2024 20-YEAR TRANSMISSION OUTLOOK

California ISO

July 31, 2024

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Appendices

Executive Summary

California has dramatically accelerated its pace for integrating new clean resources onto the electric grid and faces an even greater need for additional renewable energy over the next 10 to 20 years. This heightened requirement is being driven by the requirements of Senate Bill 100 that renewable energy and zero-carbon resources supply 100 percent of electric retail sales to end-use customers by 2045, and the continuing electrification of transportation and other industries. This transformation is not only driving significant investment in a technologically and geographically diverse fleet of resources, including storage, but also major transmission to accommodate all the new capacity being added. The transmission needs will range from new lines designed to open access to major generation pockets, including solar energy, offshore wind and geothermal resources located inside the state, as well as new high-voltage lines that will traverse significant distances to access out-of-state resources. Given the lead times needed for these facilities primarily due to right-of-way acquisition and environmental permitting requirements, the California Independent System Operator (ISO) and our partners in state and local government have found that a longer-term blueprint is essential to chart the transmission planning horizon beyond the conventional 10-year timeframe used in the past.

The ISO, working closely with the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), other local regulatory authorities, and members of the energy industry, has developed this 2024 20-Year Transmission Outlook (20-Year Outlook). It provides a long-term conceptual plan for the transmission grid in the year 2045 to reliably serve load and interconnect resources in alignment with planning by the state's principal energy agencies to meet state policy objectives regarding greenhouse gas reduction and renewable energy targets. The 20-Year Outlook also helps clarify the magnitude of the challenge in building major pieces of infrastructure – inside and outside the state – necessary for California to achieve the carbon-free grid envisioned under state energy policy.

The ISO released its first 20-Year Transmission Outlook in May 2022, providing a macro analysis of the broad architecture of California's future transmission network. In 2023, again in collaboration with the CPUC and the CEC, the ISO initiated work on updating the 20-Year Outlook with the objective of extending its range from 2040 to 2045. Doing so enables us to incorporate specific transmission projects approved over the last two years and to assess at a high level how the changes in load and resource forecasts since the first Outlook was drafted would affect the required transmission investments for 2045.

The CEC, CPUC, and the ISO collaborated in developing 2045 hourly load forecasts and a 2045 resource portfolio[1] for use by the ISO in this update[2]. The 2045 peak load forecast is 77,430 megawatts (MW), an increase of 3,521 MW from the 2040 forecast of 73,909 MW that was included in the original Outlook. The resource requirements also grew accordingly and, of particular note, the amount of offshore wind overall doubled from 10 GW to 20 GW in this updated 20-Year Outlook[3]. This increase took place primarily by more than tripling the forecast capacity in the North Coast area, from 4,000 MW to 14,700 MW. As the North Coast area has virtually no capacity to export offshore wind to load centers today, these volumes drive substantial increases in transmission requirements from the initial Outlook. The updated Outlook aligns with the California Energy Commission's Offshore Wind Energy Strategic Plan adopted July 10, 2024 as required by AB 525. The plan calls for up to 25,000 MW of wind energy from the California coast by 2045.

Accordingly, a comparison to the initial 20-Year Outlook shows some relatively modest additional requirements in-state for on-land resources, a relatively consistent requirement for transmission to access out-of-state resources, and substantial new requirements to access North Coast offshore wind, with the latter being the primary driver of cost differences.

In summary, the anticipated load growth to 2045 and the expectation of major offshore wind generation are driving the higher estimated cost for future transmission needs from approximately $30.5 billion over a 20-year timeframe identified in the first Outlook to the estimated $45.8 billion to $63.2 billion over the next two decades, with offshore wind development the primary driver of these higher projected costs. The range for future project cost estimates over this timeframe varies significantly due to detailed design requirements and uncertainty in permitting timelines, routing decisions, and equipment and labor costs. Also, the high-level analysis to determine feasible transmission alternatives included a bulk system power flow assessment for a range of load and resource scenarios. These costs do not include transmission that has already been approved by the ISO and is under development, but not yet in service[4].

Despite being developed over 20 years, and the costs amortized over the physical life of the transmission, the additions are significant investments. They must be considered in the context of the diverse fleet of resources they access, and the benefits provided by a diversified resource fleet in reducing total costs to consumers. The ISO recognizes and will continue to take steps to address concerns regarding the ratepayer impacts of the capital projects identified in the 20-Year Outlook and this update. Further, for a number of these additions, lead times of eight to 10 years are reasonable or even optimistic. This highlights the need for longer-term decisions to be made and development activities to be initiated in the annual transmission planning processes.

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[1] Consistent with the resource planning underpinning the initial 20 Year Outlook, the CEC and CPUC relied on the CEC's SB100-related processes for achieving the state's 2045 objectives as a platform for portfolio development, and CAISO collaborated with the state agencies on an approach to develop scenarios to be studied in the Outlook.

[2] https://www.energy.ca.gov/publications/2023/2045-scenario-update-20-year-transmission-outlook

[3] As the amount of solar and storage continues to grow, and the reliance on gas-fired generation decreases, greater resource diversity is called for in the resource fleet.

[4] In particular, the transmission requirements identified in this updated 2024 Outlook do not include the costs of reinforcement already approved by the ISO in the 2022-2023 transmission plan since the 2022 Outlook was prepared.

The ISO will continue to work with state agencies and stakeholders to refine these options to develop the most cost-effective solutions to meet California's reliability and clean-energy objectives. It is also important to keep in mind that preliminary cost estimates are subject to change and refinement depending on what ultimately gets built and the associated cost allocation methodologies. For inter-regional transmission lines, for example, some of the costs may be shared with participants outside California, so the costs would not all be borne by California ratepayers.

Resource and Transmission Requirements:

The 2045 portfolio referenced above identified the resource development to meet forecasted load growth as well as a projected reduction of 15,000 megawatts (MW) of natural gas-fired generation from plants being retired while also providing an effective trajectory to achieving 2045 state greenhouse gas reduction objectives. The reduction in natural gas-fired generation enabled analysis of not only system-wide needs, but also the local need of major load centers dependent on natural gas-fired generation for reliable service today, and the retirement assumptions focused on age and proximity to disadvantaged communities.

To meet these needs, the 2045 portfolio called for 48,813 MW of battery energy storage, 4,000 MW of long-duration storage, 5,000 MW of generic clean firm or long-duration storage, 69,640 MW of utility scale solar, 2,332 MW of geothermal, and over 35,000 MW of wind generation – the latter split between out-of-state and in-state onshore, and in-state offshore resources. The bulk of the in-state wind resources consist of offshore wind. These total 165.1 GW of new resources for the 2045 portfolio. The 2045 portfolio also provided specific locations for the new resources, except for some portion of the out-of-state and offshore wind.

The resulting updated Outlook developed to access these resources and reliably serve load calls for significant 500 kV AC and HVDC development to access offshore wind and out-of-state wind, while also reinforcing the existing ISO footprint. Figure ES-1 provides an illustrative diagram of the transmission development required to integrate the resources of the 2045 portfolio and reliably serve the 2045 load forecast. This analysis focused on high-voltage bulk transmission, recognizing that local transmission needs and generation interconnections will ultimately need to be addressed as well.

Figure ES-1: Transmission Development

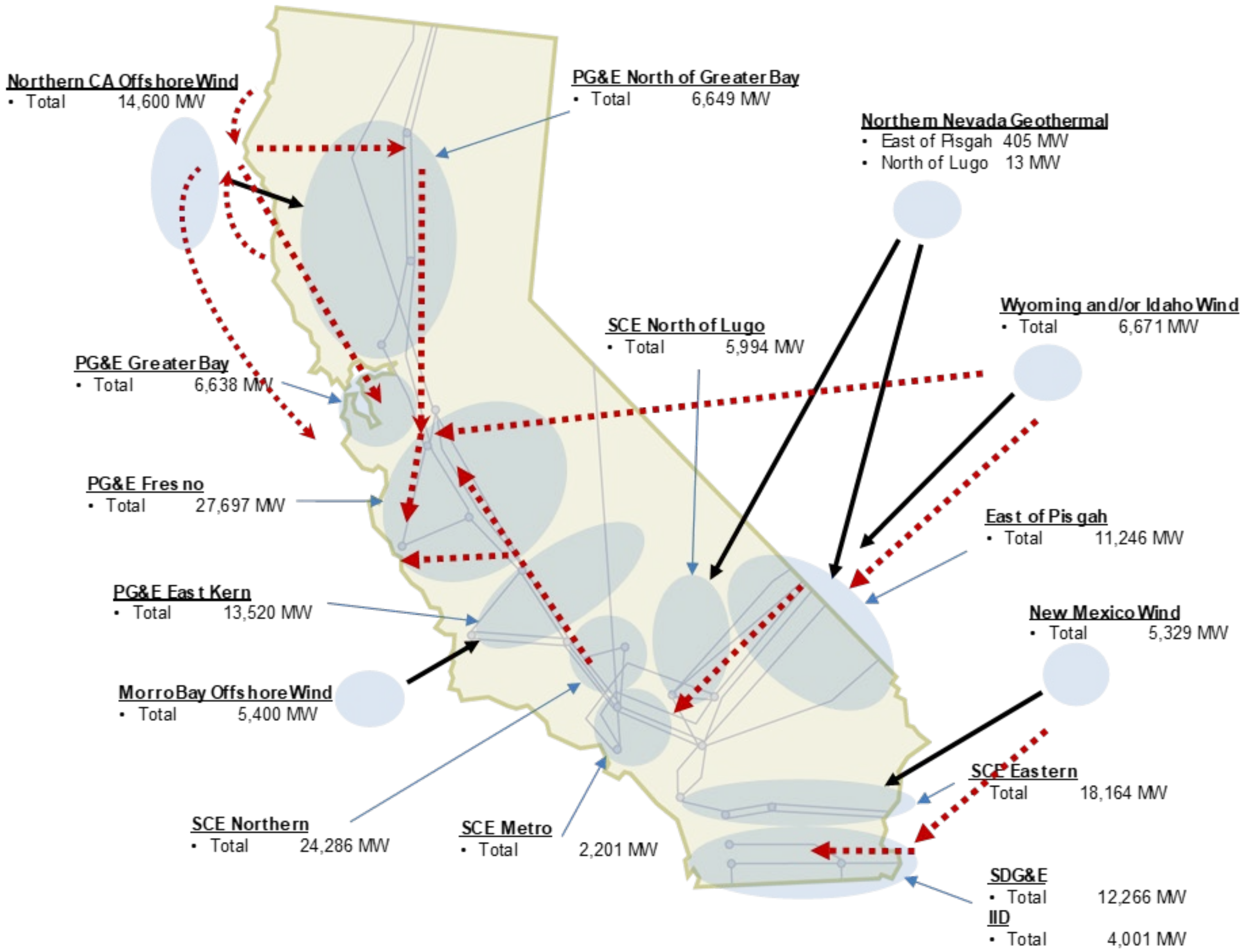

Table ES-1: provides the high-level summary of the transmission development required for upgrades to the existing ISO footprint, offshore wind integration and out-of-state wind integration along with estimated cost. The range of cost estimate is commensurate with estimates developed at this stage of planning, with the costs in constant dollars.

Table ES-1: Cost estimate of transmission development to integrate resources of 2045 Scenario

Transmission Development	Estimated Cost ($ billions)
Upgrades to existing ISO bulk transmission footprint consisting of: • 230 kV and 500 kV AC lines • HVDC lines • Substation upgrades	$9.3 B – $11.5 B
Offshore wind integration consisting of: • 500 kV AC lines • HVDC lines	$25.0 B – $36.5 B
Out-of-state wind integration consisting of: • 500 kV AC lines • HVDC lines	$11.6 B - $15.2 B
Total estimated cost of transmission development[5]	**$45.8 B – 63.2 B**

The ISO recognizes that resource planning and procurement decisions may differ over the years ahead from some of the assumptions used to establish the baseline the 20-Year Outlook provides for longer-term planning. Those changes will be managed by adapting future plans around the baseline architecture in subsequent updates, and in the ISO's transmission planning processes that approve and initiate specific projects annually.

The ISO also plans to conduct additional stakeholder dialogue through 2024 about next steps as well as the long-term architecture set out in this 2024 20-Year Outlook. Stakeholder feedback at a meeting in January on the updated 20-Year Outlook preliminary results was overwhelmingly supportive of the 20-Year Outlook effort, and focused on how the ISO may move to initiate the transmission development it identified – or particular developments of specific interest to the individual commenters. A number of stakeholders requested analysis and detail that were beyond the scope of this year's efforts, and that feedback will be taken into account as the ISO refines its plans for developing future iterations.

Finally, this effort could not have been undertaken without the collaboration and support of the CPUC and CEC. The ISO appreciates the efforts of both organizations in supporting the development of this document.

[5] These values represent the capital cost of the identified projects; several are currently being developed under a subscriber model – with the transmission costs incorporated into the energy costs – and not rate-base projects receiving cost-of-service cost recovery that would be added to ISO transmission access charges.

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Chapter 1

1 Introduction

1.1 Purpose

The ISO released a final version of its first 20-Year Outlook in May 2022. The Outlook provided a long-term conceptual plan of the transmission grid in the year 2040 to reliably serve the load and interconnect the resources aligned with the California Energy Commission (CEC) and California Public Utilities Commission (CPUC) inputs aimed at meeting the state's greenhouse gas reduction and renewable energy objectives. The Outlook also helped clarify our vision and the magnitude of the challenge in building major pieces of infrastructure – inside and outside the state – necessary for California to achieve the carbon-free grid envisioned under state energy policy.

The CEC's SB100-related processes for achieving the state's 2045 objectives were used as a platform and the ISO collaborated with the state agencies on an approach to develop scenarios that can be studied in the Outlook, which is necessary for a number of important reasons, including:

- To ensure that the ISO's longer-term transmission plan initially articulated in 2022 remains relevant;
- That the longer-term Outlook continues to provide a longer-term view of transmission needed in California and can help inform the ISO's annual transmission planning process;
- That the ISO's transmission planning is aligned with state agency inputs on evolving resource and load projections, particularly as the need for long lead-time transmission assets grows due to increasing offshore and out-of-state wind resources and as the gas generation fleet starts retiring; and
- To provide an updated conceptual map of transmission required to meet SB100 requirements for 2045.

The update will also be informed by transmission projects that were approved as part of the ISO's 2022-2023 transmission plan and those recommended for approval in the transmission plan for 2023-2024.

In this updated 20-Year Outlook, the ISO continued to engage and collaborate with the state agencies to develop scenarios for study purposes based on extending the study timeframe to 2045 and incorporating updated resource and load forecasts. The study timeframe also aligns well with the SB100 legislation timelines requiring all retail electricity sold in California to be from renewable and zero-carbon resources by 2045.

The 20-Year Outlook Update for the ISO grid explores the longer-term grid requirements and options for meeting the State's greenhouse gas reduction and renewable energy objectives reliably and cost-effectively.

The Outlook provides:

- A transparent process to develop transmission information responsive to supporting and informing the CPUC's Integrated Resource Planning processes, the CEC's Integrated Energy Policy Report and the joint agencies' SB100 efforts
- Longer-term context for and framing of issues in the ISO's 10-Year Transmission Plan which gets updated annually

The ISO launched the effort to update the 20-Year Outlook in parallel with the 2023-2024 transmission planning cycle. The 20-Year Outlook Update provides a baseline for longer-term planning, recognizing that future resource planning and procurement decisions will differ from assumptions used in this study. Those changes will be managed by adapting future plans around the baseline architecture in future updates, and in the ISO's annual transmission planning processes that approve and initiate specific projects.

1.2 Challenges

Senate Bill (SB) 100 establishes a policy that renewable and zero-carbon resources supply 60 percent of California's retail sales and electricity procured to serve all state agencies by 2030, and 100 percent by 2045.

These goals are in addition to those established earlier via Senate Bill (SB) 350 that update the 2030 renewables goal. SB 350 set the requirement to achieve the 2030 greenhouse gas reduction targets established by the California Air Resources Board (CARB), in coordination with the California Public Utilities Commission (CPUC) and California Energy Commission (CEC) that would also meet or exceed the current 2030 renewables portfolio standard requirement established by SB 100. It is also critical that goals focused on 2030 objectives reasonably establish a trajectory to meeting 2045 renewables portfolio standard goals that were also established in SB 100.

The ISO relies extensively on coordination with the state energy agencies for resource planning input, in particular with the CPUC, which takes the lead role in developing resource forecasts for the 10-year planning horizon and with input from the CEC and the ISO. In looking beyond the 10-year horizon, the CEC takes a more central role in establishing forecast resource requirements via the analysis the CEC leads pursuant to its SB 100 responsibilities. As it did with the original 20-Year Outlook, the ISO turned to the two state agencies for input to support the development of the 20-Year Outlook update.

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

1.3 Other Process Issues

1.3.1 Infrastructure

In the more than 10 years since the ISO redesigned its transmission planning process and subsequently adapted it to fully conform with Federal Energy Regulatory Commission (FERC) Order No. 1000 provisions, the challenges placed on the electricity system – and correspondingly on the transmission system - have evolved and grown considerably. While these past challenges were significant at the time, the energy industry is now at an inflection point marking a far more impactful increase in the rate of growth in renewable resources and the need for faster integration onto the grid. For context, it is useful to note that when the ISO prepared its 2020-2021 transmission plan, state agency-provided forecasts called for adding approximately 1,000 MW of new resources per year over the next 10 years. Now, just three years later in the ISO's draft 2023-2024 transmission plan, state agency forecasts call for adding approximately 7,000 to 8,000 MW of new resources every year for each of the next 10 years.

In addition to the reasons stated above, the accelerating resource requirements over the next decade are driven by a number of circumstances, including the escalating need to decarbonize the electricity grid in light of emerging climate change impacts, the expected electrification of transportation and other carbon-emitting industries driving higher electricity forecasts, concerns regarding reduced access to imports as neighboring systems also decarbonize, higher than anticipated impacts of peak loads shifting to later-day hours when solar resources are not available, and the need to maintain system reliability in light of retiring gas-fired generation relying on coastal waters for once-through cooling and the planned closing of the Diablo Canyon Power Plant. These resource requirements, on the path to total decarbonization of the grid, will call for greater volumes of solar photovoltaic resources and battery storage, as well as greater diversity beyond the current focus on those resource types. Geothermal resources, out-of-state resources and offshore resources all are expected to play greater roles, and create unique challenges in the planning and interconnection processes. Meeting those challenges requires adaptations and enhancements to existing processes and efforts.

At the same time as this shift in longer-term resource requirements was being established, the CPUC authorized more mid-term procurement in a June 24, 2021 decision than last year's 10-year transmission plan was based on. It was the largest single procurement ever authorized by the CPUC. Responding to these signals and previously approved authorizations, the resource development industry came forward with a record-setting number of new interconnection requests in April, 2021 – some 373 new interconnection requests received in the ISO's Cluster 14 open window, layered on top of an already heavily populated interconnection queue.[6] The 605 projects totaling 236,225 MW now in the queue exceeds mid-term requirements by an order of magnitude. This level of hyper competition actually creates barriers to moving forward effectively with the resources that do need to be added to the grid, and places extreme

[6] ISO Board of Governors July 7, 2021 Briefing on renewable and energy storage in the generator interconnection queue, http://www.caiso.com/Documents/Briefing-Renewables-GeneratorInterconnection-Queue-Memo-July-2021.pdf

demands on finite planning, engineering and project management resources from the ISO and transmission owners.

In parallel with enhancements in the transmission planning process, enhancements are also being pursued to more tightly synchronize state agency resource planning processes with the ISO's resource interconnection process, and in the overall coordination of the procurement and construction of new resources and related transmission network upgrades. These led to the development of a more proactive and coordinated strategic direction set forth in a joint Memorandum of Understanding (MOU)[7] signed by the three parties in December 2022. 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.

Transmission Planning:

In addition to the incremental improvements the ISO makes in each year's transmission planning cycle, the ISO has re-examined the effectiveness of certain planning processes both due to evolving issues within our own footprint, and also in response to the FERC Advance Notice of Proposed Rulemaking (ANOPR) regarding transmission planning, cost allocation and generator interconnection released on April 21, 2022.

The ISO noted in its comments responding to the ANOPR[8] that the "ISO's existing transmission planning and generator interconnection processes reflect many of the reforms and concepts discussed in the FERC's proposed rulemaking. At the same time, given the ISO's escalating challenges arising from existing supply conditions, the need to accelerate and then sustain the pace of procurement and interconnection to meet climate goals, and an "overheated" generation interconnection queue, the ISO must "get in front" of these issues and move forward with transmission planning and generation interconnection process enhancements ahead of the likely timeline for any Final Rule in the FERC proceeding. Enhancements and improvements to the ISO regional transmission planning processes are already moving forward, including the introduction of the 20-Year Outlook framework that it is outside of the tariff-based project approval planning process, and other enhancements that do not require tariff changes to implement.

In responding to the ANOPR, the ISO also acknowledged that the interregional coordination process related to transmission has not met expectations in actually leading to more interregional transmission being developed across the United States, and that there are opportunities to remove certain barriers, foster collaboration with state regulators, and promote more rigor in, and reporting on, interregional coordination efforts. Accordingly, the ISO is exploring a few alternative courses of action to advance potential interregional opportunities, drawing largely on the flexibility supported by FERC in its policy statement, "State Voluntary Agreements to Plan and Pay for Transmission Facilities" issued on June 17, 2021, in addition to

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

[8] COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON ADVANCE NOTICE OF PROPOSED RULEMAKING, submitted October 12, 2021, FERC Docket No. RM21-17-000, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection http://www.caiso.com/Documents/Oct12-2021-Comments-AdvanceNoticeOfProposedRulemaking-BuildingTransmissionSystemoftheFuture-RM21-17.pdf

meeting all expectations, responsibilities and obligations associated with the ISO interregional coordination tariff provisions related to FERC Order No.1000.

On May 13, 2024, FERC adopted Order No. 1920, a final rule in RM21-17, largely consistent with the ANOPR of April 21, 2022. The ISO is reviewing the order, and will be developing its compliance filing and related process changes over the course of the next year. Compliance filings are due in June, 2025.

Resource Interconnection:

In 2023, the ISO launched its 2023 Interconnection Process Enhancements initiative in response to excessive volumes of interconnection requests received in recent application windows, focusing on making significant and transformative improvements regarding coordination of resource planning, transmission planning, interconnection queuing and power procurement to achieve state reliability and policy needs.

The 2023 Interconnection Process Enhancements initiative is part of a larger set of foundational framework improvements being coordinated among the CPUC, the CEC, and the ISO. The overall strategic direction is set forth in the joint Memorandum of Understanding (MOU) signed by the three parties in December 2022 to set the direction for tightening linkages among resource and transmission planning activities, interconnection processes and resource procurement. The ISO is now taking on additional reforms to the interconnection queuing process that will leverage the improved coordinated planning resulting from the MOU and help further break down barriers to efficient and timely resource development. The ISO's Interconnection Process Enhancements proposal was approved by its Board of Governors on June 12, 2024, and will be filed with FERC in August. This proposal builds on the compliance filing submitted by the ISO on May 16, 2024 in response to FERC Order No. 2023[9], which FERC issued to "ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner, and [which] will prevent undue discrimination."

Procurement and Project Execution:

In addition to the above processes, the ISO is also taking on additional efforts to:

- Coordinate with the CPUC, CEC, and the state of California's GO-Biz office to identify and help mitigate supply chain and other issues that could delay new resources meeting in-service dates,
- Together with the CPUC, work with participating transmission owners to improve 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,

[9] On July 27, 2023, the Federal Energy Regulatory Commission (FERC) issued Order No. 2023, Improvements to Generator Interconnection Procedures and Agreements. On March 21, 2024, FERC issued Order No. 2023-A, revising some requirements.

- 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, and,
- Continue to explore opportunities using grid-enhancing technologies – flow controllers and advanced conductors in particular – to expedite transmission capacity development and minimize costs.

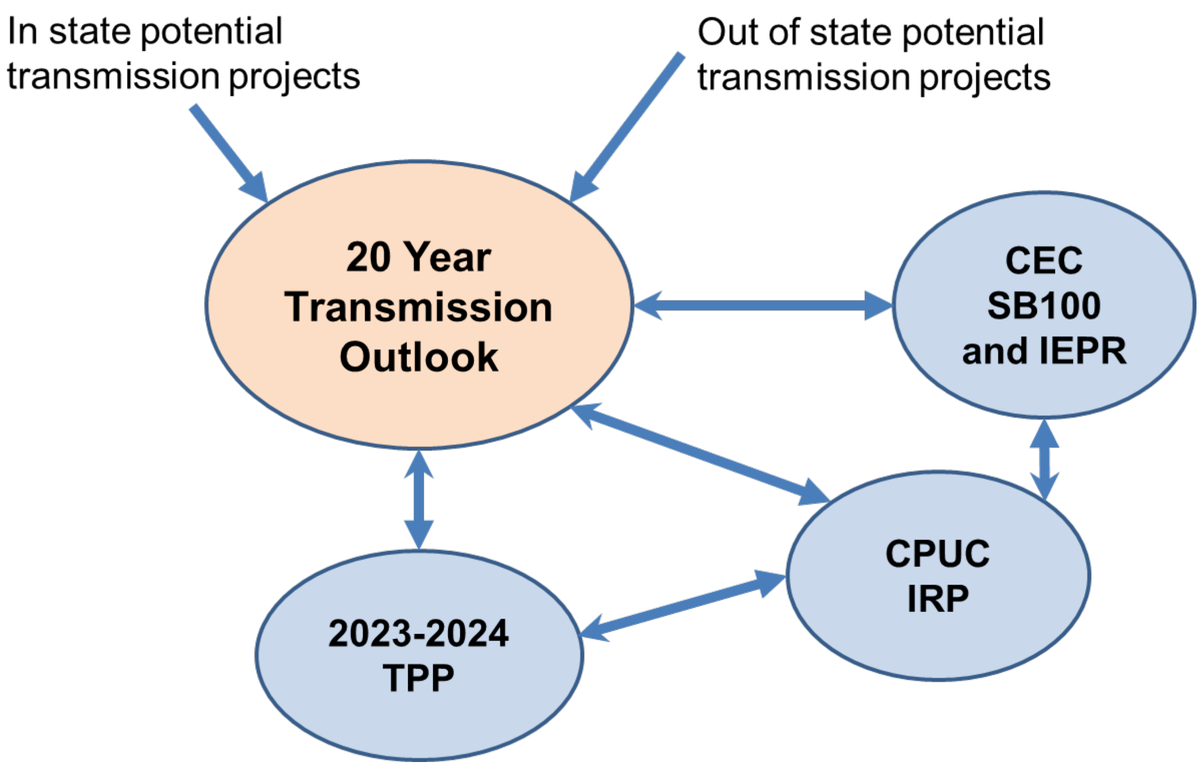
These enhancements and coordination efforts will collectively support and enable the state reaching its renewable energy objectives reliably.

Chapter 2

2 Coordination with State Agencies

The development of the 20-YearTransmission Outlook Update has been coordinated with the 2023-2024 transmission planning process and with the forecasting and planning done by the CEC and CPUC. These efforts have included ISO stakeholder calls and joint agency workshops as a part of the SB100 process.

Figure 2-1: 20-Year Outlook Update coordination with other initiatives and agencies



On June 23, 2023, the CEC held its public "Joint Agency Staff Workshop[10] on Resource Portfolio Assumptions for the Next CAISO 20-Year Outlook" with CAISO and CPUC participation to discuss resource portfolio assumptions for the 20-Year Outlook Update.

On July 14, 2023 the CEC docketed the 2045 Scenario for the Update of the ISO 20-Year Outlook[11] in its SB 100 proceeding.

[10] https://efiling.energy.ca.gov/GetDocument.aspx?tn=250717

[11] https://www.energy.ca.gov/publications/2023/2045-scenario-update-20-year-transmission-outlook

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Chapter 3

3 Process and Inputs

The objective of the ISO's 20-Year Outlook Update is to explore longer-term grid requirements and options for reliably meeting the state's greenhouse gas reduction goals. The 20-Year Outlook Update will provide a "baseline" vision for future planning activities. To achieve this, the ISO used a resource development scenario developed through the CEC SB100-related activities that considers:

- Diverse resources known to require transmission development such as offshore wind energy, out-of-state resources, geothermal resources; and,
- Gas power plant retirements that may require transmission development to reduce local area constraints.

The ISO also developed conceptual transmission system additions and conducted high-level technical studies to test feasibility of these alternatives, focusing on the bulk transmission system.

This basis for the 20-Year Outlook Update is to help map the broad architecture of California's future transmission network and clarify our vision and the magnitude of the challenge the state and electricity industry face in building major pieces of infrastructure – inside and outside the state – necessary for California to achieve the carbon-free grid envisioned under Senate Bill 100, which was signed into law in 2018. The Outlook Update will also allow the state to further refine long-term resource planning inputs and provide longer-term context for decisions made in the ISO's annually updated 10-year transmission planning process.

The high-level analysis to determine feasible transmission alternatives included bulk system power flow assessment for a range of load and resource scenarios.

Particular focus was applied to conducting a high-level assessment of local area (primarily the Bay Area and LA Basin) needs with gas retirement, building off the initial 20-Year Outlook, past informational studies conducted in recent ISO transmission planning studies, and other technical analyses.

3.1 Key Inputs

This section provides background and detail on key load and resource forecast inputs into the 20-Year Outlook Update process.

SB 100 requires the CEC, CPUC, and California Air Resources Board (CARB) to have developed and submitted a joint-agency report on decarbonization progress and strategies to the Legislature by January 1, 2021, and at least every four years thereafter. The CEC, CPUC, and the ISO collaborated on an approach to develop a scenario for use by the ISO in the 20-Year Outlook Update[12]. The CEC and CPUC expect that the information from the 20-Year

[12] https://www.energy.ca.gov/publications/2023/2045-scenario-update-20-year-transmission-outlook

Outlook Update will help inform future electric sector planning, including the next SB 100 joint-agency report.

