APPENDIX F: Detailed Policy Assessment

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Contents

F Policy-Driven Need Assessment

F.1 Background and Objectives

The overarching public policy objective for the California ISO's Policy-Driven Need Assessment is the state's mandate for meeting renewable energy and greenhouse gas (GHG) reduction targets while maintaining reliability. For the purposes of the transmission planning process, this high-level objective is comprised of two sub-objectives: first, to support Resource Adequacy (RA) deliverability status for the renewable generation and energy storage resources identified in the portfolio as requiring that status, and second, to support the economic delivery of renewable energy over the course of all hours of the year.

The more coordinated and proactive approach taken in the ISO's current annual transmission planning process is part of a larger set of interrelated and coordinated planning and resource development activities being undertaken between the state energy agencies and the ISO. The ISO, for example, relies in particular on the CPUC for its lead role in developing resource forecasts for the long-term planning horizon, with both the ISO and CEC providing input to the CPUC for those resource forecasts. The ISO also relies on the CEC for its lead role in forecasting customer load requirements and the MOU signed by the three parties in December 2022 reaffirms our respective roles and commitment to ensure we are working in concert with one another. As such, the MOU also sets the overall strategic direction for tightening linkages among resource and transmission planning activities, interconnection processes and resource procurement so the three entities are synchronized in working for the timely integration of new resources.

The CPUC issued a Decision[1] on February 8, 2018, which adopted the integrated resource planning (IRP) process designed to ensure that the electric sector is on track to help the State achieve its 2030 GHG reduction target, at least cost, while maintaining electric service reliability and meeting other state goals. In subsequent years, the CPUC has been developing integrated resource plans and transmitting them to the ISO for use in the annual transmission planning process.

The CPUC issued Decision 23-02-040[2] adopting a base portfolio and a sensitivity portfolio for use in the 2023-2024 Transmission Planning Process (TPP). The portfolios are based on the 30 million metric ton (MMT) greenhouse gas (GHG) target by 2030 and the 2021 Integrated Energy Policy Report demand forecast utilizing the additional transportation electrification (ATE) scenario. The base portfolio is used to identify reliability and policy-driven transmission needs for approval in the ISO 2023-2024 TPP. The sensitivity portfolio is intended to test the transmission needs associated with 13.4 GW of offshore wind (OSW). The Decision is accompanied by a document entitled Modeling Assumptions for the 2023-2024 Transmission

[1] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K878/209878964.PDF

[2] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF

Planning Process[3], which provides the methodology and results of the resources-to-busbar mapping process as well as other assumptions for use in the ISO TPP.

F.2 Objectives of policy-driven assessment

Key objectives of the policy-driven assessment are to:

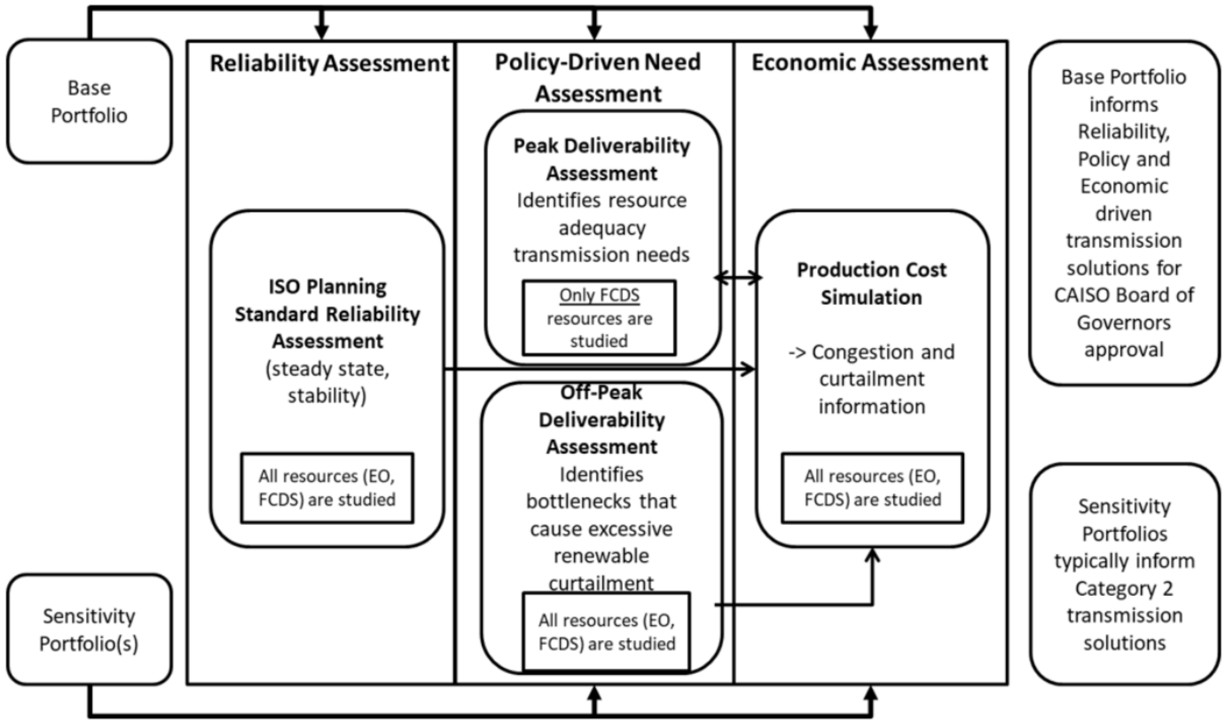
- Assess the transmission impacts of portfolio resources using:
  - Reliability assessment,
  - Peak and Off-peak deliverability assessment, and
  - Production cost simulation;
- Identify transmission upgrades or other solutions needed to ensure reliability deliverability or alleviate excessive curtailment; and
- Gain further insights to inform future portfolio development.

