 and #3	PCM
Silvergate-Bay Boulevard	Silvergate-Bay Boulevard 230 kV	Miguel-Mission 230 kV #1 and #2	PCM

Doublet Tap-Friars Constraint

The Doublet Tap-Friars 138 kV line loading limits energy in the Imperial Valley area as well as various locations inside the SDGE load pocket from being delivered to the rest of the CAISO system. The net export from the pocket is higher during off-peak period than the peak period. There are about 1914 MW of flexible capacity and 1479 MW of solar resources behind this constraint. During spring afternoons, the load seen at the transmission level is projected to be between 438 MW to 1322 MW. The analysis results for this generation pocket are shown in Table 6.4-8. The historical value of k is 0.8, corresponding to 84% margin. If more energy storage is added in this area, k would increase and the margin will reduce. It was estimated that more than 500 MW of energy storage could be added without hitting the transmission limitation.

Table 6.4-8: Doublet Tap-Friars Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=0.8)
Flexible Gen	100	0	1914	129
Solar Gen	1450	0	1479	1312
Load	438	438	1322	522
Monitored Flow	18			126
Flow Margin				84%

San Luis Rey-San Onofre Constraint

The San Luis Rey-San Onofre 230 kV line loading limits energy in the Imperial Valley area as well as various locations inside the SDG&E load pocket from being delivered to the rest of the CAISO system. The net export from the pocket is higher during off-peak period than the peak period. There are about 3698 MW of flexible capacity and 1479 MW of solar resources behind this constraint. During spring afternoons, the load seen at the transmission level is projected to be between 941 MW to 2577 MW. The analysis results for this generation pocket is shown in Table 6.4-9. Different values of k were tested. The deliverability margin reduces ask increases. The historical value of k is about 1.2, corresponding to 40% margin. If more energy storage is added in this area, k would increase and the margin will reduce. There is not much margin to add energy storage before this constraint will be binding.

Table 6.4-9: San Luis Rey-San Onofre Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=1.2)	Max Flow Point (k=2)	Max Flow Point (k=3)
Flexible Gen	0	0	3698	1353	2300	2300
Solar Gen	1450	0	1479	894	894	1079
Load	941	941	2577	1568	1568	1359
Monitored Flow (with RAS)	541			694	941	1077
Flow Margin (with RAS)				40%	18%	6%

Silvergate-Bay Boulevard Constraint

The Silvergate-Bay Boulevard 230 kV line loading limits energy in the Imperial Valley area as well as various locations inside the SDG&E load pocket from being delivered to the rest of the CAISO system. The net export from the pocket is higher during off-peak period than the peak period. There are about 2068 MW of flexible capacity and 1423 MW of solar resources behind this constraint. During spring afternoons, the load seen at the transmission level is projected to be between 152 MW to 494 MW. The analysis results for this generation pocket is shown in Table 6.4-10. Different values of k were tested. The deliverability margin reduces ask increases. The historical value of k is about 1.2, corresponding to 44% margin. If more energy storage is added in the pocket, k would increase and the margin will reduce. It was estimated that more than 500 MW of energy storage could be added without hitting the transmission limitation.

Table 6.4-10: Silvergate-Bay Boulevard Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=1.2)	Max Flow Point (k=3)	Max Flow Point (k=10)
Flexible Gen	0	0	2068	2068	2068	2068
Solar Gen	1395	0	1423	11	842	1229
Load	152	152	494	491	287	193
Monitored Flow	460			663	767	816
Flow Margin				44%	35%	31%

6.4.4.3 PG&E area results

Three generation pockets were identified and analyzed in the PG&E area. These generation pockets are shown in Table 6.4-11.

Table 6.4-11: PG&E Potential Flexible Deliverability Constraints

Constraint Name	Monitored	Contingency	Source
North of Fresno # 1	Mosslanding-LosAguilas 230 kV	Mosslanding-LosBanos 500 kV	Cluster 11 Phase I/ RTM
North of Fresno # 2	Los Banos-Quinto 230 kV Line	Tesla-LosBanos 500 kV line	RTM

North of Fresno Constraint # 1

The Moss Landing-Las Aguilas 230 kV line limits energy delivery from Fresno area to the rest of the CAISO system. The net export from the pocket is higher during off-peak period than the peak period. There are about 760 MW of flexible capacity and 1349 MW of solar resources in the Fresno area. During spring afternoons, the load seen at the transmission level is projected to be between 174 MW to 566 MW. The analysis results for this generation pocket are shown in Table 6.4-12. Different values of k were tested. The deliverability margin reduces ask increases. The historical value of k is about 1, corresponding to 32% margin. If more energy storage is added in Fresno area, k would increase and the margin will reduce. It was estimated that about 700 MW energy storage could be added without hitting the transmission limitation. This estimates are location sensitive and the estimates are highly variable depending on the location of these energy storage resources.

Table 6.4-12: North of Fresno # 1 constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=2)	Max Flow Point (k=3)	Max Flow Point (k=10)
Flexible Gen	35	204	760	600	760	760
Solar Gen	1192	0	1349	842	1108	1186
Load	174	148	566	255	174	150
Monitored Flow	266			272	314	323
Flow Margin				32%	21%	19%

North of Fresno Constraint # 2

The Los Banos-Quinto 230 kV line limits energy delivery from Fresno area to the rest of the CAISO system. The net export from the pocket is higher during off-peak period than the peak period. There is about 1921 MW of flexible capacity and 2530 of MW solar resources in the Fresno area. During spring afternoons, the load seen at the transmission level is projected to be between 128 MW to 1921 MW. The analysis results for this generation pocket are shown in Table 6.4-13. Different values of k were tested. The deliverability margin reduces ask increases. The historical value of k is about 1, corresponding to 74% margin. No energy storage estimates are provided due to very high flow margin in this case. The margin is primarily due to a new upgrade not present in historical congestion data.

Table 6.4-13: North of Fresno # 2 constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=2)	Max Flow Point (k=3)	Max Flow Point (k=10)
Flexible Gen	128	211	1921	1100	1545	1921
Solar Gen	3051	0	3051	3051	3004	3030
Load	995	844	2530	844	870	857
Monitored Flow	265			307	329	353
Flow Margin				74%	72%	70%

6.4.5 Future Work

This assessment did not identify any flexible deliverability concerns. However, future work is needed to improve the assessment methodology.

The assessment focused on the candidate generation pockets. All load and resource variables inside the generation pocket are examined and solved through an optimization tool to find the condition that stressed the transmission. Generation outside the generation pocket was scaled evenly to balance the load and resource changes from the generation pocket. How the conditions change outside the generation pocket impacts flows on the transmission facilities and needs to be refined.

Inside the generation pocket, the transmission constraint is linearized and the correlation among flexible generation, solar output and load is also linearized. This is partly due to the dimensional limit of the tool being used. Capturing the non-linearity of the transmission constraint requires the actual power flow equations in the optimization and a more accurate correlation involves time-sequence data of the load and resources.

Other uncertainties, such as planned outages of transmission facilities, were not considered in the assessment.

Work is being planned to address the above issues. In addition, the future work will also consider assessing energy storage charging capability to allow ramping of energy storage facilities to meet flexible capacity needs.