3.1.1 Load and Distributed Energy Resources Growth Scenarios

The 2045 load and resource portfolio forecast used for the 20-year Outlook Update assessment was developed by CEC and CPUC in collaboration with CAISO and can be found on the CEC docket at the link below [13]. The hourly load forecast provided for year 2045 includes the baseline consumption, behind-the-meter PV, behind-the-meter storage, light duty vehicle charging load, medium to high duty vehicle charging load, additional available energy efficiency and additional available fuel substitute load. Within the technical studies of this 20-Year Outlook Update, the following three study cases were considered similar to the initial 20-Year Outlook:

- Net peak load
- Peak consumption
- Off-peak load

The following table provides the details of the load forecast for the three study cases:

Table 3-1: Load and Load Modifiers

Study Scenario	Date/ Time	TAC Area	Baseline_ Consumption	BTM_PV	BTM_ Storage	LDV3	MDHD3	AAEE3	AAFS3	System Load (1-in-2)	System Load (1-in-5)
Net Peak Load (HSN)	9/5/2045 HE19	PG&E	24,520	-45	-647	3,546	828	-1,402	732	27,532	28,758
		SCE	26,612	-2	-363	3,190	698	-1,600	412	28,948	30,279
		SDG&E	5,163	0	-156	652	63	-290	32	5,464	5,723
		CAISO [1]	56,450	-46	-1,166	7,388	1,589	-3,291	1,176	62,100	**64,923**
Peak Consumption (SSN)	9/5/2045 HE14	PG&E	26,043	-15,980	36	5,804	1,383	-1,452	302	16,136	17,438
		SCE	30,503	-10,439	-1	4,824	1,239	-1,986	307	24,445	25,970
		SDG&E	5,653	-3,642	2	1,588	200	-376	33	3,459	3,741
		CAISO	62,356	-30,061	37	12,216	2,822	-3,815	642	44,197	**47,315**
Off Peak [2]	4/15/2045 HE13	PG&E	13,993	-16,744	34	3,615	1,134	-935	358	1,455	1,455
		SCE	12,683	-11,550	3	3,110	1,015	-1,027	290	4,524	4,524
		SDG&E	2,737	-3,944	-2	942	163	-215	29	-291	-291
		CAISO	29,489	-32,238	35	7,666	2,312	-2,177	677	5,764	**5,764**

[1] CAISO's Baseline Consumption and System Load values include VEA load

[2] To study more stressed off peak scenario, the 1-in-2 off peak system load was studied

[13] https://www.energy.ca.gov/publications/2023/2045-scenario-update-20-year-transmission-outlook

3.1.2 Resource Planning and Portfolio Development

Table 3-2 provides the resource portfolio provided by the CPUC for use in the 2023-2024 transmission planning process for the year 2035, the resource portfolio used in the 2022 20-Year Outlook, and the resource portfolio for use in this 20-Year Outlook Update for year 2045.

Table 3-2: Resource assumptions in 2023-2024 transmission planning process for 2035 and the 20-Year Outlook resource portfolio for 2040 and 2045

Resource Type	2023-2024 TPP Base Portfolio for 2035 (MW)	Previous 20-Year Outlook (2040) (MW)	20-Year Outlook Update (2045)
Natural gas fired power plants	0	(15,000)	(15,000)
In State Biomass	134	0	134
Battery energy storage	28,374	37,000	48,814
Long-duration energy storage	2,000	4,000	4,000
Distributed Solar	125	0	125
Utility-scale solar	38,947	53,212	69,640
In-state wind	3,074	2,237	3,074
Offshore wind	4,707	10,000	20,000
Out-of-state wind	5,618	12,000	12,000
Geothermal	2,037	2,332	2,332
Generic Clean-Firm/LDES	0	0	5,000

3.1.3 Natural gas-fired power plants

Similar to the initial 20-Year Outlook, the 2045 Portfolio includes an assumption that 15,000 MW of natural gas power plant capacity would be retired by 2045.

Table 3-3 provides the assumption on total retirement of gas-fired generation by local capacity areas. The same methodology detailed in the last Outlook[14] was used in this study to implement gas retirement assumptions in different study cases.

[14] http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf (section 3.1.3)

Table 3-3: Assumed gas-fired generation retired by local capacity area

Local Capacity Area	Capacity (MW)
Greater Bay Area	4427
Sierra	153
Stockton	361
Fresno	669
Kern	407
LA Basin	3,632
Big Creek-Ventura	695
San Diego-IV	131
ISO System	3,933
Total	**14,408**

3.1.4 Battery energy storage

The 2045 Portfolio identified 48,814 MW of battery energy storage resources along with associated busbar mapping. Table 3-4 provides a summary of total battery energy storage resources in different CAISO study areas. Chapter 4 provides the busbar mapping of the resources for different study areas.

Table 3-4: Battery energy storage resources for the 20-Year Outlook

CAISO Study Area	20-Year Outlook
PG&E East Kern Study Area	5,497
PG&E Fresno Study Area	7,990
PG&E North of Greater Bay Study Area	4,903
PG&E S500 Study Area	930
East of Pisgah Study Area	3,517
SCE Eastern Study Area	6,692
SCE Metro Study Area	2,177
SCE North of Lugo (NOL) Study Area	1,884
SCE Northern Area	9,048
SDG&E Study Area	4,676
IID	1,501
Total	**48,814**

3.1.5 Long-duration energy storage (LDES) or firm generic clean resources

The 2045 Portfolio identified 4,000 MW of LDES resources. In addition, 5,000 MW of resources identified as firm generic clean or LDES resources are also included in the portfolio. Table 3-5 and Table 3-6 provides a summary of total LDES resources and a summary of total firm generic clean or LDES resources in different CAISO study areas. Chapter 4 provides the busbar mapping of the resources for different study areas.

Table 3-5: LDES resources for the 20-Year Outlook

CAISO Study Area	20-Year Outlook
PG&E East Kern Study Area	600
PG&E Fresno Study Area	0
PG&E North of Greater Bay Study Area	400
PG&E S500 Study Area	0
East of Pisgah Study Area	0
SCE Eastern Study Area	1,500
SCE Metro Study Area	0
SCE North of Lugo (NOL) Study Area	0
SCE Northern Area	1,000
SDG&E Study Area	500
IID	0
Total	**4,000**

Table 3-6: Firm generic-clean/LDES resources for the 20-Year Outlook

CAISO Study Area	20-Year Outlook
PG&E East Kern Study Area	0
PG&E Fresno Study Area	250
PG&E North of Greater Bay Study Area	1,650
PG&E S500 Study Area	1,500
East of Pisgah Study Area	500
SCE Eastern Study Area	0
SCE Metro Study Area	0
SCE North of Lugo (NOL) Study Area	600
SCE Northern Area	500
SDG&E Study Area	0
IID	0
Total	**5,000**

3.1.6 Utility-scale solar

The 2045 Portfolio identified 69,640 MW of utility-scale solar resources along with busbar mapping of the resources. Table 3-7 provides a summary of total utility-scale solar resources in different CAISO study areas. Chapter 4 provides the busbar mapping of the resources for different study areas.

Table 3-7: Utility-scale solar resources for the 20-Year Outlook

CAISO Study Area	20-Year Outlook
PG&E East Kern Study Area	10,514
PG&E Fresno Study Area	12,317
PG&E North of Greater Bay Study Area	4,957
PG&E S500 Study Area	1,050
East of Pisgah Study Area	6,326
SCE Eastern Study Area	9,493
SCE Metro Study Area	0
SCE North of Lugo (NOL) Study Area	3,460
SCE Northern Area	13,378
SDG&E Study Area	5,645
IID	2,500
Total	**69,640**

3.1.7 Onshore, In-state Wind

The 2045 Portfolio identified 3,074 MW of onshore in-state wind along with busbar mapping of the resources. Table 3-8 provides a summary of total onshore in-state resources in different CAISO study areas. Chapter 4 provides the busbar mapping of the resources for different study areas.

Table 3-8: Onshore, in-state wind resources for the 20-Year Outlook

CAISO Study Area	20-Year Outlook
PG&E East Kern Study Area	255
PG&E Fresno Study Area	249
PG&E North of Greater Bay Study Area	1,095
PG&E S500 Study Area	0
East of Pisgah Study Area	403
SCE Eastern Study Area	127
SCE Metro Study Area	0
SCE North of Lugo (NOL) Study Area	0
SCE Northern Area	345
SDG&E Study Area	600
IID	0
Total	**3,074**

3.1.8 Offshore Wind

The 2045 Portfolio identified a total of 20,000 MW of offshore wind off the North and Central Coast of California. Table 3-9 provides a summary of total offshore wind resources in different resource areas along with their point of interconnection. As shown in Table 3-9, the offshore wind in Del Norte and Cape Mendocino are not mapped to a CAISO substation. A discussion on the transmission options to interconnect these resources are provided in Section 4.2.2.

Table 3-9: Offshore wind resources for the 20-Year Outlook

CAISO Substation	Resource Area	20-Year Outlook
Diablo 500 kV or proposed Morro Bay 500 kV	Morro Bay Offshore Wind	5,400
Humboldt 500 kV (Proposed)	Humboldt Bay Offshore Wind	2,700
Unknown Substation(s)	Del Norte Offshore Wind	7,000
Unknown Substation(s)	Cape Mendocino Offshore Wind	4,900
Total		**20,000**

3.1.9 Out-of-state wind

The 2045 Portfolio identified 12,000 MW of out-of-state wind resources. Table 3-10 provides a summary of out-of-state wind resources in different resource areas along with their point of interconnection. The out-of-state wind has been identified in as either requiring new transmission to bring the resources to the ISO transmission grid (11,220 MW) or being able to use existing transmission (780 MW). TransWest Express, SWIP North, and SunZia are projects that are at different stages of development and in total provide approximately 4,800 MW of transmission capacity to the ISO[15].

Section 4.3 details the number of options that are considered in this study to interconnect 3,500 MW of Wyoming wind and 2,882 MW of New Mexico wind that are not mapped to a substation in Table 3-10.

[15] This represents the ISO's proposed share of SWIP North "North to South" capacity of 1117 MW, the 1500 MW Wyoming-Nevada capacity provided by TransWest Express, and 2131 MW representing the transmission capacity into Palo Verde from the Sunzia project, limited by its entitlements on existing transmission system from Pinal Central to Palo Verde.

Table 3-10: Out-of-state wind resources for the 20-Year Outlook

Study	Substation	Resource Type/ Location	Out-of-CAISO Transmission Utilized	20-Year Outlook
2023-2024 TPP	Mead 230 kV	SW Wind Ext Tx	Existing Tx	300
	Palo Verde 500 kV	SW Wind Ext Tx	Existing Tx	119
	Eldorado 500 kV	SW Wind Ext Tx	Existing Tx	371
	Eldorado 500 kV	Wyoming Wind	New Tx (TransWest Express)	1,500
	Harry Allen 500 kV	Idaho Wind	New Tx (SWIP North)	1,000
	Palo Verde 500 kV	New Mexico Wind	New Tx (SunZia)	2,328
20-Year Outlook mapping additions	Unknown Substation(s)	Wyoming Wind	New Tx (TBD)	3,500
	Unknown Substation(s)	New Mexico Wind	New Tx (TBD)	2,882
			Total	**12,000**

3.1.10 Geothermal

The resource portfolio identified 2,332 MW of geothermal resources in 2045 along with busbar mapping of the resources. Table 3-11 provides a summary of total geothermal resources in different CAISO study areas. Chapter 4 provides the busbar mapping of the resources for different study areas.

Table 3-11: Geothermal resources for the 20-Year Outlook

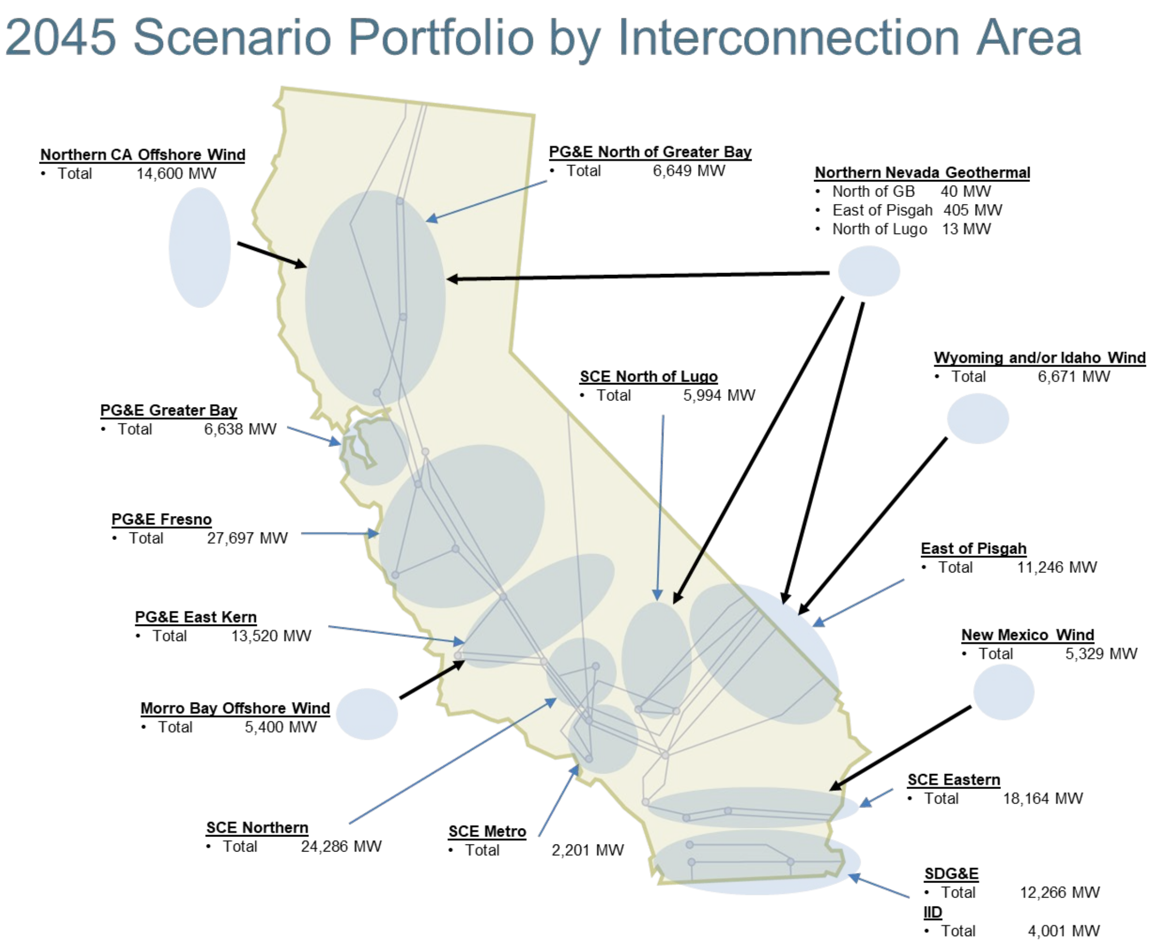
CAISO Study Area	20-Year Outlook
PG&E East Kern Study Area	0
PG&E Fresno Study Area	0
PG&E North of Greater Bay Study Area	179
PG&E S500 Study Area	0
East of Pisgah Study Area	905
SCE Eastern Study Area	850
SCE Metro Study Area	0
SCE North of Lugo (NOL) Study Area	53
SCE Northern Area	0
SDG&E Study Area	345
IID	0
Total	**2,332**

Chapter 4

4 Integration of Resources

To assess the transmission impacts and identify the transmission development concepts necessary to integrate the resources, they need to be mapped more granularly to the substations and busbars in the models. Figure 4-1 provides an illustration of the resources in the transmission zones within the ISO system.

Figure 4-1: High-level illustration of the areas of resource allocation

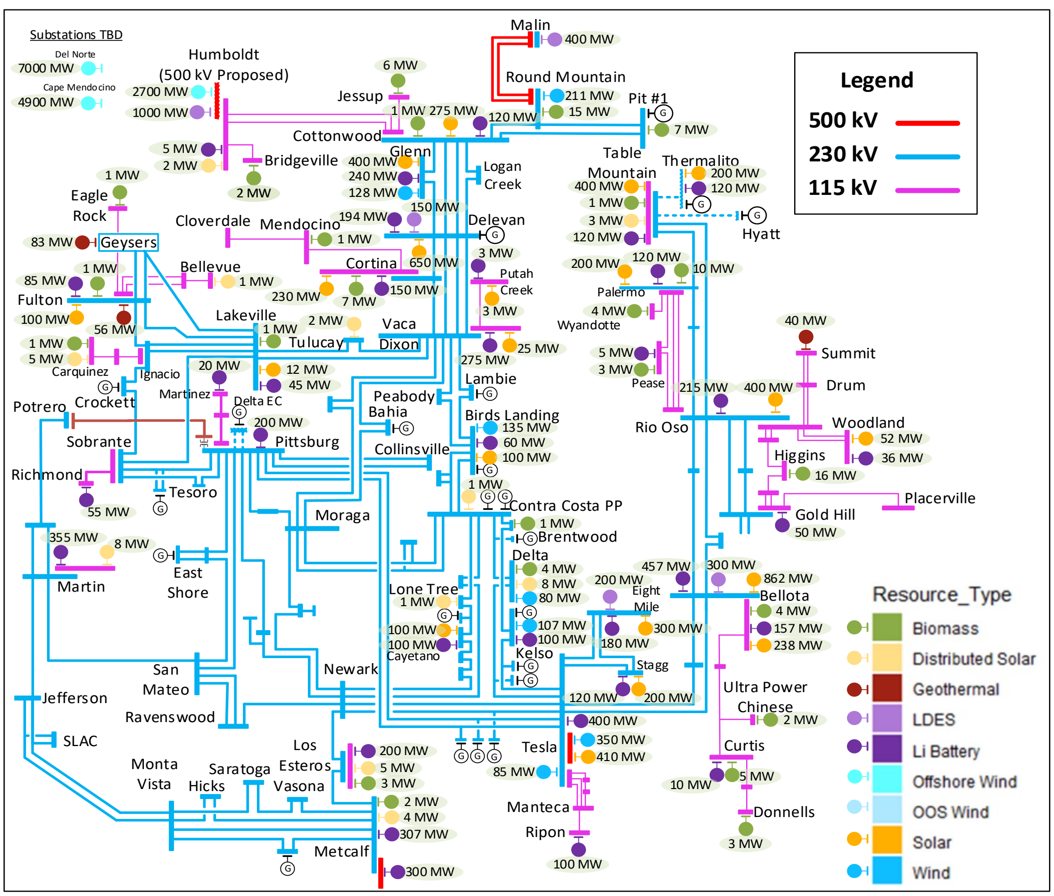


4.1 Mapping of Resources

The 2045 Portfolio identified 165,119 MW of resource capacity additions as indicated in Table 3-2. The resources have been mapped to the substations within each of the transmission zones identified in the resource portfolio. Details of busbar mapping of resources in each transmission zone are provided in tables and diagrams in the following sections:

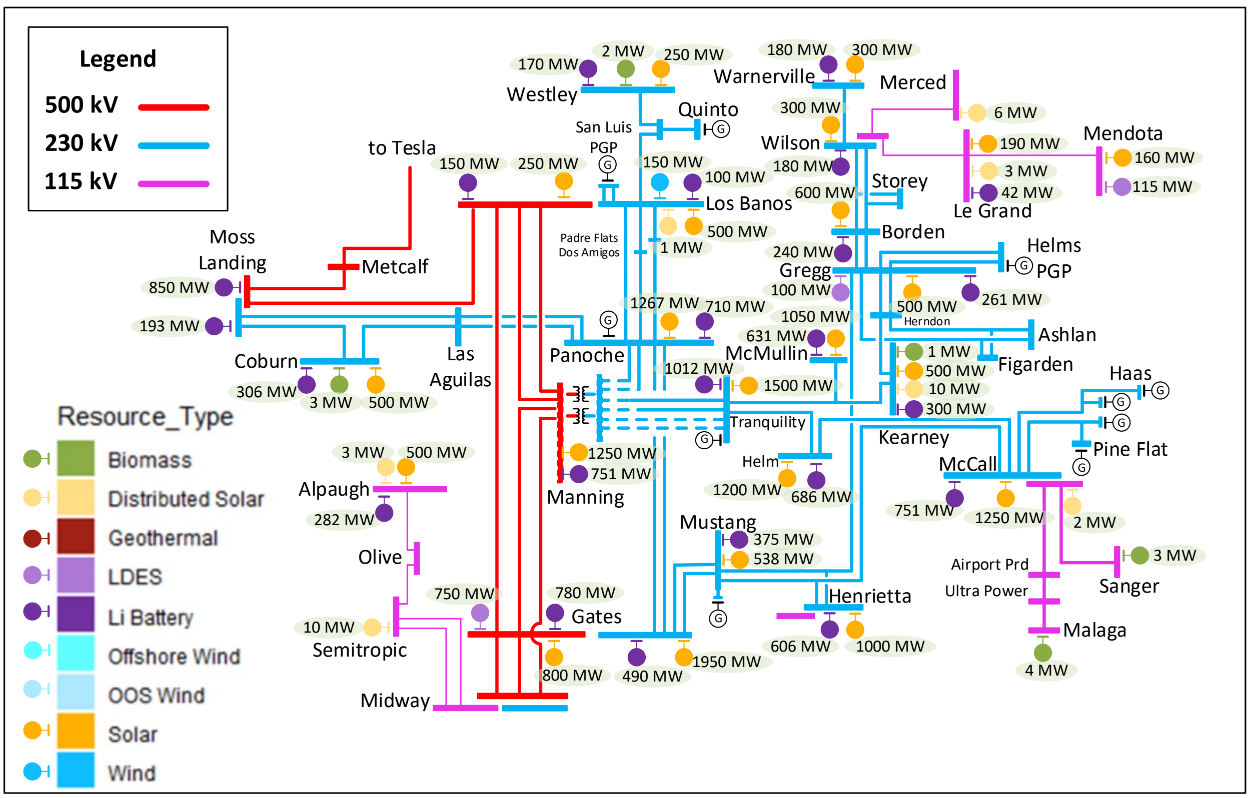
4.1.1 PG&E Greater Bay and North of Greater Bay

PG&E North of Greater Bay Study Area Total	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	4,903	0	4,903
Distributed Solar	40	0	40
Utility-scale Solar	1,649	3,308	4,957
Onshore Wind	912	184	1,095
Geothermal	179	0	179
Biomass/gas	102	0	102
Generic Clean-Firm/LDES	1,650	0	1,650
Offshore Wind	14,439	161	14,600
OOS Wind	0	0	0
LDES	400	0	400
TOTAL	24,274	36,53	27,927



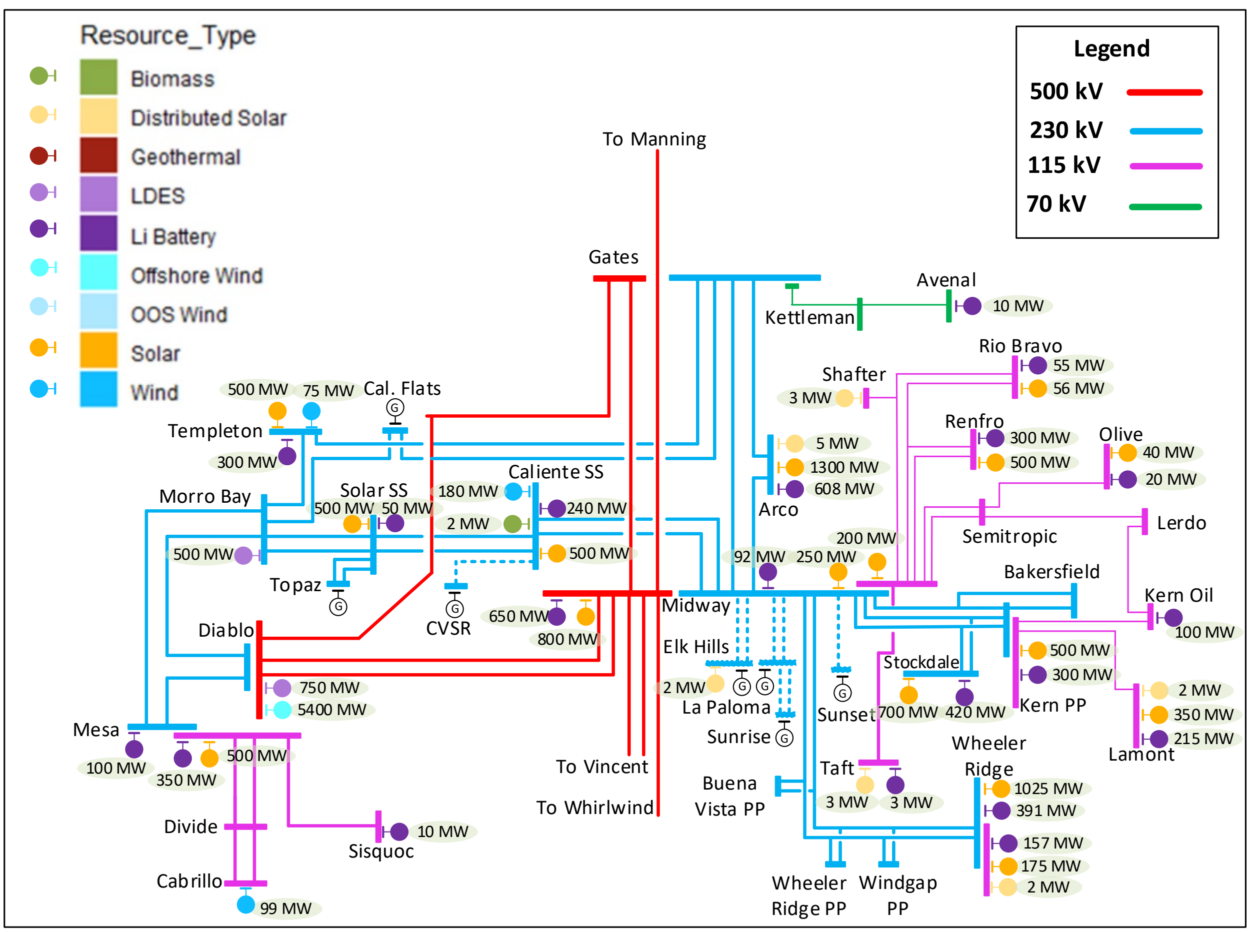
4.1.2 PG&E Fresno Study Area

PG&E Fresno Study Area	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	10,046	0	10,046
Distributed Solar	35	0	35
Utility-scale Solar	6,226	10,129	16,355
Onshore Wind	150	0	150
Geothermal	0	0	0
Biomass/gas	12	0	12
Generic Clean-Firm/LDES	1,000	0	1,000
Offshore Wind	0	0	0
OOS Wind	0	0	0
LDES	100	0	100
TOTAL	**17,568**	**10,129**	**27,697**



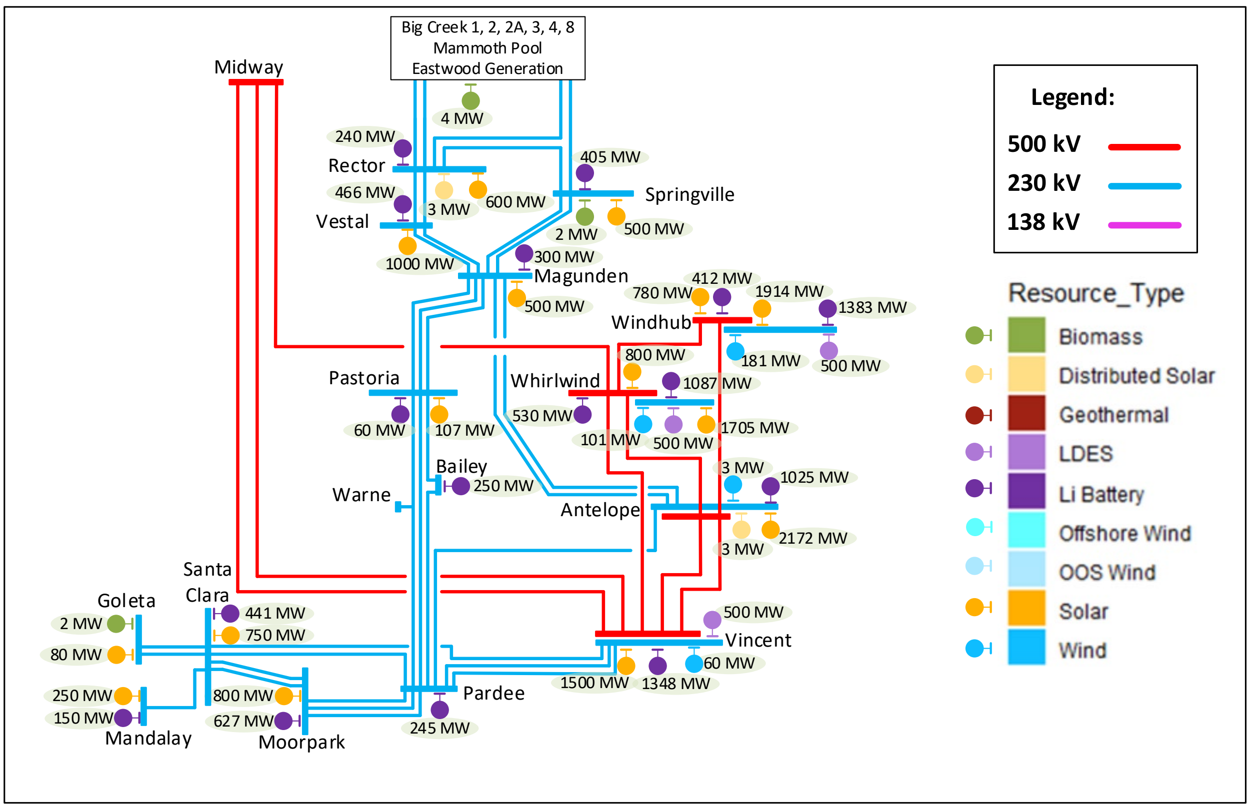
4.1.3 PG&E Kern Study Area

PG&E East Kern Study Area	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	4,370	0	4,370
Distributed Solar	18	0	18
Utility-scale Solar	2,406	5,120	7,526
Onshore Wind	354	0	354
Geothermal	0	0	0
Biomass/gas	2	0	2
Generic Clean-Firm/LDES	750	0	750
Offshore Wind	5,400	0	5,400
OOS Wind	0	0	0
LDES	500	0	500
TOTAL	**13,800**	**5,120**	**18,920**