F.3 Study methodology and components

The policy-driven assessment is an iterative process comprised of three types of technical studies as illustrated in Figure F.3-1. These studies are geared towards capturing the impact of the resource build-out on transmission infrastructure, identifying any required upgrades and generating transmission-related input for use by the CPUC in the next cycle of portfolio development.

[3] 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

Figure F.3-1: Policy-Driven Assessment Technical Studies



Reliability assessment

The CPUC's base resource portfolio is a key input in the ISO's long term reliability assessment. The reliability assessment is used to assess transmission needs in accordance with NERC, WECC and CAISO transmission planning standards and criteria. It is also used to identify constraints and potential solutions that may be modeled in production cost simulations to assess the impact of the constraints on congestion and renewable curtailment, which may lead to identification of economic transmission projects. The reliability assessment is presented in Chapter 2 and Appendix B.

On-peak deliverability assessment

The on-peak deliverability assessment is designed to ensure portfolio resources selected with full capacity deliverability status (FCDS) are deliverable and can count towards meeting resource adequacy needs. The assessment examines whether sufficient transmission capability exists to transfer resource output from a given area to the aggregate of the ISO control-area load when the generation is needed most. The ISO performs the assessment in accordance with its On-peak Deliverability Assessment Methodology.[4]

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

Off-peak deliverability assessment

The off-peak deliverability assessment is performed to identify potential transmission system limitations that may cause excessive renewable energy curtailment. Like the reliability assessment, the offpeak assessment is also used to identify constraints and transmission solutions as candidates for detailed production cost simulation studies and economic assessment. The ISO performes the assessment in accordance with its Off-Peak Deliverability Assessment Methodology.[5]

Production cost model (PCM) simulation

Production cost models for the base and sensitivity portfolios are developed and simulated to identify renewable curtailment and transmission congestion in the ISO Balancing Authority Area. The PCM for the base portfolio is used in the policy-driven assessment that is covered in this section as well as the economic assessment covered in Chapter 4 and Appendix G. The PCM with the sensitivity portfolio is used in the policy-driven assessment only. The PCM cases are developed based on study assumptions for the ISO-controlled grid outlined in the 2023-2024 transmission planning process study plan. Details of PCM modeling assumptions and approaches are provided in Appendix G.

F.4 Resource Portfolios

As mentioned in Section F.1, a base portfolio and a sensitivity portfolio were transmitted by the CPUC for study in the ISO 2023-2024 transmission planning process. The portfolio documents are available at the CPUC website.[6]

The following documents provide details regarding the base portfolio.

Final 2035 busbar mapping results for the base portfolio: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/busbardashboard2035_30mmt_hebase_vd_02-22-23.xlsx

Final 2035 busbar mapping results for the base portfolio with minor resource adjustments to the to account for PTO identified in-development resources and remaining TPD allocated resources in applicable areas: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/busbardashboard2035_30mmt_hebase_vd2_08-11-23.xlsx

Final 2035 busbar mapping results for the offshore wind sensitivity portfolio: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2023-2024-tpp-portfolios-and-modeling-assumptions/busbardashboard2035_oswsens_vd_02-23-23.xlsx

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

[6] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/portfolios-and-modeling-assumptions-for-the-2023-2024-transmission-planning-process

Baseline reconciliation and in-development resources: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2023-2024-tpp-portfolios-and-modeling-assumptions/in-dev_res_public_v02-20-23.xlsx

Retirement list of thermal generation units: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2023-2024-tpp-portfolios-and-modeling-assumptions/thermal_agebased-ret_assumptions_v011723.xlsx

The composition of each of the portfolios by resource type is provided in Table F.4-1. The table includes resources selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO). The portfolios are comprised of solar, wind (in-state, out-of-state and offshore), battery storage, geothermal, long duration energy storage, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled. The portfolios assume some of the existing gas-fired generation fleet will be retired.

Table F.4-1: Portfolio composition – FCDS+EO resources (MW)[7]

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	15,636	23,311	38,947	11,442	14,304	25,746
Wind – In State	2,511	564	3,074	2,511	564	3,074
Wind – Out-of-State (Existing TX)	690	100	790	690	100	790
Wind – Out-of-State (New TX)	4,828	-	4,828	4,828	-	4,828
Wind - Offshore	4,546	161	4,707	13,239	161	13,400
Li Battery	28,374	-	28,374	23,545	-	23,545
Geothermal	2,037	-	2,037	1,149	-	1,149
Long Duration Energy Storage (LDES)	2,000	-	2,000	1,000	-	1,000
Biomass/Biogas	134	-	134	134	-	134
Distributed Solar	125	-	125	125	-	125
Total	60,880	24,135	85,015	58,663	15,129	73,791

In the Modeling Assumptions for the 2023-2024 Transmission Planning Process, CPUC staff provide the additional guidance below on the base and offshore wind sensitivity portfolios. The ISO has considered this guidance when conducting the policy-driven assessment.

Alignment with CAISO Queue Resources with Allocated TPD

As was done in the July 1, 2022 transmittal letter to the ISO for the 2022-2023 TPP sensitivity portfolio, CPUC staff requested that the that CAISO continue the necessary studies to inform and enable opportunities to provide Maximum Import Capability (MIC) expansion and the development of incremental transmission capacity to support the OOS and long-lead time (LLT)

[7] https://files.cpuc.ca.gov/energy/modeling/BusbarMapping_30MMT_HESens_Dashboard_08_22_22_TPD_v2.xlsx

resources mapped in the base portfolio, while preserving the existing transmission capacity that has been allocated to other projects earlier in the interconnection queue. CPUC Working Group staff sought to align the mapping with resources in the ISO's interconnection queue that have been assigned transmission plan deliverability (TPD) while still aligning with the various other busbar mapping criteria. To that end, not all the assigned TPD in the transmission areas key to OOS and LLT resources were accounted for by mapped resources. CPUC staff compiled the MW amounts and locations of these TPD allocated resources as shown in Table F.4-2 so that the CAISO can include them in addition to the mapped portfolio resources when conducting TPP analysis. Minor adjustments were also made to account for additional in-development resources identified by PTOs as shown in Table F.4-3[8].