6.5 PG&E Area Wildfire Impact Assessment

6.5.1 Background

High temperatures, extreme dryness and record-high winds have created conditions in the state of California increasing the risk of major wildfires. If severe weather threatens a portion of the electric system, it may be necessary for PG&E to turn off electricity in the interest of public safety. This practice is carried out by a Public Safety Power Shutoff or known as the PSPS events. In PG&E area, multiple PSPS events were carried out in 2019 and 2020. The multi-phase October 26 2019 event impacted customers in counties of Amador, Butte, Colusa, El Dorado, Glenn, Nevada, Placer, Plumas, San Joaquin, Sierra, Siskiyou, Shasta, Tehama, Yuba, Lake, Marin, Mendocino, Napa, Solano, Sonoma, Yolo, Alameda, Contra Costa, Monterey, San Benito, San Mateo, Santa Clara, Santa Cruz, Stanislaus, Alpine, Calaveras, Mariposa, Tuolumne, Humboldt, Trinity and Kern.

The CASIO, as part of the 2020-2021 Transmission Planning Process (TPP), conducted studies to assess impact of various PSPS scenarios in the PG&E area. The CAISO will continue to assess need for the similar assessment in other parts of the system in future planning cycles

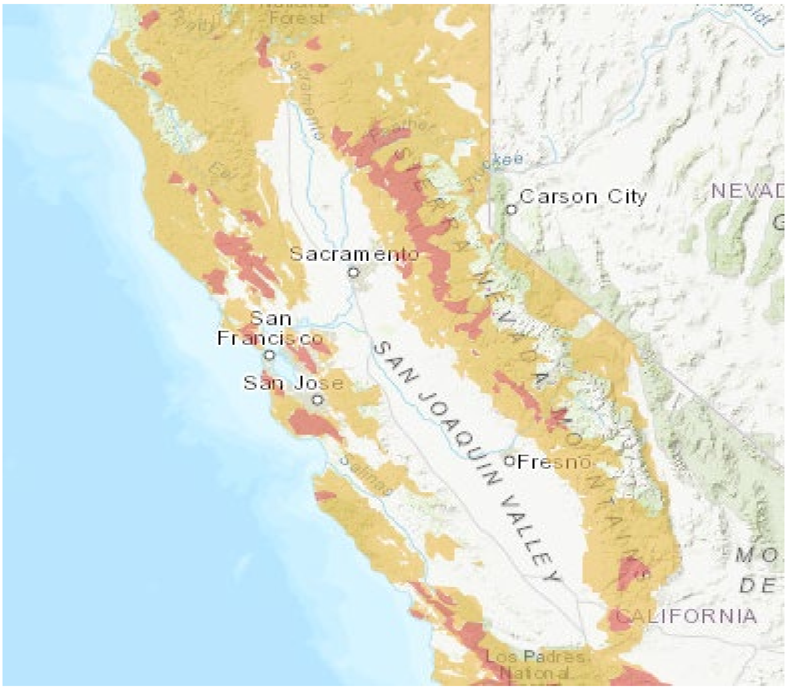
6.5.2 Objective

The objective of this assessment was to identify load at risk and potential system reliability risks under various PSPS scenarios developed and to develop potential mitigations to alleviate impact of future PSPS events from long-term planning perspective.

6.5.3 Study Approach

6.5.3.1 Wildfire Related Information Collection

The assessment began with gathering wildfire related information. This includes collecting GIS maps for fire threat zones and maps with transmission system overlaid. Such maps were used to identify transmission facilities within the different tiers of fire zone identified by the CPUC and to develop scenarios with some or all of the facilities at risk being de-energized. The information gathering also included gathering detail information about facilities de-energized as part of the different phases of PSPS events occurred in 2019. The High fire threat areas map is depicted below.



Source: https://ia.cpuc.ca.gov/firemap/

Using the fire threat map, the CAISO identified transmission lines that pass through these fire threat areas for the purpose of developing scenarios for study. The Table 6.5-1 below provides count of transmission lines in tier 2 and tier 3 fire zones by PG&E planning area and voltage levels.

Table 6.5-1: Count of the CAISO controlled transmission lines in tier 2 and tier 3 fire zones by planning area and voltage level

Planning Area	60 kV		115 kV		230 kV		500 kV		Total
	Tier 2	Tier 3	Tier 2	Tier 3	Tier 2	Tier 3	Tier 2	Tier 3	
Greater Bay Area	4	6	11	22	9	21	1	1	75
North Coast/North Bay	17	14	7	15	4	18	0	0	75
Central Coast/Los Padres	7	3	17	10	2	9	0	2	50
Greater Fresno Area	5	3	3	1	4	0	0	0	16
Central Valley	22	14	18	19	11	3	0	0	87
Humboldt	6	2	2	1	0	0	0	0	11
North Valley	19	15	4	10	14	9	0	0	71
Total	80	57	62	78	44	60	1	3	385

6.5.3.2 Scenario Development

Scenario development was a critical part of the assessment. The range of scenarios selected needed to represent a reasonable boundary conditions, as well as needed to be based on a fact-based framework. Also, the scenarios needed to be feasible; for example de-energizing all facilities within a fire risk zone might not be infeasible for some areas. At the same time, the number of scenarios also needed to be manageable within the study timeline.

Scenarios were developed by de-energizing transmission facilities in fire zones within various planning areas. Different scenarios were developed by de-energizing combination of different voltage facilities and/or facilities within various levels of fire threat zones. Additional scenarios were also be created based on 2019 PSPS events. PG&E also implemented various wildfire related mitigations since last year's PSPS events. The CAISO also worked with PG&E to develop additional PSPS scenario for similar weather conditions as last year's that triggered PSPS events, but incorporating improvements put in place by PG&E since last year. PG&E also helped develop additional scenario using historical weather conditions meeting today's criteria that could have triggered PSPS events.

6.5.3.3 Study scenarios

Using the approach mentioned in above section, five scenarios were developed for each planning area. The five scenarios are listed below:

Table 6.5-2 Scenarios assessed

Scenario Number	Scenario Name	Scenario Description
1	All T 2&3	All tier 2 & tier 3 lines de-energized
2	All T3	All tier 3 lines de-energized
3	10-26 PSPS	Lines de-energized in October 26 2019 PSPS event
4	10-26 PSPS-WFM	Lines de-energized based upon October 26 2019 PSPS event conditions with PG&E's wildfire mitigations
5	PSPS-HWC-All	Based upon potential PSPS events corresponding to historical weather conditions, de-energize all lines

Out of the above five scenarios, the scenarios 1 and 2 are considered boundary condition scenarios due to the high number of transmission line de-energized within these scenarios compared to actual events occurred in 2019 and 2020. The scenario 3 is also considered implausible as based on the recent information provided by PG&E, the weather condition that triggered the October 26, 2019 event is associated with the worst weather condition in looking ten years historical weather conditions and also the similar weather condition today would produce much smaller PSPS scope due the mitigations that PG&E has put in place since last year. This can also be seen by comparing the scope of line de-energization between the scenarios 3 and 4 in the table below. Scenarios 4 and 5 are considered more plausible scenarios with the scenario 5 being a bit unrealistic as the scenario includes de-energizing all transmission lines included one or more of the potential 25 PSPS events based on the 10 year historical weather conditions. The table below provides count of transmission lines de-energized in each scenario by PG&E planning area and voltage levels.