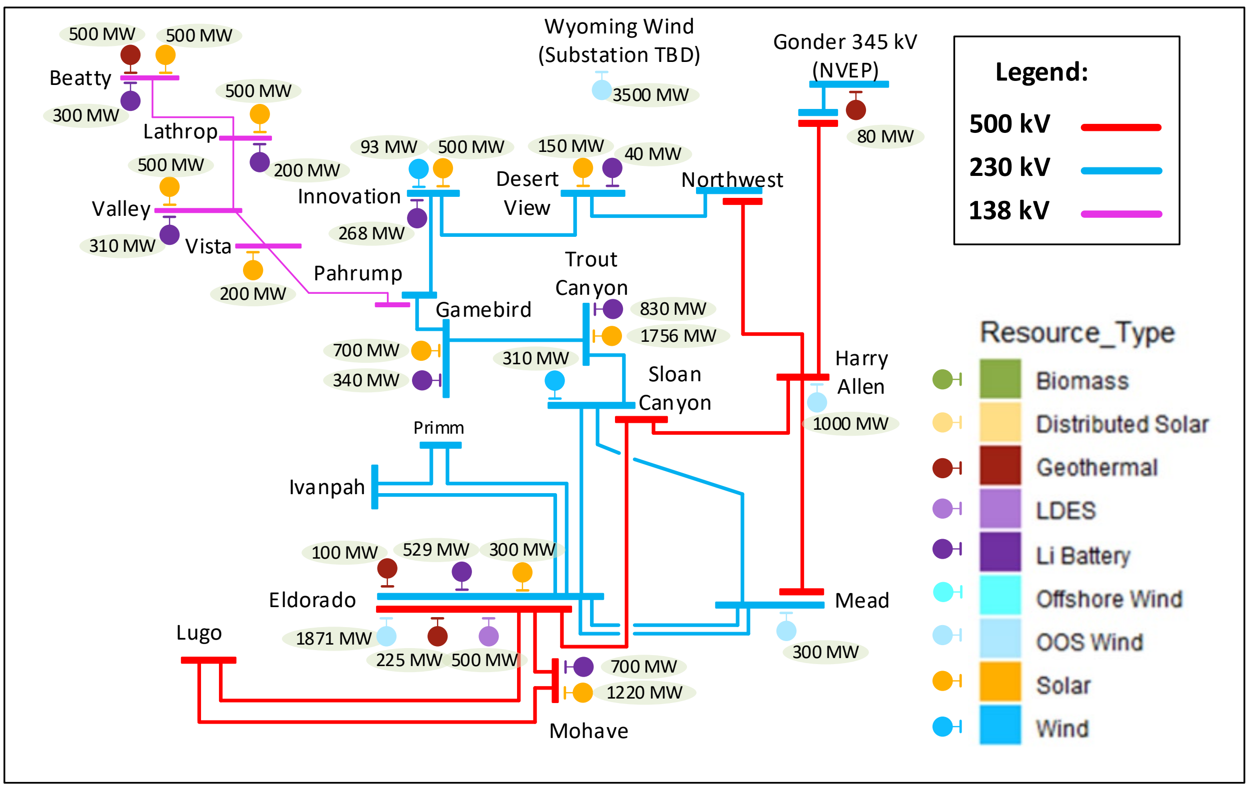
4.1.4 SCE Northern Study Area

SCE Northern Area	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	9048	0	9048
Distributed Solar	6	0	6
Utility-scale Solar	5,142	8,237	13,378
Onshore Wind	345	0	345
Geothermal	0	0	0
Biomass/gas	8	0	8
Generic Clean-Firm/LDES	500	0	500
Offshore Wind	0	0	0
OOS Wind	0	0	0
LDES	1,000	0	1,000
TOTAL	**16049**	**8237**	**24286**



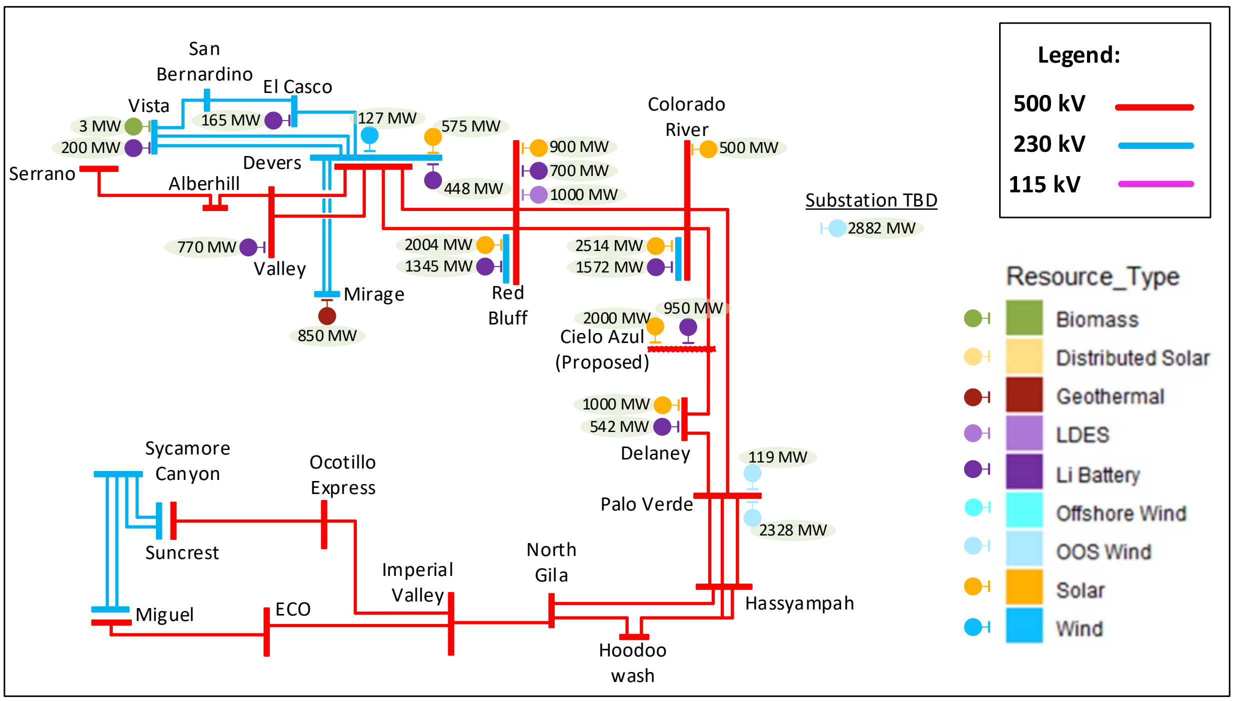
4.1.5 East of Pisgah Study Area

East of Pisgah Total	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	3,517	0	3,517
Distributed Solar	0	0	0
Utility-scale Solar	2,573	3,753	6,326
Onshore Wind	403	0	403
Geothermal	905	0	905
Biomass/gas	0	0	0
Generic Clean-Firm/LDES	500	0	500
Offshore Wind	0	0	0
OOS Wind	6,571	100	6,671
LDES	0	0	0
TOTAL	**14,469**	**3,853**	**18,322**



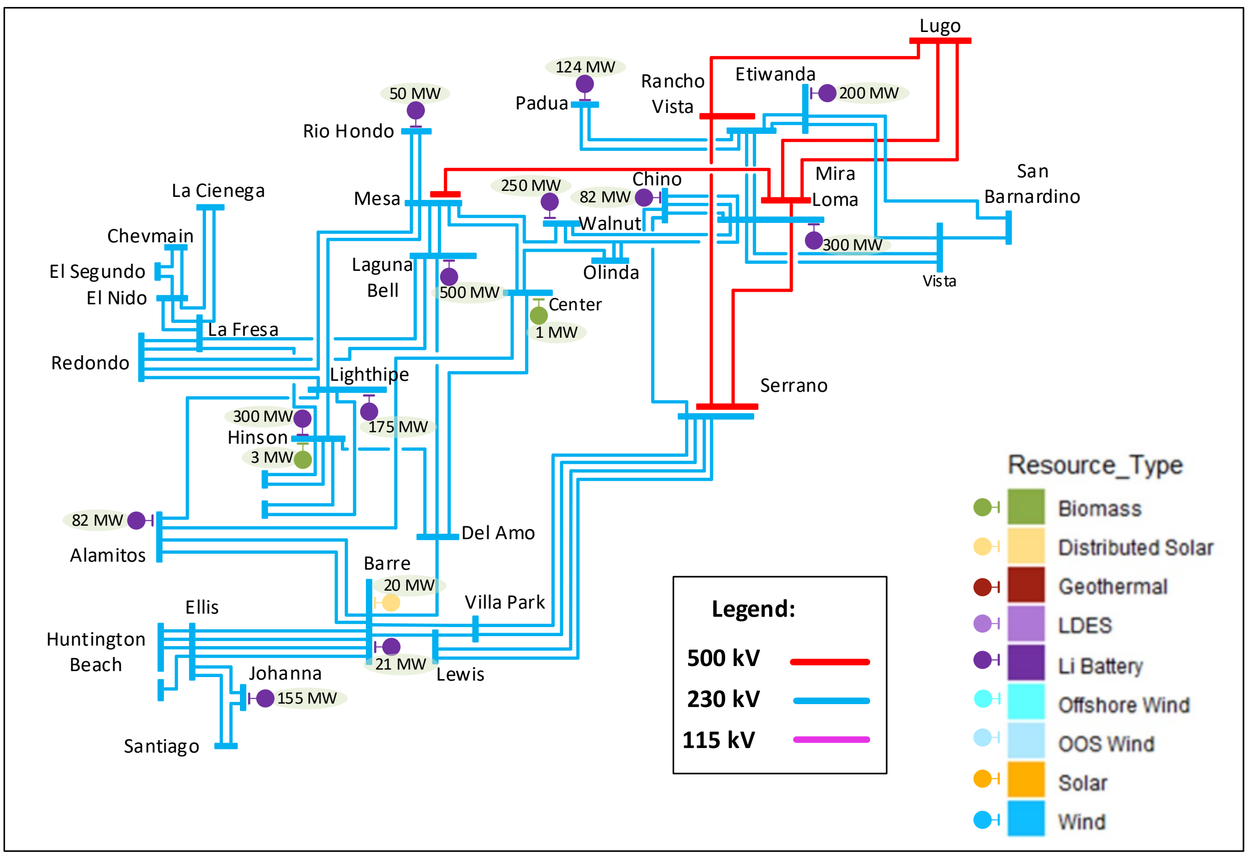
4.1.6 SCE Eastern Study Area

SCE Eastern Total	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	6,692	0	6,692
Distributed Solar	0	0	0
Utility-scale Solar	2,929	6,564	9,493
Onshore Wind	107	20	127
Geothermal	850	0	850
Biomass/gas	3	0	3
Generic Clean-Firm/LDES	0	0	0
Offshore Wind	0	0	0
OOS Wind	5,329	0	5,329
LDES	1,000	0	1,000
TOTAL	**16,910**	**6,584**	**23,493**



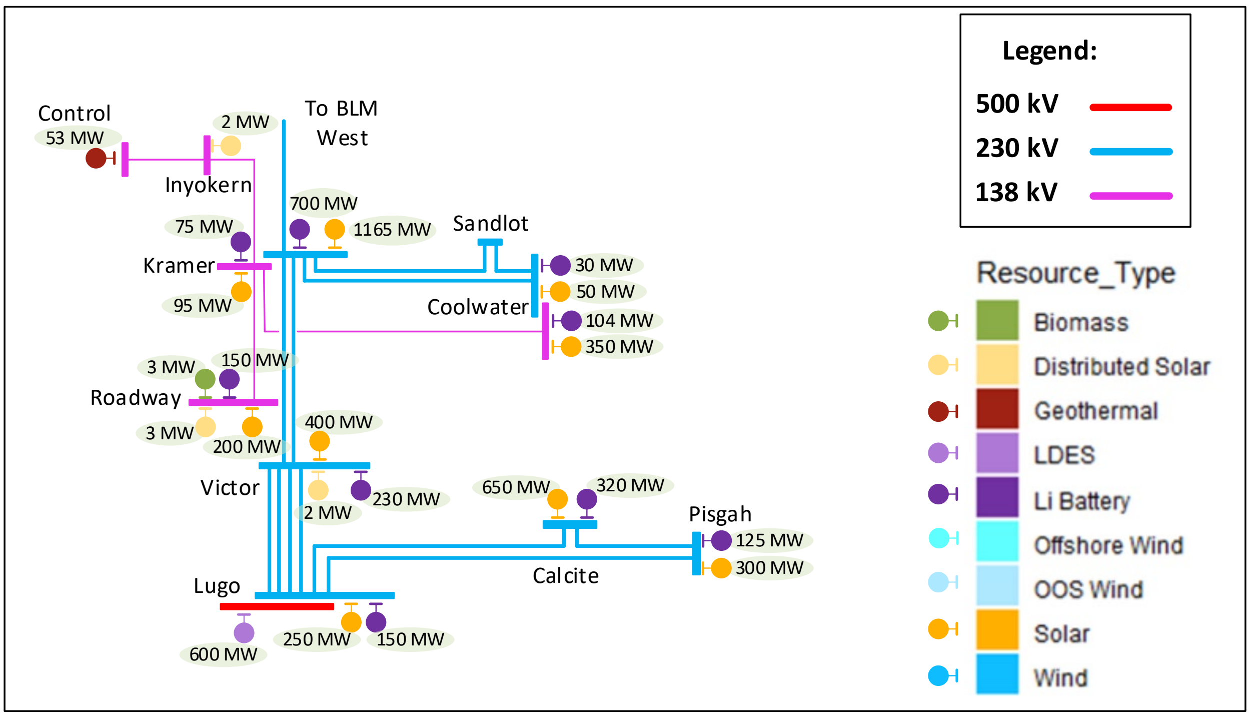
4.1.7 SCE Metro Study Area

SCE Metro Study Area	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	2,177	0	2,177
Distributed Solar	20	0	20
Utility-scale Solar	0	0	0
Onshore Wind	0	0	0
Geothermal	0	0	0
Biomass/gas	4	0	4
Generic Clean-Firm/LDES	0	0	0
Offshore Wind	0	0	0
OOS Wind	0	0	0
LDES	0	0	0
TOTAL	**2,201**	**0**	**2,201**



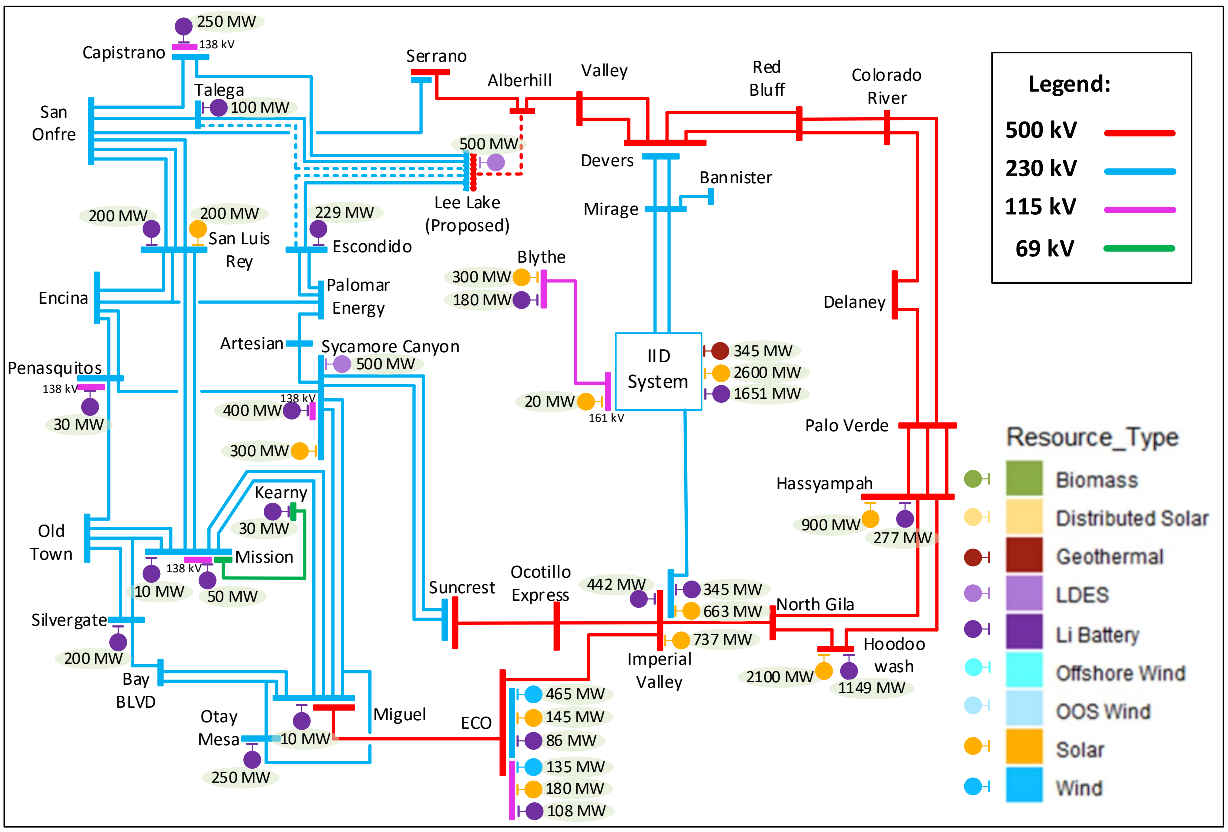
4.1.8 SCE North of Lugo Study Area

SCE North of Lugo Total	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	1,884	0	1884
Distributed Solar	7	0	7
Utility-scale Solar	1,550	1,910	3,460
Onshore Wind	0	0	0
Geothermal	53	0	53
Biomass/gas	3	0	3
Generic Clean-Firm/LDES	600	0	600
Offshore Wind	0	0	0
OOS Wind	0	0	0
LDES	0	0	0
TOTAL	**4,097**	**1,910**	**6,007**



4.1.9 SDG&E Study Area

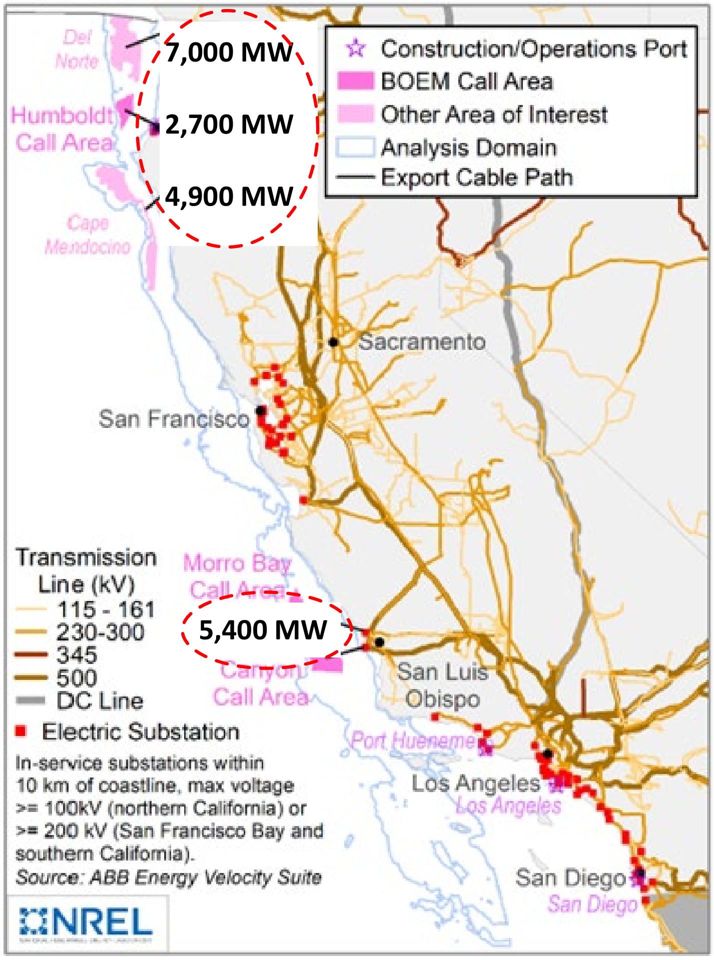
SDG&E + IID Total	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	6177	0	6177
Distributed Solar	0	0	0
Utility-scale Solar	2378	5767	8145
Onshore Wind	240	360	600
Geothermal	345	0	345
Biomass/gas	0	0	0
Generic Clean-Firm/LDES	0	0	0
Offshore Wind	0	0	0
OOS Wind	0	0	0
LDES	1000	0	1000
TOTAL	**10140**	**6127**	**16267**



4.2 Offshore Wind Interconnection

As discussed in Section 3.1.8, the 2045 Portfolio includes a total of 20,000 MW of offshore wind. Figure 4-2 shows the approximate location of the assumed offshore wind development in this study.

Figure 4-2: Offshore Wind Development Location Assumptions[16]



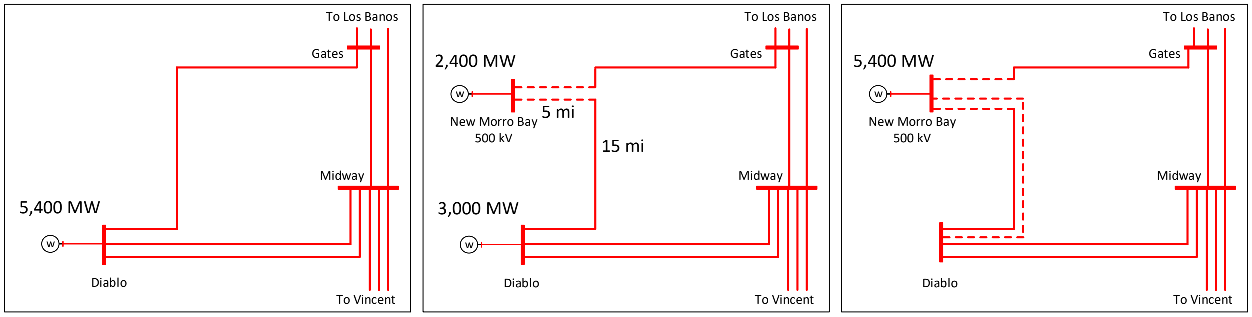
Base map source: The Cost of Floating Offshore Wind Energy in California Between 2019 and 2032 (nrel.gov)

4.2.1 Interconnection of Central Coast Offshore Wind

The analysis performed as part of the 2021-2022 transmission planning process (TPP) cycle indicated that the existing 500 kV transmission system in Diablo/Morro Bay area has the capacity for interconnection of more than 5,300 MW of generation with Full Capacity Deliverability Status (FCDS). With the retirement of the Diablo Canyon Power Plant, the 5,400 MW offshore wind in the central coast could be connected at either Diablo or new Morro Bay 500 kV substation. Additional reinforcements such as a new line from Diablo to Morro Bay would be required if more than around 2,400 MW is connected to the Morro Bay substation (Figure 4-3).

[16] The Cost of Floating Offshore Wind Energy in California Between 2019 and 2032 (nrel.gov) (Page 39)

Figure 4-3: Central Coast Offshore Wind Interconnection Options



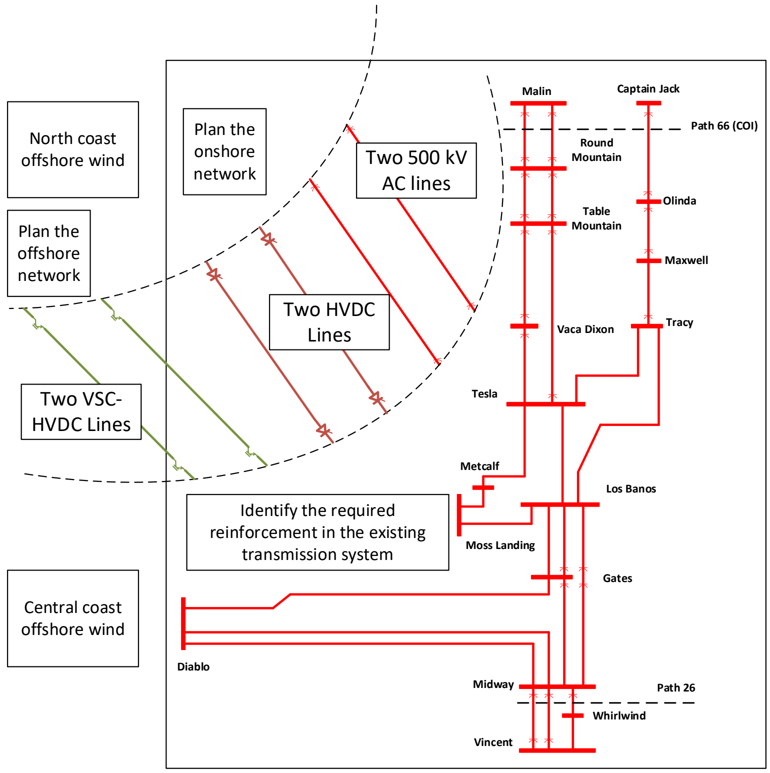
4.2.2 Interconnection of North Coast Offshore Wind

The transmission concept recommended in the 2021-2022 Transmission Plan to interconnect the North Coast offshore wind to the rest of the CAISO system is illustrated in Figure 4-4. The same transmission concepts were used as the transfer path in this 20-Year Outlook Update study. The line ratings and the interconnection points are provided in Table 4-1. The details of the overall transmission interconnection options are provided in the following sections.

Table 4-1: Rating Assumptions for Bulk Transmission Technology Options

Technology and Interconnection point	Normal Rating Assumptions (MVA)	Emergency Rating Assumptions (MVA)
500 kV AC line to Fern Road	3,500	4,500
Onshore overhead VSC-HVDC to Collinsville Substation	3,000	3,500
Offshore sea cable VSC-HVDC to a Substation in the Bay Area	2,000	2,500

Figure 4-4: North Coast Offshore Wind Interconnection Assumption



4.2.2.1 Two 500 kV AC Interconnections to Fern Road

The sensitivity analysis in the 2023-2024 transmission planning process (TPP) cycle includes 8,045 MW of offshore wind in the North Coast. The results of that study indicated that with injection of offshore wind at Fern Road, the existing transmission path between Fern Road and Tesla 500 kV substations experience overload under normal and contingency conditions. A potential mitigation for the overloads is to build two 500 kV AC lines from Fern Road to Vaca Dixon to Tesla substations.

- Alternative 1: Build two 500 kV AC lines from Fern Road to Vaca Dixon to Tesla 500 kV substation. This alternative requires a total of around 650 miles of single circuit 500 kV lines to be built but is more flexible than other alternatives as a) it could be implemented with minimal to no impact to the existing 500 kV lines from Fern Road to Tesla, and b) it makes the Fern Road a hub for interconnection of potential future major transmission projects, especially if the 500 kV lines north of Fern Road to Northwest system are also upgraded.
- Alternative 2: Build one 500 kV AC line from Fern Road to Vaca Dixon to Tesla 500 kV substation and upgrade the two existing 500 kV lines from Fern Road to Tesla 500 kV substation. This alternative requires around 450 miles of new lines and upgrade of another 400 miles of existing 500 kV lines. This alternative could potentially make better use of the existing rights of way, but significant coordination and alignment in timing is needed to ensure the required outages of the existing 500 kV lines from Fern Road to Tesla will not be scheduled when the interchange between the CAISO and the Northwest is high.

Interconnection to Tesla 500 kV:

PG&E's Transmission Interconnection Handbook[17] indicates that the Tesla 500 kV substation cannot accept new points of interconnection (POIs). Therefore it is assumed that a new substation will be built next to the existing Tesla 500 kV substation to facilitate the connection of the proposed new Fern Road – Tesla 500 kV lines as well as the interconnection of the out-of-state wind from Wyoming.

4.2.2.2 Two Overhead VSC-HVDC to Collinsville

The sensitivity analysis results in the 2023-2024 TPP cycles that included an interconnection option with two HVDC lines to Collinsville, indicated N-0 overload on the Collinsville to Pittsburg 230 kV lines. Series reactors on the Collinsville – Pittsburg lines are recommended for approval as the mitigation measure. The series reactors are assumed in the starting base case in this analysis.

4.2.2.3 Two subsea VSC-HVDC to Bay Area

The two subsea VSC-HVDC links to Bay Area were studied in two different alternative interconnections.

- Alternative 1: Both VSC-HVDC lines terminate at the BayHub converter station in the Bay area with converter station connecting to major substations (Potrero, East Shore, Los Esteros, Monta Vista, San Mateo, and Newark 230 kV substations) in the Bay Area with six 230 kV cables
- Alternative 2: One VSC-HVDC line terminates at the BayHub converter station in Bay Area with three 230 kV cables connecting the BayHub station to Potrero, East Shore and Los Esteros 230 kV substations. The second VSC-HVDC line will terminate at Moss Landing 500 kV substation.

4.2.2.4 Interconnection of Del Norte, Humboldt, and Cape Mendocino Wind

The CPUC Modelling Assumptions for the 2023-2024 TPP provided the following guidance regarding offshore wind development in the North Coast:

"... offshore wind have been mapped to ... three separate locations on the North Coast (Humboldt, Del Norte, and Cape Mendocino) to allow CAISO to identify transmission upgrades and cost information necessary to further advance offshore wind planning in line with the state's offshore wind policy goals."