Table F.4-2: Adjustments to the base portfolio to account for adjustments to in-development resources and TPD allocations

Transmission Area	Substation	Voltage	Resource Type	FCDS (MW)
SCE Eastern Study Area	Delaney	500	Storage	102.0
SDG&E Study Area	Hoodoo Wash	500	Storage	42.5
East of Pisgah Study Area	Ivanpah	230	Storage	200.0
East of Pisgah Study Area	Mohave	500	Storage	120.0
SCE Eastern Study Area	Redbluff	230	Storage	12.5
			Total	**477.0**

Table F.4-3: Adjustments to the base portfolio to account additional in-development resources identified

				Adopted Base Portfolio Resources (2035)			Post Decision Adjustments			Updated Base Portfolio Resources (2035)		
Transmission Area	**CAISO Substation**	**Voltage**	**Resource Type**	**FCDS (MW)**	**EODS (MW)**	**Total (MW)**	**FCDS (MW)**	**EODS (MW)**	**Total (MW)**	**FCDS (MW)**	**EODS (MW)**	**Total (MW)**
SCE Northern Area	Windhub	500	Li_Battery	412	-	412	(412)	-	(412)	-	-	-
	Windhub	230	Li_Battery	1,255	-	1,255	412	-	412	1,667	-	1,667
	Windhub	500	Solar	780	-	780	-	-	-	780	-	780
	Windhub	230	Solar	846	1,068	1,914	-	-	-	846	1,068	1,914
				3,293	**1,068**	**4,361**	**-**	**-**	**-**	**3,293**	**1,068**	**4,361**

[8] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/busbardashboard2035_30mmt_hebase_vd2_08-11-23.xlsx

Offshore Wind

In mapping both Humboldt and Morro Bay offshore wind, the CPUC has not made specific interconnection and transmission project upgrade recommendations and is requesting the ISO to identify optimal transmission solutions for interconnecting the offshore wind resources through its TPP analysis. The base case portfolio has 161 MW of Humboldt offshore wind in 2033 and 1,607 MW in 2035. In alignment with the commercial interest currently in the CAISO's interconnection queue, the CPUC mapped the 161 MW as interconnecting with energy only deliverability at the existing 115 kV Humboldt substation. The remaining 1,446 MW are mapped to a proposed new 500 kV Humboldt substation in the 2035 mapping results that requires new transmission to interconnect to the CAISO system. CPUC staff has indicated that the ISO can consider all base case Humboldt offshore wind resources mapped to a single substation to avoid significant upgrades to the existing 115 kV system solely for the small amount of offshore wind mapped. The ISO modeled 161 MW EO OSW and the 1,446 MW FCDS OSW as mapped by the CPUC because significant upgrades were not identified to the existing 115 kV system in previous studies as a result of the EO resource.

CPUC mapped the 3,100 MW of Morro Bay offshore wind in both the 2033 and 2035 base case portfolios interconnecting to the existing Diablo Canyon 500 kV substation, following guidance from CAISO staff. CPUC staff requested ISO consider this mapping arrangement and the potential to connect some or all of the Morro Bay offshore wind to a proposed new 500 kV Morro Bay substation as identified in the 21-22 TPP offshore wind sensitivity portfolio results. The ISO modeled the 3,100 MW of Morro Bay offshore wind to the existing Diablo Canyon 500 kV substation as mapped to avoid the cost of the new 500 kV substation and to provide a POI connecting to three 500 kV lines instead of two.

Out-of-State Wind on New Out-of-State Transmission

The amount of OOS wind on new transmission is significantly higher (4,828 MW in total) in this base case portfolio than in the 21-22 and 22-23 TPP base cases, which had 1,062 MW and 1,500 MW respectively. In those two previous cases, CPUC staff did not specify the location of that OOS wind or its injection location into the CAISO system. For the 4,828 MW of OOS wind in this base case, the Working Group did map the resources to specific injection points and identify specific locations as sources of the OOS wind, with 1,000 MW of Idaho Wind and 1,500 MW of Wyoming wind interconnecting at Harry Allen or El Dorado 500 kV substations and 2,328 MW of New Mexico Wind interconnecting at the Palo Verde substation.The OOS wind resources were modeled consistent with CPUC's guidance.

Out-of-CAISO Resources and Maximum Import Capability (MIC)

The 2023-24 TPP base portfolio, in addition to the over 4,800 MW of OOS wind on new transmission, has a significant amount of geothermal mapped to IID and areas in Nevada beyond the CAISO's Balancing Area. As was done for the 2022-2023 TPP portfolio, busbar Working Group staff specified in the Mapping Dashboard the out-of-CAISO transmission and MIC assumptions for these resources including whether the resources should be treated by CAISO in TPP analysis as using existing MIC allocations or require MIC expansion. For all the OOS wind on new transmission and most of the geothermal resources, Working Group staff identified the resources as requiring MIC expansion. Full details of the out-of-CAISO resources, which can be found on the "OutsideCAISO_Res_Summary" tab of the Mapping Dashboards, was used to model the resources.

