California ISO

2024-2025 TRANSMISSION PLAN

BOARD APPROVED
May 30, 2025

Foreword

At the May 22, 2025 ISO Board of Governors meeting the ISO Board of Governors approved the 2024-2025 Transmission Plan.

Table of Contents

Intentionally left blank

Executive Summary

The California Independent System Operator (ISO) has prepared this 2024-2025 Transmission Plan as part of its core responsibility to identify and plan the development of solutions to comprehensively meet the future needs of the ISO-controlled transmission grid. The Plan was prepared through the annual transmission planning process (TPP) that will culminate in an ISO Board of Governors (Board) approved comprehensive transmission plan.

The need for additional generation of electricity over the next 10 years has escalated rapidly in California as it continues transitioning to the carbon-free electrical grid required by the state's clean-energy policies. This in turn has been driving a dramatically accelerated pace for new transmission development in the last two, current, and future planning cycles. To help ensure we have the transmission in place to achieve this transition reliably and cost-effectively, the ISO's 2024-2025 Transmission Plan builds on the much more strategic and proactive approach initially adopted in the 2022-2023 Transmission Plan and carried forward since to better synchronize power and transmission planning, interconnection queuing and resource procurement. Similar to last year, the Plan is put forward in close coordination with the state's primary energy planning and regulatory entities, the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC), as well as local regulatory authorities.

The proactive and coordinated strategic direction reflected in this year's transmission plan was initially set forth in a joint Memorandum of Understanding (MOU) signed by the three parties in December 2022.[1] The MOU tightens the linkages between resource and transmission planning, interconnections, and procurement so California is better equipped to meet its reliability needs and clean-energy policy objectives required by Senate Bill 100.[2]

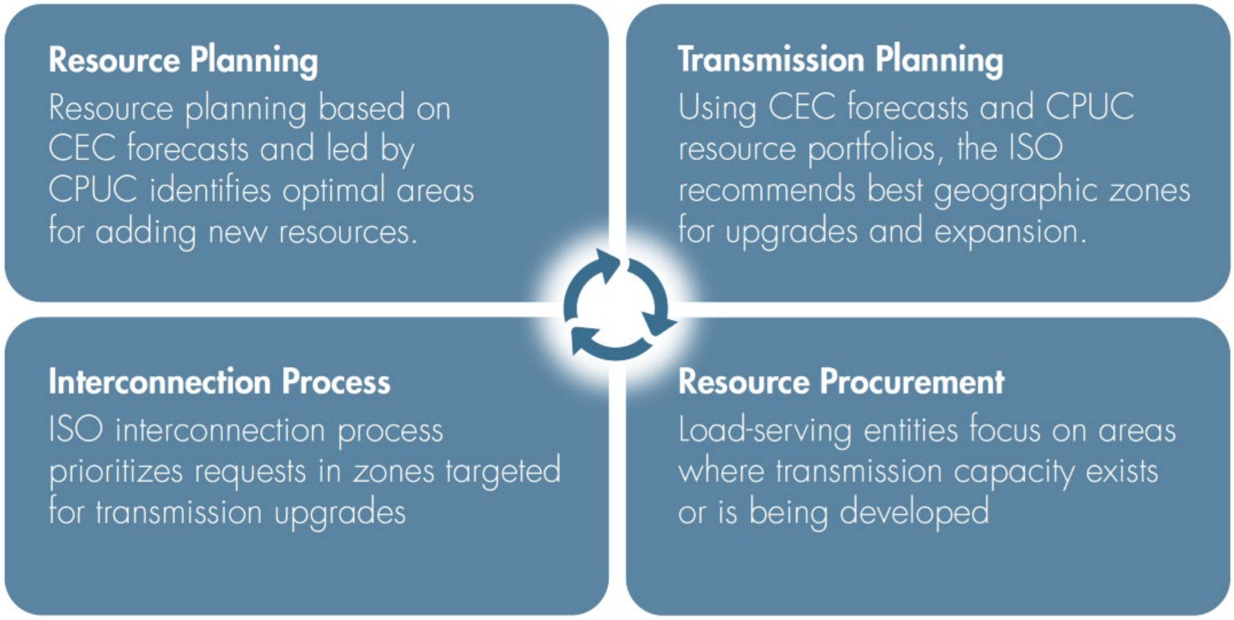
As set out in the MOU, expectations are that the CPUC[3] will continue to provide resource planning information to the ISO as it did for this transmission planning cycle. The ISO will develop a final transmission plan, initiate the transmission projects and communicate to the electricity industry specific geographic zones that are being targeted for transmission projects along with the capacity made available in those zones. The CPUC will in turn provide clear direction to load-serving entities to focus their energy procurement in those key transmission zones, in alignment with the transmission plan. To bring this more coordinated approach full circle, the ISO will also give greater priority to interconnection requests located within those same zones in its generation interconnection process.

[1] http://www.caiso.com/Documents/ISO-CEC-and-CPUC-Memorandum-of-Understanding-Dec-2022.pdf

[2] SB 100, the 100% Clean Energy Act of 2018, 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% renewable resources target by December 31, 2026, and to achieve a 60% target by December 31, 2030. The bill also set out the state policy that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

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

Figure ES-1: Tightening linkages of resource and transmission planning activities, interconnection processes and resource procurement



As the most recent CEC forecast informs the transmission planning for each year and simultaneously the resource planning conducted for the next year's transmission plan, there is an inherent lag when significant changes occur in load forecast. The latest forecast is taken into account immediately in the transmission planning process, but an additional year elapses before resource portfolios are available for transmission planning purposes that also reflect the previous year's increased load forecast.

This year's transmission plan is based on state projections[4] provided to the ISO in 2024 that California needs to add more than 76 GW of capacity[5] by 2039. This reflects greenhouse gas reduction goals and load growth, including the potential for increased electrification[6] occurring in other sectors of the economy, most notably in transportation and the building industry. This capacity requirement is consistent with the base portfolio amounts that were the basis of the 2023-2024 transmission plan. The sensitivity assessment provided information related to the potential retirement of a portion of the existing gas-fired generation resources.

While the resource planning needs have not increased materially from those reflected in last year's transmission plan, the increased rate of load growth reflected in the most recent load

[4] In planning for the new resources required to meet system-wide resource needs, CPUC portfolios also took into account the announced retirements of approximately 3700 MW of gas-fired generation to comply with state requirements for thermal generation relying on coastal water for once-through cooling, and the planned retirement of the Diablo Canyon Power Plant. The ISO is not relying on the gas-fired generation or Diablo Canyon Power Plant to meet any local capacity or grid support purposes beyond the planned retirement dates. However, the ISO must continue to ensure that they are reliably interconnected and can continue to operate through any potential extension period, so the resources are modeled in the ISO's studies for those purposes only.

[5] The CPUC-provided portfolio calls for 76 GW of installed capacity, beyond its baseline of existing resources and resources already contracted for and under development.

[6] https://www.energy.ca.gov/data-reports/reports/2023-integrated-energy-policy-report/2023-iepr-workshops-notices-and-2

forecast associated with building and other electrification, data center growth, and transportation electrification results in significant reliability-driven needs in this year's transmission plan.

This plan, and the projects described on the following page, enable the forecasted load growth and critical resource development, including:

- Over 30 GW of solar generation distributed across the state in solar development regions that include the Westlands area in the Central Valley, Tehachapi, the Kramer area in San Bernardino County, Riverside County, and also in southern Nevada and western Arizona;
- Over 7 GW of in-state wind generation in existing wind development regions, including Tehachapi;
- 2 GW of geothermal development, primarily in the Imperial Valley and in southern Nevada;
- Access for battery storage projects co-located with renewable generation projects across the state, as well as stand-alone storage located closer to major load centers in the LA Basin, greater Bay Area, and San Diego;
- The import of over 9 GW of out-of-state wind generation from Idaho, Wyoming and New Mexico, by enhancing corridors from the ISO border in southeastern Nevada and from western Arizona into California load centers; and
- Over 4.5 GW of offshore wind with 2.9 GW in the Central Coast (Morro Bay call area) and 1.6 GW in the North Coast area (Humboldt call area).
- An increase in the year-over-year rate of peak demand growth from 0.99 to 1.53, and in particular, a change from 1.22 to 2.14 in the Greater Bay area, which represents an increase in the 2035 peak load forecast of over 2,000 MW in the Greater Bay from the previous planning cycle.

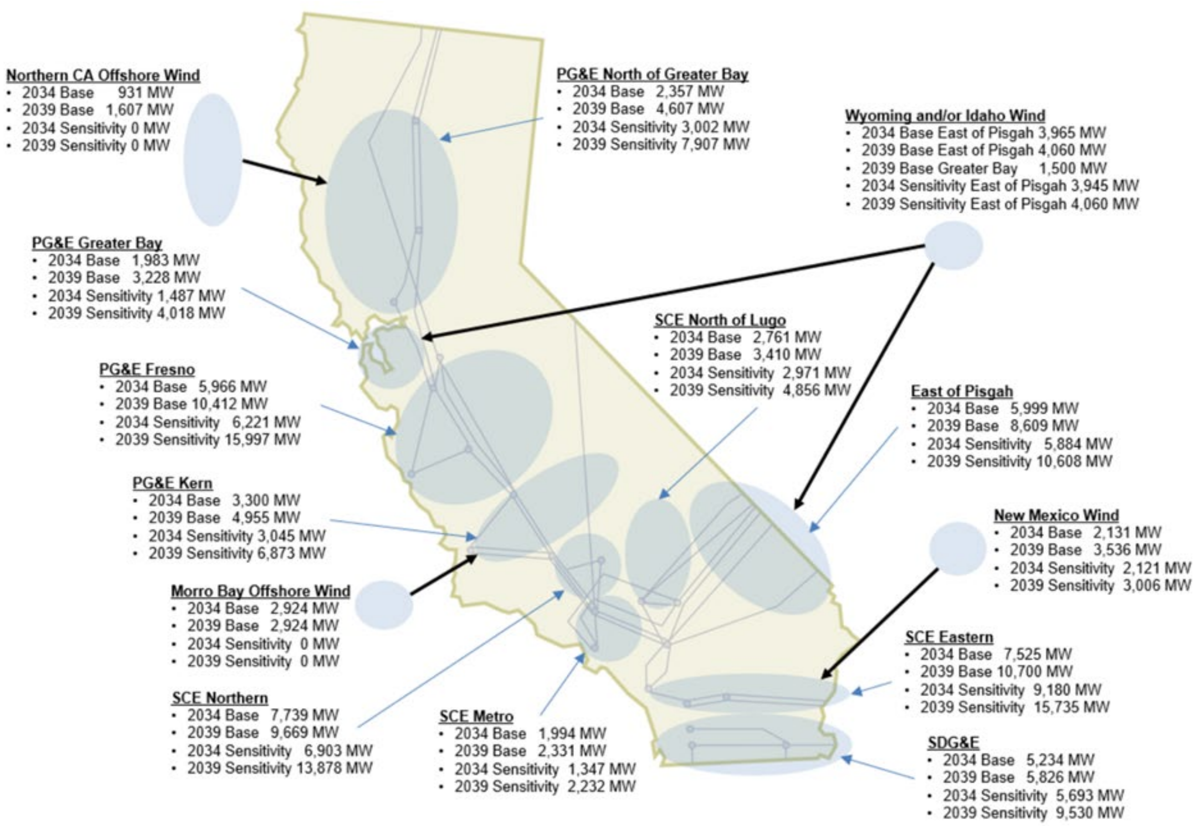
To achieve these outcomes, the ISO has found the need for 31 transmission projects, for a total infrastructure investment of an estimated $4.8 billion. The comprehensive analysis included screening of hundreds of options and detailed assessments of alternatives in addition to the recommended projects. The alternative analysis considered transmission upgrades, preferred resources (such as storage), grid-enhancing technologies (GETs) and remedial action schemes. The recommended reliability-driven and policy-driven projects, most notably related to load growth in the Greater Bay area, include:

- Greater Bay Area 500 kV Transmission Reinforcement - new 500 kV line to supply the south Greater Bay area;
- San Jose B – Northern Receiving Station (NRS) 230 kV Line – a new 230 kV line in the San Jose area;
- South Bay Reinforcement – reconductoring of five 115 kV lines and 115 kV system reconfigurations in the San Jose area;

- North Oakland Reinforcement - integrating two new 115 kV sources into north Oakland area and upgrading the capacity of existing 115 kV lines and substations in area;
- South Oakland Reinforcement - reconductoring of three 115 kV lines; and
- A host of smaller upgrades improving supply of load and access to other smaller resource zones.

Figure ES-2 illustrates the specific zones and capacities in each zone enabled by this Transmission Plan. The network upgrades are recommended in this plan to make all of the base amounts available with the focus on the sensitivity portfolio to assess the transmission needs with additional offshore wind in the North Coast area.

Figure ES-2: Transmission Planning Zones and Capacity



The transmission projects recommended for approval in this plan represent significant investments that are phased in over lead times of up to eight to 10 years, which are reasonable for some of the projects to be completed. These costs translate to approximately 0.5 cents per kWh over the life of the projects, phased in as the new facilities come online. The costs for consumers are ultimately determined as part of the rate design process between utilities and their regulatory authorities. These projects are consistent with the ISO's 20-Year Transmission Outlook and co-optimized with resource planning through the CPUC's integrated resource planning process. The ISO also conducted detailed evaluations of alternatives to ensure achievement of the most efficient and cost-effective long-term solutions. The infrastructure investments also have tremendous reliability and economic benefits for California and the transmission upgrades are required to cost-effectively bring reliable decarbonized power to California consumers and industry across all seasons of the year.

Transmission projects are categorized as reliability-driven needed to serve load reliably and meeting NERC national standards; policy-driven needed to deliver renewable generation to load centers to meet state clean energy goals, and economic-driven that will reduce the cost of energy to ratepayers by, for example, reducing grid congestion costs.

Transmission Projects Recommended for Approval

The 31 new reliability-driven and policy-driven transmission projects found to be needed in the 2024-2025 transmission planning process totaling $4.8 billion are as follows:

Reliability-Driven Projects: Reliability projects driven by load growth and evolving grid conditions as the generation fleet transitions to increased renewable generation represent 28 of the new projects, totaling $4.6 billion. The projects are required to reliably meet the increase in forecasted load related to electrification and electric vehicle transportation loads. The 28 projects are set out in Table ES-1.

Table ES-1: Reliability-Driven Transmission Projects Recommended for Approval

No.	Project Name	PTO Area	Planning Area	Est Cost ($M)
1	Jefferson-Stanford 60 kV Recabling[7]	PG&E	GBA	40
2	Konocti – Eagle Rock 60 kV Line Reconductoring[7]	PG&E	NCNB	32.5
3	Moraga 230/115 kV Transformer Bank Addition[7]	PG&E	GBA	40
4	Pittsburg-Kirker 115 kV Line Section Limiting Elements Upgrade[7]	PG&E	GBA	0.2
5	San Miguel New 70 kV Line[7]	PG&E	CCLP	30
6	Sobrante 230 kV Bus Upgrade[7]	PG&E	GBA	15
7	Coronado Island Reliability Reinforcement Phase I[7]	SDG&E	SDG&E	42

[7] These projects have already been approved by ISO Management, ahead of the rest of the Plan being considered by the ISO's Board of Governors, pursuant to the ISO's tariff, after stakeholders were informed of Management's intention to approve, and given an opportunity to raise concerns with Management or the Board of Governors.

No.	Project Name	PTO Area	Planning Area	Est Cost ($M)
8	Sloan Canyon Tertiary Reactors	GLW	VEA	10
9	Ames Distribution – Palo Alto 115 kV transmission line	PG&E	GBA	84
10	Cortina #3 60 kV Reconductoring	PG&E	CVLY	55.5
11	Gold Hill-El Dorado Reinforcement	PG&E	CVLY	127
12	Greater Bay Area 500 kV Transmission Reinforcement	PG&E	GBA	700
13	Metcalf Substation 500/230 kV Transformer Bank Addition	PG&E	GBA	182
14	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade Re-scope	PG&E	GBA	135
15	North Oakland Reinforcement Project	PG&E	GBA	1127
16	San Jose B – NRS 230 kV line	PG&E	GBA	200
17	San Mateo 230/115 kV Transformer Bank Addition Project	PG&E	GBA	110
18	South Bay Reinforcement Project	PG&E	GBA	434
19	South Oakland Reinforcement Project	PG&E	GBA	250
20	West Fresno 115 kV Voltage Support	PG&E	Fresno	60
21	Alamitos 230 kV SCD Upgrade	SCE	SCE Main	5
22	Julian Hinds-Mirage 230 kV Advanced Reconductor	SCE	Eastern	76
23	Kramer-Coolwater 115 kV Line Looping into Tortilla 115 kV Substation	SCE	NOL	37
24	Serrano 230 kV SCD GIS Bus Split	SCE	SCE Main	28
25	Serrano 500 kV SCD Mitigation	SCE	SCE Main	183
26	Tortilla 115 kV Capacitor Replacement	SCE	NOL	5
27	Coronado Island Reliability Reinforcement Phase II	SDG&E	SDG&E	66
28	Downtown Reliability Reinforcement	SDG&E	SDG&E	500
			Total	**4574.2**

The following reliability-driven reconductoring projects will utilize advanced conductors to achieve the required ratings.

- Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade Re-scope:
    - Piercy-Metcalf 115 kV line;
    - Swift-Metcalf 115 kV line;
    - Newark-Dixon Landing 115 kV line; and
    - McKee-Piercy 115 kV line;
- Julian Hinds-Mirage 230 kV Advanced Reconductor.

As a result of increasing load forecast levels in Greater Bay area, the ISO has recommended for approval a number of transmission projects in the area, including the Greater Bay area 500 kV transmission reinforcement project. The ISO has also reviewed the Warnerville-Newark Transmission Expansion Project (WaNTEP) that Hetch Hetchy Water and Power (HHWP) submitted into the request window. The ISO will continue discussions with HHWP on this project as an alternative to further address the long-term reliability needs in the Greater Bay area related to this planning cycle as well as those anticipated in the 2025-2026 transmission planning cycle.

Policy-Driven Projects: The ISO found the need for three transmission projects that are policy driven. These total $289.5 million and are listed in Table ES-2. They are needed to meet the renewable generation requirements established in the CPUC-developed renewable generation portfolios.

Table ES-2: Policy-Driven Transmission Projects Recommended for Approval

No.	Project Name	PTO Area	Planning Area	Est. Cost ($M)
1	Eagle Rock- Fulton- Silverado 115 kV Line Reconductor	PG&E	NCNB	92.9
2	Reconductor of GWF – Kingsburg 115 kV line	PG&E	Fresno	81.6
3	New Helm 230/70 kV Bank #2	PG&E	Fresno	115
			Total	**289.5**

Economic-Driven Projects*:* Each year the ISO studies and monitors expected levels of congestion on the transmission system through detailed production cost modeling, and prioritizes study areas to assess if the benefits of alleviating that congestion exceed the cost of additional transmission upgrades. This also takes into account other potential economic benefits of possible transmission upgrades. Accordingly, the ISO conducted several economic studies in this planning cycle investigating opportunities to reduce total costs to ratepayers through transmission upgrades not otherwise needed for reliably accessing renewables and serving load. No projects driven solely by economic considerations are being recommended in this plan.

Competitive Transmission Procurement: The ISO federal 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. The following projects are eligible for competitive solicitation, and the ISO will provide a schedule for those processes in May, 2025:

- San Jose B – NRS 230 kV line
- Metcalf – Manning 500 kV line

Other Studies

As in past transmission planning cycles, the ISO undertook additional technical studies to help inform future transmission or resource planning activities. These are informational only but may be of interest to stakeholders. They include the local capacity technical study analyses, frequency response analysis and examination of viability of congestion revenue rights. These studies are set out in Chapters 6 and 7.

Other Findings and Observations

The ISO considers a number of social, economic, and policy-related drivers in the resource planning, transmission planning and infrastructure development process, and will continue to adapt to the policy landscape in future planning cycles. These include the following:

- Relevant federal rulemakings¸ such as FERC Orders No. 1920 and 1920-A, requiring long-term transmission planning;
- West-wide transmission planning in the context of FERC Orders No. 1920 and 1920-A and development of an actionable West-wide transmission study through the Western Transmission Expansion Coalition;
- Planning for large loads associated with development of new infrastructure such as data-centers or hydrogen facilities;
- Transmission project execution and the importance of addressing barriers to timely siting, permitting, financing, and construction of energy infrastructure;
- Possible re-scoping of approved transmission projects to account for increased load growth or other changes in forecasts;
- Continued consideration of grid-enhancing technologies, not only as a best practice, but as required by FERC Orders No. 1920/1920-A and 2023, and encouraged in California legislation;
- Consideration of storage as a transmission asset;
- Coordination and consultation with state agencies and local regulatory authorities to meet legislative requirements; and
- Opportunities to continue leadership in transmission planning and interconnection.

Conclusions and Recommendations

The 2024-2025 Transmission Plan provides a comprehensive evaluation of the ISO transmission grid to identify upgrades needed to adequately keep pace with California's policy goals, address grid reliability requirements, identify zones of resource development and bring economic benefits to consumers. This year's Plan identified 31 transmission projects, with a total capital cost estimate of $4.8 billion, as needed to maintain the reliability of the ISO transmission system and unlock access to renewable generation resources to meet state energy needs. Several of these projects include the use of grid enhancing technologies.

Once approved by the ISO Board of Governors at its May, 2025 meeting, the Plan serves to:

- Authorize cost recovery for the 31[8] identified transmission solutions through ISO transmission rates, subject to regulatory approval; and
- Initiate the ISO's competitive solicitation process for the two eligible projects identified above.

The ISO will also continue to evaluate and discuss with Hetch Hetchy Water and Power (HHWP) the Warnerville-Newark Transmission Expansion Project (WaNTEP) that HHWP submitted into the request window, as a possible extension of this planning cycle.

[8] As noted earlier, 7 reliability projects have already been approved by Management pursuant to the ISO tariff, and do not require additional approval by the Board of Governors.

Intentionally left blank

Chapter 1

1 Overview of the Transmission Planning Process

1.1 Introduction

The 2024-2025 Transmission Plan continues to build off of the two significant course changes in the 2022-2023 Transmission Plan. The first is the proactive zonal transmission planning foundation for transformational changes the ISO is pursuing in close coordination with the CPUC and the CEC to tighten linkages between resource and transmission planning activities, interconnection processes and resource procurement. The second responds to the rapid escalation in the projected resource requirements over the next 10 to 15 years to meet California's clean-energy needs.

As part of these transformational changes and to help shape and inform the generator interconnection process and procurement while also enhancing the state's ability to achieve reliability and decarbonization goals in a timely and cost-effective manner, the ISO continues to employ a much more proactive approach to transmission planning. This proactive, targeted zonal approach is grounded in the policy and reliability needs of the state. Our strategic intent in drafting the Transmission Plan in this manner is to take into account priority zones identified in resource portfolios to develop the transmission infrastructure required and recommended for approval.

These changes to our planning process build on enhancements and improvements to the ISO's regional transmission planning that have already been moving forward, including the 20-Year Transmission Outlook framework. The 20-Year Outlook framework has also been coordinated with, and supported by the CEC and CPUC, particularly in the development of customized resource portfolios under the auspices of the CEC's SB 100 activities and responsibilities.

The ISO relies on the resource plans of local regulatory authorities as the basis for the annual Transmission Plan. This 2024-2025 transmission planning cycle accounts for the needs of all local regulatory authorities, including non-CPUC jurisdictional load-serving entities, an endeavor that the ISO looks forward to continuing to build upon in future cycles. The CPUC, in particular, plays a critical role in developing resource forecasts, with both the ISO and CEC providing input to the CPUC in development of the resource forecasts. The ISO also relies on the CEC for its lead role in forecasting customer load requirements. The MOU that was signed by the three parties in December 2022 reaffirms our respective roles and commitments to ensure we are working in concert with one another. As such, the MOU also sets the overall strategic direction for tightening linkages among resource and transmission planning activities, interconnection processes and resource procurement. The ISO is synchronized with state energy agencies and local regulatory authorities in working toward the timely integration of new resources.

In the 10-plus years since the ISO redesigned its transmission planning process, and subsequently adapted it to meet provisions of Order No.1000 from the Federal Energy Regulatory Commission (FERC), challenges that have been placed on the electricity system –

and correspondingly on the transmission system – have evolved and grown substantially. Over the last four years, the annual requirement for new resources has ramped up from about a 1,000 MW per year to a sustained expectation of 5,000 to 7,000 MW per year. Recent transmission plans have accordingly advanced a great deal of policy-driven transmission needed to access renewable energy zones primarily inside California, or to boost transfer capacity from the ISO border to load centers, meeting forecast needs 10 to 15 years out. The ISO anticipates additional intra-ISO policy-driven upgrades to continue to be identified on a more measured pace now that the higher trajectory has been established, to address new emerging needs and push the planning horizon out further to the 2045 target for clean energy goals. Additional development will be also required to access the called-for out of state resources and offshore wind. However, the increasing rate of load growth tied to the success of electrification of transportation and building electrification, and data center load growth, is expected to create new challenges, calling for additional strengthening of the grid to provide reliable service to load centers.

It will be essential for local regulatory authorities, including the CPUC, to continue the timely pace of new resource authorizations in parallel with reinforcement of the transmission system. Over the last 5 years, the ISO has seen tremendous success in the development of interconnection of new resources, stemming largely from authorizations by the CPUC. The CPUC adopted Decision (D.) 19-11-016 on November 7, 2019, which ordered procurement of 3,300 MW of incremental resources, with 50% required to be online by August 2021. As part of a separate proceeding (R.20-05-003), the CPUC adopted D.21-06-035 on June 24, 2021 to address mid-term reliability needs of the electricity system within the ISO's balancing authority area. This decision requires at least 11,500 MW of additional procurement, with 2,000 MW required by August 2023; 6,000 MW by June 2024; 1,500 MW by June 2025; and 2,000 MW of long lead-time resources by June 2026. In that same proceeding, on February 23, 2023, the CPUC adopted Decision (D.) 23-02-040, which ordered supplemental mid-term reliability procurement of an additional 2,000 MW in each of 2026 and 2027. Since then, the ISO is observing new interconnections moving forward as load serving entities move to comply with their own integrated resource plans – even if not required to do so, and the CPUC has further requested the California Department of Water Resources to explore contracts for certain long lead-time resources. The CPUC's anticipated Reliable and Clean Power Procurement Plan is also expected to set the stage for sustained resource development.

Resource Interconnections:

The increasing need for large quantities of new clean resources to meet California's demand led to unmanageable increases in interconnection requests in 2021 and 2023. The sheer volume of interconnection requests received in cluster 14 (2021) and cluster 15 (2023) application windows compromised the accuracy and usability of the interconnection study results, so it became necessary for the ISO to develop a means of prioritizing interconnection requests, with the most viable requests advancing to the study process. In 2023, the ISO initiated a stakeholder initiative to establish new standards and processes for resource interconnection and queue management. The reformed interconnection request intake process, approved by FERC on September 30, 2024, prioritizes alignment with state and local resource plans, transmission availability, procurement needs, and project readiness. Implementation is currently underway, and preliminary data suggests that the reform effort successfully reduced study volumes to reasonable amounts that align with anticipated need.

The ISO is in the process of finalizing additional enhancements to the interconnection process related to deliverability, a resource's ability to provide capacity during times of stressed system conditions. Later in 2025, the ISO will commence a new Interconnection Process Enhancements stakeholder initiative to consider any necessary or appropriate adjustments to the interconnection process prior to cluster 16, which will open in October of 2026.

Procurement and Project Execution:

The ISO is also taking on additional efforts to:

- Coordinate with the CPUC, CEC, and the Governor's Office of Business and Economic Development (GO-Biz) to identify and help mitigate issues that could delay new resources meeting in-service dates;
- Together with the CPUC, work with the participating transmission owners in hosting the Transmission Development Forums held quarterly to improve the transparency of the status of transmission projects focusing on network upgrades approved in prior ISO transmission plans, or that resources with executed interconnection agreements are dependent on;
- Provide more information publicly regarding where resources are able to connect to the grid with no or minimal network upgrade requirements, to assist load-serving entities to shape their procurement activities towards areas and resources that are better positioned to achieve necessary commercial operation dates; and
- Coordinate with the CPUC regarding the progress of procurement activities by load-serving entities and assessing the timeliness of those procured resources meeting near and mid-term reliability requirements.

These enhancements and coordination efforts will collectively support and help the state reliably reach its renewable energy objectives.

1.2 Key Inputs

This Section 1.2 provides background and detail on key load and resource forecast inputs into the 2024-2025 Transmission Planning Process.

1.2.1 Load Forecasting and Distributed Energy Resources Growth Scenarios

1.2.1.1 Base Forecasts

As discussed earlier, the ISO relies on load forecasts and load modifier forecasts prepared by the CEC through its Integrated Energy Policy Report (IEPR) processes. The combined effect of changing customer load patterns and evolving load modifiers are particularly important, and have driven the need for far more attention not only on peak loads and total energy consumption but also on the characteristics of the aggregate customer load shape on an hourly, daily, and seasonal basis.

The rapid deployment of behind-the-meter rooftop generation in particular has driven changes in forecasting, planning and operating frameworks for both the transmission system and generation fleet. This has led to the shift in many areas of the peak "net sales" — the load served by the transmission and distribution grids — 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 to later times of the day and out of the window when grid-connected solar generation is available.

Further developments related to load electrification due to fuel switching and electric vehicle deployment and goals have led to a significant increase in energy and demand forecasts starting in the year 2028 and beyond, as seen in the 2022 IEPR Energy Demand Forecast, 2022-2035 adopted by the CEC on January 25, 2023.[9]

1.2.2 Resource Planning and Portfolio Development

The ISO's transmission plan is built upon the inputs of the State's demand forecast and local regulatory authority resource plans. As described in the joint MOU signed in December 2022, the ISO relies extensively on coordination with the state energy agencies, in particular with the CPUC, which takes the lead in developing resource forecasts for the 10-year planning horizon with input from the CEC and ISO. These resource forecasts are provided in the form of resource portfolios, with input also received on other key assumptions. In recent years, the focus has been on achieving 2030 greenhouse gas reduction targets established by the California Air Resources Board (CARB), in coordination with the CPUC and CEC, as directed by Senate Bill (SB) 350. These targets also meet or exceed the current 2030 renewables portfolio standard (RPS) requirement established by SB 100. The past focus has also been on establishing a reasonable trajectory to meet the 2045 renewables portfolio standard goals that were also established in SB 100.

The CPUC, via Decision 24-02-047[10] issued on February 15, 2024, provided the ISO a base portfolio along with a sensitivity portfolio for use in the 2024-2025 TPP. The base portfolio is designed to meet the 25 million metric tons (MMT) greenhouse gas (GHG) emissions target by 2035. In addition the base portfolio continues to highlight the projected off-shore wind generation to ensure delivery to load centers, and the reduction of need to rely on "non-preferred resources in local capacity areas". The primary focus of the sensitivity was to study the transmission needs with a large amount of fossil-fuel generation retirement to include 5.4 GW of natural gas retirements by 2034, and 12.3 GW of natural gas retirements by 2039.[11]

---

[9] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2022-integrated-energy-policy-report-update-2

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

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

1.2.2.1 Consideration of Large Scale Retirement of the Gas-Fired Generation Fleet

In developing the base portfolio for the 2024-2025 transmission planning cycle, the CPUC's modeling showed that while no new natural gas-fired power plants are identified in the 2035 new resource mix, existing gas-fired plants – other than those relying on once-through-cooling and scheduled for retirement - are needed in 2035 as operable and operating resources providing a renewable integration service.

The portfolios for the 2024-2025 transmission planning portfolios do consider approximately 2,000 MW of gas-fired generation retirement in the base portfolio and a sensitivity portfolio with approximately 10,000 MW of gas-fired generation retirement by 2039, not including the once-through-cooling generation retirements.

1.2.2.2 Offshore Wind Generation

Starting with the 2021-2022 transmission planning process and the 20-Year Transmission Outlook, the ISO began assessing the transmission capabilities for integrating offshore wind in the Central Coast and North Coast areas.

The analysis indicated there is transmission capability in the Central Coast of approximately 5,300 MW around the Diablo Canyon Power plant that was planned to be retried 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 retains certain deliverability retention options for repowering that can remain in effect for up to three years following the retirement of the nuclear plant. With Diablo online or deliverability retained, capacity available in the area for the interconnection of offshore wind would be about 3,000 MW.

In this year's planning cycle, the ISO has continued this assessment with 2,924 MW of offshore wind in the 2034 and 2039 base portfolio in the Morro Bay call area, with 931 MW in 2034 and 1,607 MW in 2039 for the Humboldt call area. The ISO has continued to assess transmission alternatives for offshore wind generation integration, to build on the transmission development projects approved in the previous 2023-2024 Transmission Plan. The offshore wind capacity in the CPUC portfolio for this planning cycle is consistent with the previous planning cycle, and with this the ISO will reserve any additional transmission plan deliverability in the 2024-2025 TPP beyond what has already been reserved.

1.2.2.3 Deliverability Reservations for Long Lead-Time Resources

In previous cycles, the ISO has reserved deliverability for long lead-time generation resources to ensure that policy-driven transmission projects are used to deliver resources specified in resource plans.

Below, the ISO lists the capacity that has been or will be reserved based on previous local regulatory authority portfolios, and the locations on the system where it is expected to interconnect.

The CPUC base portfolios for the 2024-2025 Transmission Planning Process include the following resources in 2034 and 2039, for which the ISO will reserve deliverability. Many of these resources were included in the CPUC base portfolios for the 2023-2024 Transmission Planning Process, and some of this deliverability has already been allocated. The amounts listed below reflect total cumulative reservations in the 2024-2025 Transmission Plan.

- Wyoming wind (Eldorado)
  - 2034 – 2,905 MW
  - 2039 – 3,000 MW
  - Current deliverability reservation at Eldorado: 1,500 MW[12]
- Wyoming wind (Tesla)
  - 2034 – 0 MW
  - 2039 – 1,500 MW
  - Current deliverability reservation at Tesla: 0 MW[13]
- Idaho wind (Harry Allen)
  - 2034 – 1,060 MW
  - 2039 – 1,060 MW
  - Current deliverability reservation at Harry Allen: 1,060 MW
- New Mexico Wind (Palo Verde)
  - 2034 – 2,131 MW
  - 2039 – 3,099 MW
  - Current deliverability reservation at Palo Verde: 3,099 MW.
- Offshore wind (North Coast)
  - 2034 – 931 MW
  - 2039 – 1,607 MW
  - The ISO will reserve deliverability for 1,607 MW on the North Coast[14]
- Offshore wind – Central Coast (Diablo Canyon)
  - 2034 – 2,924 MW
  - 2039 – 2,924 MW
  - Current deliverability reservation at Diablo Canyon: 2,924 MW
- Geothermal - Imperial Irrigation District (Mirage and Imperial Valley)
  - o 2034 – 950 MW
  - o 2039 – 950 MW
  - Current deliverability reservation from Imperial Irrigation District: 950 MW

The CPUC Decision[15] for the 2025-2026 Transmission Planning Process proposes deliverability reservations for additional resource types and locations, which the ISO will consider in the 2025-2026 Transmission Planning Process, using the process described in the 2023 Interconnection Process Enhancements Track 3 Initiative, which was recently approved by the ISO's Board of Governors and will require FERC approval.

[12] The capacity listed is included in 2024-2025 TPP portfolios; however, as indicated in the CPUC Decision for the 2025-2026 TPP only 1,500 MW will be reserved for out-of-state wind resources at this location at this time.

[13] The capacity listed is included in 2024-2025 TPP portfolios; however, as indicated in the CPUC Decision for the 2025-2026 TPP the ISO will not be reserving any for wind resource at this location at this time.

[14] The ISO has not yet reserved deliverability for the offshore wind resources on the North Coast, because the ISO has not yet selected a sponsor for the transmission project that will deliver this resource. However, the ISO intends to reserve deliverability for this resource prior to the 2025 TPD Allocation study and the Cluster 16 interconnection request application window.

[15] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M557/K879/557879249.PDF

1.3 The Transmission Planning Process

The transmission plan's primary purpose is to identify, using the best available information at the time the Plan is prepared, needed transmission facilities based upon three main categories of transmission solutions: reliability, public policy, and economic needs. The ISO 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 ISO takes into account an array of considerations, with advancing the state's objectives of a cleaner future grid playing a major part in those considerations.

Reliability-driven needs:

The ISO 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, as well as the ISO's own transmission planning standards. The reliability studies, necessary to ensure such compliance comprise a foundational element of the transmission planning process. During the 2024-2025 planning cycle, ISO staff performed a comprehensive assessment of the ISO-controlled grid to verify compliance with applicable NERC reliability standards.[16] The ISO performed this analysis across a 15-year planning horizon and modeled a range of peak, off-peak, and partial-peak conditions. The ISO assessed the transmission facilities under ISO operational control, which range in voltage from 60 kV to 500 kV. The ISO 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 ISO 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.

Policy-driven needs:

Public policy-driven transmission solutions are those needed to enable the grid infrastructure to support local, 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. In the past, the focus of the goals was on the renewables portfolio standard (RPS) set out in various legislation. First, on the trajectory to achieving the 33% renewables portfolio standard set out in the state directive SBX1-2, and then, on the 60%

[16] 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.

renewables portfolio standard by 2030 objective in Senate Bill (SB) 100[17] that became law in September, 2018. More recently, the focus has shifted to the more aggressive 2030 greenhouse gas reduction targets established by the California Air Resources Board (CARB). This is also in coordination with the CPUC and CEC as directed by SB 350[18] that would also meet or exceed the renewables portfolio standard requirement and reasonably establish a trajectory to meeting 2045 RPS goals established in SB 100. Section 1.4 provides specific details.

Economic-driven needs:

Economic-driven solutions are those that provide net economic benefits to consumers as determined by ISO studies, which include 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 solutions to mitigate renewable integration challenges and potential reductions to the generation fleet located in local capacity areas.

Over the past four planning cycles, the ISO has programmatically studied the economic benefits of transmission and combinations of transmission upgrades and storage to reduce reliance on gas-fired generation in local capacity areas. In this 2024-2025 transmission planning study, the focus has been on specific economic study requests whether in or outside local capacity areas.

Comprehensive planning:

Although the ISO's planning process considers reliability, public policy, and economic projects sequentially, it allows the ISO to revisit projects identified in a prior stage of the process if an alternative project identified in a subsequent stage can meet the previously identified need and provide additional benefits not considered earlier in the process. Thus, the ISO's iterative planning process ultimately allows the ISO to consider and approve transmission projects with multiple benefit streams (e.g., reliability, public policy, and economic) and to modify or upsize transmission solutions identified in earlier stages to achieve additional benefits. For example, the ISO's transmission planning process does not allow earlier-identified reliability projects to reduce the benefits that potential economic projects might produce. That is because the ISO's sequential process allows it to "back out" of previously identified reliability projects inside the planning cycle and count the avoided cost of a separate reliability project as an economic benefit. This is an important distinction, as it is critical to avoid the misconception that a project

---

[17] SB 100, the 100% Clean Energy Act of 2018, 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% renewable resources target by December 31, 2026, and to achieve a 60% target by December 31, 2030. The bill also set out the state policy that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electricity to California end-use customers and 100% of electricity procured to serve all state agencies by December 31, 2045. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

[18] 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% below 1990 levels by 2030 and to 80% below 1990 levels by 2050. The law also established targets to increase retail sales of qualified renewable electricity to at least 50% by 2030 that have now been superseded by the provisions of Senate Bill 100.

must be supported by solely reliability benefits, *or* policy benefits, *or* economic benefits exclusively, *i.e*., the ISO does not approve projects through a siloed approach.

Consideration of Interregional Transmission Solutions:

A final step in the development of recommendations in each year's transmission plan is the consideration of potential interregional transmission solutions through a biennial process in place with the ISO's neighboring planning regions, WestConnect and NorthernGrid, pursuant to each party's coordinated processes established under FERC Order No. 1000. Through that process, each planning entity assesses if it has regional needs that an interregional project can meet more efficiently and cost-effectively, and if so, the cost allocation that would result based on each party's benefits. The actions taken by the ISO in each year's transmission planning cycle differ based on whether that planning cycle is the first or second year of the biennial coordination process. The 2024-2025 transmission planning cycle is the first year of the two-year interregional coordination planning cycle.

Other study efforts:

In addition to the consideration of reliability, policy-driven, and economic-driven needs and solutions, this year's transmission plan also considered:

1. Reliability Requirement for Resource Adequacy: Local Capacity Requirements and Resource Adequacy import capability. The 2024-2025 transmission planning cycle includes an additional long term Local Capacity Requirement Assessment which covers a 10-year and 15-year study, which is conducted every other year.
2. Long Term Congestion Revenue Rights (LT CRR) Simultaneous Feasibility Test Studies: Ensuring 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 ISO-controlled grid.
3. Frequency Response Assessment and Data Requirements: Assessing frequency response impact from increase in inverter-based resources (IBR) when unplanned system outages and events occur.

1.3.1 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 2024-2025 planning cycle began in January 2024 and concludes in May 2025.

1.3.1.1 Phase 1

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.

The unified planning assumptions establish a common set of assumptions for the reliability and other planning studies the ISO 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 ISO adds other pertinent information, including network upgrades and additions identified in studies conducted under the ISO's generation interconnection procedures and incorporated in executed generator interconnection agreements (GIA). In the unified planning assumptions, the ISO also specifies the public policy requirements and directives that it will consider in assessing the need for new transmission infrastructure.

Consistent with past transmission planning cycles and as discussed above in Section 1.2, development of the unified planning assumptions for this planning cycle continued to benefit from the ongoing coordination efforts between the CPUC, CEC, and ISO, building on the staff-level, inter-agency process alignment forum in place to improve infrastructure planning coordination within the three core processes:

- The CEC's long-term resource planning produced as part of SB 100-related activities and long-term forecasts of energy demand produced as part of its biennial Integrated Energy Policy Report (IEPR);
- The CPUC's biennial Integrated Resource Planning (IRP) proceedings; and
- The ISO's annual Transmission Planning Process (TPP).

The assumptions include demand, supply, and system infrastructure elements, including the renewables portfolios, and are discussed in more detail in Section 1.4.

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 each study's purpose, and lays out a schedule for the stakeholder process throughout the entire planning cycle. The ISO 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 ISO then selects high-priority studies from these requests and includes them in the study plan published at the end of Phase 1. The ISO may later modify the list of high-priority studies based on new information such as revised generation development assumptions and preliminary production cost simulation results.

1.3.1.2 Phase 2

In Phase 2, the ISO performs studies to identify solutions to meet the various needs that culminate in the annual comprehensive transmission plan. This phase takes approximately 14 months and ends with Board approval of the transmission plan. Thus, Phases 1 and 2 take 17 months to complete. Identifying non-transmission alternatives that the ISO 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.

In this phase, the ISO performs all necessary technical studies, conducts a series of stakeholder meetings and develops an annual comprehensive transmission plan for the ISO-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. Accordingly, the ISO conducts the several 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 ISO'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 ISO 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 ISO 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 in Generator Interconnection Procedures (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 an analysis of potential policy-driven solutions to identify those elements that should be approved as category 1 transmission elements,[19] which are 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.
- 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 restrictions on the use of coastal and estuarine waters for power

[19] Pursuant to the ISO tariff, 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.

plant cooling, which is commonly referred to as once-through cooling and AB 1318 legislative requirements for ISO 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.
- Consolidates the results of the above activities to formulate a final, annual comprehensive transmission plan that the ISO 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.

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 ISO transmission rates of those transmission projects included in the Plan that require Board approval.[20] As indicated above, the ISO 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 ISO will determine whether the category 2 solutions should be elevated to category 1 status, remain as category 2 projects for another cycle, or be removed from the transmission plan.

1.3.1.3 Phase 3

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 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 ISO tariff.

In addition, the ISO 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.

Phase 3 takes place after the Board approves the Plan if there are projects eligible for competitive solicitation. Projects eligible for competitive solicitation include regional transmission facilities (*i.e.*, transmission facilities 200 kV and above) except for regional transmission

[20] 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.

solutions that are upgrades to existing facilities. Transmission facilities below 200 kV are not subject to competitive solicitation unless they span more than two participating transmission owner service territories or extend from the ISO balancing authority area to another balancing authority area.

If the approved transmission plan includes regional transmission facilities eligible for competitive solicitation, the ISO will commence Phase 3 by opening a window for the entities to submit applications to compete to build and own such facilities. The ISO will then evaluate the proposals and, if there are multiple qualified project sponsors seeking to finance, build, and own the same facilities, the ISO 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 ISO will authorize that sponsor to move forward to project permitting and siting.

1.3.2 Interregional Transmission Coordination per FERC Order No. 1000

Following guiding principles largely developed through coordination activities, the ISO along with the other Western Planning Regions[21] participates in and advances 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 are is achieved in a manner consistent with expectations of FERC Order No. 1000. The guiding principles are documented in the ISO's Transmission Planning Business Practice Manual, as well as in comparable documents of the other Western Planning Regions.

The 2024-2025 transmission planning cycle is the first year of the two-year interregional coordination planning process that the ISO conducts with its neighboring planning regions WestConnect and NorthernGrid. Accordingly, the Western Planning Regions initiated a new biennial Interregional Transmission coordination cycle beginning in January 2024. The ISO hosted its submission period in the first quarter of 2024 in which proponents were able to request evaluation of an interregional transmission project. The submission period began on January 1 and closed March 31, 2024 with five interregional transmission projects being submitted to the ISO. The Western Planning Regions held Interregional Coordination Meeting(s) on March 26, 2024, June 21, 2024, and March 26, 2025 to provide all stakeholders an opportunity to engage with the Western Planning Regions on interregional related topics.[22] This process and results of the evaluations conducted with the other relevant planning regions, NorthernGrid and WestConnect, are set out in Chapter 5.

FERC Orders 1920/1920A will require changes and add new considerations to regional transmission planning and interregional transmission coordination.

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

[22] Documents related to the 2018-2019 interregional transmission coordination meetings are available on the ISO website athttp://www.caiso.com/planning/Pages/InterregionalTransmissionCoordination/default.aspx

1.4 Additional Transmission Plan Influences

In addition to the key study plan inputs described above, the ISO must address a range of considerations in its planning process that shift in content and priority over the years to ensure overall safe, reliable, and efficient operation and develop effective solutions to emerging challenges.

This section discusses a number of the issues and other actions that the ISO took into account in preparing the 2024-2025 Plan.

1.4.1 Grid-Enhancing Technologies (GETs)

GETs encompass a range of technologies with specific benefits and opportunities. Currently, the term is used to describe:

- Advanced conductors – high temperature, low sag characteristics
- Dynamic line ratings
- Power Flow Controllers
- Topology Optimizations

The ISO supports appropriate application and deployment of these technologies, and has considered them on a case by case basis as potential alternatives in past annual transmission planning processes.

The ISO typically considers advanced conductors and power flow controllers as planning tools providing an alternative to other capital expenditures. We also consider dynamic thermal line ratings and topology optimizations in accessing operational benefits through additional capacity providing economic or emergency measure uses.

> The ISO leads the transmission expansion planning and interconnection process for systems in its footprint. Transmission owners are responsible for capital maintenance programs on the transmission system – including "like for like" replacement that may involve incidental capacity increases. They are also responsible for all planning and maintenance on sub-transmission systems that are classed as distribution and are not under ISO operational control.

In the ISO's transmission planning processes, we have considered both advanced conductors and flow controllers in a number of applications. Flow controllers have to date been more successful. Examples include the Imperial Valley phase shifting transformer, HVDC flow control via two projects under development in San Jose, multiple uses of reactors and Smart Wires technology, multiple uses of statcoms, static VAR compensators, synchronous condensers, and series capacitors.

Advanced conductors have been studied in certain applications and the ISO has recently approved the first transmission planning application in the 2022-2023 transmission planning process. While the ISO will continue to consider advanced conductors and seek their appropriate applications, it is important to highlight some considerations in addition to costs:

- Reconductoring often requires taking circuits out of service to conduct the work. This presents additional challenges when transmission constraints already exist, or suggests live-line work.
- While some conductors show lower line loss savings when run at the same level of loading as the existing ACSR, the losses climb exponentially as the loading continues to increase.

Advanced conductors have been selected by transmission owners to address particular challenges, such as the use by Southern California Edison (SCE) to address clearance issues – with minimal tower modifications – on the Big Creek-Ventura 220 kV network. (The ISO then approved terminal improvements to access the incidental incremental capacity). Other uses have apparently been made, especially in select urban areas, where the higher tension capabilities and low sag characteristics allowed lower towers to be employed without having to shorten spacing between towers.

The ISO will continue to evaluate and consider opportunities for GETs in the annual transmission planning process. This is now required under FERC Orders No. 1920 and 1920-A. In addition, FERC Order No. 2023 requires transmission providers to consider opportunities to deploy GETs in the resource interconnection process.

1.4.2 Non-Transmission Alternatives and Storage

Since implementing the current comprehensive transmission planning process in 2010, the ISO has considered and placed a great deal of emphasis on assessing non-transmission alternatives, including conventional generation, preferred resources (*e.g.*, energy efficiency, demand response, renewable generating resources), and market-based energy storage solutions as a means to meet local transmission system needs. As stated earlier, the ISO cannot specifically approve non-transmission alternatives as projects or elements in the comprehensive transmission plan but 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. As the volumes of renewable generation and storage required to meet system needs have escalated rapidly in recent years, the challenge has shifted from seeking to support resources that may not otherwise develop, to testing the effectiveness of preferred resources to meeting the local needs and encouraging system capacity resources be procured in optimal locations.

The methodology used for assessing the effectiveness of local preferred resources is based on the initial methodology issued on September 4, 2013,[23] as part of the 2013-2014 transmission planning cycle to support California's policy emphasizing use of preferred resources[24] — energy efficiency, demand response, renewable generating resources, and energy storage — that was further advanced and refined through the development of the Moorpark Sub-area Local

[23] "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

[24] 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.

Capacity Alternative Study released on August 16, 2017.[25] Storage also played a major role in consideration of preferred resource alternatives in LA Basin studies as well as the Oakland Clean-Energy Initiative approved in the 2017-2018 Transmission Plan and modified in the 2018-2019 Plan. These efforts help scope and frame the necessary characteristics and attributes of preferred resources in considering them as potential alternatives to meeting identified needs.

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 Plan also identifies areas where future reinforcement may be necessary but immediate action is not required. The ISO has also expanded the scope of the biennial 10-year local capacity technical requirements study to provide additional information on the characteristics which define needs in the areas and sub-areas. The ISO 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.

Once preferred resources – and storage in particular – have been identified as the best solution taking into account overall cost effectiveness and technical requirements, coordination with the CPUC and other local regulatory authorities is needed to achieve procurement of the resources.

The dispersion of procurement responsibility across a steadily increasing number of load-serving entities has increased the complexity and concerns regarding the efficacy of relying on market-based resources which have been procured for system needs targeted in specific areas to also meet local needs. It appears the Central Procurement Entities (CPEs) may play a larger role in acquiring these resources. Further, the CPEs can now contract with resources for five years or less that shall be deemed reasonable and preapproved if certain conditions are met, and can contract for longer than five years subject to filing a Tier 3 Advice Letter for approval, as set out in CPUC Decision (D.) 22-03-034.

Accordingly, the ISO is continuing to follow its current approach to meet local needs with storage where possible, but is concerned with the progress made on resources being acquired to meet previously-identified needs.

Energy storage solutions can be a transmission resource or a non-transmission alternative (*e.g.*, market-based). The ISO has considered storage in both contexts in the transmission planning process, although market-based approaches have generally prevailed due to their ability to also participate in the electricity market.

Other Use-limited resources, including demand response:

The ISO 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.

[25] *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.

In 2019, the ISO vetted the market processes it will use to dispatch slow demand response resources on a pre-contingency basis.[26] This work was founded on the analysis of the necessary characteristics for "slow response" demand response programs that was undertaken initially through special study work in the 2016-2017 Transmission Plan, which continued into 2017 through a joint stakeholder process with the CPUC.[27]

This work has helped guide the approach the ISO 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.

1.4.3 System Modeling, Performance, and Assessments

The grid is 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 constant managing of thermal, stability, and voltage limits across a broader range of operating conditions.

This has in turn led to the need for greater accuracy in planning studies at the same time the challenges are compounded by the complexity of the settings in Inverter Based Resource models. The ISO's study work, built off the initial special study initiative undertaken in the 2016-2017 planning cycle, found and reaffirmed year after year the practical need to improve generator model accuracy in addition to ensuring compliance with NERC mandatory standards. The ISO has made significant progress in establishing and implementing a more comprehensive framework for the collection of accurate generator model data through the process developed and set out in Section 10 of the ISO's Transmission Planning Process – Business Practice Manual. This established a schedule for validating models, and the ISO will be continuing with its efforts, in coordination with Participating Transmission Owners, to collect this important information and ensure generation owners provide validated models.

1.5 ISO Processes coordinated with the Transmission Plan

The ISO coordinates the transmission planning process with several other ISO processes in addition to the generator interconnection procedures discussed in section 1.1.

1.5.1 Distributed Generation (DG) Deliverability

The ISO 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 ISO completed the first cycle of the new process in 2013 in

[26] 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

[27] 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

time to qualify additional distributed generation resources to provide RA capacity for the 2014 RA compliance year.

The ISO annually performs two sequential steps. The first step is a deliverability study, which the ISO 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 ISO-controlled grid — who then assign deliverability status, in accordance with ISO 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 ISO performs a DG deliverability study to identify available transmission capacity at specific grid nodes to support deliverability status for distributed generation resources. This is done without requiring any additional delivery network upgrades to the ISO-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 ISO 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. This is done 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. It also 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 ISO 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 ISO 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 ISO 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.

1.5.2 Critical Energy Infrastructure Information (CEII)

The ISO protects CEII as set out in the ISO's tariff.[28] Release of this information is governed by tariff requirements. In previous transmission planning cycles, the ISO has determined — out of an abundance of caution on this sensitive area — that additional measures should be taken to protect CEII information. Accordingly, the ISO has placed more sensitive detailed discussions of system needs into appendices that are not released through the ISO's public website. Rather, this information can be accessed only through the ISO's market participant portal after the appropriate nondisclosure agreements are executed.

1.5.3 Planning Coordinator Footprint

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

The ISO had initially developed its interpretation of its planning authority/planning coordinator area in 2014 based on its operational control of its participating transmission owner assets. This was done partly in response to a broader WECC initiative to clarify planning coordinator areas and responsibilities, and the ISO documented its interpretation in a technical bulletin.[29]

Beginning in 2015, the ISO reached out to several "adjacent systems" that are inside the ISO's balancing authority area and were confirmed transmission owners, but which did not appear to be registered as a planning coordinator. The ISO did this to determine whether these adjacent systems had a planning coordinator out of concern for overall system reliability and, if they did not have one, offered to provide planning coordinator services through a fee-based planning coordinator services agreement. Unlike the requirements for the ISO's participating transmission owners who have placed their facilities under the ISO's operational control, the ISO is not responsible for planning and approving mitigations to identified reliability issues under the planning coordinator services agreement – but is only responsible for 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 ISO's FERC-approved tariff governing transmission planning activities for facilities placed under ISO operational control. As such, the results are documented separately, and do not form part of this transmission plan.

In addition to the entities discussed above, the ISO provides planning coordinator services under a separate agreement to Southern California Edison for a subset of its facilities that are

[28] 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.

[29] Technical Bulletin – "California ISO Planning Coordinator Area Definition" (created August 4, 2014, last revised July 28, 2016 to update URL for Appendix 2).

not under ISO operational control but which were found to be Bulk Electric System facilities as defined by NERC.

Considering the entirety of the ISO-controlled grid, the ISO is not anticipating a need to offer these services to other parties as the ISO is not aware of other systems inside the boundaries of the ISO's planning coordinator footprint requiring these services.