Based on a recent CEC report[18], the environmental analysis performed by the Schatz Center identifies significant environmental challenges to build overhead lines along the coast from Del Norte to Humboldt to Cape Mendocino. Therefore, any transmission option interconnecting Del Norte and Cape Mendocino Point of Interconnections to Humboldt is assumed to be VSC-HVDC with either underground or subsea HVDC cable.

[17] https://www.pge.com/assets/pge/docs/about/doing-business-with-pge/g2.pdf (Table G2)

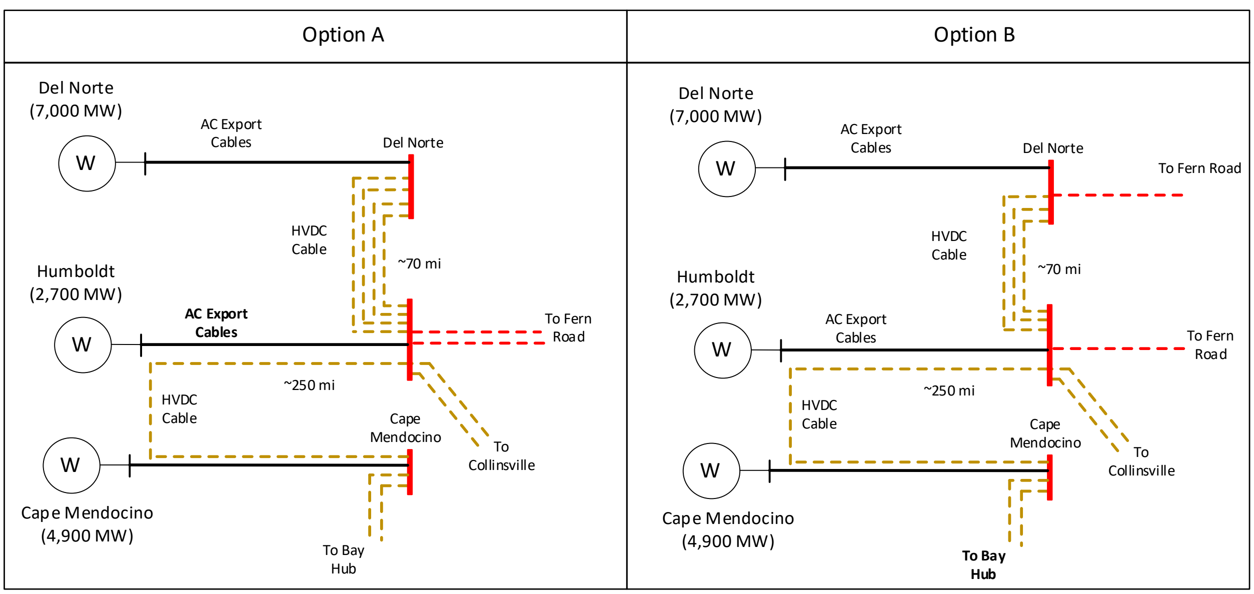
[18] Schatz Center - Northern California and Southern Oregon Offshore Wind Transmission study https://efiling.energy.ca.gov/GetDocument.aspx?tn=252604

Two options have been considered to interconnect the offshore wind in the North Coast to the rest of the system. As shown in Figure 4-5, in both alternatives, it is assumed AC export cables bring power from offshore wind plants to the onshore point of interconnections at the Humboldt, Del Norte, and Cape Mendocino substations.

In both options, the Humboldt and Cape Mendocino substations are connected through a subsea VSC-HVDC link. The reason for the length of the line (~250 mi) is the subsea canyons in the area which makes a near shore connection between Humboldt and Cape Mendocino very challenging due to seabed conditions. Therefore such an HVDC cable would need to be routed away from shore and in deeper waters. While routing the cables away from the shore may avoid the subsea canyons, the water depth may reach 4,000 m while current feasibility has been identified as only up to 1500 m. Further assessment will be required to determine whether all technical issues that may limit the feasibility of the subsea cable from North Coast to Bay Area can be addressed. If technical issues of subsea cables from North Coast to Bay Area cannot be resolved, additional onshore HVDC line(s) may be required. To have similar performance, it will be critical that the onshore HVDC line(s) could create a similar concept as Bay Hub but from different routing (i.e. from the North Bay Area west of Collinsville).

Del Norte substation is the POI for 7,000 MW of offshore wind. In Option A, four subsea HVDC cables interconnect Del Norte to Humboldt substation and two 500 kV AC lines interconnect Humboldt to Fern Road substation. In Option B, three subsea HVDC cables interconnect Del Norte to Humboldt substation and one 500 kV AC interconnects Del Norte substation to Fern Road substation. Transmission options A and option B are shown in Figure 4-5.

Figure 4-5: Transmission Options for Integration of North Coast Offshore Wind



While both options provide the required capacity to transfer the power to the shore and to the existing system, the optimum option will be determined based on the development sequence of the North Coast offshore wind and the availability of right of way for 500 kV AC lines from Humboldt and Del Norte to Fern Road substation.

Interconnection to Humboldt 115 kV System

The Humboldt area is currently supplied by local gas generation and through two 115 kV lines from Cottonwood substation around 120 miles away. To enhance the resiliency of the Humboldt 115 kV system and allow for the retirement of gas generation in the long term, in all alternatives the ISO is proposing to provide another supply to the area from the Humboldt 500 kV substation. The interconnection includes a 500/115 kV transformer at Humboldt 500 kV substation, a 115 kV line from Humboldt 500 kV to existing Humboldt 115 kV substation, and a 115kV/115 kV phase shifting transformer (PST) at Humboldt 115 kV substation. The PST will help to control the flow and prevent overload as the amount of offshore wind generation varies in real time operation. The schematic diagram of the interconnection is provided in Figure 4-6.

Figure 4-6: Interconnecting Humboldt 500 kV substation to Humboldt 115 kV substation

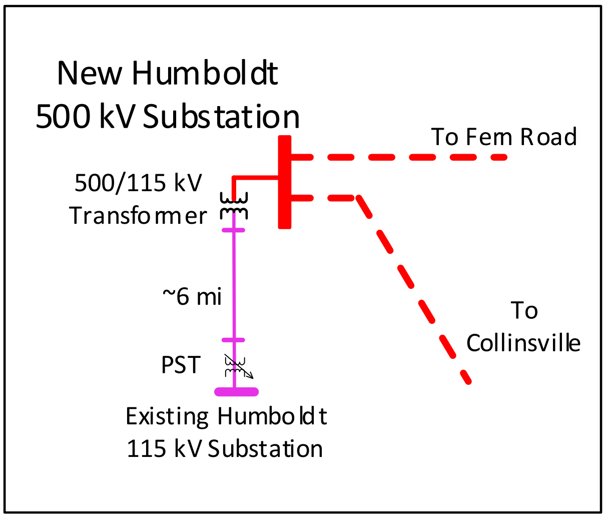


Figure 4-7 - Figure 4-10 provide four transmission concepts to integrate 14,600 MW of offshore wind in the North Coast to the rest of the CAISO system. The variations are based on whether the subsea VSC-HVDC link from Cape Mendocino terminates at Moss Landing or at Bay Hub with more 230 kV cable connections to Bay Area substations, or whether the termination of the second 500 kV AC line from Fern Road is Humboldt Bay 500 kV bus or Del Norte 500 kV bus.

Figure 4-7: Transmission Concept 20YTO-A to Integrate North Coast Offshore Wind

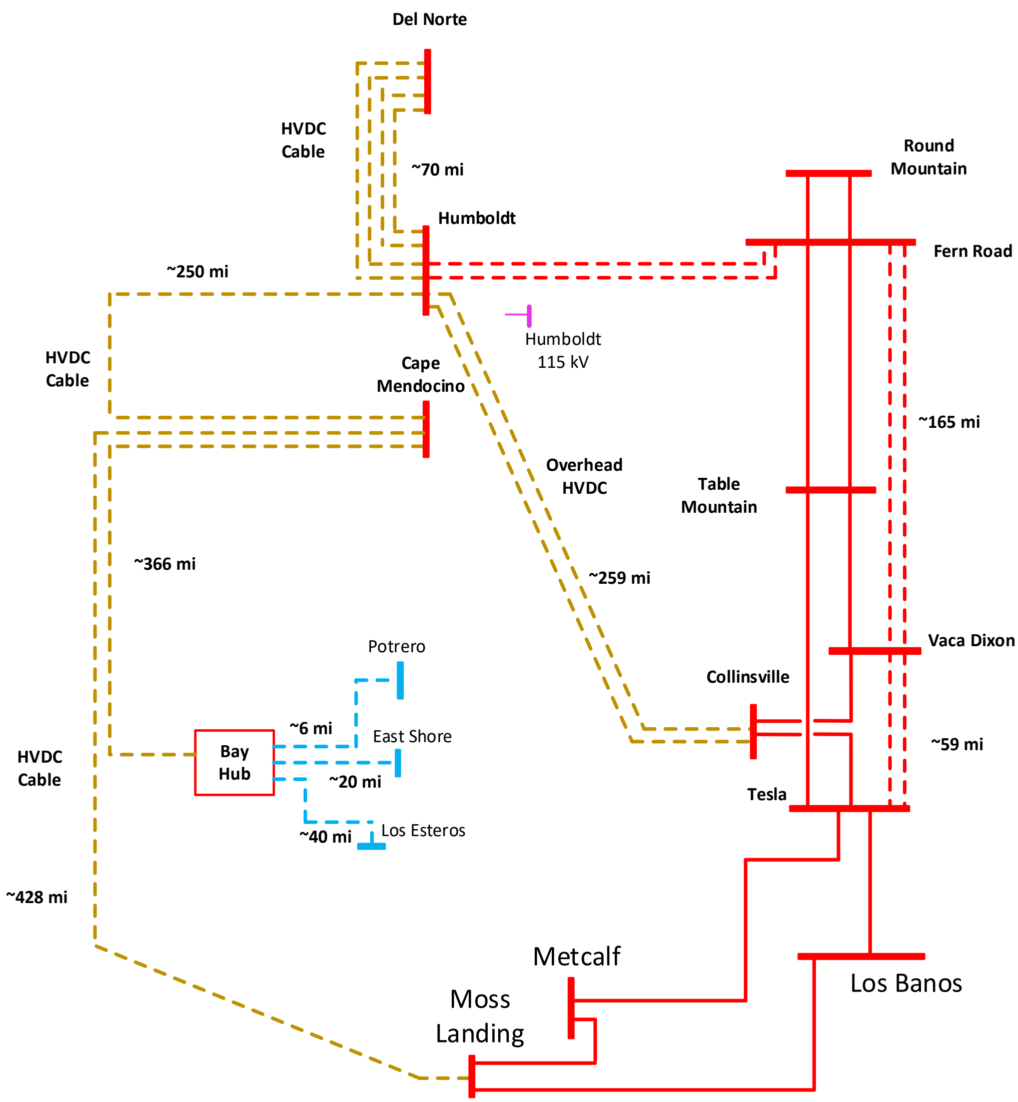


Figure 4-8: Transmission Concept 20YTO-B to Integrate North Coast Offshore Wind

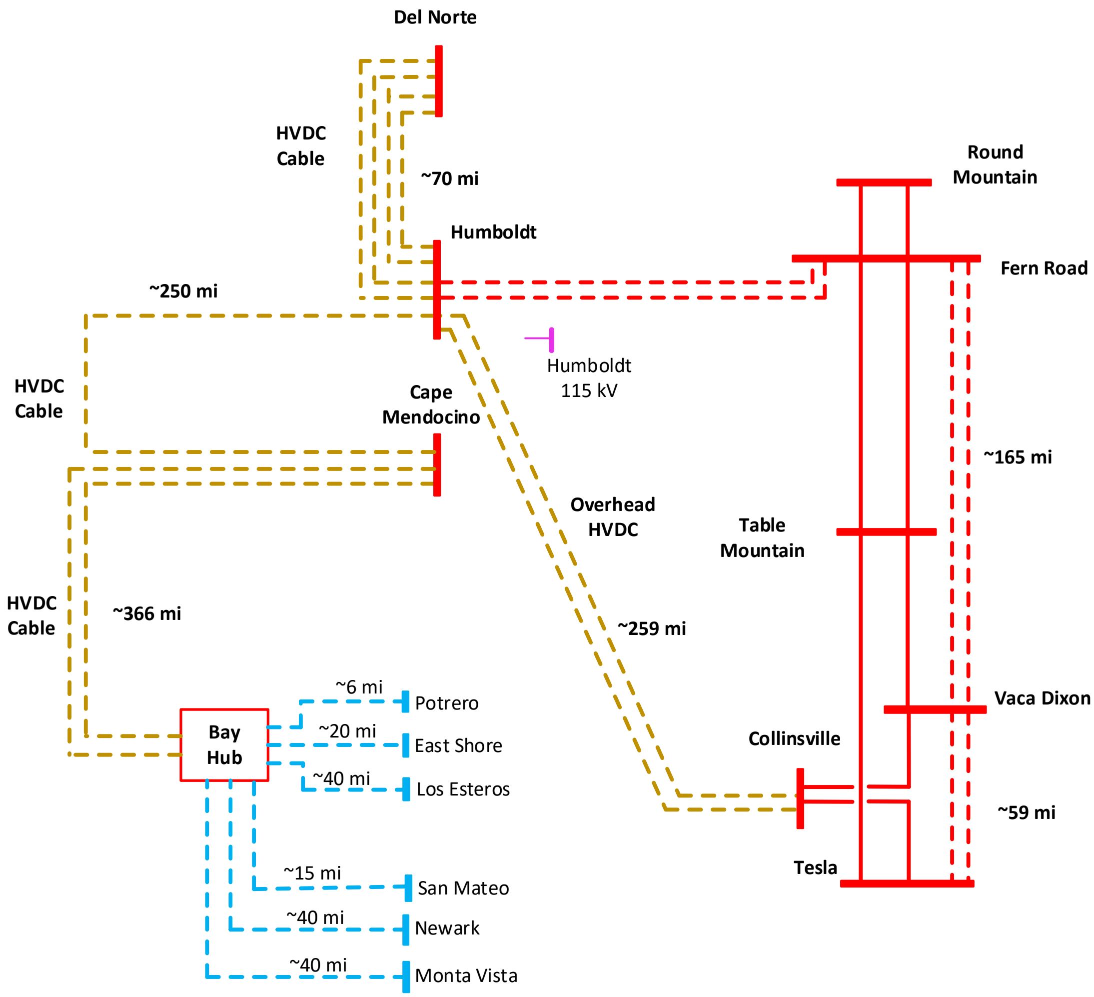


Figure 4-9: Transmission Concept 20YTO-C to Integrate North Coast Offshore Wind

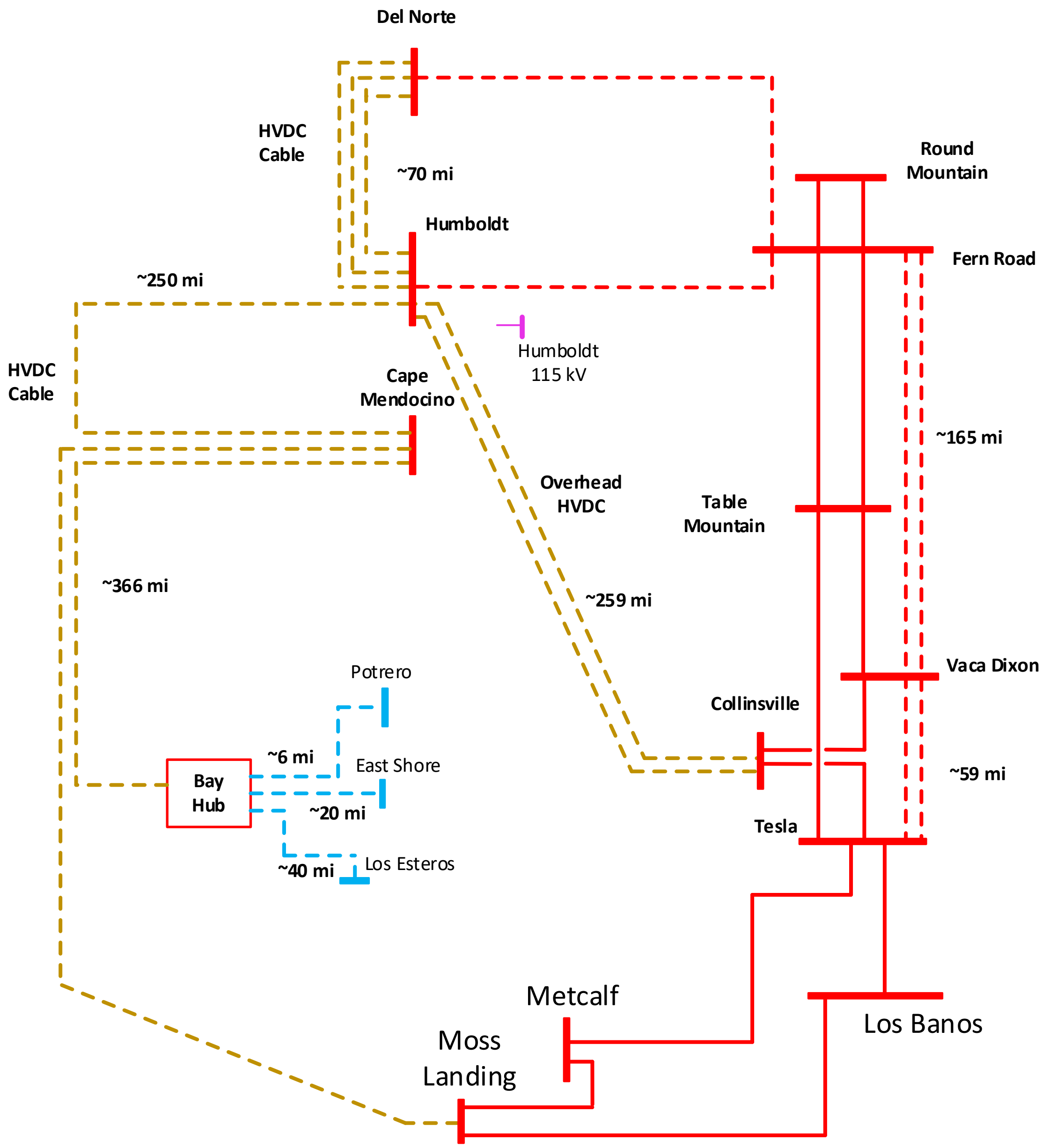
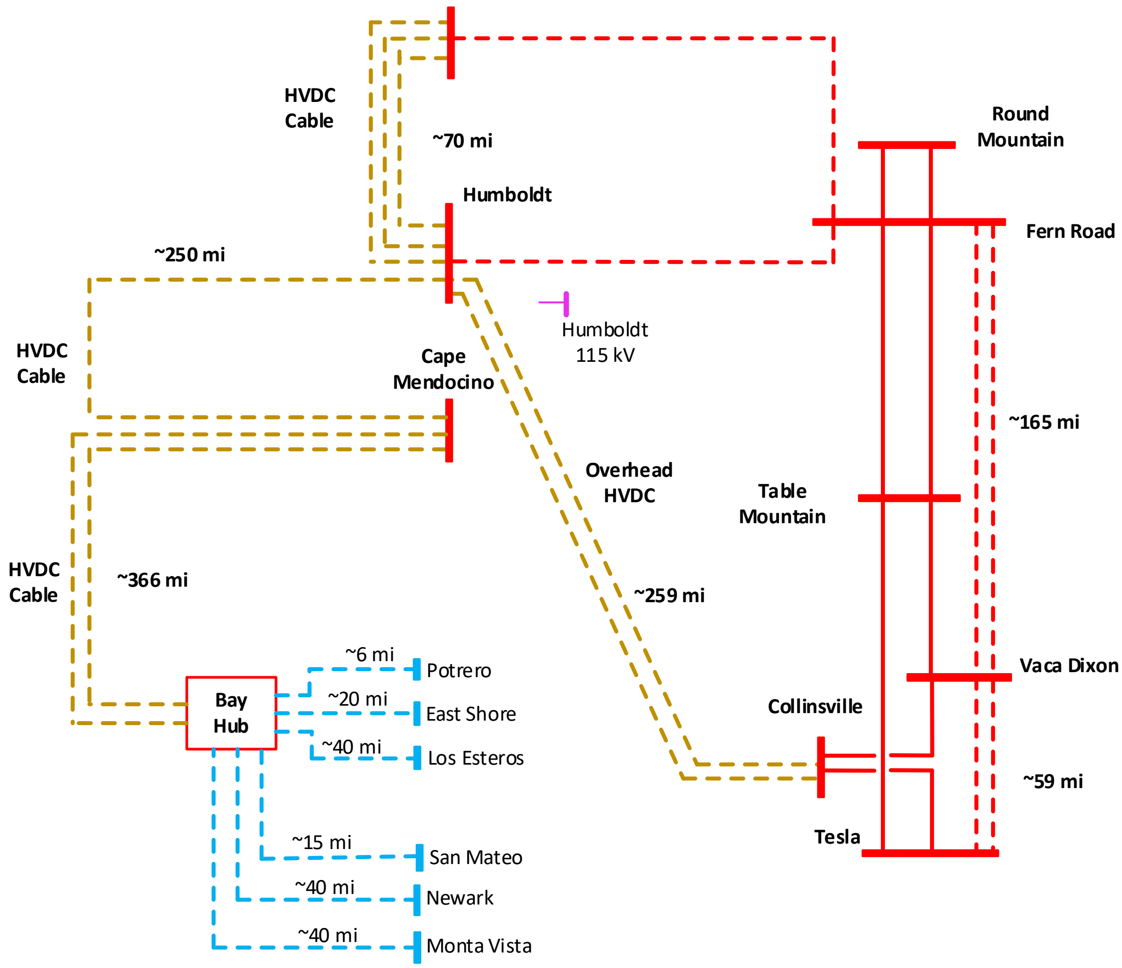


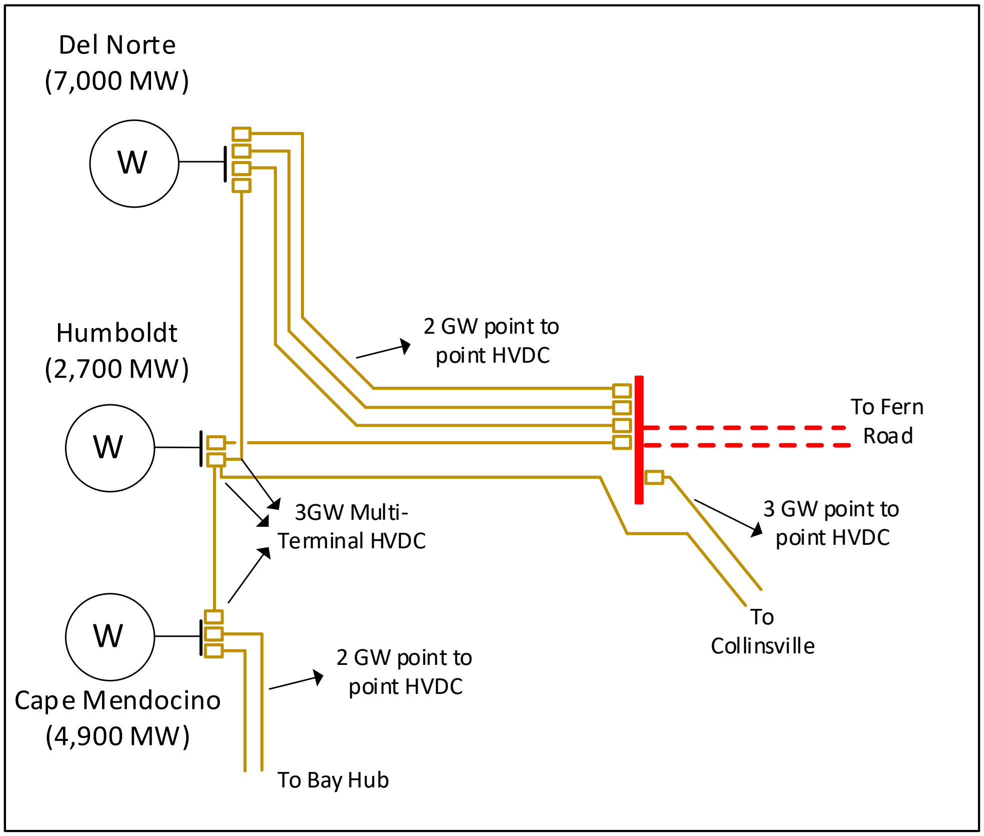
Figure 4-10: Transmission Concept 20YTO-D to Integrate North Coast Offshore Wind



4.2.2.5 Floating Offshore HVDC Converter Station and Grid

The offshore wind integration alternatives in this study so far have been based on the assumption that the export cables interconnecting the offshore wind plants to the onshore POI are AC cables. Floating offshore HVDC converter stations and HVDC dynamic cables are technologies under development that allow for fewer high capacity HVDC cables to transfer power from floating offshore HVDC converter stations to the shore. A potential concept assuming the availability of the floating offshore HVDC converter station and dynamic HVDC cables is provided in Figure 4-11.

Figure 4-11: Transmission Concept Based on Floating Offshore HVDC Converter Station



A potential advantage of such configuration is to have fewer cables coming to the shore and also increase the overall reliability of supply under contingency conditions. The idea has been explored in other systems such as New York[19] and Denmark[20].

As well, floating offshore HVDC converter stations could provide options for creating an offshore grid that could be expanded to connect to Pacific Northwest offshore wind development and further strengthen transfer capabilities between the regions.

Given that such technology does not exist at this time and as a result, feasibility, cost and ratings of such schemes are not available, no further analysis was performed on this transmission concept in this study.

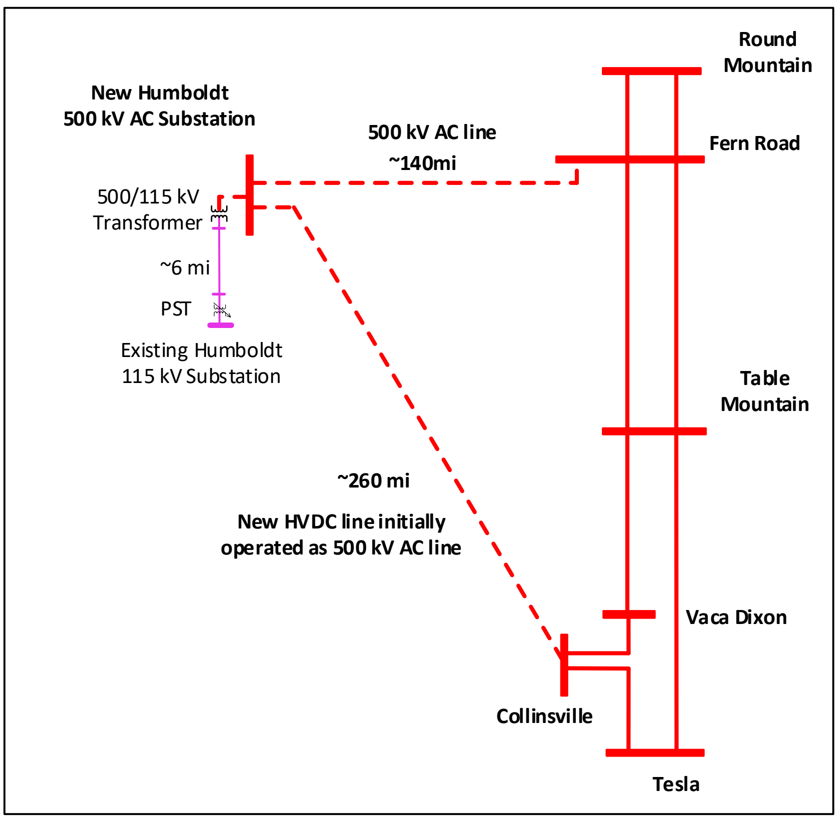
[19] The Benefit and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York (brattle.com)

[20] A132994-2-4 Elektriske systemer for Bornholm I + II, Nordsøen II + III og Området vest for Nordsøen II + III (ens.dk) (in Danish)

4.2.3 Recommended Transmission Project for Humboldt Offshore Wind in 2023-2024 Transmission Plan

The CPUC base and sensitivity resource portfolios submitted to CAISO as part of the 2023-2024 TPP included 1,607 MW offshore wind in the North Coast in the base portfolio and 8,045 MW of offshore wind in the North Coast in the sensitivity portfolio. Chapter 3 and Appendix F of the Draft 2023-2024 Transmission Plan provide details of the analyses performed on different transmission alternatives to integrate the above offshore wind in the North Coast in the base and sensitivity portfolios and how such alternatives fit into the development of the ultimate plan in the 20-Year Outlook. Figure 4-12 provides the schematic diagram of the transmission project recommended for approval for integration of 1,607 MW of Humboldt offshore wind. The project scope includes a 500 kV AC line from the new Humboldt 500 kV station to Fern Road substation and an HVDC line, initially energized at 500 kV AC, from the new Humboldt 500 kV substation to Collinsville substation. The cost estimate for the project including mitigation measures is $3.1B – $4.5B. The project is recommended for approval as part of the Draft 2023-2024 Transmission Plan

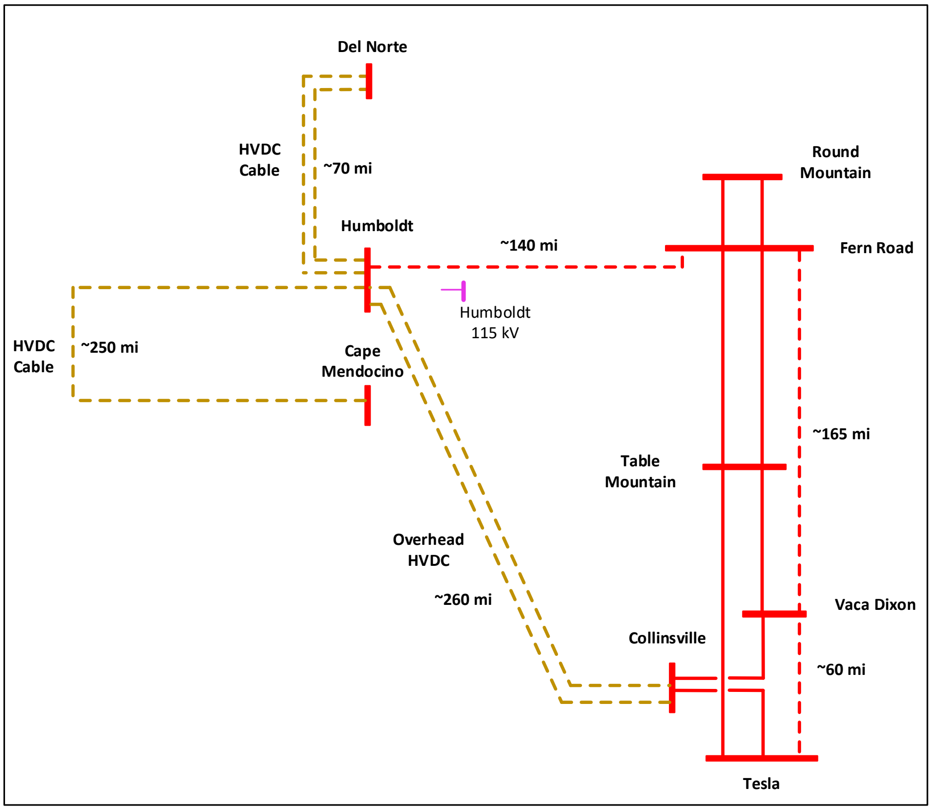
Figure 4-12: Recommended Transmission Project for Humboldt Offshore Wind



Four different alternatives were studied for the integration of 8,045 MW of offshore wind in the North Coast. One of the alternatives is shown in Figure 4-13 that includes two HVDC lines to Collinsville and a 500 kV AC line to Fern Road substation. The cost estimates for different alternatives in the sensitivity analysis are in the $13.2B – $21.1B range.