Battery Storage-Specific Transmission Upgrades and Battery Storage as Transmission Upgrade Alternatives

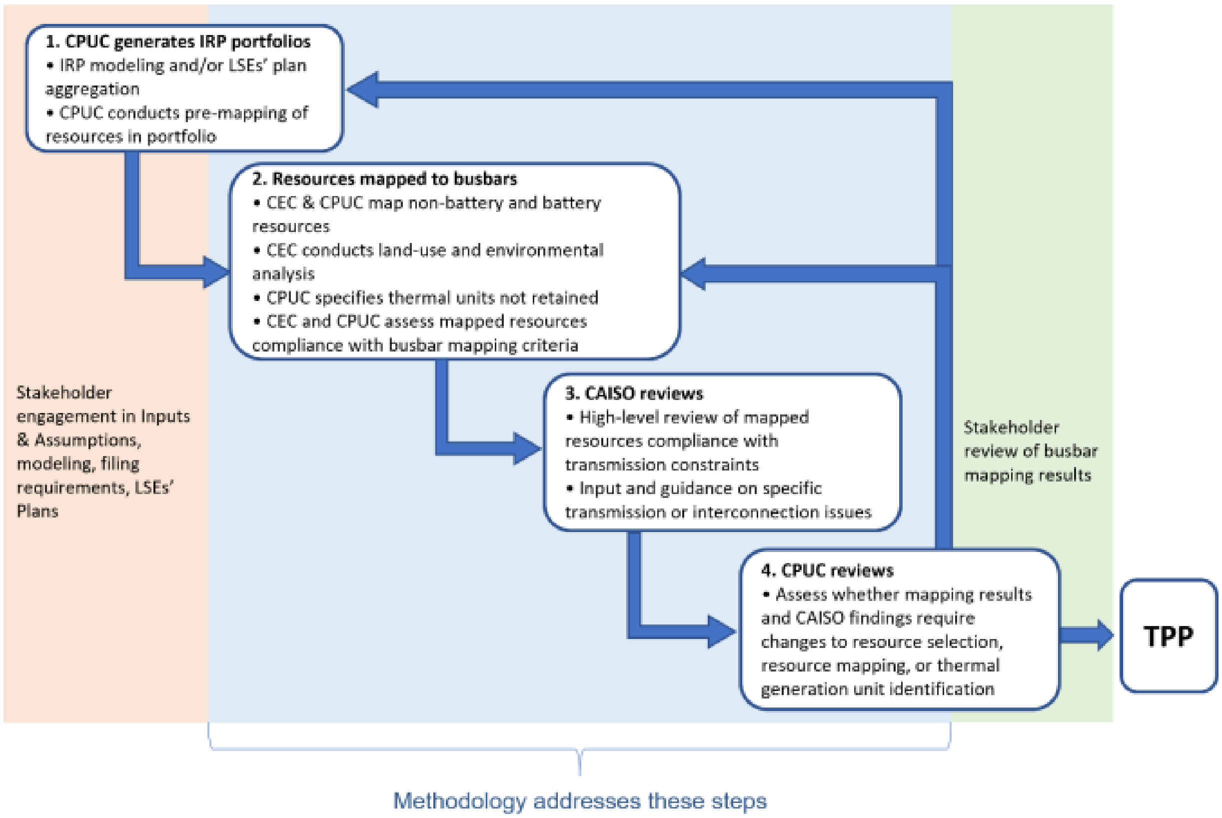
As with the past two TPP portfolio submittals, CPUC requests ISO to consult the CPUC before moving forward with any new policy-driven transmission upgrades associated specifically with storage mapping in this planning cycle. Additionally, to the extent that storage resources are required for mitigation of transmission issues identified in the CAISO's 2022-2023 Transmission Plan, CPUC staff would expect to coordinate with CAISO to enable small adjustments in the CPUC's mapping of storage resources to allow for the inclusion of this storage in the CAISO's analysis of these 2023-2024 TPP portfolios. Such adjustments were not made as storage resources were not required for mitigation of transmission issues identified in the CAISO's 2022-2023 Transmission Plan.

The portfolios that RESOLVE generates are at the zonal level. As a result, the portfolios have to be mapped to the busbar level for use in the ISO transmission planning process. The resource-to-busbar mapping process is documented in the CPUC report entitled Methodology for Resource-to-Busbar Mapping & Assumptions for the Annual TPP[9] with further refinements as described in the CPUC staff report entitled Modeling Assumptions for the 2023-2024 Transmission Planning Process.[10] Figure F.4-1 shows a flowchart of the CPUC busbar mapping process for the 2023-2024 transmission planning process.