1.6 Additional Policy Considerations

The ISO considers a number of social, economic, and policy-related drivers in the transmission planning process, and will continue to adapt to the policy landscape in future processes. This section provides additional context for the 2024-2025 transmission planning process as well as emerging policy issues that are being considered now and will influence future plans. Appendix K also lists infrastructure-related submissions to the 2024 stakeholder policy catalog, with ISO responses to each submission.

1.6.1 FERC Orders No. 1920 and 1920-A

FERC Orders No. 1920 and 1920-A require longer-term transmission planning with consideration of specific scenarios, as well as increased engagement with Tribal, state, and local governments. While the ISO already complies with the bulk of the intent of the Orders, the ISO intends to comply with the specific requirements as well, which will result in some changes to ISO's current 15-month annual transmission planning process. In compliance with the Order, the ISO has initiated a six-month engagement with relevant state entities to discuss the current regional transmission cost allocation methodology, and does not at this time propose changes to the methodology.

While the ISO is not anticipating any changes to the regional transmission cost allocation methodology, significant changes to the transmission planning process and timeline will be necessary. Further, the ISO will continue close coordination with its neighboring planning regions, WestConnect and NorthernGrid, to align on interregional transmission planning studies and timelines. On February 11, 2025, the Committee on Regional Electric Power Cooperation's (CREPC) 1920 Ad Hoc Committee submitted a joint motion for an extension of (1) the State Engagement Period and (2) the deadline for the FERC-jurisdictional transmission providers to submit their compliance plans for both the NorthernGrid and WestConnect transmission planning regions.[30]

In light of the need for continued and increased interregional coordination, the ISO on March 12, 2025 filed a request to extend its compliance deadline by six months, with the intention of ongoing discussion with the planning regions in development of complementary compliance plans.

The ISO convened one stakeholder meeting on March 13, 2025 to update stakeholders on compliance plans and related issues, and will continue apprise stakeholders of new developments as the compliance filing deadline approaches.

[30] https://www.caiso.com/documents/mar-12-2025-motion-for-extension-of-time-to-submit-compliance-filings-order-no-1920-rm21-17.pdf

1.6.2 Engagement with Tribes

The ISO recognizes that Tribes seek more meaningful and ongoing engagement in the transmission planning process. The ISO will seek feedback from Tribes on how best to ensure awareness and open communication during the transmission planning process. Further, FERC Order No. 1920 requires the ISO to consider federally-recognized Tribal laws and regulations affecting resource mix and demand, regulations on decarbonization and electrification, and policy goals that affect Long-Term Transmission Needs. The ISO is an independent, non-profit, public benefit corporation, and not a government agency; therefore, the ISO does not engage as a government representative in any government-to-government consultation with Tribes. However, the ISO will establish a Tribal engagement policy that enables more open and transparent communication with Tribes as we consider future transmission approvals.

1.6.3 West-wide Transmission Planning

Given the need for increased regional diversity in resource portfolios needed to achieve reliability and policy goals at lowest cost, the ISO will continue to participate in West-wide regional transmission planning discussions. These discussions can occur under the FERC Order No. 1000 interregional transmission planning process, however, the ISO has had more success approving multistate transmission projects through the negotiated agreement option, which allows for voluntary agreements between states and transmission providers to plan and pay for transmission facilities outside of the Order No. 1000 process.

Delivery of energy from out-of-state resources to the ISO balancing authority area will require development of long-distance transmission infrastructure to deliver power across multiple states and balancing authority areas. The ISO developed the subscriber participating transmission owner (sPTO) model to enable efficient and cost-effective delivery of generation from areas outside of the ISO’s balancing area without increasing the transmission access charge. Once in service, these transmission facilities will be placed under the ISO’s operational control.

The ISO is also participating in the Western Transmission Expansion Coalition, a West-wide effort to develop an actionable transmission study to support the needs of the future energy grid. The final deliverable will be a West-wide transmission needs study looking out over 10- and 20-year periods.

1.6.4 Planning for Large Loads

Within the ISO footprint, large load interconnections have been relatively infrequent compared to other regions. Based on input from utilities and the CEC, the ISO expects both the volume and nature of large load interconnections to increase substantially in the near future due to a variety of factors, including datacenter proliferation, the potential for hydrogen production facilities, and electrification of the building and transportation sectors. In order to inform and continuously improve planning and operations, the ISO is considering the technical complexities associated with large inverter-based loads and the issue of the potential for co-location of existing or new generation with large loads. While primary responsibility for managing new load interconnections to the transmission system rests with the utilities, the ISO will be reviewing its practices as well as the potential need for overarching reliability standards or interconnection requirements that may be needed more broadly.

1.6.5 Transmission Project Execution and Completion

As the demand for new generation continues to increase, the ISO is focused on ensuring timely completion of transmission projects and network upgrades needed to serve load and alleviate congestion. The ISO, in coordination with the CPUC and the participating transmission owners, initiated the Transmission Development Forum in January 2022. The purpose of the Transmission Development Forum is to create a single forum to track the status of transmission network upgrade projects that affect generators and all other transmission projects approved in the ISO's transmission planning process. In 2022 and 2023, the Transmission Development Forum was held quarterly. Starting in 2024, the transmission development forum schedule shifted to twice a year, with stakeholder calls held in January and July. This schedule change enables coordination with the CPUC's Transmission Project Review Process, initiated on January 1, 2024, as a part of the Commission's Resolution E-5252.[31]

The ISO also participates in the Tracking Energy Development (TED) Task Force, a joint effort of staff at the CPUC, CEC, GO-Biz, and the ISO to track new energy projects under development. The TED Task Force is focused on identifying barriers and coordinating action to address barriers that may impact energy development throughout the State. The TED Task Force can potentially provide project development support, as appropriate, in particular with issues related to government involvement in energy development.

The ISO's transmission planning process reflects the need for new generation and storage resources identified by local regulatory authorities to satisfy reliability needs and achieve policy requirements at lowest cost. The ISO is committed to developing cost-effective transmission solutions to deliver generation and storage resources to load, but also acknowledges that transmission owner access to capital is critical to timely infrastructure development. The ISO is open to exploration of alternative financing models that complement the current process for planning and approving transmission projects. Currently, no prohibition of alternative financing exists

1.6.6 Assignment of Re-scoped, Previously Approved Transmission Projects

The ISO is considering adding clarity in the Transmission Planning Business Practice Manual on the considerations it takes into account in deciding whether to cancel a project and re-bid an alternative, negotiate a modification to an awarded project, or take some other action when modifications are needed to a competitively awarded project.

The ISO's planning authority allows the ISO to change or cancel a previously approved project, through its open and transparent planning process, culminating in approval by the Board of Governors. These reviews are conducted on a case-by-case basis when the ISO or stakeholders identify a material change in circumstance. Once the Board of Governors approves a changes in scope, ISO management is responsible for implementing the change by

[31] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/transmission-project-review-process

notifying the incumbent participating transmission owner for projects that were not competitively awarded, or projects that were competitively awarded, canceling the original project and re-bidding the alternative or negotiating a change in scope with the existing approved project sponsor. The ISO has recently had to make material changes to the scope of two competitively awarded projects in the San Jose area. While the ISO has occasionally had to cancel competitively awarded projects in the past, this was the first occurrence of needing to modify, but continue with, a competitively awarded project. Stakeholders asked for clarity as to how the ISO will decide to amend a competitively awarded project's scope versus canceling the project and re-bidding an alternative in the future

Including such clarity in the tariff appears too rigid and inflexible given the "guidance" nature of the considerations. The ISO is consulting on this issue in parallel with FERC Order No. 1920/1920A consultations, but any tariff changes would require a separate Section 205 application, as this is not a FERC Order 1920/1920-A compliance issue.

1.6.7 Grid-enhancing technologies and non-wires solutions

Stakeholders have suggested that establish a framework to integrate Grid-Enhancing Technologies (GETs) into the transmission planning process and transmission operations, noting the significant benefits of GETs in reducing congestion and curtailment, mitigating constraints, enhancing traditional transmission upgrades, and serving as alternatives to traditional upgrades in the transmission or interconnection process.

As noted previously, the ISO supports appropriate application and deployment of these technologies, and will continue to evaluate and consider opportunities for GETs in the annual transmission planning process as we have done for several years. This consideration is now required under FERC Orders No. 1920 and 1920-A. In addition, FERC Order No. 2023 requires transmission providers to consider opportunities to deploy GETs in the resource interconnection process. The California also passed legislation related to GETs in 2024, described further below.

1.6.8 Relevant State Legislation

The ISO is also aware of several pieces of California legislation related to infrastructure development, and is committed to coordination with relevant entities in fulfillment of these responsibilities.

- Assembly Bill 2779 (Petrie-Norris, 2024) requires the ISO to provide an update to the PUC and Legislature after each new Transmission Plan that outlines the new GETs approved and how they would save on costs and/or additional transmission buildout.
- Senate Bill 1006 (Padilla, 2024) requires the IOUs to evaluate their lines and submit a plan for GETs integration into the ISO's annual transmission planning process, beginning in 2026.
- AB 3264 (Petrie-Norris, 2024) requires the CPUC, in consultation with the ISO, CEC, and the California Infrastructure and Economic Development Bank, by July 1, 2025, to

submit to the Governor and the Legislature a study identifying proposals to reduce the cost to ratepayers of expanding the state's electrical transmission grid as necessary to achieve the state's goals, to meet the state's requirements, and to reduce the emissions of greenhouse gases.

- AB 1373 (Garcia, 2023) Accelerates permitting for electric transmission projects that have been identified as needed by the ISO by establishing a rebuttable presumption in CPUC proceedings evaluating the issuance of a certificate of public convenience and necessity for proposed transmission projects. The rebuttable presumption would be in favor of an ISO governing board-approved need evaluation, if certain criteria is satisfied.
- Senate Bill 887 (Becker, 2022) provides state policy direction on a number of resource planning and transmission planning issues, including direction to the CPUC and CEC regarding inputs to be provided to the ISO in future planning cycles. The bill also provides direction about requests the CPUC is to make of the ISO in the process of conducting its FERC tariff-based planning processes in this and future planning cycles.
- Other legislation: In addition to the enacted legislation summarized above, the ISO will consult with state agencies on a number of reports and projects related to infrastructure development and California's generation resource portfolio.

Chapter 2

2 Reliability Assessment

2.1 Overview of the ISO Reliability Assessment

The ISO conducts its annual reliability assessment to identify facilities that demonstrate a potential of not meeting the applicable reliability performance requirements and identifies needed reliability solutions to ensure transmission system performance complies with all North American Electric Reliability Corporation (NERC) standards, Western Electricity Coordinating Council (WECC) regional criteria, and ISO transmission planning standards. These requirements are set out in Section B2.2 of Appendix B. The reliability studies necessary to ensure such compliance comprise a foundational element of the transmission planning process. During the 2024-2025 planning cycle, the ISO staff performed a comprehensive assessment of the ISO-controlled grid to verify compliance with applicable reliability standards. The ISO performed this analysis across a 15-year planning horizon and modeled a range of peak, off-peak, and partial-peak conditions.

This study is part of the annual transmission planning process and performed in accordance with Section 24 of the ISO tariff and as defined in the Business Process Manual (BPM) for the Transmission Planning Process.

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

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

The WECC full-loop power flow base cases provide the foundation for the study. The detailed assumptions, methodologies and reliability assessment results are provided in Appendix B and Appendix C.

In addition, the ISO has incorporated into this study process a review of short-circuit studies conducted by the transmission owners to proactively identify and address potential fault level issues affecting future resource additions.

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

2.2 Reliability Standards Compliance Criteria

The 2024-2025 transmission plan spans a 15-year planning horizon[32] and, as stated earlier, was conducted to ensure the ISO-controlled grid is in compliance with NERC standards, WECC regional criteria, and ISO planning standards across the 2024-2039 planning horizon. Sections B1.2.1 through B1.2.4 in Appendix B describe how these planning standards were applied for the studies of the 2024-2025 transmission planning process.

2.3 Study Assumptions

In Phase 1 of the ISO annual transmission planning process, the ISO develops the Unified Planning Assumptions and Study Plan[33] for this planning cycle. The study assumptions and methodologies are included in Section B.1.3 of Appendix B. The following sections summarize the study assumptions used for the reliability assessment.

2.3.1 Load and Resource Assumptions

The ISO's annual transmission planning process reliability assessment uses as inputs assumptions developed by the California Energy Commission's (CEC) energy demand forecast and the California Public Utilities Commission's (CPUC) base portfolio developed through the CPUC's integrated resource plan. As described in Section 1.2, the reliability analysis is based on the CEC's 2023 IEPR[34] and the base portfolio provided to the ISO via CPUC Decision (D) 24-02-047[35] issued on February 15, 2024.

Table 2.3-1 provides the non-coincident load for each of the planning areas in the PG&E, SCE, SDG&E and VEA planning areas.

[32] CEC 2023 IEPR forecast and CPUC portfolios go out to 2040 and 2039 respectively

[33] https://stakeholdercenter.caiso.com/InitiativeDocuments/Final-Study-Plan-2024-2025-Transmission-Planning-Process.pdf

[34] The CEC adopted the 2023 IEPR Energy Demand Forecast, 2023-2040 on February 14, 2024 https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2023-integrated-energy-policy-report

[35] CPUC Decision 23-02-040 issued on February 15, 2024 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M525/K918/525918033.PDF

Table 2.3-1: Non-Coincident Load[36] Forecast for Planning Areas

PTO	Planning Area	2026	2029	2034	2039
PG&E	Humboldt	153	169	211	N/A
	North Coast & North Bay	1472	1599	2058	N/A
	North Valley	877	920	1038	N/A
	Central Valley	4119	4310	5244	N/A
	Greater Bay Area	9475	10459	12641	18195
	Greater Fresno	3603	3646	4117	N/A
	Kern	1977	2047	2216	N/A
	Central Coast & Los Padres	1293	1616	1858	N/A
SCE	Tehachapi and Big Creek Corridor	2508	2374	2411	N/A
	North of Lugo area	1386	966	904	N/A
	Eastern	5009	4814	4359	N/A
	Main	25265	25643	27929	30751
SDG&E	SDG&E	4807	4967	5420	5891
VEA	VEA	170	182	198	213

2.3.2 Study Horizon and Years

The studies that comply with TPL-001-5 were conducted for both the near-term[37] (2026-2029) and longer-term[38] (2030-2034) per the requirements of the reliability standards.

Within the identified near and longer term study horizons, the ISO conducted detailed analysis for years 2026, 2029, 2034, and 2039.

2.4 Reliability Studies

In Phase 2 of the annual transmission planning process, the reliability assessment is conducted based upon the Unified Planning Assumptions and Study Plan that were developed as a part of Phase 1 of the planning process. The preliminary reliability results were posted on the ISO webpage and with this posting the Request Window opens for the participating transmission owner to submit potential alternatives to address identified reliability constraints by September 15 and for all other stakeholders to submit their potential mitigation alternatives by October 15. In addition, the ISO held a stakeholder meeting to present the reliability results and for the participating transmission owners to present the potential alternatives that they submitted into the Request Window. The Request Window submissions have been posted on the ISO Market Participant Portal and a list of the submissions is provided in Appendix D. The detailed reliability contingency analysis is provided in Appendix C.

The ISO then conducts its reliability assessment, including technical and economic evaluations of the alternatives identified by the ISO or stakeholders, to select the most effective and efficient

[36] The loads reflect the peak forecast load for the planning area, the load of the area at the time of the PTO area peak load.

[37] 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.

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

recommendation. Details of the reliability studies, request window submission assessments and mitigation assessments are provided in Appendix B.

2.5 Reliability-Projects Needed

The reliability-driven projects that have been identified as needed to mitigate reliability constraints identified in Appendix C are presented below. The comprehensive and detailed technical and economic evaluation of the constraints and the alternatives the ISO considered in selecting the recommended reliability-driven projects are set out in Appendix B.

In total, the reliability assessment has identified 28 new reliability-driven projects required in this transmission planning cycle for a total estimated cost of $4.6 billion. Management Approved Projects

2.5.1 Management Approved Projects

The reliability-driven projects within this section were identified as being needed in the reliability assessment with an estimated cost of less than $50 million and were presented to stakeholders as being recommended for management approval at the November 13, 2024 stakeholder meeting. Based on comments received and no objection raised at the following ISO Board of Governors meeting on December 19, 2024, ISO Management approved the transmission projects and informed the respective participating transmission owners of those approvals.

Pittsburg-Kirker 115 kV Line Section Limiting Elements Upgrade Project

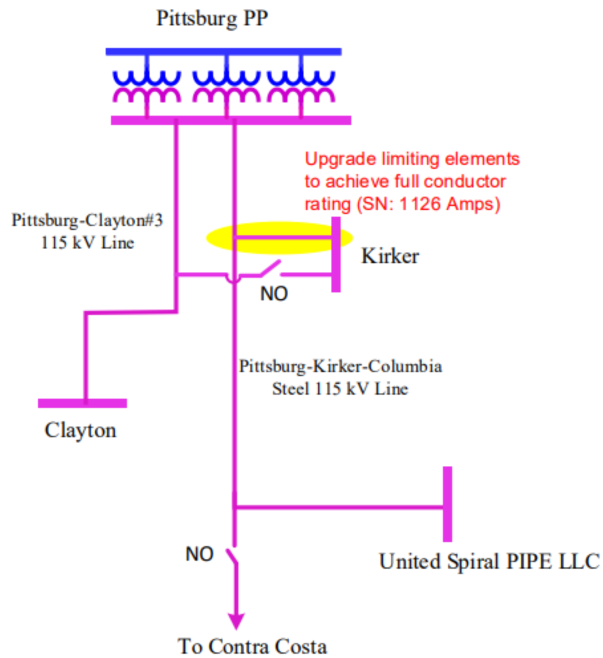
The Kirker 115 kV substation, located in Contra Costa County, serves over 27,000 transmission customers. Its primary power feed comes from the Pittsburg-Kirker-Columbia Steel 115 kV Line, and it has a backup feed from the Pittsburg-Clayton #3 115 kV Line.

The Kirker substation is currently experiencing a rapid increase in load due to factors such as electric vehicle charging (EV), electrification, commercial growth, and mixed-use and residential loads. Typically, the highest electric demand occurs during the summer months, with a projected peak of approximately 104.7 MW expected in 2026, and a projected annual growth rate of 2.4 MW per year.

This project aims to protect against NERC Category P0 normal overloads, and to increase load serving capability and customer reliability. The most severe normal overload is estimated to reach 108% of its summer normal rating by 2034 in the Pittsburg-Kirker 115 kV section, which spans about 1.5 miles.

The project scope is to upgrade any limiting elements on the Pittsburg-Kirker-Columbia Steel 115 kV Line for the section from Pittsburg to Kirker Substation to achieve the full conductor rating of 1126 Amps of summer normal rating. The estimated cost for this project is $100K - $200K with an expected in-service date of May 2028.

Figure 2.5-1: Pittsburg-Kirker 115 kV Line Section Limiting Elements Upgrade Project



The ISO evaluated other alternatives to solve the reliability concerns, which proved to be ineffective or infeasible. Further details are presented in section B.3.5 of Appendix B.

Sobrante 230 kV Bus Upgrade Project

The Sobrante Substation in Contra Costa County is part of the Pacific Gas and Electric's Diablo Division. Sobrante 230 kV Substation has four 230 kV transmission lines and two 230/115 kV transformer banks. The third 230/115 kV transformer bank was approved in the 2023-2024ISO Transmission Planning Process (TPP) with the expected in-service year of 2034. The Sobrante 230 kV Bus is a double bus, single breaker design and currently has only one section.

This project protects against NERC Category P2 contingency that involves the loss of the bus tie breaker at Sobrante 230 kV Bus. This P2 contingency results in the opening of all the circuit breakers on the Sobrante 230 kV Bus 1 and 2 to isolate the faulted breaker.

Sobrante substation is the main source for serving the load at Tidewater, Tesoro, Christie, El Cerrito, Richmond, Standard Oil, San Pablo, Grizzly, and Hillside Substations. With the P2 contingency taking out the entire Sobrante 230 kV substations, most of the load will need to be served from the Moraga source which leads to overloads on Sobrante-Moraga, Moraga-Claremont#1 and #2 115 kV lines.

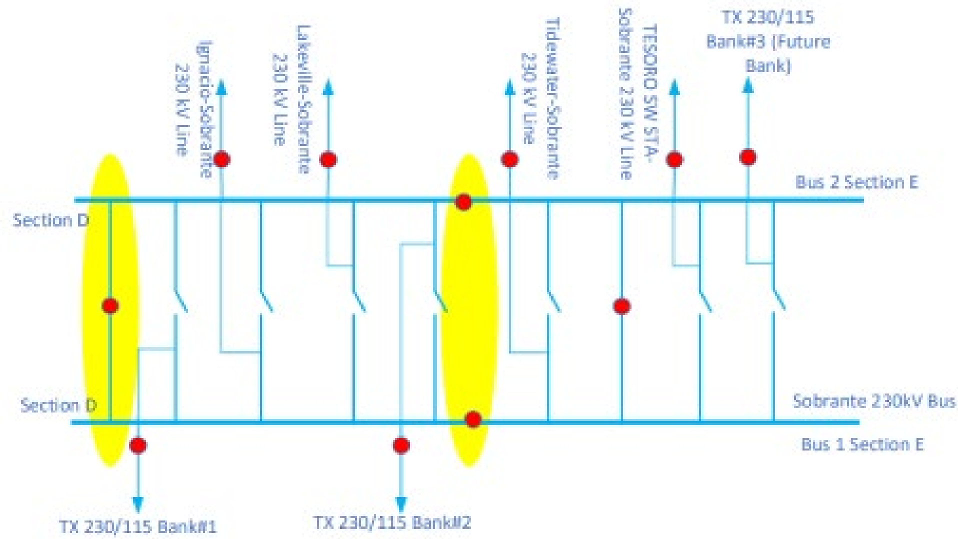
Project scope includes the following:

- Expand the Sobrante 230 kV bus and split it into two sections, section D and section E by adding two sectionalizing breakers and one bus-tie breaker. Terminals for the future Sobrante 230/115 kV transformer bank #3, Tesoro SW STA-Sobrante 230 kV Line and Tidewater-Sobrante 230 kV Line will be connected to the section E. Terminals for

Lakeville-Sobrante 230 kV Line, Ignacio-Sobrante 230 kV Line and 230/115 kV Transformer bank #1 & #2 will be connected to section D; and

- Upgrade protection systems as needed.

Figure 2.5-2: Sobrante 230 kV Bus Upgrade Project



The project has an estimated cost of $7.5 million to $15 million with an expected in-service date of May 2033. The ISO evaluated other alternatives to solve the reliability concerns, but they proved to be ineffective or unfeasible mitigation solutions. Further details are presented in section B.3.5 *of Appendix B.*

Jefferson-Stanford 60 kV Line Reconductoring Project

The Jefferson-Stanford 60 kV line is in the Peninsula, Menlo area. Powered by the PG&E Jefferson Substation, the 60 kV line normally serves Emerald Lake Substation customers and Stanford University. Stanford is the largest load customer with recorded summer peak demand ranging from 43 MW to 52 MW from 2021 to 2024. Built with overhead conductors and underground cables, the Jefferson-Stanford 60 kV line has an underground section between Menlo Substation and SLAC 60 kV Tap. This section, approximately 0.9 miles in length, is conductored with an 800 kcmil AL cable with a normal capacity of 580 Amps or 60.27 MVA. A recent underground cable rating study using line loading data resulted in a cable capacity derate to 525 Amps or 54 MVA.

Power flow analysis indicates this underground cable section could experience 105% normal overload in 2026 with the regular Stanford load and the mentioned derate on the underground section.

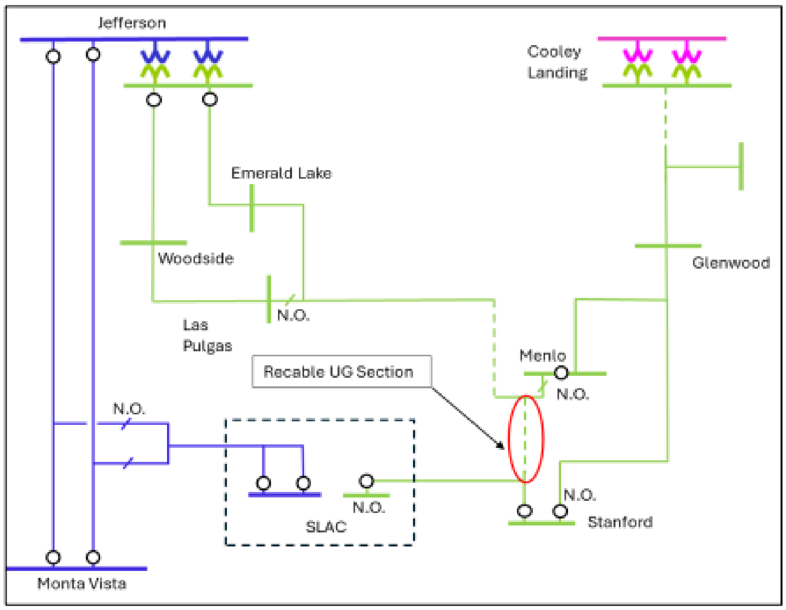
Project scope includes the following:

- Install temporary overhead shoo-fly transmission line to bypass existing underground cable section between Menlo Substation and SLAC 60 kV Tap for continuous electric customer service;

- Replace 0.9 mile of existing 800 kcmil AL underground cable with larger size cable of at least 1000 Amps capacity at normal conditions; and
- Upgrade limiting electrical equipment as necessary to achieve full cable capacity.

This project has an estimated cost of $20 million - $40 million with an expected in-service date of May 2029. Preliminary assessment suggests cable replacement could be achieved using existing PG&E Right of Ways with minor Right of Way acquisitions.

Figure 2.5-3: Jefferson-Stanford 60 kV Line Reconductoring Project



The ISO evaluated other alternatives to solve the reliability concerns, but they proved to be ineffective or unfeasible mitigation solutions. Further details are presented in section B.3.5 of Appendix B.

Moraga 230/115 kV Transformer Bank Addition Project

The Moraga Substation in Contra Costa County is part of the Pacific Gas and Electric's Diablo Division. Moraga Substation has three 230/115 kV transformers, critical for serving customer loads within the East Bay Area including the cities of Oakland, Alameda, and San Leandro. The Oakland area is experiencing rapid load increase due to industrial and commercial growth and the rise in the EV Charging and Electrification loads.

Power flow studies show that after losing any two of the three Moraga 230/115 kV transformers, most of the load in the East Bay Area will be served through the remaining Moraga 230/115 kV transformer. The most severe P6 contingency will lead to the loading of Moraga 230/115 kV transformers up to 118% of their summer emergency rating for the 2034 summer peak.

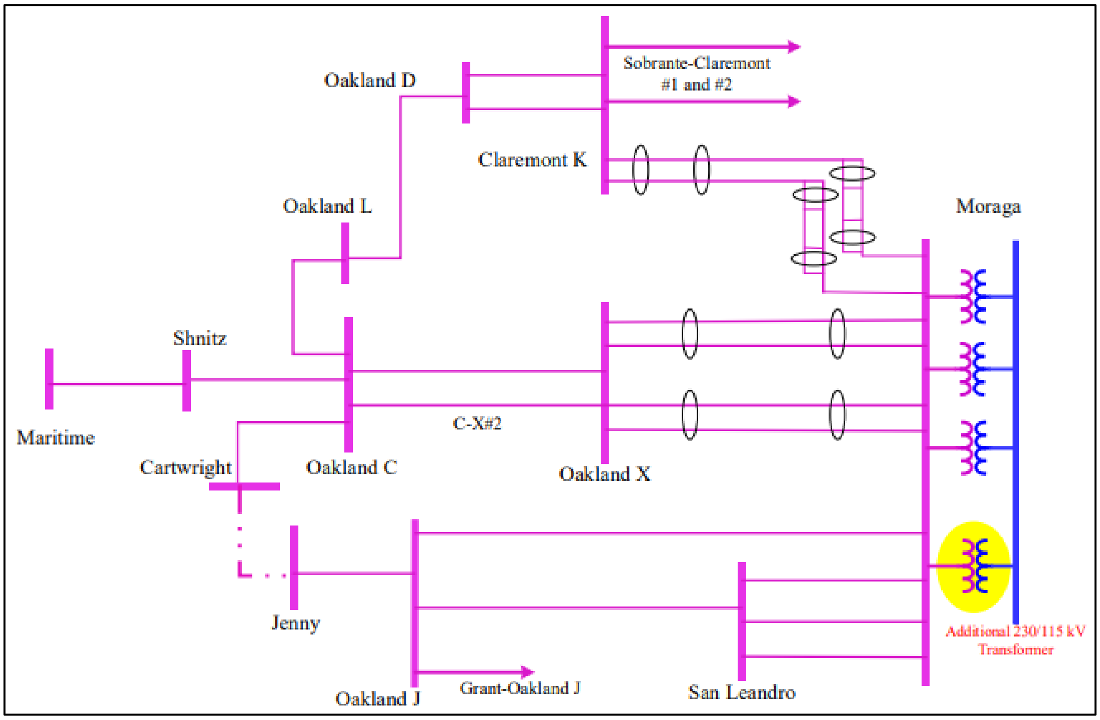
This project protects against NERC TPL-001-5 Category P2 and P6 violations and will establish Moraga Substation as a stronger source for serving the East Bay Area and providing sufficient transmission capacity to meet the future local demand. It will also increase operating flexibility and customer reliability.

The project scope includes:

- Install a new 230/115 kV transformer bank at Moraga Substation with minimum 420 MVA for the summer normal rating and 462 MVA for summer emergency rating; and
- Upgrade Moraga 115 kV bus and any limiting elements to achieve full bank capacity.

This project has a cost estimate of $20 million - $40 million with an expected in-service date of May 2031.

Figure 2.5-4: Moraga 230/115 kV Transformer Bank Addition Project



The ISO evaluated other alternatives to solve the reliability concerns, which proved to be ineffective or infeasible. Further details are presented in section B.3.5 of Appendix B.

Konocti-Eagle Rock 60 kV Reconductoring Project

The Konocti-Eagle Rock 60 kV line is part of the Eagle Rock to Mendocino 60 kV path which is parallel to the Eagle Rock to Mendocino 115 kV paths. Therefore, a contingency of one of the 115 kV paths to Mendocino could cause overloads on the Konocti-Eagle Rock 60 kV line with the most severe one being the Geysers #3-Cloverdale 115 kV line. This project will mitigate thermal overloads and will avoid customers in Konocti, Middletown, Clearlake, Hartley and Upperlake stations that are at risk needing to be dropped during summer peak loading conditions.

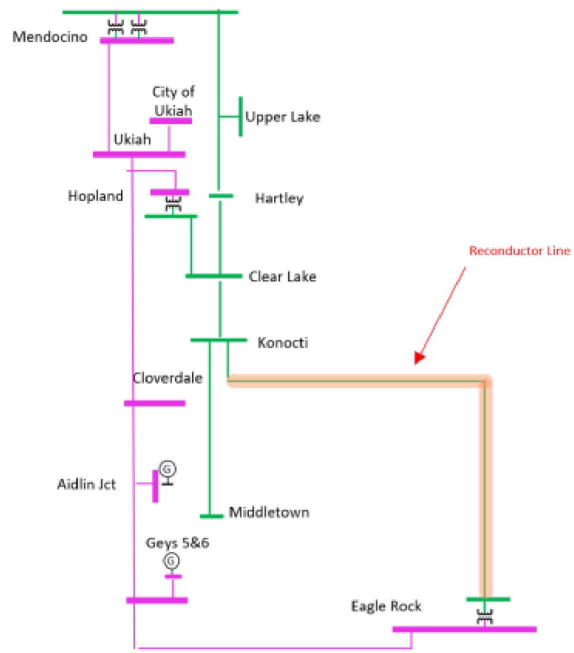
The Konocti-Eagle Rock 60 kV reconductoring project includes:

- Reconductor Konocti-Eagle Rock 60 kV (about 10.0 miles) to achieve minimum conductor rating of 954 Amps for summer normal rating and 1100 Amps for summer emergency rating; and

- Upgrade any limiting components as necessary to achieve full conductor capacity.

The estimated cost for this project is $16.2 million - $32.5 million with a targeted in-service date of May 2030.

Figure 2.5-5: Konocti-Eagle Rock 60 kV Reconductoring Project



The ISO evaluated other alternatives to solve the reliability concerns, such as an energy storage and flow control devices, but they proved to be ineffective or unfeasible mitigation solutions. Further details are presented in PG&E area, North Coast North Bay local area reliability assessment of Appendix B.

San Miguel New 70 kV Line Project

San Miguel Substation is in San Luis Obispo County. It is currently supplied by two 70 kV lines, one from Paso Robles substation 10 miles (circuit distance) away in the south and the other from Coalinga Substation 38 miles away in the north. Loss of the shorter line from Paso Robles will leave San Miguel load supplied by a weak tie from Coalinga and result in low voltage in peak load conditions. This situation will not be mitigated by the Estrella Substation Project in the area, which will provide a new 230/70 kV source and loop San Miguel-Paso Robles into Union Substation in 2029. The critical contingency of losing San Miguel-Union line will still leave San Miguel supplied by a long line from Coalinga. Given the recently forecasted load increases at San Miguel, low voltage violation has been observed at San Miguel through NERC TPL assessment in all near-term and long-term Summer Peak scenarios.

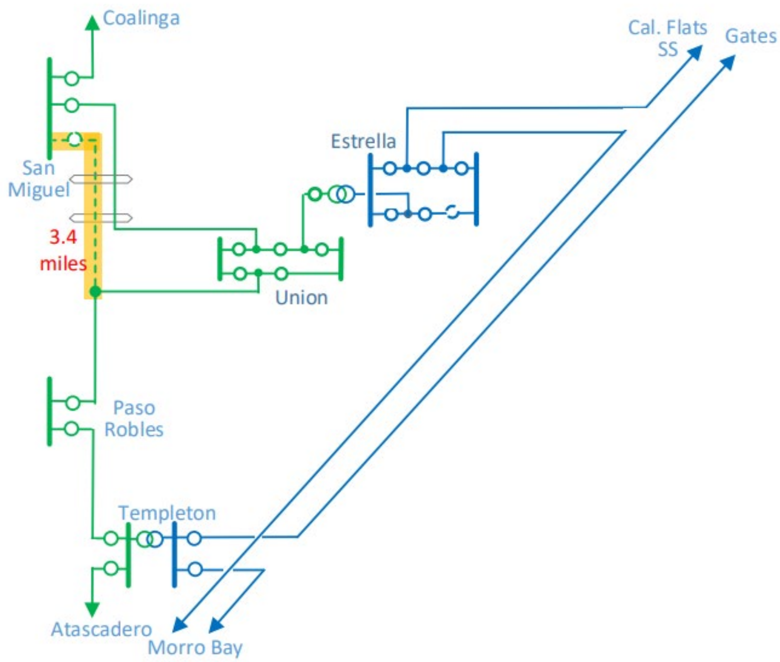
The San Miguel New 70 kV Line Project protects against the NERC TPL-001-5 Category P1 violations. It will mitigate the low voltage issues mentioned above. This project will also increase load serving capability, improve customer reliability, and reduce losses.

The project consists of following components:

- Build approximately 3.4 miles of new 70 kV line section from San Miguel substation to where the existing San Miguel-Paso Robles 70 kV line will be opened to loop into the future Union substation (refer to Estrella Substation Project), i.e., str. 003/065 besides Wellsona Road. Connect this new line section to the future Union-Paso Robles line via a tap. A minimum summer emergency rating of 1048 Amps is required for the new line section; and
- Terminate the new line section at San Miguel substation by adding a new position.

The estimated cost for this project is $15.5 million - $30 million with a targeted in-service date of May 2032 or earlier.

Figure 2.5-6: San Miguel New 70 kV Line Project



The ISO evaluated other alternatives to solve the reliability concerns, such as an energy storage and flow control devices, but they proved to be ineffective or unfeasible mitigation solutions. Further details are presented in PGAE area, Central Coast Los Padres local area reliability assessment of Appendix B.

Coronado Island Reliability Reinforcement Phase I

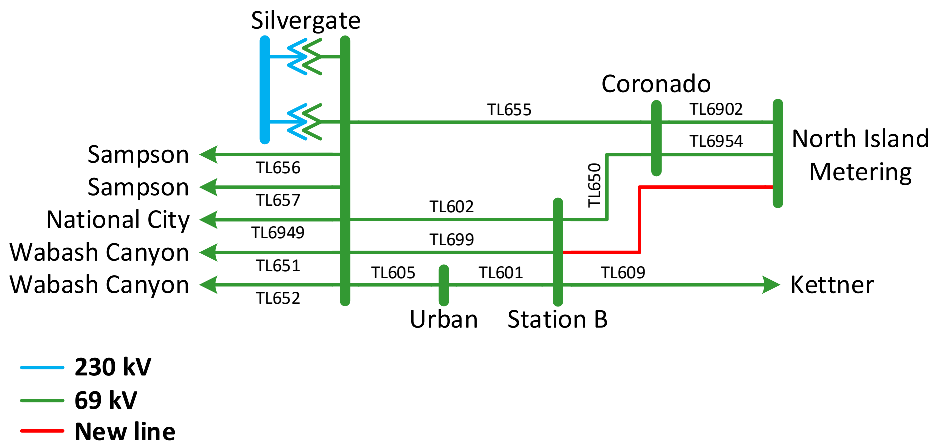
This project was proposed by SDG&E as a reliability transmission solution to the overload of TL650 Station B – Coronado and TL655 Silvergate – Coronado that serve the load of Coronado Island. The US Navy submitted a load interconnection request to SDG&E that will add 95 MVA of load at North Island Metering substation from 2023 to 2042, therefore the reliability assessment of the SDG&E planning area showed the need to increase the load serving capability, as P1 and P3 contingency overloads were observed in the near term and long term planning horizons. In particular, Phase I would be sufficient to serve the forecasted load from 2028 to 2034.

The project involves the following:

- Build a new underground 69 kV line from Station B to North Island Metering.

The estimated cost for this project is $42 million with a targeted in-service date of Q3 2027.

Figure 2.5-7: Coronado Island Reliability Reinforcement Phase I



The ISO evaluated other alternatives to solve the reliability concerns, such as a 69 kV line from Bay Boulevard to North Island Metering, energy storage, flow control devices and RAS, but they proved to be ineffective or unfeasible mitigation solutions. Further details are presented in SDG&E area reliability assessment Section B.5 of Appendix B.

2.5.2 Projects Recommended for Approval

Coronado Island Reliability Reinforcement Phase II

This project was proposed by SDG&E as a reliability transmission solution to the overload of TL650 Station B – Coronado and TL655 Silvergate – Coronado. After the addition of the third 69 kV line identified in Coronado Island Reliability Reinforcement Phase I, the reliability assessment of the SDG&E planning area showed P1 contingency concerns due to the outage TL604 Old Town – Vine 69 kV line. This would overload TL655, starting in 2035, and the outage of TL655 would overload TL650, starting 2040, all of which is driven by the additional US Navy load.

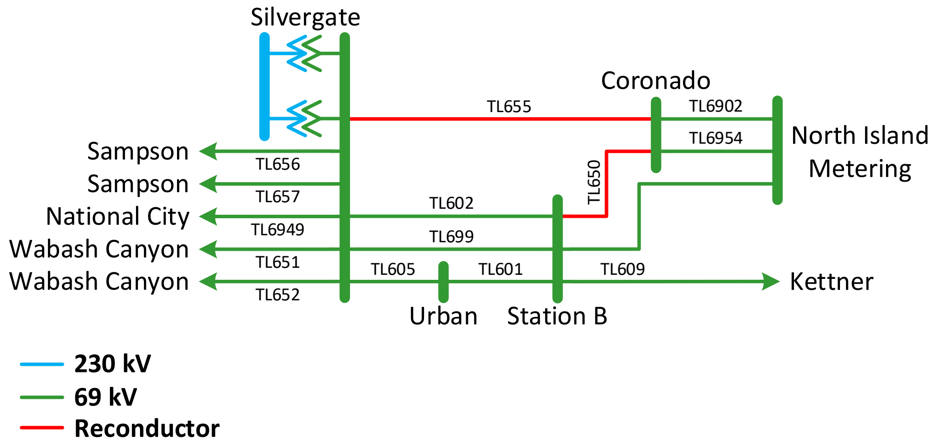
The project involves the following:

- Reconductor TL650 *Station B – Coronado and TL655 Silvergate – Coronado to increase their normal rating to 150 MVA.*

The estimated cost for this project is $66 million with a targeted in-service date of Q4 2028.

Even if the project is actually needed in 2035, SDG&E requested an in-service date of Q4 2028 to avoid the risk of potential load drop during the construction process as the reconductoring of each 69 kV line could take between nine to 12 months. The ISO evaluated this assumption and confirmed that once the first block of additional US Navy load comes into service, there would be no time window during the year where the reconductoring could take place without the risk of potential load drop, which is contrary to the ISO Planning Standards[39].

Figure 2.5-8: Coronado Island Reliability Reinforcement Phase II



The ISO evaluated other alternatives to solve the reliability concerns, such as energy storage, flow control devices and *remedial action scheme (RAS), but they proved to be ineffective or unfeasible mitigation solutions. Further details are presented in SDG&E area reliability assessment Section B.5 of Appendix B.*

Downtown Reliability Reinforcement

This project was proposed by SDG&E as a reliability transmission solution to address the thermal overload of *Old Town 230/69 kV banks and TL604 Old Town – Vine 69 kV line. Old Town 230/69 kV banks are one of the main sources to San Diego Downtown area and the reliability assessment showed that the P1 and P4 outages of either of these banks could overload the remaining one in the near term and long term planning horizons. Additionally, TL604 could overload for P1 and P3 outages that include any of the Silvergate 230/69 kV banks.*

The project involves the following:

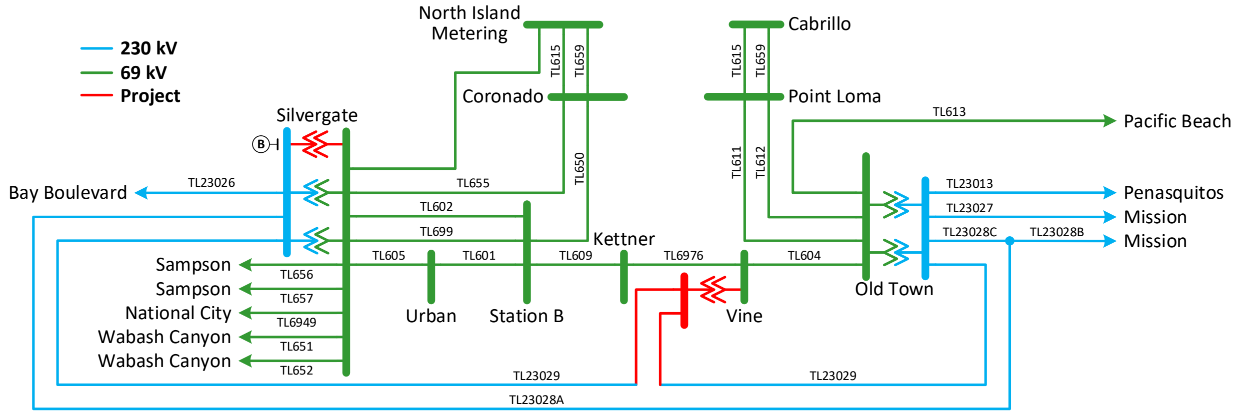
- Energize Silvergate 230/69 kV spare bank;
- Upgrade Sampson 69 kV circuit breakers (CBs);
- Expand existing Vine 69/12 kV substation to 230/69/12 kV;
- *Loop TL23029 Old Town – Mission into Vine substation; and*

[39] ISO Planning Standards, Section 8.2 Scheduled Outage Planning Standard

- *Install a 230/69 kV 350 MVA bank at Vine substation.*

The estimated cost for this project is $400-500 million, where energizing Silvergate 230/69 kV spare bank has a cost of $10-15 million, upgrading Sampson CBs $10-15 million, and expanding Vine substation $385-475 million. Additionally, the first two upgrades have a targeted in-service date of 2029 while the Vine expansion is targeted for 2037.

Figure 2.5-9: Downtown Reliability Reinforcement



The ISO evaluated other alternatives to solve the reliability concerns *that require rebuilding Old Town substation to GIS, either to install higher capacity 230/69 kV banks or flow control devices. Both of these alternatives need additional transmission upgrades, which would have a similar or higher cost than the proposed project. Furthermore, these alternatives would be difficult to build since there might not be a time window during the year to perform the scheduled outages at Old Town substation, which would be contrary of the ISO Planning Standards.*[40] *Installing energy storage in the load pocket was found to be ineffective. Further details are presented in SDG&E area reliability assessment Section B.5 of Appendix B.*

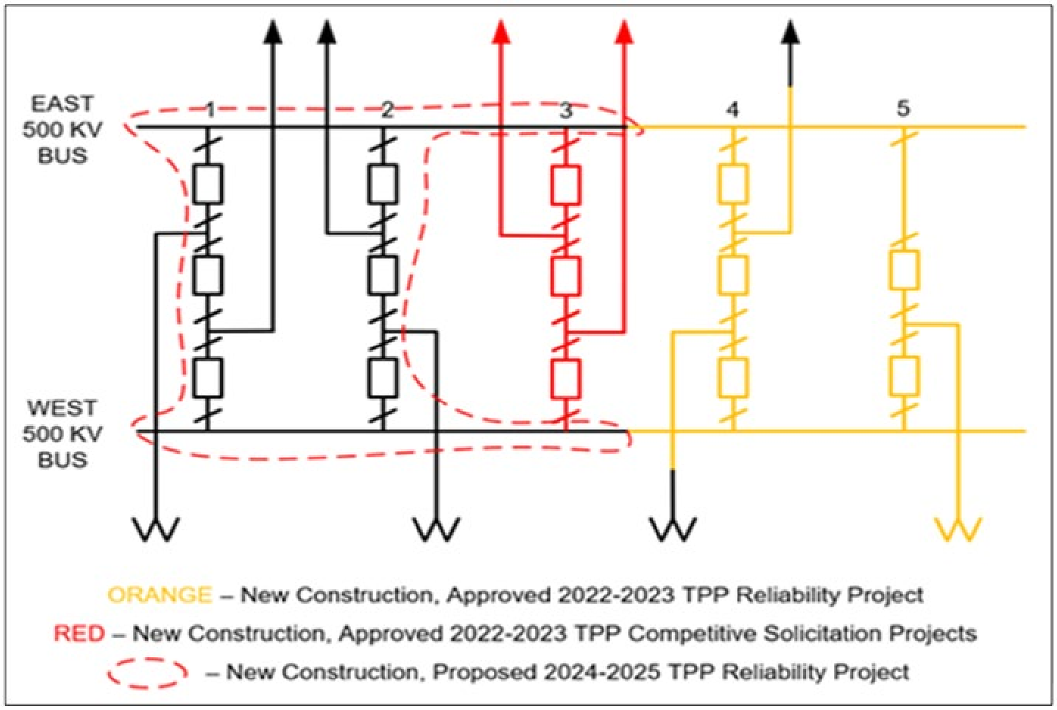
Serrano 500 kV SCD Mitigation Project

The project was submitted by Southern California Edison as a reliability need to address the short circuit duty (SCD) concern at Serrano 500 kV substation in conjunction with the previously approved projects at Serrano in the 2022-2023 transmission plan, that exacerbate the short-circuit duty at the Serrano 500 kV bus, causing circuit breaker (CB) loading to exceed 95% in the near-term planning case and 100% in the long-term planning case.

The ISO recommends approval of the Serrano 500 kV SCD mitigation project as a reliability mitigation. The project scope consists of replacing the 40 kA-rated 500 kV GIS bus positions No. 1 through No. 3 with 63 kA-rated equivalent equipment, as shown in Figure 2.5-10. The total estimated cost of the project is $183 million. Its expected in-service date is December 31, 2029.

[40] ISO Planning Standards, Section 8.2 Scheduled Outage Planning Standard

Figure 2.5-10: Serrano 500 kV SCD Mitigation Project

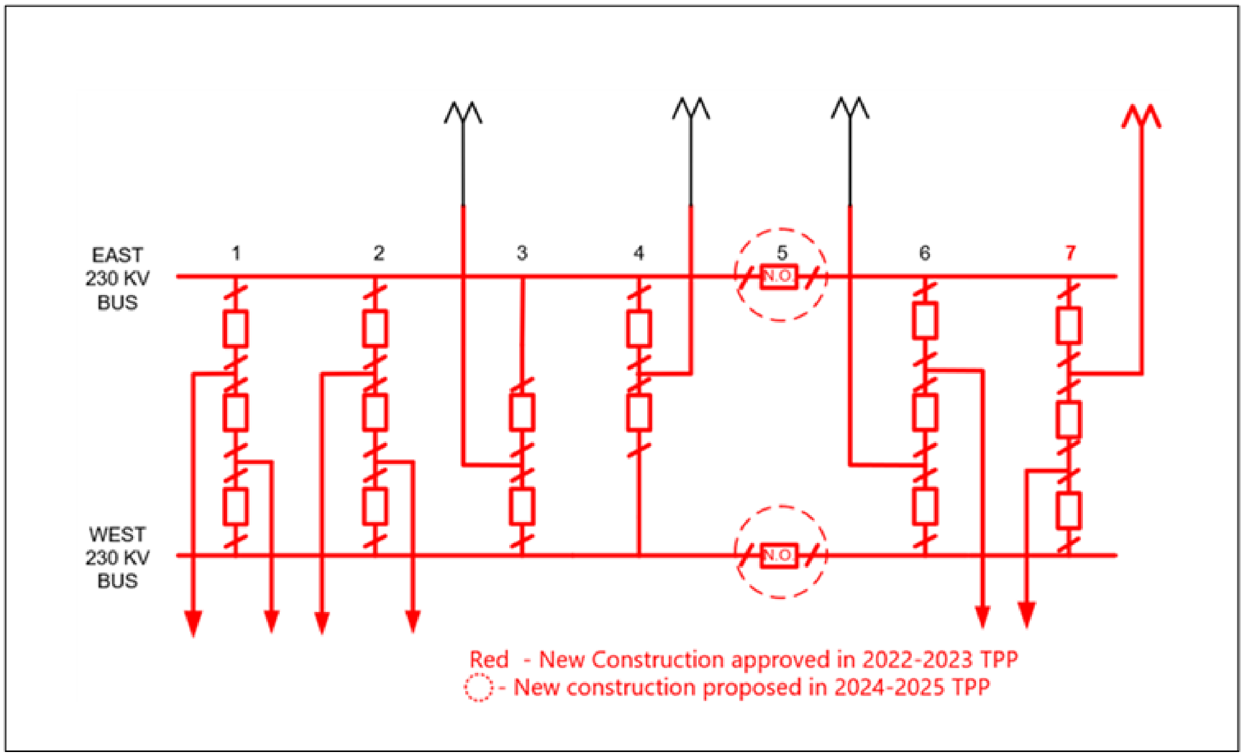


Serrano 230 kV SCD GIS Bus Split Project

The project was submitted by Southern California Edison as a reliability need to address the short circuit duty (SCD) concern at the neighboring Villa Park 230 kV substation which exceeds 100% capacity in the long-term planning scenario of 2039.

The ISO recommends approval of the Serrano 230 kV SCD GIS bus split project as a reliability mitigation. The scope of this project consists of splitting the Serrano 230 kV bus by installing two (2) 230 kV sectionalizing circuit breakers and performing the construction work with the previously ISO-approved TPP projects at Serrano to gain cost saving efficiencies, as shown in Figure 2.5-11. The total estimated cost of the project is $28 million. Its expected in-service date is December 31, 2029.

Figure 2.5-11: Serrano 230 kV SCD GIS Bus Split Project

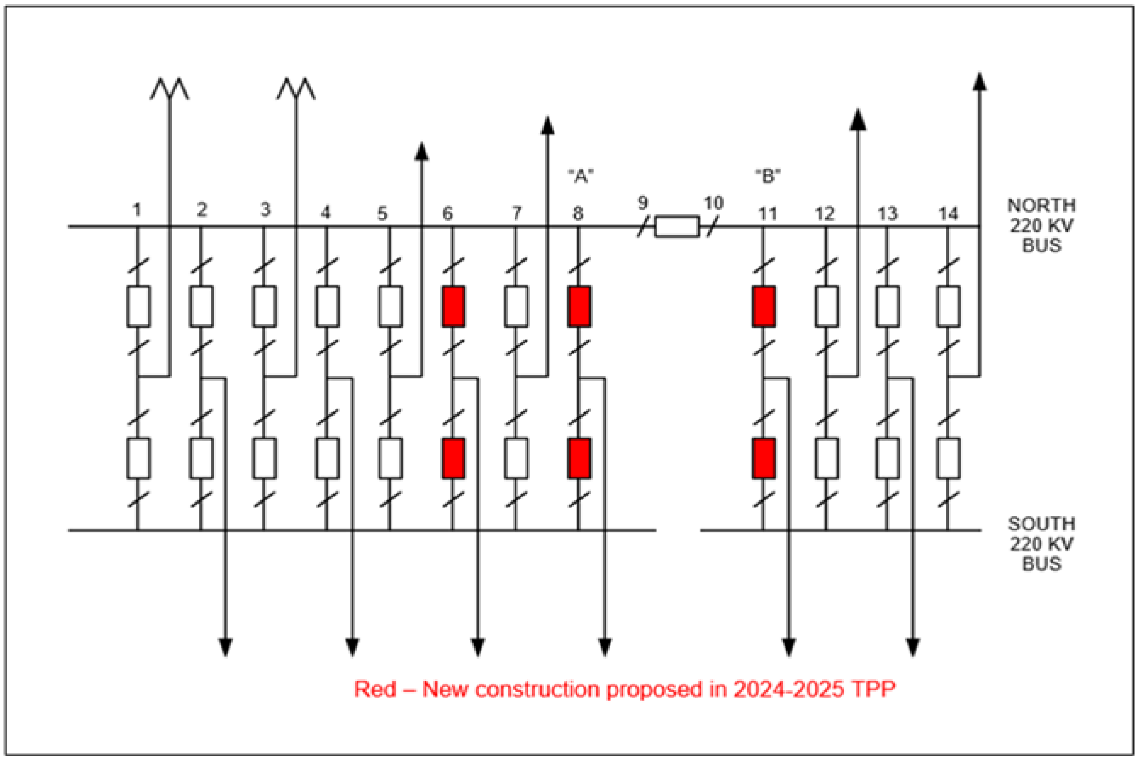


Alamitos 230 kV SCD Upgrade

The project was submitted by Southern California Edison as a reliability need to address the short circuit duty (SCD) concern at the Alamitos 230 kV substation which exceeds 100% of the circuit breaker capacity in the long-term planning cases of 2034 and 2039.

The ISO recommends approval of the Alamitos 230 kV SCD upgrade project as a reliability mitigation. The scope of this project consists of upgrading six (6) 230 kV circuit breakers at Alamitos A and B 230 kV to 63 kA, as shown in Figure 2.5-12. The total estimated cost of the project is $5 million. Its expected in-service date is December 31, 2032.