The recommended transmission project for approval to integrate 1,607 MW of offshore wind has the flexibility to be expanded into any of the alternatives considered for the sensitivity scenario with 8,045 MW offshore wind in the North Coast and into any of the alternatives considered for the 20-Year Outlook update with 14,600 MW of North Coast offshore wind including an offshore HVDC grid.

Figure 4-13: One of the Transmission Alternatives for 8,045 MW North Coast OSW



4.3 Out-of-State Wind Interconnection

The resource portfolio for 2045 includes 3,500 MW of Wyoming wind and 2,882 MW of New Mexico wind that will be transferred to CAISO on new transmission. These resources are not mapped to a substation in the CAISO system. The new transmission projects could either bring the out-of-state wind to the border of the ISO system, requiring additional transmission within the ISO system to bring the energy to the load centers, or could be brought to interconnection points within the ISO, such as Tesla and Lugo substations. Transmission lines to connect to interconnection points within the ISO system could potentially facilitate coordination with the Los Angeles Department of Water and Power (LADWP) and the Balancing Authority of Northern California (BANC) to bring in additional out-of-state wind that they may require for their resource portfolios. Both alternatives are evaluated in this study at a high level.

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Chapter 5

5 High-Level Assessment

5.1 Introduction

The objective of the high-level assessment is to gain insight into the transmission enhancements required to reliably transfer power from the portfolio resources to the load across the system under different load and generation conditions. Typically, production cost simulation analysis is performed to identify the system snapshots that will stress the transmission system, with power flow and transient stability analysis then performed on those stressed snapshots. However since production cost simulation was not performed as part of the high level assessment, the following snapshots were considered as candidates to identify system enhancement requirements:

Net-Peak Load Study

The Net-Peak Load study is based on the High System Need (HSN) in deliverability studies and reflects the system in early evening summer conditions. In this case, the electricity consumption is around 90 percent of the maximum but due to evening hours there is no solar or behind-the-meter photovoltaic (BTM-PV) generation. A number of HSN snapshots with varying level of wind, import, battery storage, and gas generation were developed to assess system performance under different supply scenarios.

Peak Consumption Study

The Peak consumption study is based on the Secondary System Need (SSN) in deliverability studies and reflects the system in early afternoon summer conditions. In this case, electricity consumption is at a maximum but a significant portion of it is served by the solar and the BTM-PV generation. The in-state, out-of-state, and offshore wind generation assumptions are in line with the SSN deliverability analysis and the import level is assumed to be close to zero. The battery storage is assumed to be fully charged in this case in preparation to be generating power during the evening ramp and evening hours.

Off-Peak Study

The Off-Peak study reflects the system in the middle of the day in spring when electricity consumption is low and at the same time the solar and BTM-PV generation are high. The in-state, out-of-state, and offshore wind generation assumptions are in line with the off- peak deliverability analysis and it is assumed the ISO system will export around 5,000 MW of power to the neighboring system. The battery storage is assumed to be in full charging mode in this case.

A number of base cases reflecting the above snapshots were developed for the contingency analysis to identify the potential transmission enhancement requirements. The system data and analysis of the study results are detailed in the following sections.

5.2 System Data and Study Assumptions

5.2.1 Load Forecast Assumptions

The following table provides the load and the BTM-PV generation for the three study cases. More details are provided in Section 3.1.1.

Table 5-1: Load and BTM-PV assumptions

Study Cases	Date/Time assumption	Load (MW)	BTM-PV Generation (MW)
Net peak load (HSN)	9/5/2045 HE 19	64,923	~0
Peak Consumption (SSN)	9/5/2045 HE14	77,430	30,061
Off peak	4/15/2045 HE13	29,489	32,238

5.2.2 Generation Assumptions

The following table provides the generation dispatch assumptions in the study cases. The capacity assumptions for the resource portfolio are provided in section 3.1.2 and the wind generation assumptions for the in-state, offshore and out-of-state resources under different studies are detailed in Chapter 3 of the 2023-2024 Transmission Plan.

Table 5-2: Generation dispatch assumptions

	Generation Output (MW)			
Supply Type	**Net Peak 1 (HSN-00)**	**Net Peak 2 (HSN-01)**	**Net Peak 3 (HSN-02)**	**Net Peak 4 (HSN-03)**
Gas	0	0	9,934	10,444
Hydro	5,574	5,574	5,574	5,574
Pumped hydro	2,651	2,651	2,651	2,651
Geothermal	2,004	2,004	2,004	2,004
Bio	415	415	415	415
Solar	0	0	0	0
In-State Wind	3,402	3,402	3,402	3,402
Offshore wind	20,000	20,000	20,000	0
Out-of-state wind	12,000	12,000	12,000	0
Battery Storage	19,335	29,302	19,335	51,053
BTM-PV	0	0	0	0
Import	9,944	(781)	(1,143)	(1,409)

5.2.3 Transmission Projects

In addition to all the transmission projects that have been approved in previous Transmission Planning Process (TPP) cycles, the following projects are also modelled in the starting base cases to identify which further system re-enforcements are needed at a conceptual level. More information on these projects is provided in sections 2 through 4 of the 2023-2024 Transmission Plan.

Projects Recommended in 2023-2024 TPP

- New Humboldt 500 kV Substation (with 500/115 kV transformer) and 500 kV line to Collinsville [HVDC operated as AC]
- New Humboldt to Fern Road 500 kV Line
- New Humboldt 500/115 kV Phase Shifter with 115 kV line to Humboldt 115 kV Substation
- Series reactor on Collinsville – Pittsburg 230 kV lines
- North Dublin -Vineyard 230 kV Reconductoring
- Tesla - Newark 230 kV Line No. 2 Reconductoring

Reactive Support Assumptions

Several reactive support devices are added to the system to be able to solve the cases as the system load was scaled up or down to create different study cases.

5.3 Study Methodology and Results

5.3.1 Study Methodology

Load Profile in 2045

Starting with the 2035 Summer Peak case developed in the 2023-2024 Transmission Planning Process, the load and load modifiers across the CAISO system were scaled up or down to match the required load level discussed in section 3.1.1. Given the load increase, reactive support devices were assumed at critical busses to solve the cases with increased load.

Contingency Analysis

The objective of the contingency analysis in this study is to gain insight to the required transmission enhancements across the system under different cases. Considering that objective, the following assumptions were made in the analysis:

- Generic branch contingencies created by TARA tool was considered
- 500 kV contingencies were evaluated for N-0 and N-1, and N-1-1 analysis
- 230 kV contingencies were evaluated for N-1 analysis across the system and for N-1-1 analysis only for Bay Area and LA Basin.

- No Remedial Action Scheme (RAS) action was modelled in the contingency analysis, however existing RAS that could address overloads were considered as mitigation measures in post processing of the results.
- Generators were not re-dispatched before or after the contingencies, however if re-dispatch could address an overload, it was considered as a mitigation measure in post processing of the results.
- Only power flow analysis was performed focusing on thermal overloads.
- It is assumed that local area overloads are addressed with local transmission upgrades

5.3.2 2045 Net-Peak Study Results

The Net-peak load study is based on the High System Need (HSN) study in deliverability studies and reflects the system in an early evening summer conditions without solar generation. The electricity consumption in the ISO system is around 65 GW, which is mostly supplied by battery storage, wind, imports, and hydro units. The rest of the generation is coming from other sources such as pumped hydro, geothermal, and gas generation in the Bay Area. Details of generation for this study are discussed in section 5.2.2.

The assumption on the amount of generation from different sources will have an impact on the required transmission enhancements to serve the load. Four generation scenarios to serve the net-peak load in 2045 were considered in this study. A high level summary of resources are provided in Table 5-3 below with details provided in Table 5-2 in Section 5.2.

Table 5-3: Resource Dispatches in Net Peak (HSN) Scenarios

	Wind	Import	BESS	Gas
2045-HSN_00	High	Ave	Ave	~0
2045-HSN_01	High	Low	High	~0
2045-HSN_02	High	Low	Ave	As needed
2045-HSN_03	Low	Low	~Max	As needed

The contingency study results are grouped based on the area of the system and the type of the contingencies as follows:

- Offshore Wind and Bay Area Results under N-0 and N-1 Contingencies
- Out-of-State Wind Interconnection Impact under N-0 and N-1 Contingencies
- Overloads under low wind, low import, max BESS (HSN-03) under N-0 and N-1 Contingencies
- Greater Bay Area Study Results under N-1-1 Contingencies
- LA Basin Area (500 kV) under N-1-1 Contingencies

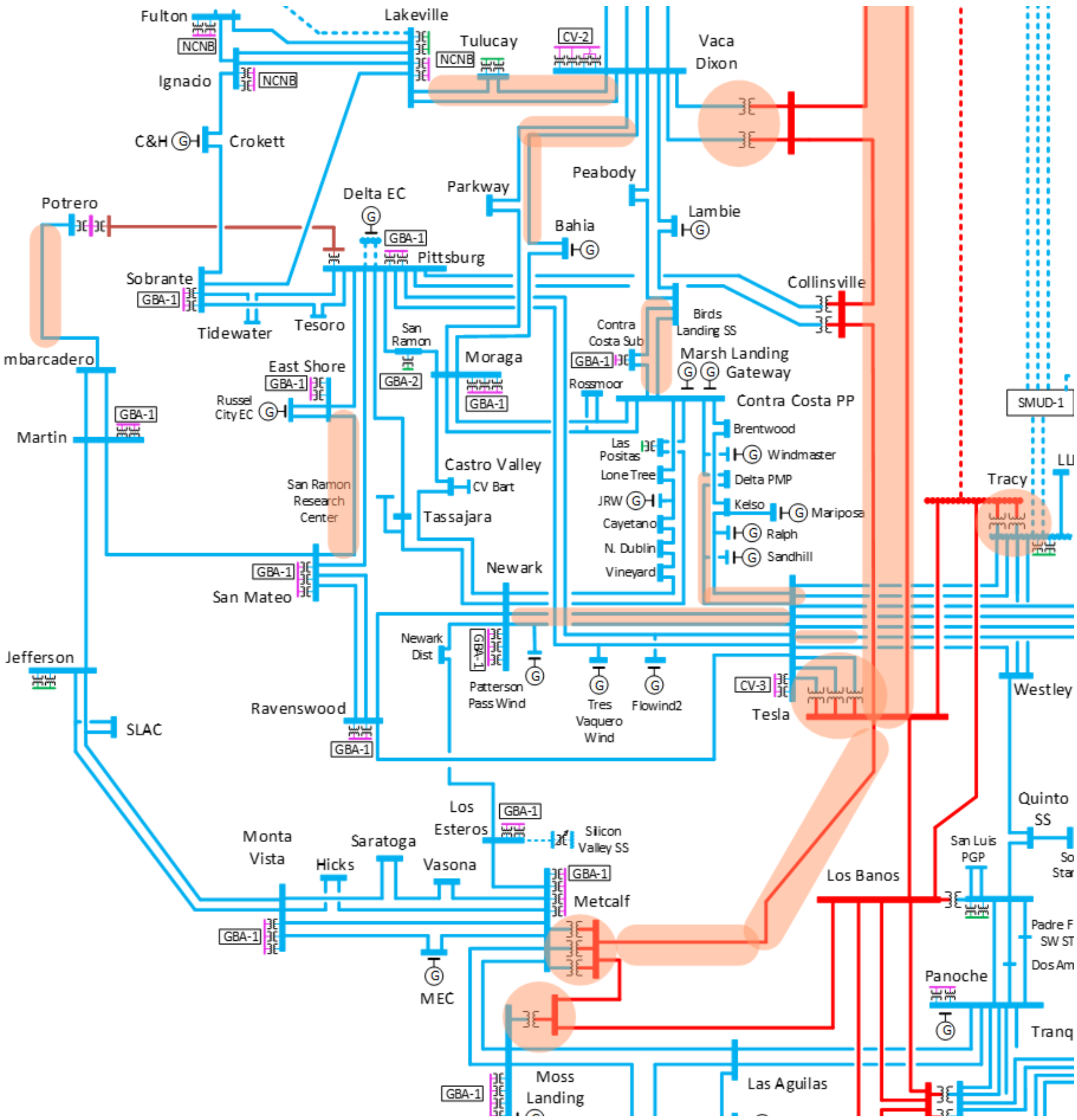
5.3.2.1 Offshore Wind and Bay Area Results under N-0 and N-1 Contingencies

Figure 5-1 shows the transmission system in the Greater Bay Area and the surrounding system. Considering the gas retirement in the area and the low dispatch of gas in the studied scenarios (HSN-00, HSN-01), there were a number of overloads are identified under N-0 and N-1 contingency conditions to transfer the north coast offshore wind to serve the load in the Greater Bay Area. The identified overloads are highlighted in Figure 5-1 and potential mitigation measures are provided in Table 5-4. More details of the potential transmission projects to address the identified overloads are provided in Section 5.4 of this report.

Table 5-4: N-0 and N-1 Contingency Analysis Results Summary for Offshore Wind and Bay Area

Overload	Comments	Potential Mitigation
Fern Road to Tesla 500 kV lines	N-0, N-1 under high OSW	Reconductor/rebuild existing lines or build a second Fern Road - Tesla line
Vaca Dixon 500/230 kV Txes and the 230 kV lines out of Vaca Dixon (Lakeville, Bahia, Parkway)	N-1 in all, N-0 in no gas, average BESS (HSN-00)	A combination of transmission enhancements and adding BESS
Tesla 500/230 kV Txes	N-0 in all, N-1 in all but average gas, high BESS (HSN-03)	Transmission enhancements/BESS
Metcalf 500/230 kV Txes	N-1 in all scenarios with HVDC to Moss Landing	Upgrade/add transformer or two HVDC to Bay Hub option
Moss Landing 500/230 kV Tx		
Tracy 500/230 kV Txes	N-1 only in no gas, average BESS (HSN-00)	Transmission enhancements/BESS
Round Mountain - Cottonwood 230 kV		Rebuild the line or create offshore wind – COI nomogram
Table Mountain - Palermo 230 kV		
Tesla - Metcalf 500 kV	N-1 only in no gas scenarios (HSN-00, HSN-01)	Transmission enhancements/BESS
Tesla - Sand Hill - Delta, Tesla - Newark, Tesla - Eight Mile		
Birds Landing – Contra Costa		
Embarcadero - Potrero 230 kV	N-1 under high OSW	
East Shore - San Mateo	N-1 under average gas, average BESS (HSN-02)	Transmission enhancements/BESS or two HVDC to Bay Hub option

Figure 5-1: Transmission system in Bay Area and identified overloads under N-0 and N-1 Contingencies



5.3.2.2 Out-of-State Wind Interconnection Impact under N-0 and N-1 Contingencies

Details of the out-of-state wind resources in the 2045 portfolio are provided in Section 3.1.9. In the portfolio, 3,500 MW of Wyoming wind and 2,882 MW of New Mexico wind are not mapped to any substation. In this study, 1,500 MW of Wyoming wind is mapped to Tesla 500 kV substation and 2,000 MW is mapped to Eldorado 500 kV substation. Two options were considered for the interconnection of the New Mexico wind. In one option, all the 2,882 MW is mapped to Palo Verde 500 kV substation and in another option 2,882 MW is mapped to Lugo 500 kV substation. Figure 5-2 and Figure 5-3 show the transmission system transferring power from Eldorado and Palo Verde substations to the rest of the CAISO system respectively. A number of overloads were identified under N-0 and N-1 contingency conditions to transfer the out-of-state wind to the rest of the CAISO system. The identified overloads are highlighted in Figure 5-2 and Figure 5-3 and potential mitigation measures are provided in Table 5-6. More details of the potential transmission projects to address the identified overloads are provided in Section 5.4.

Table 5-5: N-0 and N-1 Contingency Analysis Results Summary for Out-of-State Wind

<table>
<tr><th>Overload</th><th>Comments</th><th>Potential Mitigation</th></tr>
<tr><td>Eldorado - McCullough 500 kV</td><td>OOS wind at Eldorado</td><td>Upgrade the short line or interconnect OOS wind to a substation in the north such as Tesla</td></tr>
<tr><td>Hassayampa - North Gila - Imperial Valley</td><td>Only in high wind, average import (HSN-00)</td><td>Rebuild the lines, or interconnect the OOS wind at Lugo/Imperial Valley, or implement OOS vs. import nomogram</td></tr>
<tr><td>Lugo - Victorville 500 kV</td><td>Only in high wind, average import (HSN-00)</td><td rowspan="3">Build another line (Trout Canyon/Eldorado – Lugo), or terminate the OOS wind at Lugo, or implement OOS wind vs. Import nomogram</td></tr>
<tr><td>Pisgah - Lugo 230 kV</td><td>N-1, Only in high wind, average import (HSN-00)</td></tr>
<tr><td>Calcite - Lugo 230 kV</td><td>N-0, N-1, Only in high wind, average import (HSN-00)</td></tr>
</table>

Figure 5-2: Transmission system to transfer Out-of-State Wind from Eldorado and the identified overload under N-0 and N-1 contingencies

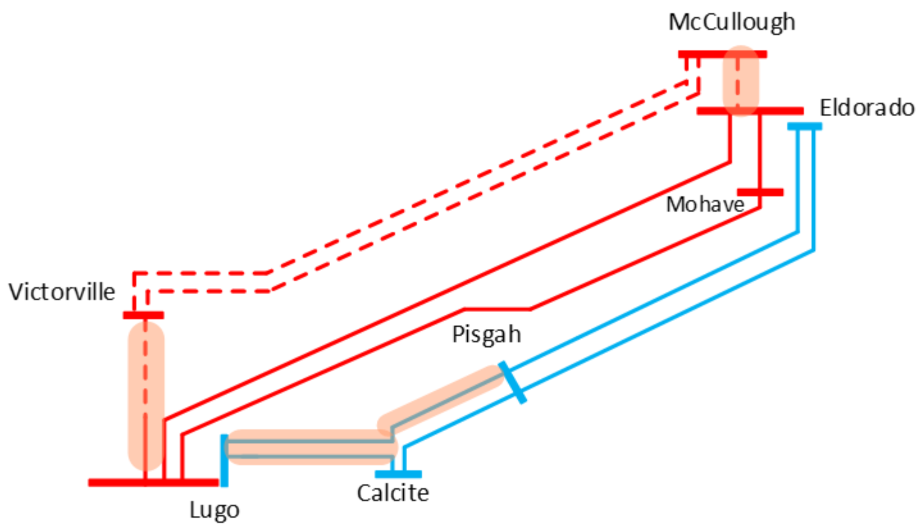
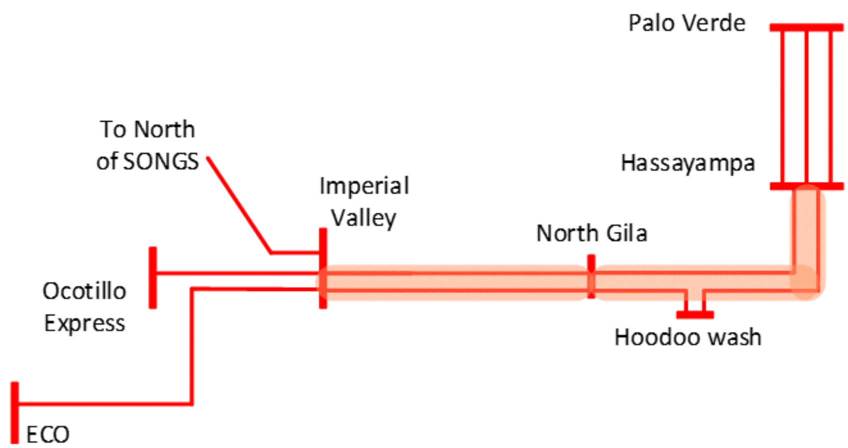


Figure 5-3: Transmission system to transfer Out-of-State Wind from Palo Verde and the identified overload under N-0 and N-1 contingencies



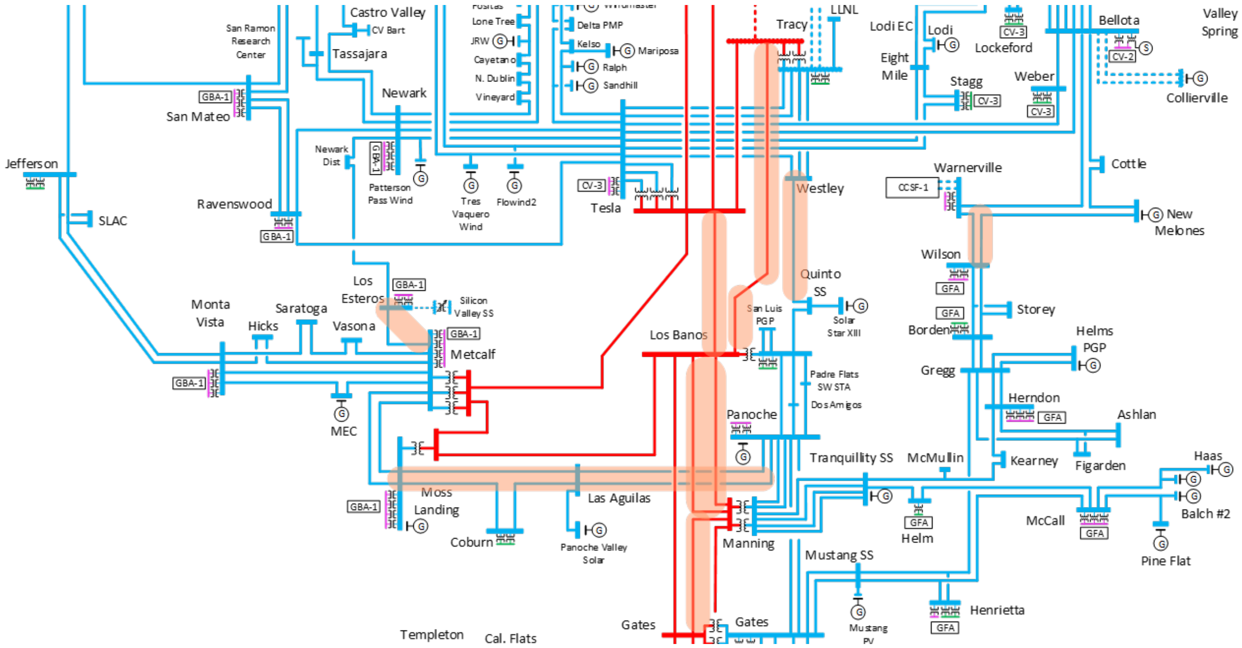
5.3.2.3 Overloads under low wind, low import, max BESS (HSN-03) under N-0 and N-1 Contingencies

Under the low wind, low import, and max BESS scenario (HSN-03) the assumption is that a significant portion of the CAISO load is served by BESS as the supply of other resources in that specific snapshot is low. Given the mapping of BESS resources in the portfolio, the transmission system is overloaded in transferring power from BESS to supply the load in the Bay Area. A number of overloads were identified under N-0 and N-1 contingency conditions in this scenario. The identified overloads are highlighted in Figure 5-4 and potential mitigation measures are provided in Table 5-6. More details of the potential transmission projects to address the identified overloads are provided in Section 5.4.

Table 5-6: N-0 and N-1 Contingency Analysis Results Summary under HSN-03 Scenario

<table>
<tr><th>Overload</th><th>Comments</th><th>Potential Mitigation</th></tr>
<tr><td>Tesla - Los Banos</td><td rowspan="8">N-0, N-1
Only in low wind, low import, max BESS (HSN-03)</td><td rowspan="6">Manning – Moss Landing line (AC or DC)</td></tr>
<tr><td>Manning - Los Banos</td></tr>
<tr><td>Warnerville - Wilson 230 kV</td></tr>
<tr><td>Moss Landing - Las Aguilas – Panoche 230 kV</td></tr>
<tr><td>Los Banos - Westly 230 kV</td></tr>
<tr><td>Tracy - Los Banos 500 kV</td></tr>
<tr><td>Metcalf – Los Esteros 230 kV</td><td>Rebuild the line or dispatch Bay Hub HVDC under no wind conditions.</td></tr>
<tr><td>Gates – Manning 500 kV</td><td>Add series compensation to Gates – Los Banos #3, Loop in Midway – Manning 500 kV line into Gates substation</td></tr>
</table>

Figure 5-4: Overloads Identified under Low Wind, Low Import, Max BESS Scenario (HSN-03)



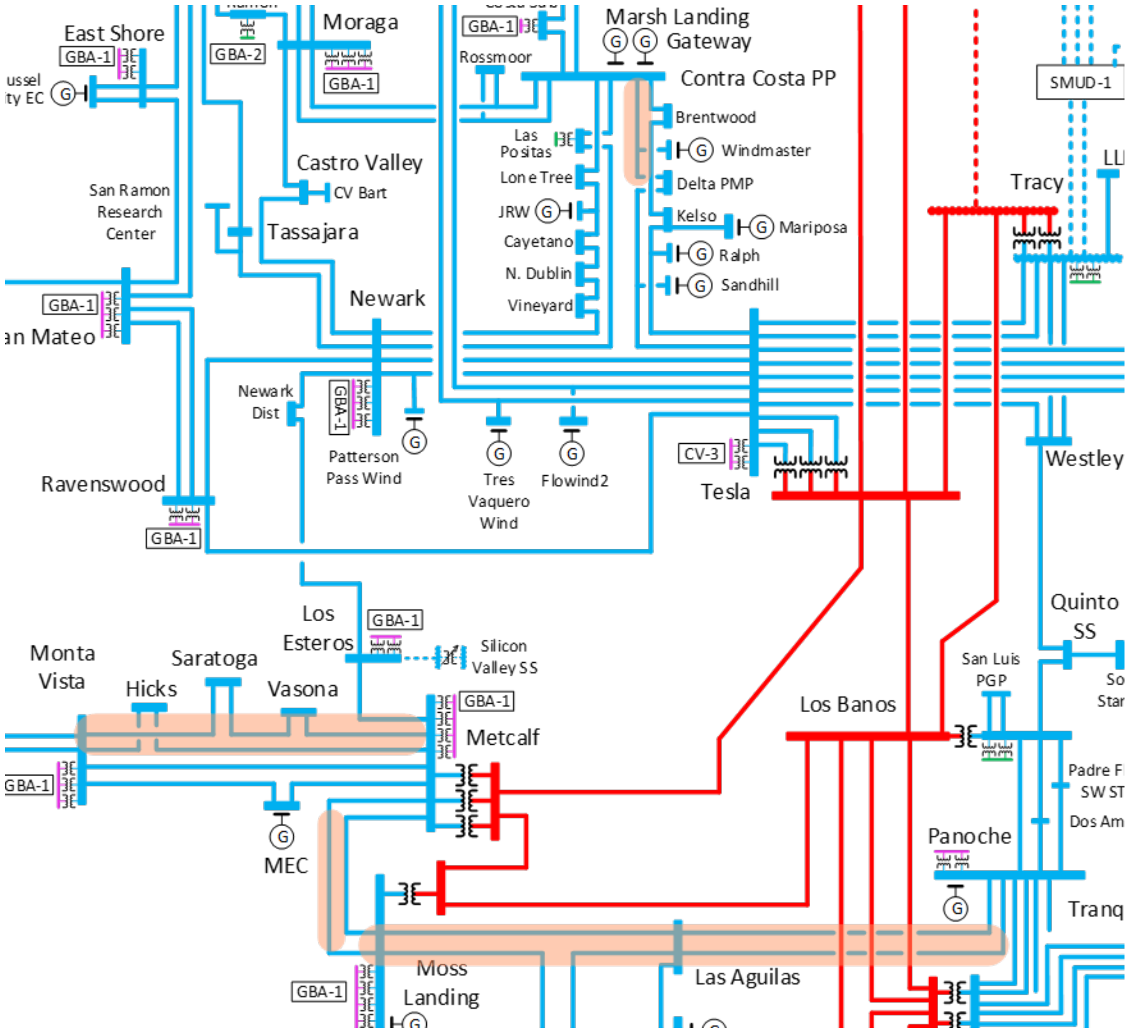
5.3.2.4 Greater Bay Area Study Results under N-1-1 Contingencies

A number of overloads were identified in the Greater Bay Area under N-1-1 contingency conditions with different HSN scenarios. These overloads are in addition to overloads identified under N-0 and N-1 contingency conditions discussed earlier in Section 5.3.2.1. The identified overloads are highlighted in Figure 5-4 and potential mitigation measures are provided in Table 5-6. Given the overloads are under N-1-1 contingencies, it may be possible to re-dispatch generators after the first N-1 contingency to prevent the identified overload following the second N-1 contingency. Such detailed analysis will be performed in local studies in the future. More details of the potential transmission projects to address the identified overloads are provided in Section 5.4 of this report.