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

[10] 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

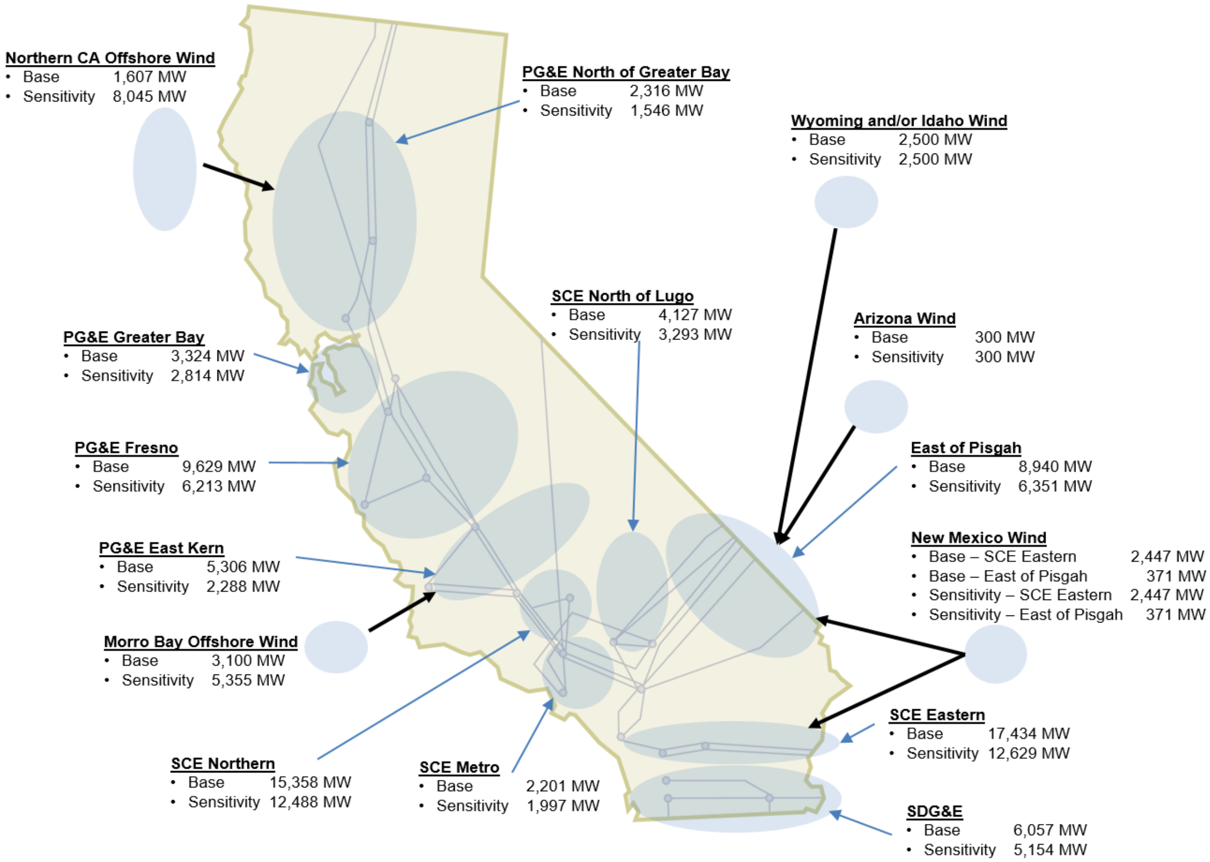
Figure F.4-1: Flowchart of the CPUC 2023-2024 TPP busbar mapping process[11]



The porfolio resources were modeled in the ISO studies in accordance with the results of the mapping process. Figure F.4-2 below identifies the interconnection areas and the capacities of the resources in the CPUC's base and sensitivity portfolios. The resource types within each interconnection area and the mapping of the resources is provided in the sections below. Links to the detailed busbar mapping results have been provided in section F.4.

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

Figure F.4-2: Base and Sensitivity Portfolios Total MW in each Interconnection Area



F.4.1 Transmission capability estimates and utilization by portfolios

One of the key inputs in the portfolio development and busbar mapping process is the transmission capability estimates provided by the ISO. The transmission capability estimates limit the amount of FCDS and EODS resources that can be selected in the part of the system that is affected by the constraint. Due to timing, the previous transmission capability estimates the ISO published in a white paper on July 19, 2021[12] were used in the development of the resource portfolios for the current TPP. Some capability estimates have been updated by CPUC based on information provided by the ISO.

The utilization of estimated available FCDS and EODS transmission capability by resource portfolios is monitored by the CPUC in the portfolio development process using RESOLVE and in the busbar mapping process using spreadsheet calculations. The results of the evaluation for the 2023-2024 TPP 2035 base portfolio based on the 2021 white paper are posted on the

[12] http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=79BEBAD0-E696-4E04-A958-1AAF53A12248

CPUC website[13]. The CPUC has also re-calculated transmission capability exceedances by the current portfolio using the ISO's updated 2023 transmission capability estimates[14], with additional updates provided in response to CPUC requests or stakeholder comments, for the purpose of comparing the portfolio with the base portfolio for the 2024-2025 TPP, which is also available on the CPUC website[15].

Exceedances of actual transmission capability limits indicate a high likelihood of the need for transmission upgrades or other mitigation solutions for the delivery of portfolio resources behind the constraints, which the CPUC takes into account in the development and mapping of the resource portfolios. However, the spreadsheet analysis should not be viewed as a substitute for the analysis the ISO performed as part of this policy-driven assessment using detailed power system models.

F.5 On-Peak Deliverability Assessment

The primary objective of the policy-driven on-peak deliverability assessment is to support deliverability of the renewable generation and energy storage resources that are identified in the portfolios as requiring FCDS status so they can count towards meeting resource adequacy needs. The assessment evaluates whether the net resource output from a given area can be simultaneously transferred to the remainder of the ISO Control Area during periods of peak system load. The on-peak deliverability assessment of the base and sensitivity portfolios was performed in accordance with the on-peak deliverability assessment methodology.[16]

F.5.1 On-peak deliverability assessment assumptions

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

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

[13] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/busbardashboard2035_30mmt_hebase_vd_02-22-23.xlsx. See 2_Tx_Calculator Tab.

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

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

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

The ISO performed the on-peak deliverability assessment for both HSN and SSN scenarios. For each scenario and each portfolio, the ISO developed a master on-peak deliverability assessment base case from which area cases are derived. Key assumptions of the deliverability assessment are described below.

Transmission

The ISO modeled the same transmission system as in the 2035 peak load base case that is used in the reliability assessment performed as part of the current transmission planning process.

System load

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

Maximum resource output (Pmax) assumptions

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

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

The maximum resource output (Pmax) assumptions used in the HSN and SSN deliverability assessment for FCDS resources are shown in Table F.5-1. For resources with partial deliverability status (PCDS), the Pmax amounts in the table are derated by the deliverable percentage.