Figure 2.5-12: Alamitos 230 kV SCD Upgrade Project



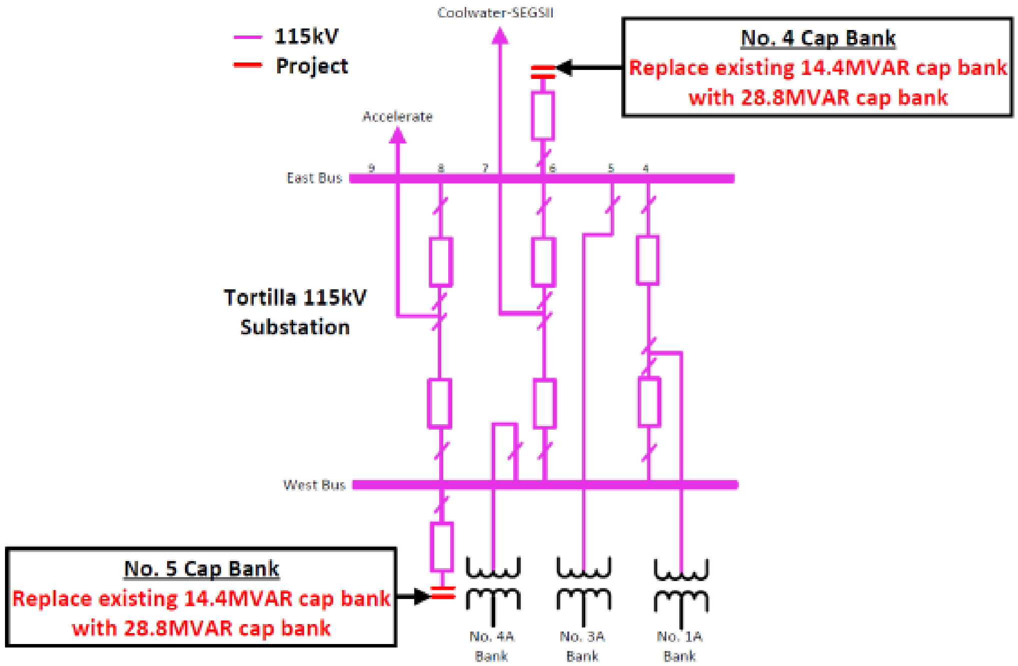
Tortilla 115 kV Capacitor Replacement

The project was submitted by Southern California Edison *as a reliability transmission project to address low voltage and voltage collapse concerns in the North of Lugo area under various contingency conditions. The decline in post-contingency voltage is primarily driven by the significant increase in load at Tortilla and Edwards substations. The proposed capacitor replacement will complement the Kramer-Coolwater 115 kV line looping into the Tortilla 115 kV substation (described below), which addresses thermal overloads and helps address low voltage concerns as well.*

The scope of this project consists of replacing the existing two (2) 14.4MVAR 115 kV capacitors at the Tortilla 115/33kV substation with two (2) 28.8MVAR115 kV capacitors.

The ISO recommends approval of the Tortilla 115 kV Capacitor Replacement *project. The estimated cost for this project is $5 million with an expected in-service date of June 30, 2029.*

Figure 2.5-13: Tortilla 115 kV Capacitor Replacement



The ISO evaluated other alternatives to solve the reliability concerns that includes looping the Kramer-Coolwater 115 kV line into the Tortilla 115 kV substation by itself and an 80MW Battery Energy Storage System (BESS). The Kramer-Coolwater 115 kV line looping into Tortilla 115 kV substation provides some additional *voltage support but does not resolve the low voltage issues expected in the coming years. The BESS option was considered to mitigate the low voltage and voltage collapse concerns. However, low voltages were identified when charging the large BESS in the 2029 Summer Off-Peak case, which would likely prohibit fully recharging the BESS during extended transmission contingency conditions.*

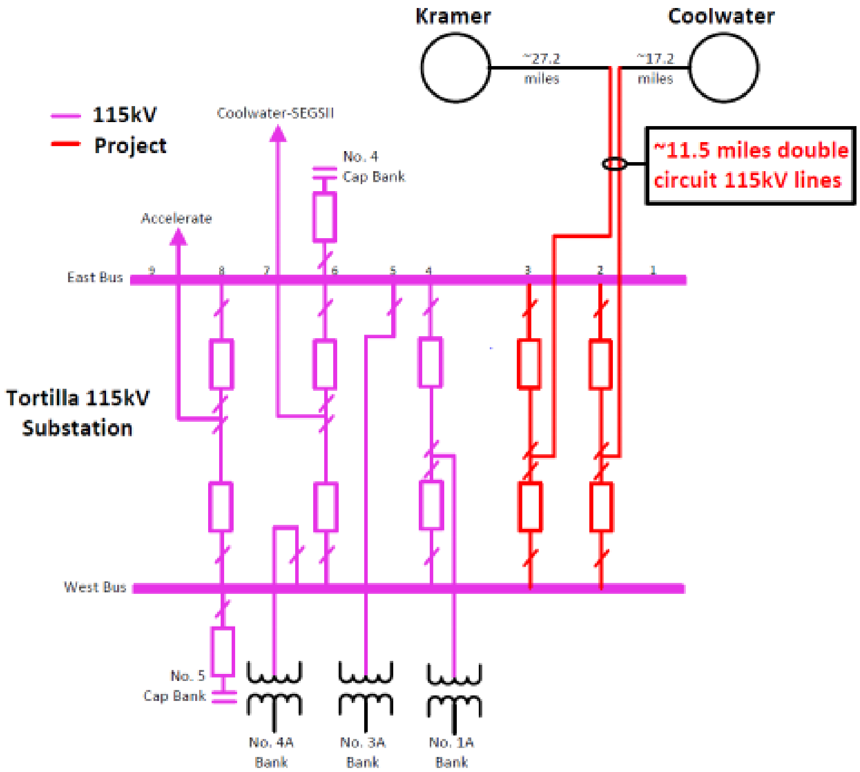
Kramer-Coolwater 115 kV Line Looping into Tortilla 115 kV Substation

The project was submitted by Southern California Edison as a reliability transmission project to address thermal overloads and reduce the risk of voltage collapse under various contingency conditions. *The decline in post-contingency voltage is primarily driven by the significant increase in load at Tortilla and Edwards substations.*

The scope of this project is to utilize the existing Kramer-Coolwater 115 kV transmission line to loop in the Tortilla 115/33kV substation via an approximate 11.5-mile double-circuit line extension and switchrack expansion at the Tortilla 115/33 kV substation.

The ISO recommends approval of the Kramer-Coolwater 115 kV line looping into Tortilla 115 kV Substation Project. The estimated cost for this project is $37 million with an expected in-service date of June 30, 2034.

Figure 2.5-14: Kramer-Coolwater 115 kV Line Looping into Tortilla 115 kV



The ISO evaluated the use of an 80MW Battery Energy Storage System (BESS) to address the *thermal overloads and voltage collapse concerns. However, low voltages were identified when charging the large BESS in the 2029 Summer Off-Peak case, which would likely prohibit fully recharging the batteries during extended transmission contingency conditions.*

Constructing a new 11.4-mile 115 kV circuit from Coolwater to Tortilla was considered, however, this solution would result in Tortilla being supported by only three lines instead of four. Additional work at the Coolwater Substation would be required to accommodate the new line position, and the Coolwater-SEGS-Tortilla 115 kV line would face long outages during the construction phase.

Julian Hinds-Mirage 230 kV Advanced Reconductor Project

The project was submitted by Southern California Edison to address the thermally constrained Julian Hinds-Mirage 230 kV line, which has been subject to the Blythe Energy Remedial Action Scheme (RAS). Historically, the Blythe RAS was activated ten times between 2019 and 2023, curtailing over 1.46 GW of generation to prevent overloading the Julian Hinds-Mirage 230 kV line. Increasing the power transfer capability of this line will reduce the frequency of RAS operations and associated generation curtailments. This will enhance renewable energy integration and increase the overall reliability of transmission services for neighboring systems, including the Metropolitan Water District, Western Area Power Administration, and Imperial

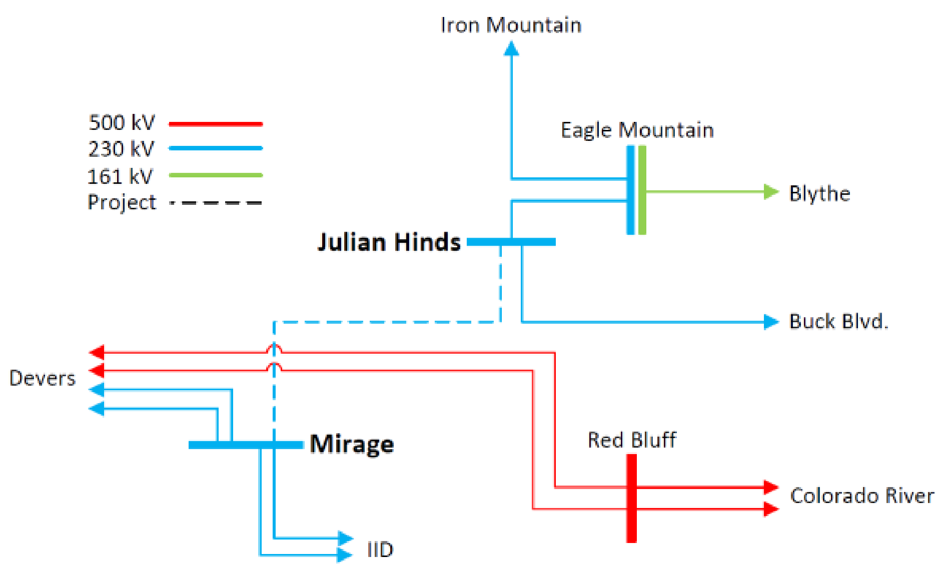
Irrigation District. The project also improves the line's performance at higher temperatures which would help address potential ambient adjusted rating (AAR) derates, in line with FERC Order 881 requirements. In addition, without considering any potential derates, 35 hours and 111 hours of congestion was identified on the Julian Hinds-Mirage 230 kV line in the 2034 and 2039 Base portfolio production cost models, respectively. With the proposed project, this congestion would be eliminated.

The reliability assessment shows the Julian Hinds-Mirage 230 kV line overloaded under several P1 and P6 contingencies in 2026 Summer Peak, 2026 Spring Off-Peak, and 2034 Summer Peak scenarios. To address these overloads, the Blythe RAS would be the solution. Contingency analysis indicates that the updated line ratings from reconductoring the Julian Hinds-Mirage 230 kV line would effectively mitigate the thermal overloads without the need to activate the Blythe RAS.

The scope of this project is reconductoring approximately 47 miles of the Julian Hinds-Mirage 230 kV Line with high-temperature, low-sag advanced conductors to achieve ratings of 1,525 A (normal) and 1,625 A (4-hr emergency). Additionally, select towers will be upgraded to support the new conductor and modifications to the existing Blythe RAS will be necessary to accommodate the increased line rating.

The ISO recommends approval of the Julian Hinds-Mirage 230 kV Advanced Reconductor Project. The estimated cost for this project is $76 million with an expected in-service date of April 1, 2030. These upgrade costs are expected to be partially subsidized by the U.S. Department of Energy GRIP grant funding awarded through the CHARGE 2T project.

Figure 2.5-15: Julian Hinds-Mirage 230 kV Advanced Reconductor



Sloan Canyon Tertiary Reactor Project

This project was proposed by Gridliance West as a reliability transmission project to address high voltage under contingency conditions. During the P6 contingency the Harry Allen-Sloan

Canyon 500 kV and Sloan Canyon-Eldorado 500 kV lines the 500 kV bus voltage at Sloan Canyon was 560 kV in the 2029 summer peak base case which exceeds the 550 kV high voltage limit.

The scope of this project is to install three 66 MVAR shunt reactors on the 24.9 kV tertiary of the Sloan Canyon 500/230 kV transformer.

The ISO recommends approval of the Sloan Canyon Tertiary Reactor Project. The estimated cost for this project is $5 to 10 million with an expected in-service date of December, 31 2027.

Cortina #3 60 kV Reconductoring Project

The Cortina #3 60 kV line serves the Williams, Colusa, and Meridian substations in Sacramento, with the Williams Substation currently relying on a radial configuration. The area's load capacity is constrained by transmission limits and this radial setup. Demand at the Williams Substation is projected to increase significantly due to a planned EV charging distribution project, expected to add 3 MW by 2025, 10 MW by 2028, and 20 MW by 2030.

According to the 2024-2025 TPP results, under the NERC TPL-001-5 Category P0 and P1 violations, the Cortina #3 60 kV line is projected to overload up to 173% in 2026, 177% in 2029, and 164% in 2034.

The ISO recommends approval of the “Cortina #3 60 kV Reconductoring Project” with the following scope:

- Reconductor about 6.0 miles between the Cortina Substation and Wadham Jct on the Cortina #3 60 kV to achieve minimum conductor rating of 1014 Amps for summer normal rating and 1127 Amps for summer emergency rating;
- Reconductor about 1.5 miles between the Wadham Jct and Wescot (007/125) on the Cortina #3 60 kV to achieve minimum conductor rating of 1014 Amps for summer normal rating and 1127 Amps for summer emergency rating;
- Reconductor about 1.5 miles between the Wescot (007/125) and Williams Substation on the Cortina #3 60 kV to achieve minimum conductor rating of 1014 Amps for summer normal rating and 1127 Amps for summer emergency rating;
- Install a 15 MVAR shunt capacitor at Meridian 60 kV substation; and
- Upgrade any limiting components as necessary to achieve full conductor capacity.

Figure 2.5-16: Cortina #3 60 kV Reconductoring Project - Existing

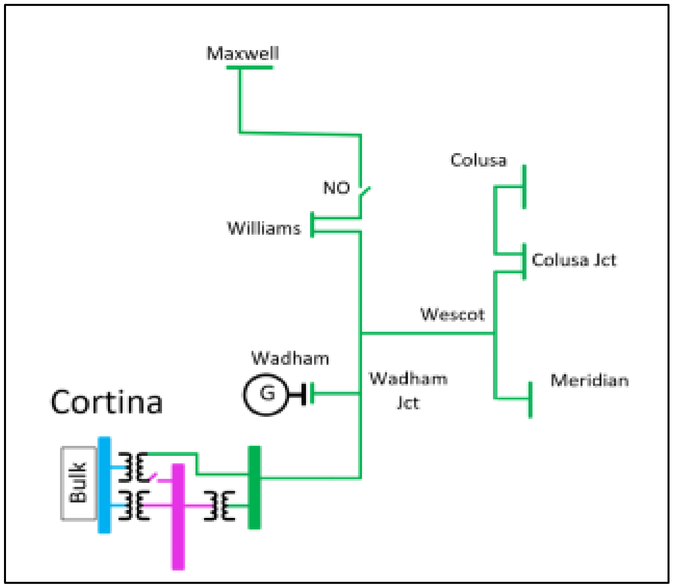
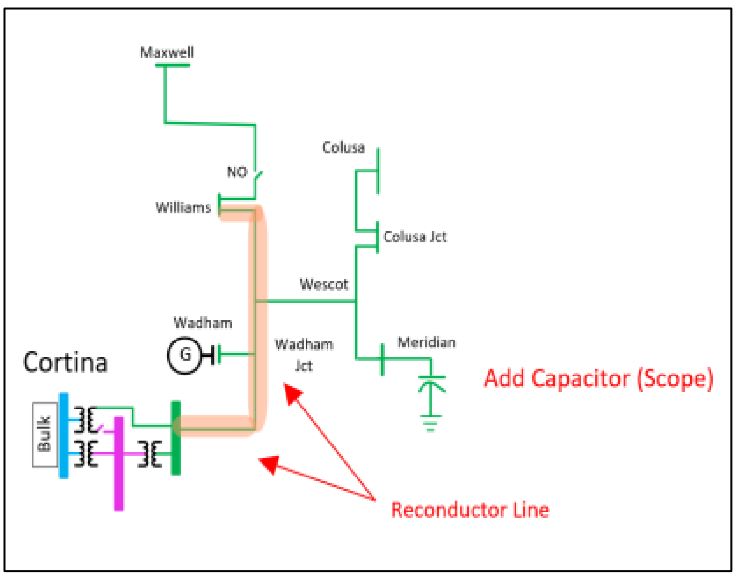


Figure 2.5-17: Cortina #3 60 kV Reconductoring Project - Proposed



The estimated cost of this project is $27.8 million - $55.5 million. The expected in-service date of this project is May 2031. In the interim, the load ramp will be limited to the available capacity. Operating solutions will also be relied upon in the interim if needed.

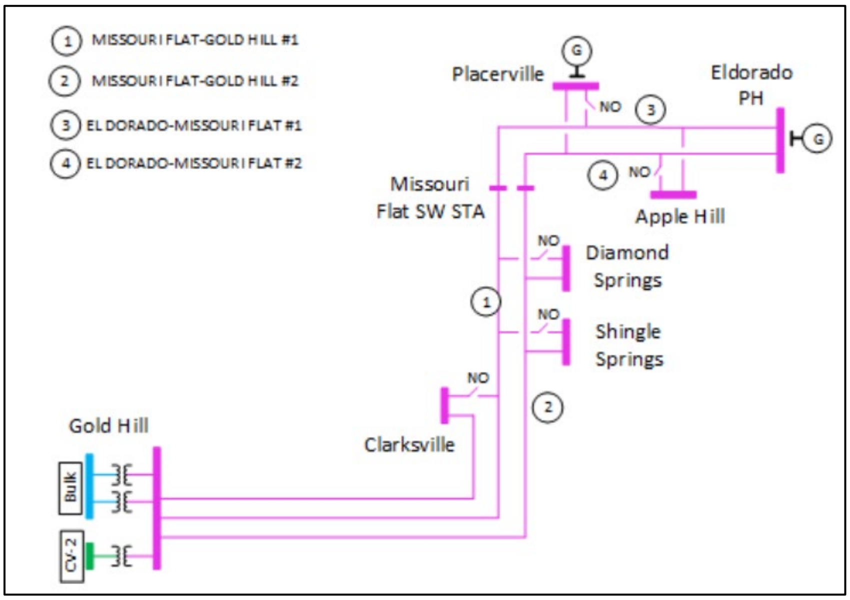
The ISO evaluated other alternatives to solve the reliability concerns, such as an energy storage and flow control devices, but they proved to be ineffective or unfeasible mitigation solutions. Further details are presented in PG&E area, Central Valley area reliability assessment of Appendix B.

Gold Hill-El Dorado Reinforcement Project

Gold Hill 230/115 kV Substation in Sacramento County, which is the main power source for El Dorado County. Four 115 kV substations — Shingle Springs, Diamond Springs, Placerville, and Apple Hill — serve over 45,000 customers in El Dorado County. Gold Hill supplies these substations through two parallel lines, with #2 line feeding Shingle Springs, Diamond Springs, and Placerville, and #1 line feeding Apple Hill. The El Dorado PH generation offers limited load support.

NERC Category P2-1 overloads and low voltage issues are identified in 2024-2025 TPP results in the Gold Hill–El Dorado area. If the line between Gold Hill and Shingle Springs on Missouri Flat–Gold Hill #2 115 kV line opens, power reroutes through alternate lines to supply Placerville, Diamond Springs, and Shingle Springs, potentially causing severe overloads and low voltage issues.

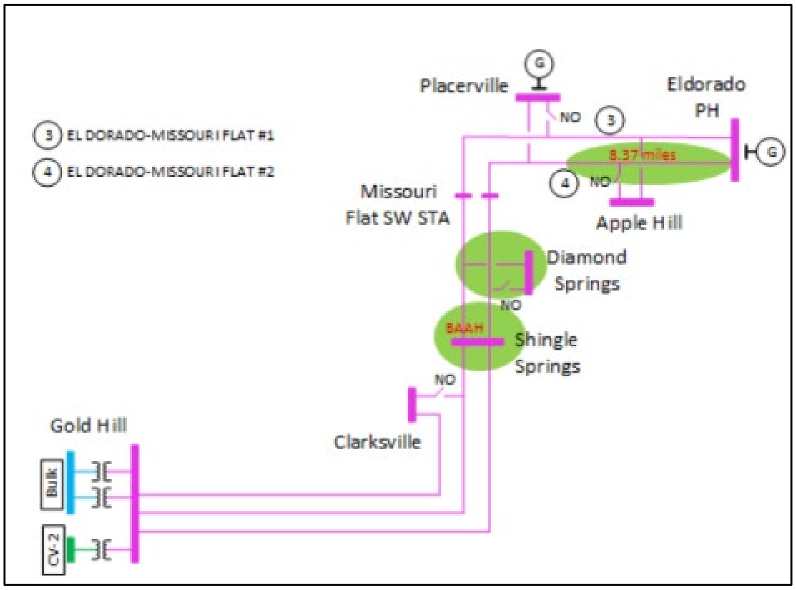
Figure 2.5-18: Gold Hill-El Dorado Reinforcement Project - Existing



The ISO recommends approval of the "Gold Hill-El Dorado Reinforcement" project with the following scope:

- Serve Diamond Springs 115 kV Substation from Missouri Flat – Gold Hill #1 115 kV Line;
- Convert Shingle Springs Substation 115 kV bus to breaker-and-a-half (BAAH) configuration;
- Reconductor approximately 8.8 circuit miles between El Dorado and 008/062 of the El Dorado – Missouri Flat #2 115 kV Line with larger conductor to achieve minimum 577 Amps of summer emergency rating; and
- Remove any limiting components as necessary to achieve full conductor capacity.

Figure 2.5-19: Gold Hill-El Dorado Reinforcement Project - Proposed



The total estimated cost of this project is $63.5 million – $127 million. The expected in-service date of this project is May 2032. Operating solutions will be relied upon in the interim if needed.

The ISO evaluated other alternatives to solve the reliability concerns, such as a ring bus conversion at Missouri Flat, install shunt capacitor, energy storage and flow control devices, but they proved to be ineffective or unfeasible mitigation solutions. Further details are presented in PG&E area, Central Valley area reliability assessment of Appendix B.

West Fresno 115 kV Voltage support project

TPP 2024-2025 Greater Fresno area results show low voltages for all near term to long term at California Avenue and West Fresno 115 kV stations. In addition, during summer peak loading conditions, frequent low voltage issues are being observed in real time operations at West Fresno and neighboring California Avenue substation. Voltages fell below lower operating limit of 109 kV. With growing distribution level forecast, low voltages at West Fresno are expected to continue and worsen if not mitigated. Hence, ISO recommends approval of West Fresno 115 kV voltage support Project, which includes the following:

- Install 75 MVar voltage support at West Fresno Substation
- Expand West Fresno 115 kV bus as needed for voltage support interconnection.

Figure 2.5-20: West Fresno 115 kV Voltage support project - Existing

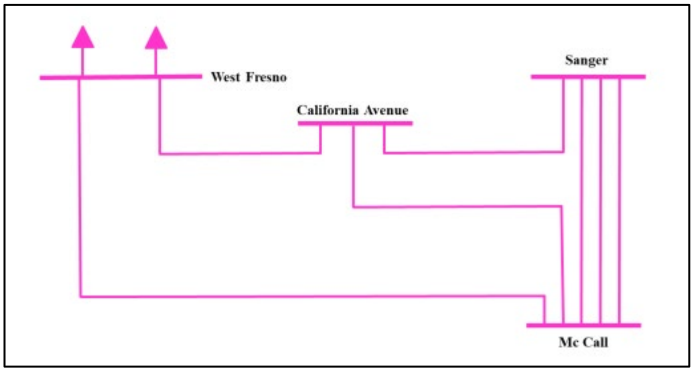
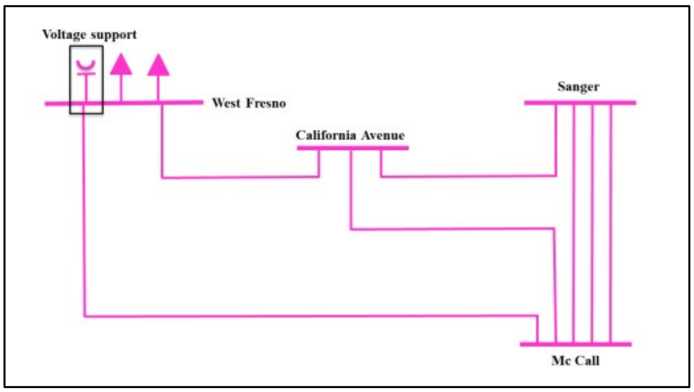


Figure 2.5-21: West Fresno 115 kV Voltage support project - Proposed



This project has a cost estimate of $30 million - $60 million and in-service date of May 2031. The ISO evaluated other alternatives to solve the reliability concerns, which proved to be ineffective or infeasible. Further details are presented in Section 3.6.6 of Appendix B.

San Mateo 230/115 kV Transformer Bank Addition Project

The San Mateo Substation, located in the Peninsula area, is a crucial transmission substation that provides electricity to customers in San Francisco and San Mateo counties. The three existing 230/115 kV transformer banks at this substation are primary sources of power for the San Francisco and Peninsula 115 kV systems. In addition to the San Mateo 230/115 kV transformer banks, other sources that supply this area include the Trans Bay Cable (TBC), Martin Substation, and Ravenswood Substation. The growth in electricity demand in this region is primarily driven by distribution customers in San Francisco and the Peninsula, the increasing demand for electric vehicle (EV) charging, electrification loads, and the interconnection of large customer loads.

This project protects against the NERC TPL-001-5 Category P6 violations by mitigating the observed thermal violations. Power flow studies indicate that after losing two of the three existing 230/115 kV transformers, the third 230/115 kV transformer bank will be overloaded up to 20% in 2026, 23% in 2029 and 38% in 2034. The forecasted Additional Achievable Transportation Electrification (AATE) and Additional Achievable Fuel Substitution (AAFS) loads will further increase these overloads beyond 2034.

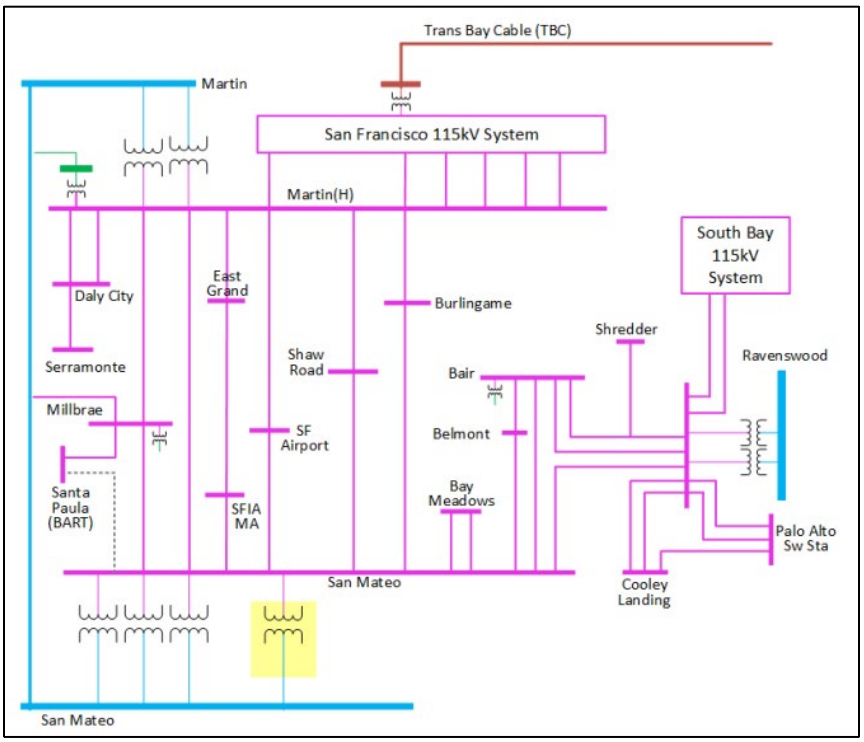
This project will enhance San Mateo Substation as a stronger source for the San Francisco and Peninsula 115 kV pocket and will provide sufficient transmission capacity to meet the future local demand. It will also increase operating flexibility and customer reliability.

ISO recommends approval of the San Mateo 230/115 kV Transformer Bank Addition Project that consists of the following components:

- Install a new 230/115 kV transformer at the San Mateo Substation to achieve a minimum summer rating of 420 MVA under normal conditions and 462 MVA in emergency.
- Upgrade San Mateo 230 kV bus and any limiting components as necessary to achieve the full transformer capacity.

This project has a cost estimate of $55 million - $110 million and in-service date of May 2032.

Figure 2.5-22: San Mateo 230/115 kV Transformer Bank Addition Project



The ISO evaluated other alternatives to solve the reliability concerns, *which proved to be ineffective or infeasible. Further details are presented in section B.3.5 of Appendix B.*

North Oakland Reinforcement Project

The North Oakland 115 kV pocket is mainly served by Moraga Substation via six 115 kV overhead transmission lines from Moraga Substation to Oakland X and Claremont Substations. These six 115 kV transmission lines provide power to Claremont, Oakland C, Oakland K, Oakland X, Oakland D, and Oakland L to serve the load in the North Oakland pocket. Additionally, there are three other customer 115 kV substations radially connected from Oakland C: Alameda Municipal Power's Cartwright Substation, Maritime Substation (located at the Port of Oakland) and Schnitzer Steel Products and the Oakland Power Plant is also connected to Oakland C. Currently, only the Oakland Power Plant unit #2 is retired, and the other two operate as a Reliability-Must-Run (RMR), but for the long term scenarios, it is expected to have all the remaining units retired as well.

In previous planning cycles the Oakland Clean Energy Initiative (OCEI) project was approved as the ultimate long term transmission reinforcement project for the Oakland North area. However, this area is experiencing rapid load increase due to industrial and commercial growth and the rise in the EV Charging and Electrification loads. Based on the latest 2024-2025 TPP load forecast, North Oakland area is expected to increase significantly in the next 15 years. The local area demand (includes Claremont, Oakland X, Oakland C, Oakland D, Oakland L, Cartwright, Port of Oakland) is projected at 376.7 MW in 2024 and expected to reach 458.2 MW by year 2039.

Given this anticipated load growth in the area, the OCEI was proven not sufficient to mitigate the overload issues in the 115 kV network. This has led to the need for additional transmission upgrades in the area. The North Oakland Reinforcement Project aims to supply the load in Oakland without relying on the local aging Oakland thermal units. In this sense, the ISO recommends the previously approved OCEI project to move forward as designed, which will help reduce reliance on the local thermal units while the additional transmission upgrades are being implemented.

This project protects against NERC Categories P1, P2, P3 and P6 thermal violations. In the absence of the existing Oakland Power Plant, power flow studies identified thermal violations in most of the lines/cables in North Oakland area including K-D#1, K-D#2, C-L#1, C-X#2, D-L#1, Sobrante-Grizzly-Claremont #1 and #2 115 kV lines. The most severe of P6 contingencies may lead to loading of C-L#1, C-X#2, D-L#1115 kV UG cables to 127.5%, 145.1% and 158.9% of their summer emergency rating for year 2034 summer peak.

This project aims to provide a comprehensive solution to address the high demand growth in North Oakland by integrating two new 115 kV sources to this pocket. In addition to increasing the load serving capability, the project will mitigate asset related risks through strategic rebuilding of the existing aging infrastructure. Furthermore, it will enhance system reliability through diversifying the sources serving North Oakland, by including the Sobrante substation as an additional source to this pocket and reducing dependence on the Moraga source. By increasing transmission capacity for serving North Oakland Pocket, this project will ensure long-term reliability of the grid and its ability to serve the growing needs.

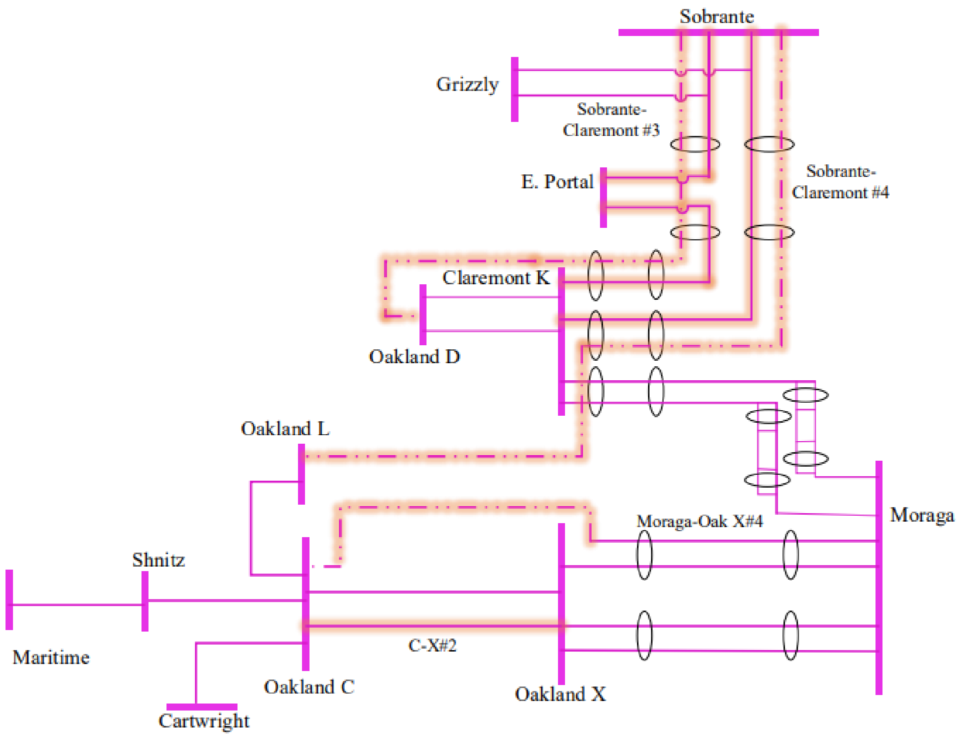
The North Oakland reinforcement project consists of the following components:

- Rebuild existing two Sobrante-Grizzly-Claremont #1 and #2 115 kV lines into four lines with at least 1714 Amps of summer normal rating. Each of the existing lines are about 8.4 circuit miles in length with 6.8 miles of parallel conductor. Two of the four lines will bypass Claremont Substation and connect to Oakland D and Oakland L Substations through new underground (UG) cable sections.
- Build a new UG cable to connect one of the new rebuilt lines to Oakland D with at least 1380 Amps of summer normal rating.
- Build a new UG cable to connect one of the new rebuilt lines to Oakland L with at least 1380 Amps of summer normal rating.
- Reroute the Moraga-Oakland X #4 line to bypass the Oakland X Substation.
- Build a new UG cable section to connect the Moraga-Oakland#4 115 kV line to Oakland C with at least 1380 Amps of summer normal rating.
- Convert Oakland C to GIS.
- Replace the Oakland C-X#2 115 kV underground cable with larger size cable with at least 1380 Amps of summer normal rating.
- Disconnect existing Oakland D-Oakland L 115 kV cable.

For the proposed reconductoring portions of this project, PG&E will conduct a thorough evaluation of the feasibility and cost-effectiveness of utilizing advanced high capacity conductors.

This project has a cost estimate of $564 million - $1127 million and expected in-service date of May 2032.

Figure 2.5-23: North Oakland Reinforcement Project



Based on the projected load growth and the Oakland grid topology, a new 230 kV supply from various different sources were considered along with other alternatives. However, considering need for the 115 kV system upgrade even with a 230 kV source, load serving capabilities, need for 115 kV upgrade from the aging facilities and overall cost perspective, this alternative is recommended for approval. For more details, please refer to Appendix B.

South Oakland Reinforcement Project

This year's reliability assessment identified multiple overloads under various P1 to P7 contingencies in the South Oakland area between PG&E's Moraga 115 kV and East Shore 115 kV Substations caused by significant projected local load increases. Significant load growth is anticipated at San Leandro, Edes, Oakland J, and Grant 115 kV Substations. Additionally, data center load interconnection projects totaling more than 300 MW have been requested and are actively being studied near the East Shore 115 kV Substation, with additional interest in load interconnection projects anticipated in this area.

Moraga Substation is a strong source likely capable of accommodating the additional load growth in this area. However, the existing 115 kV transmission lines that serve this region from Moraga do not have the required capacity. The other source into this system is from East Shore. However, the strength of the East Shore source is considerably weaker compared to that of Moraga.

This project aims to protect against thermal violations under P1, P2, P3, P6, and P7 NERC contingency categories. Power flow studies have identified thermal violations in most of the 115 kV lines and cables in the South Oakland area following the failure of single circuits or double line outages, as well as during bus failures at important substations such as Moraga and San Leandro. Among these 115 kV overloaded lines, the three Moraga-San Leandro, San Leandro-Oakland J, and Moraga-Oakland J are expected to carry the majority of the load in the Oakland South pocket, both under normal conditions and during critical contingencies.

Additionally, there are other facilities that show overload issues, such as the East Shore – Grant #1 & #2, and Grant – Oakland J 115 kV lines, as well as the East Shore 230/115 kV transformers banks. However, these issues are less critical and can be resolved through operational solutions or minor projects, such as installing additional breakers and series reactors. These alternatives will be further evaluated in the future cycle and are also being considered in the load interconnection process.

This project aims to provide a comprehensive solution to address the high demand growth in South Oakland by upgrading five 115 kV lines which serve as the primary source in this pocket. By increasing transmission capacity for serving South Oakland Pocket, this project will ensure long-term reliability of the grid and its ability to serve the growing needs.

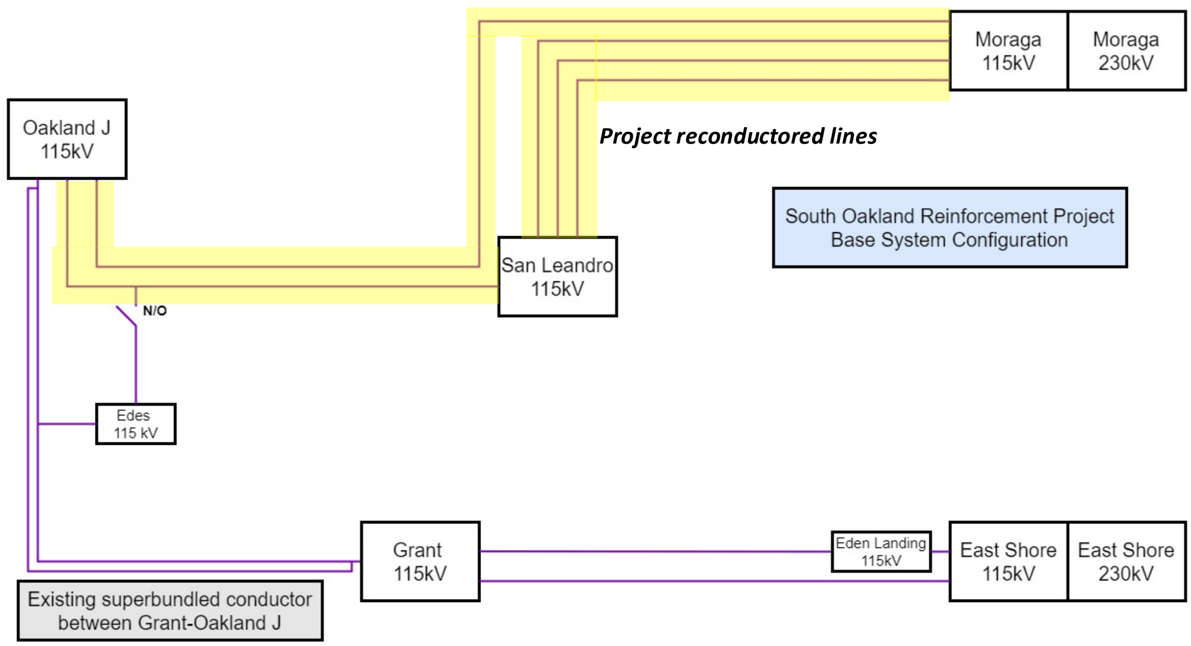
The South Oakland reinforcement project consists of the following components:

- Reconductor the Moraga-San Leandro #1, #2, and #3 115 kV lines to achieve a minimum capacity of 2288 Amps or higher;
- Reconductor the Moraga-Oakland J 115 kV line to achieve a minimum capacity of 2288 Amps or higher; and
- Reconductor the San Leandro-Oakland J 115 kV line to achieve a minimum capacity of 2288 Amps or higher.

For the proposed reconductoring portions of this project, PG&E will conduct a thorough evaluation of the feasibility and cost-effectiveness of utilizing advanced high capacity conductors.

This project has a cost estimate of $125 million – $250 million and expected in-service date of May 2032.

Figure 2.5-24: South Oakland Reinforcement



Considering the projected load growth and the topology of the Oakland South area, a new 230 kV supply from various sources was evaluated alongside with other alternatives. However, this type of solution does not avoid the reconductoring need in the region, particularly for the lines running from Moraga and San Leandro to Oakland J. While it does reduce the ampacity requirements for the reconductoring and could potentially postpone the need for reconductors, it does not eliminate the necessity for further significant improvements to the existing 115 kV infrastructure. For additional details, please refer to Appendix B.

Greater Bay Area 500 kV Transmission Reinforcement

The primary supply sources for the Greater Bay Area (GBA) are four 500 kV substations: Vaca Dixon in the North Bay Area, Tesla on the eastern side, and Metcalf and Moss Landing in the southern part. The first three substations are equipped with high-capacity 500/230 kV transformer banks and multiple 230 kV lines, effectively covering the entire GBA footprint, which includes Alameda, Contra Costa, Santa Clara, San Mateo, and San Francisco counties. By 2028, an additional 500/230 kV supply source will be established at Collinsville, located in the northeastern part of the Bay Area. This new facility will provide stronger support for the East Bay and alleviate stress on the 230 kV lines, particularly in the Contra Costa region. This source was approved in the ISO's 2021-202 transmission plan, and while it may also provide a termination for the proposed Humboldt-Collinsville transmission line subsequently proposed in the ISO's 2023-224 transmission plan, it is not dependent on the Humboldt-Collinsville project.

Recent planning cycles have shown a significant increase in load demand, driven by factors such as transportation electrification, fuel substitution, and anticipated large load interconnections in various areas within the GBA. According to load forecasts, a major ramp-up in demand is expected in the long-term, particularly in scenarios beyond 2034. The anticipated increase in load significantly surpasses the available transmission resources and internal generation capacity. The latest long-term Local Capacity Requirement (LCR) study indicates a deficiency of nearly 5,000 MW in the 2039 scenario.

This LCR deficiency stems from the potential loss of two of the three 500/230 kV transformer banks at Metcalf or loss of the two 500 kV sources to Metcalf and Moss Landing substations. Metcalf is one of the primary supply sources for the GBA, especially for the South Bay, which is becoming the main energy consumption center in the Bay Area and the entire PG&E system. With substantial loads connected in the San Jose, Silicon Valley, and Morgan Hill areas — primarily driven by data centers — this relatively small urban area is projected to experience a load growth of 2.5 GW between 2026 and 2039. This increase represents 40% of the total load growth expected for the GBA during that period.

In addition to the reliability need to bring additional bulk supply to the Greater Bay Area, the ideal alternative should also relieve known congestion on the Panoche-Las Aguillas-Moss Landing 230 kV path.

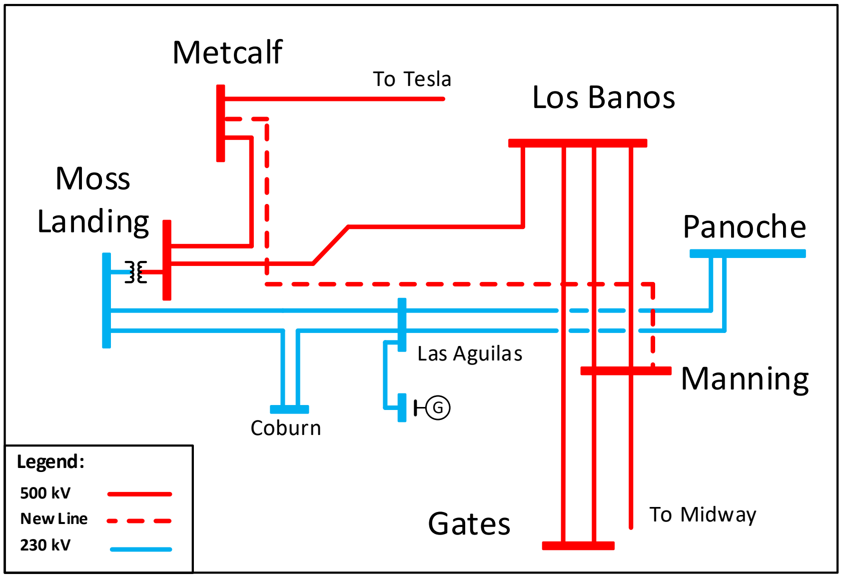
To address this rapid load growth in the South Bay, three projects are in progress. One of these is the San Jose Area HVDC lines, proposed in the TPP 2022-2023 and recently re-scoped. Additionally, there is a proposal to add another 500/230 kV transformer at Metcalf and to reinforce the South Bay area's 115 kV transmission lines, facilitating energy distribution within the region.

The proposed Greater Bay Area 500 kV Transmission Reinforcement is essential for supporting the increased supply needs in the Bay Area and relieving known congestion on the Panoche-Las Aguillas-Moss Landing 230 kV path. With this new supply, the Collinsville substation in the northeast, and the strengthening of Tesla as a major interconnection point for out-of-state wind energy from Wyoming, the GBA will have all three major supply sources with adequate capacity to meet the forecasted long-term demand reliably and economically.

The Greater Bay Area 500 kV Transmission Reinforcement Project consists of the following components:

- Build a new 500 kV line from Manning to Metcalf;
- One new 500 kV connection at both ends of the proposed line; and
- The required 500 kV series capacitors and line reactors.

Figure 2.5-25: Greater Bay Area 500 kV Transmission Reinforcement



The estimated cost of this project ranges from $500 million to $700 million and in-service date of June 2034. Appendix B presents alternative options that were evaluated as part of the decision-making process for this project.

Metcalf 500/230 kV Transformer Bank Addition Project

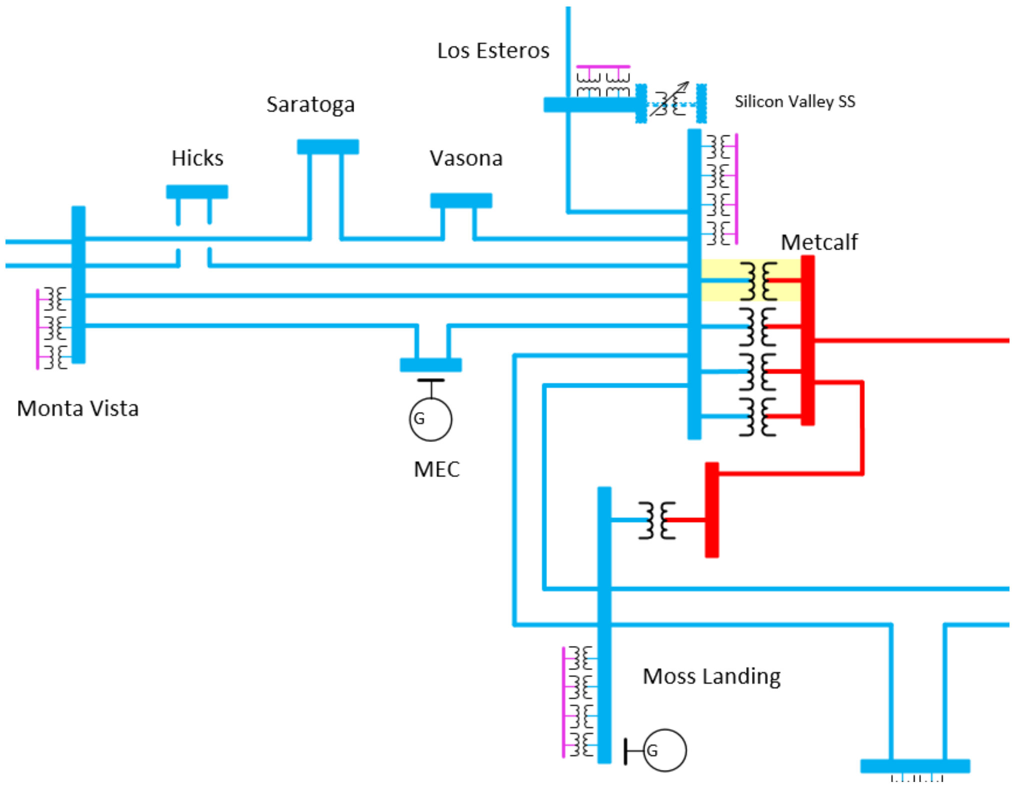
The Metcalf Substation is one of the main supply sources in the South Bay Area, particularly for the San Jose/Silicon Valley area. The three existing 500/230 kV banks at the Metcalf Substation serve as one of the main sources for electricity supply in this region. The demand in this pocket is mainly driven by the distribution customers in the Silicon Valley area and newly interconnected large load, such as data centers and other related data-driven industries.

This project protects against NERC TPL-001-5 Category P6 contingencies and can mitigate the observed thermal violations. After losing two of the three existing 500/230 kV transformers at Metcalf Substation, all the load will be served through the remaining 500/230 kV transformer bank resulting in an overload.
This project will enhance Metcalf Substation as a stronger source for the Bay Area and will provide additional transmission capacity to meet the future local demand. It will also increase this local pocket's operating flexibility and customer reliability. The Metcalf 500/230 kV Transformer Bank Addition Project consists of the following components:

- Install a new (4th) 500/230 kV transformer at the Metcalf Substation to achieve at least 1122 MVA summer emergency rating;
- Upgrade any limiting components as necessary to achieve full transformer capacity; and
- Relocate existing equipment within the substation to accommodate the new transformer.

This project has a cost estimate of $91 million - $182 million with an in-service date of May 2034.

Figure 2.5-26: Metcalf 500/230 kV Transformer Bank Addition Project



Appendix B presents other alternative options that were considered for addressing the identified overload issues.

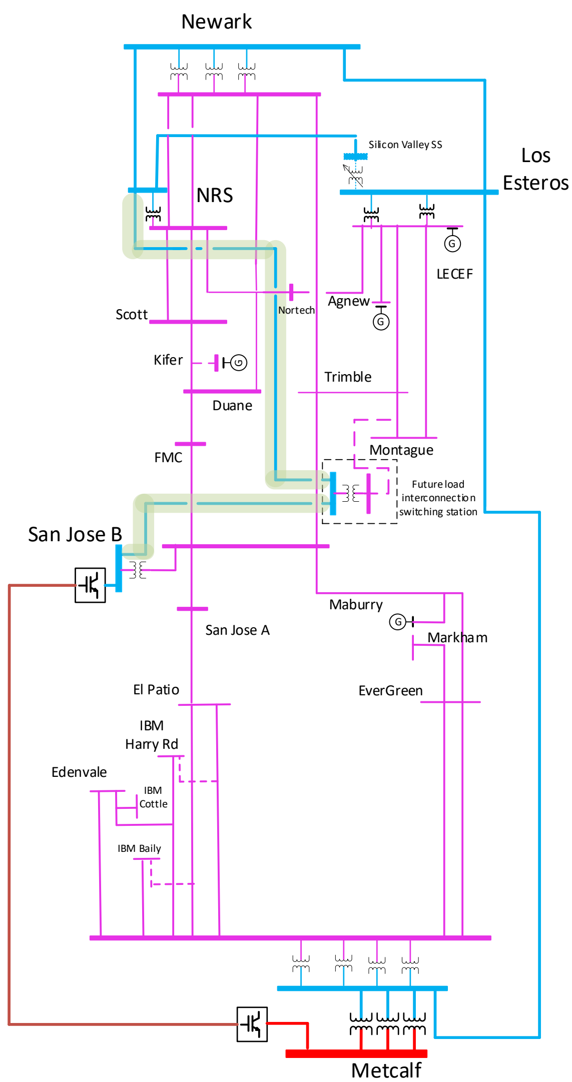
San Jose B-NRS 230 kV line

The long term load forecast in the San Jose area has increased from 2,100 MW in the 2021-2022 transmission plan to around 3,400 MW in the base scenario and around 4,200 MW in the sensitivity scenario in the current 2024-2025 transmission planning studies. Given the significant increase in the long term load forecast in the area, the ISO's studies identified that the previously approved two San Jose area HVDC projects no longer provide the required capacity to reliably serve the load in the area and therefore have been revised and approved by the ISO Board in October 2024. To complement these scope changes and provide further load serving capability in the area, a new 230 kV line is needed between the new San Jose B 230 kV (to be created as part of the Metcalf-San Jose B HVDC project) and Silicon Valley Power (SVP) NRS 230 kV station, as shown in Figure 2.5-27.

This new line provides additional path for the 1000 MW injection at the San Jose B from the HVDC line and also provide 230 kV source to San Jose B during outage of the DC supply.

The distance between the two stations is about 7 miles. To bring this 230 kV source close to the 115 kV network that serves existing and future large data center loads in the area, this new line will also need to be looped into a planned 230/115 kV switching station to be built to connect one of the committed large load interconnections. Using the unit cost, the estimated cost of the project is $150 million to 200 million. The target in-service date June 1, 2030.

Figure 2.5-27: New San Jose B-NRS 230 kV line



South Bay Reinforcement Project

The South Bay planning area is in Santa Clara County. The South Bay (San Jose) is located east of the Lawrence Expressway and is served by three major sources: Newark Substation, Los Esteros Substation, and Metcalf Substation. The Silicon Valley Power (SVP) is within this area. Three SVP receiving stations receive power supplied from the PG&E 230 kV and 115 kV systems. On the PG&E side, power is provided through Newark Substation (115 kV connection), Los Esteros Substation (230 kV and 115 kV connection), and San Jose B substation (115 kV connection).

This area hosts many high-tech companies and serves as a hub for new technologies, including Artificial Intelligence and various data-driven services and applications. The forecasted increase in load in this region is substantial. Previously approved projects, including the San Jose area HVDC lines and the Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV upgrade, were intended to accommodate the anticipated load growth outlined in earlier Transmission Plans. However, due to the aggressive trends reflected in the current load forecast, these projects are no longer sufficient to meet the demand. As a result, the San Jose area HVDC lines have been re-scoped and already approved, and the Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV upgrade is being proposed for re-scoping within this planning cycle. Further details can be found below and in the Greater Bay Area section titled "Reliability Issues with Previously Approved Reliability Projects" in Appendix B.

Moreover, it is not just the South Bay that has been experiencing extraordinary increases in demand in recent forecasts. Other regions, such as the East Bay and the Peninsula, are also seeing significant growth in power demand. This highlights the necessity to enhance the power supply to the Greater Bay Area. In this context, the 500 kV supply for the Bay Area and the Metcalf 500/230 kV Transformer Bank addition projects are also being proposed during this cycle (refer to the project description provided earlier).

With this major transmission projects updates, a reassessment was performed to identify potential new issues in the South Bay 115 kV network to complete the ultimate transmission reinforcement project for this area. The findings after this assessment showed NERC Categories P1, P2, P3 and P6 thermal violations in some sections of the 115 kV paths connecting Metcalf with San Jose B and Monta Vista with Ravenswood, as well as in the 230 kV line Los Esteros – Metcalf.