Area	Scenario 1 (All T2&3)				Scenario 2 (All T3)				Scenario 3 (10-26 PSPS)				Scenario 4 (10-26 PSPS-WFM)				Scenario 5 (PSPS-HWC-All)			
	60/70 kV	115 kV	230 kV	500 kV	60/70 kV	115 kV	230 kV	500 kV	60/70 kV	115 kV	230 kV	500 kV	60/70 kV	115 kV	230 kV	500 kV	60/70 kV	115 kV	230 kV	500 kV
Central Coast/Los Padres	14	27	11	-	3	10	9	2	-	2	-	-	-	-	-	-	1	-	-	-
Central Valley	37	37	14	-	15	19	5	-	22	11	3	-	14	10	1	-	18	12	1	-
Greater Bay Area	13	34	34	1	7	22	24	1	6	3	4	-	3	-	2	-	3	-	2	-
Greater Fresno Area	9	4	4	-	3	1	-	-	-	-	-	-	2	-	-	-	4	-	-	-
Humboldt	8	3	-	-	2	1	-	-	5	3	-	-	5	2	-	-	7	2	-	-
North Coast/North Bay	31	22	18	-	14	15	14		18	11	7	-	12	6	5	-	13	6	7	-
North Valley	34	14	23	-	15	10	9	-	15	6	1	-	3	3	-	-	9	4	1	-

6.5.3.4 Scope of Assessment

Using the scenarios developed, the CAISO conducted study with the following scope of assessment on the load drop and potential impact on grid performance:

- Local or radial system load impact (direct impact) and
- Area supply or system performance impact (indirect impact)

The first step of the assessment was to record the amount of load lost as a result of radial system or island created due to the facilities de-energized as part of the scenario. This is also referred to as direct impact. The next step involved assessing base case system performance after modeling each PSPS scenario. If any normal reliability issues identified in the base case, further actions were taken in the form of opening the overloaded lines or further load drop to alleviate issues in the base cases. These further actions are recorded as indirect impact. Once the base case was prepared with no normal violations, relevant P1 contingencies were taken to make sure that the base case is secure for the next worst P1 contingency. System performance following the P1 contingencies were assessed and recorded for reporting.

The 2020-2021 TPP 2022 summer peak base case for planning area was used as a starting base case. Each scenario was applied to the starting case one at a time with all facilities within the PSPS scope being de-energized concurrently. The sequential load isolated due to application of PSPS scope is then identified as the direct load impact. Further, any normal overloads or voltage issues are identified and mitigated with generation re-dispatch, system reconfiguration or load drop. The load drop is thereafter identified as indirect load impact.

6.5.3.5 Mitigation Development

In most of the areas, the issue is confined to direct load impact and no performance deficiencies following the P1 contingency analysis were identified for the plausible scenarios. Following the assessment and based on the evaluation of direct impact, high impact facilities in each areas have been identified. The high impact facilities are such that if excluded from the scope of PSPS scenario, the exclusion will have a significant impact on reducing the risk of PSPS impact in terms of direct load loss. The CAISO will coordinate with PG&E to evaluate mitigation options within the utilities' wildfire mitigation plan to be able to exclude these facilities from the future PSPS events.

The CAISO has also looked into the active CAISO approved projects in the area to explore if any of the projects could potentially reduce the impact of load loss from the different scenarios assessed. No projects were found to have significant impact on reducing the risk of PSPS impact from plausible scenarios. Similarly, as part of the potential mitigation, the CAISO also assessed opportunities for minor scope change of active projects that could help reduce the load loss impact and found no project to have any significant impact.

No new upgrades were developed as most of the issues were confined to direct load impact and no performance deficiencies following the P1 contingency analysis were identified for the plausible scenarios.

6.5.4 Assessment Results

Greater Bay Area

The Greater Bay Area has a total of 75 transmission lines that pass through the tier 2 and/or tier 3 fire risk zones. Of these, 2 are 500 kV, 30 are 230 kV, 33 are 115 kV and 10 are 60 kV

The results of the assessment of the five scenarios identified in the section 6.5.3.3 show that there could be a significant amount of load loss and system performance concerns in the boundary condition scenarios, like scenarios 1 and 2. However, the plausible scenarios, like scenarios 4 and 5, show that the direct load loss is only within the Peninsula 230 kV and South Bay 60 kV system. In regards to the system performance from the contingency analyses, the performance deficiencies are confined to the Peninsula 60 kV system. Table 6.5-3 summarizes the results from all five scenarios in terms of the direct load impact and system performance following the contingency analyses.

Table 6.5-3 Greater Bay Area PSPS Impact

	Scenario 1 (All T 2&3)	Scenario 2 (All T3)	Scenario 3 (10-26 PSPS)	Scenario 4 (10-26 PSPS-WFM)	Scenario 5 (PSPS-HWC-All)

GBA Division	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact
East Bay	646	Contingency analysis not performed due to large number of base case overloads.	572	Contingency analysis shows large number of N-1 overloads mostly in South Bay, Mission and Peninsula.	19	Contingency analysis shows overloads on South Bay 230 kV lines.	0	Contingency analysis shows overloads in Peninsula 60 kV system.	0	Contingency analysis shows overloads in Peninsula 60 kV system.
Diablo	1166		203		0		0		0	
San Francisco	0		0		0		0		0	
Peninsula	87		80		22		58		58	
Mission	488		78		0		0		0	
South Bay	177		4		7		3		3	

Based on the plausible scenarios, following are the high impact facilities in the Peninsula 230 kV and South Bay 60 kV system to address direct load loss.

- Monta Vista-Jefferson #1 230 kV line
- Monta Vista-Jefferson #2 230 kV line and
- Monta Vista-Burns 60 kV line.

If excluded from the future scope of PSPS scenario, they will have a significant impact on reducing the risk of PSPS impact in terms of direct load loss. The CAISO will continue to coordinate with PG&E to evaluate mitigation options within the utilities' wildfire mitigation plan to be able to exclude these facilities from the future PSPS events. In regards to the system performance concerns identified in the Peninsula 60 kV system from the contingency analyses, it is expected that the approved TPP project in the area will address the identified performance deficiencies.

Humboldt Region

The Humboldt region has a total of 11 transmission lines that pass through the tier 2 and/or tier 3 fire risk zones. Of these, 8 lines are 60 kV and 3 lines are 115 kV.

The results of the assessment of the five scenarios identified in the section 6.5.3.3 show that the Humboldt transmission system gets isolated in most of the scenarios, including the plausible scenarios like scenarios 4 and 5. As such, the concern in the Humboldt region from the potential PSPS event is the loss of load due to direct impact. No system performance concerns were identified from the contingency analyses of these scenarios. The Table 6.5-4 summarizes the results from all five scenarios in terms of the direct load impact and system performance following the contingency analyses.