Table F.5-1: Maximum FCDS resource output tested in the deliverability assessment

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

Import Levels

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

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

F.5.2 General On-peak deliverability assessment procedure

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

Screening for Potential Deliverability Problems Using DC Power Flow Tool

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

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

or

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

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

Verifying and Refining the Analysis Using AC Power Flow Tool

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

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

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

On-peak deliverability assessment for the 2035 base portfolio was performed for both southern and northern California. The assessment for the OSW sensitivity portfolio was performed for northern California only because the sensitivity portfolio is intended to test the transmission needs associated with 13.4 GW of offshore wind connecting in northern California and contains less resources in southern California than the base portfolio.

Potential mitigation options considered to address on-peak deliverability constraints include Remedial Action Schemes (RAS), reduction of energy storage behind the constraints and transmission upgrades.

F.6 Off-Peak Deliverability assessment

The ISO modified its on-peak deliverability assessment to reflect the changing contribution of solar to meeting resource adequacy needs. Additional solar resources provide a much lower incremental resource adequacy benefit to the system than the initial solar resources, because their output profile ceases to align with the peak hour of demand on the transmission system which has shifted to later in the day due to the proliferation of behind-the-meter solar. As a result, there is a reduced need for transmission upgrades to support deliverability of additional solar resources for resource adequacy purposes. Generation developers have been relying on transmission upgrades required under the previous on-peak deliverability assessment methodology to ensure that generation would not be exposed to excessive curtailment due to transmission limitations. Therefore, the off-peak deliverability assessment methodology[17] was developed to address renewable energy delivery during hours outside of the summer peak load period to ensure some minimal level of protection from otherwise potentially unlimited curtailment.

Accordingly, the key objectives of the policy-driven off-peak deliverability assessment are to:

- Identify transmission constraints that would cause excessive renewable curtailment in accordance with the off-peak deliverability methodology
- Identify potential transmission upgrades and other solutions needed to relieve excessive renewable curtailment
- Select the constraints and the identified transmission upgrades as candidates for a more thorough evaluation using production cost simulation

F.6.1 Off-peak deliverability assessment methodology

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

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

The dispatch assumptions discussed above apply to both full capacity and energy-only resources. However, depending on the amount of generation in the portfolio, it may be impossible to balance load and resources under such conditions with all portfolio generation dispatched. The dispatch assumptions are applied to all existing, under-construction and

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

contracted generators first, then some portfolio generators if needed to balance load and resources. This establishes a system-wide dispatch base case or master base case that is the starting case for developing each of the study area base cases to be used in the off-peak deliverability assessments. Table F.6-1 summarizes the generation dispatch assumptions in the master base case.

Table F.6-1: ISO System-Wide Generator Dispatch Assumptions

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

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

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

If the renewables inside the study area are predominantly wind resources (more than 70% of total study area capacity), wind resource dispatch is increased as shown in Table F.6-2. All the solar resources in the wind pocket are dispatched at the system-wide level of 68%. If the renewables inside the study area are not predominantly wind resources, then the dispatch assumptions in Table F.6-3 are used. The dispatch assumptions for out-of-state and off-shore wind used in the current study are provided in Table F.6-4.

Table F.6-2: Local Area Solar and Wind Dispatch Assumptions in Wind Area

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

Table F.6-3: Local Area Solar and Wind Dispatch Assumptions in Solar Area

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

Table F.6-4: Additional Local Area Dispatch Assumptions

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

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

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

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

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

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

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

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

Off-peak deliverability assessment for the 2035 base portfolio was performed for both southern and northern California. The assessment for the OSW sensitivity portfolio was performed for northern California only because the sensitivity portfolio is intended to test the transmission needs associated with 13.4 GW of offshore wind connecting in northern California and contains less resources in southern California than the base portfolio.The potential solutions considered to address off-peak deliverability constraints include Remedial Action Schemes (RAS), dispatching available battery storage behind the constraints and transmission upgrades.