The project scope to mitigate the overload issues include:

- Reconductor the line drop at San Jose A and at El Patio between the El Patio and San Jose A Substation on the El Patio – San Jose A 115 kV line with a larger conductor to achieve at least 3000 Amps during summer emergency conditions;
- Reconductor the Trimble – San Jose B 115 kV Line with a larger conductor to achieve at least 3000 Amps during summer emergency conditions;
- Reconductor the Kiefer – FMC 115 kV Line with a larger conductor to achieve at least 1400 Amps during summer emergency conditions.
- Reconductor the Mountain View – Monta Vista 115 kV Line with a larger conductor to achieve at least 3000 Amps during summer emergency conditions;
- Reconductor the Whisman – Monta Vista 115 kV Line with a larger conductor to achieve at least 3000 Amps during summer emergency conditions;
- Remove the limiting elements at the Metcalf Substation on the Los Esteros – Metcalf 230 kV line to achieve at least 725 MVA during summer emergency conditions;
- Ringwood loop: Loop Ringwood onto the Los Esteros-Montague 115 kV line by extending Los Esteros-Montague via two new line sections to Ringwood to terminate the new Los Esteros – Ringwood and Ringwood – Montague 115 kV lines. The looping

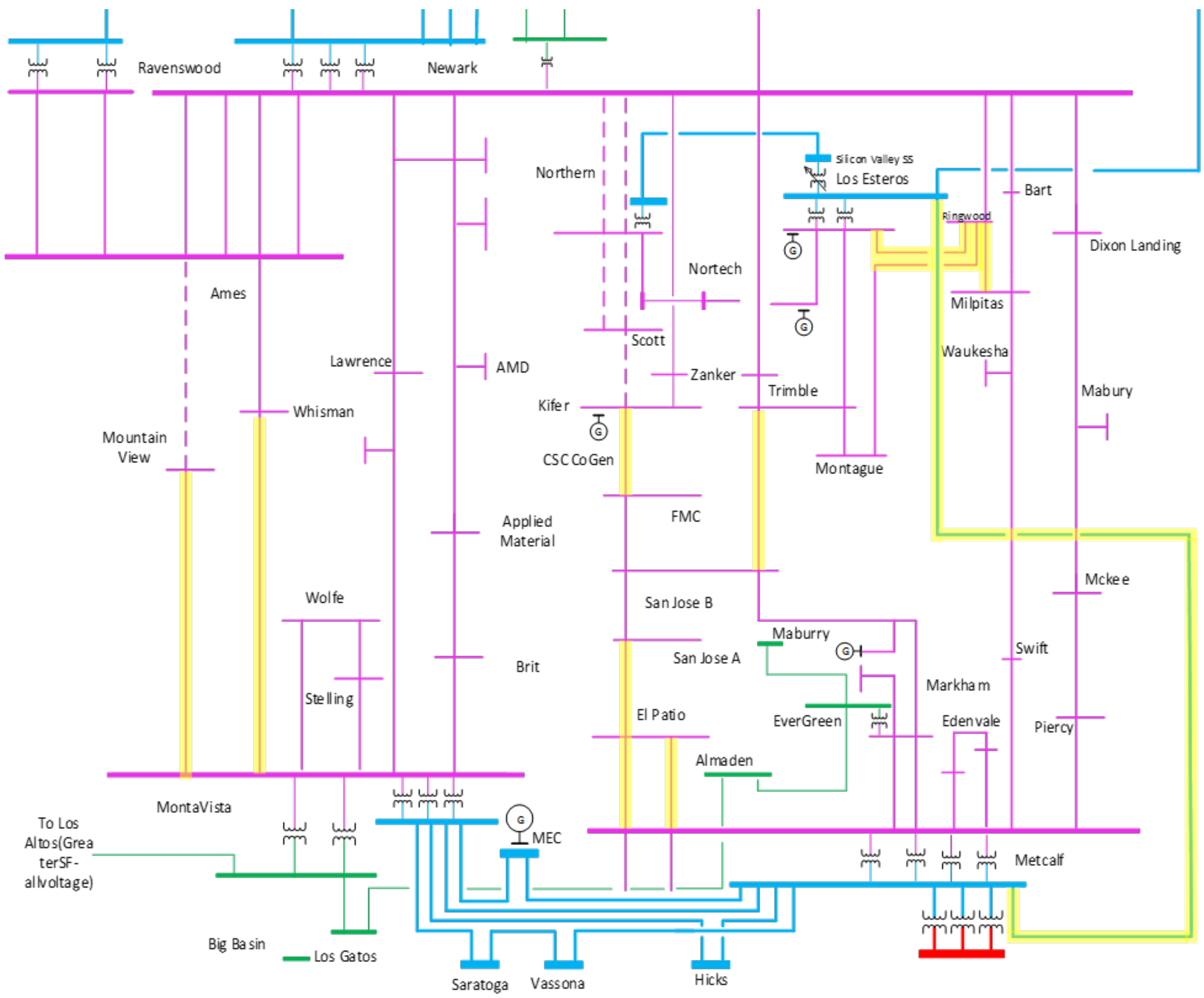
conductor must achieve at least 2000 Amps during summer emergency conditions, and 3000 Amps during summer emergency conditions is preferred; and

- Reconductor the Ringwood – Milpitas 115 kV Line with a larger conductor to achieve at least 3000 Amps during summer emergency conditions.

The set of 115 kV reinforcements proposed in this project, along with the major 500 kV transmission new project for the Bay Area and the re-scoping of two other projects in the San Jose area, will provide sufficient transmission capacity to meet long-term load growth needs. For this reason, Appendix B presents alternative options that may be more suitable for addressing the identified overload issues.

This project has a cost estimate of $217 million - $434 million with an expected in-service date May 2032; however, components of the project may have different in-service dates due to the complex dynamics of load interconnections in this region or other technical difficulties associated with the particular component of the project.

Figure 2.5-28: South Bay Reinforcement Project



Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade (re-scope)

The San Jose area has two main supply sources, the Metcalf and Newark substations, which are connected by different 115 kV loops. One of the most important corridors links the Metcalf-Piercy and Newark-Dixon Landing substations, while another connects the Metcalf-Swift and Newark-Milpitas substations. These two corridors are expected to carry a net load of 466 MW in 2026, with an anticipated increase to 882 MW by 2039.

The Newark-Dixon Landing, Piercy-Metcalf, McKee-Piercy, and Metcalf-Swift 115 kV lines are projected to be overloaded during multiple P1, P2, P6, and P7 contingency scenarios in the summer peak cases of 2026, 2034, and 2039. This would occur when one or two of the lines at either end (Newark or Metcalf) fail, leaving the load connected through a single 115 kV circuit.

The Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade project, which was approved in the 2003 Transmission Planning Process (TPP), was intended to alleviate these long-term overloads. However, due to significant increases in the load forecast, as cited in previous projects, and the additional load growth expectation in the San Jose area has motivated new transmission projects for the area and the re-scoping of existing ones.

Particularly for this project, the reconductor capacity proposed for these lines is now deemed insufficient to prevent overloads during multiple contingency scenarios. Consequently, the project's scope has been revised, resulting in changes to both the scope of work and the cost estimates. The ISO has agreed with this revision and is recommending approval of the changes to the project scope as follows:

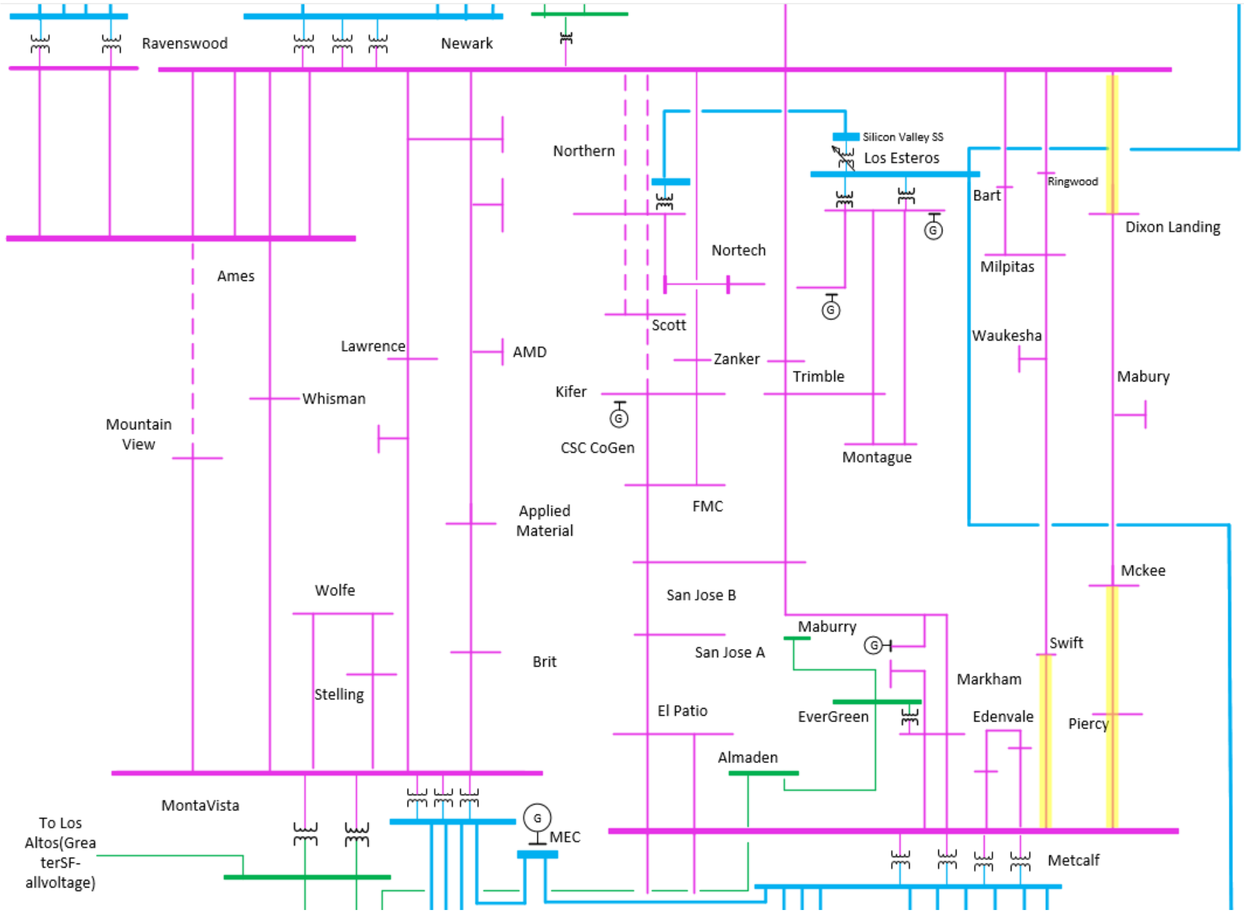
Original Scope:

The project originally proposed to reconductor the following 115 kV lines to 795 ACSS conductors or an equivalent: Piercy-Metcalf, Swift-Metcalf, and Newark-Dixon Landing. At the time of the proposal, the estimated cost was between $20 million - $50 million. However, the current cost estimate is $92 million - $184 million.

Proposed New Scope:

The revised scope aims to reconductor the following 115 kV lines using advanced conductors to achieve a summer emergency rating of 3,000 Amps or higher: Piercy-Metcalf, Swift-Metcalf, Newark-Dixon Landing, and McKee-Piercy. The estimated cost for this new scope is between $124 million and $248 million, with an expected in-service date in the first quarter of 2028.

Figure 2.5-29: Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade (re-scope)



Ames Distribution – Palo Alto 115 kV transmission line

The City of Palo Alto, Utilities (CPAU) is interconnected to theISO control grid at the Palo Alto Switching Station and served via three 115 kV lines from Ravenswood and Cooley Landing Substations. The three lines share a common corridor and create two double circuit tower lines (DCTL) south of Ravenswood. The Ravenswood-Palo Alto Nos. 1 & 2 115 kV DCTL begins at Ravenswood Substation while the Ravenswood-Palo Alto No. 1 & Cooley Landing-Palo Alto 115 kV DCTL begins south of Cooley Landing Substation. This configuration has the potential to leave the City of Palo Alto served with a single 115 kV line in the event of either of the two DCTL outages.

The reliability assessment identified P6 and P7 NERC category contingencies that result in thermal overloads on the Ravenswood - Palo Alto #1 and #2, and the Cooley Landing-Palo Alto 115 kV lines, starting in 2034. Additionally, the CPAU anticipates that its load will grow even faster than what is projected in the current load forecast, which includes new data centers, electric vehicles, and the electrification of buildings.

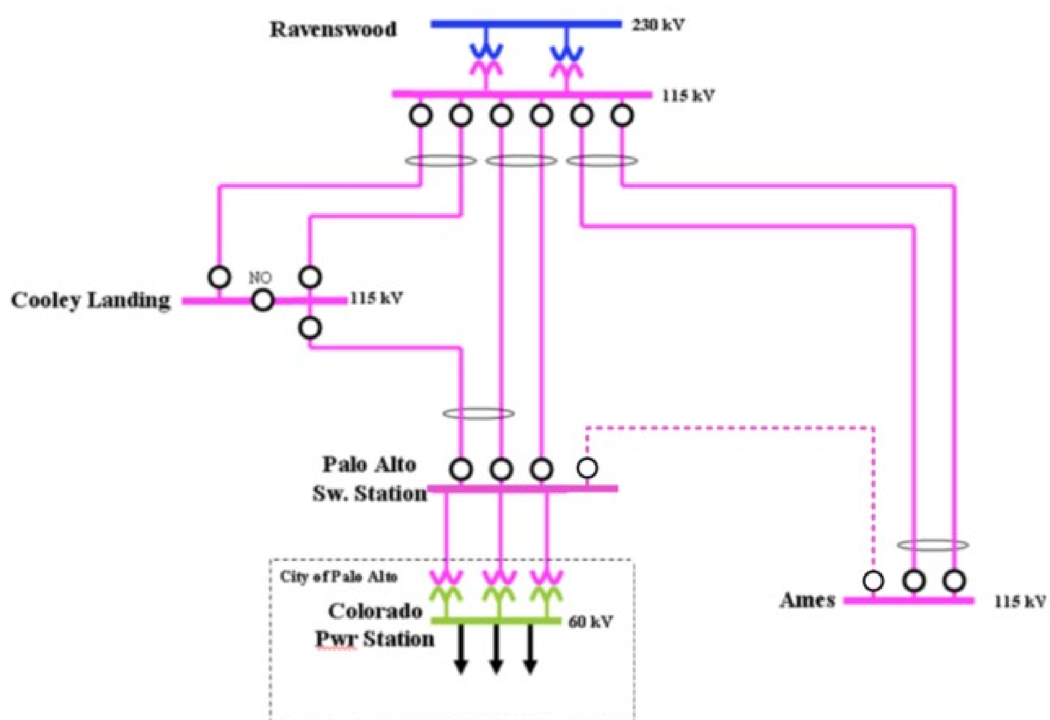
Another significant concern to consider is that the common corridor shared by all three 115 kV lines serving the City of Palo Alto is located near the end of a runway at a Santa Clara County General Aviation Airport. This corridor has experienced two aircraft strikes in recent years. To address this safety issue, it is recommended to establish a new 115 kV circuit from a different location, avoiding both Cooley Landing and Ravenswood, thus steering clear of the aforementioned common corridor.

The project scope to mitigate overload issues and provide a new supply source for Palo Alto includes the following:

- Construct a new Ames Distribution – Palo Alto 115 kV line using existing vacant tower positions and idle lines, with a minimum capacity requirement of 1500 Amps;
- Expand the Ames Distribution Station to allow for one additional 115 kV connection. It requires the upgrade Ames Distribution to ring bus station; and
- Expand the Palo Alto Switching Station to allow for one additional 115 kV connection.

The estimated cost for this project ranges from $42 million to $84 million with an in-service date of May 2034. There is an existing maintenance project to upgrade Palo Alto Switching station to BAAH. This maintenance project needs to be completed for the connection of the new Ames Distribution-Palo Alto line at the Palo Alto switching station. Appendix B presents other alternative options that were considered for addressing the identified overload issues.

Figure 2.5-30: Ames – Palo Alto 115 kV transmission line



2.5.3 Previously Approved Projects on Hold

Moraga-Sobrante 115 kV Line Reconductor Project

The ISO recommends the Moraga-Sobrante remain on hold for this planning cycle. The reliability assessment of the PG&E Greater Bay planning area identified P2 contingencies which resulted in overloads on the Moraga-Sobrante 115 kV line only in the longer-term planning horizon. The ISO will continue to assess the need in future planning cycles.

2.5.4 Previously Approved Projects recommended to be cancelled

Ravenswood 230/115 kV Transformer #1 Limiting Facility Upgrade

The Ravenswood 230/115 kV transformer #1 limiting facility upgrade project was approved in the 2018-2019 TPP. Upon further assessment with PG&E, the rating of the identified limiting facilities are higher than originally indicated and the upgrade project is no longer required. The ISO is recommending canceling the Ravenswood 230/115 kV transformer #1 limiting facility upgrade project.

2.5.5 Projects for Review in 2024-2025 Transmission Planning Process

Warnerville-Newark Transmission Expansion Project (WaNTEP)

As a result of increasing load forecast levels in Greater Bay area, the ISO has recommended for approval a number of transmission projects in the area, including the Greater Bay area 500 kV transmission reinforcement project. The ISO has also reviewed the Warnerville-Newark Transmission Expansion Project (WaNTEP) that Hetch Hetchy Water and Power (HHWP) submitted into the request window. While the ISO's analysis to date has not identified a sufficient need for the transmission project, the ISO will continue discussions with HHWP on this project as an alternative to further address the long-term reliability needs in the Greater Bay area related to this planning cycle as well as those anticipated in the 2025-2026 transmission planning cycle.

2.6 Conclusion

The 28 new reliability-driven projects are required in this transmission planning cycle for a total estimated cost of $4.574 billion are listed below. Table 2.6-1 includes the seven projects that were approved by ISO management in this planning cycle for an estimated total cost of $199.7 million. Table 2.6-2 lists the 21 projects recommended for approval in this planning cycle for and estimated cost of 4.374 billion.

Table 2.6-1: Management Approved Transmission Projects

No.	Project Name	PTO Area	Planning Area	Est Cost ($M)
1	Jefferson-Stanford 60 kV Re-cabling	PG&E	GBA	40
2	Konocti – Eagle Rock 60 kV Line Reconductoring	PG&E	NCNB	32.5
3	Moraga 230/115 kV Transformer Bank Addition	PG&E	GBA	40

No.	Project Name	PTO Area	Planning Area	Est Cost ($M)
4	Pittsburg-Kirker 115 kV Line Section Limiting Elements Upgrade	PG&E	GBA	0.2
5	San Miguel New 70 kV Line	PG&E	CCLP	30
6	Sobrante 230 kV Bus Upgrade	PG&E	GBA	15
7	Coronado Island Reliability Reinforcement Phase I	SDG&E	SDG&E	42
			Total	**199.7**

Also, further assessment of the Warnerville-Newark Transmission Expansion Project as an additional potential reinforcement to address long-term reliability needs will be conducted as an extension of the 2024-2025 Transmission Plan.

Table 2.6-2: Recommended Reliability Transmission Projects

No.	Project Name	PTO Area	Planning Area	Est Cost ($M)
1	Sloan Canyon Tertiary Reactors	GLW	VEA	10
2	Ames Distribution – Palo Alto 115 kV transmission line	PG&E	GBA	84
3	Cortina #3 60 kV Reconductoring	PG&E	CVLY	55.5
4	Gold Hill-El Dorado Reinforcement	PG&E	CVLY	127
5	Greater Bay Area 500 kV Transmission Reinforcement	PG&E	GBA	700
6	Metcalf Substation 500/230 kV Transformer Bank Addition	PG&E	GBA	182
7	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade Re-scope	PG&E	GBA	135
8	North Oakland Reinforcement Project	PG&E	GBA	1127
9	San Jose B – NRS 230 kV line	PG&E	GBA	200
10	San Mateo 230/115 kV Transformer Bank Addition Project	PG&E	GBA	110
11	South Bay Reinforcement Project	PG&E	GBA	434
12	South Oakland Reinforcement Project	PG&E	GBA	250
13	West Fresno 115 kV Voltage Support	PG&E	Fresno	60
14	Alamitos 230 kV SCD Upgrade	SCE	SCE Main	5
15	Julian Hinds-Mirage 230 kV Advanced Reconductor	SCE	Eastern	76
16	Kramer-Coolwater 115 kV Line Looping into Tortilla 115 kV Substation	SCE	NOL	37
17	Serrano 230 kV SCD GIS Bus Split	SCE	SCE Main	28
18	Serrano 500 kV SCD Mitigation	SCE	SCE Main	183
19	Tortilla 115 kV Capacitor Replacement	SCE	NOL	5
20	Coronado Island Reliability Reinforcement Phase II	SDG&E	SDG&E	66
21	Downtown Reliability Reinforcement	SDG&E	SDG&E	500
			Total	**4374.5**

One previously-approved transmission project was on hold pending further assessment. Based on this reliability assessment, the ISO recommends to keep the Moraga-Sobrante 115 kV Line Reconductor project on hold.

One previously-approved transmission project is recommended for cancelation. Based on this reliability assessment, the ISO recommends to cancel the Ravenswood 230/115 kV transformer #1 limiting facility upgrade project.

Intentionally left blank

Chapter 3

3 Policy-Driven Need Assessment

3.1 Background and Objective

The overarching public policy objective for the California ISO's Policy-Driven Need Assessment is the state's mandate for meeting renewable energy and greenhouse gas (GHG) reduction targets while maintaining reliability. For 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 during all hours of the year.

The CPUC issued a Decision[41] 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 GHG reduction target at the least cost, while maintaining electric service reliability and meeting other state goals. In subsequent years, the CPUC has been developing integrated resource plans and transmitting them to the ISO for use in the annual transmission planning process.

As mentioned earlier, the more coordinated and proactive approach taken in the ISO's current annual transmission planning process is part of a larger set of interrelated and coordinated planning and resource development activities being undertaken between the state energy agencies and the ISO.

The CPUC issued Decision 24-02-047 [42] on February 15, 2024 adopting the 2023 Preferred System Plan (PSP) as the base portfolio and a sensitivity portfolio with high gas retirement assumptions for use in the 2024-2025 Transmission Planning Process (TPP). The portfolios are based on the 25 million metric ton (MMT) greenhouse gas (GHG) target by 2035 and the California Energy Commission's 2022 Integrated Energy Policy Report demand forecast. The base portfolio is used to identify reliability and policy-driven transmission needs for approval in the ISO 2024-2025 TPP. The sensitivity portfolio is designed to test the transmission buildout needed for a grid stress case where about 12.3 gigawatts of natural gas generation resources are retired by 2039. The Decision is accompanied by a document entitled Modeling Assumptions for the 2024-2025 Transmission Planning Process[43], which provides the methodology and results of the resources-to-busbar mapping[44] process as well as other assumptions for use in the ISO TPP. This detailed information establishing resource types and

---

41 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K878/209878964.PDF

42 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M525/K918/525918033.PDF

43 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp/modeling_assumptions_24-25tpp.pdf

44 The busbar is the electrical connection within the ISO planning models where the generator is connected to the electrical system.

locations is pivotal to the zonal approach to transmission planning, which is used to shape and guide interconnection and resource procurement processes.

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;
- Gain further insights to inform future portfolio development; and
- Set out the zonal capacities that are being established through coordinated transmission planning and resource planning, to shape and guide interconnection and resource procurement.

3.3 Study methodology and components

The policy assessment is geared towards capturing the impact of resource 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. The following provides a description of the assessments the ISO undertakes under the umbrella of the overall policy-driven transmission analysis to integrate the resources identified in the CPUC portfolios to meet the state's greenhouse gas goals.

Policy-driven reliability assessment

The policy-driven reliability assessment is used to identify transmission constraints that need to be modeled in production cost simulations to capture the impact on renewable curtailment of the constraints caused by transmission congestion. The reliability assessment component of the overall policy-driven analysis is addressed in the reliability assessment presented in Chapter 2 and Appendix B.

On-peak deliverability assessment

The on-peak deliverability assessment is designed to ensure portfolio resources selected with full capacity deliverability status (FCDS) are deliverable and can count towards meeting resource adequacy needs. The assessment examines whether sufficient transmission capability exists to transfer resource output from a given sub-area to the aggregate of the ISO control-area load when the generation is needed most. The ISO performs the assessment in accordance with the On-peak Deliverability Assessment Methodology.[45]

[45] https://www.caiso.com/documents/on-peak-deliverability-assessment-methodology.pdf

Off-peak deliverability assessment

The off-peak deliverability assessment is performed to identify potential transmission system limitations that may cause excessive renewable energy curtailment. The ISO performs the assessment in accordance with the Off-Peak Deliverability Assessment Methodology.[46]

Production cost model (PCM) simulation

Production cost models for the base and sensitivity portfolios are used to identify renewable curtailment and transmission congestion in the ISO Balancing Authority Area. The PCM for the base portfolio is used in the policy-driven assessment covered in this section as well as the economic assessment discussed in Chapter 4 and Appendix G. The PCM with the sensitivity portfolios is used only in the policy-driven assessment. Details of PCM modeling assumptions and approaches are provided in Chapter 4 and Appendix G.

3.4 Resource Portfolios

As mentioned in Section 3.1, the 2023 PSP base portfolio and high gas generation retirement sensitivity portfolio were transmitted by the CPUC for study in the ISO 2024-2025 transmission planning process. The detailed portfolios are available at the CPUC website.[47]

Table 3.4-1 includes the total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO). The numbers also include any portfolio adjustments based on CPUC guidance including unaccounted for TPD allocation modeled and additional in-development resources modeled by PTOs based on projects status. The portfolios are comprised of solar, wind (in-state, out-of-state and offshore), battery storage (4-hour and 8-hour), geothermal, long-duration energy storage, biomass/biogas and distributed solar resources and net dependable gas generation capacity not retained. All portfolio resources are modeled in policy-driven assessments based on the study plan and deliverability methodology.

46 http://www.caiso.com/Documents/Off-PeakDeliverabilityAssessmentMethodology.pdf

47 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp

Table 3.4-1: Base and Sensitivity Portfolios by Resource Type and Deliverability Status

Resource Type	2034 Baseline Portfolio			2039 Base Portfolio			2039 Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	8,501	10,715	19,216	10,878	19,608	30,486	21,324	30,614	51,938
Wind – In State	5,203	921	6,123	6,103	921	7,023	4,885	855	5,739
Wind – Out-of-State	6,096	0	6,096	9,096	0	9,096	7,066	0	7,066
Wind - Offshore	3,855	0	3,855	4,531	0	4,531	0	0	0
Li Battery – 4 hr	18,951	468	19,419	18,227	468	18,695	13,047	468	13,515
Li Battery – 8 hr	1,618	0	1,618	7,115	0	7,115	15,612	0	15,612
Long Duration Energy Storage (LDES)	1,030	0	1,030	1,080	0	1,080	3,680	0	3,680
Geothermal	1,969	0	1,969	1,969	0	1,969	5,089	0	5,089
Biomass/Biogas	171	0	171	171	0	171	22	0	22
Distributed Solar	260	0	260	283	0	283	335	0	335
Net Dependable Gas Capacity not Retained	(3,448)	0	(3,448)	(4,418)	0	(4,418)	(12,274)	0	(12,274)
Total	44,206	12,104	56,309	55,035	20,997	76,031	58,786	31,937	90,722

3.4.1 Mapping of portfolio resources to transmission substations

The portfolios that RESOLVE[48] generates are at the zonal level. As a result, the portfolios have to be mapped to the busbar level for use in the ISO transmission planning process. The resource-to-busbar mapping process is documented in the CPUC report entitled *Methodology for Resource-to-Busbar Mapping & Assumptions for the Annual TPP*[49] with further refinements as described in the CPUC staff report entitled *Modeling Assumptions for the 2024-2025 Transmission Planning Process.*[50] Workbooks containing the busbar mapping results are provided for years 2034 and 2039[51] for the base portfolio and year 2039[52] for the sensitivity portfolio. The policy-driven assessment is primarily performed for year 2034.

Figure 3.4-1 illustrates the interconnection planning areas along with total base and sensitivity portfolio resource amounts in each area for year 2034 and 2039 based on the CPUC busbar mapping results.

48 RESOLVE is the resource optimization model that the CPUC uses to develop resource portfolios

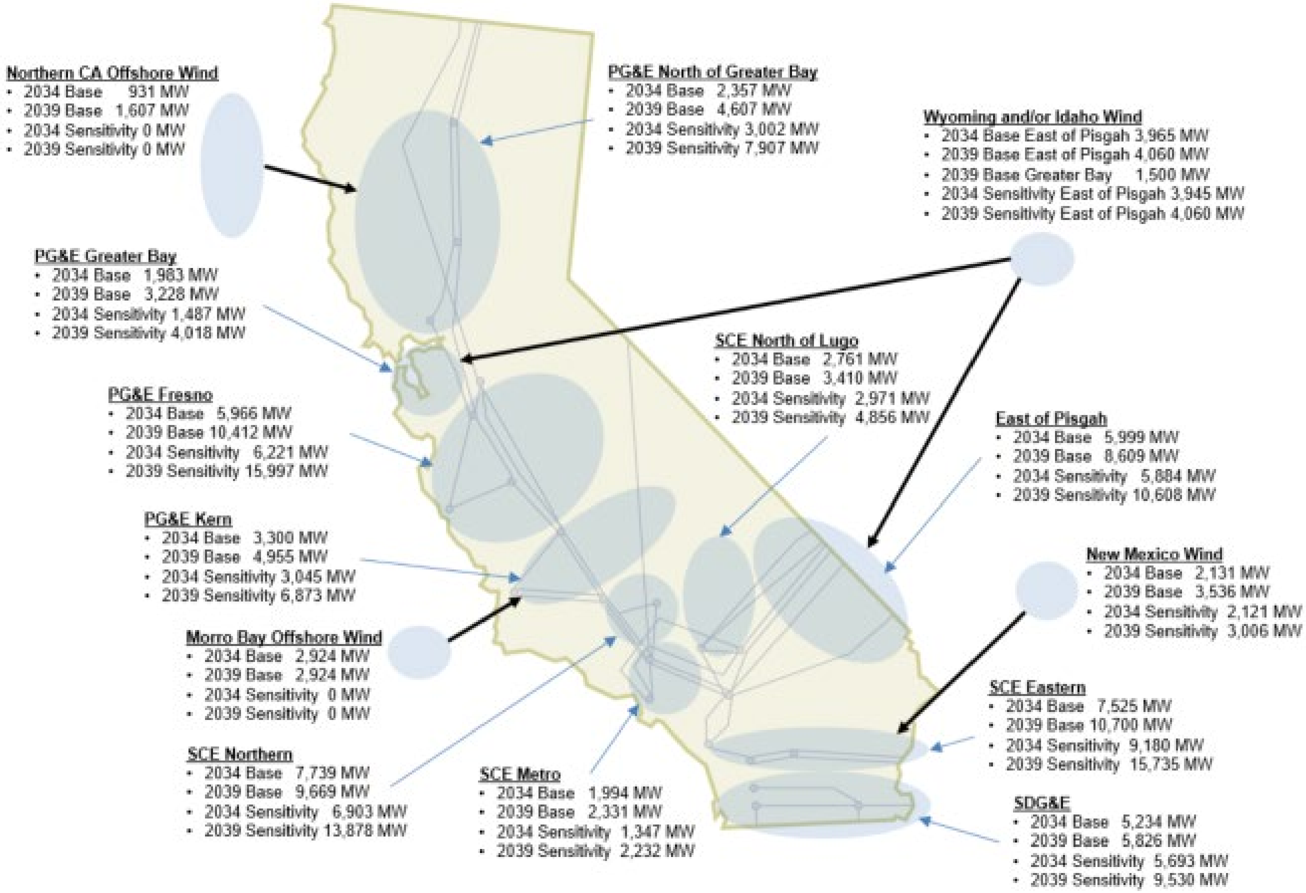
49 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2023-2024-tpp-portfolios-and-modeling-assumptions/busbarmethodologyfortppv20230109.pdf

50 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp/modeling_assumptions_24-25tpp.pdf

51 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/assumptions-for-the-2024-2025-tpp/final_dashboard_24-25tpp_02-15-24.xlsx

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

Figure 3.4-1: 2034 and 2039 Base and Sensitivity Portfolios by Area



3.5 Transmission Interconnection Zone Assessments

On-peak and off-peak deliverability assessments were conducted for each of the transmission interconnection zones to determine where constraints are on the transmission system that limit deliverability of portfolio resources. The on-peak deliverability assessment for the sensitivity portfolio was also performed to test the transmission needs associated with 16 GW gas generation retirement.

Transmission mitigation is identified to address the constraints after considering other solutions so resources in the portfolio can be deliverable. The ISO then conducts its technical and economic evaluations of the transmission alternatives identified by the ISO or by stakeholders to select the most effective and efficient solution. Details of the technical assessments and comparisons of alternatives are provided in Appendix F.

The following section summaries the policy assessment results for each interconnection area and the potential mitigation solutions.

3.5.1 PG&E North of Greater Bay Interconnection Area

The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E and North of

Greater Bay interconnection area are listed in Table 3.5-1. The portfolios in the interconnection area are comprised of solar, wind (in-state and offshore), battery storage, geothermal, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-1: PG&E North of Greater Bay Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	2034 Baseline Portfolio			2039 Base Portfolio			2039 Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	275	320	595	430	1,115	1,545	1,275	2,457	3,732
Wind – In State	778	320	1,097	1,678	320	1,997	674	260	933
Wind – Out-of-State	0	0	0	1,500	0	1,500	0	0	0
Wind - Offshore	931	0	931	1,607	0	1,607	0	0	0
Li Battery – 4 hr	293	0	293	293	0	293	93	0	93
Li Battery – 8 hr	88	0	88	488	0	488	1,073	0	1,073
Long Duration Energy Storage (LDES)	5	0	5	5	0	5	959	0	959
Geothermal	144	0	144	144	0	144	1,074	0	1,074
Biomass/Biogas	96	0	96	96	0	96	6	0	6
Distributed Solar	37	0	37	37	0	37	37	0	37
Total	**2,647**	**639**	**3,287**	**6,279**	**1,434**	**7,713**	**5,191**	**2,716**	**7,907**

The resources as identified in the CPUC busbar mapping for the PG&E North of Greater Bay interconnection area are illustrated on the single-line diagram in Figure 3.5-1 and Figure 3.5-2.

Figure 3.5-1: North of Greater Bay Interconnection Area – Mapped 2034 Baseline Portfolio

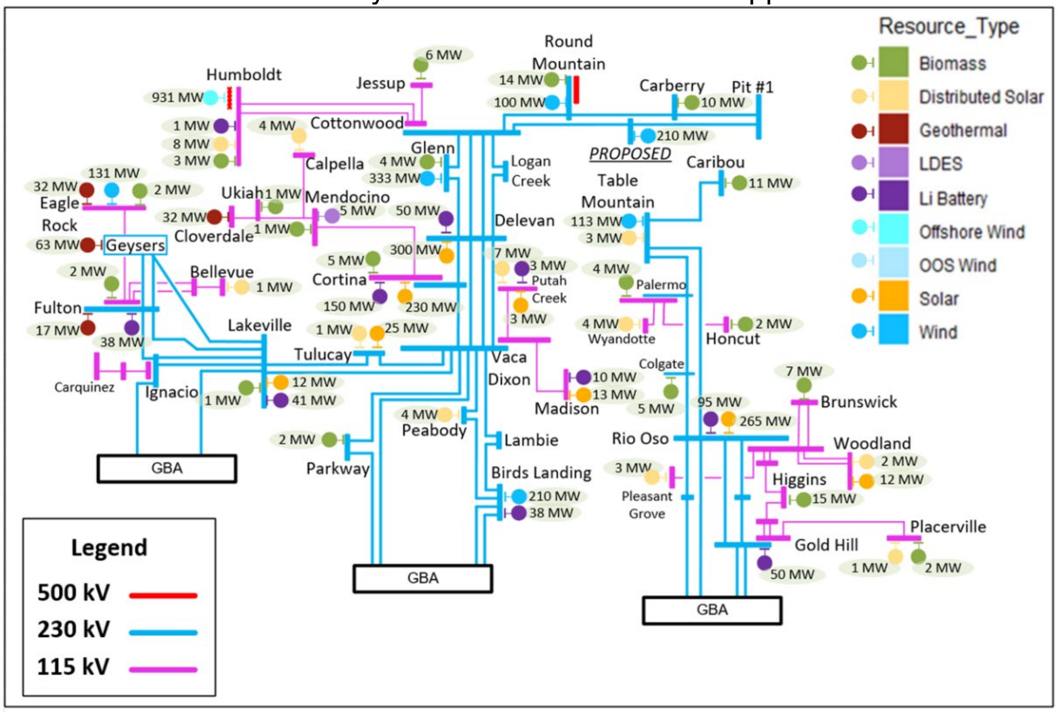
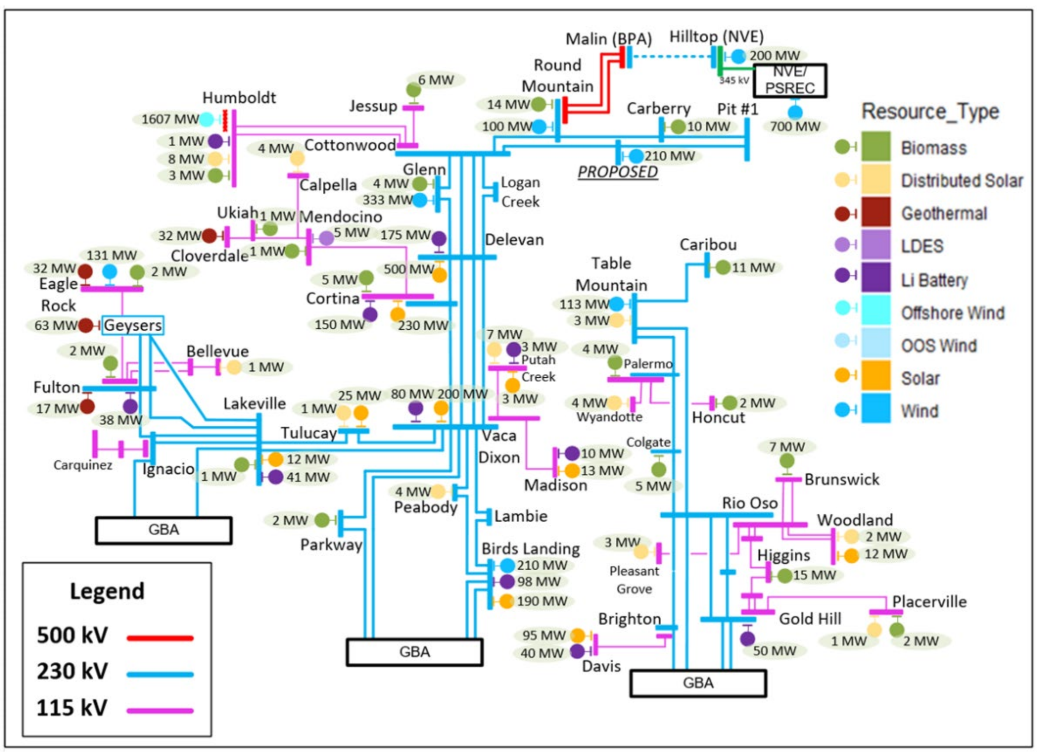


Figure 3.5-2: North of Greater Bay Interconnection Area – Mapped 2039 Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the North of Greater Bay interconnection areas along with the recommended mitigation plans are identified in Table 3.5-2.

Table 3.5-2: North of Greater Bay Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Cortina - Mendocino No.1 115 kV (Mendocino Sub 115 kV to Lucerine Jct1 115 kV)	2039 Sensitivity	81	150	0	347	Sensitivity Only
Cortina - Vaca 230 kV Line	2039 Baseline	720	0	549	1224	Continue to Monitor
	2039 Sensitivity	706	330	680	1693	
Eagle Rock- Fulton-Silverado 115 kV (Eagle rock sub to Ricon Jct Jct2 115 kV)	2034 Baseline	282	150	147	290	Reconductor Eagle Rock-Fulton- Silverado 115 kV Line
	2039 Baseline	277	0	165	134	
	2039Sensitivity	273	155	355	94	
Fulton - Hopland 60 kV (Hopland Jct 60 kV to Cloverdale Jct 60 kV)	2034 Baseline	202	150	53	350	Local constraint. Will be addressed in GIP.
	2039 Baseline	197	0	53	553	
	2039 Sensitivity	193	155	207	531	
Geyser # 12 - Fulton 230 kV (Fulton - Geyser#14 Jct)	2039 Baseline	60	0	61	2	Continue to Monitor
GEYSER # 3 - CLOVERDALE 115K (CLOVERDALE 115KV to MPE TAP115KV)	2034 Baseline	159	0	0	353	Local constraint. Will be addressed in GIP.
	2039 Sensitivity	157	0	0	439	
Geyser #3 - Eagle Rock 115 kV	2034 Baseline	90	0	64	30	Local constraint. Will be addressed in GIP.
	2039 Baseline	85	0	70	33	
	2039 Sensitivity	85	0	81	22	
HOPLAND BANK 115/60.00 BANK NO.2	2034 Baseline	202	0	39	239	Maintenance Project
	2039 Baseline	197	0	20	642	
	2039 Sensitivity	193	5	45	618	
Konocti - Eagle Rock 60 kV	2034 Baseline	191	0	53	179	Local constraint. Will be

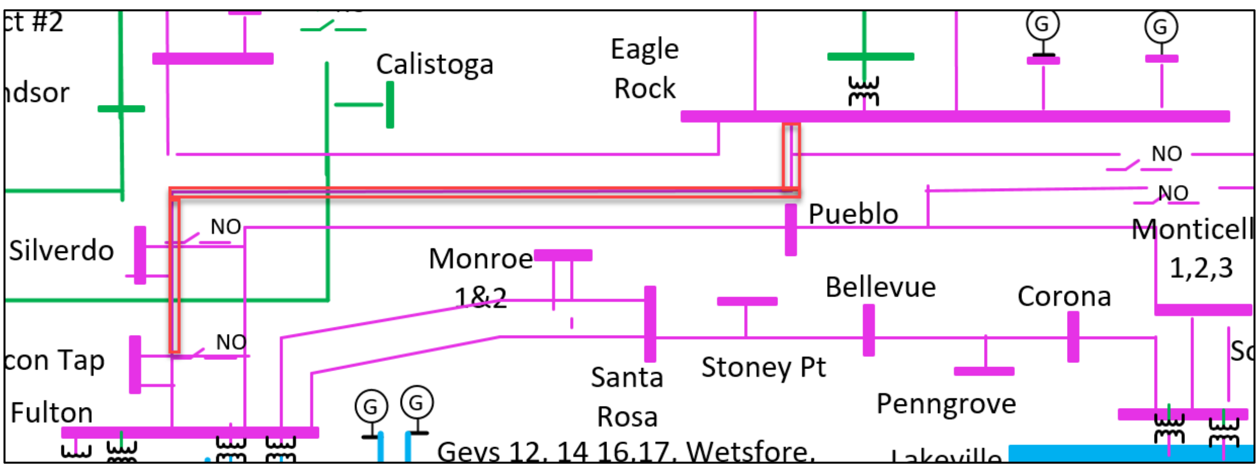
Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
						addressed in GIP.
Lincoln - Pleasant Grove 115 kV Line	2039 Baseline	100	0	0	459	Local constraint. Will be addressed in GIP.
	2039 Sensitivity	82	135	0	539	
Ukiah-Hopland-Cloverdale 115 kV (Ukiah sub 115 kV to Hopland Jct 115 kV)	2034 Baseline	191	0	0	455	Local constraint. Will be addressed in GIP.
	2039 Sensitivity	189	0	0	471	

Based on the constraints identified in Table 3.5-2, there is one policy-driven upgrade identified in the North of Greater Bay interconnection planning areas.

Eagle Rock-Fulton-Silverado 115 kV Line Reconductor

To mitigate overloads identified in the on-peak baseline deliverability study, the ISO is recommending approval of the reconductor of the Eagle Rock-Fulton-Silverado 115 kV line. The estimated project cost is $92.9M, with an estimated in-service year of 2031. The scope includes reconductoring Eagle Rock-020/087A (about 27 miles) with minimum rating of 1236 Amps or higher and update any limiting components at the substation (may require relay upgrades) and reconductoring 020/87A-037/191A (about 3 miles) with minimum rating of 1687 Amps or higher and update any limiting components at the substation (if any).

Figure 3.5-3: Eagle Rock-Fulton-Silverado 115 kV Line Reconductor



Off-Peak Deliverability Assessment

In the off-peak deliverability assessment of the North of Greater Bay interconnection, there were no constraints identified for the base portfolios.

Conclusion and recommendation

The PGE North of Greater Bay area base and sensitivity portfolios deliverability assessment identified on-peak deliverability constraints. The Eagle Rock-Fulton-Silverado 115 kV (Eagle rock substation to Ricon Jct 2 115 kV) line constraint is identified in 2034 on-peak scenario and theISO recommends reconductoring the line as mitigation.

3.5.2 PG&E Greater Bay Interconnection Area

The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E Greater Bay interconnection area are listed in Table 3.5-1. The portfolios in the interconnection area are comprised of solar, wind (in-state and offshore), battery storage, geothermal, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-3: PG&E Greater Bay Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	2034 Baseline Portfolio			2039 Base Portfolio			2039 Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	0	100	100	470	215	685	670	670	1,340
Wind – In State	688	90	778	688	90	778	698	90	788
Wind – Out-of-State	0	0	0	0	0	0	0	0	0
Wind - Offshore	0	0	0	0	0	0	0	0	0
Li Battery – 4 hr	829	0	829	879	0	879	170	0	170
Li Battery – 8 hr	212	0	212	822	0	822	1,645	0	1,645
Long Duration Energy Storage (LDES)	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0
Biomass/Biogas	26	0	26	26	0	26	5	0	5
Distributed Solar	40	0	40	40	0	40	69	0	69
Total	1,794	190	1,984	2,924	305	3,229	3,258	760	4,018

The resources as identified in the CPUC busbar mapping for the PG&E Greater Bay interconnection area are illustrated on the single-line diagram in Figure 3.5-4 and Figure 3.5-5.

Figure 3.5-4: Greater Bay Interconnection Area – Mapped 2034 Baseline Portfolio

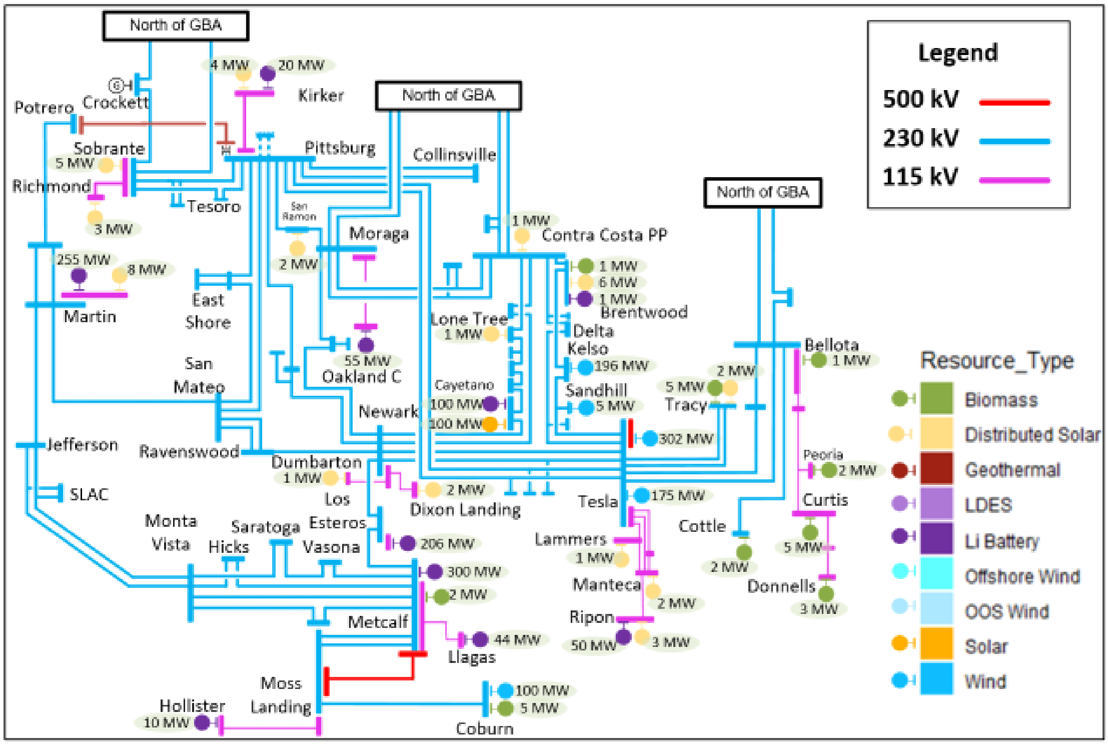
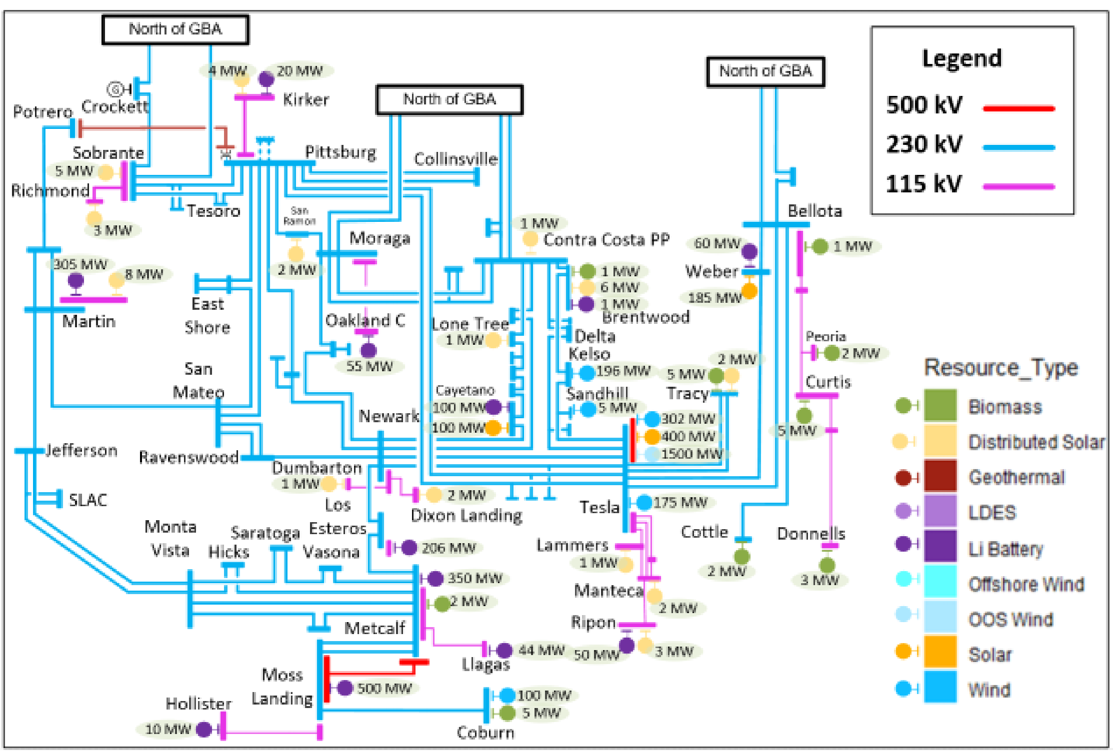


Figure 3.5-5: Greater Bay Interconnection Area – Mapped 2039 Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the Greater Bay interconnection area along with the recommended mitigation plans are identified in Table 3.5-4.

Table 3.5-4: Greater Bay Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Bellota - Lockford 230 kV Line	2039 Baseline	253	0	0	861	Local constraint. Will be addressed in GIP.
	2039 Sensitivity	244	228	362	762	
Eastshore-San Mateo 230 kV Line	2034 Baseline	1	0	0	11	Continue to monitor
El Patio-San Jose Sta. 'A' 115 kV Line	2039 Sensitivity	0	470	0	683	Sensitivity Only
Kifer-FMC 115 kV Line	2034 Baseline	2	376	229	149	Reduce Portfolio BESS
Los Esteros - Nortech 115 kV line	2039 Sensitivity	0	206	0	479	Sensitivity Only
Manteca - Vierra 115 kV Lin	2034 Baseline	1	0	0	186	Local constraint. Will be addressed in GIP.
Melones - Cottle 230 kV Line	2034 Baseline	455	0	0	761	SSN Only
Metcalf-El Patio No. 2 115 kV Line	2034 Baseline	0	300	240	60	Reduce Portfolio BESS
Newark-Northern Receiving Station #1 115 kV Line	2039 Baseline	1	0	0	115	Sensitivity Only
Ripon - Ripon Jct 115 kV Line	2034 Baseline	3	50	48	5	Reduce Portfolio BESS
San Jose - Trimble 115 kV Line	2034 Baseline	2	420	0	692	SSN only
San Jose Sta 'A'-'B' 115 kV Line	2039 Sensitivity	0	470	0	560	Sensitivity Only
Tesla - Westley 230 kV Line	2034 Baseline	1099	201	159	1901	Bay Area Supply Project
	2039 Baseline	899	0	109	1604	
	2039 Sensitivity	898	201	255	1736	

Based on the constraints identified in Table 3.5-4, there are no policy-driven upgrades identified in the Greater Bay interconnection planning areas.

Off-Peak Deliverability Assessment

In the off-peak deliverability assessment of the Greater Bay interconnection area, there was one constraint identified for the base portfolios. The constraints that were observed in the baseline portfolio only are listed in Table 3.5-5. Potential mitigation has been identified for further assessment in the economic study.

Table 3.5-5: Greater Bay Interconnection Area Off-Peak Deliverability Baseline Portfolio

Constraint	Contingency	Loading	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
Trimble - San Jose B - DG 115 kV line	FMC-SAN JOSE B 115KV	122.07	1.8	344	344	Reconductor if economic

Conclusion and recommendation

The PGE Greater Bay area base and sensitivity portfolio deliverability assessment identified on-peak and off-peak deliverability constraints. These constraints are provided for informative purposes and do not require mitigation. These constraints will be mitigated through the GIP track or through projects that are already approved. No new mitigation is identified.

3.5.3 PG&E Greater Fresno Interconnection Area

The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E Greater Fresno interconnection area are listed in Table 3.5-6. The portfolios are comprised of solar, wind (in-state), battery storage, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-6: PG&E Greater Fresno Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	2034 Baseline Portfolio			2039 Base Portfolio			2039 Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	2,636	869	3,505	3,027	3,404	6,430	5,338	5,823	11,160
Wind – In State	394	96	490	394	96	490	360	40	400
Wind – Out-of-State	0	0	0	0	0	0	0	0	0
Wind - Offshore	0	0	0	0	0	0	0	0	0
Li Battery – 4 hr	1,554	0	1,554	1,669	0	1,669	1,455	0	1,455
Li Battery – 8 hr	200	0	200	1,607	0	1,607	2,780	0	2,780
Long Duration Energy Storage (LDES)	130	0	130	130	0	130	131	0	131
Geothermal	0	0	0	0	0	0	0	0	0
Biomass/Biogas	20	0	20	20	0	20	3	0	3
Distributed Solar	66	0	66	66	0	66	68	0	68
Total	**5,001**	**965**	**5,966**	**6,913**	**3,500**	**10,412**	**10,134**	**5,863**	**15,997**

The resources as identified in the CPUC busbar mapping for the PG&E Greater Fresno interconnection area are illustrated on the single-line diagram in Figure 3.5-6 and Figure 3.5-7.