Table 6.5-4: Humboldt Region PSPS Impact

Scenario 1 (All T 2&3)		Scenario 2 (All T3)		Scenario 3 (10-26 PSPS)		Scenario 4 (10-26 PSPS-WFM)		Scenario 5 (PSPS-HWC-All)	
Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact
130	Humboldt system isolated	11	No base case overload	130	Humboldt system isolated	130	Humboldt system isolated	130	Humboldt system isolated

Based on the plausible scenarios, following are the high impact facilities in the Humboldt system to address direct load loss.

- Bridgeville-Cottonwood 115 kV line and
- Humboldt-Trinity 115 kV line

If excluded from the future scope of PSPS scenario, they will have a significant impact on reducing the risk of PSPS impact in terms of direct load loss. The CAISO will continue to coordinate with PG&E to evaluate mitigation options within the utilities' wildfire mitigation plan to be able to exclude these facilities from the future PSPS events. In regards to the system performance concerns, no system performance concerns were identified from the contingency analyses.

North Coast & North Bay Area

The North Coast & North Bay Area has a total of 75 transmission lines that pass through the tier 2 and/or tier 3 fire risk zones. Of these, 22 are 230 kV, 22 are 115 kV and 31 are 60 kV.

The results of the assessment of the five scenarios identified in the section 6.5.3.3 show that there could be a significant amount of load loss and system performance concerns in the boundary condition scenarios, like scenarios 1 and 2. However, the plausible scenarios, like scenarios 4 and 5, show that the direct load loss is only within the Hopland and Mendocino 60 kV system and Hopland, Eagle Rock and Mendocino 115 kV system.

Table 6.5-5 summarizes the results from all five scenarios in terms of the direct load impact and system performance following the contingency analyses.

Table 6.5-5: NCNB Area PSPS Impact

NCNB Area Division	Scenario 1 (All T 2&3)		Scenario 2 (All T3)		Scenario 3 (10-26 PSPS)		Scenario 4 (10-26 PSPS-WFM)		Scenario 5 (PSPS-HWC-All)	
	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact
North Coast	274	Contingency analysis not performed due to large number of base case overloads	261	Contingency analysis not performed due to large number of base case overloads	144	Contingency analysis not performed due to large number of base case overloads	106	Contingency analysis identified one overload in Hopland and Mendocino 60 kV system and Hopland, Eagle Rock and Mendocino 115 kV system.	109	Contingency analysis identified one overload in Hopland and Mendocino 60 kV system and Hopland, Eagle Rock and Mendocino 115 kV system.
North Bay	345		149		223		164		164	

Based on the plausible scenarios, following are the high impact facilities in the North Coast and North Bay system to address direct load loss.

- Fulton-Pueblo 115 kV line
- Eagle Rock-Fulton-Silverdo 115 kV line
- Sonoma-Pueblo 115 kV line
- Windsor-Fitch Mountain 60 kV line and
- Mendocino-Willits-Fort Bragg 60 kV line

If excluded from the future scope of PSPS scenario, they will have a significant impact on reducing the risk of PSPS impact in terms of direct load loss. The CAISO will continue to coordinate with PG&E to evaluate mitigation options within the utilities' wildfire mitigation plan to be able to exclude these facilities from the future PSPS events. In regards to the system performance concerns identified, further work is needed to determine load loss due to distribution line de-energization only.

North Valley Area,

The North Valley Area has a total of 71 transmission lines that pass through the tier 2 and/or tier 3 fire risk zones. Of these, 23 are 230 kV, 14 are 115 kV and 34 are 60 kV.

The results of the assessment of the five scenarios identified in the section 6.5.3.3 show that there could be a significant amount of load loss and system performance concerns in the boundary condition scenarios, such as scenarios 1 and 2 with a direct load impact in the Cascade/ Cottonwood 115 kV, Cottonwood/ Red Bluff 60 kV, Table Mountain/ Palermo 230 kV and Bridgeville/ Cottonwood 115 kV systems. However, the plausible scenarios, such as scenarios 4 and 5, show that the direct load loss is only within the Cottonwood 60 kV system. In regards to the system performance from the contingency analyses, the performance deficiencies are confined to the Cottonwood 60 kV system. Table 6.5-6 summarizes the results from all five scenarios in terms of the direct load impact and system performance following the contingency analyses.

Table 6.5-6: North Valley Region PSPS Impact

Scenario 1 (All T 2&3)		Scenario 2 (All T3)		Scenario 3 (10-26 PSPS)		Scenario 4 (10-26 PSPS-WFM)		Scenario 5 (PSPS-HWC-All)	
Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact
356	Diverge	127	Diverge	182	Contingency Analysis identified no reliability issues	11	Contingency analysis identified one overload in cottonwood 60 kV system	30	Contingency analysis identified four overloads in cottonwood 60 kV system

Based on the plausible scenarios, following are the high impact facilities in the North Valley system to address direct load loss.

- Centerville-Table Mtn-Oroville 60 kV line

If excluded from the future scope of PSPS scenario, will have a significant impact on reducing the risk of PSPS impact in terms of direct load loss. The CAISO will continue to coordinate with PG&E to evaluate mitigation options within the utilities' wildfire mitigation plan, to be able to exclude these facilities from the future PSPS events. In regards to the system performance concerns identified in the Cottonwood 60 kV system from the contingency analyses, it is expected that the approved transmission planning process project in the area will address the identified performance deficiencies.

Central Valley Area

The Central Valley Area has a total of 87 transmission lines that pass through the tier 2 and/or tier 3 fire risk zones. Of these, 14 are 230 kV, 37 are 115 kV and 36 are 60 kV.

The results of the assessment of the five scenarios identified in the section 6.5.3.3 show that there could be a significant amount of load loss in the boundary condition scenarios, like scenarios 1 and 2 in the Sierra and Stockton divisions in the Drum/ Placer 115/60 kV, Gold Hill/ Placerville 115 kV, Stanislaus 115 kV and Valley Springs 115 kV systems. However, the plausible scenarios, like scenarios 4 and 5, show that the direct load loss is only within the Sierra and Stockton regions. In regards to the system performance from the contingency analyses, there are no reliability concerns in any of the five scenarios. Table 6.5-7 summarizes the results from all five scenarios in terms of the direct load impact and system performance following the contingency analyses.

Table 6.5-7: Central Valley Area PSPS Impact

Central Valley Area Division	Scenario 1 (All T 2&3)		Scenario 2 (All T3)		Scenario 3 (10-26 PSPS)		Scenario 4 (10-26 PSPS-WFM)		Scenario 5 (PSPS-HWC-All)	
	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact
Sacramento	32	Contingency analysis identified no reliability concerns.	0	Contingency analysis identified no reliability concerns.	0	Contingency analysis identified no reliability concerns.	3	Contingency analysis identified no reliability concerns.	16	Contingency analysis identified no reliability concerns.
Sierra	500		226		205		161		162	
Stockton	289		61		83		43		90	

Based on the plausible scenarios, following are the high impact facilities in the Central Valley system to address direct load loss.

- El Dorado-Missouri Flat #1 115 kV line
- El Dorado-Missouri Flat #2 115 kV line
- West Point-Valley Springs 60 kV line
- Drum-Rio Oso #1 115 kV line and
- Drum-Rio Oso #2 115 kV line

If excluded from the future scope of PSPS scenario, will have significant impact on reducing the risk of PSPS impact in terms of direct load loss. The CAISO will continue to coordinate with PG&E to evaluate mitigation options within the utilities’ wildfire mitigation plan to be able to exclude these facilities from the future PSPS events.