Table 5-7: Greater Bay Area Study Resutls Under N-1-1 Contingencies

Overload	Contingency/Scenario	Potential Mitigation
Panoche - Las Aguilas - Moss Landing 230 kV lines	Tesla - Metcalf and Los Banos - Moss Landing in low wind, low import, max BESS (HSN-03)	Manning - Moss Landing 500 kV line
Monta Vista - Hicks, Saratoga - Vasona, Metcalf - Hicks	Metcalf - Monta Vista 230 kV lines in all scenarios	Rebuild the lines, or build two Bay Hub HVDC, or re-dispatch after the first contingency
Delta - Contra Costa 230 kV line	Birds Landing - Contra Costa 230 kV lines in no gas scenarios (HSN-00 and HSN-01)	A combination of rebuilding the line and adding BESS, or re-dispatch after the first contingency
Metcalf - Moss Landing 230 kV #1 or #2	Metcalf - Moss Landing 230 kV #1 or #2 and Metcalf - Moss Landing 500 kV in no gas, average BESS (HSN-01) and no wind, max BESS (HSN-03)	Rebuild the lines or trip the remaining 230 kV line with SPS, or re-dispatch after the first contingency

Figure 5-5: Overloads identified in Bay Area under N-1-1 Contingecies



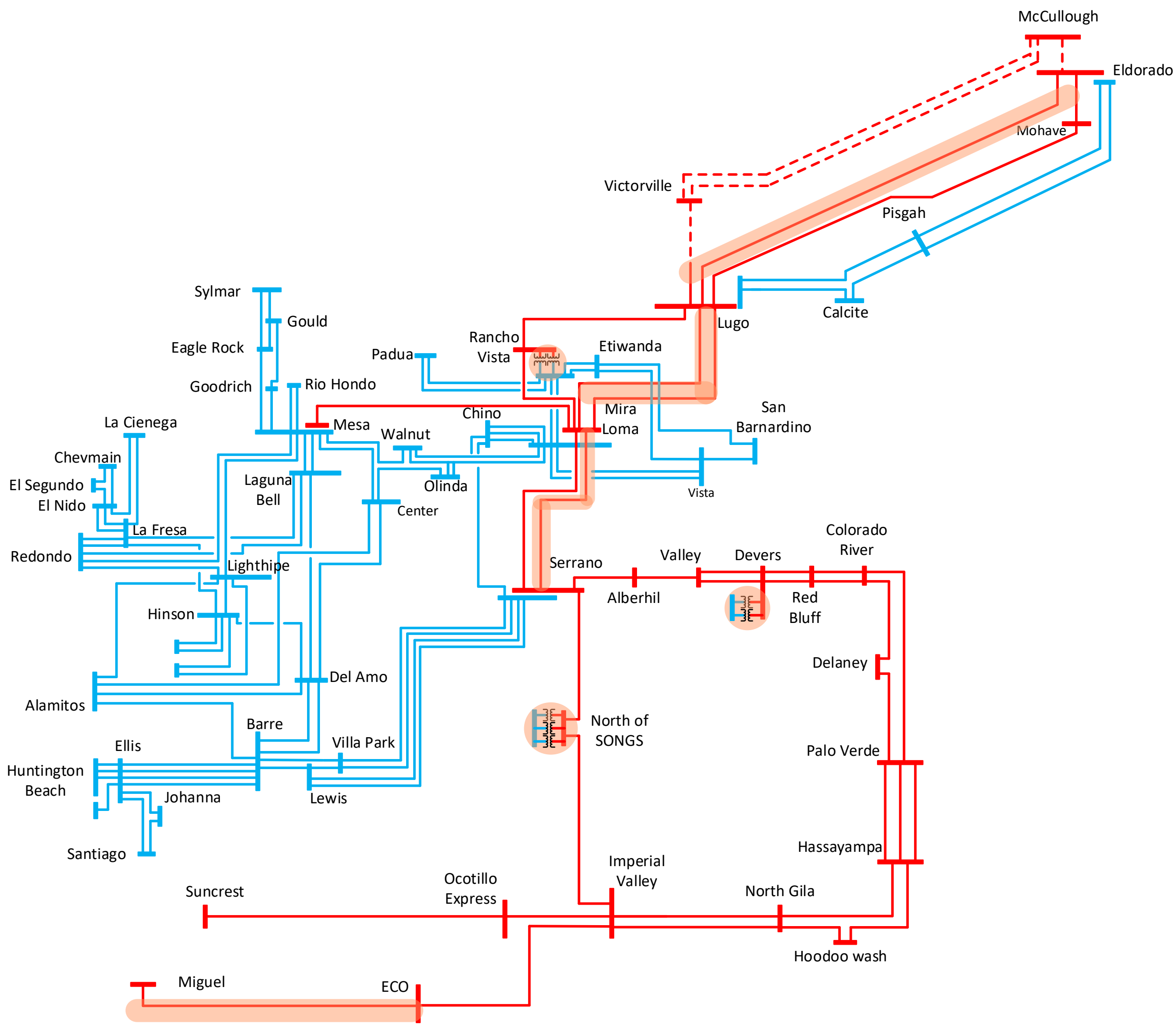
5.3.2.5 LA Basin Area (500 kV) under N-1-1 Contingencies

While no overloads were identified under N-0 and N-1 contingency conditions in the LA Basin area, a number of overloads were identified under N-1-1 contingency conditions with different HSN scenarios. The identified overloads on the 500 kV system are highlighted in Figure 5-6 and potential mitigation measures are provided in Table 5-8. The 230 kV overloads are discussed in the next section (5.3.2.6). Given the overloads are under N-1-1 contingencies, it may be possible to re-dispatch generators after the first N-1 contingency to prevent the identified overload following the second N-1 contingency. Such detailed analysis will be performed in local studies in the future. More details of the potential transmission projects to address the identified overloads are provided in Section 5.4 of this report.

Table 5-8: LA Basin 500 kV Study Resutls Under N-1-1 Contingencies

Overload	Contingency/Scenario	Potential Mitigation
Eldorado - Lugo 500 kV	Lugo - Victorville and Imperial Valley - N. of SONGS 500 kV. Only in high import, high OOS (HSN-00)	Build Trout Canyon – Lugo line, or terminate the OOS wind at Lugo, or implement OOS wind vs. Import nomogram, or Re-dispatch after the first contingency
Lugo - Mira Loma #2 or #3 500 kV	Lugo - Mira Loma #2 or #3 and Lugo - Rancho Vista 500 kV in all scenarios but HSN-03 (no OOS wind, low import, max BESS)	Re-dispatch after the first contingency
Eco - Miguel 500 kV	Imperial Valley - N. SONGS and Imperial Valley - Ocotillo or Ocotillo-Suncrest only in high import, high OOS (HSN-00)	Re-dispatch after the first contingency or implement OOS wind vs. Import nomogram
Serrano - Mira Loma #2 500 kV	Serrano or Valley - Alberhill and Serrano - Mira Loma #1 500 kV in no gas scenarios (HSN-00, HSN-01)	Re-dispatch after the first contingency
Devers 500/230 kV Tx #1 or #2	Devers 500/230 kV Tx #1 or #2 and Alberhill - Serrano or Valley 500 kV in no gas scenarios (HSN-00, HSN-01)	Re-dispatch after the first contingency
Rancho Vista #3 or #4 500/230 kV Tx	Rancho Vista #3 or #4 500/230 kV Tx and Rancho Vista - Mira Loma 500 kV in all scenarios but HSN-03 (no OOS wind, low import, max BESS)	Re-dispatch after the first contingency
Third Transformer at N. SONGS	Two transformers at N. SONGS in no gas scenarios (HSN-00, HSN-01)	Re-dispatch after the first contingency

Figure 5-6: Overloads Identified in LA Basin 500 kV Study Area under N-1-1 Contingencies



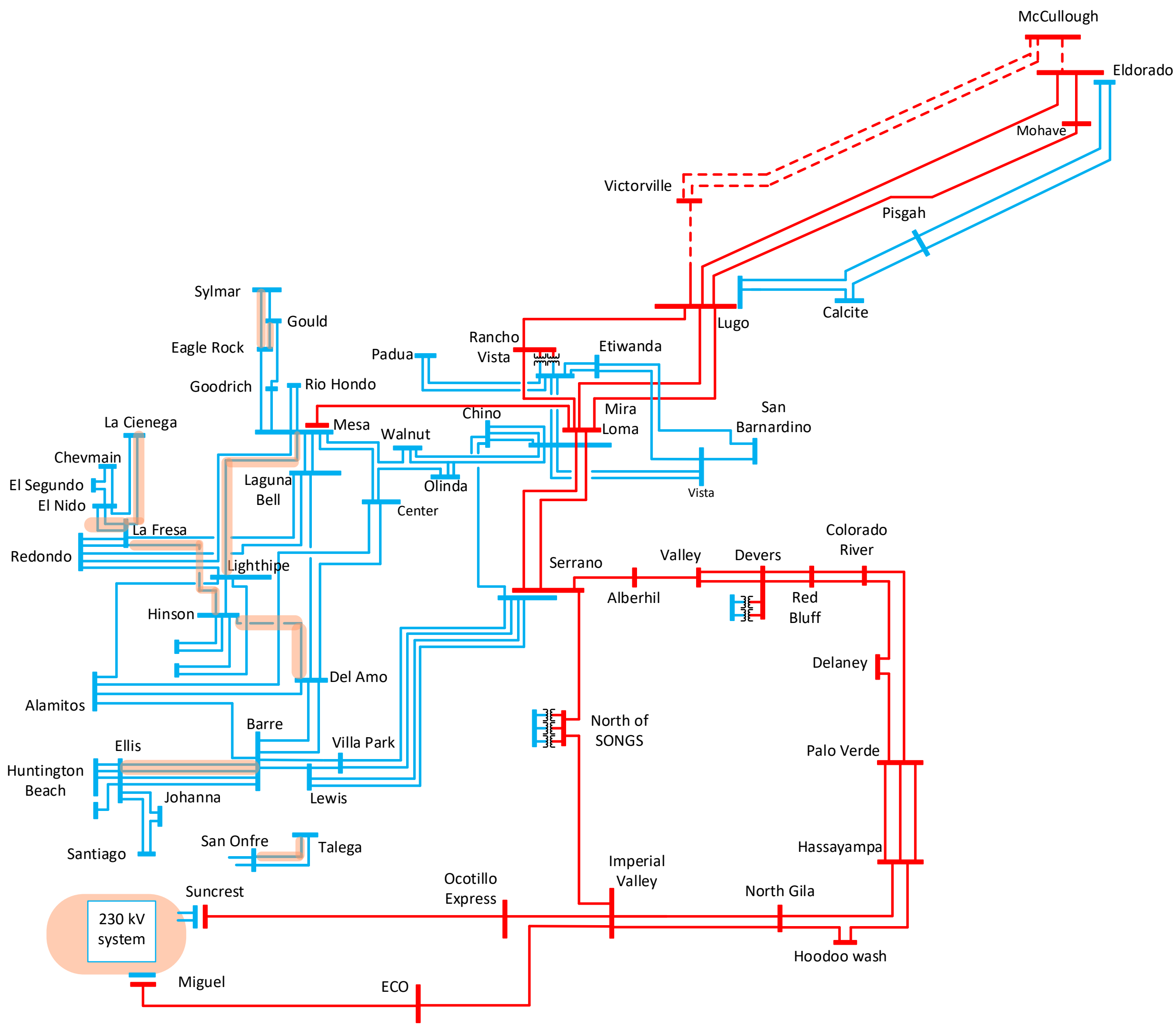
5.3.2.6 LA Basin Area (230 kV) under N-1-1 Contingencies

While no overloads were identified under N-0 and N-1 contingency conditions in the LA Basin area, a number of overloads are identified under N-1-1 contingency conditions within the different HSN scenarios. The 500 kV overloads are discussed earlier in the previous section (5.3.2.5). The identified overloads on the 230 kV system are highlighted in Figure 5-7 and potential mitigation measures are provided in Table 5-9. Given the overloads are under N-1-1 contingencies, it may be possible to re-dispatch generators after the first N-1 contingency to prevent the identified overload following the second N-1 contingency. Such detailed analysis will be performed in local studies in the future.

Table 5-9: LA Basin 230 kV Study Resutls Under N-1-1 Contingencies

Overload	Contingency/Scenario	Potential Mitigation
Talega - S. ONOFRE #2	Talega - S. ONOFRE #1 and Imperial Valley - ECO or ECO – Miguel only in no gas, average BESS (HSN-00)	Since no overload is identified in the average gas, high BESS scenarios, re-dispatching generation after the first contingency would most likely address the identified overloads Battery charging capability needs to be assessed in future local area studies
Barre - Ellis #1 or #2	Barre - Ellis #1 or #2 and Imperial Valley –N. of SONGS or Barre – Lewis only in no gas (HSN-00, HSN-01)	
Eagle Rock - Gould and Eagle Rock - Sylmar 230 kV	Lugo - Victorville 500 kV and Sylmar - Gould 230 kV in all scenarios but HSN-03	
La Fresa - El Nido #3 or #4 230 kV	La Fresa - El Nido #3 or #4 and La Fresa – La Cienega 230 kV in no gas (HSN-00, HSN-01)	
Del Amo - Hinson 230 kV	Lighthipe - Mesa and Del Amo - Alamitos 230 kV only in no gas, average BESS (HSN-00)	
La Fresa - Hinson 230 kV	La Fresa - Laguna Bell #1 and Mesa to Redondo 230 kV only in no gas (HSN-00, HSN-01)	
La Fresa - La Cienega 230 kV	El Nido - La Fresa #3 and #4 230 kV only in no gas (HSN-00, HSN-01)	
Lighthipe - Mesa 230 kV	Laguna Bell - Mesa - Redondo 230 kV in all scenarios but HSN-03	
Overload on the underlying 230 kV	Imperial Valley - Suncrest and Imperial Valley to Miguel 500 kV only in no gas (HSN-00, HSN-01)	

Figure 5-7: Overloads Identified in LA Basin 230 kV Study Area under N-1-1 Contingencies



5.3.3 2045 Peak Consumption and Off-Peak Study Results

The mitigation measures identified in the 2045 Net Peak analysis (HSN analysis) discussed in Section 5.3.2 were modeled in the Peak Consumption (SSN) and off-peak cases before running the contingency analysis. The contingency analysis did not identify any overloads on the bulk system that could not be resolved by re-dispatching generation or curtailing solar or wind under off peak scenarios.

In the SSN case, while the consumption is ~13 GW higher than the net peak condition (Table 5-10), there is ~30 GW of BTM-PV generation to offset the additional load and reduce loading on the bulk transmission lines.

In the off peak case, the BTM-PV is higher than the load at the given hour which will result in transmission connected solar and wind resources being used for charging the storage units.

Detailed production cost simulations could be performed in the future to assess whether economic projects could be recommended to reduce congestion instead of curtailing wind and solar generation.

Table 5-10: Load and BTM-PV assumptions

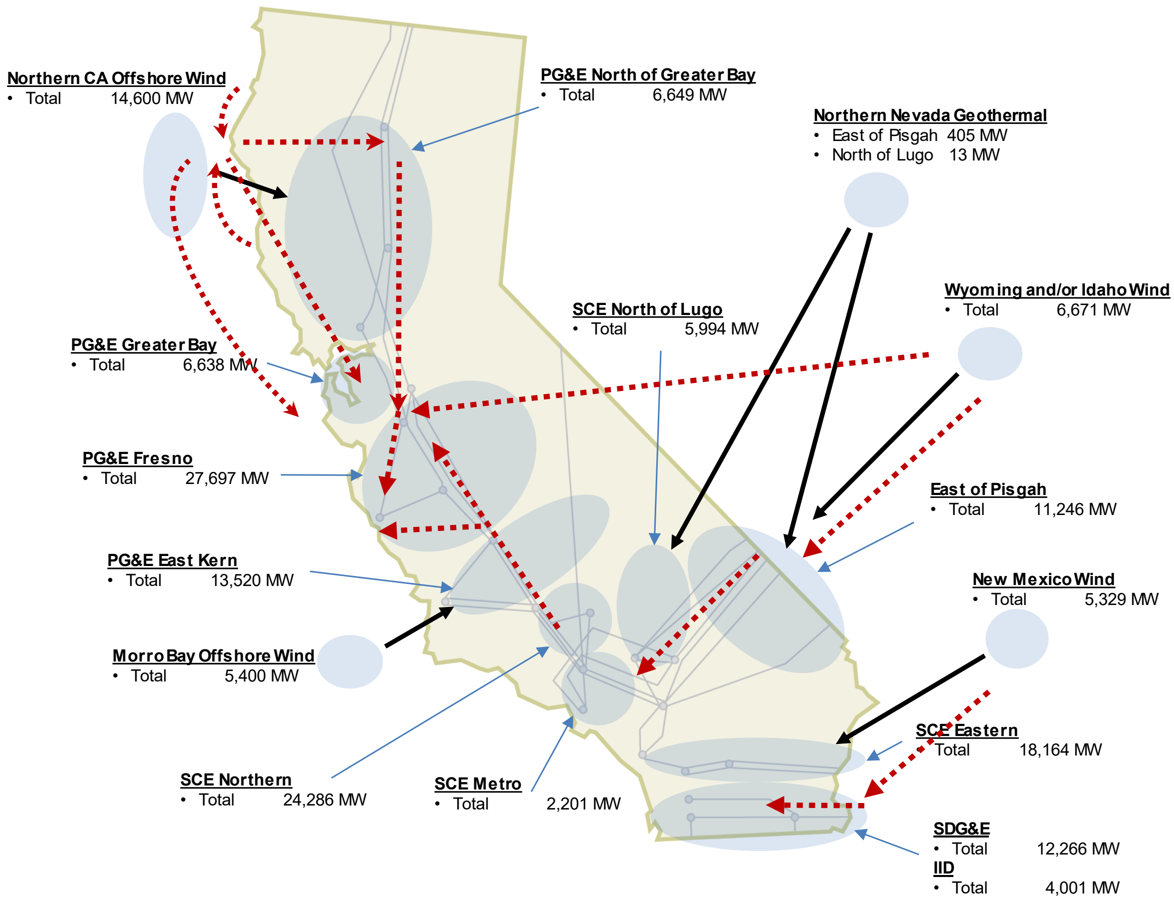
Study Cases	Date/Time assumption	Load (MW)	BTM-PV Generation (MW)
Net peak load (HSN)	9/5/2045 HE 19	64,923	~0
Peak Consumption (SSN)	9/5/2045 HE14	77,430	30,061
Off peak	4/15/2045 HE13	29,489	32,238

5.4 Transmission Development Alternatives

5.4.1 ISO System Transmission Development

Based on the analysis of the three study cases, the following system upgrades will be required, in addition to the projects already modelled in the starting base cases, to address overload issues. A high level description of the project and a schematic diagram of the area are provided in this section.

Figure 5-8: Illustrative Diagram of Transmission Development

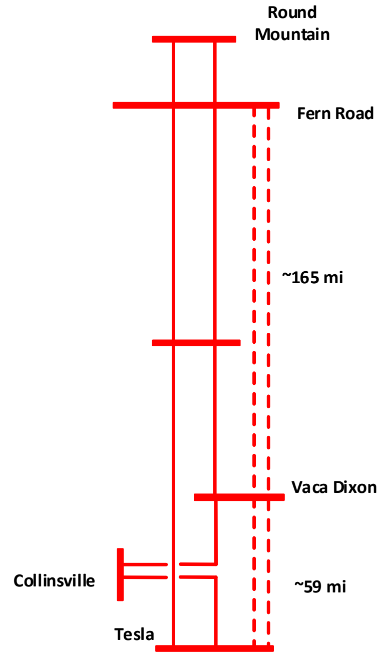


The following transmission projects described below have been identified as transmission development to accommodate the resources identified in the 2045 scenario and address the constraints identified in the high-level assessment of the bulk transmission system.

Figure 5-9: Major transmission development to existing ISO system to integrate the 2045 SB 100 portfolio scenario

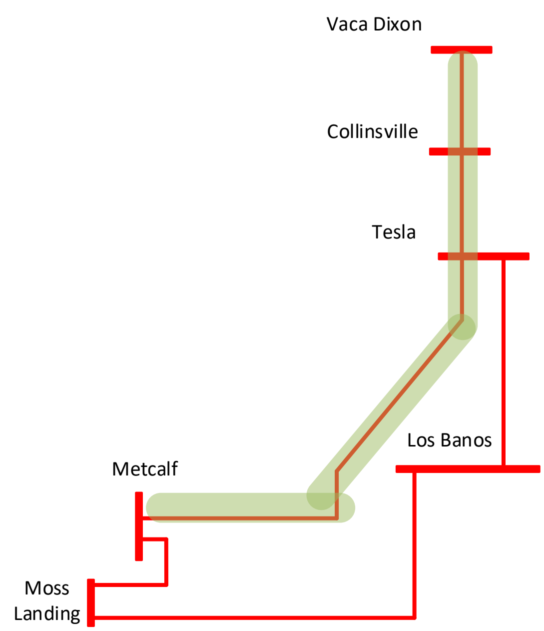
Two Fern Road to Tesla 500 kV Line Project

The 2045 portfolio includes 14,600 MW of offshore wind in the North Coast. All the recommended alternatives in this analysis include two 500 kV AC lines to Fern Road. Considering offshore wind flow injected at Fern Road, two new 500 kV lines are required to transfer power to Tesla and the rest of the system. Depending on the timing and pace of the offshore wind development, one new 500 kV line could be built and the existing lines could be reconductored with advanced conductors.



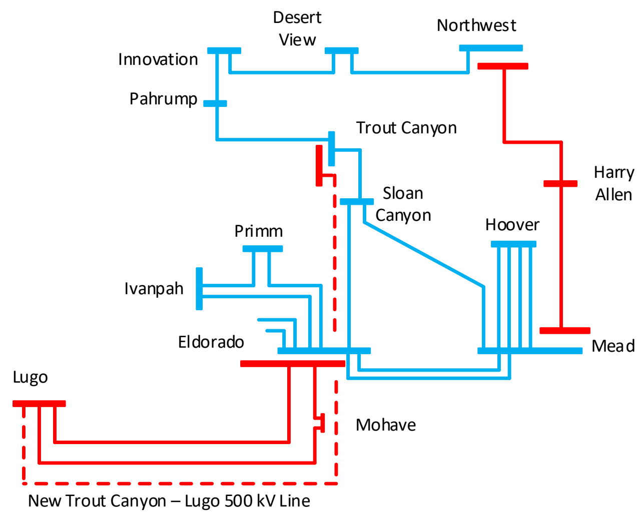
Reconductor Vaca Dixon – Collinsville – Tesla – Metcalf 500 kV Line Project

The 2045 portfolio includes more than 4 GW of gas retirement in the Bay Area. In scenarios with low local gas and high offshore wind, the existing Vaca Dixon – Collinsville – Tesla – Metcalf line overloads under base case and contingency conditions. Reconductoring the 500 kV lines with advanced conductors will address the issue. Depending on the timing and pace of the gas retirement and offshore wind development, it might be challenging to reconductor the existing lines and new lines need to be built in parallel to the existing ones.



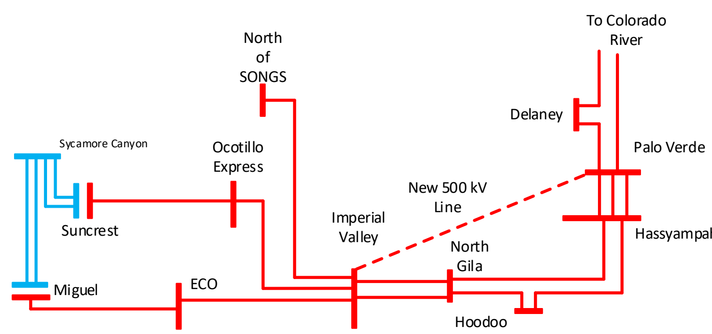
<u>Trout Canyon – Lugo 500 kV Line Project</u>

The 2045 portfolio includes solar resources in the Southern Nevada and Eldorado areas. In addition, in this study it was assumed that 3,500 MW of out-of-state wind will be injected at Eldorado 500 kV substation. Considering that the majority of these resources will flow on the Eldorado – Lugo 500 kV path, the new Trout Canyon - Lugo 500 kV line was assumed to address the overloads under normal and contingency conditions.



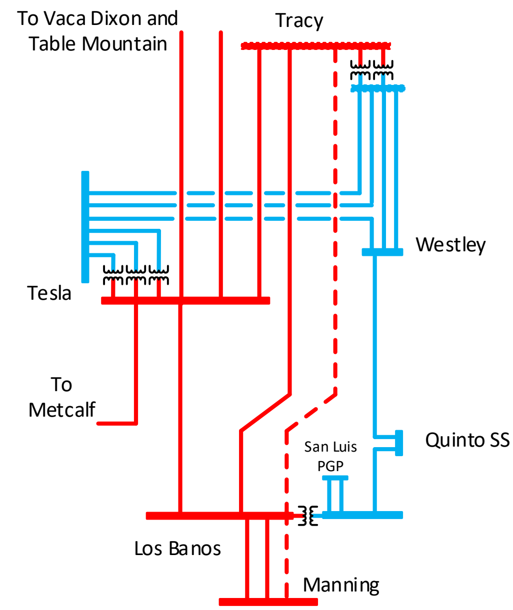
<u>Palo Verde – Imperial Valley 500 kV line</u>

The 2045 portfolio includes solar resources in Riverside and Palm Springs, Greater Imperial, and Arizona solar areas. In addition, in this study it was assumed that 2,882 MW of out-of-state wind will be injected at the Palo Verde 500 kV substation. Considering all these resource connections, a new Palo Verde – Imperial Valley 500 kV line was considered to address the overloads under normal and contingency conditions.



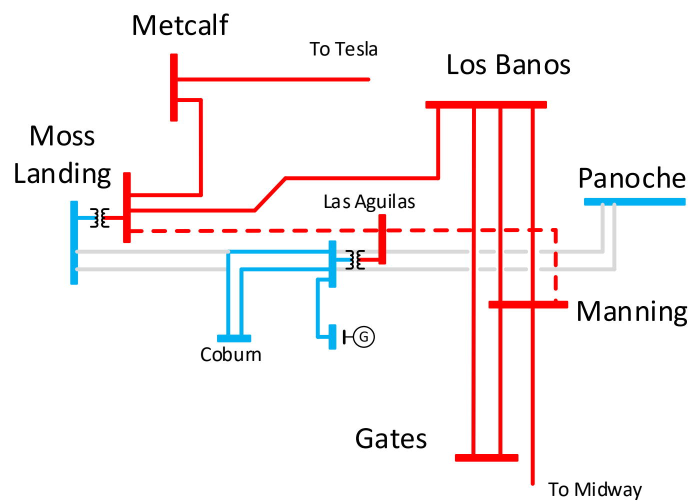
Manning - Tracy 500 kV line

As indicated in the study results, the existing Los Banos – Tracy 500 kV line overloads under normal and contingency conditions for certain scenarios. The contingency of the line also causes overload on the underlying 230 kV system. A potential mitigation considered in this study is a new Manning – Tracy 500 kV line.



Manning – Moss Landing 500 kV line

The study results indicated overload on the Manning – Los Banos 500 kV lines and on the 230 kV path from Panoche to Moss Landing. A 500 kV line from Manning to Moss Landing will address these overloads and also provides another 500 kV connection to the Bay Area to address overloads under N-1-1 contingencies.



5.4.2 Transmission Development Estimated Costs

Based on the review of per unit capital cost estimate for transmission infrastructure development in multiple sources, [21, 22] the CAISO used the information in Table 5-11 to calculate a planning level cost estimate for different transmission enhancement concepts identified in this report.

Table 5-11: Estimated cost per mile or per unit of transmission infrastructure

Transmission Infrastructure	Cost Estimate
500 kV Substation/expansion	$100 M - $150 M
500 kV AC line in the mountains	$7 M - $10 M/mi
500 kV AC line in the valley	$5 M - $7 M/mi
HVDC line onshore in the mountains	$7 M - $10 M/mi
HVDC converter station (2GW)	$400 M - $600M
HVDC converter station (3GW)	$600 M - $900M
HVDC offshore cable (2GW)	$7 M - $10 M/mi
High capacity 230 kV Cable	$15 M - $20 M/mi
Reconductor 230 kV Lines	$3.5 M – $4.5 M/mi
Reconductor 500 kV Lines	$3.5 M – $5 M/mi

The transmission development to integrate the resources in the 2045 resource portfolio has been identified in three sections, as reflected in Table 5-11:

- Upgrades to existing ISO footprint;
- Offshore wind; and
- Out-of-state wind.