F.7 PG&E Greater Bay and North of Greater Bay Interconnection Area

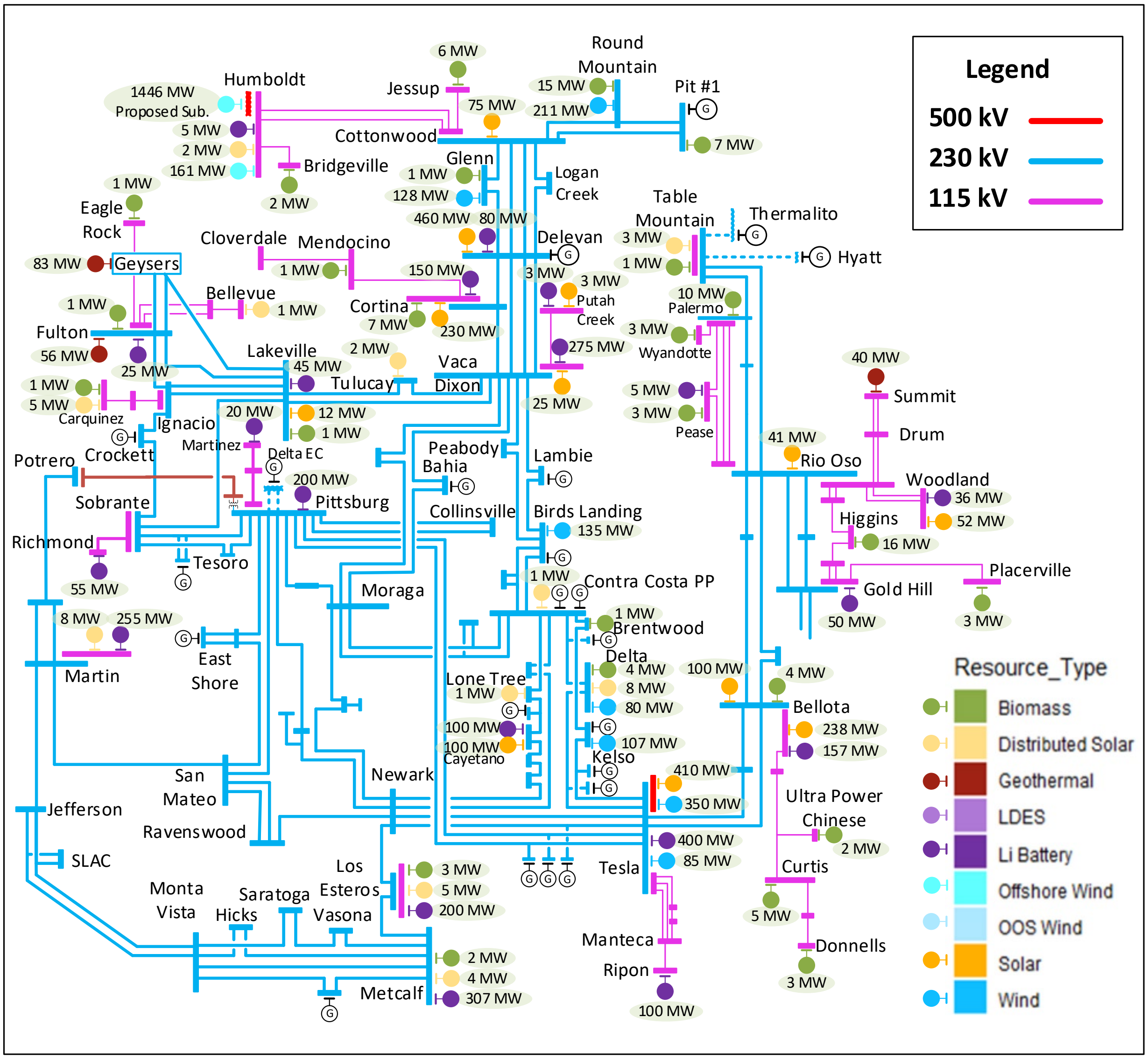
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E Greater Bay and North of Greater Bay interconnection area are listed in Table F.7-1. The portfolios in the interconnection area are comprised of solar, wind (in-state and offshore), battery storage, geothermal, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table F.7-1: PG&E Greater Bay and North of Greater Bay Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	685	1,061	1,746	5	615	620
Wind – In State	912	184	1,095	912	184	1,095
Wind – Out-of-State (Existing TX)	-	-	-	-	-	-
Wind – Out-of-State (New TX)	-	-	-	-	-	-
Wind – Offshore	1,446	161	1,607	7,884	161	8,045
Li Battery	,2477		2,477	2,368	-	2,368
Geothermal	179	-	179	135	-	135
Long Duration Energy Storage (LDES)	-	-		-	-	-
Biomass/Biogas	102	-	102	102	-	102
Distributed Solar	40	-	40	40	-	40
Total	**5,841**	**1,406**	**7,274**	**11,446**	**960**	**12,405**

The resources as identified in the CPUC busbar mapping for the PG&E Greater Bay and North of Greater Bay interconnection area are illustrated on the single-line diagram in Figure F.7-1. No adjustments were made to the portfolios in this area to account for allocated TPD and additional in-development resources identified.

Figure F.7-1: Greater Bay and North of Greater Bay Interconnection Area – Mapped Base Portfolio



With the resource mix specified in Table F.7.1-1 modeled in the base cases, the on-peak deliverability assessment identified the following constraints in PG&E study areas:

F.7.1 On-peak results

Hopland Bank 115/60 kV #2 on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Hopland Bank 115/60 kV #2 under N-2 conditions as shown in Table F.7-2. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.7-3, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint can be mitigated by a planed PG&E maintenance project.

Table F.7-2: Hopland Bank 115/60 kV #2 on-peak deliverability constraint

Overloaded Facility	Contingency	Scenario	Loading	
			BASE	SENS
HOPLAND BANK 115/60 BANK NO.2	GEYSERS #9-LAKEVILLE & EAGLE ROCK-FULTON-SILVERADO LINES	HSN	115%	112%

Table F.7-3: Hopland Bank 115/60 kV #2 on-peak deliverability constraint summary

Affected transmission zones: PG&E North Of Greater Bay Area			
		Base	**Sensitivity**
Generic Portfolio MW behind the constraint (installed FCDS capacity)		2	1
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		0	22
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		62	466
Mitigation Options	RAS	N/A	N/A
	Re-locate generic portfolio battery storage (MW)	N/A	N/A
	Transmission upgrade including cost	Maintenance Project	Maintenance Project
Recommended Mitigation		Maintenance Project	

Geyser56-MPE Tap 115 kV line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Geyser56-MPE Tap 115 kV line under N-2 conditions as shown in Table F.7-4. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.7-5, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint would be considered an LDNU and therefore will be addressed through the GIP.

Table F.7-4: Geyser56-MPE Tap 115 kV line on-peak deliverability constraint

Overloaded Facility	Contingency	Scenario	Loading	
			BASE	SENS
Geyser56-MPE Tap 115 kV	EAGLE ROCK -REDBUD & CORTINA-MENDOCINO #1 LINES	HSN	105%	104%

Table F.7-5: Geyser56-MPE Tap 115 kV line on-peak deliverability constraint summary

Affected transmission zones: PG&E North Of Greater Bay Area			
		Base	**Sensitivity**
Generic Portfolio MW behind the constraint (installed FCDS capacity)		1	0
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		0	0
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		119	0
Mitigation Options	RAS	RAS Crieteria Violation	RAS Crieteria Violation
	Re-locate generic portfolio battery storage (MW)	N/A	N/A
	Transmission upgrade including cost	Reconductor ($13.2M- $26.4M)	Reconductor ($13.2M- $26.4M)
Recommended Mitigation		This constraint would be considered a local constraint and therefore will be addressed in the GIP.	