Greater Fresno Area

The Greater Fresno Area has a total of 16 transmission lines that pass through the tier 2 and/or tier 3 fire risk zones. Of these, 4 are 230 kV, 4 are 115 kV and 8 are 60 kV.

The results of the assessment of the five scenarios identified in the section 6.5.3.3 show that there could be moderate amounts of load loss and system performance concerns in the boundary condition scenarios, like scenarios 1 and 2. However, the plausible scenarios, like scenarios 4 and 5, show that the direct load loss is minor in both the Yosemite region and the Fresno region. Table 6.5-8 below summarizes the results from all five scenarios in terms of the direct load impact and system performance following the contingency analyses.

Table 6.5-8: Greater Fresno Area PSPS Impact

Greater Fresno Area Division	Scenario 1 (All T 2&3)		Scenario 2 (All T3)		Scenario 3 (10-26 PSPS)		Scenario 4 (10-26 PSPS-WFM)		Scenario 5 (PSPS-HWC-All)	
	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact
Yosemite	69	Contingency analysis identified no reliability concerns.	14	Contingency analysis identified no reliability concerns.	No Impact		6	Contingency analysis identified no reliability concerns.	14	Contingency analysis identified no reliability concerns.
Fresno	19		13				13		13	

Based on the plausible scenarios, following are the high impact facilities in the Fresno system to address direct load loss.

- Wishon-Coppermine 70 kV line

If excluded from the future scope of PSPS scenario, they will have a significant impact on reducing the risk of PSPS impact in terms of direct load loss. The CAISO will continue to coordinate with PG&E to evaluate mitigation options within the utilities' wildfire mitigation plan to be able to exclude these facilities from the future PSPS events. As no system performance concerns were identified from the contingency analyses, no mitigation is required to address any performance deficiencies associated with potential PSPS event in the Fresno region.

Central Coast & Los Padres Area

The Central Coast & Los Padres Area, has a total of 50 transmission lines that pass through the tier 2 and/or tier 3 fire risk zones. Of these, 2 are 500kV, 11 are 230 kV, 27 are 115 kV and 10 are 60 kV.

The results of the assessment of the five scenarios identified in the section 6.5.3.3 show that there could be a significant amount of load loss and system performance concerns in the boundary condition scenarios, like scenarios 1 and 2. However, the plausible scenarios, like scenarios 4 and 5, show no direct load loss because there are no lines impacted in the scope. Table 6.5-9 summarizes the results from all five scenarios in terms of the direct load impact and system performance following the contingency analyses.

Table 6.5-9: Central Coast Los Padres Area PSPS Impact

CCLP Area Division	Scenario 1 (All T 2&3)		Scenario 2 (All T3)		Scenario 3 (10-26 PSPS)		Scenario 4 (10-26 PSPS-WFM)		Scenario 5 (PSPS-HWC-All)	
	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact	Load Impact (MW)	System Impact
Central Coast	415	Contingency analysis identified some overloads in Los Padres 70 kV system mitigated by TPP approved project	110	Contingency analysis identified some overloads in Los Padres 70 kV system mitigated by TPP approved project	99	Contingency analysis identified no reliability concerns.	No lines in scope		One line in scope. No impact.	
Los Padres	395		296		0					

As no direct load loss or system performance concerns were identified from the contingency analyses of the plausible scenarios, no mitigation is required to address any performance deficiencies associated with potential PSPS event in the Central Coast & Los Padres Area region.

6.5.5 Conclusion

The transmission issues are confined to direct load impact and no performance deficiencies following the P1 contingency analysis were identified for the plausible scenarios. High impact facilities in each areas have been identified. The high impact facilities are such that if excluded from the scope of PSPS scenario, the exclusion will have a significant impact on reducing the risk of PSPS impact in terms of direct load loss. The CAISO will continue to coordinate with PG&E to evaluate mitigation options within the utilities' wildfire mitigation plan to be able to exclude these facilities from the future PSPS events. With this no new upgrades were developed.

Chapter 7

7 Special Reliability Studies and Results

In addition to the mandated analysis framework set out in the CAISO's tariff described above, the CAISO has also pursued in past transmission planning cycles a number of additional "special studies" in parallel with the tariff-specified study processes, to help prepare for future planning cycles that reach further into the issues emerging through the transformation of the California electricity grid. These studies are provided on an informational basis only and are not the basis for identifying needs or mitigations for CAISO Board of Governor approval. A number of those studies have now been incorporated into analysis set out in chapter 4 exploring resource portfolio scenarios, or are now being conducted on an annual basis and are set out in chapter 6. In the 2020-2021 transmission planning cycle, the CAISO did not undertake any additional "special studies".

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Chapter 8

8 Transmission Project List

8.1 Transmission Project Updates

Table 8.1-1 and Table 8.1-2 provide updates on expected in-service dates of previously approved transmission projects. In previous transmission plans, the CAISO determined these projects were needed to mitigate identified reliability concerns, interconnect new renewable generation via a location constrained resource interconnection facility project or enhance economic efficiencies.

Table 8.1-1: Status of Previously Approved Projects Costing Less than $50 M

No	Project	PTO	Expected In-Service Date
1	Estrella Substation Project	NEET West/PG&E[156]	Nov-2026
2	Cascade 115/60 kV No.2 Transformer Project	PG&E	Jan-2025
3	Clear Lake 60 kV System Reinforcement	PG&E	Feb-2027
4	Coburn-Oil Fields 60 kV system project	PG&E	Sept-2029
5	Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines Rerate	PG&E	Nov-2022
6	Cottonwood 230/115 kV Transformers 1 and 4 Replacement Project	PG&E	Nov-2023
7	Delevan 230 kV Substation Shunt Reactor	PG&E	Completed
8	East Shore-Oakland J 115 kV Reconductoring Project (name changed from East Shore-Oakland J 115 kV Reconductoring Project & Pittsburg-San Mateo 230 kV Looping Project since only the 115 kV part was approved)	PG&E	Apr-2022
9	Fulton-Hopland 60 kV Line Project	PG&E	Mar-2020
10	Glenn 230/60 kV Transformer No. 1 Replacement	PG&E	Dec-2021
11	Gregg-Herndon #2 230 kV Line Circuit Breaker Upgrade	PG&E	Jan-2020
12	Herndon-Bullard 115 kV Reconductoring Project	PG&E	Jan-2024
13	Ignacio Area Upgrade	PG&E	Dec-2027
14	Kern PP 230 kV Area Reinforcement	PG&E	Mar-2021

[156] NEET West was awarded the 230 kV substation component of the project through competitive solicitation. PG&E will construct and own the 70 kV substation and associated upgrades.