[21] Schatz Center - Northern California and Southern Oregon Offshore Wind Transmission study https://efiling.energy.ca.gov/GetDocument.aspx?tn=252604

[22] https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Participating-transmission-owner-per-unit-costs-2023

Table 5-12: Estimated cost[23] for transmission development to integrate the resources in 2045 Scenario

Transmission Development	Description	Cost Estimate
Upgrades to existing ISO footprint		**$9.3 B - $11.5 B**
Trout Canyon – Lugo 500 kV line	- 180 mi of 500 kV line - Series compensation in number of locations	$2 B
Manning – Tracy 500 kV line	107 mi of 500 kV line	$0.5 B - $0.7 B
Manning – Moss Landing 500 kV line	- 78 mi of 500 kV line - New 500/230 kV substation with two transformers ($100M)	$0.4 B - $0.5 B
Two Fern Road – Tesla 500 kV Lines	2 x 250 mi of 500 kV line	$2.5 B - $3.5 B
Palo Verde/Hassayampa – Imperial Valley 500 kV line	~200 mi of 500 kV line	$2 B
Reconductor Vaca Dixon – Collinsville – Tesla – Metcalf 500 kV line	~ 36 miles of 500 kV line	$0.4 B - $0.5 B
Upgrade 500/230 kV transformers at Vaca Dixon, Tesla, Metcalf, Moss Landing, Tracy	A total of eleven 500/230 kV transformers need to be upgraded. The assumption is that there space limitation to add new transformers.	$0.6 B - $1.1 B
Add series compensation to Gates – Los Banos #3, Loop in Midway – Manning 500 kV line into Gates substation		$0.1 B
Upgrade the following 230 kV lines	Total of 287 miles	$0.8 B - $1.1 B
• Reconductor[24] Vaca – Lakeville 230 kV lines (2 x 42 mi)		
• Reconductor Vaca – Bahia 230 kV line (33 mi)		
• Reconductor Vaca – Parkway 230 kV line (26 mi)		
• Reconductor Birds Landing – Contra Costa 230 kV lines (2 x 10 mi)		
• Reconductor Round Mountain - Cottonwood 230 kV line (34 mi)		
• Reconductor Table Mountain - Palermo 230 kV line (15 mi)		
• Reconductor Tesla - Sand Hill – Delta 230 kV line (10 mi)		
• Reconductor Tesla - Eight Mile 230 kV line (27 mi)		
• Reconductor Embarcadero - Potrero 230 kV cable (2.5 mi)		
• Reconductor East Shore - San Mateo 230 kV line (9 mi)		
• Reconductor Metcalf – Los Esteros 230 kV line (26 mi)		

[23] These values represent the capital cost of the identified projects; several are currently being developed under a subscriber model – with the transmission costs incorporated into the energy costs – and not rate-base projects receiving cost-of-service cost recovery that would be added to ISO transmission access charges.

[24] Reconuctoring could include use of advanced conductors

Transmission Development	Description	Cost Estimate
Offshore Wind		**$25 B – $36.5 B**
Humboldt Bay Offshore wind area	Total of 14,600 MW offshore wind connected through 500 kV AC lines, overhead HVDC, and subsea HVDC lines to Fern Road, Collinsville, and Bay Hub substations. (Figure 4-7)	$24.8 B – $36.1 B
Diablo – Morro Bay Offshore wind area	- Total of 5,400 MW offshore wind. Connected to Diablo 500 kV and the new Morro Bay 500 kV substation. - The cost estimate for a 500 kV switching station and looping in the existing Diablo – Gates 500 kV line into it is 0.15 B – 0.22 B. If more than ~2,400 MW generation is connected the new Morro Bay 500 kV substation, a second Morro Bay – Diablo 500 kV line with $100 M to $140 M will be required.	0.15 B – 0.36 B
Out-of-State Wind		**$11.6 B – $15.2 B** [25]
TransWest Express	732 Mile transmission system consisting of HVDC and 500 kV facilities to access Wyoming wind. Project is designed to potentially provide 1500 MW to LADWP at the IPP facilities in Utah and 1500 MW to the ISO at Harry Allen/Eldorado	-
SunZia	530 mile HVDC line and 35 mile 500 kV AC line plus scheduling rights on existing lines from Pinal Central to Palo Verde connecting to the ISO system to access New Mexico wind resources	-
Additional transmission for additional wind resources from Wyoming/Idaho area	HVDC transmission line from the wind resource area to northern California (Eldorado/Tesla area)	$8.1 B – $10.4 B
Additional transmission for additional wind resources from New Mexico area	HVDC transmission line from the wind resource area to southern California (Lugo area)	$3.5 B – $4.9 B
Total estimated cost for transmission Development		**$45.8 B – $63.2 B**

[25] The TransWest Express and SunZia projects are being developed providing transmission service to resources seeking access to California markets on a Subscriber Participating Transmission Owner (SPTO) model. The transmission costs would not be included in the ISO TAC.

5.5 Summary and Conclusions

The 20-Year Outlook Update builds upon the analysis performed in the last 20-Year Outlook published in May 2022 and explores the longer-term grid requirements and options for meeting the State's greenhouse gas reduction and renewable energy objectives reliably and cost-effectively. The expanded planning horizon to year 2045 provides valuable input for resource planning processes conducted by the CPUC and CEC, and provides a longer-term context and framing of pertinent issues in the ISO's ongoing annual 10-Year Transmission Plan. One of the main differences in key input assumptions in this study compared to the last 20-Year Outlook is the increase of the offshore wind resources from 10,000 MW in the last outlook to 20,000 MW in this study.

The exercise was undertaken recognizing that California is facing an unprecedented need for new clean energy resources over the next 10 to 20 years, driven by increased customer demand for clean energy, the continuing electrification of transportation and other industries and by the requirements of Senate Bill 100 that California must get 100 percent of its retail electricity from non-carbon-producing sources by 2045.

This 20-Year Outlook Update focused on meeting the needs identified through the CEC's SB100-related processes for achieving the state's 2045 objectives, with the 2045 load forecast and resource requirements developed through a collaborative approach with the CEC, CPUC, other local regulatory authorities, stakeholders and ISO staff. The planning exercise demonstrated that the energy transformation will not only drive significant investment in a technologically and geographically diverse fleet of resources, including storage, but also significant transmission to accommodate all the new capacity being added.

Table 5-13 provides the high-level summary of the transmission development required for upgrades to the existing ISO footprint, offshore wind integration and out-of-state wind integration. The range of cost estimate is commensurate with estimates developed at this stage of planning, with the costs in constant dollars.

Table 5-13: High level cost estimate of transmission development

Transmission Development	**Estimated Cost ($ billions)**
Upgrades to existing ISO footprint consisting of: • 230 kV and 500 kV AC lines • HVDC lines • Substation upgrades	$9.3 B - $11.5 B
Offshore wind integration consisting of: • 500 kV AC lines • HVDC lines	$25 B - $36.5 B
Out-of-state wind integration consisting of: • 500 kV AC lines • HVDC lines	$11.6 B - $15.2 B
Total estimated cost of transmission development	**$ 45.8 B – 63.2 B**

In summary, the anticipated load growth to 2045 and the expectation of major offshore wind generation are driving the higher estimated cost for future transmission needs from approximately $30.5 billion over a 20-year timeframe identified in the first Outlook to the estimated $43.8 billion to $63.2 billion in future transmission costs identified in this update. These costs do not include transmission that has already been approved by the ISO and is under development, but not yet in service.

The ISO expects to conduct additional stakeholder dialogue through 2024 about next steps as well as the long-term architecture set out in this 20-Year Outlook. Those additional efforts, along with evolving resource planning and procurement, will inform the ISO's annual transmission planning processes that approve and initiate specific projects.

APPENDIX A: 2045 Scenario

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California Energy Commission and
California Public Utilities Commission

STAFF PAPER

2045 Scenario for the Update of the 20-Year Transmission Outlook

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California Public Utilities Commission, Energy Division

July 2023 | CEC-700-2023-006

DISCLAIMER

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ABSTRACT

The *2045 Scenario for the Update of the 20-Year Transmission Outlook* staff paper describes a 2045 demand and resource scenario for use by the California Independent System Operator in the update of the 20-Year Transmission Outlook. The staff paper outlines the demand and resource assumptions within the scenario. The staff paper details the method for resource mapping the new renewable resource and energy storage capacity within the scenario.

Keywords: Demand scenario, clean energy resources, offshore wind, land use, transmission planning

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EXECUTIVE SUMMARY

California's energy transition is underway, but the next two decades will require an unprecedented amount of generation and transmission to supply clean, reliable power. The need for record-setting buildout of new utility-scale clean energy resources and energy storage is being driven by increased customer demand for clean energy, the continuing electrification of transportation and other industries to achieve the state policy of economy-wide carbon neutrality by 2045, and the state's target of 100 percent clean electricity. The 100 Percent Clean Energy Act of 2018 (Senate Bill 100, De León, Chapter 312, Statutes of 2018) sets a 2045 target of supplying all retail electricity sold in California and state agency electricity needs with renewable and zero-carbon energy resources.

Senate Bill (SB) 100 also increases the state's Renewables Portfolio Standard (RPS) procurement target to 60 percent of retail sales by December 31, 2030, and requires all state agencies to incorporate the 2030 and 2045 targets into their relevant planning. SB 100 requires the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and California Air Resources Board (CARB) to use programs under existing laws to achieve 100 percent clean energy and issue a joint policy report on SB 100 by 2021 and every four years thereafter.

The first 2021 Joint Agency SB 100 Report was released in March 2021 and assessed various pathways to achieve the SB 100 targets and included an initial assessment of costs and benefits. One key finding from the report was that sustained record-setting renewable generation and energy storage capacity build rates will be required to meet the target in a high electrification future, citing growing electricity demand as a significant driver. Effectively integrating 100 percent renewable and zero-carbon technologies in California by 2045 will require rigorous analysis of implementation considerations and coordinated planning across different levels of government and with grid operators throughout the state. One such track of analysis, which emerged following the 2021 Joint Agency SB 100 Report, is the California Independent System Operator's (California ISO's) 20-Year Transmission Outlook (20-year outlook).

The California ISO's 20-year outlook explores longer term grid requirements and options for meeting the state's greenhouse gas reduction and renewable energy targets reliably. The CEC, CPUC, and California ISO collaborated on an approach to translate the analysis conducted for the 2021 SB 100 Joint Agency Report into a 2040 Starting Point Scenario for use by the California ISO in the first 20-year outlook, which was released in May 2022.

Following the release of the first SB 100 Joint Agency Report, the CEC, CPUC, and California ISO, began to focus on the resource build requirements to achieve SB 100 (Docket 21-SIT-01). This collaboration includes a public stakeholder process, with several workshops held in 2021 and 2022, and is ongoing. In December 2022, the CEC, CPUC, and California ISO signed a "Memorandum of Understanding (MOU) Regarding Transmission and Resource Planning and Implementation," reinforcing cooperation and collaboration of the three parties in the timely development of resources needed to achieve the state's clean energy goals reliably and economically.

A near-term priority for collaborative efforts is providing an updated 2045 Scenario for California ISO to use in the next 20-Year Transmission Outlook, which is anticipated in 2024. The next 20-year transmission outlook will inform the 2025 SB 100 Joint Agency Report.

The *2045 Scenario for the Update of the 20-Year Transmission Outlook* staff paper describes a 2045 demand and resource scenario for use by the California ISO in the update of the 20-Year Transmission Outlook. The staff paper describes the load and resource assumptions within the scenario, which assumes 100 percent of retail sales is supplied by renewable and zero-carbon electricity resources by 2045. The staff paper details the method for resource mapping the new renewable resource and energy storage capacity within the scenario. Consistent with the scenarios from the 2021 SB 100 Joint Agency report, the 2045 Scenario for the 20-Year Outlook includes significant capacity additions by 2045.

CHAPTER 1: Background

Senate Bill 100 Targets

The 100 Percent Clean Energy Act of 2018 (Senate Bill 100, De León, Chapter 312, Statutes of 2018) sets a 2045 target of supplying all retail electricity sold in California and state agency electricity needs with renewable and zero-carbon resources.[1] SB 100 also increases the state's Renewables Portfolio Standard (RPS) procurement target to 60 percent of retail sales by December 31, 2030, and requires all state agencies to incorporate the 2030 and 2045 targets into their relevant planning. SB 100 requires the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and California Air Resources Board (CARB) to use programs under existing laws to achieve 100 percent clean energy and issue a joint policy report on SB 100 by 2021 and every four years thereafter.

The Clean Energy, Jobs, and Affordability Act of 2022 (Senate Bill 1020, Laird, Chapter 361, Statutes of 2022) revises SB 100 targets to instead provide that eligible renewable energy resources and zero-carbon resources supply:

- 90 percent of all retail sales of electricity to California end-use customers by December 31, 2035.
- 95 percent of all retail sales of electricity to California end-customers by December 31, 2040.
- 100 percent of all retail sales of electricity to California end-use customers by December 31, 2045.
- 100 percent of electricity procured to serve all states agencies by December 31, 2035.

2021 Joint Agency SB 100 Report

The 2021 Joint Agency SB 100 Report assessed various pathways to achieve the SB 100 targets and an initial assessment of costs and benefits. One key finding from the report was that sustained record-setting renewable generation and energy storage capacity build rates will be required to meet the target in a high electrification future, citing growing electricity demand as a significant driver.[2] Effectively integrating 100 percent renewable and zero-carbon technologies in California by 2045 will require rigorous analysis of implementation considerations and coordinated planning across different levels of government and with grid operators throughout the state. One such track of analysis, which emerged following the 2021

1 Senate Bill 100 (De León, Chapter 312, Statutes of 2018). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.

2 CEC, CPUC, and CARB. 2021. *2021 SB 100 Joint Agency Report Achieving 100 Percent Clean Electricity in California: An Initial Assessment.* Publication Number: CEC-200-2021. https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349.

Joint Agency SB 100 Report, is the California Independent System Operator's (California ISO's) *20-Year Transmission Outlook*[3] (20-year outlook).

20-Year Transmission Outlook

The California ISO's 20-year outlook explores longer-term grid requirements and options for meeting the state's greenhouse gas reduction and renewable energy targets reliably. The California ISO initiated the 20-year outlook to have a longer-term outlook and stakeholder process outside the formal tariff-based Transmission Planning Process (TPP), which focuses on transmission project needs and transmission project approvals over a 10-year planning horizon. The California ISO will conduct the update of the 20-year outlook in parallel with its current 2023–2024 TPP. The 20-year outlook is intended to support state electric sector planning by providing long-term context and framing of key transmission-related issues.

The CEC, CPUC, and California ISO collaborated on an approach to translate the analysis conducted for the 2021 SB 100 Joint Agency Report into a 2040 Starting Point Scenario for use by the California ISO in the first 20-year outlook, which was released in May 2022. The first 20-year outlook identified the need for significant 500 kilovolt (kV) alternating current (AC) and high-voltage direct current (HVDC) transmission development to access offshore wind (OSW) and out-of-state wind and reinforce the transmission system within the existing California ISO footprint. Figure 1 diagrams the transmission development required to integrate the resources of the SB 100 Starting Point Scenario and high electrification load projection by 2040.

3 California Independent System Operator. May 2022. 20-Year Transmission Outlook. http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf. Page 20.

Figure 1: Diagram of Transmission Development in the 20-Year Outlook (2022)

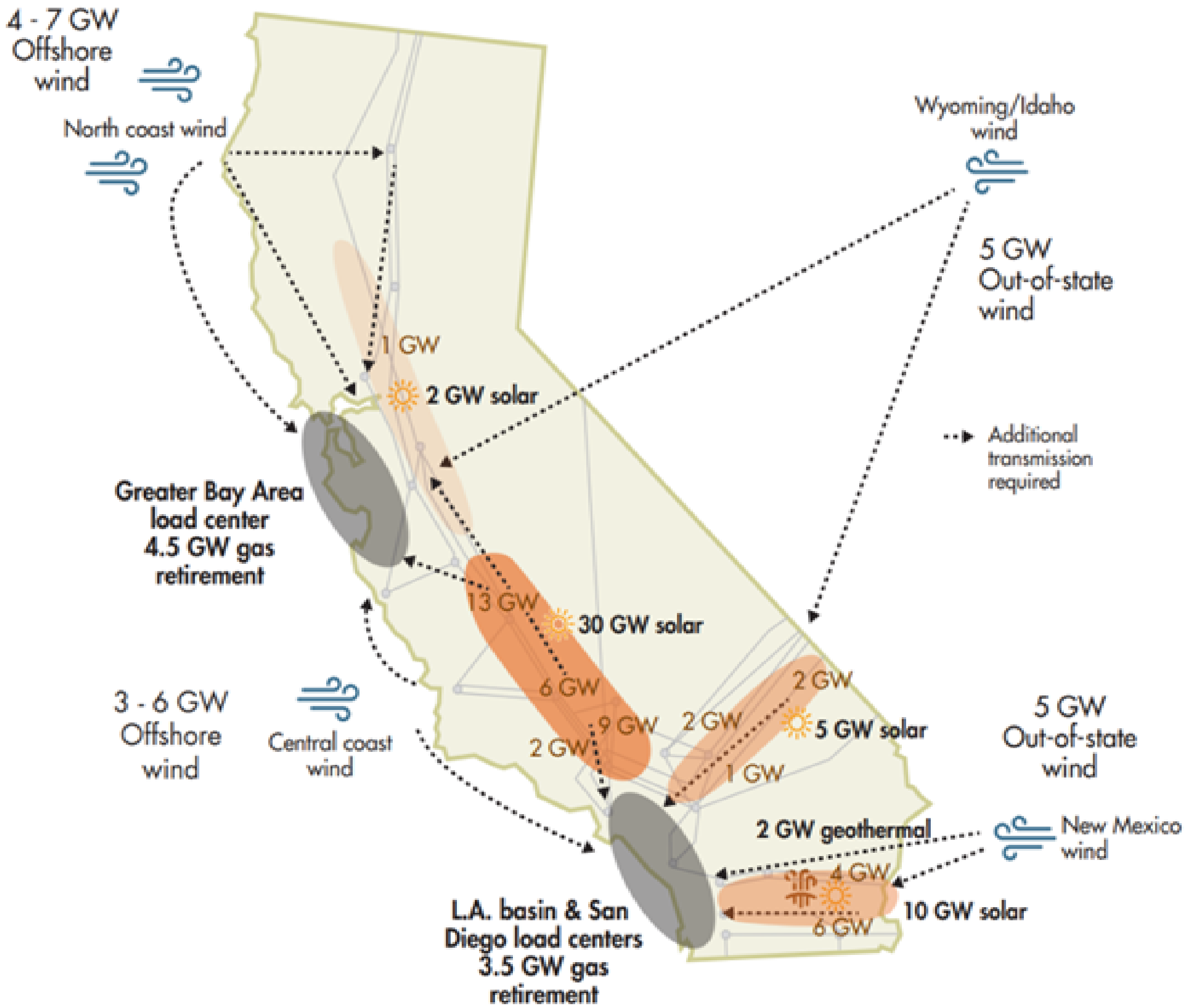

Diagram of transmission development identified in the California ISO 20-Year Outlook (May 2022).

Source: California ISO

Following the release of the first SB 100 Joint Agency Report, the CEC, CPUC, and California ISO focused on the resource build requirements to achieve SB 100 (Docket 21-SIT-01). This collaboration includes a public stakeholder process, with several workshops held in 2021 and 2022, and is ongoing. In December 2022, the CEC, CPUC, and California ISO signed the "Memorandum of Understanding (MOU) Regarding Transmission and Resource Planning and Implementation," reinforcing cooperation and collaboration of the three parties in the timely development of resources needed to achieve the state's clean energy goals reliably and economically.

A near-term priority for collaboration is providing a 2045 Scenario for California ISO to use in the next 20-Year Transmission Outlook, which is anticipated in 2024. The next 20-Year Transmission Outlook will inform the 2025 SB 100 Joint Agency Report.

The 2045 Scenario is informed by several recent long-term resource planning scenarios (Table 1). Given the 20-plus-year planning horizon, the resource and storage mix presented in this scenario does not account for the full suite of development uncertainties, such as cost, commercial readiness, technical challenges, supply chain, and permitting. Therefore, the use of the 2045 Scenario is not a commitment to the resource and storage mix included in the scenario. Instead, the 2045 Scenario is designed to provide information for a wide range of potential transmission needs driven by a combination of potential renewable and zero-carbon resource and storage opportunities. The 2045 Scenario is informational only and should not be used, on its own, to support approval of near-term infrastructure investments.

Table 1: Summary of Long-Term Planning Scenarios that Inform the 2045 Scenario

Study Name	Scenario Description	Year Studied	Links to Report
SB 100 Core Scenario	The core scenario from the 2021 Joint Agency SB 100 Report. This scenario includes retail sales and state loads, high electrification demand, and all candidate resources available. This scenario includes 145 GW of new resources by 2045.	2045	2021 SB 100 Joint Agency Report Achieving 100 Percent Clean Electricity in California: An Initial Assessment. (https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349)
2040 Starting Point Scenario	The 2040 Starting Point Scenario (2021) was developed by the CEC and CPUC for use by the California ISO in the 20-year transmission outlook (2022). This scenario includes 120 GW of new resources by 2040. This scenario also includes 15,000 of assumed natural gas retirements.	2040	SB 100 Starting Point Scenario for the CAISO 20-year Transmission Outlook. (https://efiling.energy.ca.gov/GetDocument.aspx?tn=239685&DocumentContentId=73101)
2023-2024 TPP Base Case	A base case portfolio for both reliability and policy-driven purposes produced by the CPUC and evaluated by the California ISO to determine transmission investments needed. The portfolio expects 85 GW of new resources by 2035 to be built to meet a 30 million metric ton greenhouse gas emissions target in 2030 and uses the CEC's 2021 Integrated Energy Policy Report "Additional Transportation Electrification" load scenario.	2035	Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmission Electric Resource Portfolios to California Independent System Operator for 2023-2024 Transmission Planning Process. (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF)

Table 1 describes long-term resource planning scenarios which inform the 2045 Scenario for the 20-Year Transmission Outlook.

Source: CEC staff

CHAPTER 2: Demand Assumptions

The 2021 SB 100 Starting Point Scenario, which informed the 2022 California ISO 20-year outlook, used the PATHWAYS High Electrification demand scenario that was used in the SB 100 Core Scenario. The peak load in 2040, before accounting for behind-the-meter (BTM) solar photovoltaic (PV), was projected to be 73,900 megawatts (MW) for the California ISO region. For the 2024 California ISO 20-year outlook, a more recent demand scenario produced by the CEC is used that projects a peak load of 68,800 MW in 2040 before accounting for BTM PV.

Demand Scenario for the 2045 Scenario

The 2045 Scenario will use the CEC's 2021 Mid-Mid Case extrapolated to 2045, with the transportation load swapped for the 2022 Integrated Energy Policy Report (IEPR) Update Forecast results. The Mid-Mid Case was chosen for the 20-year transmission outlook because this is a longer-term system-wide study, in contrast to the TPP which is a localized study and relies on higher demand assumptions due to the increased uncertainty when disaggregating to the load bus level.[4] The projected peak load for this scenario in 2045 is 61,900 MW, and annual energy demand is 313,000 GWh for the California ISO region which includes generation from BTM PV.

CEC's California Energy Demand Forecast is a cornerstone component of the state's energy planning process. The forecast includes several products that are used across several energy planning proceedings such as Resource Adequacy and Integrated Resource Planning. CEC's 2021 Mid-Mid Case[5] is the main product that informs these proceedings. Each year, forecasts are updated to account for changes in key energy demand drivers and historical datasets. The 2021 Mid-Mid Case is based on economic and demographic forecast drivers, historical energy consumption data, electricity and natural gas rates projections, adoption forecasts for BTM PV and battery storage, energy efficiency, fuel substitution, and electric vehicles. Moreover, adjustments were made to the forecast to account for changes in demand due to climate

[4] For comparison, the Additional Transportation Electrification scenario adopted in May 2022 which will be used for the 2023-24 TPP projected a peak load of 55,500 MW and 281,000 annual GWh in 2035 for the California ISO region, compared to the scenario used for the 20-year outlook which projects a peak load of 54,900 MW and 265,000 annual GWh in 2035.

[5] Javanbakht, Heidi, Cary Garcia, Ingrid Neumann, Anitha Rednam, Stephanie Bailey, and Quentin Gee. 2022. Final 2021 Integrated Energy Policy Report, Volume IV: California Energy Demand Forecast. California Energy Commission. Publication Number: CEC-100- 2021-001-V4.

change. As mentioned above, the 2045 Scenario swaps the 2021 Mid-Case transportation load for the *2022 IEPR Update* transportation forecast.[6]

The *2022 IEPR Update* transportation forecast provides a key update to incorporate the recently adopted vehicle regulations established by the California Air Resources Board (CARB). The Advanced Clean Cars II regulation and the Advanced Clean Fleets regulation require a much larger growth in zero-emission vehicles than forecasted in the *2021 IEPR*. Current market conditions strongly indicate that battery-electric vehicles will represent the vast majority of zero-emission vehicles. A new forecast framework was developed to account for these additional vehicles, called Additional Achievable Transportation Electrification. The adoption of these regulations results in a significant growth in electric vehicle load compared to the original 2021 Mid-Mid Case.

CEC mapped the Additional Achievable Transportation Electrification, Additional Achievable Energy Efficiency, and Additional Achievable Fuel Substitution components of the forecast to the busbar level through 2035. For 2036 through 2045, the California ISO will disaggregate the load from the transmission access charge area to busbar using a weighting approach.

Behind-the-Meter Resource Assumptions

BTM resource adoption and its associated impacts on electricity demand are imbedded in the 2021 Mid-Mid Case. The demand scenario includes approximately 42 GW of BTM PV capacity in 2045. Forecasted BTM PV adoption is based on system payback periods calculated from projections for technology costs, economic conditions, hourly BTM system performance, electricity rates, and incentives. It's important to note that cost calculations incorporate CPUC's Net Energy Metering (NEM) 2.0 tariff and the federal government's Investment Tax Credit (ITC).[7] BTM energy storage adoption was predicted from historic adoption trends for both BTM storage and solar PV. Thus, any impacts on storage adoption influenced by NEM 2.0 or ITC are assumed to be embedded in the projections. Forecasted BTM solar PV and storage adoption forecasts were adjusted to account for growth in these resources based on Title 24 standards for new buildings. Finally, annual as well as hourly demand impacts resulting from cumulative BTM resource adoption were forecasted using hourly BTM system performance data.

[6] Bailey, Stephanie, Jane Berner, David Erne, Noemí Gallardo, Quentin Gee, Akruti Gupta, Heidi Javanbakht, Hilary Poore, John Reid, and Kristen Widdifield. 2023. Final 2022 Integrated Energy Policy Report. California Energy Commission. Publication Number: CEC-100-2022001-CMF.

7 Note that CPUC adopted NEM 3.0 in 2023 which is not reflected in the 2021 IEPR forecast. Additionally, the 2021 IEPR forecast does not reflect the extension of the ITC which was slated to end in 2023. These updates will be reflected in the 2023 IEPR forecast.

CHAPTER 3: Resource Assumptions

The 2021 SB 100 Starting Point Scenario, which informed the 2022 California ISO 20-year outlook, was developed by taking the 2040 SB 100 Core Scenario and increasing assumed natural gas power plant retirements to 15,000 MW. This increase allowed for an evaluation of the impact of more gas power plant retirements on the transmission system than was identified in the SB 100 Core scenario, in conjunction with bringing new energy storage and renewable energy resources online. In addition, to generally offset the additional assumed natural gas power plant retirements, geothermal, offshore wind (OSW), out-of-state wind, and battery-energy storage systems capacity was added to levels that are generally reflective of other 2021 SB 100 Report scenarios. The scenarios in the 2021 SB 100 Report were developed through a comprehensive interagency stakeholder process to meet a statewide 2045 policy, which includes balancing area authorities (BAA) outside the California ISO.

Table 2: Resource Assumptions in the 2040 SB 100 Starting Point Scenario

Resource Type	2040 Starting Point Scenario (MW)
Natural gas-fired power plants	(-15,000)
Utility-scale solar	53,212
In-state wind	2,837
Offshore wind	10,000
Out-of-state wind	12,000
Geothermal	2,332
Battery-energy storage	37,000
Long-duration energy storage	4,000

Table 1 details the resource assumptions in the 2040 Starting Point Scenario which the California ISO used in the 20-year transmission outlook (2022).

Source: CEC staff

Resource Assumptions for the 2045 Scenario

The 2045 Scenario was developed by taking the resource portfolio from the 2040 Starting Point Scenario with the following adjustments:

- Retain 15 gigawatts (GW) natural gas retirement assumptions.
- Increase offshore wind to 20 GW to reflect updated state policy and executive actions.
- Add resources to help offset additional natural gas retirements in-line with resources included in the previous Starting Point Scenario for the 20-year transmission outlook.

- Add 5 GW of generic clean firm resources/long-duration energy storage.
- Add resources and update resource mapping assumptions to align with resource locations in the latest IRP portfolios for the TPP.[8]

Table 2 provides an overview of the resource assumptions in the 2045 Scenario.

Table 3: New Resource Assumptions in the 2045 Scenario

Resource Type	2045 Scenario (MW)
Natural gas fired power plants	(-15,000)
Utility-scale solar	69,640
Distributed Solar	125
In-state wind	3,074
Offshore wind	20,000
Out-of-state wind	12,000
Geothermal	2,332
Biomass	134
Battery-energy storage	48,813
Long-duration energy storage	4,000
Generic clean firm/long-duration energy storage	5,000

Table 2 details the resource assumptions in the 2045 Scenario which the California ISO will use in the 20-year transmission outlook (anticipated 2024).

Source: CEC and CPUC staff

To further illustrate the 2045 Scenario, Table 3 below compares the SB 100 Core Scenario (2045), the 2040 Starting Point Scenario, and the 2023–2024 TPP base portfolio and OSW Sensitivity (2035) with the 2045 Scenario.

8 CPUC. February 2023. Modeling Assumptions for the 2023-2024 Transmission Planning Process. Staff Report. 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/modeling_assumptions_2023-24tpp_v02-23-23.pdf.