Figure 3.5-6: PG&E Greater Fresno Interconnection Area – Mapped 2034 Baseline Portfolio

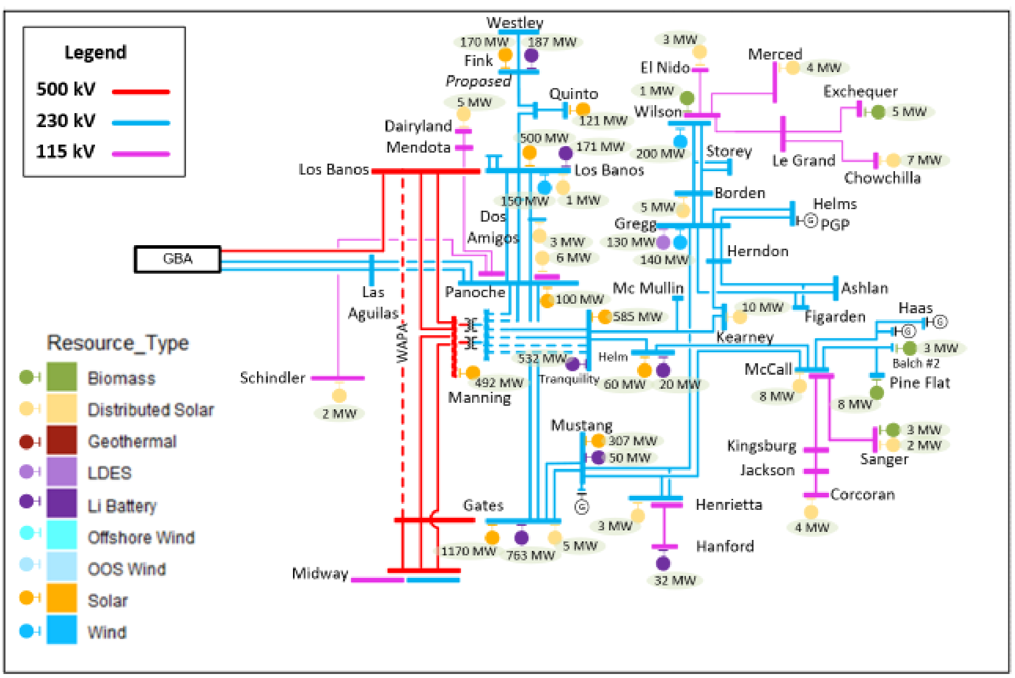
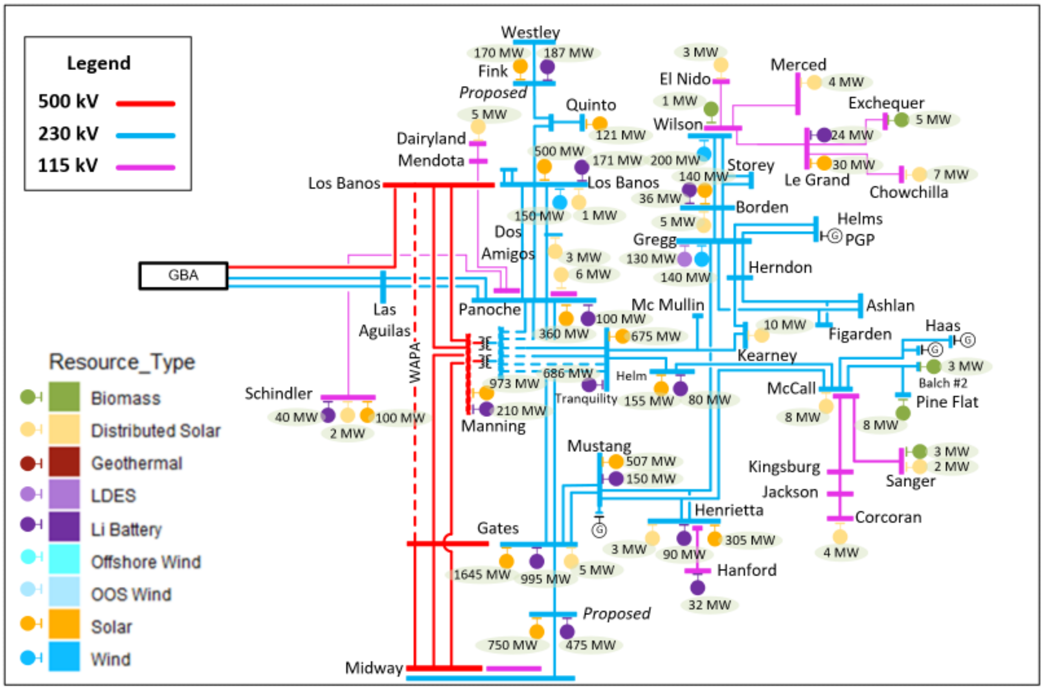


Figure 3.5-7: PG&E Greater Fresno Interconnection Area – Mapped 3039 Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the Greater Fresno interconnection area along with the recommended mitigation plans are identified in Table 3.5-7

Table 3.5-7: PG&E Greater Fresno Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

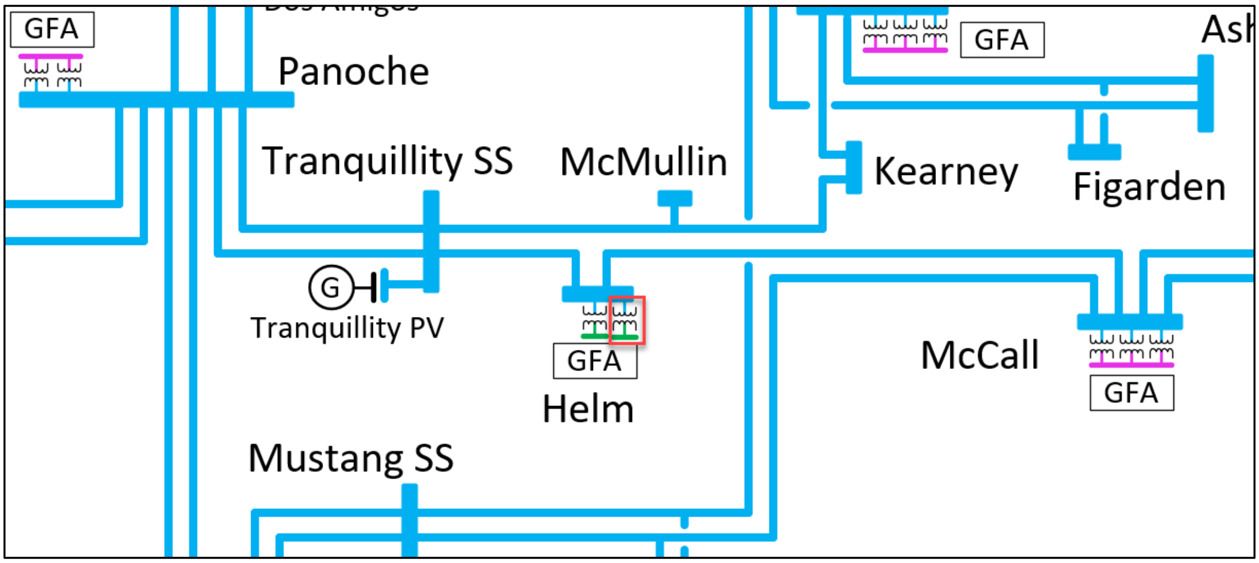
Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
GWF-Kingsburg 115 kV Line	2034 Baseline	314	32	314	127	Reconductor GWF-Kingsburg 115 kV Line
Corcoran-Smyrna (Alpaugh-Smyrna) 115 kV Line	2039 Sensitivity	24	10	34	0	Sensitivity only
Helm 230/70 kV Transformer #1	2034 Baseline	200	81	220	61	SSN only
Herndon-Woodward 115 kV Line	2034 Baseline	240	0	0	566	Local constraint. Will be addressed in GIP.
	2039 Baseline	189	0	0	785	
	2039 Sensitivity	189	166	0	709	
McCall-Sanger #1 115 kV Line	2039 Baseline	21	0	0	163	Local constraint. Will be addressed in GIP.
	2039 Sensitivity	10	32	0	146	
McCall-Sanger #2 115 kV Line	2039 Baseline	21	0	0	163	Local constraint. Will be addressed in GIP.
	2039 Sensitivity	10	32	0	146	
McCall-Sanger #3 115 kV Line	2034 Baseline	21	32	0	316	Local constraint. Will be addressed in GIP.
Panoche-Schindler #2 115 kV Line	2034 Baseline	202	81	182	147	SSN only
Schindler - Paiges SLR JCT 70 kV Line	2034 Baseline	202	81	162	121	SSN only
Schindler 115/70 kV Transformer #1	2034 Baseline	200	91	166	134	SSN only
Schindler-Coalinga #2 70 kV Line	2034 Baseline	202	81	168	115	SSN only
Schindler-Huron-Gates 70 kV Line	2034 Baseline	202	81	190	102	SSN only
Helm-Crescent 70 kV Line	2034 Baseline	200	81	184	97	Install new Helm 230/70 kV Bank #2
	2039 Baseline	201	0	0	295	
	2039 Sensitivity	201	106	216	110	
Warnerville - Wilson 230 kV Line	2034 Baseline	789	102	300	2243	SSN only
Wilson- Borden -Storey 230 kV Line	2034 Baseline	596	82	300	1237	SSN only

Based on the constraints identified in Table 3.5-7, there are two policy-driven upgrades identified in the Fresno interconnection planning areas.

New Helm 230/70 kV Bank #2

To mitigate overloads identified in the on-peak baseline deliverability study, the ISO is recommending approval of the addition of a new 230/70 kV bank at Helm. The estimated project cost is $115M, with an estimated in-service date of 2031. The scope includes a new 230/70 kV Bank at Helm Substation with a 200 MVA rating. The project scope also includes converting both 230 kV and 70 kV busses to breaker and a half and upgrading limiting equipment to achieve this transformer rating.

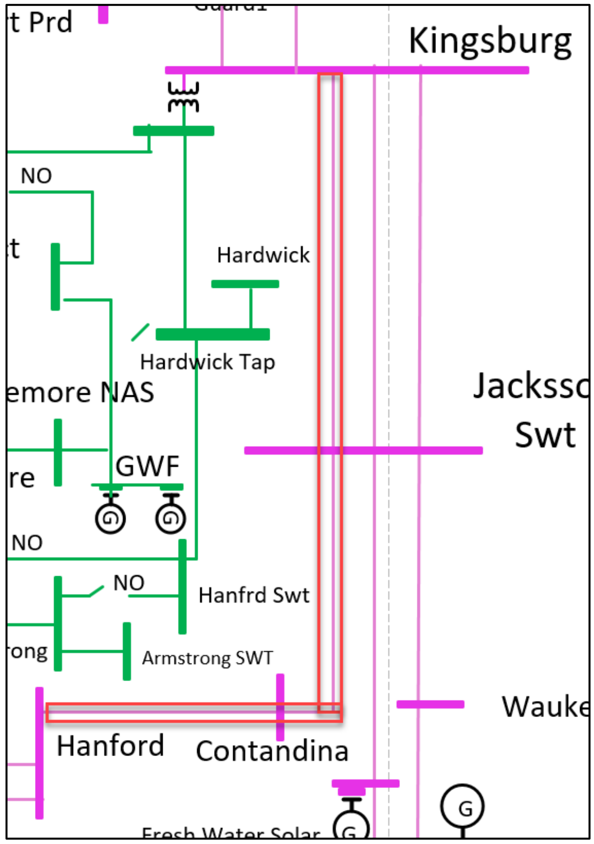
Figure 3.5-8: New Helm 230/70 kV Bank #2



Reconductor of GWF – Kingsburg 115 kV line

To mitigate overloads identified in the on-peak baseline deliverability study, the ISO is recommending approval of the reconductor of the GWF – Kingsburg 115 kV line. The estimated project cost is $81.6M, with an estimated in-service date of 2029. The project scope includes Reconductor the entire GWF-Kingsburg 115 kV Line (about 22 miles) with minimum summer emergency rating of 1500 Amps or higher and update the limiting components at the substations if there is any. Protection may also need to be upgraded.

Figure 3.5-9: Reconductor of GWF-Kingsburg 115 kV Line



Off-Peak Deliverability Assessment

The off-peak deliverability constraints identified in the base portfolio assessment of the Greater Fresno interconnection areas, along with the recommended mitigation plans, are identified in Table 3.5-8. Potential mitigation has been identified for further assessment in the economic study.

Table 3.5-8: PG&E Greater Fresno Interconnection Area Off-Peak Deliverability Constraints in Base Portfolio

Constraint	Contingency	Loading	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
BARTON-AIRWAYS-SANGER 115 kV Line	P7-1:A14:26:_HENTAP1-MUSTANGSS #1 230KV [0] & TRANQLTYSS-MCMULLN1 #1 230KV [0]	106.82	23	0	0	Reconductor if economic
Chowchilla-Kerckhoff 115 kV Line	P7-1:A13:1:_WILSON-BORDEN 230KV #1 & #2 [9001]	149.78	2	0	0	Reconductor if economic

Constraint	Contingency	Loading	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
Crescent Switching Station - Schindler 70 kV Line	P12:A13:22:_TRANQUILLITY SW STA-HELM 230KV [5370]	167.58	371	101	68	68 MW Portfolio Battery dispatched in charging mode
Fink Switching Station - Westley 230 kV Line	P1-2:A13:4:_QUINTO SW STA-WESTLEY 230KV [5070]	123.55	985	201	201	Reconductor if economic
Fivepoint SSS - Calflax #1 70 kV Line	P1-3:A14:28:_HELM 230/70KV TB 1	144.6	350	81	49	49 MW Portfolio Battery dispatched in charging mode
Gates - Huron - Calflax 70 kV Line	P1-3:A14:28:_HELM 230/70KV TB 1	154.31	350	81	58	58 MW Portfolio Battery dispatched in charging mode
Gates-Panoche #1 230 kV Line	P1-2:A0:23:_GATES-MANNING 500KV [0]	149.18	858	116	116	Reconductor if economic
Gates-Panoche #2 230 kV Line	P1-2:A0:23:_GATES-MANNING 500KV [0]	158.49	858	116	116	Reconductor if economic
GWF - Kingsburg 115 kV Line	P7-1:A14:17:_HELM-MCCALL 230KV [4860] & HENTAP2-MUSTANGSS #1 230KV [0]	126.15	14	33	33	Reconductor if economic
Helm 230/70KV TB 1	P7-1:A14:10:_PANOCHE-SCHINDLER #1 115KV [3250] & EXCELSIORSS-PANOCHE2 115KV [3231]	152.25	350	91	91	Reconductor if economic
Le Grand - Dairyland 115 kV Line	P7-1:A13:13:_BORDEN-GREGG 230KV #1 & #2 [4400]	111.57	5	0	0	Reconductor if economic
Los Banos - Manning #1 500 kV Line	P1-2:A0:16:_LOSBANOS-MANNING 500KV [0] (2)	158.53	492	0	0	Reconductor if economic
Los Banos - Manning #2 500 kV Line	P1-2:A0:15:_LOSBANOS-MANNING 500KV [0]	158.53	492	0	0	Reconductor if economic
Los Banos - Panoche #2 230 kV Line	P1-3:A0:15:_LOSBANOS 500/230KV TB 1	125.32	108	0	0	Reconductor if economic
Los Banos-Quinto Switching Station 230 kV Line	P1-2:A0:11:_TESLA-LOS BANOS #1 500KV [6100]	173.06	836	171	171	Reconductor if economic
Manning - Gates 500 kV Line	Base Case	135.84	3783	307	307	Reconductor if economic
Mc Call - Sanger #3 115 kV Line	P7-1:A14:26:_HENTAP1-MUSTANGSS #1 230KV [0] & TRANQLTYSS-MCMULLN1 #1 230KV [0]	115.27	21	0	0	Reconductor if economic
Melones - Wilson 230 kV Line	P12:A13:3:_WARNERVILLE-WILSON 230KV [5870]	124.14	519	0	0	Reconductor if economic
Moss Landing-Las Aguilas Switching Station 230 kV Line	P1-2:A0:13:_MOSS LANDING-LOS BANOS 500KV [6040]	144.61	100	0	0	Reconductor if economic
Panoche - Excelsior Switching Station #2 115 kV Line	P1-3:A14:28:_HELM 230/70KV TB 1	124.02	350	81	33	33 MW Portfolio Battery dispatched in charging mode
Panoche-Schindler #1 115 kV Line	P1-3:A14:28:_HELM 230/70KV TB 1	123.35	431	81	56	56 MW Portfolio Battery dispatched in charging mode

Constraint	Contingency	Loading	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
Quinto Switching Station - Fink Switching Station 230 kV Line	P1-2:A13:4:_QUINTO SW STA-WESTLEY 230KV [5070]	117.19	985	201	201	Reconductor if economic
Quinto Switching Station-Westley 230 kV Line	P1-2:A13:1:_FINKSWSTA-WESTLEY #1 230KV [0]	123.24	985	201	201	Reconductor if economic
Schindler 115/70 kV Transformer #1	P1-3:A14:28:_HELM 230/70KV TB 1	214.23	348	90	90	Reconductor if economic
Schindler-Coalinga #2 70 kV Line	P1-3:A14:28:_HELM 230/70KV TB 1	123.84	350	81	21	21 MW Portfolio Battery dispatched in charging mode
Warnerville - Wilson 230 kV Line	P1-2:A12:2:_COTTLE-MELONES 230KV [4530]	220.06	554	83	83	Reconductor if economic
Wilson - Borden #1 230 kV Line	P1-2:A13:27:_WILSON-BORDEN #2 230KV [9001]	178.29	332	83	83	Reconductor if economic
Wilson - Borden #2 230 kV Line	P1-2:A13:26:_WILSON-BORDEN #1 230KV [5890]	154.45	332	83	83	Reconductor if economic
Wilson-Le Grand 115 kV Line	P7-1:A13:1:_WILSON-BORDEN 230KV #1 & #2 [9001]	105.41	17	0	0	Reconductor if economic
Wilson-Oro Loma 115 kV Line	P7-1:A13:13:_BORDEN-GREGG 230KV #1 & #2 [4400]	186.31	0.8	0	0	Reconductor if economic

Conclusion and recommendation

The PGE Greater Fresno area base and sensitivity portfolios deliverability assessment identified on-peak and off-peak deliverability constraints. The GWF-Kingsburg 115 kV line constraint is identified in 2034 on-peak scenario and the ISO recommends reconductoring the line as mitigation. The ISO also recommends installing a second 230/70 kV transformer bank at Helm substation to mitigate the Helm-Crescent 70 kV line constraint.

3.5.4 PG&E Kern Interconnection Area

The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E Kern interconnection area are listed in

Table 3.5-9. The portfolios in the interconnect area are comprised of solar, wind (in-state and offshore), battery storage, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-9: PG&E Kern Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	2034 Baseline Portfolio			2039 Base Portfolio			2039 Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	680	1,301	1,981	1,036	2,061	3,096	2,029	2,762	4,791
Wind – In State	300	10	310	300	10	310	190	10	200
Wind – Out-of-State	0	0	0	0	0	0	0	0	0
Wind - Offshore	2,924	0	2,924	2,924	0	2,924	0	0	0
Li Battery – 4 hr	777	0	777	777	0	777	186	0	186
Li Battery – 8 hr	142	0	142	682	0	682	1,217	0	1,217
Long Duration Energy Storage (LDES)	0	0	0	0	0	0	400	0	400
Geothermal	0	0	0	0	0	0	0	0	0
Biomass/Biogas	18	0	18	18	0	18	0	0	0
Distributed Solar	73	0	73	73	0	73	79	0	79
Total	**4,913**	**1,311**	**6,224**	**5,809**	**2,071**	**7,879**	**4,101**	**2,772**	**6,873**

The resources as identified in the CPUC busbar mapping for the PG&E Kern interconnection area are illustrated on the single-line diagram in Figure 3.5-10 and Figure 3.5-11.

Figure 3.5-10: PG&E Kern Interconnection Area – Mapped 2034 Baseline Portfolio

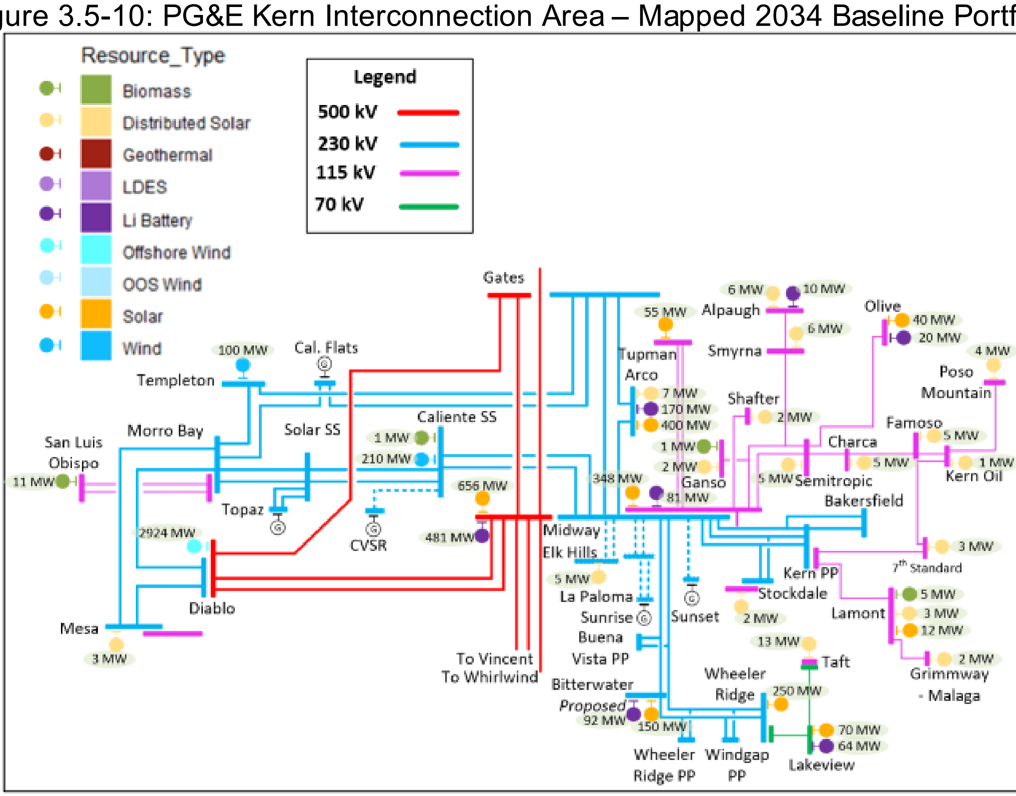
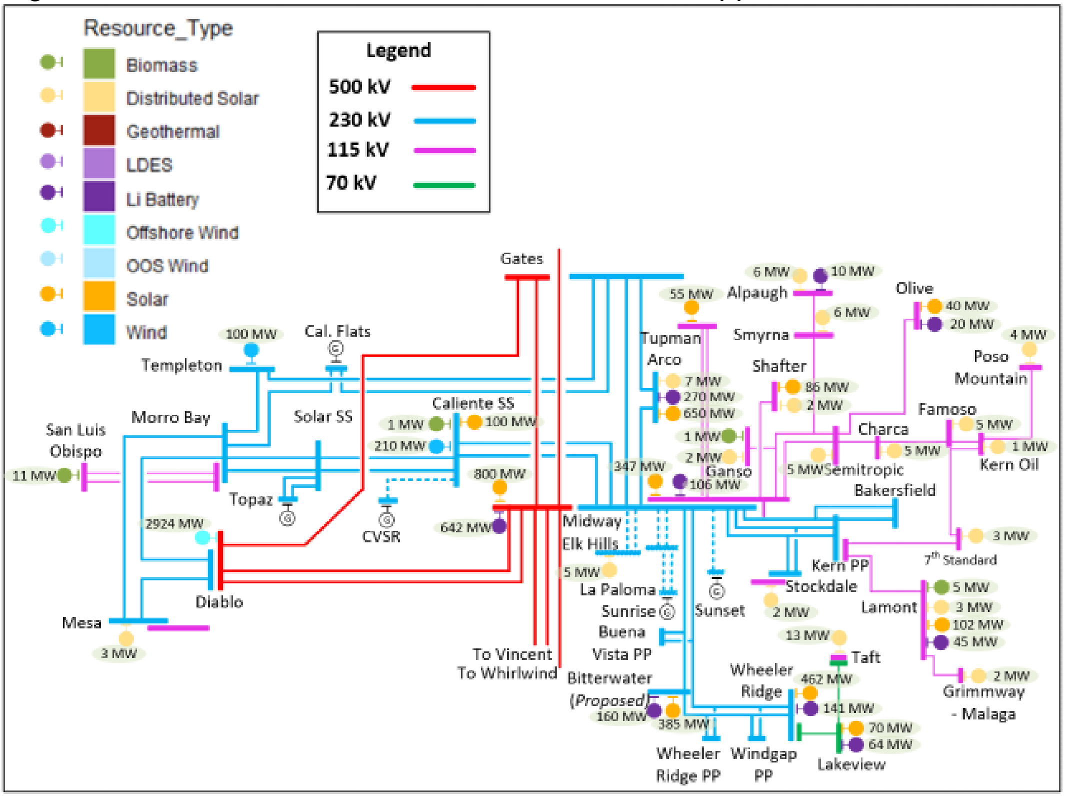


Figure 3.5-11: PG&E Kern Interconnection Area – Mapped 2039 Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the Kern interconnection area along with the recommended mitigation plans are identified in Table 3.5-10.

Table 3.5-10: PG&E Kern Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Copus-Old River 70 kV Line	2034 Baseline	13	0	0	15	SSN only
Oceano-Callender Sw. Sta 115 kV Line	2034 Baseline	189	110	29	271	SSN only
South Kern Jct - San Emidio 70 kV Line	2034 Baseline	13	0	0	15	SSN only

Based on the constraints identified in Table 3.5-10 there are no policy-driven upgrades identified in the Kern interconnection planning areas.

Off-Peak Deliverability Assessment

The off-peak deliverability constraints identified in the base portfolio assessment of the Kern interconnection areas along with the recommended mitigation plans are identified in Table 3.5-11. Potential mitigation has been identified for further assessment in the economic study.

Table 3.5-11: PG&E Kern Interconnection Area Off-Peak Deliverability Constraints in Base Portfolio

Constraint	Contingency	Loading	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
Callendar Switching Station - Mesa 115 kV Line	P7-1:A20:16:_Morro Bay-Mesa and Morro Bay-Diablo 230 kV Lines	271.12	503.2	115.92	105.92	Reconductor if economic
San Miguel - UnionPGAE 70 kV Line	P7-1:A14:14:_TEMPLETON-GATES 230KV [5934] & GATES-CALFLATSSS #1 230KV [0]	114.38	614.2	115.92	104	104 MW Portfolio Battery dispatched in charging mode

Conclusion and recommendation

The PGE Kern area base portfolio deliverability assessment identified on-peak (SSN scenario only) and off-peak deliverability constraints. These constraints are provided for informative purposes and do not require mitigation.

3.5.5 East of Pisgah Interconnection Area

The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the East of Pisgah interconnection area are listed in Table 3.5-12. The portfolios in the interconnection area are comprised of solar, wind (in-state and out-of-state), battery storage and geothermal resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-12: East of Pisgah Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	2034 Baseline Portfolio			2039 Base Portfolio			2039 Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	1,075	1,565	**2,640**	1,200	3,030	**4,230**	2,425	3,855	**6,280**
Wind – In State	620	0	**620**	620	0	**620**	620	0	**620**
Wind – Out-of-State	3,965	0	**3,965**	4,060	0	**4,060**	4,060	0	**4,060**

Resource Type	2034 Baseline Portfolio			2039 Base Portfolio			2039 Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Wind - Offshore	0	0	**0**	0	0	**0**	0	0	**0**
Li Battery – 4 hr	3,954	0	**3,954**	3,735	0	**3,735**	2,839	0	**2,839**
Li Battery – 8 hr	180	0	**180**	696	0	**696**	1,769	0	**1,769**
Long Duration Energy Storage (LDES)	0	0	**0**	0	0	**0**	0	0	**0**
Geothermal	875	0	**875**	875	0	**875**	1,315	0	**1,315**
Biomass/Biogas	0	0	**0**	0	0	**0**	0	0	**0**
Distributed Solar	0	0	**0**	0	0	**0**	0	0	**0**
Total	**10,669**	**1,565**	**12,234**	**11,186**	**3,030**	**14,216**	**13,028**	**3,855**	**16,883**

The resources as identified in the CPUC busbar mapping for the East of Pisgah interconnection area are illustrated on the single-line diagram in Figure 3.5-12 and Figure 3.5-13.

Figure 3.5-12: East of Pisgah Interconnection Area – Mapped 2034 Baseline Portfolio

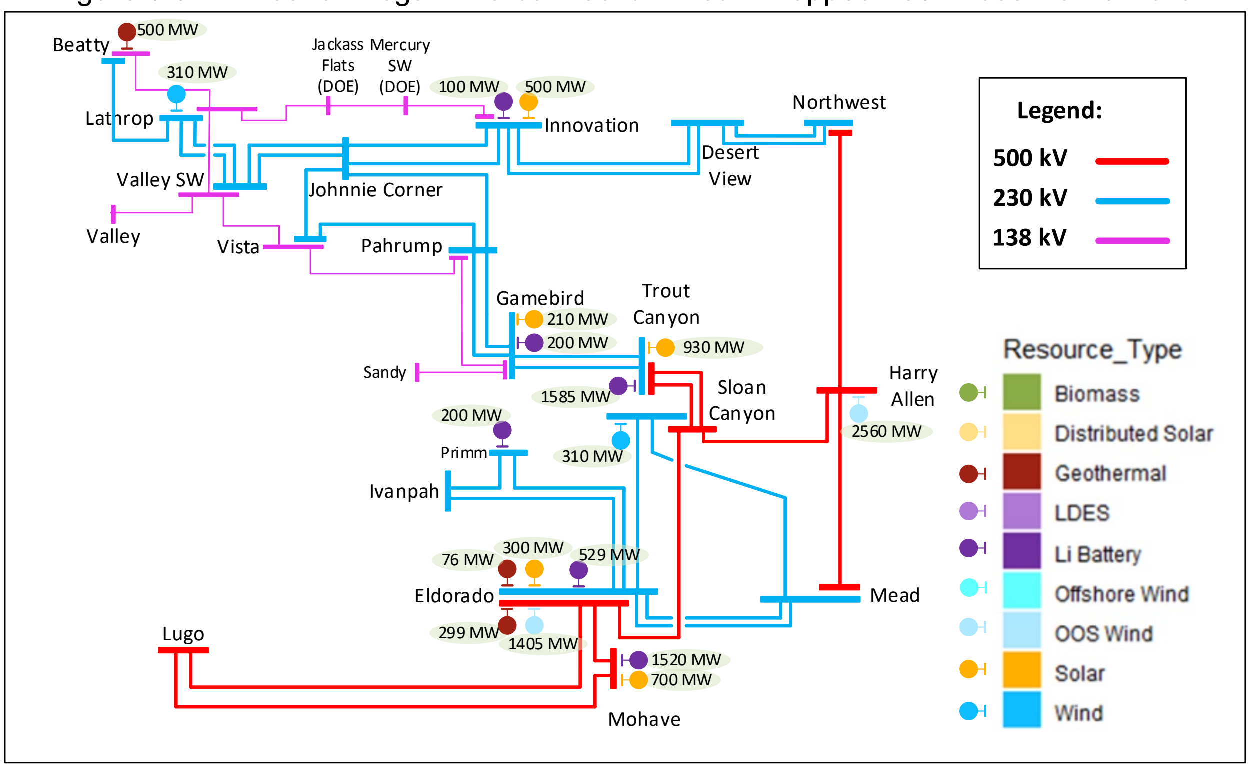
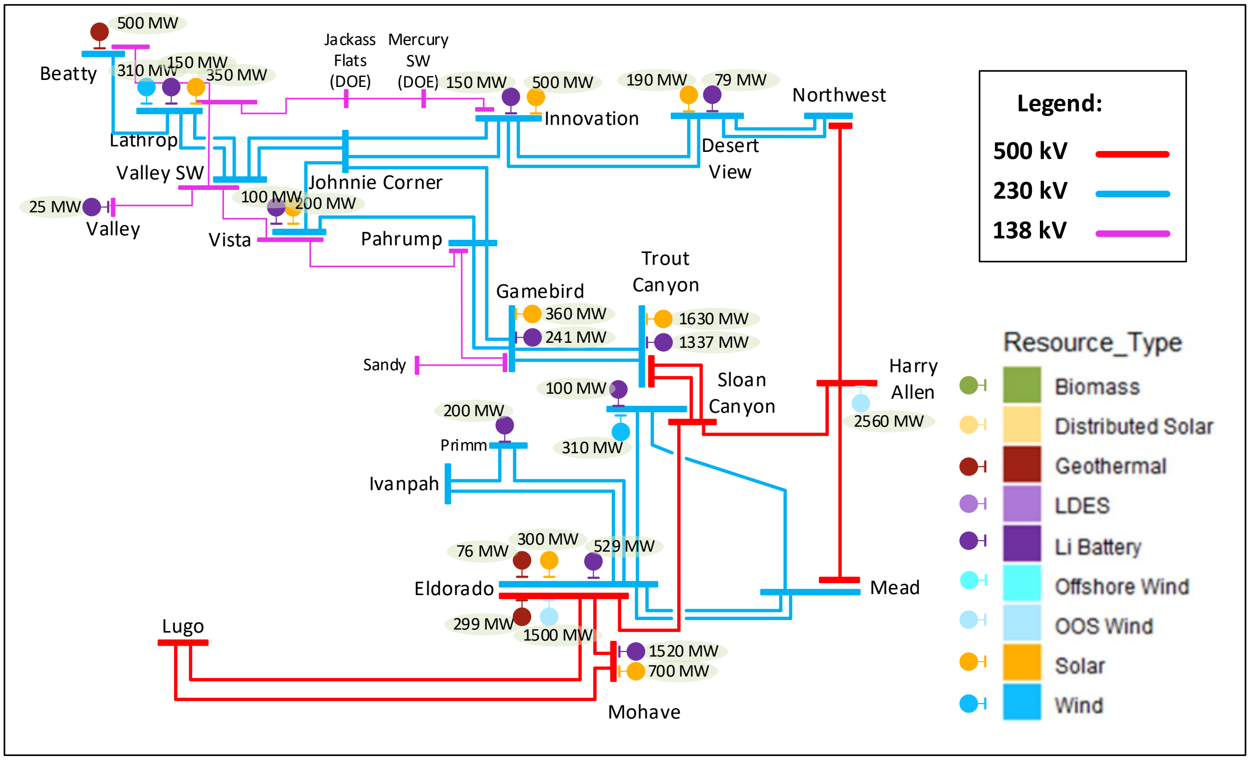


Figure 3.5-13: East of Pisgah Interconnection Area – Mapped 2039 Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the East of Pisgah interconnection areas along with the recommended mitigation plans are identified in Table 3.5-13.

Table 3.5-13: East of Pisgah Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
GLW-VEA area constraint	2034 Baseline	3,460	1,700	1,568	1,892	TBD
	2039 Base	3,476	1,891	2,259	1,217	RAS identified in GIP
	2039 Sensitivity	4,239	2,033	2,016	2,223	TBD

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Eldorado – McCullough	2034 Baseline	10,480	4,070	7,721	2,759	TBD
	2039 Base	11,119	4,413	7,072	4,047	
	2039 Sensitivity	13,133	4,660	8,243	4,890	
Lugo - Victorville	2034 Baseline	14,178	5,022	13,994	184	Existing Lugo – Victorville RAS
	2039 Base	17,145	5,770	12,610	4,535	TBD
	2039 Sensitivity	18,697	5,808	12,009	6,688	

As detailed in Appendix F, a Wyoming wind sensitivity study was performed to evaluate a few alternatives to mitigate the constraints identified in EOP on-peak deliverability assessment and to bring in the additional 1,500 MW Wyoming wind beyond TransWest Express capacity. The ISO will keep evaluating potential transmission upgrades in the future TPP cycles, and will not recommend any projects at this time. This will ensure consistency with the CPUC directive in the Decision for the 2025-2026 TPP. The directive aims not to trigger upgrades related to the additional out-of-state wind amounts in the portfolio that are beyond the amounts that can be accommodated on the already-identified and in-development transmission upgrades.

Off-Peak Deliverability Assessment

The off-peak deliverability assessment did not identify any constraints in the EOP interconnection area.

3.5.6 SCE Northern Interconnection Area

The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE Northern interconnection area are listed in Table 3.5-14. The portfolios in the interconnection area are comprised of solar, wind (in-state), battery storage, long-duration energy storage, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-14: SCE Northern Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	2034 Baseline Portfolio			2039 Base Portfolio			2039 Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	1,653	2,093	**3,746**	1,654	3,057	**4,711**	3,259	5,107	**8,366**
Wind – In State	564	16	**580**	564	16	**580**	514	16	**530**
Wind – Out-of-State	0	0	**0**	0	0	**0**	0	0	**0**
Wind - Offshore	0	0	**0**	0	0	**0**	0	0	**0**
Li Battery – 4 hr	3,735	0	**3,735**	3,485	0	**3,485**	2,610	0	**2,610**
Li Battery – 8 hr	170	0	**170**	734	0	**734**	2,294	0	**2,294**
Long Duration Energy Storage (LDES)	458	0	**458**	458	0	**458**	500	0	**500**
Geothermal	0	0	**0**	0	0	**0**	0	0	**0**
Biomass/Biogas	1	0	**1**	1	0	**1**	0	0	**0**
Distributed Solar	5	0	**5**	5	0	**5**	8	0	**8**
Total	**6,586**	**2,109**	**8,695**	**6,901**	**3,073**	**9,974**	**9,185**	**5,123**	**14,308**

The 2034 Baseline Portfolio resources, as identified in the CPUC busbar mapping for the SCE Northern interconnection area, are illustrated on the single-line diagram in Figure 3.5-14.

The 2039 Base Portfolio resources, as identified in the CPUC busbar mapping for the SCE Northern interconnection area, are illustrated on the single-line diagram in Figure 3.5-15.

.

Figure 3.5-14: SCE Northern Interconnection Area – Mapped[53] 2034 Baseline Portfolio

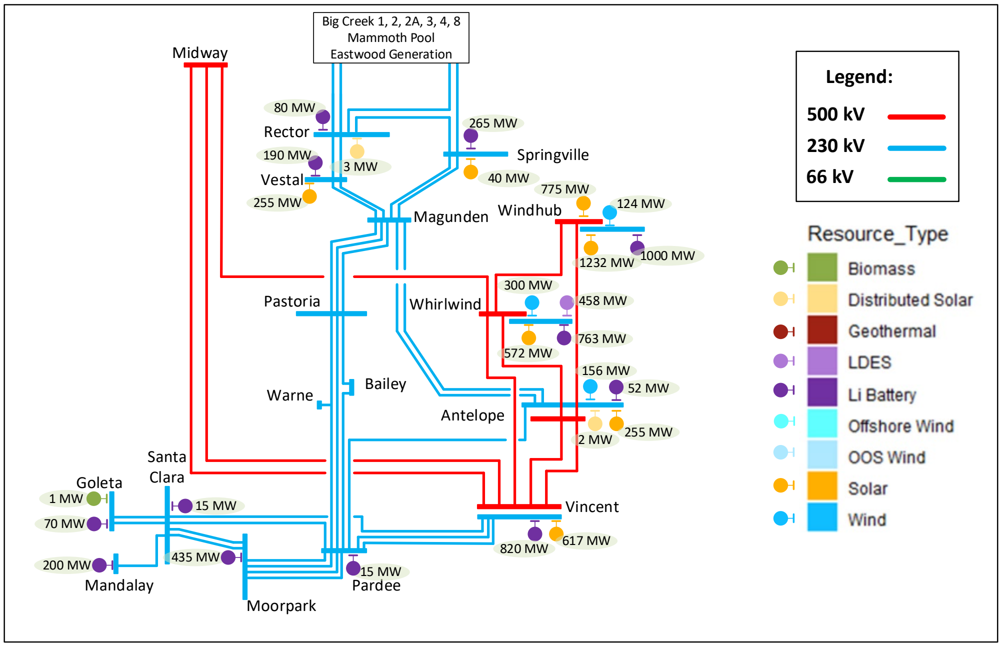
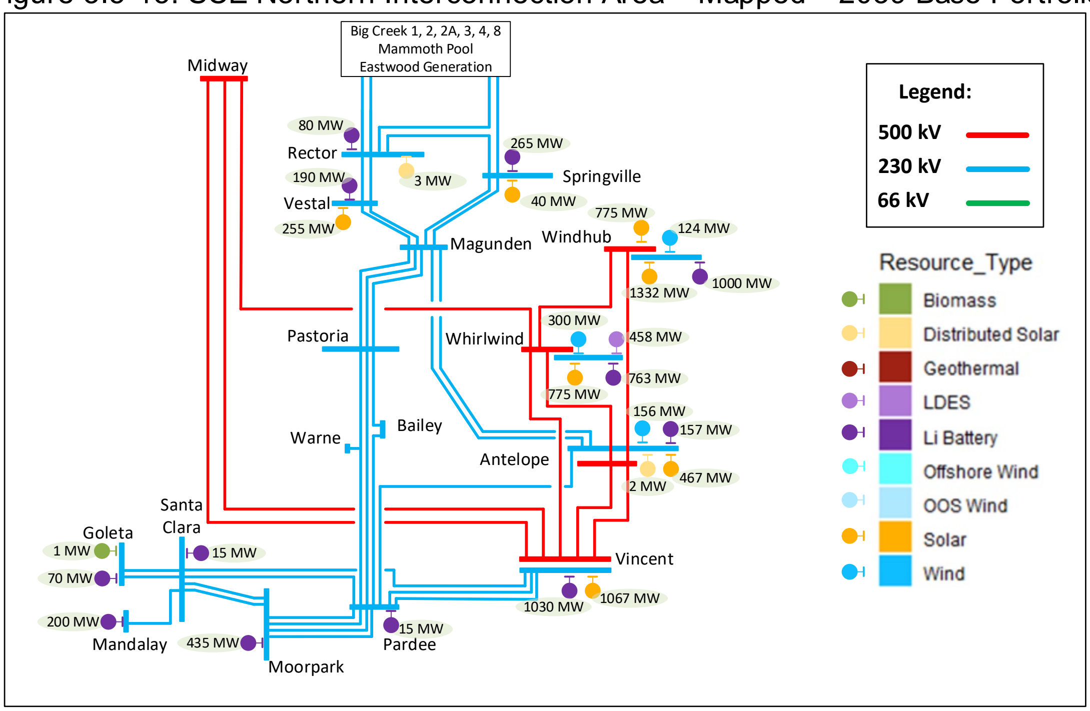


Figure 3.5-15: SCE Northern Interconnection Area – Mapped[54] 2039 Base Portfolio



53 Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the SCE Northern Interconnection Area to account for allocated TPD and additional in-development resources identified in Appendix F.

54 Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the SCE Northern Interconnection Area to account for allocated TPD and additional in-development resources identified in Appendix F.

On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the SCE Northern interconnection area along with the recommended mitigation plans are identified in Table 3.5-15.

Table 3.5-15: SCE Northern Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolios

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Windhub #1 and #2 500/230 kV transformer	2034 Baseline	1373	1016	621	752	Existing Windhub AA Bank CRAS
	2039 Base	1368	1012	623	745	
	2039 Sensitivity	1368	1012	623	745	
Whirlwind #1, #3 or #4 500/230 kV transformer	2034 Baseline	1848	758	1742	106	Planned Whirlwind AA Bank CRAS. SSN Only
	2039 Base	N/A	N/A	N/A	N/A	N/A
	2039 Sensitivity	N/A	N/A	N/A	N/A	N/A
Midway–Whirlwind 500 kV line	2034 Baseline	5165	2838	4735	430	Congestion Management. SSN Only
	2039 Base	N/A	N/A	N/A	N/A	N/A
	2039 Sensitivity	N/A	N/A	N/A	N/A	N/A
Windhub Area Export	2034 Baseline	N/A	N/A	N/A	N/A	N/A
	2039 Base	N/A	N/A	N/A	N/A	N/A
	2039 Sensitivity	2338	1154	2273	65	Relocate generic portfolio storage

Off-Peak Deliverability Assessment

The Off-peak deliverability constraints identified in the base portfolio assessment of the SCE Northern interconnection areas along with the recommended mitigation plans are identified in Table 3.5-16.

Table 3.5-16: SCE Northern Interconnection Area Off-Peak Deliverability Constraints in Base Portfolio

Constraint	Portfolio	Portfolio solar and wind MW behind the constraint	Energy storage portfolio MW behind the constraint	Renewable curtailment without mitigation (MW)	Mitigation
Windhub #1 and #2 500/230 kV transformer	2034 Baseline	1382	1016	728	Existing Windhub AA Bank CRAS
Midway–Whirlwind 500 kV line	2034 Baseline	3755	3202	1258	Baseline energy storage in charging mode

Conclusion and recommendation

The SCE Northern area base and sensitivity portfolios deliverability assessment identified on-peak and off-peak deliverability constraints. The Windhub and Whirlwind 500/230 kV transformer constraints can be addressed by using CRAS. The Windhub area export constraint identified in the 2039 sensitivity portfolio can be mitigated by relocating at least 65 MW of generic battery energy storage to other substations.

Several alternatives to mitigate the Midway-Whirlwind 500 kV line constraint in the 2034 on-peak SSN and off-peak scenarios were evaluated, but the economic assessment did not show sufficient economic benefits to reduce the Path 26 congestion or renewable energy curtailment.

In consequence, transmission upgrades were not found to be needed in the area in the current planning cycle.

3.5.7 SCE North of Lugo Interconnection Area

The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE North of Lugo interconnection area are listed in Table 3.5-17. The portfolios in the interconnection area are comprised of solar, battery storage, geothermal, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-17: SCE North of Lugo Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	2034 Baseline Portfolio			2039 Base Portfolio			2039 Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	672	937	**1,609**	752	1,285	**2,037**	1,268	1,723	**2,991**
Wind – In State	310	50	**360**	310	50	**360**	310	50	**360**
Wind – Out-of-State	0	0	**0**	0	0	**0**	0	0	**0**
Wind - Offshore	0	0	**0**	0	0	**0**	0	0	**0**
Li Battery – 4 hr	770	0	**770**	800	0	**800**	435	0	**435**
Li Battery – 8 hr	90	0	**90**	265	0	**265**	683	0	**683**
Long Duration Energy Storage (LDES)	0	0	**0**	0	0	**0**	0	0	**0**
Geothermal	0	0	**0**	0	0	**0**	454	0	**454**
Biomass/Biogas	2	0	**2**	2	0	**2**	0	0	**0**
Distributed Solar	11	0	**11**	27	0	**27**	34	0	**34**
Total	**1,855**	**987**	**2,842**	**2,156**	**1,335**	**3,491**	**3,184**	**1,773**	**4,957**

Base portfolio resources as identified in the CPUC busbar mapping for the SCE North of Lugo interconnection area are illustrated on the single-line diagrams in

Figure 3.5-16 and Figure 3.5-17.

Figure 3.5-16: SCE North of Lugo Interconnection Area – Mapped 2034 Base Portfolio

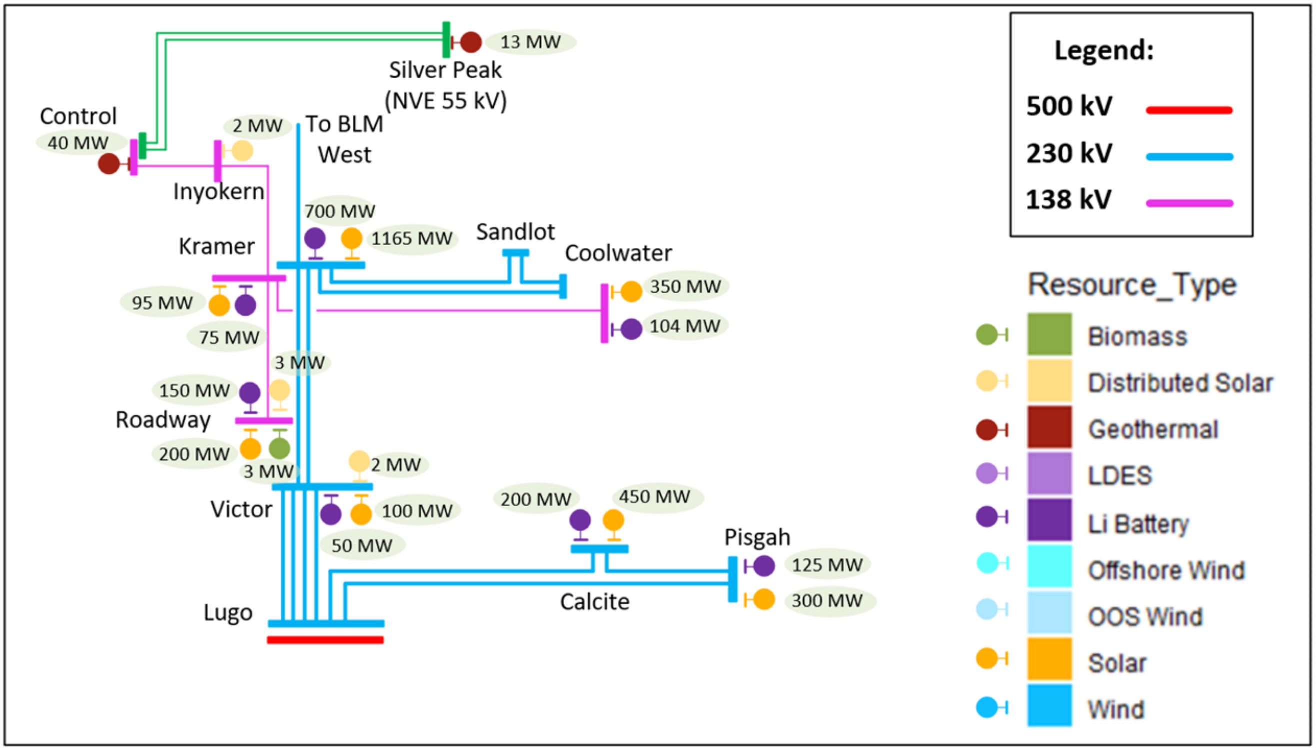
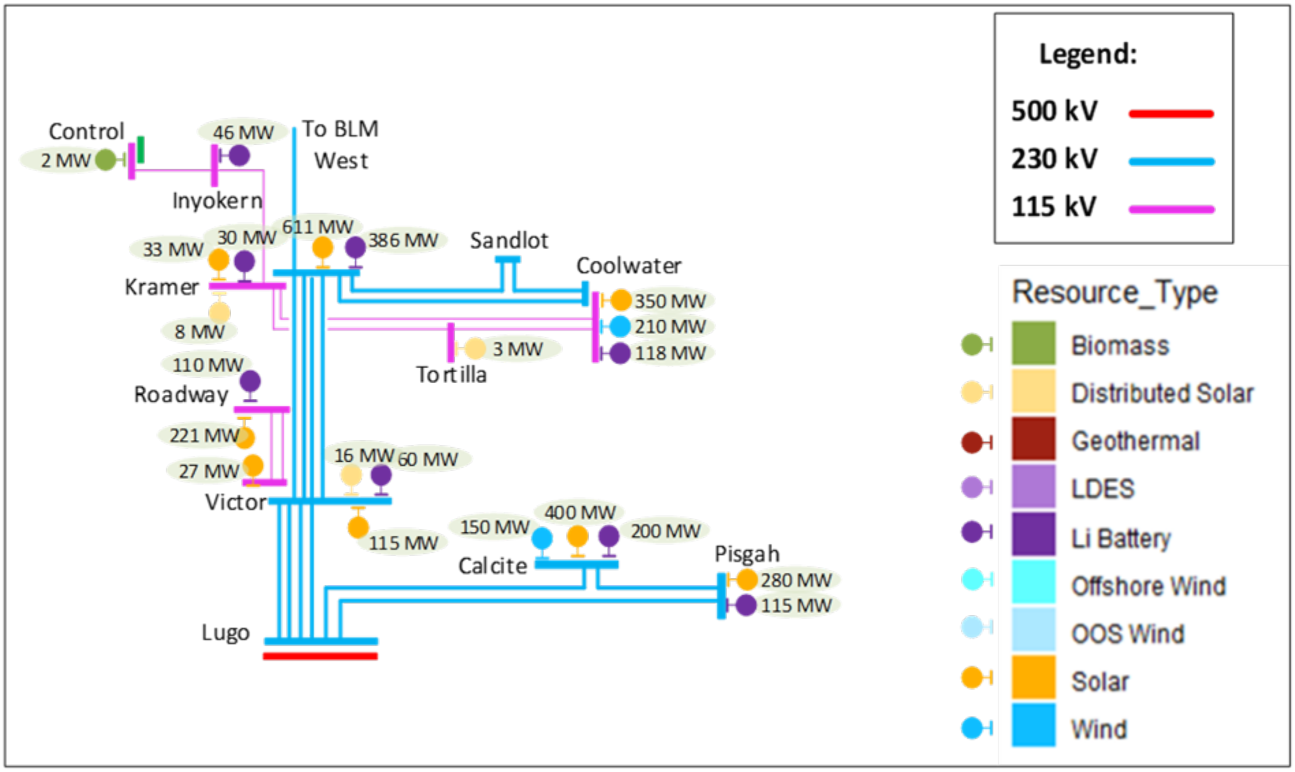


Figure 3.5-17: SCE North of Lugo Interconnection Area – Mapped 2039 Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the SCE North of Lugo interconnection area along with the recommended mitigation plans are identified in Table 3.5-18.

Table 3.5-18: SCE North of Lugo Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Coolwater- Kramer Corridor	2034 Baseline	1,227	417	880	553	Mohave Desert RAS
	2039 Base	916	417	765	151	Mohave Desert RAS
	2039 Sensitivity	916	417	765	151	Mohave Desert RAS
Control- Inyokern 115 kV lines	2034 Baseline	55	0	33	22	Bishop RAS
	2039 Base	55	0	55	0	Bishop RAS
	2039 Sensitivity	507	0	55	452	Control-Inyokern-Kramer 220 kV upgrade (~$2B)
Lugo- Victor 230 kV lines	2034 Baseline	3006	1229	2262	1086	HDPP RAS
	2039 Base	N/A	N/A	N/A	N/A	N/A
	2039 Sensitivity	N/A	N/A	N/A	N/A	N/A
Calcite- Lugo 230 kV line	2034 Baseline	N/A	N/A	N/A	N/A	N/A
	2039 Base	1145	315	1115	30	Pisgah substation loop in project ($218M)
	2039 Sensitivity	1725	295	1663	62	Pisgah substation loop in project ($218M)

Off-Peak Deliverability Assessment

The off-peak deliverability constraints identified in the base and sensitivity portfolio assessment of the SCE North of Lugo interconnection areas along with the recommended mitigation plans are identified in Table 3.5-19.

Table 3.5-19: SCE North of Lugo Interconnection Area Off-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Curtailment MW w/o mitigation	Mitigation
Coolwater–Kramer 230/115 kV Corridor	Base	1,062	645	364	Mojave Desert RAS
	Sensitivity	N/A			
Lugo–Victor 230 kV Corridor	Base	2406	1480	449	HDPP RAS
	Sensitivity	N/A			
Lugo–Calcite-Pisgah 230 kV Corridor	Base	550	200	86	Planned Calcite RAS
	Sensitivity	N/A			

Conclusion and recommendation

The following conclusions can be made based on the North of Lugo (NOL) Area deliverability assessment that is performed with the transmission upgrades approved for the NOL Area modeled:

- All portfolio resources in the NOL area are deliverable with existing or expanded Remedial Action Schemes (RAS) except for the 2039 Base and Sensitivity portfolio due to Lugo- Calcite overload (P0). Off-peak deliverability constraints can be addressed using RAS or dispatching portfolio battery storage in charging mode; and
- Out of the 13 MW of California Community Power's SILVERPK_BG MIC expansion request, 0 MW is deliverable as the MIC expansion request contributes to constraints in the North of Lugo area.

3.5.8 SCE Metro Interconnection Area

The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE Metro interconnection area, are listed in Table 3.5-20. The portfolios in the interconnection area are comprised of battery storage resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-20: SCE Metro Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	2034 Baseline Portfolio			2039 Base Portfolio			2039 Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	0	0	**0**	0	0	**0**	0	0	**0**
Wind – In State	0	0	**0**	0	0	**0**	0	0	**0**
Wind – Out-of-State	0	0	**0**	0	0	**0**	0	0	**0**
Wind - Offshore	0	0	**0**	0	0	**0**	0	0	**0**
Li Battery – 4 hr	1,879	0	**1,879**	1,929	0	**1,929**	979	0	**979**
Li Battery – 8 hr	167	0	**167**	447	0	**447**	1,292	0	**1,292**
Long Duration Energy Storage (LDES)	0	0	**0**	0	0	**0**	0	0	**0**
Geothermal	0	0	**0**	0	0	**0**	0	0	**0**
Biomass/Biogas	6	0	**6**	6	0	**6**	6	0	**6**
Distributed Solar	27	0	**27**	34	0	**34**	40	0	**40**
Total	**2,078**	**0**	**2,078**	**2,415**	**0**	**2,415**	**2,316**	**0**	**2,316**

The resources as identified in the CPUC busbar mapping for the SCE Metro interconnection area are illustrated on the single-line diagram in Figure 3.5-18.