No	Project	PTO	Expected In-Service Date
15	Lakeville 60 kV Area Reinforcement	PG&E	Dec-2021
16	Los Esteros 230 kV Substation Shunt Reactor	PG&E	May-2021
17	Maple Creek Reactive Support	PG&E	Jul-2026
18	Metcalf-Evergreen 115 kV Line Reconductoring	PG&E	Completed
18	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	Apr-2029
18	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase	PG&E	May-2021
19	Midway-Temblor 115 kV Line Reconductor and Voltage Support	PG&E	Dec-2027
20	Monta Vista 230 kV Bus Upgrade	PG&E	Mar-2023
21	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	Mar-2025
22	Morgan Hill Area Reinforcement (formerly Spring 230/115 kV substation)	PG&E	Jul-2026
23	Mosher Transmission Project	PG&E	Mar-2022
24	Newark-Lawrence 115 kV Line Limiting Facility Upgrade	PG&E	Canceled
25	Newark-Milpitas #1 115 kV Line Limiting Facility Upgrade	PG&E	Nov-2022
25	North Tower 115 kV Looping Project	PG&E	Dec-2030
26	Oakland Clean Energy Initiative	PG&E	Aug-2022
27	Oro Loma 70 kV Area Reinforcement	PG&E	Apr-2025
28	Panoche – Ora Loma 115 kV Line Reconductoring	PG&E	Apr-2023
29	Pease 115/60 kV Transformer Addition and Bus Upgrade	PG&E	Mar-2020
30	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	Jan-2026
31	Ravenswood – Cooley Landing 115 kV Line Reconductor	PG&E	Feb-2022
32	Reedley 70 kV Reinforcement (Renamed to Reedley 70 kV Area Reinforcement Projects)	PG&E	May-2023
33	Rio Oso 230/115 kV Transformer Upgrades	PG&E	Jun-2024
34	Rio Oso Area 230 kV Voltage Support	PG&E	Sept-2024
35	San Bernard – Tejon 70 kV Line Reconductor	PG&E	Dec-2020
36	Semitropic – Midway 115 kV Line Reconductor	PG&E	Mar-2021
37	South of San Mateo Capacity Increase	PG&E	Mar-2027

No	Project	PTO	Expected In-Service Date
38	Vaca Dixon-Lakeville 230 kV Corridor Series Compensation	PG&E	Apr-2027
39	Vierra 115 kV Looping Project	PG&E	Jan-2026
40	Warnerville-Bellota 230 kV line reconductoring	PG&E	Apri-2024
41	West Point – Valley Springs 60 kV Line	PG&E	Jul-2020
42	Wheeler Ridge Voltage Support	PG&E	Apr-2021
43	Wilson 115 kV Area Reinforcement	PG&E	May-2028
44	Wilson 115 kV SVC	PG&E	Apr-2021
45	Wilson-Le Grand 115 kV line reconductoring	PG&E	Apr-2021
46	Tyler 60 kV Shunt Capacitor	PG&E	Dec-2024
47	Cottonwood 115 kV Bus Sectionalizing Breaker	PG&E	Dec-2027
48	Gold Hill 230/115 kV Transformer Addition Project	PG&E	Dec-2028
49	Jefferson 230 kV Bus Upgrade	PG&E	May-2026
50	Christie-Sobrante 115 kV Line Reconductor	PG&E	Dec-2028
51	Moraga-Sobrante 115 kV Line Reconductor	PG&E	On hold
52	Ravenswood 230/115 kV transformer #1 Limiting Facility Upgrade	PG&E	Jun-2024
53	Tesla 230 kV Bus Series Reactor project	PG&E	Dec-2023
54	South of Mesa Upgrade	PG&E	Dec-2027
55	Giffen Line Reconductoring Project	PG&E	Apr-2024
56	East Marysville 115/60 kV Project	PG&E	Dec-2027
57	East Shore 230 kV Bus Terminals Reconfiguration	PG&E	2026
58	Wilson-Oro Loma 115kV Line Reconductoring	PG&E	2026
59	Borden 230/70 kV Transformer Bank #1 Capacity Increase	PG&E	2027
60	Tulucay-Napa #2 60 kV Line Capacity Increase	PG&E	2026
61	2nd Escondido-San Marcos 69 kV T/L	SDG&E	May-2022
62	2nd Pomerado - Poway 69kV Circuit	SDG&E	Cancelled
63	Bernardo-Ranche Carmel-Poway 69 kV lines upgrade (replacing previously-approved New Sycamore - Bernardo 69 kV line)	SDG&E	Completed

No	Project	PTO	Expected In-Service Date
64	IID S-Line Upgrade	Citizens Energy	2023
65	Miramar-Mesa Rim 69 kV System Reconfiguration	SDG&E	Completed
66	Reconductor TL 605 Silvergate – Urban	SDG&E	Jun-2027
67	Reconductor TL692: Japanese Mesa - Las Pulgas	SDG&E	Dec-2021
68	Rose Canyon-La Jolla 69 kV T/L	SDG&E	Nov 2022
69	San Ysidro 69 kV Reconductoring	SDG&E	Complete
70	Sweetwater Reliability Enhancement	SDG&E	Dec-2027
71	TL13834 Trabuco-Capistrano 138 kV Line Upgrade	SDG&E	Dec-2021
72	TL600: “Mesa Heights Loop-in + Reconductor	SDG&E	Cancelled
73	TL632 Granite Loop-In and TL6914 Reconfiguration	SDG&E	Dec-2024
74	TL644, South Bay-Sweetwater: Reconductor	SDG&E	Apr-2022
75	TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap)	SDG&E	Oct-2021
76	TL690E, Stuart Tap-Las Pulgas 69 kV Reconductor	SDG&E	Feb-2027
77	TL695B Japanese Mesa-Talega Tap Reconductor	SDG&E	Apr-2023
78	Laguna Bell Corridor Upgrade	SCE	Mar-2022
79	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	Dec-2024
80	Method of Service for Wildlife 230/66 kV Substation	SCE	Oct-2026
81	Lugo – Victorville 500 kV Upgrade (SCE portion)	SCE	Jun-2023
82	Pardee-Sylmar 230 kV Line Rating Increase Project	SCE	May 2023
83	Moorpark-Pardee No. 4 230 kV Circuit	SCE	Jun-2021
84	Tie line Phasor Measurement Units	PG&E, SCE, VEA	Dec-2021
85	Bob-Mead 230 kV Reconductoring	VEA	Jan-2021
86	Gamebird 230/138 kV Transformer Upgrade	VEA/GLW	Sep 2021