Table 4: Comparison of SB 100 Core, 2040 Starting Point Scenario, CPUC IRP TPP Base and Sensitivity Portfolios, and 2045 Scenario

Resource Type (MW)	SB 100 Core (2045)	Starting Point Scenario (2040)	2023–2024 TPP Base Portfolio (2035)	2023–2024 TPP OSW Sensitivity (2035)	2045 Scenario (2045)
Natural Gas Fired Power Plants	(-4,722)	(-15,000)	-	-	(-15,000)
Utility-Scale Solar	69,640	53,212	38,947	25,746	69,640
Distributed Solar	-	-	125	125	125
In-state wind	2,837	2,837	3,074	3,074	3,074
Offshore wind	10,000	10,000	5,497	13,400	20,000
Out-of-state wind	2,837	12,000	5,618	5,618	12,000
Geothermal	135	2,332	2,037	1,149	2,332
Biomass	-	-	134	134	134
Battery-energy storage	48,813	37,000	28,373	23,545	48,813
Long-duration energy storage	4,000	4,000	2,000	1,000	4,000
Generic clean firm/long-duration energy storage	-	-	-	-	5,000

Table 3 compares resource assumptions across recent state resource and transmission planning studies.

Source: CEC and CPUC staff

Offshore Wind

The 2021 Starting Point Scenario included 10,000 MW of offshore wind in 2040. The 2045 Scenario includes 20,000 MW of offshore wind to reflect updated state policy and executive actions.

Following the publication of the 2021 Starting Point Scenario, on September 23, 2021, Governor Gavin Newsom signed into law Assembly Bill 525 (AB 525, Chiu, Chapter 231, Statutes of 2021), which took effect January 1, 2022. AB 525 requires the CEC, in coordination with federal, state, and local agencies and a wide variety of stakeholders, to develop a strategic plan for offshore wind energy deployment off the California coast in federal waters.

In a July 22, 2022, letter to the chair of the California Air Resources Board, Governor Newsom asked the CEC to establish an offshore wind planning goal of at least 20 GW by 2045, among other requested actions.[9] In August 2022, the CEC published the *Offshore Wind Energy Development off the California Coast*[10] report, which established a potentially achievable but aspirational planning goal of 25,000 MW for 2045. The CEC report also established 21.8 GW as a reference point for technically feasible capacity that the CEC will continue to evaluate in developing the AB 525 strategic plan.

The 20 GW of OSW resources assumed in the 2045 Scenario is within the range of California OSW technically feasible capacity evaluated in the 2022 CEC report.

Generic Clean Firm Resources/Long-Duration Energy Storage

The assumed retirement of 15,000 MW of gas resources creates the presumptive need for additional capacity to meet peak demand needs. After adding the additional offshore wind capacity and additional renewable resources in line with the previous 20-year transmission outlook and the 23-24 TPP base case portfolio, the CPUC and CEC staff estimate that an additional 5,000 MW of generic clean firm resources or long-duration energy storage capacity is needed. SB 423 (Stern, Chapter 243, Statues of 2021) defines "firm zero-carbon resources" as electrical resources that can individually, or in combination, deliver zero-carbon electricity with high availability for the expected duration of multiday extreme or atypical weather events, including periods of low renewable energy generation, and facilitate integration of eligible renewable energy resources into the electrical grid and the transition to a zero-carbon electrical grid.[11] Examples of zero-carbon firm resources include geothermal, biomass and resources that generate electricity from zero-carbon hydrogen. The option for long-duration energy storage resources likewise represent an array of existing and emerging long-duration storage types including pumped storage, compressed air, iron-air batteries, and other battery storage technologies. The key requirement is to be able to serve additional capacity to meet peak demand needs on the eight-hour to multi-day time frame.

Distributed Solar

The 2045 Scenario includes considerations for BTM solar and distributed solar. BTM solar is included through the load assumptions, as described in Chapter 2. In addition to BTM solar, the 2045 Scenario includes 125 MW of distributed solar. Distributed solar is separate from BTM

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9 Governor Gavin Newsom, letter to chair of the California Air Resources Board. July 22, 2022. https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf?emrc=1054d6.

10 Flint, Scott, Rhetta DeMesa, Pamela Doughman, and Elizabeth Huber. 2022. *Offshore Wind Development off the California Coast: Maximum Feasible Capacity and Megawatt Planning Goals for 2030 and 2045*. California Energy Commission. Publication Number: CEC-800-2022-001-REV. https://www.energy.ca.gov/publications/2022/offshore-wind-energy-development-california-coast-maximum-feasible-capacity-and

11 Senate Bill 423. (Stern, Chapter 243, Statues of 2021). Public Resources Code 25216.7(d)(2). https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220SB423.

solar PV and represents in-front of the meter large-scale commercial rooftop to community scale solar.

CHAPTER 4: Geographic Allocation of Resources

The 20-year outlook requires geographically mapping resources to specific locations, to the extent feasible. This section describes, for each resource in the 2045 Scenario, criteria for the California ISO to use in the 20-year outlook. Wherever possible, the mapping criteria aligns with the current CPUC integrated resource plan (IRP) portfolios being studied within the 2023-2024 TPP. In Appendix B, a table with the geographic allocations for the 20-year transmission outlook for each resource is included, as applicable. All MW values discussed below are assumed to occur by 2045.

Natural Gas Power Plant Retirements

The 2045 Scenario retains the assumption from the 2021 Starting Point Scenario that 15,000 MW of natural gas power plant capacity would be retired by 2040, which is about 50 percent of natural gas power plant capacity assumed in the 2021 SB 100 Report scenarios. This assumption is made only to support the objective of California ISO's informational study and has not been analyzed or modeled through any other process. To identify the locations of assumed retirements for this 20-year transmission outlook, the California ISO should follow the criteria established in the 2021 Starting Point Scenario and first 20-year transmission outlook. These criteria are the following:

- The oldest natural gas power plants retire first, with a priority for those that are in and adjacent to disadvantaged communities.[12]
- At least 3,000 MW of the 15,000 MW of retirements are assigned to natural gas power plants that rely on the Aliso Canyon storage facility as provided by the agencies, with a priority on the oldest power plants and those that are in and adjacent to disadvantaged communities.

Table 3.1-4 in the first 20-year outlook provides an overview of the assumed natural gas-fired generation retired by local capacity area.[13]

New Energy Generation and Storage Capacity

Lithium ion-battery (Li-battery) energy storage: The 2045 Scenario includes 48,813 MW of battery energy storage. The approach used for assigning battery energy storage to transmission zones for the 20-year outlook draws on the approach applied to battery energy

12 Disadvantaged communities are defined and identified by the California Office of Environmental Health Hazard Assessment and are available in the CalEnviroScreen 3.0 webtool at https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30. For this 2045 Scenario, a natural gas power plant "adjacent to" a disadvantaged community is defined as within a 2.5-mile radius.

13 California Independent System Operator. May 2022. [20-Year Transmission Outlook](http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf). http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf. Page 20.

storage in the CPUC's IRP process for the California ISO's TPP. As shown in Appendix B, the 48,813 MW of battery energy storage is allocated as follows:

- The 28,373 MW of battery energy storage already mapped in the IRP resource portfolio for the 2023–2024 TPP base case is carried over without any changes.
- The remaining 20,440 MW of battery energy storage will be allocated by expanding upon the approach from the 2023-2024 TPP base case:
    - Co-locate at substations where utility-scale solar resources are mapped.
    - Stand-alone in local capacity areas to displace gas resources.

Long-duration energy storage: Long-duration energy storage (LDES) was modeled in the 2021 SB 100 Joint Agency Report as pumped hydroelectric energy storage.[14] However, any long-duration storage technology with eight hours or longer of energy generation at maximum output would represent similar attributes. Thus, for the 2045 Scenario, any long duration energy storage technology is considered and not just limited to potential pumped storage resources. The 4,000 MW of LDES in the 2045 Scenario is allocated by building off the current 2023–2024 TPP base case, as well as current commercial interest.

The 4,000 MW of LDES is allocated by:

- 2,000 MW of LDES already mapped in the IRP resource portfolio for the 2023–2024 TPP base case.
- 2,000 MW of LDES aligned with LDES identified in the current California ISO interconnection queue.

Generic clean firm/LDES: Given the current commercial interests and development uncertainty of various emerging technologies, the 5,000 MW of generic clean firm resources and long duration energy storage resources are mapped specifically outside of local areas, near renewable generation. Mapping of these resources outside of the local reliability areas enables study of greater transmission needs into local areas.

Utility-scale solar: The 2045 Scenario includes 69,640 MW of utility-scale solar, which is consistent with the SB 100 Core Scenario from the 2021 SB 100 Joint Agency report. The approach used for allocating utility-scale solar for the 20-year outlook draws on the approach applied to mapping utility-scale solar in the CPUC's IRP process for the California ISO's TPP. As shown in Appendix B, the 69,640 MW of utility-scale solar is allocated as follows:

- 38,947 MW of utility-scale solar energy is already mapped in the IRP resource portfolio for the 2023–2024 TPP base case and is carried over without any changes.
- The allocation of the remaining 30,693 MW of utility-scale solar will be guided by these criteria, which are informed by criteria applied in busbar mapping of the IRP resource portfolios for the TPP:

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14 An energy storage technology consisting of two water reservoirs separated vertically; during off-peak hours, water is pumped from the lower reservoir to the upper reservoir, allowing the off-peak electrical energy to be stored indefinitely as gravitational energy in the upper reservoir. During peak hours, water from the upper reservoir is released and passed through hydraulic turbines to generate electricity, as needed.

- *Commercial interest*: Commercial interest, as used in this 2045 Scenario, is determined by using the California ISO's publicly available interconnection queue information.[15] This information includes projects in the queue through the Cluster 14 study window.
- *Environmental and land-use evaluation*: The CEC used the core land-use screen[16] to assess whether substations that were mapped in the 2023–2024 IRP portfolios had sufficient availability of "lower implication"[17] land to map additional utility-scale solar capacity. Other substations that are on the 500 or 230/220 kV system were considered for possible distribution of new resources. Staff performed a geospatial analysis by intersecting 15-mile buffers around each substation with the area remaining outside the core land-use screen. This "lower implication" land with technical resource potential is aggregated within these buffered circles. Land with existing solar facilities were removed from this sum. A limit of 50 percent of the technical resource potential area was chosen for how much new resource could be mapped to a given substation before it was considered "full". See Appendix C for additional information on the core land-use screen.

In-state wind: The 2045 Scenario includes 3,074 MW of in-state wind resources. The 3,074 MW of in-state wind resources already mapped in the IRP resource portfolio for the 2023–2024 TPP base case is carried over without any changes. The allocation of in-state wind resources is shown in Appendix B.

Out-of-state (OOS) wind: The 2045 Scenario includes 12,000 MW of wind energy resources generated outside of the existing California ISO system. As shown in Appendix B, the 12,000 MW of out-of-state wind is allocated as follows:

- 790 MW from Arizona and New Mexico on existing out-of-state (OOS) transmission
- 1,000 MW from Idaho on new OOS transmission
- 5,000 MW from Wyoming on new OOS transmission
- 5,210 MW from New Mexico on new OOS transmission

Offshore wind: The 2045 Scenario includes 20,000 MW of offshore wind (OSW) resources. To identify the regions for mapping the 20,000 MW of OSW resources, the staff started with the 13,400 MW of OSW resources already mapped in the high OSW sensitivity from the IRP resource portfolio for the 2023-2024 TPP. The resources in the CPUC's high OSW sensitivity were mapped to the following locations: Morro Bay Wind Energy Area (5,400 MW), Humboldt Wind Energy Area (2,600 MW), Del Norte Interest Area (3,400 MW), and Cape Mendocino

15 http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx

16 Hossainzadeh, Saffia, Erica Brand, Travis David, and Gabriel Blossom. 2023. *Land-Use Screens for Electric System Planning: Using Geographic Information Systems to Model Opportunities and Constraints for Renewable Resource Technical Potential in California.* California Energy Commission. Forthcoming publication.

17 In the CEC staff statewide land-use screening for electric system planning, *implication* is defined as a possible significance or a likely consequence of an action, for example, planning for energy infrastructure development in an area of higher biodiversity has *implications* for other land-use priorities.

Interest Area (2,000 MW). To inform mapping the remaining 6,600 MW of OSW resources, the staff consulted two in-progress analyses to understand a range of generation potentials and possible constraints:

- The OSW Development Scenarios under development and evaluation by the Schatz Energy Research Center for the *Northern California and Southern Oregon Offshore Wind Transmission Study*.[18] The analysis considers three scales of OSW development in Northern California, including:
  - Low Development Scenario: 4,100 MW of OSW capacity.
  - Mid-Range Development Scenario: 9,300 MW of OSW capacity.
  - High Development Scenario: 16,000 MW of OSW capacity.
- The in-development AB 525 sea space area identification. During a June 1, 2023, workshop, CEC staff presented a draft range of estimated generation potential from within lease areas and AB 525 sea space areas.[19] The additional AB 525 sea space areas identified are based on wind resource and technical characteristics, such as ocean bottom depth, ocean bottom slope, and distance to shore. These areas will likely reduce in size once screened for conflicts such as existing ocean uses and cultural and biological resources. The draft ranges are:
  - Humboldt Leases: 1,600–3,000 MW
  - North Coast AB 525 sea space: 27,000–45,000 MW
  - Morro Bay Leases: 3,000–6,000 MW
  - South Central Coast AB 525 sea space: 3,500–6,000 MW

After consulting the two in-progress analyses, staff allocated the remaining 6,600 MW of OSW to the Humboldt Wind Energy Area (100MW), the Del Norte Interest Area (3,600 MW), and the Cape Mendocino Interest Area (2,900 MW).

As shown in Appendix B, the CEC and CPUC staff allocated the full 20,000 MW of OSW as follows:

- 7,000 MW potential from Del Norte Interest Area
- 2,700 MW from Humboldt Wind Energy Area
- 4,900 MW potential from Cape Mendocino Interest Area
- 5,400 MW from Morro Bay Wind Energy Area

The geographic allocation of the OSW resources fits within the generation potential ranges under evaluation in the Schatz Energy Research Center *Northern California and Southern Oregon Offshore Wind Transmission Study* and the CEC AB 525 sea space identification.

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18 CEC AB 525 Workshop. May 25, 2023. Presentation slides available online at https://efiling.energy.ca.gov/GetDocument.aspx?tn=250371&DocumentContentId=85115. Starts at slide 41.

19 CEC AB 525 Workshop. June 1, 2023. Presentation slides available online at https://efiling.energy.ca.gov/GetDocument.aspx?tn=250471. Slide 59.

Geothermal: The 2045 Scenario includes 2,332 MW of geothermal resources. As shown in Appendix B, the 2,332 MW of geothermal resources is allocated as follows:

- The 2,037 MW of geothermal resources already mapped in the IRP resource portfolio for the 2023–2024 TPP base case is carried over without any changes.
- The remaining 295 MW are mapped to the Imperial region bringing the total geothermal mapped to the Imperial area to 1,195 MW. The Salton Sea area has significant geothermal resource potential beyond what was mapped to in the 23-24 TPP base portfolio and the previous 20-year outlook mapped a significant portion of the geothermal resources to the Salton Sea area.

Biomass: The 2045 Scenario includes 134 MW of biomass resources. The 134 MW of biomass resources already mapped in the IRP resource portfolio for the 2023–2024 TPP base case is carried over without any changes.

APPENDIX A
Glossary

Term	Definition
2021 SB 100 Starting Point Scenario	A scenario is a plausible description of how the future may develop based on a coherent and internally consistent set of assumptions about key driving forces (for example, rate of technological change, prices) and relationships. Note that scenarios are neither predictions nor forecasts but are used to provide a view of the implications of developments and actions. The 2021 SB 100 Starting Point Scenario was developed for use by the California ISO in the 20-year transmission outlook.
Additional Achievable Transportation Electrification	A CEC transportation energy demand forecasting framework that allows for standard forecasting model modifications to account for transportation policy changes that are reasonably expected to occur. These modifications can be made even if standard economic forecasting tools do not have the ability to capture such policies. For example, standard demand forecasting can capture policies that influence the demand for electric vehicles, but supply-side policies that influence vehicle manufacturers may not be captured under standard demand forecasting techniques.
Advanced Clean Cars II regulation	Two-pronged regulation from California Air Resources Board (CARB). First, it amends the Zero-emission Vehicle Regulation to require an increasing number of zero-emission vehicles, and relies on currently available advanced vehicle technologies, including battery-electric, hydrogen fuel cell electric and plug-in hybrid electric-vehicles, to meet air quality and climate change emissions standards. These amendments support Governor Newsom's 2020 Executive Order N-79-20 that requires all new passenger

	vehicles sold in California to be zero emissions by 2035. Second, the Low-emission Vehicle Regulations were amended to include increasingly stringent standards for gasoline cars and heavier passenger trucks to continue to reduce smog-forming emissions. For more information see, Advanced Clean Cars II Regulations.
Advanced Clean Fleets regulation (ACF)	The Advanced Clean Fleets regulation is part of the California Air Resources Board's (CARB or Board) overall approach to accelerate a large-scale transition to zero-emission medium- and heavy-duty vehicles. This regulation works in conjunction with the Advanced Clean Trucks (ACT) regulation, approved March 2021, which helps ensure that zero-emission vehicles (ZEV) are brought to market. For more information see, Advanced Clean Fleets Regulation.
Aliso Canyon storage facility	Aliso Canyon is a depleted oil field that has been used to store natural gas for the Los Angeles region since 1972. SoCalGas has historically used Aliso Canyon to help balance supply and demand in the summer and to help meet peak demand in the winter. On October 23, 2015, a massive leak at the Aliso Canyon natural gas storage facility was discovered and continued until it was sealed on February 18, 2016. In response to the leak at the Aliso Canyon, the state limited its use.
Alternating current (AC)	Flow of electricity that constantly changes (alternates) direction between positive and negative sides in a sine curve. Almost all power produced by electric utilities in the United States moves in current that shifts direction at a rate of 60 times per second.
Balancing authority	A balancing authority is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time. Balancing authorities in California include the Balancing Authority

	of Northern California (BANC), California ISO, Imperial Irrigation District (IID), Turlock Irrigation District (TID) and Los Angeles Department of Water and Power (LADWP). The California ISO is the largest of about 38 balancing authorities in the Western Interconnection, handling an estimated 35 percent of the electric load in the West and 80 percent of the electric load in California. For more information, see the WECC Overview of System Operations: Balancing Authority and Regulation Overview Web page.
California Energy Demand Forecast (CED)	CED is a set of several forecasting products that are used in various energy planning proceedings, including the California Public Utilities Commission's (CPUC's) oversight of energy procurement and the California Independent System Operator's (California ISO's) transmission planning. The demand forecast generally includes: Ten-year annual end-use consumption forecasts for electricity and natural gas by customer sector, eight planning areas, and 20 forecast zones. Annual peak electric system load with different weather variants for eight planning areas. Annual projections of load modifier impacts including adoption of photovoltaic and other self-generation technologies, energy efficiency standards, and program impacts. For more information, see the Final 2021 Integrated Energy Policy Report Volume IV: California Energy Demand Forecast.
California ISO's 20-Year Transmission Outlook	A report published by the California ISO to provide a long-term conceptual plan of the transmission grid in 20 years, meeting the resource and electric load needs aligned with state agency input on integrated load forecasting and resource planning. The report is developed in collaboration with the California Public Utilities Commission and the California Energy Commission. For more

	information, see the 20 Year Transmission Outlook report.
Direct current (DC)	Electricity that flows continuously in the same direction rather than alternating (see above).
CPUC Integrated Resource Planning (IRP)	A planning proceeding to consider all the CPUC's electric procurement policies and programs and ensure California has a safe, reliable, and cost-effective electricity supply. The integrated resource planning process ensures that load-serving entities (LSEs) detail the procured and planned resources in their portfolios that allow the electricity sector to meet electricity demand while also contributing to meeting California's economywide greenhouse gas emissions reductions goals.
Kilovolt (kV)	One-thousand volts (1,000). Distribution lines in residential areas usually are 12 kV (12,000 volts).
PATHWAYS High Electrification Demand Scenario	The PATHWAYS model, developed by Energy and Environmental Economics, Inc (E3), is an economy-wide scenario tool used to identify pathways to achieve economy-wide decarbonization. For more information, see PATHWAYS Model.
Renewables Portfolio Standard (RPS)	The Renewables Portfolio Standard, also referred to as RPS, is a program that sets continuously escalating renewable energy procurement requirements for California's load-serving entities. The generation must be procured from RPS-certified facilities (which include solar, wind, geothermal, biomass, biomethane derived from landfill and/or digester, small hydroelectric, and fuel cells using renewable fuel and/or qualifying hydrogen gas). More information can be found at the CEC Renewables Portfolio Standard web page and the CPUC RPS Web page.
SB 100 Core Scenario	A scenario is a plausible description of how the future may develop based on a coherent and internally consistent set of assumptions

	about key driving forces (for example, rate of technological change, prices) and relationships. Note that scenarios are neither predictions nor forecasts, but are used to provide a view of the implications of developments and actions. The SB 100 Core Scenario from 2021 SB 100 Joint Agency Report is based on retail sales and in-state demand.

APPENDIX B
Resource Allocations for the 2045 Scenario for the 20-Year Outlook

Table B-1 provides an overview of the resource allocations by RESOLVE resource area[20] for the 2045 Scenario for the 20-year outlook. A full breakdown of the resources, including the mapping by substation and mapping analysis, can be found in the 2045 Scenario Portfolio Dashboard in CEC Docket 21-SIT-01.

Table B-1: Resource Allocations for the 2045 Scenario for the 20-Year Transmission Outlook

		2040 SB 100 Starting Point Scenario	23-24 TPP Base Case	2045 Scenario
		2040	2035	2045
InState Biomass	Biomass/Biogas	-	134	134
Solano_Geothermal	Geothermal	-	139	139
Northern_California_Geothermal	Geothermal	-	-	-
Inyokern_North_Kramer_Geothermal	Geothermal	-	53	53
Southern_Nevada_Geothermal	Geothermal	320	500	500
Northern_Nevada_Geothermal	Geothermal	-	445	445
Riverside_Palm_Springs_Geothermal	Geothermal	-	-	-
Greater_Imperial_Geothermal	Geothermal	2,012	900	1,195
Distributed Solar	Solar	-	125	125
Northern_CA	Solar	1,167	898	2,847
Greater_Bay	Solar	-	510	510
Central_Valley_LosBanos	Solar	809	1,208	3,391

20 CPUC. June 2023. Draft Inputs and Assumptions. 2022-2023 Integrated Resource Planning (IRP). 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/draft_2023_i_and_a.pdf

SPGE_Westlands_Fresno	Solar	12,925	4,805	14,065
SPGE_Greater_Carrizo	Solar	-	230	1,630
SPGE_Kern	Solar	6,154	2,957	6,396
Big_Creek-Magunden	Solar	-	1,205	2,600
Greater_Tehachapi	Solar	9,544	6,829	8,978
Ventura_Area	Solar	2,066	750	1,800
Greater_LA	Solar	-	-	-
Greater_Kramer	Solar	3,510	2,660	3,460
SouthernNV_Desert	Solar	2,272	4,943	6,326
Riverside	Solar	4,922	6,493	6,793
Arizona	Solar	3,952	4,497	6,000
Greater_Imperial	Solar	4,807	963	4,345
San_Diego	Solar	995	-	500
Northern_California_Wind	Wind	866	339	339
Solano_Wind	Wind	542	757	757
Humboldt_Wind	Wind	34	-	-
Kern_Greater_Carrizo_Wind	Wind	60	180	180
Carrizo_Wind	Wind	287	174	174
Central_Valley_North_Los_Banos_Wind	Wind	173	150	150
North_Victor_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	275	345	345
Southern_Nevada_Wind	Wind	-	403	403
Riverside_Palm_Springs_Wind	Wind	-	127	127
Baja_California_Wind	Wind	600	600	600
Wyoming_Wind	OOS Wind	4,685	1,500	5,000
Idaho_Wind	OOS Wind	-	1,000	1,000

New_Mexico_Wind	OOS Wind	5,215	2,328	5,210
SW_Ext_Tx_Wind	OOS Wind	-	790	790
NW_Ext_Tx_Wind	OOS Wind	1,500	-	-
North_Coast_Offshore_Wind	Offshore Wind	4,000	n/a	n/a
Humboldt_Bay_Offshore_Wind	Offshore Wind	n/a	1,607	2,700
Cape_Mendocino_Offshore_Wind	Offshore Wind	n/a	-	4,900
Del_Norte_Offshore_Wind	Offshore Wind	n/a	-	7,000
Central_Coast_Offshore_Wind	Offshore Wind	6,000	n/a	n/a
Morro_Bay_Offshore_Wind	Offshore Wind	n/a	3,100	5,400
Diablo_Canyon_Offshore_Wind	Offshore Wind	n/a	-	-
Renewable Resource Total		**79,692**	**54,642**	**107,305**
Northern_CA	Li_Battery	64	674	1,843
Greater_Bay	Li_Battery	250	2,479	3,079
Central_Valley_LosBanos	Li_Battery	-	537	1,846
SPGE_Westlands_Fresno	Li_Battery	431	2,341	7,899
SPGE_Greater_Carrizo	Li_Battery	50	210	1,050
SPGE_Kern	Li_Battery	95	1,441	3,603
Big_Creek-Magunden	Li_Battery	-	575	1,411
Greater_Tehachapi	Li_Battery	4,036	4,471	6,339
Ventura_Area	Li_Battery	500	668	1,298
Greater_LA	Li_Battery	1,651	2,527	2,527
Greater_Kramer	Li_Battery	176	1,404	1,884
SouthernNV_Desert	Li_Battery	700	2,689	3,517
Riverside	Li_Battery	-	4,900	5,380
Arizona	Li_Battery	695	1,567	2,918

Greater_Imperial	Li_Battery	-	603	2,632
San_Diego	Li_Battery	720	1,289	1,589
Unspecified_Locations	Li_Battery	27,632	-	-
Li_Battery_Total		**37,000**	**28,374**	**48,814**
SPGE_Greater_Carrizo	LDES	-	300	500
SPGE_Westlands_Fresno	LDES	-	-	100
Greater_Tehachapi	LDES	-	500	1,000
Riverside	LDES	1,900	700	1,500
San_Diego	LDES	500	500	500
Northern_CA_LDES	LDES	-	-	400
Unspecified_Locations	LDES	1,600	-	-
LDES Total		**4,000**	**2,000**	**4,000**
Storage Total		**41,000**	**30,374**	**52,814**
Generic Clean-Firm or LDES	Unspecified	-	-	5,000
Total New Resources		**120,692**	**85,015**	**165,118**

APPENDIX C
Core Land-Use Screen

The core land-use screen is the primary screen established by the geospatial analysis in the CEC Land-Use Screens Report.[21] The core land-use screen identifies:

(1) areas of the state that should be excluded from resource potential consideration because of technical and economic criteria commonly applied in energy infrastructure development,[22] and

(2) areas where utility-scale renewable energy or transmission development is precluded by state or federal law, policy or regulation.[23]

The geospatial datasets consisting of these categories of data are identified and compiled into a single map at statewide scale. They are referred to as the technoeconomic exclusion layer and the protected area layer and form the base exclusions of the core land-use screen.

The other components of the core land-use screen address several state policy priorities, including sustaining agriculture, protecting natural lands that support biodiversity,[24] and conserving intact landscapes. These additional land-use planning considerations fall into three categories used in the core screen:

(1) Biological Planning Priorities: Combines mapped delineations of U.S. Fish and Wildlife Service critical habitat (including the proposed bistate sage grouse), high ranks of California Department of Fish and Wildlife's Areas of Conservation Emphasis Terrestrial Connectivity, Biodiversity and Irreplaceability, and lands classified as wetlands.

(2) Terrestrial Landscape Intactness: A multicriteria evaluation model[25] result representing landscape condition based on the extent to which human impacts such as agriculture,

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21 Hossainzadeh, Saffia, Erica Brand, Travis David, and Gabriel Blossom. 2023. *Land-Use Screens for Electric System Planning: Using Geographic Information Systems to Model Opportunities and Constraints for Renewable Resource Technical Potential in California.* California Energy Commission. Forthcoming publication.

22 Spatial datasets that capture technical (for example, competitive wind resource locations), physical (for example, slope, water bodies) and socioeconomic or hazardous (for example, densely populated areas, railways, airports, highways, mines) criteria. This category also includes military lands. This layer was developed by CPUC staff.

23 Example designations of lands that fall under the protected area layer are National Parks, GAP Status 1 and 2, Open Spaces, Wilderness Areas, National Conservation Lands, Scenic Areas, easements, and Recreation Areas. For a full description and list of categories see Table D-1 and Table D-2 of the California Energy Commission, *Land-Use Screens for Electric System Planning: Using Geographic Information Systems to Model Opportunities and Constraints for Renewable Resource Technical Potential in California.* Staff report. Forthcoming publication.

24 [Executive Order N-82-20](https://www.gov.ca.gov/wp-content/uploads/2020/10/10.07.2020-EO-N-82-20-.pdf), available at https://www.gov.ca.gov/wp-content/uploads/2020/10/10.07.2020-EO-N-82-20-.pdf.

25 A multicriteria evaluation is common in geospatial analyses when multiple inputs affect an overall value decision for an area. This method allows each input data layer to be transformed onto a common scale and weights each dataset according to relative importance. The result is a summation of the input data layers into a single-gridded map.

urban development, natural resource extraction, and invasive species have disrupted the landscape across California.[26]

(3) CEC Cropland Index Model: For lands used to produce crops, CEC developed a multicriteria evaluation model that uses information on soil quality, farmland designation, and existence of crops to create a numerically weighted index for the relative suitability of an area for crop production.

The CEC Cropland Index Model and the CBI Landscape Intactness modeled results are evaluated, then partitioned at the mean to produce areas of higher and lower implication, with higher implication areas recommended for resource potential exclusion. These are then combined with the base exclusions and the biological planning priorities to produce the core land-use screen. The areas remaining outside the screen are considered as lower implication areas and can be quantified, typically in units of acres and capacity (megawatt or gigawatt), to estimate renewable resource technical potential for electric system modeling and energy resource planning.

26 Degagne, R., J. Brice, M. Gough, T. Sheehan, and J. Strittholt. 2016. "Landscape Intactness (1 km), California." Conservation Biology Institute. From DataBasin.org: https://databasin.org/datasets/e3ee00e8d94a4de58082fdbc91248a65.