Figure 3.5-18: SCE Metro Interconnection Area – 2034 Base Portfolio

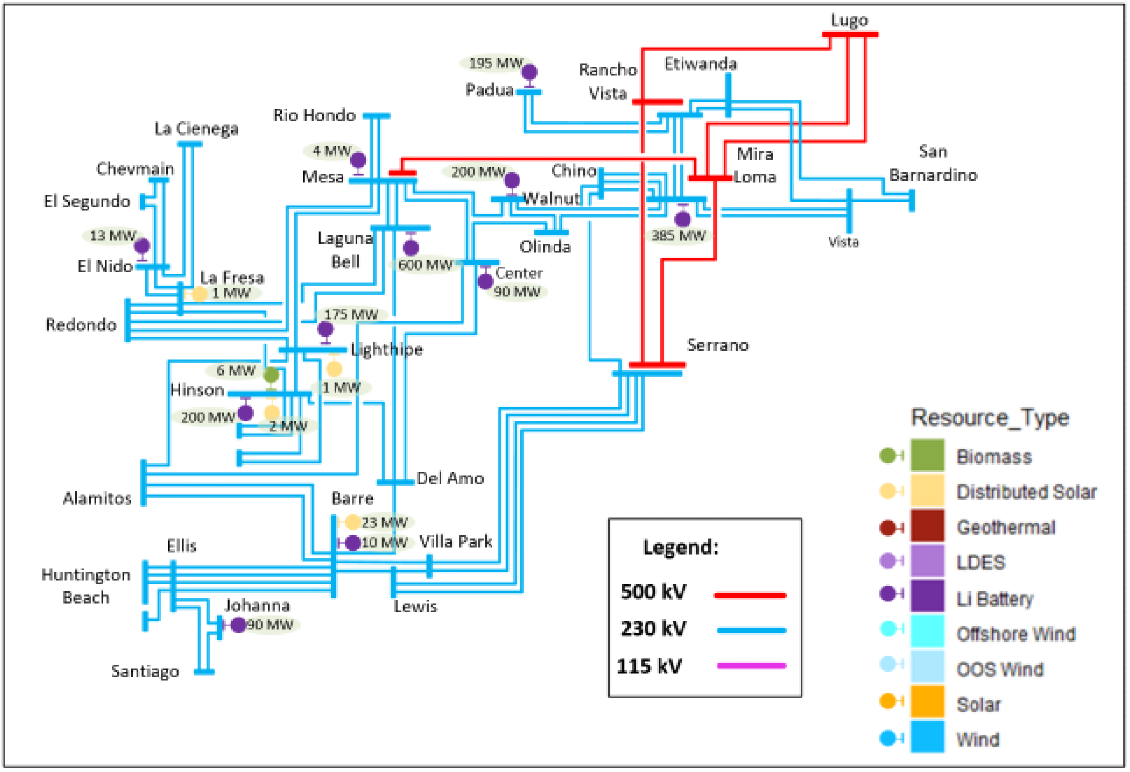
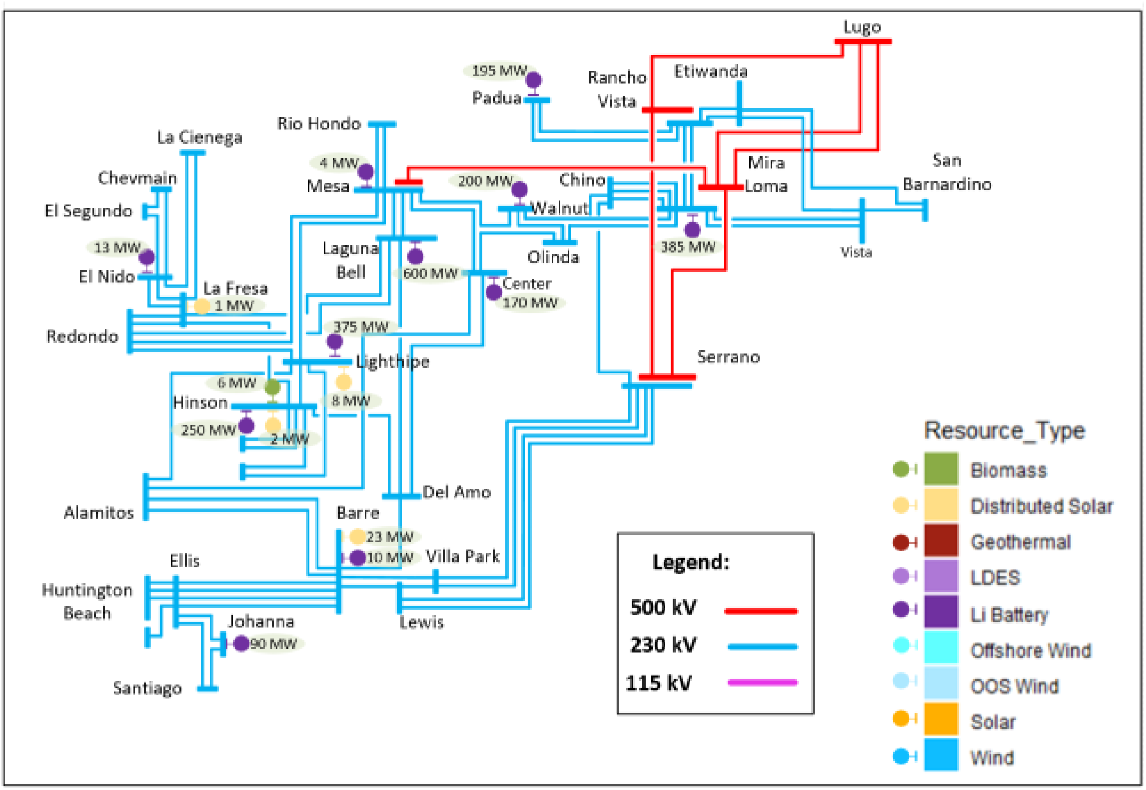


Figure 3.5-19: SCE Metro Interconnection Area – 2039 Base Portfolio



On-Peak Deliverability

The on-peak deliverability did not identify any constraints in the base portfolio assessment of the SCE Metro interconnection area.

Off-Peak Deliverability

The off-peak deliverability did not identify any constraints in the base portfolio assessment of the SCE Metro interconnection area.

3.5.9 SCE Eastern Interconnection Area

The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE Eastern interconnection area are listed in Table 3.5-21. The portfolios are comprised of solar, wind (in-state and out-of-state), battery storage and biomass/biogas resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-21: SCE Eastern Interconnection Area – Base and Sensitivity Portfolio by Resource Types (FCDS, EO and Total)

Resource Type	2034 Baseline Portfolio			2039 Base Portfolio			2039 Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	810	2,649	**3,459**	1,610	4,224	**5,834**	3,410	5,674	**8,784**
Wind – In State	224	100	**324**	224	100	**324**	224	100	**324**
Wind – Out-of-State	2,131	0	**2,131**	3,536	0	**3,536**	3,006	0	**3,006**
Wind - Offshore	0	0	**0**	0	0	**0**	0	0	**0**
Li Battery – 4 hr	3,770	468	**4,238**	3,270	468	**3,738**	3,179	468	**3,647**
Li Battery – 8 hr	270	0	**270**	1,070	0	**1,070**	1,875	0	**1,875**
Long Duration Energy Storage (LDES)	0	0	**0**	0	0	**0**	1,190	0	**1,190**
Geothermal	790	0	**790**	790	0	**790**	1,380	0	**1,380**
Biomass/Biogas	3	0	**3**	3	0	**3**	3	0	**3**
Distributed Solar	0	0	**0**	0	0	**0**	0	0	**0**
Total	**7,997**	**3,217**	**11,214**	**10,502**	**4,792**	**15,294**	**14,266**	**6,242**	**20,508**

The resources as identified in the CPUC busbar mapping for the SCE Eastern interconnection area are illustrated on the single-line diagram in Figure 3.5-20 and Figure 3.5-21.

Figure 3.5-20: SCE Eastern Interconnection Area – Mapped 2034 Baseline Portfolio

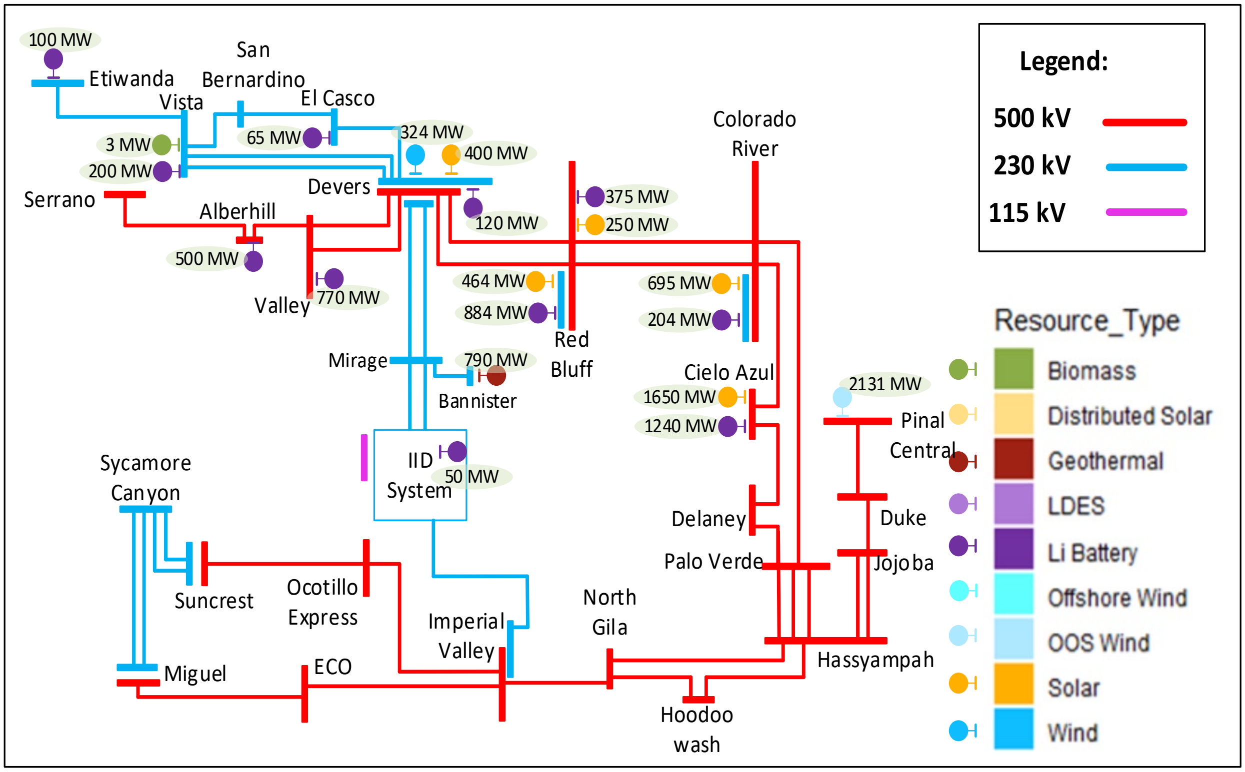
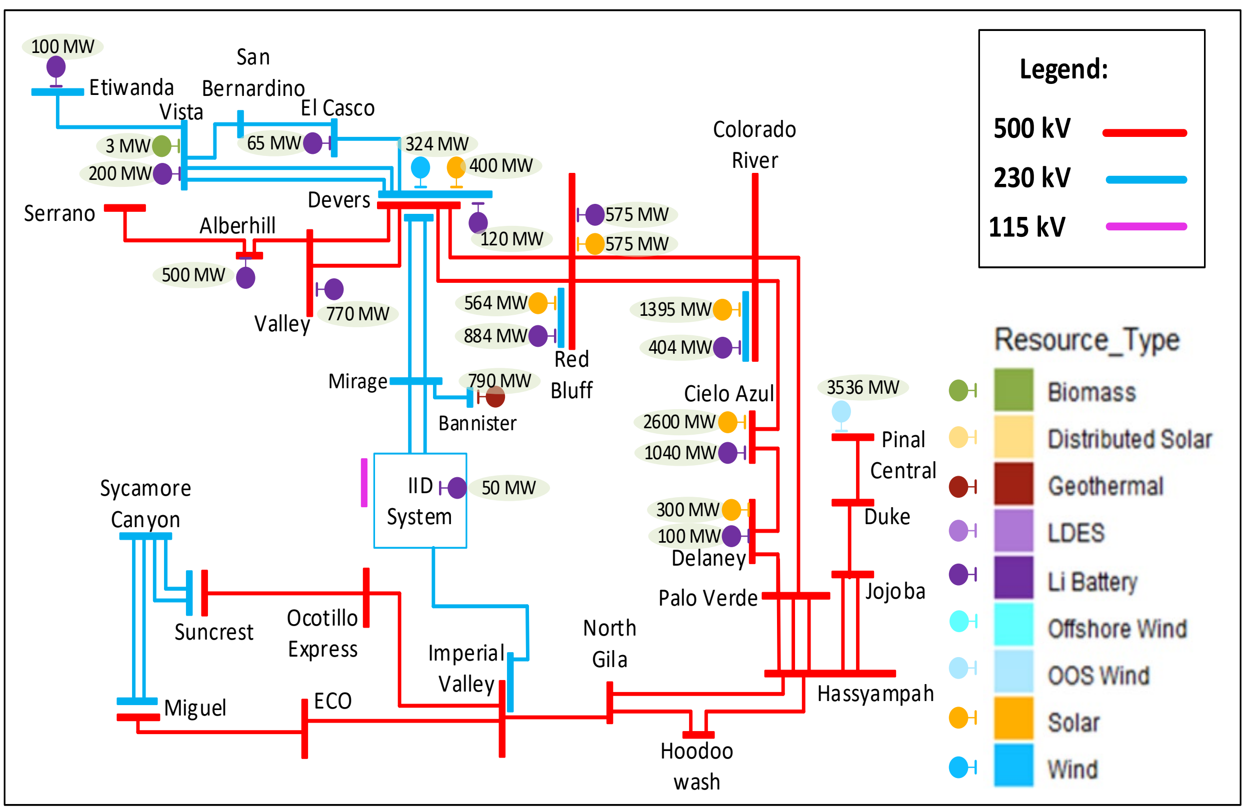


Figure 3.5-21: SCE Eastern Interconnection Area – Mapped 2039 Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the SCE Eastern interconnection area along with the recommended mitigation plans are identified in Table 3.5-22.

Table 3.5-22: SCE Eastern Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolios

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Colorado River 500/230 kV transformers	2034 Baseline	455	160	0	556	Existing West of Colorado River CRAS
	2039 Base	857	360	0	958	
	2039 Sensitivity	1500	500	0	1609	Transmission upgrades only needed for sensitivity case
Devers-Red Bluff	2034 Baseline	N/A				
	2039 Base	8038	2456	7860	178	Existing West of Colorado River CRAS
	2039 Sensitivity	10419	2969	8591	1828	Transmission upgrades only needed for sensitivity case
WECC Path 42	2034 Baseline	N/A				
	2039 Base	N/A				
	2039 Sensitivity	1608	0	1355	253	Path 42 RAS expansion only needed for sensitivity case
Serrano-Alberhill-Valley	2034 Baseline	N/A				
	2039 Base	N/A				
	2039 Sensitivity	11725	3775	11250	475	Transmission upgrades only needed for sensitivity case

Off-Peak Deliverability Assessment

The off-peak deliverability constraints identified in the base portfolio assessment of the SCE Eastern interconnection area along with the recommended mitigation plans are identified in Table 3.5-23.

Table 3.5-23: SCE Eastern Interconnection Area Off-Peak Deliverability Constraints in Base Portfolio

Constraint	Portfolio	Portfolio solar and wind MW behind the constraint	Energy storage portfolio MW behind the constraint	Curtailment MW w/o mitigation	Mitigation
Colorado River 500/230 kV transformers	2034 Baseline	651	160	615	Existing West of Colorado River CRAS and/or batteries in charging mode
Red Bluff 500/230 kV transformers	2034 Baseline	471	924	370	Existing West of Colorado River CRAS and/or batteries in charging mode

Conclusion and recommendation

The SCE Eastern area base and sensitivity portfolios deliverability assessment identified on-peak and off-peak deliverability constraints. RAS can be used to mitigate several of these constraints. The off-peak deliverability constraints can also be mitigated by dispatching battery storage in charging mode. And while transmission upgrades were considered, none of those upgrades are being recommended for approval in this planning cycle given that they are only needed for the 2039 sensitivity portfolio.

3.5.10 SDG&E Interconnection Area

Table 3.5-24 includes the total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SDG&E interconnection area. The portfolios in the interconnection area are comprised of solar, wind (in-state), battery storage, geothermal, and long-duration energy storage resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table 3.5-24: SDG&E Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	2034 Baseline Portfolio			2039 Base Portfolio			2039 Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	700	882	**1,582**	700	1,219	**1,919**	1,950	2,544	**4,494**
Wind – In State	1,325	239	**1,564**	1,325	239	**1,564**	1,295	289	**1,584**
Wind – Out-of-State	0	0	**0**	0	0	**0**	0	0	**0**
Wind - Offshore	0	0	**0**	0	0	**0**	0	0	**0**
Li Battery – 4 hr	1,390	0	**1,390**	1,390	0	**1,390**	1,100	0	**1,100**
Li Battery – 8 hr	100	0	**100**	305	0	**305**	985	0	**985**
Long Duration Energy Storage (LDES)	437	0	**437**	487	0	**487**	500	0	**500**
Geothermal	160	0	**160**	160	0	**160**	866	0	**866**
Biomass/Biogas	0	0	**0**	0	0	**0**	0	0	**0**
Distributed Solar	1	0	**1**	1	0	**1**	1	0	**1**
Total	**4,113**	**1,121**	**5,234**	**4,368**	**1,458**	**5,826**	**6,697**	**2,833**	**9,530**

The resources as identified in the CPUC busbar mapping for the SDG&E interconnection area are illustrated on the single-line diagram in Figure 3.5-22 and Figure 3.5-23.

Figure 3.5-22: SDG&E Interconnection Area – Mapped 2034 Baseline Portfolio

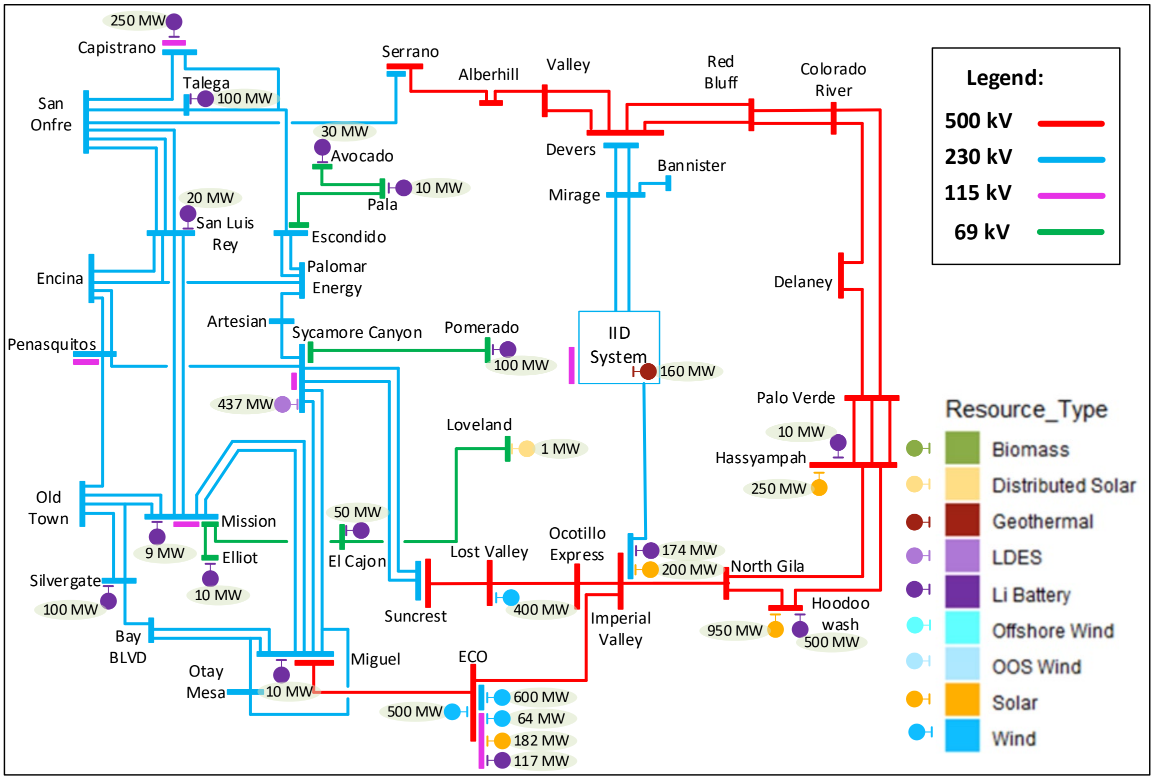
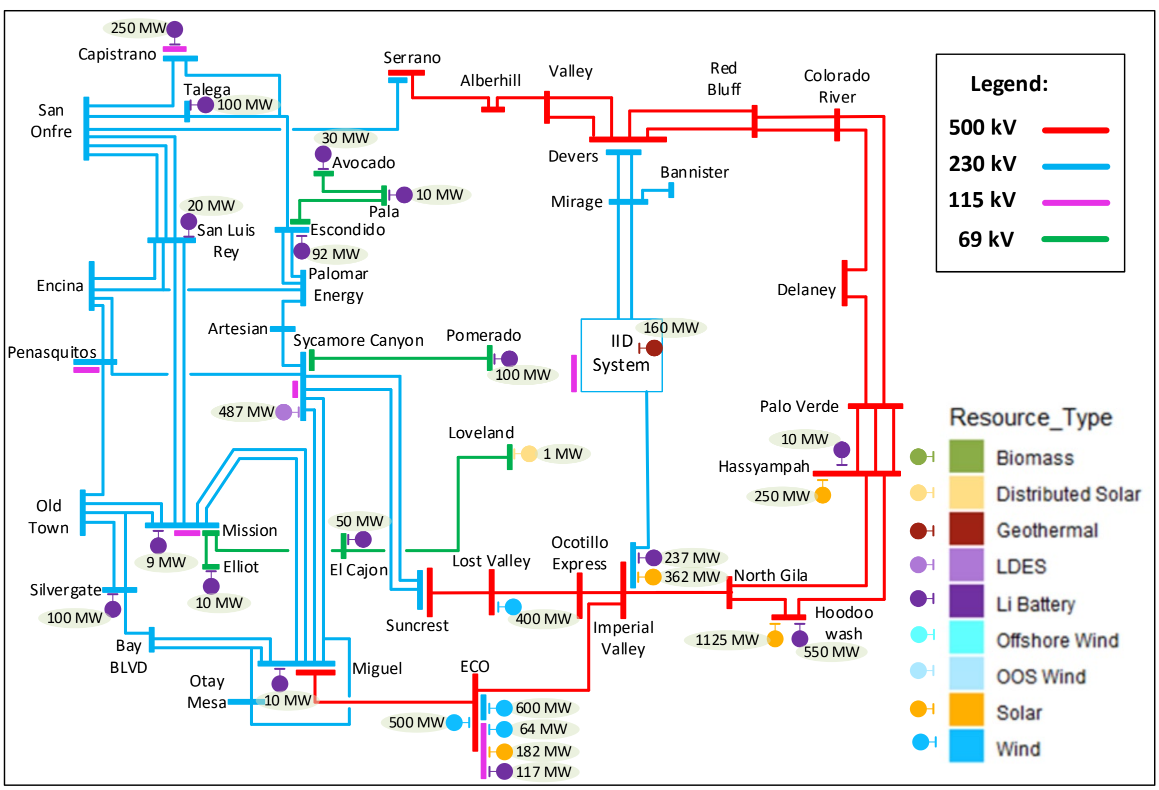


Figure 3.5-23: SDG&E Interconnection Area – Mapped 2039 Base Portfolio



On-Peak Deliverability Assessment

The constraints identified in the on-peak deliverability assessment of the SDG&E interconnection area along with the recommended mitigation plans are identified in Table 3.5-25.

Table 3.5-25: SDG&E Interconnection Area On-Peak Deliverability Constraints in Base and Sensitivity Portfolio

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
BB-SG	2034 Baseline	746	121	0	971	Use 2 hour emergency rating
	2039 Base	1579	342	1579	0	
	2039 Sensitivity	3064	562	2699	364	
SG-OT	2034 Baseline	501	184	136	365	Use 30 minute emergency rating
	2039 Base	1303	236	1303	0	
	2039 Sensitivity	1971	236	1862	109	
EA-SLR	2034 Baseline	2990	448	1783	1207	Existing 230 kV TL 23003 Encina-San Luis Rey/ TL 23011 Encina-San Luis Rey-Palomar RAS
	2039 Base	3196	1052	3196	0	
	2039 Sensitivity	4646	1271	4348	298	
SLR-SO	2034 Baseline	3800	726	3325	475	Existing 230 kV TL 23006 San Luis Rey-San Onofre RAS
	2039 Base	N/A				
	2039 Sensitivity					
Old Town	2034 Baseline	N/A				Downtown Reliability Reinforcement project (identified in reliability study)
	2039 Base	0	0	0	0	
	2039 Sensitivity					
Sycamore-Scripps	2034 Baseline	N/A				Use 30 minute emergency rating
	2039 Base	591	101	479	113	
	2039 Sensitivity	601	101	489	113	
ES-SM	2034 Baseline	N/A				Existing 230 kV TL 23003 Encina-San Luis Rey/ TL 23011 Encina-San Luis Rey-Palomar RAS
	2039 Base	634	143	634	0	
	2039 Sensitivity	643	143	521	122	

Off-Peak Deliverability Assessment

The off-peak deliverability assessment did not identify any constraints in the SDG&E area.

3.6 Out-of-State Wind

CPUC Portfolio Requirements

In the CPUC submitted portfolios for out-of-state wind resources for the 2024-2025 TPP, there is a total of approximately 6 GW for 2034 and 9 GW for 2039 in the base portfolios. For 2034, the base portfolio includes 1,060 MW from Idaho, 2,905 MW from Wyoming, and 2,131 MW from New Mexico. For 2039, in the base portfolio, in addition to the these amounts, there is an additional 1,500 MW from Wyoming and an additional 1,405 MW from New Mexico currently mapped to the ISO footprint at Tesla and Palo Verde respectively. All the required MW amounts require developing new transmission as well as transmission upgrades within the ISO footprint.

Transmission projects that are currently in development include SWIP-North, TransWest Express (TWE) and SunZia. TWE and SunZia are the two ISO Board-approved subscriber transmission developments that help integrate out-of-state wind resources from Wyoming and New Mexico respectively for the amounts that were specified in the CPUC submitted portfolio for the 2023-2024 TPP. Specifically, TWE will help integrate 1,500 MW from Wyoming and SunZia will help integrate 2,131 MW of out-of-state wind resources from New Mexico initially. TransWest Express LLC's PTO application was approved in December 2022 and the Board approved the tariff changes for the Subscriber Participating TO model in July 2023, which was accepted by FERC in March 2024. SunZia submitted an application to be a PTO in January 2024 which was approved by the ISO Board in May 2024 followed by FERC approval of the SunZia Transmission APTOA on September 4, 2024 under Docket No. ER24-2471-000.

SWIP-North, which would help integrate wind resources from Idaho, was approved by the ISO Board in October 4, 2024 as an addendum to the 2022-2023 transmission plan and which would help the project to move forward.[55] The Board approval of SWIP-North included approving the application of Great Basin Transmission, LLC to be a participating transmission owner and allowing the Department of Energy as an alternative to the contractual arrangement with Idaho Power for the 22.8% of the northbound transmission. The ISO continues to engage with Idaho Power on its need for and interest in SWIP-North, for 500 MW in the South-North direction.

More recently, on January 21, 2025, the FERC unconditionally approved the Development Agreement between the ISO and Great Basin Transmission under Docket No. ER25-543-000 for the SWIP-North transmission project. The Development Agreement includes establishing requirements during construction modeled largely upon the ISO's *proforma* Approved Project Sponsor Agreement (APSA), the ISO's 77.169% funding of the transmission project in exchange for assuming operational control of Great Basin's transmission entitlements on SWIP-North and the One Nevada line (ON), and cost containment provisions in order to reduce uncertainty and mitigate the risks of cost escalation.

Challenges with integrating additional out-of-state wind resources

The three noted transmission projects combined help in integrating about 5.7 GW of out-of-state resources from Idaho, Wyoming, and New Mexico. The ISO needs to determine additional transmission projects that would be needed to integrate the additional amounts of wind resources from Wyoming and New Mexico. This, however, can be challenging for a number of reasons.

[55] On December 14, 2023, the ISO Board of Governors approved including the SWIP-North project as a transmission solution in an addendum to the 2022-2023 transmission plan, subject to the satisfaction of four conditions, which were subsequently updated by the ISO and approved therein by the ISO Board on October 4, 2024.

First, the current in-development transmission projects such as TWE and SunZia are appropriately right-sized to deliver 1,500 MW from Wyoming to the ISO footprint at Harry Allen and approximately 3,500 MW from New Mexico to Palo Verde respectively, based on previously submitted CPUC resource portfolios for consideration in the ISO's transmission planning processes. It should also be noted that the scheduling right on SunZia from Pinal Central to Palo Verde is about 2,131 MW. The 2039 base portfolio has 3,536 MW New Mexico wind which equals 2,369 MW study amount. After taking into account 5% lost factor on HVDC line, there is still not enough scheduling rights from Pinal Central to Palo Verde. In light of the recent CPUC resource portfolios, for the 2024-2025 TPP and the 2025-2026 TPP, these transmission projects would most likely need to be redesigned to accommodate increased MW amounts from Wyoming and New Mexico which may not be practical. There is also the issue of developing additional new resources in these states that can then interconnect with these "redesigned" transmission projects.

Second, though there are transmission projects being developed in the West, there are no known transmission projects being developed, in addition to the ones mentioned, that bring additional amounts of wind resources from Wyoming and New Mexico **directly** to the ISO footprint. In other words, there seems to be a lack of developer interest in developing transmission to integrate additional amounts of out-of-state wind from Wyoming and New Mexico with the ISO footprint. Moreover, the in-development projects in the Western Interconnection that could potentially be considered as beneficial to California, may already be fully subscribed or close to it.

Third, it is challenging to build interregional transmission to integrate out-of-state wind as it requires coordination and negotiations with entities or utilities outside the ISO footprint. This can be challenging because it is not only the ISO, but also the entity that the ISO engages with that must also see potential benefits in developing and placing into service interregional transmission lines through their respective integrated planning processes. The issue of cost allocation commensurate with benefits would also need to be addressed.

The ISO's engagement in monitoring transmission developments and studies in the Western Interconnection

The ISO continues to monitor transmission developments in the Western Interconnection such as PacifiCorp's Gateway projects, NV Energy's GreenLink projects, TransCanyon's CrossTie transmission project, Grid United's Southline transmission project and the RioSol transmission project.

Various segments of the Gateway project are either in service or currently in development. The Greenlink West transmission project (Harry Allen – Ft. Churchill) is expected to be in service in May 2027 and the Greenlink North transmission project (Robinson – Ft. Churchill) is expected to be in service by the end of 2028. The RioSol transmission project connects New Mexico and Arizona and will generally follow the same route as SunZia serving as an AC transmission line. Based on the completion of SunZia, RioSol's construction is expected to commence in 2026 and is expected to be in-service by 2028. Grid United and Black Forest Partners are co-developing the Southline Transmission Project, a 278-mile, double-circuit, high voltage transmission line and associated substation facilities. The project will enable wind and solar resources from the Desert Southwest to reach key markets.

These transmission projects provide access to renewable resources in the region and could potentially serve interregional needs including those of California. The ISO will be considering these projects and engaging with the project proponents as appropriate to study any options that may be available to leverage these transmission projects to integrate additional amount of out-of-state wind resources from New Mexico and Wyoming.

The ISO continues to participate in and contribute to studies recently undertaken by NERC (Interregional transmission capability studies or ITCS), DOE (National Transmission Planning Study, National Transmission Needs Study, and Designation of National Interest Electric Transmission Corridors – NIETC), and CREPC/WIRAB (Connected West Study). These studies lead up to transmission solution recommendations which clearly establish the need to develop interregional planning efforts and build appropriate transmission solutions to enable access to renewable resources over a wide region thereby creating resource diversity, reduce or eliminate congestion and curtailment, meet state GHG reduction targets or RPS goals, support resource adequacy and planning margin objectives, strengthen grid resiliency, and help develop efficient economic transmission solutions. Stakeholders must note that the study outcomes from these various initiatives and studies are aligned with the ISO's transmission projects approved under its transmission planning cycles, its long term transmission outlook most recently updated in 2024, and the underlying coordination efforts between the ISO and California state agencies including the CPUC and the CEC in recommending and approving transmission projects based on CPUC submitted resource portfolios and the CEC's Integrated Energy Policy Report (IEPR) process.

The ISO is also participating in the Western Power Pool's WestTEC efforts. WestTEC is a West-wide transmission planning initiative and includes a number of stakeholders including utilities in the West. Expected outcomes from this initiative include developing interregional transmission recommendations in the 10-year and 20-year time horizons based on long-term load and resource forecasted scenarios and associated power flow and production cost modeling studies. Study results from WestTEC will also help inform the ISO's future recommendations on interregional transmission projects and upgrading transmission internal to California, for integrating out-of-state resources.

Recommendation

The ISO is not proposing the approval of any transmission project or upgrade in the 2024-2025 TPP for integrating additional out-of-state resources from Wyoming and New Mexico. This is also consistent with the CPUC directive in Decision 25-02-026, issued on February 20, 2025, not to trigger upgrades related to the additional out-of-state wind amounts in the portfolio that are beyond the amounts that can be accommodated on the already-identified and in-development transmission upgrades.

The ISO will undertake a special study of the various routes and combinations for the out-of-state wind amounts to learn more information about the details of potential routes. This will allow for analysis of alternative locations for injecting the resources onto the ISO grid and the potential transmission solutions. Moreover, the ISO will coordinate with CPUC staff as it pursues additional modeling with new out-of-state wind profiles and cost estimates to confirm the need for the high level of out-of-state wind. Engagement with utilities in the West to seek mutually beneficial transmission solutions and results from the WestTEC studies will also help inform the ISO as it works towards developing transmission solutions to integrate additional out-of-state resources.

While the ISO is working on transmission solutions to integrate additional out-of-state wind resources, it must be noted that there are known short-circuit duty (SCD) issues at Tesla substation, which could require SCD related upgrades in order to support the 1500 MW of Wyoming wind interconnecting to Tesla 500 kV. Currently there are some SCD upgrades planned at the Tesla substation to support new generations in the ISO interconnection queue. The ISO is coordinating with PG&E to make sure that the planned Tesla substation expansion project identified through the generator interconnection process aligns with this potential future need for intake of the Wyoming out-of-state wind. Additional analysis will be performed in future cycles to evaluate if additional updates to this project are required.

Northern California Wind was also evaluated as part of the 2024-2025 TPP. About 900 MW of wind resources connecting to the new/existing substations on the NVE 345 kV system between Hilltop and Ft. Sage in the Lassen/Modoc counties were modeled. Based on a high level review of the transmission system in the area, the NVE 345 kV system around Hilltop doesn't seem to have enough capacity to deliver 900 MW of wind resources to Malin 500 kV. However, if the resources are mapped to the Hilltop 230 kV system, it seem to have sufficient capacity to deliver the resources to Malin 500 kV. In regards to delivering capacity from these resources to the ISO system, the ISO assumed that these resources will be replacing historical imports (schedules) on the Malin 500 kV branch group and hence, will fit within the Malin branch group MIC.

3.7 Conclusion and Recommendations

The policy assessment has identified three new policy-driven projects recommended for approval in the 2024-2025 TPP cycle for a total estimated cost of $290 million as listed in Table 3.7-1.

Table 3.7-1: Recommended Policy-Driven Transmission Projects for Approval

Project Name	PTO	Planning Area	Cost($M)
Eagle Rock-Fulton-Silverado 115 kV line reconductor	PG&E	NCNB	93
GWF – Kingsburg 115 kV line reconductor	PG&E	Fresno	82
New Helm 230/70 kV Bank #2	PG&E	Fresno	115
		Total	**290**

In previous cycles, the ISO has reserved deliverability for long lead-time generation resources to ensure that policy-driven transmission projects are used to deliver resources specified in resource plans. These 2024-2025 policy-driven projects do not necessitate reservation of deliverability for any long lead-time generation or storage resources.

The CPUC resource portfolios included a sensitivity scenario to be assessed in the 2024-2025 TPP that was based on elevated levels of retirement of gas-fired generation. The assessment was for informational purposes with detailed reliability, policy and economic analysis undertaken. The ISO also assessed the sensitivity scenario in the long-term local capacity technical analysis. The detailed analysis is included in the applicable Appendices B, G, F and J. The following observations were made:

- In the Greater Bay area, the reliability constraints and resource deficiencies increase;
- In the LA Basin area, the LCR requirements increase in the 15-year planning horizon. With increased storage resources in the portfolio in the LA Basin area, the constraint can be addressed with local dynamic voltage support; and
- In the Moorpark area, thermal constraints were observed in the 15-year planning horizon.

Intentionally left blank

Chapter 4 Economic Planning Study

4.1 Introduction

The ISO's economic planning study is an integral part of its 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 ISO.

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. 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.

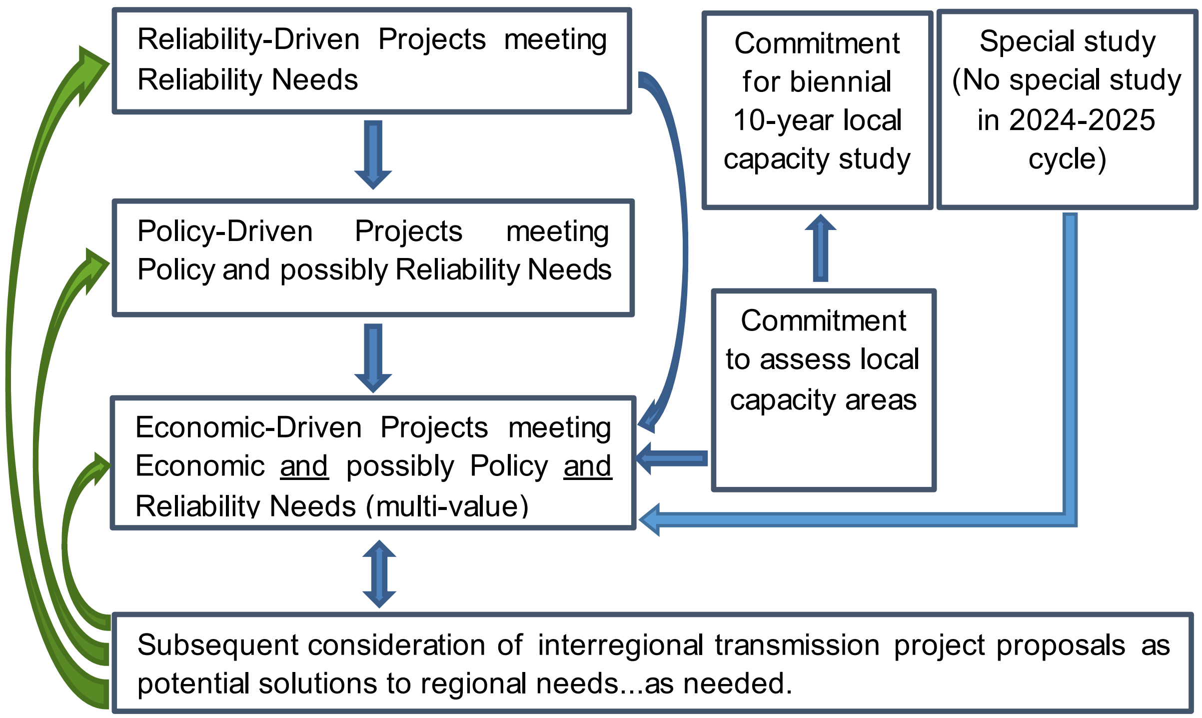
Economic study requirements are being driven from a growing number of sources and needs, including:

- The ISO'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 analyses 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.

All transmission solutions identified in this transmission plan as needed for grid reliability and renewable integration were modeled in the production cost simulation database. The ISO then performed the economic planning study to identify additional cost-effective transmission solutions to mitigate grid congestion and increase production efficiency within the ISO. These more comprehensive economic studies can also lead to replacing or upscaling a solution initially identified at the reliability or policy stage. The analysis focuses on reducing costs to ISO ratepayers; the potential economic benefits are quantified as reductions of ratepayer costs based on the ISO's documented Transmission Economic Analysis Methodology (TEAM).[56]

The above issues led to requiring a broader view of economic study methodologies and developing stronger interrelationships between studies conducted under different aspects of the transmission planning process. These interrelationships are illustrated in Figure 4.1-1.

Figure 4.1-1: Interrelationship of Transmission Planning Studies



The production cost modeling simulations 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.

4.2 Technical Study Approach and Process

Different components of ISO ratepayer benefits are assessed and quantified under the economic planning study.

[56] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

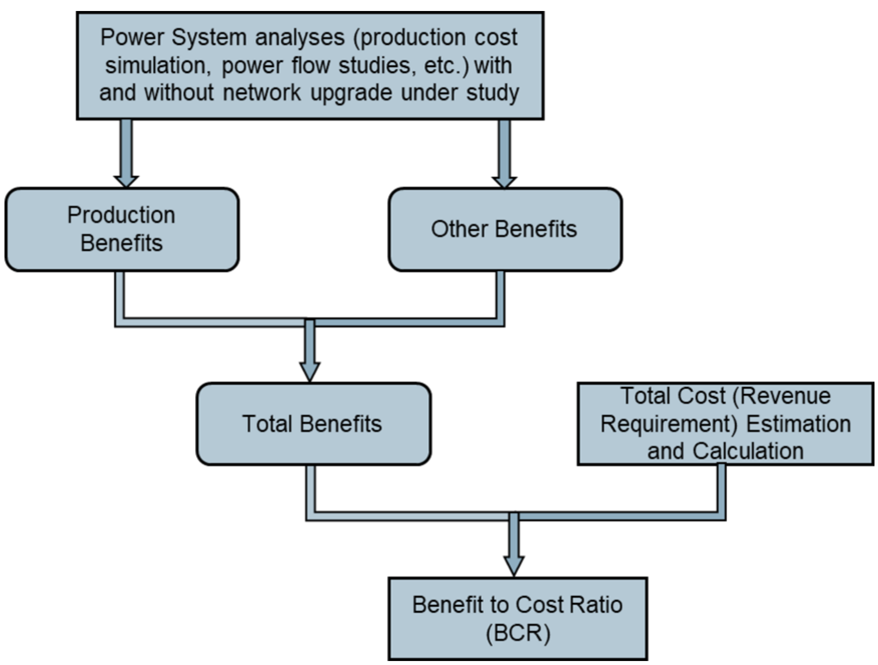
First, production benefits are quantified by the production cost simulation that computes unit commitment, generator dispatch, locational marginal prices and transmission line flows over 8,760 hours in a study year. With the objective to minimize production costs, the computation balances supply and 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. These include: consumer energy cost decreases; increased load-serving entity-owned generation revenues; and increased transmission congestion revenues.

Additionally, other benefits including capacity benefits are also assessed. Capacity benefits may include system and flexible resource adequacy (RA) savings and local capacity savings, assessed through power flow analysis. The system RA benefit corresponds to a situation where a transmission solution for importing energy leads to a reduction of ISO 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.

Once the total economic benefit is calculated, it is weighed against the cost, which is the total revenue requirement of the project under study.

The technical approach of the economic planning study is depicted in Figure 4.2-1.

Figure 4.2-1: Technical approach of economic planning study



4.3 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 2024 U.S. dollars and discounted to the assumed operation year of the studied solution to calculate the net-present values.

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, operation and maintenance expenses and other relevant costs, using the financial parameters and assumptions set out in Appendix G. The net present value of the costs (and benefits) is calculated using a social discount rate of 7% (real) with sensitivities at 5% as needed.

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 ISO then uses typical financial information to determine annual revenue requirements, and from there to calculate the present value of the annual revenue requirements stream. For screening purposes, the multiplier of 1.3 is used in this study to estimate the present value of the annual revenue requirement stemming from a capital investment, reflective of a 7% real discount rate and based on 40 to 50-year lifespans.

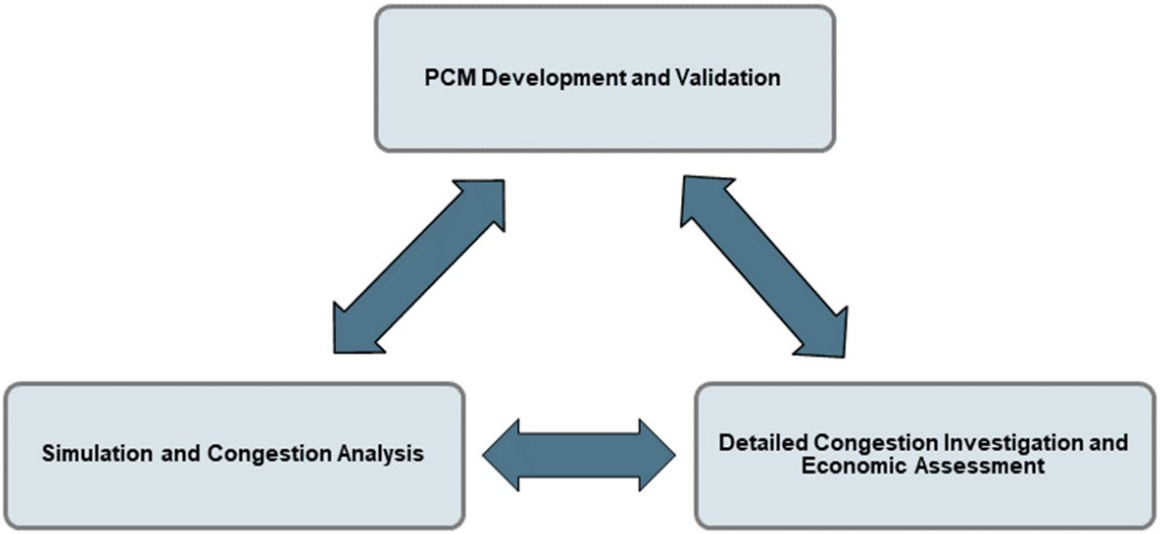
As the “capital cost to revenue requirement” multiplier was developed on the basis of the long lives associated with transmission lines, the multiplier is not appropriate for shorter lifespans expected for current battery technologies. Accordingly, levelized annual revenue requirement values can be developed for battery storage capital costs and can then be compared to the annual benefits identified for those projects.

In considering how to assess the value to ratepayers of proposals to reduce gas-fired generation local capacity requirements in areas, the ISO recognizes that additional coordination on the long-term need for gas-fired generation for system capacity and flexibility requirements will need to take place with the CPUC through future integrated resource planning processes. If there are sufficient gas-fired generation resources to meet local capacity needs over the planning horizon, there are no needs 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, the gas-fired generation may still be required for system or flexible capacity reasons.

4.4 Study Steps of Production Cost Simulation in Economic Planning

As discussed earlier, 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 to be coordinate with the entire WECC and the 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 development and validation, simulation and congestion analysis, and production benefit assessments of congestion mitigation. Each of these steps is described in more detail in Appendix G. Because of the complexity of the models and analysis, there is often iteration between the three steps as a careful review of results lead to revisiting model aspects. Figure 4.4-1 shows these components and their interaction.

Figure 4.4-1: Steps of Production Cost Simulation in Economic Planning



The final product of this analysis is an assessment of the volume and cost impact of congestion on the transmission system, as well as of the effectiveness of different mitigations across all hours of the study year. These results must then be combined with other economic benefits derived through power flow analysis.

4.5 Production cost simulation tools and database

The ISO primarily uses the Hitachi GridView™ software for the economic planning study.

The ISO normally develops a database for the 10-year case as the primary case for congestion analysis and benefit calculation. The ISO 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. In the 2024-2025 planning cycle, the CPUC provided the 2034 and 2039 IRP portfolios to the ISO for transmission planning study. Therefore, the 10-year and the 15-year production cost simulation cases were developed.

The major assumptions of system modeling used in the GridView PCM development for the economic planning study are set out in Appendix G.

The 2024-2025 transmission planning process PCM development started from the Western Interconnection Anchor Data Set production cost simulation model (ADS PCM) 2034 PCM case. The ISO then modified the network model for the ISO system to exactly match the 2024-2025 cycle's policy assessment power flow cases for the entire ISO planning area. The transmission topology, transmission line and transformer ratings, generator location, and load distribution are identical between the PCM and policy assessment power flow cases. Appendix G also highlights the major ISO enhancements and modifications to the ADS PCM database that were incorporated into the ISO's database. It is noted that details of the modeling assumptions and the model itself are not itemized for the rest of the Western Interconnection in this document, but the final PCM is posted on the ISO's market participant portal once the study is final.

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 conditions across the ISO system. Specifically in the 2024-2025 cycle, the CEC California Energy Demand Updated Forecast for 2034 and 2039, consistent with the reliability assessment as described in Chapter 2, were used to develop the 2034 and 2039 PCM cases, respectively.

One 2034 PCM case and two 2039 PCM cases were developed using different CPUC resource portfolios. The CPUC 2034 base portfolio was used to develop the generator model in the 2034 PCM case. The CPUC 2039 base portfolio and the CPUC 2039 sensitivity portfolio (i.e. the high gas retirement portfolio) were used to develop the generator models in the 2039 PCM cases, respectively. Generator locations and installed capacities in the PCM are consistent with the policy assessment power flow cases, including both conventional and renewable generators. Chapter 3 provides more details about the renewables portfolio.

The CPUC base and sensitivity portfolios include out-of-state wind resources in different areas. Some of the out-of-state wind resources in the CPUC portfolios are expected to require new transmission, while some of the resources rely on existing transmission to deliver their wind energy to the ISO load. For the out-of-state wind resources that require new transmission, the CPUC portfolio provided specified injection points to the ISO system, but did not specify particular out-of-state transmission projects to deliver the resources to the ISO boundary.

In the planning PCM in this planning cycle, New Mexico wind generation that requires new transmission was modeled at the Pinal Central 500 kV bus in Arizona, which is consistent with the last planning cycle. This is equivalent to assuming that a new transmission line would be built to deliver New Mexico wind generation to the Pinal Central 500 kV bus.

The CPUC base portfolio included out-of-state wind identified in Wyoming areas and in Idaho areas, which are expected to require new transmission. In the planning PCM in this planning cycle, Wyoming wind was modeled associated with the TransWest Express project. The Idaho wind was modeled associated with the SWIP North project as baseline assumption in the base portfolio PCM.

The 2024-2025 planning PCM continued to use the multi-block renewable generator model that was first developed and used in the 2019~2020 planning cycle PCM. This model was applied to all ISO 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

The ISO continued its modeling of battery storage, refined 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 cycle life (i.e. 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.

4.6 Base Portfolio Production Cost Simulation Results

This section shows the summary of base portfolio production cost simulation results. The detailed results are included in Appendix G.

4.6.1 Summary of congestion results

High-level assessments were conducted in this section on the constraints that may have a large impact on the bulk system or the heavily congested areas, or showed recurring congestion. The assessment results are shown in Table 4.6-1.

Table 4.6-1: Summary of high-level investigation on major transmission congestions

Constrained area or branch group	2034 Base portfolio PCM		2039 Base portfolio PCM		Overview of investigation
	Cost (M$)	Duration (Hours)	Cost (M$)	Duration (Hours)	
Path 15 Corridor	389.42	5,468	521.80	7,343	Path 15 corridor congestion was attributed to both Path 15 path rating binding and binding of the 500 kV or 230 kV lines of the path when the flow is from south to north. Renewable generators in the PG&E Fresno/Kern area and offshore wind modeled at Diablo Canyon contributed to the Path 15 corridor congestion. The Path 15 corridor congestion was also correlated with the Path 26 congestion, which was also observed when the flow is from south to north.
Path 26 Corridor	241.10	4,503	206.28	4,197	Path 26 corridor congestion was mostly attributed to the Path 26 path rating binding and the Whirlwind- Midway 500 kV line normal rating binding. The congestion was mostly observed when the Path 26 flow was from south to north. The main driver of the Path 26 corridor congestion is the large amount of renewable generation and battery in Southern CA identified in the CPUC portfolio
East of Pisgah	35.61	1,378	86.87	3,334	Majority of East of Pisgah area congestion was observed on the Path 61 corridor, the Eldorado – McCullough 500 kV line, and the Sloan Canyon – Eldorado 500 kV line. Renewable generation in the CPUC portfolio delivered to the Eldorado buses, including the renewable generation in the Eldorado/Mohave area and the GLW/VEA area, and the out-of-state wind in Wyoming and/or Idaho, contributed to the congestion in the East of Pisgah area.
SCE Northern	19.69	1,743	78.62	3,348	Majority of SCE Northern area congestion was observed on the Windhub transformer from 230 kV to 500 kV and on the Vincent transformer from 500 kV to 230 kV. Busbar mapping of the portfolio resources on the 500 kV or 230 kV sides impact the congestion on these transformers. Congestions on 230 kV lines in this area were also observed, but have relatively small congestion cost.
SCE Metro	16.05	179	67.89	1,328	SCE Metro area congestion mainly was observed on the La Fresa – La Cienega 230 kV line under La Fresa – El Nido 230 kV lines N-2
SWIP North	51.29	716	51.61	748	SWIP North congestion was observed when the flow is from south to north. Renewable surplus in Southern California, Southern Nevada, Arizona, and Utah contributes to the congestion on SWIP North.
SCE North of Lugo	8.04	4,492	32.55	6,531	Congestion in the SCE North of Lugo area in this planning cycle was observed mainly on the Calsite-Lugo 230 KV line. Renewable resources in the Calsite area, identified in the CPUC base portfolio, are the driver of the congestion.
Path 42	11.29	495	24.13	594	Path 42 congestion was observed when the flow is from IID to SCE. The solar and geothermal generation in the IID area are the main driver of this congestion.
Path 65 PDCI	28.53	1,679	22.99	1,380	PDCI congestion was observed when the flow is from south to north. The LADWP's operation limit of PDCI was the binding constraint of the PDCI congestion.