Table 8.1-2: Status of Previously-Approved Projects Costing $50 M or More

No	Project	PTO	Expected In-Service Date
1	Delaney-Colorado River 500 kV line	DCR Transmission	Dec-2021
2	Suncrest 300 Mvar dynamic reactive device	NEET West	Completed
3	Red Bluff-Coleman 60 kV Reinforcement	PG&E	May-2023
4	Gates #2 500/230 kV Transformer Addition	PG&E	Completed
5	Kern PP 115 kV Area Reinforcement	PG&E	Dec-2027
6	Lockeford-Lodi Area 230 kV Development	PG&E	Jul-2026
7	Martin 230 kV Bus Extension	PG&E	Jan-2024
8	Midway – Kern PP #2 230 kV Line	PG&E	May-2024
9	North of Mesa Upgrade (formerly Midway-Andrew 230 kV Project)[157]	PG&E	TBD
10	Northern Fresno 115 kV Area Reinforcement	PG&E	Completed
11	South of Palermo 115 kV Reinforcement Project	PG&E	Nov-2021
12	Vaca Dixon Area Reinforcement	PG&E	Feb-2025
13	Wheeler Ridge Junction Substation	PG&E	TBD
14	Round Mountain 500 kV Dynamic Voltage Support	PG&E	Dec-2024
15	Gates 500 kV Dynamic Voltage Support	PG&E	Dec-2024
16	Artesian 230 kV Sub & loop-in TL23051	SDG&E	Jun-2022
17	Southern Orange County Reliability Upgrade Project – Alternative 3 (Rebuild Capistrano Substation, construct a new SONGS-Capistrano 230 kV line and a new 230 kV tap line to Capistrano)	SDG&E	May-2023
18	Alberhill 500 kV Method of Service	SCE	TBD
19	Lugo – Eldorado series cap and terminal equipment upgrade	SCE	Jun-2022
20	Lugo-Mohave series capacitor upgrade	SCE	Jun-2022
21	Mesa 500 kV Substation Loop-In	SCE	Mar-2022
22	Harry Allen-Eldorado 500 kV transmission project	DesertLink LLC	Completed

[157] The Midway-Andrew 230 kV Project has been renamed the North of Mesa Upgrade, and remains on hold. The south of Mesa component has been separated into a standalone project named the South of Mesa Upgrade, and approval of that project was recommended in the 2018-2019 Transmission Plan.

8.2 Transmission Projects found to be needed in the 2020-2021 Planning Cycle

In the 2020-2021 transmission planning process, the CAISO determined that three transmission projects were needed to mitigate identified reliability concerns; no policy-driven projects were needed to meet the 60 percent RPS and no economic-driven projects were found to be needed. The summary of these transmission projects are in Table 8.2-1, Table 8.2-2, and Table 8.2-3.

A list of projects that came through the 2020 Request Window can be found in Appendix E.

Table 8.2-1: New Reliability Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
1	Palermo – Wyandotte 115 kV Line Section Reconductoring Project	PG&E	2023	$0.125M - $0.250M
2	Manteca #1 60 kV Line Section Reconductoring Project	PG&E	2024	$1.4M - $2.8M
3	Kasson – Kasson Junction 1 115 kV Line Section Reconductoring Project	PG&E	2023	$0.25M - $0.5M

Table 8.2-2: New Policy-driven Transmission Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
	No policy-driven projects identified in the 2020-2021 Transmission Plan			

Table 8.2-3: New Economic-driven Transmission Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost
	No economic-driven projects identified in the 2020-2021 Transmission Plan			

8.3 Reliance on Preferred Resources

The CAISO has relied on a range of preferred resources in past transmission plans as well as in this 2019-2020Transmission Plan. In some areas, such as the LA Basin, this reliance has been overt through the testing of various resource portfolios being considered for procurement, and in other areas through reliance on demand side resources such as additional achievable energy efficiency and other existing or forecast preferred resources.

As set out in the 2019-2020 Transmission Planning Process Unified Planning Assumptions and Study Plan, the CAISO assesses the potential for existing and planned demand side resources to meet identified needs as a first step in considering mitigations to address reliability concerns.

The bulk of the CAISO's additional and more focused efforts consisted of the development of local capacity requirement need profiles for all areas and sub-areas, as part of the biennial 10 year local capacity technical study completed as part of this transmission planning cycle. This provides the necessary information to consider the potential to replace local capacity requirements for gas-fired generation, depending on the policy or long term resource planning direction set by the CPUC's integrated resource planning process.

As well, the CAISO studied numerous storage projects proposed as providing reliability and economic benefits, as set out in chapter 2 and 4. Given the circumstances of this year's limited planning needs, there were few opportunities for development.

In addition to relying on the preferred resources incorporated into the managed forecasts prepared by the CEC, the CAISO is also relying on preferred resources as part of integrated, multi-faceted solutions to address reliability needs in a number of study areas.

LA Basin-San Diego

Considerable amounts of grid connected and behind-the-meter preferred resources in the LA Basin and San Diego local capacity area, as described in Sections 2.6.1 and 2.9.1, were relied upon to meet the reliability needs of this large metropolitan area. Various initiatives including the LTPP local capacity long-term procurement that was approved by the CPUC have contributed to the expected development of these resources. Existing demand response was also assumed to be available within the SCE and SDG&E areas with the necessary operational characteristics (i.e., 20-minute response) for use during overlapping contingency conditions.

Oakland Sub-area

The reliability planning for the Oakland 115 kV system anticipating the retirement of local generation is advancing mitigations that include in-station transmission upgrades, an in-front-of-the-meter energy storage project and load-modifying preferred resources. These resources are being pursued through the PG&E "Oakland Clean Energy Initiative" approved in the 2017-2018 Transmission Plan. Due to the increase in the area's load forecast and based on the latest Northern Oakland area load profile, the portfolio need has increased to about 36 MW and 173 MWh for 2024 from storage to sufficiently meet the current forecasted reliability need. This includes 7 MW and 28 MWh storage at Oakland L and 29 MW and 145 MWh storage at Oakland C. The approved project is expected to be in-service in 2022.

Kern Area

There were several short and long term Category P1, P2, P6 and P7 reliability issues in the Tevis 115 and Wheeler ridge 230 kV areas that could not be mitigated without the Wheeler Ridge Junction Station Project. This project was put on hold in the 2019-20 TPP. The CAISO is recommending procurement of a 95 MW 4 hour energy storage option to mitigate the 115 kV issues on the Kern-Lamont 115 kV system. The cost of this option was compared against several options, including reconductoring of the 115 kV lines, and was determined to be the lowest cost based on CPUC recommendation of including only the interconnection cost and not the full capital cost of the energy storage projects that are otherwise needed for system capacity purposes according to the CPUC-provided resource portfolios.

Central Coast & Los Padres Area

To provide sufficient maintenance window within winter months for facilities in the area as required by the CAISO planning standards, the CAISO recommends the mitigation plan for procurement of approximately 50 MW 4 hour BESS at Mesa 115 kV substation to address the maintenance requirements and for the North of Mesa upgrade project to remain on hold pending procurement of the battery storage.

Moorpark and Santa Clara Sub-areas

As set out in section 2.7.5, the CAISO is supporting the SCE's preferred resource procurement effort for the Santa Clara sub-area submitted to the CPUC Energy Division on December 21, 2017, by providing input into SCE's procurement activities and validating the effectiveness of potential portfolios identified by SCE. This procurement, together with the stringing of a fourth Moorpark-Pardee 230 kV circuit on existing double circuit towers which was approved in the CAISO's 2017-2018 Transmission Plan, will enable the retirement of the Mandalay Generating Station and the Ormond Beach Generating Station in compliance with state policy regarding the use of coastal and estuary water for once-through cooling.

8.4 Competitive Solicitation for New Transmission Elements

Phase 3 of the CAISO's transmission planning process includes a competitive solicitation process for reliability-driven, policy-driven and economic-driven regional transmission facilities. Where the CAISO selects a regional transmission solution to meet an identified need in one of the three aforementioned categories that constitutes an upgrade to or addition on an existing participating transmission owner facility, the construction or ownership of facilities on a participating transmission owner's right-of-way, or the construction or ownership of facilities within an existing participating transmission owner's substation, construction and ownership responsibility for the applicable upgrade or addition lies with the applicable participating transmission owner.