Constrained area or branch group	2034 Base portfolio PCM		2039 Base portfolio PCM		Overview of investigation
	Cost (M$)	Duration (Hours)	Cost (M$)	Duration (Hours)	
Path 46 WOR	2.37	45	19.53	308	Congestion on Path 46 (WOR) was observed in this planning cycle. The congestion cost and duration both increased from the last planning cycle as the out of state renewable resource capacity increased.
SDG&E/CFE	10.43	1,577	18.03	2,101	Congestion between the SDGE and CFE systems was observed mainly on Path 45 path rating binding. In spring, congestion on this corridor mainly occurred when there was solar surplus in the ISO system and the Path 45 flow was from SDGE to CFE. In other times of the year, congestion can be observed when the flow was from CFE to SDGE, which is mainly due to the natural gas price difference across the border. This congestion is impacted by the CFE's generation and load modeling assumption. Further clarity of such factors will be required before detailed investigations need to be conducted.
PG&E North Valley 230 kV	15.05	1,863	16.63	1,485	Renewable generators in the CPUC portfolios that were mapped in the area around the Pit and Round Mountain substation are the main driver of the congestion on PG&E North Valley 230 kV lines.
SDG&E 230 kV	3.74	634	12.34	1,293	SDG&E 230 kV system congestion was observed mainly on the San Luis Rey - S. Onofre 230 kV line when the flow is from north to south.
PG&E Kern 230 kV	6.57	997	11.58	1,548	Majority of the congestion in the PG&E Kern area 230 kV system was the Gates-Calflat 230 kV line congestion, attributed to the renewable generators in the PG&E Kern area.
SCE Eastern	0.31	19	9.63	171	Congestion on Valley 500 kV transformer was observed when the flow is from 500 kV to 115 kV. This is mainly due to the local load, especially the AATE component mapped at the Valley 115 kV bus. Minor congestion was also observers on the Red Bluff – Devers 500 kV line and Devers transformer.
PG&E Morro Bay 230 kV	0.00	0	9.51	1,169	The Diablo Canyon – Morro Bay 230 kV line can be congested due to the offshore wind that is modeled at Diablo Canyon substation.
Path 41 Sylmar transformer	4.72	298	7.93	397	The congestion on Sylmar transformer was observed when the flow is from LADWP to SCE as the flow on PDCI from north to south is high.
PG&E Sierra	1.95	475	8.39	1,053	Congestion in the PG&E Sierra area was observed mainly on Path 24 when flow was from Nevada to California.
SCE Antelope 66 kV	0.00	0	6.76	1,619	Congestion on the Antelope – Neenach 66 kV line was observed, which is caused by the loop flow between the 230 kV and 66 kV systems.
PG&E Greater Bay area	1.10	186	5.79	459	Majority of PG&E Greater Bay area congestion was observer on the East Shore – San Mateo 230 kV line and the Los Positas – Newark 230 kV line, which are mainly load serving driven.
COI corridor	2.93	70	4.96	52	Congestion on COI corridor is mainly attributed to COI path rating binding, and can happen when flow is from north to south or from south to north.
PG&E Fresno 115 kV	0.08	32	4.55	227	Fresno 115 kV congestion can be attributed to load serving or loop flow between the 115 kV and the 230 kV system
SDG&E Bulk	3.67	374	3.99	447	Congestion in the SDG&E Bulk system was mainly observed on the ECO and Imperial Valley transformers due to the renewable resources that were mapped at the low voltage buses at ECO or Imperial Valley substations.
PG&E Manning – Metcalf 500 kV	0.00	0	3.65	116	Minor congestion was observed on the newly recommended Manning – Metcalf 500 kV line, which indicates the high utilization of this 500 kV upgrade.
PG&E Fresno 230 kV	0.05	32	1.23	182	Minor congestion was observed on the Fresno 230 kV lines, such as Gregg – Henrietta and McMullin – Kearney, and Gates 230 kV transformer

4.6.2 Wind and solar curtailment results

Table 4.6-2 shows wind and solar generation curtailment in the ISO system in the base portfolio PCM. 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 no obvious transmission constraints nearby.

Table 4.6-2: Wind and solar curtailment summary in the base portfolio PCM

	2034 Base Portfolio PCM				2039 Base Portfolio PCM			
Renewable zone	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio	Generation (GWh)	Curtailment (GWh)	Total potential (GWh)	Curtailment Ratio
SCE Northern	31,216	1,300	32,516	4.00%	33,455	1,373	34,828	3.94%
SCE Eastern	20,184	277	20,461	1.36%	23,695	487	24,182	2.01%
PG&E Fresno	16,628	1,709	18,337	9.32%	20,931	2,585	23,516	10.99%
East of Pisgah	12,585	764	13,349	5.72%	16,944	952	17,896	5.32%
PG&E Central Valley	11,073	416	11,488	3.62%	17,073	595	17,668	3.37%
OOS W-SunZia	8,375	1,183	9,558	12.38%	13,268	2,592	15,860	16.34%
SDG&E Eastern and Bulk	14,197	427	14,624	2.92%	14,953	525	15,477	3.39%
OSW-Diablo	13,365	769	14,134	5.44%	13,319	815	14,134	5.76%
SCE North of Lugo	10,633	411	11,044	3.72%	12,193	602	12,795	4.70%
OOS W-WY	10,761	468	11,229	4.17%	11,087	509	11,596	4.39%
PG&E Kern	6,053	322	6,375	5.06%	9,890	412	10,301	4.00%
OSW-Humboldt	4,698	54	4,752	1.14%	8,140	63	8,203	0.77%
NM	4,825	1,877	6,702	28.00%	4,447	2,255	6,702	33.65%
OOS W-Tesla	0	0	0	0.00%	5,672	126	5,798	2.18%
PG&E Central Coast	4,228	144	4,372	3.30%	4,917	281	5,198	5.40%
PG&E North Valley	3,124	147	3,271	4.50%	4,156	192	4,348	4.42%
SCE Metro	2,173	68	2,241	3.04%	3,008	107	3,115	3.43%
OOS W-ID	2,798	141	2,939	4.80%	2,780	160	2,939	5.44%
OOS W-NW	0	0	0	0.00%	1,819	983	2,802	35.09%
AZ	1,920	833	2,753	30.26%	1,708	1,045	2,753	37.96%
IID	1,408	1	1,410	0.08%	1,409	1	1,410	0.05%
PG&E Greater Bay Area	1,193	64	1,256	5.08%	1,206	50	1,256	4.01%
San Diego	712	4	716	0.54%	713	3	716	0.48%
NW	554	28	582	4.77%	552	31	582	5.25%
SMUD	379	29	408	7.07%	384	25	408	6.06%
PG&E North Coast	387	10	397	2.42%	393	4	397	0.89%
NV	328	49	376	12.91%	322	54	376	14.38%
PG&E North Bay	56	4	60	6.85%	56	4	60	6.27%
PG&E Humboldt	12	0	12	3.79%	12	0	12	2.95%
Total	**183,865**	**11,498**	**195,364**	**5.89%**	**228,499**	**16,830**	**245,329**	**6.86%**

Compared with the last planning cycle's results, the overall renewable curtailment in this planning cycle reduced. Policy and reliability transmission upgrades, including reliability and policy projects recommended for approval in this plan, contributed to the curtailment reduction. Also, the increase of battery storage capacity and the adjustment of resource mapping compared with the last planning cycle's portfolio helped to reduce renewable curtailment. Still, curtailment of out-of-state resources in some areas increased, which are partially because the portfolio resource capacity increased in these areas and also because the overall renewable capacity increased in these areas in the ADS PCM model.

4.7 Economic Planning Study Requests

4.7.1 Overview of economic planning study requests

As part of the economic planning study process, economic planning study requests are accepted by the ISO to be considered in addition to the congestion areas identified by the ISO. 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. Those are also set out here, with the rationale for proceeding to detailed analysis where warranted.

The ISO's tariff and Business Practice Manual allows the ISO 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 ISO 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 a case-by-case basis the latest and most relevant information available.

Accordingly, the ISO reviewed each regional study or project being considered for detailed analysis. 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 stand-alone basis or as one of several options of a broader area study.

4.7.2 Summary of economic planning study request evaluation

The received study requests and the evaluation results for the requests are summarized in Table 4.7-1. Detailed evaluations for the study requests for purposes of selecting the final list of high-priority economic planning studies are included in Appendix G.

Table 4.7-1: Economic study requests

No.	Study Request	Submitted By	Location	Evaluation Results
1	PTE Project	California Western Grid Development	Northern/Southern CA	The PTE project was assessed in previous planning cycles, and did not show sufficient benefit to the ISO's ratepayers. The previous studies also demonstrated that the PTE project can help to reduce Path 26 corridor congestion. Detailed production cost simulation was conducted for The PTE project in this planning cycle because of the significant congestion on the Path 26 corridor and in the Western LA Basin area.
2	Del Amo to El Nido Underground HVDC Line project	Grid United LLC	Southern California	La Fresa – La Cienega 230 kV line congestion was observed in this planning cycle. This study request was considered as a mitigation alternative for the La Fresa – La Cienega 230 kV congestion. Detailed production cost simulation was conducted for this study request.
3	Del Amo to El Nido Underground 230 kV AC Line project	Grid United LLC	Southern California	La Fresa – La Cienega 230 kV line congestion was observed in this planning cycle. This study request was considered as a mitigation alternative for the La Fresa – La Cienega 230 kV congestion. Detailed production cost simulation was conducted for this study request.
4	Kern-Southland Energy Link (K-SEL) project (Midway – El Nido 2000 MW HVDC)	Kern-Southland Energy Link LLC	Southern California	This study request was considered as a mitigation alternative for the Path 26 corridor congestion and the Western LA Basin congestion. Detailed production cost simulation was conducted for this study request.
5	Sloan Canyon-Mead	GridLiance West	Southern Nevada	Sloan Canyon – Mead 230 kV line congestion was not observed in this planning cycle due to the renewable generator assumption change in the GridLiance/VEA area compared with the previous planning cycle. No detailed production cost simulation was conducted for this study request.
6	GLW Upsize to Sagebrush	GridLiance West	Southern Nevada	No significant congestion was observed in the GridLiance/VEA area. This study request was not identified effective to mitigate the congestion in the GridLiance/VEA area observed in this planning cycle. No detailed production cost simulation was conducted for this study request.
7	Mead- Mohave	GridLiance West	Southern Nevada	Sloan Canyon – Mead 230 kV line congestion was not observed in this planning cycle due to the renewable generator assumption change in the GridLiance/VEA area compared with the previous planning cycle. No detailed production cost simulation was conducted for this study request.
8	GLW Upsize to Esmeralda	GridLiance West	Southern Nevada	No significant congestion was observed in the GridLiance/VEA area. This study request was not identified effective to mitigate the congestion in the GridLiance/VEA area observed in this planning cycle. No detailed production cost simulation was conducted for this study request.
9	New 500 kV line from Colorado River - Red Bluff - Devers - Mira Loma	EDF Renewables North America	Southern California	Based on the congestion analysis results and evaluation provided above, the new 500 kV line from Colorado River - Red Bluff - Devers - Mira Loma project was selected for detailed analysis as an alternative for mitigating Victorville – Lugo 500 kV line congestion in this planning cycle.
10	Third Red Bluff transformer	EDF Renewables North America	Southern California	Red Bluff transformer was not congested in this planning cycle's production cost simulation. No detailed assessment was conducted for this study request.
11	230 kV Red Bluff tap to Buck Blvd - J. Hinds	EDF Renewables North America	Southern California	Minor congestion was observed on the J.Hinds – Mirage 230 kV line, which can be mitigated by the reliability upgrade of recondutoring the congested line. No detailed assessment was conducted for this study request, as the congestion in this area is minor in this planning cycle.

No.	Study Request	Submitted By	Location	Evaluation Results
12	Third Devers transformer	EDF Renewables North America	Southern California	Minor congestion was observed on the Devers 500/230 kV transformers. No detailed assessment was conducted for this study request, as the Devers transformer congestion is minor in this planning cycle.
13	Temporary reconfiguration soultions to relieve Devers 500/230 kV transformer congestion	EDF Renewables North America	Southern California	Minor congestion was observed on the Devers 500/230 kV transformers. This study request potentially impacts the Devers transformer flow. No detailed assessment was conducted for this study request, as the Devers transformer congestion is minor in this planning cycle.
14	Fourth Whirlwind transformer	EDF Renewables North America	Southern California	Whirlwind transformer was not congested in this planning cycle's production cost simulation. No detailed assessment was conducted for this study request.
15	Upgrades on PG&E 500 kV lines to add new circuits on segments • Los Banos-Gates 500 kV • Gates-Midway 500 kV • Tesla-Los Banos 500 kV • Gates-Diablo 500 kV	EDF Renewables North America	Northern California	Path 15 corridor congestion was observed in this planning cycle, and was assessed in detail in this planning cycle by considering different alternatives of Path 15 corridor congestion mitigation including segments in this study request.
16	New 500 kV line from Midway to Gregg and Gregg to Table Mountain	EDF Renewables North America	Northern California	Path 15 corridor congestion was observed in this planning cycle, and was assessed in detail in this planning cycle with considering different alternatives of Path 15 corridor congestion mitigation including segments in this study request.
17	Monarch 500 kV Transmission Project associated with the Fresno County solar plus storage projects in the WAPA SNR queue	Golden State Clean Energy, LLC ("GSCE")	Northern California	Path 15 corridor congestion was observed in this planning cycle, and was assessed in detail in this planning cycle with considering different alternatives of Path 15 corridor congestion mitigation including segments in this study request.

4.8 Detailed Investigation of Congestion and Economic Benefit Assessment

The ISO selected the high priority study areas listed in Table 4.8-1 for further detailed assessment. This was done 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. The ISO then conducts its technical and economic evaluations to select the most effective and efficient recommendation. Details of the economic and technical comparisons of alternatives are provided in Appendix G.

High-priority areas were selected not solely based on congestion costs or duration, but by taking other considerations into account. Facilities identified as potential mitigations in those study areas include stakeholder proposals from a number of sources: request window submissions that cite economic benefits, economic study requests and comments in various stakeholder sessions suggesting alternatives for reducing local capacity requirements.

Congestion on radial transmission lines or some local areas may not be selected as a high-priority study even though the congestion cost or duration are relatively large and if the congestion was only driven by local renewable generators identified in the CPUC default renewable portfolio. Congestion in these areas is subject to change with further clarity of the interconnection plans or busbar mapping of future resources.

The stakeholder-proposed mitigations being carried forward for detailed analysis are set out in Table 4.8-1 for ease of tracking where and how these stakeholder proposals were addressed.

The detailed analysis also considers other ISO-identified potential mitigations which have been listed in Table 4.8-1 as well. The detailed study results can be found in Appendix G.

Table 4.8-1: Areas receiving detailed economic benefit investigation

Detailed investigation	Alternatives	Reason for receiving detailed assessment
East of Pisgah and Path 46 congestion	The Trout Canyon to Lugo project to build a new Trout Canyon – Lugo 500 kV line with 70% compensation	Recurring congestion on the Path 61 corridor under both contingency and normal condition when the flow was from Victorville to Lugo was observed. Large congestions on the Eldorado – McCullough 500 kV line and the Sloan Canyon – Eldorado 500 kV line, and the Path 46, were also observed. The congestion in this area is mainly attributed to renewable generation in the SCE's East of Pisgah area, GridLiance West/VEA area, and the out of state wind generation delivered to the Harry Allen and Eldorado area. Solar generation in Arizona and New Mexico wind generation in the CPUC portfolios also contributed to the Path 46 congestion.
	The Marketplace to Adelanto project to convert the Marketplace-Adelanto 500 kV line to HVDC, and build a 500 kV line from Adelanto to Lugo and a 500 kV line from Marketplace to Eldorado	
	Build the second Sloan Canyon – Eldorado 500 kV line	
	Build a new Adelanto – Lugo 500 kV line	
	Build the third Colorado River – Red Bluff 500 kV line and a new Red Bluff – Mira Loma 500 kV line	
LA Basin and Path 26 corridor congestion	The PTE project	Path 26 congestion is a recurring congestion with large congestion cost. La Fresa – La Cienega 230 kV congestion was also observed. The mitigation alternatives are expected to help to mitigate the congestion,. The PTE project and the K-SEL project are also expected to reduce local capacity requirements.
	The K-SEL project (Midway – El Nido 2000 MW HVDC)	
	The Del Amo – El Nido underground HVDC project	
	The Del Amo – El Nido underground 230 kV AC line project	
	Build the third Midway – Vincent 500 kV line	
Path 15 corridor congestion	Alternative 1: Build a new Manning – Los Banos – Tesla 500 kV line	Path 15 corridor congestion showed significant increase in this planning cycle compared with the results in previous planning cycles, as the resource assumption changed in the CPUC IRP portfolio.
	Alternative 2: A1 plus a new Midway – Gates – Manning 500 kV line	
	Alternative 3: Monarch Option 1 Gates – Los Banos #3 500 kV line loops in new NewPoint 500 kV substation and build a new NewPoint to Tracy 500 kV line	

Detailed investigation	Alternatives	Reason for receiving detailed assessment
	Alternative 4: A3 plus NewPoint – Tracy looping in Tesla	
	Alternative 5: A4 plus build a new Midway – New Point 500 kV line	
	Alternative 6: Monarch Option 2 Build a new Manning – NewPoint – Tracy 500 kV line	
	Alternative 7: A6 plus NewPoint – Tracy looping in Tesla	
	Alternative 8: A7 plus build a new Midway – NewPoint 500 kV line	
	Alternative 9: Build a new 500 kV line from Midway to the new Gregg 500 kV substation to Tesla	
	Alternative 10: Install a 10 ohm series reactor on each of the two Panoche – Gates 230 kV lines	

This study step consists of conducting detailed investigations and modeling enhancements as needed. To the extent that economic assessments for potential transmission solutions are necessary, the production benefits and other benefits of potential transmission solutions are based on the ISO's Transmission Economic Analysis Methodology (TEAM),[57] 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.

Finally, it is important to reiterate that all regional transmission solutions – other than modifications to existing facilities -- are subject to the ISO's competitive solicitation process as set out in the ISO's tariff. While many projects have been submitted with narrowly defined project scopes, the ISO is not constrained to only study those scopes without modification, or to study the projects exclusively on the basis under which the proponent suggested.

4.9 Summary and Recommendations

The ISO conducted production cost modeling simulations in this economic planning study. 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 ISO'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.

[57] Transmission Economic Assessment Methodology (TEAM), California Independent System Operator, Nov. 2 2017 http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology-Nov2_2017.pdf

The ISO then conducted extensive assessments of potential economic transmission solutions. These potential transmission solutions included stakeholder proposals received from a number of sources, including: request window submissions that cited economic benefits, economic study requests, and comments in various stakeholder sessions. Alternatives also included interregional transmission projects as set out in Chapter 5 of the 2024-2025 Transmission Plan.

The study results in this planning cycle were heavily influenced by certain ISO 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. As noted earlier, existing legislation[58] calls for the CPUC to provide to the ISO by March 31, 2024 resource projections that are expected to reduce by 2035 the need to rely on non-preferred resources in local capacity areas. However, these projections are not yet reflected in the portfolios provided by the CPUC for the 2024-2025 Plan. As there were no material changes in the assumption regarding the value of reducing capacity requirements in this planning cycle, the ISO did not update the results of the local capacity reduction assessment; rather, the capacity value results of previous planning cycles were used in the economic assessment for the transmission projects that potentially had the benefit of reducing local capacity. The ISO 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 overall economic planning study results in the 2024-2025 planning cycle are summarized in Table 4.9-1.

Table 4.9-1: Summary of economic assessment in the 2024-2025 planning cycle

Congestion or study area	Alternative	Economic Assessment Result	Economic Justification	Other Justification
East of Pisgah and Path 46 congestion	The Trout Canyon to Lugo project to build a new Trout Canyon – Lugo 500 kV line with 70% compensation	This alternative can significantly reduce the following congestions: • Path 61 (Lugo – Victorville 500 kV line) congestion under normal condition and Eldorado – Lugo 500 kV line N-1 contingency • Eldorado – McCullough 500 kV congestion under Eldorado – Lugo 500 kV line N-1 or Mohave – Lugo 500 kV N-1 • Path 46 (West of River) congestion • Sloan Canyon – Eldorado 500 kV congestion Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
	The Marketplace to Adelanto project to convert the Marketplace-Adelanto 500 kV line to HVDC, and	This alternative can significantly reduce the following congestions:	No	No

[58] SB 887, the Accelerating Renewable Energy Delivery Act, authored by Senator Josh Becker, was signed into law by Governor Newsom on September 16, 2022.

Congestion or study area	Alternative	Economic Assessment Result	Economic Justification	Other Justification
	build a 500 kV line from Adelanto to Lugo and a 500 kV line from Marketplace to Eldorado	• Path 61 (Lugo – Victorville 500 kV line) congestion under normal condition and Eldorado – Lugo 500 kV line N-1 contingency • Path 46 (West of River) congestion Ratepayer benefit is not sufficient to cover the total cost of the project		
	Build the second Sloan Canyon – Eldorado 500 kV line	This alternative can mitigate the Sloan Canyon – Eldorado 500 kV congestion. Ratepayer benefit is not sufficient to cover the total cost of the project	No	No
	Build a new Adelanto – Lugo 500 kV line	This alternative can significantly reduce the following congestions: • Path 61 (Lugo – Victorville 500 kV line) congestion under normal condition and Eldorado – Lugo 500 kV line N-1 contingency Ratepayer benefit is not sufficient to cover the total cost of the project	No	No
	Build the third Colorado River – Red Bluff 500 kV line and a new Red Bluff – Mira Loma 500 kV line	This alternative can partially reduce the following congestions: • Path 61 (Lugo – Victorville 500 kV line) congestion under normal condition and Eldorado – Lugo 500 kV line N-1 contingency • Eldorado – McCullough 500 kV congestion under Eldorado – Lugo 500 kV line N-1 or Mohave – Lugo 500 kV N-1 However, it aggravated Path 46 (West of River) congestion This alternative is not as effective to mitigate Path 61 and East of Pisgah area congestion as the other alternatives above, but it can also help to mitigate SCE Eastern area congestion. This alternative showed larger production cost savings than the other alternatives above, but ratepayer benefit is still not sufficient to cover the total cost of the project.	No	No
LA Basin and Path 26 corridor congestion	The PTE project	This alternative can partially mitigate Path 26 corridor congestion and can mitigate the La Fresa – La Cienega 230 kV line congestion in the SCE's Western LA Basin area. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
	The K-SEL project (Midway – El Nido 2000 MW HVDC)	This alternative can partially mitigate Path 26 corridor congestion and can mitigate the La Fresa – La Cienega 230 kV line congestion in the SCE's Western LA Basin area. Ratepayer	No	No

Congestion or study area	Alternative	Economic Assessment Result	Economic Justification	Other Justification
		benefit is not sufficient to cover the total cost of the project.		
	The Del Amo – El Nido underground HVDC project	This alternative can mitigate the La Fresa – La Cienega 230 kV line congestion in the SCE's Western LA Basin area. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
	The Del Amo – El Nido underground 230 kV AC line project	This alternative can mitigate the La Fresa – La Cienega 230 kV line congestion in the SCE's Western LA Basin area. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
	Build the third Midway – Vincent 500 kV line	This alternative can partially mitigate Path 26 corridor congestion. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
Path 15 corridor congestion	Alternative 1: Build a new Manning – Los Banos – Tesla 500 kV line	Congestion on the south of Manning segments of Path 15 was aggravated. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
	Alternative 2: A1 plus a new Midway – Gates – Manning 500 kV line	This alternative can significantly reduce Path 15 corridor congestion, but aggravate Path 26 corridor congestion. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
	Alternative 3: Monarch Option 1 Gates – Los Banos #3 500 kV line loops in new NewPoint 500 kV substation and build a new NewPoint to Tracy 500 kV line	Congestion on the south of Manning segments of Path 15 was aggravated. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
	Alternative 4: A3 plus NewPoint – Tracy looping in Tesla	Congestion on the south of Manning segments of Path 15 was aggravated. Ratepayer benefit is not sufficient to cover the total cost of the project, but looping in Tesla can provide better production cost savings to the ISO's ratepayers than Alternative 3 without loop-in.	No	No
	Alternative 5: A4 plus build a new Midway – New Point 500 kV line	This alternative can reduce Path 15 corridor congestion, but aggravate Path 26 corridor congestion. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
	Alternative 6: Monarch Option 2 Build a new Manning – NewPoint – Tracy 500 kV line	Congestion on the south of Manning segments of Path 15 was aggravated. Ratepayer benefit is not sufficient to cover the total cost of the project, but this alternative can	No	No

Congestion or study area	Alternative	Economic Assessment Result	Economic Justification	Other Justification
		provide better production cost savings to the ISO's ratepayers than Alternative 3 Monarch Option 1.		
	Alternative 7: A6 plus NewPoint – Tracy looping in Tesla	Congestion on the south of Manning segments of Path 15 was aggravated. Ratepayer benefit is not sufficient to cover the total cost of the project, but looping in Tesla can provide better production cost savings to the ISO's ratepayers than Alternative 6 without loop-in.	No	No
	Alternative 8: A7 plus build a new Midway – NewPoint 500 kV line	This alternative can reduce Path 15 corridor congestion, but aggravate Path 26 corridor congestion. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
	Alternative 9: Build a new 500 kV line from Midway to the new Gregg 500 kV substation to Tesla	This alternative can reduce Path 15 corridor congestion, but aggravate Path 26 corridor congestion. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No
	Alternative 10: Install a 10 ohm series reactor on each of the two Panoche – Gates 230 kV lines	This alternative can reduce Panoche – Gates 230 kV line congestion. Ratepayer benefit is not sufficient to cover the total cost of the project.	No	No

In summary, detailed economic assessments were conducted for total of 20 transmission solutions. Some alternatives showed positive benefits to ISO's ratepayers, but none of them showed sufficient economic justification in this planning cycle's economic assessments. Some alternatives showed effectiveness to mitigate or partially mitigate congestion on some corridors, but may aggravate congestion in other parts of the system. Therefore, the ISO decided to not recommend these transmission upgrades for approval as economic-driven projects in this planning cycle. Comprehensive mitigation plans will be evaluated for these transmission constraints in future transmission planning cycles.

Chapter 5

5 Interregional Transmission Coordination

The ISO conducts its coordination with neighboring planning regions through the biennial interregional transmission coordination framework established in compliance with FERC Order No. 1000.

The ISO started its 2024-2026 Interregional Transmission Project (ITP) cycle in the first quarter of 2024 in which proponents were able to submit ITP proposals to the ISO and request their initial evaluation within the 2024-2025 transmission planning process. During the submission period, five projects were submitted by their project sponsors for consideration by the ISO. However, based on the assessments documented in the 2024-2025 transmission plan, no interregional project moved into year two and therefore, no further consideration of the submitted ITPs is required in this transmission planning process.

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 ISO 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 its members, these business practices were incorporated into the WPR regional processes to be followed within the development of regional plans. For the ISO, these business practices have been incorporated into the ISO's Business Practice Manual (BPM) for the Transmission Planning Process.

Similar to past interregional transmission coordination cycles, the ISO continues to engage and coordinate with the other WPRs on submitted ITP projects in addition to representing and supporting interregional coordination concepts and processes in public forums such as WECC. The ISO and other WPRs continue to facilitate coordination among its stakeholders and neighboring planning regions for the benefit of interregional coordination.

5.2 Interregional Transmission Project Submittal Requirements

As described in the ISO's BPM for the Transmission Planning Process, ITPs may be submitted into the ISO's transmission planning process on January 1 through March 31 of every even year of the interregional transmission coordination process. The ITPs must be properly submitted and in doing so must meet the following requirements:

- The ITP must electrically interconnect at least two Order No. 1000 planning regions
- While an ITP may connect two Order No. 1000 planning regions outside of the ISO, the ITP must be submitted to the ISO before it can be considered in the ISO's transmission planning process; and
- When a sponsor submits an ITP into the regional process of an Order No. 1000 planning region, it must indicate whether it is seeking cost allocation from that Order No. 1000 planning region. When a properly submitted ITP is successfully validated, the two or more Order No. 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 No. 1000 regional planning processes.

5.3 Interregional Transmission Coordination per FERC Order No. 1000

The interregional coordination order requires that each WPR: (1) commit to developing a procedure to coordinate and share the results of its 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 ISO 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 transmission planning process.

5.3.1 Procedure to Coordinate and Share ISO Planning Results with other WPRs

During each planning cycle the ISO 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 ISO for consideration in its transmission planning process. 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/March 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. NorthernGrid hosted the 2024 meeting and the ISO hosted the 2025 meeting on March 24, 2025.

In general, the purpose of the coordination meeting is to provide a forum for stakeholders to discuss planning activities in the West, including a review of each region's planning process, its needs and potential interregional solutions, update on ITP evaluation activities, and other related issues. It is important to note that the ISO's planning process are conducted annually 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.

5.3.2 Submission of Interregional Transmission Projects to the ISO

As part of its transmission planning process, the ISO provides a submission window during which proponents may submit their ITPs into the ISO'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 No. 1000 planning regions;
- While an ITP may connect two Order No. 1000 planning regions outside of the ISO, the ITP must be submitted to the ISO before it can be considered in the ISO's transmission planning process; and
- When a sponsor submits an ITP into the regional process of an Order No. 1000 planning region, it must indicate whether it is seeking cost allocation from that Order No. 1000 planning region. When a properly submitted ITP is successfully validated, the two or more Order No. 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 ISO to consider during its validation/selection process of the ITP. For the ISO 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 ISO, validated ITPs will be included in the ISO'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 No. 1000 regional planning processes.

5.3.3 Evaluation of Interregional Transmission Projects by the ISO

Once the submittal and validation process has been completed, the ISO 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 on whether the ITP will or 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.

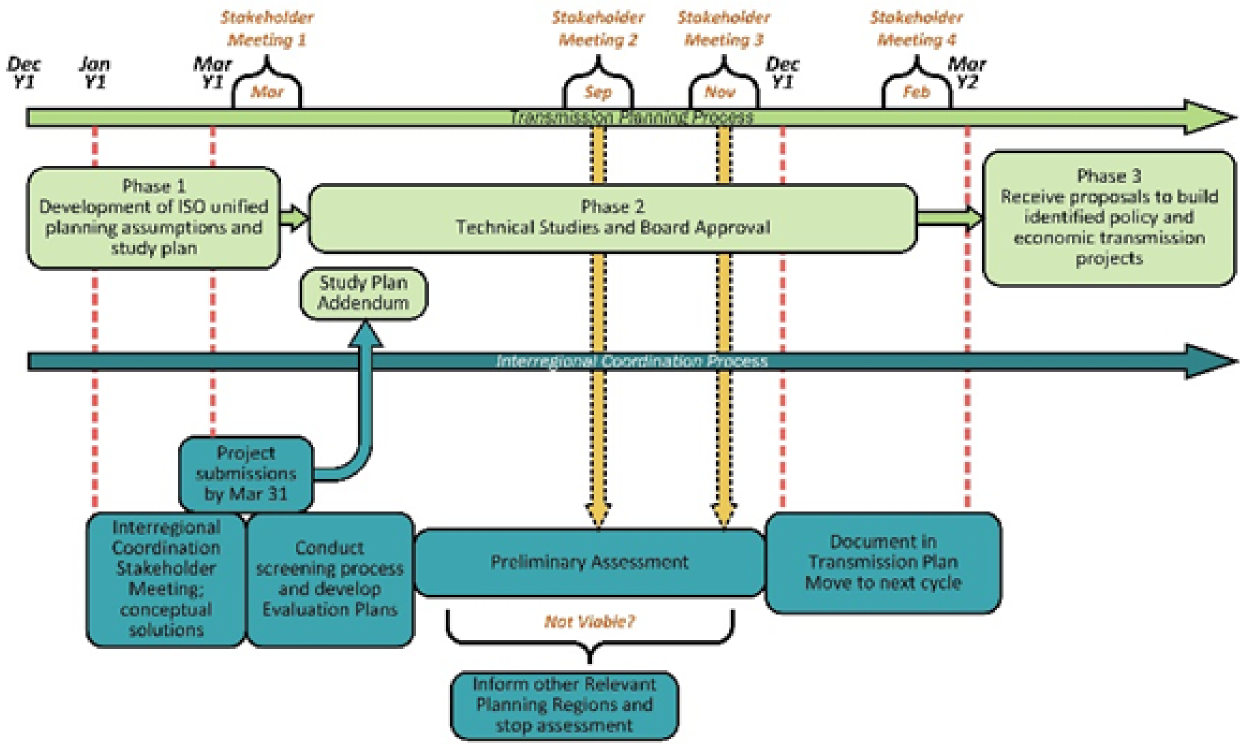
5.3.3.1 Even Year ITP Assessment

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 regions in their individual evaluations of the ITPs. 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 ISO stakeholder review a coordinated ITP evaluation process plan for each ITP. Once the ITP evaluation plans are final, 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 ISO assesses the ITP proposals under the ISO tariff and shares this information with stakeholders through its regularly scheduled stakeholder meetings, as applicable.

It is important to note that the ISO manages its assessment of an ITP proposal across the two-year interregional coordination cycle in two steps. During the even year, the ISO makes a preliminary assessment of the ITP and once it completes that task, the ISO must consider whether consideration of the ITP should continue into the next ISO 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

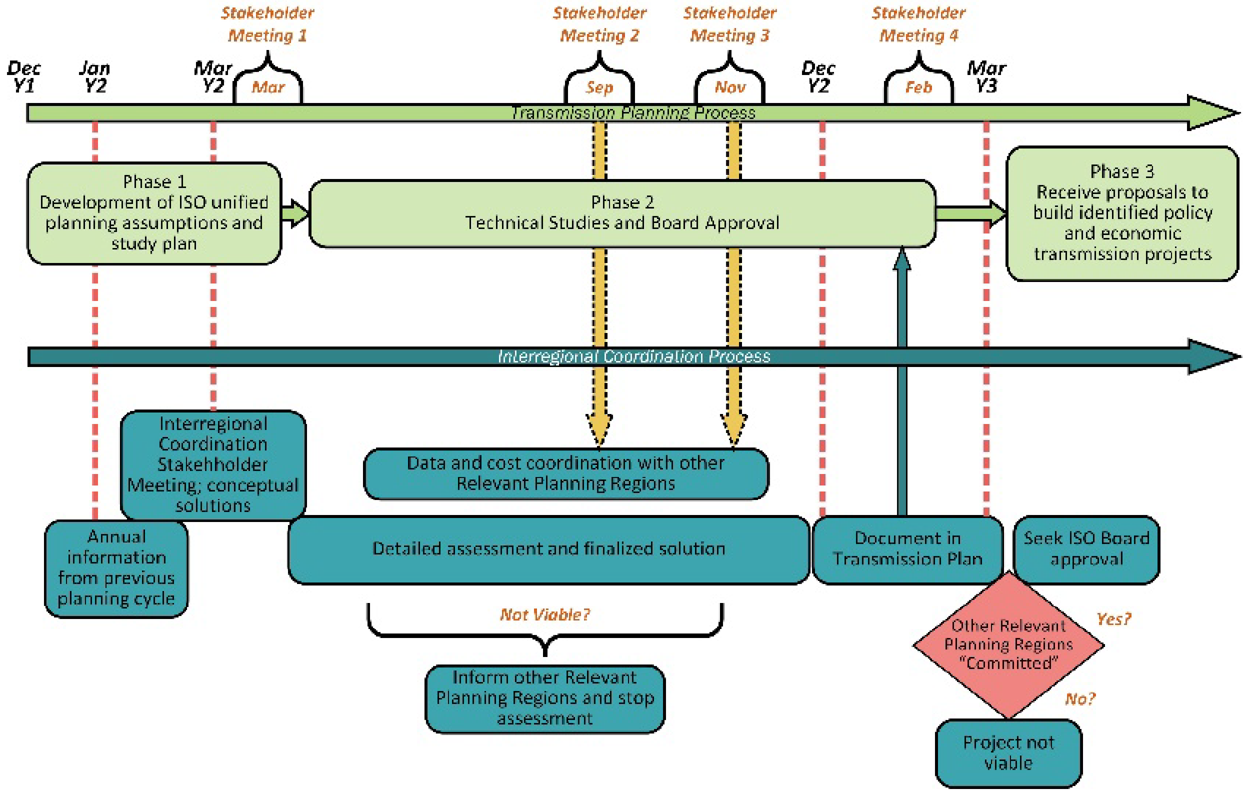


The ISO will document the results of its initial assessment of the ITP in its transmission plan including a recommendation on whether to continue assessment of the ITP in the odd year. The ISO Board's approval of the transmission plan is sufficient to enact the recommendations of the transmission plan.

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 ISO 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 ISO will conduct a more in-depth analysis of the project proposal, including consideration of the timing for when 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 ISO may also determine the regional benefits of the interregional transmission project to the ISO that will be used for purposes of allocating any costs of the ITP to the ISO.

If the ISO determines that the proposed ITP is a more efficient or cost-effective solution to meet an ISO-identified regional need and the ITP can be constructed and operational in the same timeframe as the regional solution, the ISO will then consider the ITP as the preferred solution in the ISO transmission plan. The ISO will document its analysis of the ITP and the other regional transmission solutions.

Once the ISO selects an ITP in the ISO transmission plan, the ISO will coordinate with the other relevant planning regions to determine if the ITP will be selected in their regional plans and whether a project sponsor has committed to pursue or build the project. Based on the information available, the ISO may inform the ISO 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 ISO will continue to consider the ITP in its transmission planning process and, if appropriate, select it as the preferred solution. The ISO may seek ISO Board approval to build the ITP once the ISO receives a firm commitment to construct the ITP.

5.4 2024-2025 Interregional Transmission Coordination ITP Submissions to the ISO

The ISO opened its 2024-2026 ITP submission window in the first quarter of 2024, when proponents were able to submit ITP proposals to the ISO and request their evaluation within the 2024-2025 transmission planning process. The submission period began on January 1 and closed on March 31. The submitted projects are shown in Table 5.4-1

Table 5.4-1: ITPs Submitted to the 2024-2026 Submission Period.

Project Name	Company	Project Submitted to	Relevant Planning Regions	Description	In Service Date
Sloan Canyon – Mead 230 kV Ckt 2	GridLiance West LLC	ISO, WC	ISO, WC	An 890 MVA, AC circuit to be added to the existing GLW Sloan Canyon to WAPA Mead double-circuit capable 230 kV towers	2028
Mead – Mohave	GridLiance West LLC	ISO, WC	ISO, WC	Rebuilding the existing Mead to Davis 230 kV line to 500 kV and building a 5-mile Davis to Mohave extension	2030
GLW Upsize to Sagebrush	GridLiance West LLC	ISO, NG	ISO, NG	Upgrade to sections of the ISO 2022-2023 TPP approved GridLiance West (GLW)/ Valley Electric Association (VEA) Area Upgrades and Beatty 230 kV Upgrade projects	2028
GLW Upsize to Esmeralda	GridLiance West LLC	ISO, NG	ISO, NG	The project upgrades existing double circuit 230 kV configuration to 500 kV-capable towers to sections of GLW's approved Core and Beatty upgrades	2030
Western Bounty Transmission System	Western Bounty LLC	ISO, NG, WC	ISO, NG, WC	A three-segment 500- to 800-kilovolt (kV) HVDC transmission system connecting renewable energy resources produced near Western Bounty's Hub in Esmeralda County, NV to termini in Southern California, central Oregon, and southwestern Idaho	2033

Following the submission and screening of the ITP submittals for need determination, and in coordination with the other Western planning regions, it was determined that the GridLiance West submissions did not qualify as interregional projects and the Western Bounty Transmission System project will continue to be evaluated in the next planning cycle.

- Western Planning Regions: WestConnect will not evaluate the submitted ITPs to determine if they meet any regional transmission needs because WestConnect has determined that there are no regional transmission needs in its 2024-26 regional planning cycle. NorthernGrid has yet to make a regional need determination on the submitted ITPs.

- GridLiance West (GLW) ITP Submissions: The ISO identified only some minor congestion within the GridLiance/VEA system in the 138 kV system and hence none of the GridLiance/VEA ITP study requests were selected for detailed economic assessments.
- Western Bounty Transmission System: The ISO performed a sensitivity studies to evaluate different alternatives to import additional 1,500 MW Wyoming wind beyond TransWest Express capacity and to mitigate the Lugo – Victorville constraint. The Western Bounty Transmission System project is one of the alternatives being studied. However, to be consistent with the CPUC directive not to trigger upgrades related to the additional out-of-state wind amounts in the portfolio that are beyond the amounts that can be accommodated on the already-identified and in-development transmission upgrades, the ISO will continue to evaluate potential transmission upgrades, including the Western Bounty Transmission System project, and will not recommend for approval of any project in the current TPP cycle. Additional details are in Appendix F.

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. These studies are either set out in the ISO tariff or form part of the ongoing collaborative study efforts taken on by the ISO to assist the CPUC with state regulatory needs and 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 summarizes the technical studies conducted by the ISO to comply with the reliability requirements initiative in the resource adequacy provisions under Section 40 of the ISO tariff. This section also includes additional analysis supporting long-term planning processes, 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 ISO grid. The resource adequacy import allocation study established the maximum resource adequacy import capability to be used in 2025. 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 ISO conducted short and long-term local capacity technical (LCT) analysis studies in 2024. A short-term analysis was conducted for the 2025 system configuration to determine the minimum local capacity requirements for the 2025 resource procurement process. The results were used to assess compliance with the local capacity technical study criteria as required by the ISO tariff Section 40.3. This study was conducted in January through April in a transparent stakeholder process with a final report published on April 30, 2024. For detailed information on the 2025 LCT Study Report please visit:

https://stakeholdercenter.caiso.com/InitiativeDocuments/Final2025LocalCapacityTechnicalReport.pdf

One long-term analysis was also performed identifying the local capacity needs in the 2029 period. The long-term analyses provide participants in the transmission planning process with future trends in LCR needs for up to five years. The 2029 LCT Study Report was published on April 30, 2024. For detailed information please visit:

https://stakeholdercenter.caiso.com/InitiativeDocuments/Final2029Long-TermLocalCapacityTechnicalReport.pdf

The ISO also conducts a 10-year local capacity technical study every second year, as part of the annual transmission planning process. The 10-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. Per agreement between state agencies, they are done on an every-other-year cycle.

The most recent 10-year LCR study was initiated in the 2024-2025 transmission planning process. The ISO undertook a comprehensive study of local capacity areas, examining both the load shapes and new battery charging and discharging characteristics underpinning local-capacity requirements.

For detailed information about the 2034 and selected 2039 long-term LCT study results, please refer to the stand-alone report in Appendix J of the 2024-2025 transmission planning process.

As shown in the LCT study reports and indicated in the LCT study manual that the ISO prepares each year setting out how that year's LCT studies will be performed, 12 load pockets are located throughout the ISO-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 ISO 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 170 MW. In contrast, the requirements of the Bay Area are approximately 7,400 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 2025, 2029 and 2034

LCR Area	LCR Capacity Need (MW)		
	2025	2029	2034
Humboldt	164	173	178
North Coast/North Bay	967	650	812
Sierra	1,532	1,885	1,865
Stockton	735	763	864
Bay Area	7,441	6,259	8,554
Fresno	2,532	2,512	2,695
Kern	434	241	121
Big Creek/Ventura	2,145	1,329	1,462
Los Angeles Basin	4,123	5,076	4,900
San Diego/Imperial Valley	2,709	3,121	1,902
Valley Electric	0	0	0
Metropolitan Water District	0	0	0
Total	22,782	22,009	23,353

Notes:
For more information about the LCR criteria, methodology and assumptions, please refer to the ISO LCR manual.[59]
For more information about the 2025 LCT study results, please refer to the report posted on the ISO website.
For more information about the 2029 LCT study results, please refer to the report posted on the ISO website.

[59] "Final Manual 2025 Local Capacity Area Technical Study," November 30, 2023, https://stakeholdercenter.caiso.com/InitiativeDocuments/FinalStudyManual-2025LocalCapacityRequirements.pdf.

6.1.2 Resource adequacy import capability

6.1.2.1 Maximum Import Capability for Resource Adequacy and Future Outlook

The ISO has established the maximum resource adequacy (RA) import capability to be used in year 2025 in accordance with the ISO tariff Section 40.4.6.2.1. This data can be found on the ISO website.[60] The entire import allocation process[61] is posted on the ISO website.

The future outlook for all remaining branch groups can be accessed at the following link:

https://www.caiso.com/documents/advisory-estimates-of-future-resource-adequacy-import-capability.pdf

The maximum import capability (MIC) from the Imperial Irrigation District (IID) was increased to 702 MW starting in year 2024 to accommodate renewable resources development in this area that ISO has established in accordance with Reliability Requirements BPM Section 5.1.3.5. The import capability from IID to the ISO is the combined amount from the IID-SCE_ITC and the IID-SDGE_ITC intertie.

The following are main portfolio and MIC expansion requests fully approved increases, which passed both the TPP deliverability and the GIP deliverability studies.

Table 6.1-3: Maximum Import Capability fully approved increases

Orig. Year	Driver	Intertie Name (Scheduling Point)	Equivalent MWs	Technology	NQC MWs	Waiting for:	First RA year
2015	Portfolio	IID-SDGE_ITC (IVLY2) and IID-SCE_ITC (DEVERS230 & MIR2)	240	Geothermal & Solar/Battery	240	All projects are in-service.	2024 (implemented)

Yearly NQC deliverability study:

Only five scheduling points had a MIC expansion requests that triggered an increase applicable to the 2025 RA year.

Table 6.1-4: 2025 NQC deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	BLYTHE_ITC (BLYTHE161)	Pass	MIC expansion request only.
2	MEAD_ITC (MEAD 230)	Pass	Includes both the CPUC portfolio and additional MIC expansion requests.

The appropriate amount of MWs to the scheduling points that passed the test of the 2025 NQC deliverability study were given to the LSEs as a temporary MIC increase for RA year 2025.

Permanent expansion of MIC depends on the TPP and GIP deliverability study results.

---

[60] "California ISO Maximum RA Import Capability for year 2025," available on the ISO's website at https://www.caiso.com/documents/iso-maximum-resource-adequacy-import-capability-for-year-2025.pdf .

[61] See general the Reliability Requirements page on the ISO website https://www.caiso.com/generation-transmission/resource-adequacy .

6.1.2.2 Maximum Import Capability expansions driven by the Portfolio

Per the ISO Tariff, the Base Portfolio drives approval of new transmission in order to assure all import resources are deliverable to the aggregate of load.

The following are the previous cycle's portfolio increase requests that passed the TPP deliverability study and are awaiting results of the GIP deliverability studies.

Table 6.1-5: Base portfolio driven MIC increase (per TPP) that awaits GIP deliverability studies

Orig. Year	Status	Intertie Name (Scheduling Point)	Equivalent MWs	Technology	2024 NQC MWs	Waiting for:	First RA year[62]
2022	Active	IID-SDGE_ITC (IVLY2) & IID-SCE_ITC (DEVERS230 & MIR2)	600	Geothermal	600	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036
2022	Active	MEAD_ITC (MEAD 230)	300	Wind	119	Lugo-Victorville line upgrade.	2030
2022	Active	PALOVRDE_ITC (PVWEST)	438	Wind	174	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036
2023	Active	IID-SCE_ITC (DEVERS230 & MIR2)	190	Geothermal	190	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036
2023	Active	HA500_ISL (HA500)	2500	Wind	1096	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	Active	HA500_ISL (HA500)	225	Geothermal	225	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	Active	MEAD_ITC (MEAD230)	100	Geothermal	100	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	Active	GONDIPPDC_ITC (GONIPP)	79	Geothermal	79	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2023	Active	PALOVRDE_ITC (PVWEST)	1890	Wind	749	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036
2023	Active	SUMMIT_ITC (SUMMIT120)	35	Geothermal	35	Humboldt-Fern Road 500 kV & Humboldt-Collinsville 500 kV	2035
2024	Active	HA500_ISL (HA500)	60	Wind	26	Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.	2030
2024	Active	MEAD_ITC (MEAD 230)	50	Wind	20	Lugo-Victorville line upgrade.	2030
2024	Active	PALOVRDE_ITC (PVWEST)	1208	Wind	479	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036
2024	Active	IPPCADLN_ITC (IPP & IPPUTAH)	20	Geothermal	20	Southern Area Reinforcement and Lugo-Victorville line upgrade.	2036
2024	Active	New TESLA500_ITC (TBD)	1500	Wind	658	Tesla Expansion and assumes new line from Wyoming to Tesla.	TBD

[62] First RA year must be at least 1 year out after the GIP deliverability study is complete, or the year after the last transmission element is in-service.

The ISO confirms that not 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 2024 submitted base portfolio along with existing contracts, transmission ownership rights and pre-RA import commitments under contract in 2034.

Based on the TPP deliverability studies (and potentially GIP deliverability studies) some scheduling points (branch groups) currently do not have enough deliverability available to make the main CPUC portfolio deliverable without transmission reinforcements. Transmission reinforcements are studied and if necessary will be approved through the TPP.

Table 6.1-6: Base portfolio MIC increases awaiting new TPP upgrades and GIP deliverability studies

Orig. Year	Status	Intertie Name (Scheduling Point)	Equivalent MWs	Technology	2024 NQC MWs	Status	Comments:
2024	Active	MCCULLGH_ITC (ELDORADO500)	1491	Wind	654	Failed	Mitigation under investigation

For scheduling points where the CPUC main portfolio has failed the TPP deliverability test, the long-term MIC expansion is not possible without new transmission reinforcements. Please follow the potential mitigations for specific constraints as listed in the table above.

6.1.2.3 Maximum Import Capability Expansion Requests

Per Section 3.2.2.3 of the Transmission Planning Process Business Practice Manual (TPP BPM), requests to perform deliverability studies to expand the maximum import capability have been submitted to the ISO within two weeks after the first stakeholder meeting and not later than when study plan comments were due. The valid maximum import capability expansion requests have identified the intertie(s) (branch group(s)) that require expansion.

The ISO has evaluated each maximum import capability expansion request to establish if the submitting entity meets the criteria listed in the Tariff Section 24.3.5. The table below includes the valid Maximum Import Capability expansion requests that were submitted for this planning cycle.

Table 6.1-7: Valid 2024 Maximum Import Capability expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Resource Type
1-2	Southern California Edison	BLYTHE_ITC (BLYTHE161)	22.7	Hydro
3	Clean Power Alliance	IPPDCADLN_ITC (IPP & IPPUTAH)	33	Geothermal
4		MEAD_ITC (MEAD230)	118.95	Wind
5-6	Valley Electric Association	MEAD_ITC (MEAD230)	24	Hydro
7			90	Solar/Battery
8	California Community Power	SUMMIT_ITC (SUMMIT120) MERCHANT_ITC (ELDORADO230) Back-up	18	Geothermal
9		IID-SDGE_ITC (IVLY2) IID-SCE_ITC (MIR2) Back-up	107	
10		SILVERPK_ITC (SILVERPEAK55)	13	
11	Ava Community Power	PALOVRDE_ITC (PVWEST)	99.13	Wind
12			42.5	Solar/Battery
13	San Diego Community Power	ELDORADO_ITC (WILLOWBEACH)	20.22	Wind
14-15		PALOVRDE_ITC (PVWEST)	79.7	
16		IID-SCE_ITC (MIR2)	145.5	Solar/Battery
17		IID-SDGE_ITC (IVLY2)	35	
18		BLYTHE_ITC (BLYTHE161)	160	

The ISO has received six submittals with requests for MIC expansion. They contained 19 distinct requests (LSEs provided multiple contractual requests under an individual submittal).

Based on the ISO interpretation of the Tariff and the Transmission Planning BPM (TP BPM) requirements 18 distinct requests qualify as valid requests based on the following factors:

- Power Purchase Agreements between ISO LSEs and import suppliers, not fully accounted for as Pre-RA Import Commitment or New Use Import Commitment.

For the following reasons, one distinct request does not qualify at this time:

- Power Purchase Agreements between ISO LSEs and import suppliers, fully accounted for as Pre-RA Import Commitment or New Use Import Commitment.

The ISO has coordinated the valid MIC expansion requests with the policy-driven MIC expansion and the total of the two (after elimination of duplicates) was used to identify all branch groups that do not have sufficient Remaining Import Capability to cover both the valid MIC expansion requests and the policy-driven MIC expansion.

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

Table 6.1-8: Assessment of valid 2024 Maximum Import Capability expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Triggers Expansion	Comments
1-2	Southern California Edison	BLYTHE_ITC (BLYTHE161)	22.7	Yes	Partial
3	Clean Power Alliance	IPPDCADLN_ITC (IPP & IPPUTAH)	33	In CPUC Portfolio	CPUC Portfolio triggers MIC expansion.
4		MEAD_ITC (MEAD230)	118.95		
5-6	Valley Electric Association	MEAD_ITC (MEAD230)	24	Yes	Full.
7			90		
8	California Community Power	SUMMIT_ITC (SUMMIT120) MERCHANT_ITC (ELDORADO230) Back-up	18	In CPUC Portfolio	Active as back-up only. No need for expansion.
9		IID-SDGE_ITC (IVLY2) IID-SCE_ITC (MIR2) Back-up	107		
10		SILVERPK_ITC (SILVERPEAK55)	13		Active as back-up location only.
11	Ava Community Energy	PALOVRDE_ITC (PVWEST)	99.13	In CPUC portfolio	
12			42.5	No	No need for expansion.
13	San Diego Community Power	ELDORADO_ITC (WILLOWBEACH)	20.22	In CPUC Portfolio	
14		PALOVRDE_ITC (PVWEST)	20.22		
15			59.48		
16		IID-SCE_ITC (MIR2)	145.5		
17		IID-SDGE_ITC (IVLY2)	35	Yes	Full
18		BLYTHE_ITC (BLYTHE161)	160	Yes	Full

After the elimination of: duplicate entries (vis-à-vis the CPUC Portfolio), requests for increases at branch groups that do not require a MIC increase and obsolete data from previous year's requests, the following MIC expansion requests are being modeled and explored.

Table 6.1-9: Maximum Import Capability expansion requests currently being assessed

No.	Year	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Resource Type
1-2	2024	Southern California Edison	BLYTHE_ITC (BLYTHE161)	8	Hydro
3-4		Valley Electric Association	MEAD_ITC (MEAD 230)	24	Hydro
5				90	Hybrid (Solar/Battery)
6-7		California Community Power	SILVERPK_ITC (SILVERPEAK55)[63]	13	Geothermal
			SUMMIT_ITC (SUMMIT120)[64]	18	
8		San Diego Community Power	IID-SDGE_ITC (IVLY2)	35	Hybrid (Solar/Battery)
9			BLYTHE_ITC (BLYTHE161)	160	

For the above branch groups where MIC expansion was triggered, the increase in MIC was modeled and tested through deliverability studies: the NQC deliverability study (if applicable in

[63] As back-up locations only – main delivery point included as MONAIPPDC_ITC (DWP) and part of the CPUC portfolio.

[64] As back-up locations only – main delivery point included as MEAD_ITC (MEAD 230) and part of the CPUC portfolio.

year one), the TPP deliverability study and the GIP deliverability study. One or multiple of these studies can limit the deliverability and therefore the MIC expansion.

Permanent expansion of MIC depends on the TPP and GIP deliverability study results.

TPP deliverability study:

The TPP deliverability study includes all existing resources with deliverability, new resources with deliverability as dictated by the TPP study plan, all new resources provided in the main policy portfolio provided by the CPUC and the MIC expansion requests submitted to the ISO.

Table 6.1-10: TPP deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	BLYTHE_ITC (BLYTHE161)	Failed/ Denied	Additional mitigation for Lugo-Victorville 500 kV constraint is not proposed in this expansion cycle and therefore no additional capability exists for MIC expansion requests.
2	IID-SDGE_ITC (IVLY2)	Pass/ Move forward	Subject to various mitigations already in place including, but not limited to, Southern Area Reinforcement and Lugo-Victorville line upgrade.
3	MEAD_ITC (MEAD 230)	Failed/ Denied	Part not in the CPUC portfolio. Additional mitigation for Lugo-Victorville and Eldorado-McCullough 500 kV constraints is not proposed in this expansion cycle and therefore no additional capability exists for MIC expansion requests.
4	SILVERPK_ITC (SILVERPEAK55)	Failed/ Denied	Used as back-up only – main in the CPUC portfolio. Additional mitigation for Control-Inyokern 115 kV lines (Control-Silver Peak) and Lugo-Victor #1 & #2 230 kV lines constraints is not proposed in this expansion cycle and therefore no additional capability exists for MIC expansion requests.
5	SUMMIT_ITC (SUMMIT120)	Pass/ Move forward	Used as back-up only – main in the CPUC portfolio. Waiting for Humboldt-Fern Road 500 kV & Humboldt-Collinsville 500 kV first expected RA year 2035.

The MIC expansion requests that have failed the TPP deliverability test are denied because long-term MIC expansion is not possible without new transmission reinforcements. MIC expansion requests on their own cannot trigger transmission expansion, however, some of the MIC expansion requests may end up passing as long as mitigations move forward for reliability, economic or policy need.

For those MIC expansion requests that passed, please follow the potential mitigations for specific constraints as listed in the table above.

GIP deliverability study:

The GIP deliverability study includes all resources with deliverability included in the TPP deliverability study, (including MIC expansion requests) plus additional resources that have received TPD and DGD allocation prior to this study cycle.

The interrelation between the target expanded MIC and the generation interconnection process can be found in RR BPM Section 6.1.3.6, "Modeling Expended MIC Values in GIP".

The ISO has not yet conducted a new cycle of GIP deliverability studies, however, since the GIP deliverability study includes additional new resources with prior TPD and DGD allocation beyond those modeled in the TPP deliverability study, it is reasonably assumed that if they failed the TPP deliverability study than they would fail the GIP deliverability studies.

Table 6.1-11: GIP deliverability study results regarding MIC expansion requests

No.	Intertie Name (Scheduling Point)	Status	Comments:
1	BLYTHE_ITC (BLYTHE161)	Failed*/ Denied	Additional mitigation for Lugo-Victorville 500 kV constraint is not proposed in this expansion cycle and therefore no additional capability exists for MIC expansion requests.
2	IID-SDGE_ITC (IVLY2)	TBD	Subject to various mitigations already in place including, but not limited to, Southern Area Reinforcement and Lugo-Victorville line upgrade.
3	MEAD_ITC (MEAD 230)	Failed*/ Denied	Part not in the CPUC portfolio. Additional mitigation for Lugo-Victorville and Eldorado-McCullough 500 kV constraints is not proposed in this expansion cycle and therefore no additional capability exists for MIC expansion requests.
4	SILVERPK_ITC (SILVERPEAK55)	Failed*/ Denied	Used as back-up only – main in the CPUC portfolio. Additional mitigation for Control-Inyokern 115 kV lines (Control-Silver Peak) and Lugo-Victor #1 & #2 230 kV lines constraints is not proposed in this expansion cycle and therefore no additional capability exists for MIC expansion requests.
5	SUMMIT_ITC (SUMMIT120)	TBD	Used as back-up only – main in the CPUC portfolio. Waiting for Humboldt-Fern Road 500 kV & Humboldt-Collinsville 500 kV first expected RA year 2035.

* MIC expansion requests that failed the TPP deliverability study will likely fail the GIP deliverability test and therefore long-term MIC expansion is not possible without new transmission reinforcements. The mitigations proposed in the TPP must allow the internal resources with prior TPD and DGD allocation to remain deliverable before MIC is allowed to permanently increase to account for import resources included in the CPUC portfolio and if possible to allow for further MIC increase due to MIC expansion requests.

For MIC expansion requests that passed the GIP deliverability study, please follow the potential mitigations for specific constraints as listed in the table above.

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 ISO-controlled grid.

6.2.2 Data Preparation and Assumptions

The 2024 LT CRR study leveraged the base case network topology used for the annual 2024 CRR allocation and auction process. Regional transmission engineers responsible for long-term grid planning incorporated all the new and ISO-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 2024-2025 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% of available transmission capacity. The fixed CRR representing the transmission ownership rights and merchant transmission were also set to 60%. All earlier LT CRR market awards were set to 100%, since they were awarded with the system capacity already reduced to 60%. For the study year, the market run was set up for two seasons (with season one being January through March and season three 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 saved cases for further review and record-keeping.

The ISO 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% 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 ISO tariff, the ISO 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 ISO determined in December of 2024 that there were no existing released LT CRRs "at-risk" that require further analysis. Thus, the transmission projects and elements approved in the 2024-2025 Transmission Plan did not adversely impact feasibility of the existing released LT CRRs. Hence, the ISO did not evaluate the need for additional mitigation solutions.

6.3 Frequency Response Assessment and Data Requirements

As penetration of renewable resources increases, conventional synchronous generators are being displaced with renewable resources using converter-based technologies. 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. One of the primary concerns is that there be adequate frequency response from inverter-based resources (IBR) when unplanned system outages and events occur.

Over past planning cycles, the ISO 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 the analysis. Inadequate modeling not only impacts frequency response analysis, but can also impact dynamic and voltage stability analysis as well.

In the subsections below, the progress achieved and issues to be considered going forward have been summarized, as well as the background setting the context for these efforts and the study results.

6.3.1 Frequency Response Methodology & Metrics

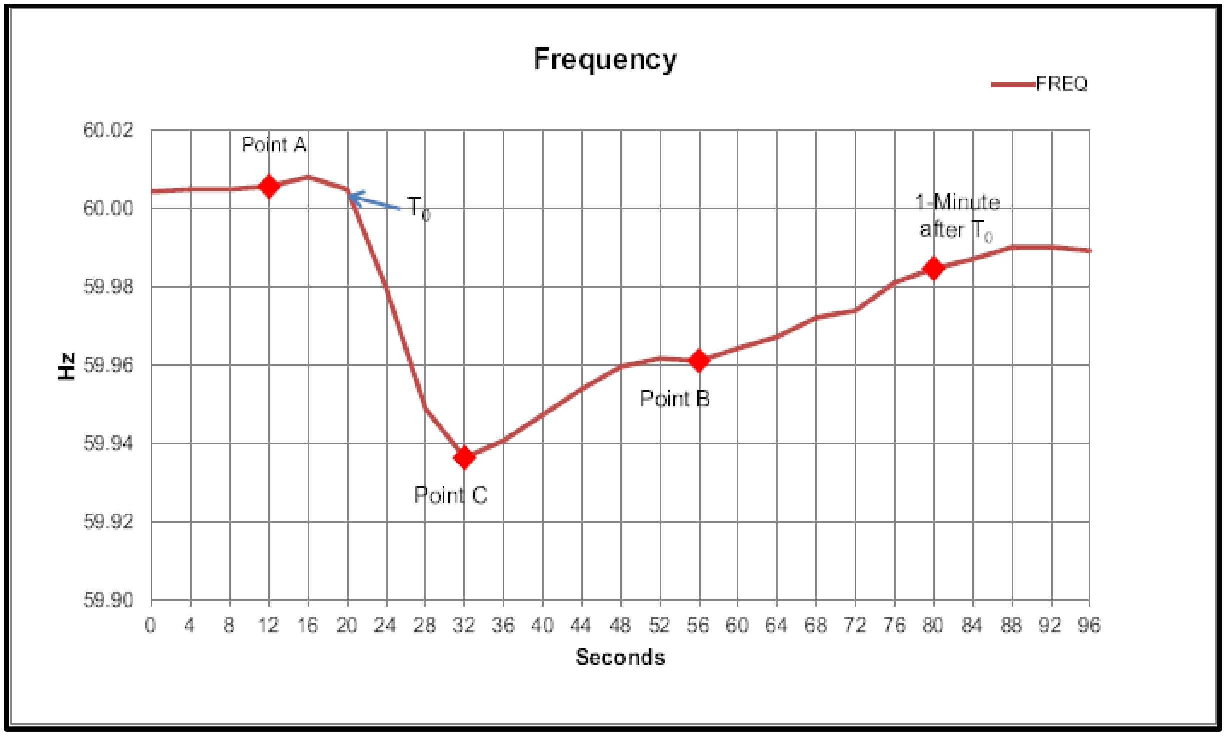
The ISO's most recent concerted study efforts in forecasting frequency response performance commenced in the 2014-2015 transmission planning cycle and continued on in subsequent years, using the latest dynamic stability models. In this planning cycle, the potential impact of inverter-based resources (IBR), particularly battery energy storage systems (BESS) as a means of aiding frequency response, was investigated.

Background on Frequency Response and Frequency Bias Setting Methodology

NERC has established the methodology for calculating frequency response obligations (FRO) outlined in Reliability Standard BAL-003-2 (Frequency Response and Frequency Bias Setting). 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.

A generic system disturbance that results in frequency decline, such as the 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.

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. This year, NERC has maintained the 2016 IFRO value of 858 MW/0.1 Hz be retained for the present operating year. The ISO's share of this obligation remains at 257.4 MW/0.1 Hz.

More conventional synchronous generators are being displaced with renewable resources. This has a significant effect on frequency response. 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 synchronous generation with governor controls, inverter-based renewable resources must specifically have a dedicated mechanism to provide inertia response to arrest frequency decline following the loss of a generating resource and to increase their MW output. When a frequency response characteristic is incorporated into IBR control parameters, the upward ramping control characteristic is only helpful if the generator is dispatched at a level that has headroom remaining. 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 ISO's FRO under BAL-003-2 for all operating conditions.

The most critical condition when frequency response may not be sufficient is when large amounts of renewable resources are online with high output concurrently with a low system load. In such cases, 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

One operating condition that is important for frequency response studies is 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, units at maximum capacity and units that don't respond to changes in frequency 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[65]; the lower the Kt, the smaller the fraction of generation that will respond. The exact definition of Kt has not been standardized.

For the ISO studies, the comparable metric is 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.

Rate of Change of Frequency (ROCOF)

- ROCOF is defined as the rate of change of frequency and is proportional to power imbalance during a system disturbance. The ROCOF value is most responsive immediately after a contingency and is increasingly being used by the industry to gauge the severity of the event and the ability of connected generators to respond in a timely manner to arrest excessive frequency excursions. ROCOF is particularly important as it anticipates the magnitude of frequency changes and in real time can be used to signal and react quickly to excessive frequency excursions.
- ROCOF is difficult to accurately measure post-contingency as the change in frequency is inherently noisy with multiple slope profiles potentially resulting in a wide margin of error. This is particularly the case in positive sequence load flow solution software. Despite this

[65] Undrill, J. (2010). Power and Frequency Control as it Relates to Wind-Powered Generation. LBNL-4143E. Berkeley, CA: Lawrence Berkeley National Laboratory

challenge, the ROCOF is a good predictor of system response to a bulk system frequency event. When reliably measured, it also provides a good means of ranking contingencies in terms of severity.

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. Per that Order, all generators including wind, solar and BESS generators that execute an LGIA on or after May 15, 2018 are required to provide frequency response.

6.3.3 2023-2024 Transmission Plan Study

In the 2023-2024 transmission planning cycle, the frequency response was assessed and it was determined that the Frequency Response Obligation (FRO) required from ISO was being met. Particular focus was centered on IBR contribution to that response. The IBR units with frequency regulation turned on with available headroom all cause a higher increase in response than would otherwise be provided.

6.3.4 2024-2025 Transmission Plan Study

As in the 2023-2024 transmission planning process, this study was to re-assess the frequency response of the ISO system to a dual Palo Verde unit outage. Once again an emphasis was being placed on the frequency response provided by IBR resources.

Solar and wind plants are IBR but are typically operated so that all energy captured from the wind and the sun is converted to electrical energy and fed into the power system. These units typically do not operate at sub-optimal capability and thus have no headroom available for when a frequency response event occurs.

BESS plants cyclically charge and discharge on an intra-day basis. This energy can be readily modulated during system events to help minimize significant frequency deviations. New plants coming on-line as per FERC Order 842 will have frequency regulation. If enabled and with enough diversity between charging and discharging plants, BESS units can help support the system during significant frequency events.

The spring off-peak case was chosen as there is a lower number of conventional gas units in operation. This case has a high proportion of solar plants on-line with most BESS plants operating in charging mode at full negative maximum plant capacity. IBR plants are those with ‘reec_c’ and ‘repc_a’ dynamic models. Turning off frequency control for these units consists of changing the up and down frequency gains to zero.

The study scenarios are summarized in Table 6.3-1. The study results for the baseline scenarios and the sensitivity study scenarios are illustrated in Figures 6.3-2 through 6.3-6.

Table 6.3-1: Study Scenarios for Frequency Response Study in the 2024-2025 TPP

	Study Scenarios				
	SC1	SC2	SC3	SC4	SC5
PFR enabled for existing IBRs?	No	Yes	Yes	Yes	Yes
Headroom	Existing	Existing	10% BESS units	Min CAISO spinning reserve	Min CAISO spinning reserve with 10% BESS
Existing IBRs and other gens droop	5%	5%	5%	5%	5%
Existing IBRs and other gens deadband (Hz)	±0.036	±0.036	±0.036	±0.036	±0.036

Scenario 1 is the reference against which to compare all others, where all BESS IBR plants have frequency regulation shut off in the dynamic plant controller model.

Scenario 2 has all IBR plant frequency regulation turned on. This scenario is identical to that of the normal 2029 and 2034 base cases and with unmodified dynamic models.

Figure 6.3-2 shows the resultant 2029 system frequency event result with both IBR frequency regulation turned on (SC2) and off (SC1). The trace with IBR turned on shows an improvement over that with it off. A similar plot for 2034 is shown in Figure 6.3-3. Again there is a marked improvement when frequency regulation is enabled.

For scenario 3, all new BESS plants were adjusted to a headroom of 10%. In both original Spring Peak cases, the BESS units are in charging mode close to or at their minimum power limit (negative pmax) which represents the IBR being in full charging mode. For this scenario, all BESS units were re-dispatched using the remaining available ISO generation to achieve 10% headroom. The net result is that there is a similar response profile for both scenarios 3 and scenario 1 (Figure 6.3-4). A 10% headroom shows a reduction in frequency response.

Scenario 4 and 5 are with the CAISO system at a minimum level of spinning reserve, one with modification of BESS output to a minimal headroom and the other with BESS output at 10% headroom. Scenario 4 and 5 are difficult cases to establish partially since most BESS are in full charging mode. Also, given the significant proportion of BESS generator, the latter redispatch requires both additional generation and path flow changes that significantly alter the character of the original Spring-Off Peak cases. Only Scenario 5 was created in this TPP cycle and comparative results between 2029 and 2034 are presented in Figure 6.3-6. The results shows a higher nadir in 2034 which is, in part, due to the higher proportion of BESS in the latter year.

These results indicate that by enabling the frequency response of the new IBR units coming on-line, particularly in 2034, the system recovers from frequency events faster and settles at higher frequencies. There is a higher proportion of IBR plants in 2034 which significantly aids the system frequency response when enabled. Also the Palo Verde outage drops a lesser proportion of the overall system generation in 2034 than it does in the 2029 base case.

Figure 6.3-2: 2029 Scenarios 1 & 2: System Frequency Response for All IBR Frequency Control On and Off

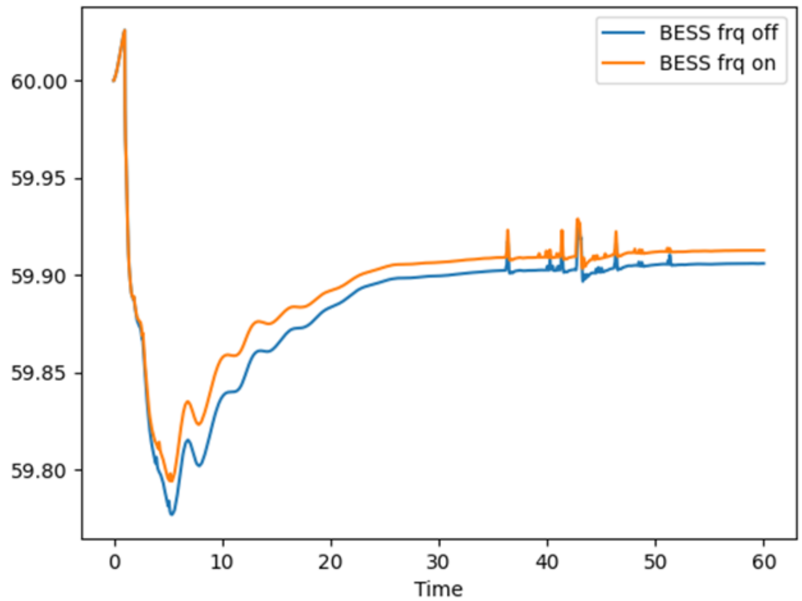


Figure 6.3-3: 2034 Scenarios 1 & 2: System Frequency Response for all IBR Frequency Control On and Off

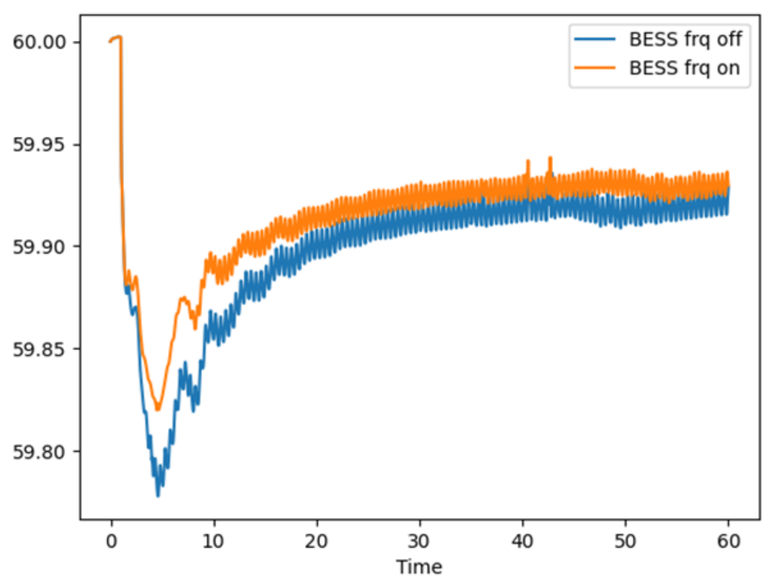


Figure 6.3-4: 2029 Scenario 3: System Frequency Response for all CAISO BESS at 10% Headroom vs Original case (SC2)

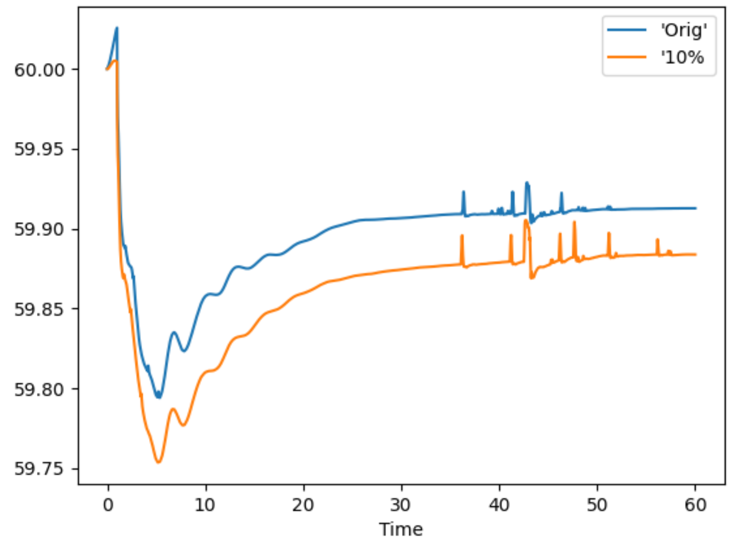


Figure 6.3-5: 2034 Scenario 3: System Frequency Response for all CAISO BESS at 10% Headroom vs Original case (SC2)

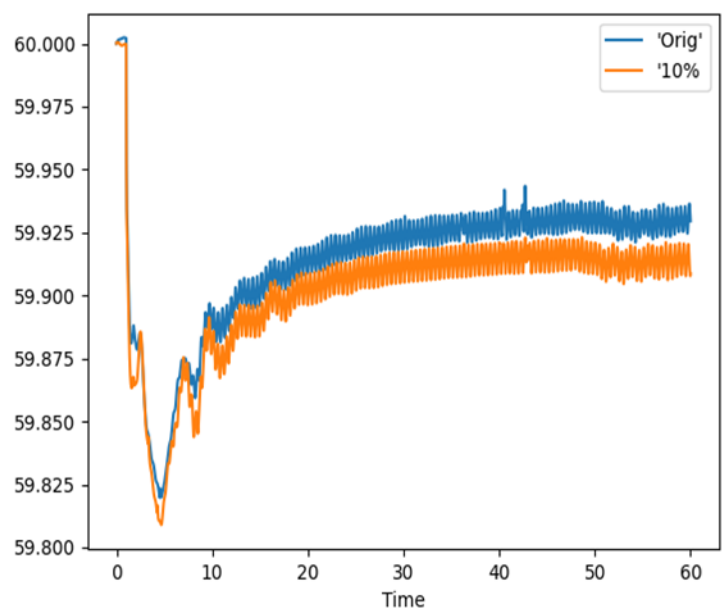
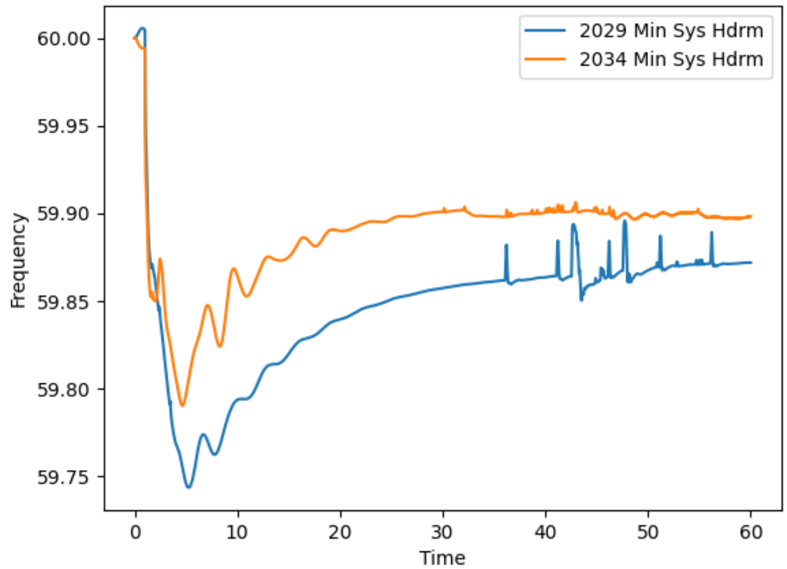


Figure 6.3-6: Scenario 5: System Frequency Response for CAISO at Minimum Headroom with BESS at 10% Headroom for 2029 and 2034



Conclusions and recommendations from the 2024-2025 transmission planning process study

This study indicates that the ISO system response to major frequency events such as two Palo Verde units improves when IBRs have headroom, also when in charging mode (ample headroom), and have frequency response enabled.

The studies illustrated that the ISO is forecasted to meet its Frequency Response Obligation (FRO) with the frequency response of new IBRs enabled per FERC Order 842.

A number of existing IBRs connected to the ISO footprint have primary frequency response (PFR) capability but there are still a significant number of units for which the PFR capabilities of the IBRs are not enabled. Considering the subset of existing IBRs that are BESS units with frequency response enabled and that all future IBR plants will have frequency response available and enabled, it is expected that the PFR capability of the IBRs would be beneficial to system recovery from frequency events and continue to meet the ISO Frequency Response Obligation (FRO).

Intentionally left blank

Chapter 7

7 Special Reliability Studies and Results

In addition to the mandated analysis framework set out in the ISO's Tariff described above, the ISO has also pursued in past transmission planning cycles a number of additional "special studies" in parallel with the tariff-specified study processes. This is done 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 for identifying needs or mitigations for ISO Board of Governor approval. A number of those studies have now been incorporated into analysis in Chapter 3 exploring resource portfolio scenarios, or are now being conducted on an annual basis and are in Chapter 6.

The ISO has not performed any special reliability studies within the 2024-2025 Transmission Planning Process.

Intentionally left blank

Chapter 8

8 Transmission Projects

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 ISO 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	Transmission Plan Approved [66]	Current Expected In-service date [67]
1	Cooley Landing-Palo Alto and Ravenswood-Cooley Landing 115 kV Lines Rerate	PG&E	2008	Dec-22
2	Dinuba Energy Storage (Rescoped from Reedley 70 kV Area Reinforcement Projects)	PG&E	2017-2018	Cancelled and re-scoped as Reedley 70 kV Capacity Increase
3	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	2011-2012	Oct-23
4	Giffen Line Reconductoring Project	PG&E	2018-2019	Dec-23
5	Glenn 230/60 kV Transformer No. 1 Replacement	PG&E	2013-2014	Mar-24
6	Kasson – Kasson Junction 1 115 kV Line Section Reconductoring Project	PG&E	2020-2021	Sep-23
7	Manteca #1 60 kV Line Section Reconductoring Project	PG&E	2020-2021	Dec-24
8	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase (Kern PP 230 kV Area Reinforcement Project)	PG&E	2010-2011	Mar-21
9	Oakland Clean Energy Initiative (Oakland X 115 kV Bus Upgrade)	PG&E	2017-2018	Jun-22
10	Palermo – Wyandotte 115 kV Line Section Reconductoring Project	PG&E	2020-2021	Jul-21
11	Panoche – Oro Loma 115 kV Line Reconductoring	PG&E	2015-2016	Apr-24

[66] Additional detail for the projects including cost information and scope can be found in the Transmission Plan in which they were approved. https://www.caiso.com/library/transmission-plans-and-studies

[67] Draft Transmission Plan in-service dates based on January 2025 Transmission Development Forum.

No	Project	PTO	Transmission Plan Approved [66]	Current Expected In-service date [67]
12	Ravenswood – Cooley Landing 115 kV Line Reconductor	PG&E	2017-2018	Dec-22
13	Ravenswood 230/115 kV transformer #1 Limiting Facility Upgrade	PG&E	2018-2019	Cancelled
14	Salinas-Firestone #1 and #2 60 kV Lines	PG&E	2019-2020	Cancelled and Re-scoped to Salinas Area Reinforcement
15	Tesla Substation 230 kV bus section D and circuit breakers 372, 382 and 842 overstress (reactors) TESLA: 230KV BUS REACTORS C - D	PG&E	2018-2019	Mar-24
16	Tesla Substation 230 kV bus section D and circuit breakers 372, 382 and 842 overstress (reactors) TESLA: 230KV BUS REACTORS D - E	PG&E	2018-2019	Jun-23
17	Tulucay-Napa #2 60 kV Line Capacity Increase	PG&E	2019-2020	N/A
18	Warnerville-Bellota 230 kV line reconductoring	PG&E	2012-2013	Mar-24
19	Wilson-Le Grand 115 kV line reconductoring	PG&E	2012-2013	Dec-23
20	Atlantic 230/60 kV transformer voltage regulator	PG&E	2021-2022	Cancelled and Rescoped to Atlantic High Voltage Mitigation
21	Atlantic High Voltage Mitigation	PG&E	2023-2024	Apr-27
22	Banta 60 kV Bus Voltage Conversion	PG&E	2022-2023	Dec-27
23	Borden 230/70 kV Transformer Bank #1 Capacity Increase	PG&E	2019-2020	May-28
24	Borden-Storey 230 kV 1 and 2 Line Reconductoring	PG&E	2022-2023	Apr-30
25	Cascade 115/60 kV No.2 Transformer Project	PG&E	2010-2011	Dec-25
26	Christie-Sobrante 115 kV Line Reconductor	PG&E	2018-2019	Feb-28
27	Clear Lake 60 kV System Reinforcement	PG&E	2009	Oct-30
28	Coburn-Oil Fields 60 kV system project	PG&E	2017-2018	Sep-30
29	Collinsville 230 kV Reactor	PG&E	2023-2024	May-28
30	Contra Costa PP 230 kV Line Terminals Reconfiguration Project	PG&E	2021-2022	Sep-25
31	Cooley Landing 60 kV Substation Circuit Breaker No #62 Upgrade	PG&E	2021-2022	Apr-25

No	Project	PTO	Transmission Plan Approved [66]	Current Expected In-service date [67]
32	Coppermine 70 kV Reinforcement Project	PG&E	2021-2022	Jun-28
33	Cortina #1 60 kV Line Reconductoring	PG&E	2023-2024	Dec-27
34	Cortina 230/115/60 kV Transformer Bank No. 1 Replacement Project	PG&E	2021-2022	Sep-27
35	Cottonwood 115 kV Bus Sectionalizing Breaker	PG&E	2018-2019	Feb-28
36	Cottonwood 230/115 kV Transformers 1 and 4 Replacement Project	PG&E	2017-2018	Oct-28
37	Covelo 60 kV Voltage Support	PG&E	2023-2024	May-30
38	Diablo Canyon Area 230 kV High Voltage Mitigation	PG&E	2023-2024	Jul-28
39	East Marysville 115/60 kV Project	PG&E	2018-2019	Feb-33
40	East Shore 230 kV Bus Terminals Reconfiguration	PG&E	2019-2020	May-27
41	Estrella Substation Project	PG&E	2013-2014	Mar-29
42	Equipment Upgrade at CCSF Owned Warnerville 230 kV Substation	PG&E	2022-2023	Nov-26
43	French Camp Reinforcement	PG&E	2023-2024	May-30
44	Gates 230/70 kV Transformer Addition	PG&E	2023-2024	May-30
45	Gold Hill 230/115 kV Transformer Addition Project	PG&E	2018-2019	Jun-29
46	Henrietta 230/115 kV Bank 3 Replacement	PG&E	2022-2023	Jul-28
47	Herndon-Bullard 115 kV Reconductoring Project	PG&E	2017-2018	Dec-27
48	Ignacio Area Upgrade	PG&E	2017-2018	Feb-28
49	Jefferson 230 kV Bus Upgrade	PG&E	2018-2019	Nov-26
50	Lakeville 60 kV Area Reinforcement	PG&E	2017-2018	Dec-28
51	Lone Tree–Cayetano–Newark Corridor Series Compensation	PG&E	2022-2023	Dec-27
52	Los Banos 230 kV Circuit Breakers Replacement	PG&E	2022-2023	Apr-28
53	Los Banos 70 kV Area Reinforcement	PG&E	2022-2023	Sep-30
54	Manteca-Ripon-Riverbank-Melones Area 115 kV Line Reconductoring Project	PG&E	2021-2022	Oct-29
55	Maple Creek Reactive Support	PG&E	2009	Oct-27
56	Martin-Millbrae 60 kV Area Reinforcement	PG&E	2023-2024	May-30

No	Project	PTO	Transmission Plan Approved [66]	Current Expected In-service date [67]
57	Mesa 230/115 kV Spare Transformer	PG&E	2022-2023	Mar-29
58	Metcalf 230 / 115 kV Transformers Circuit Breaker Addition	PG&E	2022-2023	Jun-27
59	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade	PG&E	2003	May-28
60	Midway – Kern PP #2 230 kV Line (Bakersfield-Kern Reconductor)	PG&E	2013-2014	May-30
61	Midway-Kern PP Nos. 1,3 and 4 230 kV Lines Capacity Increase (Midway 230 kV Bus Section D Upgrade Project)	PG&E	2010-2011	Aug-30
62	Midway-Temblor 115 kV Line Reconductor and Voltage Support	PG&E	2012-2013	Feb-29
63	Monta Vista 230 kV Bus Upgrade	PG&E	2012-2013	Mar-26
64	Moraga 230 kV Bus Upgrade	PG&E	2019-2020	Dec-28
65	Moraga-Castro Valley 230 kV Line Capacity Increase Project	PG&E	2010-2011	May-25
66	Moraga-Sobrante 115 kV Line Reconductor	PG&E	2018-2019	On-hold project
67	Morgan Hill Area Reinforcement (formerly Spring 230/115 kV substation)	PG&E	2013-2014	Jan-29
68	Mosher Transmission Project	PG&E	2013-2014	Feb-28
69	Moss Landing – Las Aguilas 230 kV Series Reactor Project	PG&E	2021-2022	Sep-28
70	New Humboldt 115/115 kV Phase Shifter with 115 kV line to Humboldt 115 kV Substation	PG&E	2023-2024	May-34
71	Newark 230/115 kV Transformer Bank #7 Circuit Breaker Addition	PG&E	2019-2020	Feb-29
72	Newark-Milpitas #1 115 kV Line Limiting Facility Upgrade	PG&E	2017-2018	May-27
73	North Tower 115 kV Looping Project	PG&E	2011-2012	Feb-29
74	Oro Loma 70 kV Area Reinforcement	PG&E	2010-2011	Aug-28
75	Pittsburg 115 kV Bus Reactor project	PG&E	2022-2023	May-28
76	Pittsburg 230/115 kV Transformer Capacity Increase	PG&E	2007	Sep-28
77	Reconductor Delevan-Cortina 230 kV line	PG&E	2021-2022	Feb-28
78	Reconductor Rio Oso–SPI Jct–Lincoln 115 kV line	PG&E	2021-2022	Dec-28
79	Reedley 70 kV Capacity Increase	PG&E	2023-2024	May-30

No	Project	PTO	Transmission Plan Approved [66]	Current Expected In-service date [67]
80	Rio Oso - W. Sacramento Reconductoring	PG&E	2023-2024	May-30
81	Rio Oso 230/115 kV Transformer Upgrades	PG&E	2007	May-25
82	Rio Oso Area 230 kV Voltage Support	PG&E	2011-2012	May-26
83	Santa Rosa 115 kV lines Reconductoring project	PG&E	2022-2023	Oct-29
84	Series Compensation on Los Esteros-Nortech 115 kV Line	PG&E	2021-2022	Dec-25
85	Sobrante 230/115 kV Transformer Bank Addition	PG&E	2023-2024	May-34
86	South Bay Area Limiting Element Upgrade	PG&E	2022-2023	Apr-26
87	South of Mesa Upgrade	PG&E	2018-2019	Jun-29
88	South of San Mateo Capacity Increase	PG&E	2007	Jun-28
89	Table Mountain Second 500/230 kV Transformer	PG&E	2021-2022	Oct-27
90	Tejon Area Reinforcement	PG&E	2023-2024	Aug-27
91	Tesla - Newark 230 kV Line No. 2 Reconductoring	PG&E	2023-2024	May-34
92	Tesla 115 kV Bus Reconfiguration	PG&E	2022-2023	Jun-28
93	Tie line Phasor Measurement Units	PG&E	2017-2018	Jul-26
94	Tulucay-Napa #2 60 kV line Reconductoring project	PG&E	2022-2023	Jul-27
95	Tyler 60 kV Shunt Capacitor	PG&E	2018-2019	Sep-27
96	Vaca Dixon Area Reinforcement (INSTALL (2) CAPACITOR BANKS)	PG&E	2017-2018	Apr-27
97	Vaca Dixon-Lakeville 230 kV Corridor Series Compensation	PG&E	2017-2018	Nov-26
98	Vaca-Plainfield 60 kV Line Reconductoring	PG&E	2023-2024	May-30
99	Vasona-Metcalf 230 kV Line Limiting Elements Removal Project	PG&E	2021-2022	Jul-26
100	Vierra 115 kV Looping Project	PG&E	2010-2011	May-27
101	Weber-Mormon Jct 60 kV Line Section Reconductoring Project	PG&E	2021-2022	Apr-27
102	Wilson 115 kV Area Reinforcement	PG&E	2010-2011	Aug-29
103	Wilson-Oro Loma 115 kV Line Reconductoring	PG&E	2019-2020	May-27

No	Project	PTO	Transmission Plan Approved [66]	Current Expected In-service date [67]
104	Antelope-Whirlwind Line Upgrade	SCE	2022-2023	Dec-25
105	Barre 230 kV Switchrack Conversion to BAAH Project	SCE	2022-2023	Jun-26
106	Devers 230 kV Reconfiguration Project	SCE	2021-2022	Jun-27
107	Devers-Valley 500 kV 1 Line Upgrade	SCE	2022-2023	Dec-27
108	Etiwanda 230 kV Bus SCD Mitigation	SCE	2023-2024	Dec-27
109	Inyo 230 kV Shunt Reactor	SCE	2023-2024	Dec-26
110	Laguna Bell - Mesa No. 1 230 kV Line Rating Increase Project	SCE	2021-2022	May-25
111	Lugo – Victorville 500 kV Upgrade (SCE portion)	SCE	2016-2017	May-25
112	Lugo Substation Install new 500 kV CBs for AA Banks	SCE	2008	Dec-29
113	Mira Loma 500 kV CB Upgrade Project	SCE	2022-2023	Dec-28
114	Mira Loma-Mesa Upgrade	SCE	2022-2023	Dec-26
115	New Coolwater A 115/230 kV Bank	SCE	2022-2023	Apr-27
116	Pardee-Sylmar 230 kV Line Rating Increase Project	SCE	2019-2020	Jun-29
117	San Bernardino-Vista 230 kV 1 Line Upgrade	SCE	2022-2023	Mar-29
118	Sylmar Transformer Replacement	SCE	2022-2023	Dec-26
119	Tie line Phasor Measurement Units	SCE	2017-2018	Pending
120	Victor 230 kV Switchrack Reconfiguration	SCE	2021-2022	Pending
121	Vista-Etiwanda 230 kV 1 Line Upgrade	SCE	2022-2023	Mar-29
122	TL644, South Bay-Sweetwater: Reconductor	SDG&E	2010-2011	In-Service
123	TL674A Loop-in (Del Mar-North City West) & Removal of TL666D (Del Mar-Del Mar Tap)	SDG&E	2012-2013	In-Service
124	2nd Escondido-San Marcos 69 kV T/L	SDG&E	2013-2014	In-Service
125	Reconductor TL692: Japanese Mesa - Las Pulgas	SDG&E	2013-2014	In-Service
126	Rose Canyon-La Jolla 69 kV T/L	SDG&E	2013-2014	In-Service
127	Reconductor TL 605 Silvergate – Urban	SDG&E	2015-2016	Nov-24
128	TL649D Reconductor (San Ysidro - Otay Lake Tap)	SDG&E	2017-2018	Nov-24

No	Project	PTO	Transmission Plan Approved [66]	Current Expected In-service date [67]
129	TL695B Japanese Mesa-Talega Tap Reconductor	SDG&E	2011-2012	Jan-28
130	Sweetwater Reliability Enhancement	SDG&E	2012-2013	Jul-26
131	TL632 Granite Loop-In and TL6914 Reconfiguration	SDG&E	2013-2014	Mar-27
132	TL690E, Stuart Tap-Las Pulgas 69 kV Reconductor	SDG&E	2013-2014	Dec-28
133	TL623C Reconductor (San Ysidro - Otay Tap)	SDG&E	2017-2018	Nov-26
134	3 Ohm Series Reactor on Sycamore-Penasquitos 230 kV line	SDG&E	2022-2023	Oct-26
135	Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento	SDG&E	2022-2023	N/A
136	Reconductor TL680C San Marcos -Melrose Tap	SDG&E	2022-2023	N/A
137	SG and OT Redundant Bus Differential Relay	SDG&E	2022-2023	N/A
138	Short Circuit Mitigation for Imperial Valley 230 kV Circuit Breakers Project	SDG&E	2023-2024	N/A
139	Short Circuit Mitigation for Miguel 230 kV Circuit Breakers Project	SDG&E	2023-2024	N/A
140	Upgrade TL13820 Sycamore-Chicarita 138 kV	SDG&E	2022-2023	N/A
141	Gamebird 230/138 kV Transformer Upgrade	VEA/GLW	2019-2020	In service
142	Tie line Phasor Measurement Units	VEA	2017-2018	Q2/2025
143	Collinsville 230 kV Reactor Project	LS Power	2023-2024	Jun-28

Table 8.1-2: Status of Previously-Approved Projects Costing $50 M or More

No	Project	PTO	Transmission Plan Approved	Current Expected In-service date
1	South of Palermo 115 kV Reinforcement Project	PG&E	2010-2011	In-Service
2	North of Mesa Upgrade (formerly Midway-Andrew 230 kV Project)	PG&E	2012-2013	Cancelled
3	Vaca Dixon Area Reinforcement (Original project was the "Vaca – Davis Voltage Conversion Project" approved in 2010-2011 Transmission Plan. The project was re-scoped and renamed in 2017-2018 Transmission Plan)	PG&E	2017-2018	In-Service
4	Gates 500 kV Dynamic Voltage Support	LS Power	2018-2019	In-Service
5	Camden 70 kV Reinforcement	PG&E	2023-2024	May-30
6	Crazy Horse Canyon - Salinas - Soledad #1 and #2 115 kV Line Reconductoring	PG&E	2023-2024	May-30
7	Garberville Area Reinforcement	PG&E	2022-2023	Dec-27
8	Kern PP 115 kV Area Reinforcement	PG&E	2011-2012	Aug-29
9	Lockeford-Lodi Area 230 kV Development	PG&E	2012-2013	Dec-29
10	Martin 230 kV Bus Extension	PG&E	2014-2015	Oct-28
11	Midway – Kern PP #2 230 kV Line	PG&E	2013-2014	Jun-28
12	New Collinsville 500 kV substation	PG&E	2021-2022	May-28
13	New Humboldt 500 kV Substation with 500 kV line to Collinsville [HVDC operated as AC]	PG&E	2023-2024	May-34
14	New Humboldt to Fern Road 500 kV Line	PG&E	2023-2024	May-34
15	New Manning 500 kV substation	PG&E	2021-2022	Apr-28
16	North Dublin -Vineyard 230 kV Reconductoring	PG&E	2023-2024	May-34
17	North East Kern 115 kV Line Reconductoring	PG&E	2022-2023	Aug-29
18	Oakland Clean Energy Initiative (MORAGA 115KV BUS UPGRADE & BK 3 SW)	PG&E	2017-2018	Jun-25
19	Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project	PG&E	2022-2023	Mar-28

20	Red Bluff-Coleman 60 kV Reinforcement (Original project was the "Cottonwood-Red Bluff No2 60 kV Line Project and Red Bluff Area 230/60 kV Substation Project" approved in 2010-2011 Transmission Plan. The project was re-scoped and renamed in 2017-2018 Transmission Plan.)	PG&E	2017-2018	Mar-29
21	Redwood City 115 kV System Reinforcement	PG&E	2022-2023	Mar-30
22	Salinas Area Reinforcement	PG&E	2023-2024	Dec-32
23	San Jose Area HVDC 230 kV Line (Newark - NRS)	PG&E	2021-2022	Apr-28
24	San Jose Area HVDC 500 kV Line (Metcalf – San Jose)	PG&E	2021-2022	May-28
25	Wheeler Ridge Junction Substation	PG&E	2013-2014	Jul-33
26	Alberhill 500 kV Method of Service	SCE	2009	Dec-29
27	Antelope 66 kV Circuit Breaker Duty Mitigation Project	SCE	2021-2022	May-27
28	Colorado River-Red Bluff 500 kV 1 Line Upgrade	SCE	2022-2023	Dec-27
29	Devers-Red Bluff 500 kV 1 and 2 Line Upgrade	SCE	2022-2023	Jan-30
30	Lugo – Eldorado series cap and terminal equipment upgrade	SCE	2012-2013	May-25
31	Lugo-Mohave series capacitor upgrade	SCE	2012-2013	May-25[68]
32	Lugo-Victor-Kramer Upgrade (1/3) Add 3rd Lugo 500/230 kV Transformer	SCE	2022-2023	Dec-28
33	Lugo-Victor-Kramer Upgrade (2/3) Reconductor Lugo–Victor 230 kV No. 1, 2, 3 & 4 lines using HTLS	SCE	2022-2023	May-28
34	Lugo-Victor-Kramer Upgrade (3/3) Rebuild/build Kramer–Victor 115 kV lines to 230 kV and Loop the old segment of Kramer–Victor 115 kV into Roadway	SCE	2022-2023	Jun-33
35	Method of Service for Wildlife 230/66 kV Substation	SCE	2007	Oct-29
36	New Serrano 4AA Bank & 230 kV GIS Rebuild	SCE	2022-2023	Dec-27
37	San Bernardino-Etiwanda 230 kV 1 Line Upgrade	SCE	2022-2023	Mar-29
38	Serrano-Alberhill-Valley 500 kV 1 Line Upgrade	SCE	2022-2023	Dec-27

[68] The Lugo-Mohave 500 kV series capacitor upgrade project is expected to be completed by May 2025. However, cathodic protection upgrades are needed on a parallel gas line before the Lugo-Mohave 500 kV line rating can be increased above the existing ratings of 2400 Amps. The completion date for the cathodic protection upgrade work is expected to be 2027 or earlier.

39	Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement	SCE	2022-2023	Dec-33
40	Artesian 230 kV Sub & loop-in TL23051	SDG&E	2013-2014	In-Service
41	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	2010-2011	In-Service
42	Miguel-Sycamore Canyon (TL23021) 230 kV line Loop-in to Suncrest	SDG&E	2022-2023	N/A
43	Upgrade TL13820 Sycamore-Chicarita 138 kV	SDG&E	2022-2023	N/A
44	Valley Center System Improvement	SDG&E	2023-2024	N/A
45	Beatty 230 kV Project	VEA/GLW	2022-2023	Dec-27
46	GLW/VEA area upgrades - revised scope	VEA/GLW	2021-2022 (revised scope 2022-2023)	Earliest June-27; latest Dec-27
47	Delaney-Colorado River 500 kV line	DCR Transmission	2013-2014	Jun-24
48	Collinsville 500/230 kV Substation Project	LS Power	2021-2022	Dec-27
49	Manning 500/230 kV Substation Project	LS Power	2021-2022	Dec-27
50	Metcalf - San José B HVDC Project	LS Power	2021-2022	May-28
51	Round Mountain 500 kV Dynamic Voltage Support (Fern Rd.)	LS Power	2018-2019	Jun-26
52	IV-North of Songs 500 kV line and North of Songs Substation	HWT	2022-2023	Jun-34
53	North-Gila 500 kV line	HWT	2022-2023	Jun-32
54	North of Songs-Serrano 500 kV Line	Lotus Infrastructure Global Operations	2022-2023	Jun-34

8.2 Transmission Projects found to be needed in the 2024-2025 Planning Cycle

In the 2024-2025 transmission planning process, the ISO determined that 28 transmission projects were needed to mitigate identified reliability concerns; three policy-driven projects were needed to meet the GHG reduction goals and no economic-driven projects were found to be needed. Summaries of the needed projects are in Table 8.2-1 and Table 8.2-2.

A list of projects that came through the 2024 Request Window can be found in Appendix E.

Additional details of projects can be found in Appendix H.

Table 8.2-1: New Reliability Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost (in millions of dollars)
1	Ames Distribution – Palo Alto 115 kV transmission line	PG&E	2034 Q2	84
2	Cortina #3 60 kV Reconductoring	PG&E	2031 Q2	55.5
3	Gold Hill-El Dorado Reinforcement	PG&E	2032 Q2	127
4	Greater Bay Area 500 kV Transmission Reinforcement	PG&E	2034 Q2	700
5	Jefferson-Stanford 60 kV Recabling *	PG&E	2029 Q2	40
6	Konocti – Eagle Rock 60 kV Line Reconductoring *	PG&E	2030 Q2	32.5
7	Metcalf Substation 500/230 kV Transformer Bank Addition	PG&E	2034 Q2	182
8	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade Rescope	PG&E	2027 Q1	135
9	Moraga 230/115 kV Transformer Bank Addition *	PG&E	2031 Q2	40
10	North Oakland Reinforcement Project	PG&E	2032 Q2	1127
11	Pittsburg-Kirker 115 kV Line Section Limiting Elements Upgrade *	PG&E	2028 Q2	0.2
12	San Jose B – NRS 230 kV line	PG&E	2030	200
13	San Mateo 230/115 kV Transformer Bank Addition Project	PG&E	2032 Q2	110
14	San Miguel New 70 kV Line *	PG&E	2032 Q2	30
15	Sobrante 230 kV Bus Upgrade *	PG&E	2033 Q2	15
16	South Bay Reinforcement Project	PG&E	2034 Q2	434
17	South Oakland Reinforcement Project	PG&E	2032 Q2	250
18	West Fresno 115 kV Voltage Support	PG&E	2031 Q2	60
19	Alamitos 230 kV SCD Upgrade	SCE	2032 Q4	5
20	Julian Hinds-Mirage 230 kV Advanced Reconductor	SCE	2030 Q1	76
21	Kramer-Coolwater 115 kV Line Looping into Tortilla 115 kV Substation	SCE	2034 Q2	37

22	Serrano 230 kV SCD GIS Bus Split	SCE	2029 Q4	28
23	Serrano 500 kV SCD Mitigation	SCE	2029 Q4	183
24	Tortilla 115 kV Capacitor Replacement	SCE	2029 Q2	5
25	Coronado Island Reliability Reinforcement Phase I *	SDG&E	2027 Q3	42
26	Coronado Island Reliability Reinforcement Phase II	SDG&E	2028 Q4	66
27	Downtown Reliability Reinforcement	SDG&E	2029-2037	500
28	Sloan Canyon Tertiary Reactors	GLW	2027 Q4	10

Table 8.2-2: New Policy-driven Transmission Projects Found to be needed

No.	Project Name	Service Area	Expected In-Service Date	Project Cost (in millions of dollars)
1	Eagle Rock- Fulton- Silverado 115 kV Line Reconductor	PG&E	2034	92.9
2	Reconductor of GWF – Kingsburg 115 kV line	PG&E	2034	81.6
3	New Helm 230/70 kV Bank #2	PG&E	2034	115

There are no new economic-driven transmission projects found to be needed in this planning cycle.

8.3 Grid-Enhancing Technologies (GETs)

GETs encompass a range of technologies with specific benefits and opportunities.

Currently, the term is used to describe:

- Advanced conductors – high temperature, low sag characteristics
- Dynamic line ratings
- Power Flow Controllers
- Topology Optimizations

The California ISO (ISO) supports appropriate application and deployment of these technologies, and has considered them as potential alternatives in past annual transmission planning processes.

The ISO typically considers advanced conductors and power flow controllers as planning tools providing an alternative to other capital expenditures. We also consider dynamic thermal line ratings and topology optimizations in accessing operational benefits through additional capacity providing economic or emergency measure uses.

In the ISO's transmission planning processes, we have considered both advanced conductors and flow controllers in a number of applications. Flow controllers have to date been more successful although the applications for advanced conductors are growing rapidly. The Table 8.3-1 lists GETS projects and dynamic reactive support projects that have been approved in past transmission planning processes. In the 2024-2025 transmission plan, the following projects are being proposed that will rely on advanced conductors:

- Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade:
    - Piercy-Metcalf 115 kV line;
    - Swift-Metcalf 115 kV line;
    - Newark-Dixon Landing 115 kV line; and
    - McKee-Piercy 115 kV line;
- Julian Hinds-Mirage 230 kV Advanced Reconductor

Table 8.3-1: Flow Control, Advanced Conductor and Dynamic Reactive Support Approved Projects

Projects	Transmission Plan approved	In service Date (planned or achieved)
Flow Control		
Series Reactor on Warnerville-Wilson 230 kV	2012-2013	2018
Series compensation on Eldorado-Lugo-Mohave	2012-2013	2024
Imperial Valley phase shifters	2013-2014	2017
Wilson 115 kV SVC/Statcom	2015-2016	2021

Projects	Transmission Plan approved	In service Date (planned or achieved)
San Jose-Trible 115 kV Series Reactors	2017-2018	2019
Vaca Dixon-Lakeville 230 kV Corridor Series Compensation	2017-2018	2026
Series Compensation on Los Esteros-Nortech 115 kV Line	2021-2022	2025
San Jose HVDC project - Metcalf-San Jose B	2021-2022	2028
Lone Tree – Cayetano – Newark Corridor Series Compensation	2022-2023	2027
Humboldt Phase Shifting Transformer (Part of New Humboldt 500 kV Substation with 500 kV line to Collinsville)	2023-2024	2034
Advanced Conductors		
Big Creek Rating Increase Project	2016-2017	2020
Moorpark-Pardee No. 4 230 kV Line[69]	2017-2018	2022
Laguna Bell – Mesa No. 1 Line Rating Increase Project[69]	2021-2022	2024
San Bernardino-Vista 230 kV 1 Line Upgrade[69]	2022-2023	2028
San Bernardino-Etiwanda 230 kV 1 Line Upgrade[69]	2022-2023	2031
Reconductor Lugo–Victor 230 kV No. 1, 2, 3 & 4 lines	2022-2023	2032
Dynamic Voltage Control		
Rio Oso SVC	2011-2012	2025
SVC at Suncrest	2013-2014	2017
Synchronous condensers in LA/San Diego area (loss of SONGS)		
Round Mountain 500 kV Dynamic Voltage Support (Fern Road Substation)	2018-2019	2026
Gates 500 kV Dynamic Voltage Support (Orchard Substation)	2018-2019	2025

8.4 Reliance on Preferred Resources

The ISO has relied on a range of preferred resources in past transmission plans as well as in this 2024-2025 Transmission 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.

69 Selection of advanced conductor was done by the PTO in their conductor optimization to meet the ISO requirements.

As set out in the 2024-2025 Transmission Planning Process Unified Planning Assumptions and Study Plan, the ISO 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 ISO'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 in 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.

Additionally, the ISO considered numerous storage projects included in the base and sensitivity resource portfolios provided by the CPUC as mitigation for alleviating transmission constraints as set out in Chapters 2, 3, and 4 of this plan.

In addition to relying on the preferred resources incorporated into the managed forecasts prepared by the CEC, the ISO 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 Appendix B, Sections B.4.4.11 and B.5.11, 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" (OCEI) approved in the 2017-2018 Transmission Plan. Based on the development in the procurement activities, the location of the entire 36 MW and 173 MWh storage need has been moved to Oakland C substation in the 2021-2022 TPP. Based on this year's assessment, due to the significant increase in the load forecast for the area, it was determined that the OCEI project is not going to be sufficient to address all the local area needs in absence of the local thermal generation. As such, transmission alternatives are being evaluated for the area. Since the required transmission upgrade is likely going to have significant scope and very long implementation time, the OCEI project, as scoped, is recommended to continue to help reduce reliance on local thermal generation in the meantime.

Moorpark and Santa Clara Sub-areas

The ISO is supporting 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 ISO's 2017-2018 Transmission Plan and went into service January 2022, 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. As set out in Appendix B Table 4.5-2, there is 14,011 MW of energy storage in the 2026 base portfolio that was modeled in the SCE main system which includes the Moorpark and Santa Clara Sub-areas.

8.5 Competitive Solicitation for New Transmission Elements

Phase 3 of the ISO's transmission planning process includes a competitive solicitation process for reliability-driven, policy-driven and economic-driven regional transmission facilities. Where the ISO selects a regional transmission solution to meet an identified need in one of the three categories, construction and ownership responsibility for the applicable upgrade or addition lies with the applicable participating transmission owner if that solution 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.

The ISO has identified the following regional transmission solutions recommended for approval in this 2024-2025 Transmission Plan as including transmission facilities that are eligible for competitive solicitation:

- Greater Bay Area 500 kV Transmission Reinforcement
- San Jose B - NRS 230 kV Line

The descriptions and functional specifications for the facilities eligible for competitive solicitation can be found in Appendix I.

8.6 Capital Program Impacts on Transmission High-Voltage Access Charge

8.6.1 Background

The purpose of the ISO'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 ISO's annual transmission planning processes on the access charge. The ISO 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 some of the stakeholder comments. The ISO recognizes and appreciates concerns regarding the ratepayer impacts of capital projects identified and approved in the ISO's planning process. As the ISO did in this planning cycle, it will continue to explore with stakeholders cost-effective solutions to meeting long-term needs in future planning cycles.

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 ISO'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 ISO from ISO 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 so the relative impacts of different decisions can be reasonably estimated.

The tool is based on the fundamental cost-of-service models employed by participating transmission owners, with a level of detail necessary to adequately estimate the impacts of changes in capital spending, operating costs, and other financial factors or considerations. 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 ISO to develop the comprehensive plan in its structured analysis, or by utility. The ISO is concerned that a breakout by ISO 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 appropriate 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 an ISO-wide basis, but not necessarily appropriate to apply to any one specific utility.

8.6.2 Input Assumptions and Analysis

The ISO's rate-impact model is based on publicly available information or ISO 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 ISO does not have a role regarding those costs. The 2025 model uses the average annual 2.18% energy growth rate based on the CEC 2024 IEPR 2024-2040 California Energy Demand baseline forecast, which is also used in the 2024-2025 TPP.

To account for the impact of ISO-approved transmission capital projects, the tool accommodates project-specific tax, return, depreciation and Allowances for Funds Used during Construction (AFUDC) treatment information.

In reviewing the latest estimate, as illustrated in Figure 8.5 1, the trend of the 2025 TAC value for the 2025 projection is higher than the 2024 projection for all years. The projection also includes capital projects in this year’s plan and all other transmission plan projects not already energized. The increase of $1.78 from last year’s projection for January 1, 2025 to this year’s actuals reflects the increase in TRR and TRBAA above the historical projections. The higher Gross Load Growth rate reduces the impact of the TAC Rates, with the projected rate reaching $21.137 for 2036.

Figure 8.5-1 Forecast of ISO High Voltage Transmission Access Charge Trending from First Year of Transmission Plan