No regional transmission solutions recommended for approval in this 2020-2021 transmission are eligible for competitive solicitation.

8.5 Capital Program Impacts on Transmission High Voltage Access Charge

8.5.1 Background

The purpose of the CAISO's internal High Voltage Transmission Access Charge (HV TAC) estimating tool is to provide an estimation of the impact of the capital projects identified in the CAISO's annual transmission planning processes on the access charge. The CAISO is continuing to update and enhance its model since the tool was first used in developing results documented in the 2012-2013 transmission plan, and the model itself was released to stakeholders for review and comment in November 2018. Additional upgrades to the model have been made reflecting certain of the comments received from stakeholders.

The final and actual determination of the High Voltage Transmission Access Charge is the result of numerous and extremely complex revenue requirement and cost allocation exercises conducted by the CAISO's participating transmission owners, with the costs being subject to FERC regulatory approval before being factored in the determination of a specific HV TAC rate recovered by the CAISO from CAISO customers. In seeking to provide estimates of the impacts on future access rates, we recognized it was neither helpful nor efficient to attempt to duplicate that modeling in all its detail. Rather, an excessive layer of complexity in the model would make a high level understanding of the relative impacts of different cost drivers more difficult to review and understand. However, the cost components need to be considered in sufficient detail that the relative impacts of different decisions can be reasonably estimated.

The tool is based on the fundamental cost-of-service models employed by the participating transmission owners, with a level of detail necessary to adequately estimate the impacts of changes in capital spending, operating costs, and so forth. Cost calculations included estimates associated with existing rate base and operating expenses, and, for new capital costs, tax, return, depreciation, and an operations and maintenance (O&M) component.

The model is not a detailed calculation of any individual participating transmission owner's revenue requirement – parties interested in that information should contact the specific participating transmission owner directly. For example, certain PTOs' existing rate bases were slightly adjusted to "true up" with a single rate of return and tax treatment to the actual initial revenue requirement incorporated into the TAC rate, recognizing that individual capital facilities are not subject to the identical return and tax treatment. This "true up" also accounts for construction funds already spent which the utility has received FERC approval to earn return and interest expense upon prior to the subject facilities being completed.

The tool does not attempt to break out rate impacts by category, e.g. reliability-driven, policy-driven and economic-driven categories used by the CAISO to develop the comprehensive plan in its structured analysis, or by utility. The CAISO is concerned that a breakout by CAISO tariff category can create industry confusion, as, for example, a "policy-driven" project may have also addressed the need met by a previously identified reliability-driven project that was subsequently replaced by the broader policy-driven project. While the categorization is appropriately as a "policy-driven" project for transmission planning tariff purposes, it can lead to misunderstandings of the cost implications of achieving certain policies – as the entire replacement project is attributed to “policy”. Further, certain high level cost assumptions are appropriate on a CAISO-wide basis, but not necessarily appropriate to apply to any one specific utility.

8.5.2 Input Assumptions and Analysis

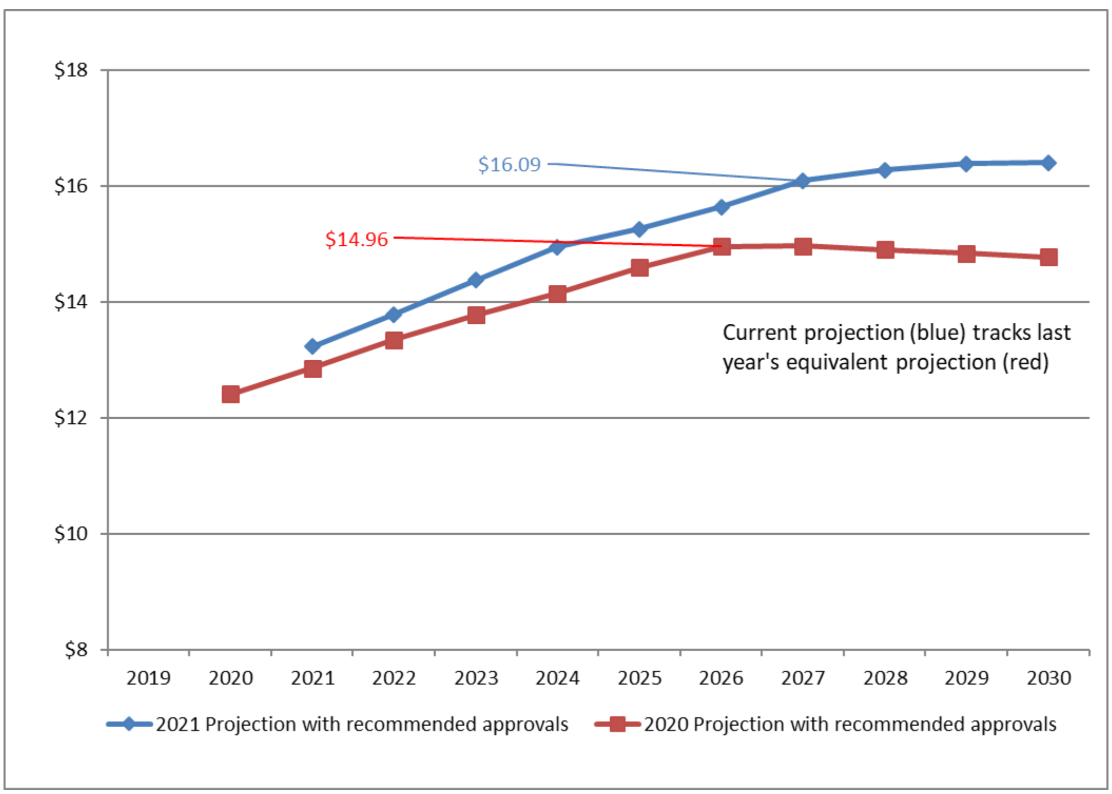
The CAISO’s rate impact model is based on publicly available information or CAISO assumptions as set out below, with clarifications provided by several utilities.

Each PTO’s most recent FERC revenue requirement approvals are relied upon for revenue requirement consisting of capital related costs and operating expense requirements, as well as plant and depreciation balances. Single tax and financing structures for each PTO are utilized, which necessitates some adjustments to rate base. These adjustments are “back-calculated” such that each PTO’s total revenue requirement aligned with the filing.

Total existing costs are then adjusted on a going forward basis through escalation of O&M costs, adjustments for capital maintenance costs, and depreciation impacts. PTO input is sought each year regarding these values, recognizing that the CAISO does not have a role regarding those costs.

To account for the impact of CAISO-approved transmission capital projects, the tool accommodates project-specific tax, return, depreciation and Allowances for Funds Used during Construction (AFUDC) treatment information.

Figure 8.5-1 Forecast of ISO High Voltage Transmission Access Charge Trending from First Year of Transmission Plan



In reviewing the latest estimate, as illustrated in Figure 8.5 1, the trend of the 2020 TAC value for the 2020 projection remains relatively consistent with the 2019 projection though with an increase primarily driven by the costs of the revenue requirements in the PTO's most recent FERC revenue requirement approvals.