Ukiah-Hopland-Cloverdale 115 kV (Ukiah sub 115 kV to Hopland Jct 115 kV) line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Ukiah-Hopland-Cloverdale 115 kV (Ukiah sub 115kv to Hopland Jct 115 kV) line under N-2 conditions as shown in Table F.7-6. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.7-7, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint would be considered an LDNU and therefore will be addressed through the GIP.

Table F.7-6: Ukiah-Hopland-Cloverdale 115 kV (Ukiah sub 115 kV to Hopland Jct 115 kV) line on-peak deliverability constraint

Overloaded Facility	Contingency	Scenario	Loading	
			BASE	SENS
Ukiah-Hopland-Cloverdale 115 kV (Ukiah sub 115kv to Hopland Jct 115kv)	EAGLE ROCK -REDBUD & CORTINA-MENDOCINO #1 LINES	HSN	107%	107%

Table F.7-7: Ukiah-Hopland-Cloverdale 115 kV (Ukiah sub 115kv to Hopland Jct 115 kV) line on-peak deliverability constraint summary

Affected transmission zones: PG&E North Of Greater Bay Area			
		Base	**Sensitivity**
Generic Portfolio MW behind the constraint (installed FCDS capacity)		1	1
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		0	22
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		217	60
Mitigation Options	RAS	RAS Criteria Violation	RAS Criteria Violation
	Re-locate generic portfolio battery storage (MW)	N/A	N/A
	Transmission upgrade including cost	Reconductor ($34.5M-$69M)	Reconductor ($34.5M-$69M)
Recommended Mitigation		This constraint would be considered a Local constraint and therefore will be addressed in the GIP.	

Fulton – Hopland 60 kV Line (Hopland Jct. 60 kV to Cloverdale Jct. 60 kV) line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of several lines in the Fulton – Hopland 60 kV Line (Hopland Jct. 60 kV to Cloverdale Jct. 60 kV) line under basecase conditions as shown in Table F.7-8. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.7-9, 84 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint would be considered an LDNU and therefore will be addressed through the GIP.

Table F.7-8: Fulton – Hopland 60 kV Line (Hopland Jct. 60 kV to Cloverdale Jct. 60 kV) line on-peak deliverability constraint

Overloaded Facility	Contingency	Scenario	Loading	
			BASE	SENS-01
Fulton - Hopland 60 kV (Hopland Jct 60 kV to Cloverdale Jct 60 kV to Geysers Jct 60 kV)	GEYSERS #9-LAKEVILLE & EAGLE ROCK-FULTON-SILVERADO LINES	HSN	117%	115%

Table F.7-9: Fulton – Hopland 60 kV Line (Hopland Jct. 60 kV to Cloverdale Jct. 60 kV) line on-peak deliverability constraint summary

Affected transmission zones: PG&E North Of Greater Bay Area			
		Base	**Sensitivity**
Generic Portfolio MW behind the constraint (installed FCDS capacity)		2	206
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		232	432
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		84	614
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		151	34
Mitigation Options	RAS	N/A	N/A
	Re-locate generic portfolio battery storage (MW)	N/A	N/A
	Transmission upgrade including cost	Exsisting LDNU	Exsisting LDNU
Recommended Mitigation		Exsiting LDNU	

Cascade – Deschutes 60 kV Line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Cascade – Deschutes 60 kV line under Basecase conditions as shown in Table F.7-10. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.7-11, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint would be considered an LDNU and therefore will be addressed through the GIP.

Table F.7-10: Cascade – Deschutes 60 kV Line on-peak deliverability constraint

Overloaded Facility	Contingency	Scenario	Loading	
			BASE	SENS-01
Cascade-Deschutes 60 kV Line	Base Case	HSN	107%	109%
	COLEMAN-COTTONWOOD 60KV	HSN	100%	<100%

Table F.7-11: Cascade – Deschutes 60 kV Line on-peak deliverability constraint summary

Affected transmission zones: PG&E North Of Greater Bay Area			
		Base	**Sensitivity**
Generic Portfolio MW behind the constraint (installed FCDS capacity)		5	1
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		5	22
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		28	29
Mitigation Options	RAS	RAS Criteria Violation	RAS Criteria Violation
	Re-locate generic portfolio battery storage (MW)	N/A	N/A
	Transmission upgrade including cost	Reconductor($7M-$14M)	Reconductor($7M-$14M)
Recommended Mitigation		This constraint would be considered a Local constraint and therefore will be addressed in the GIP.	

Donnels-Curtis 115kV Line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Donnels-Curtis 115kV line under Basecase conditions as shown in Table F.7-12. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.7-13, 1.5 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint would be considered an LDNU and therefore will be addressed through the GIP.

Table F.7-12: Donnels-Curtis 115kV Line on-peak deliverability constraint

Overloaded Facility	Contingency	Scenario	Loading	
			BASE	SENS-01
Spring Gap-MI-WUK 115 kV Line	Base Case	HSN	101%	101%

Table F.7-13: Donnels-Curtis 115kV Line on-peak deliverability constraint summary

Affected transmission zones: PG&E Greater Bay Area			
		Base	**Sensitivity**
Generic Portfolio MW behind the constraint (installed FCDS capacity)		3	0
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		0	0
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		1.55	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		1.45	0
Mitigation Options	RAS	RAS Criteria Violation	RAS Criteria Violation
	Re-locate generic portfolio battery storage (MW)	N/A	N/A
	Transmission upgrade including cost	Reconductor ($18M-$36M)	Reconductor ($18M-$36M)
Recommended Mitigation		This constraint would be considered a Local constraint and therefore will be addressed in the GIP.	

<u>Sobrante 230/115 kV Transformer Bank #1 & #2 on-peak deliverability constraint</u>

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Sobrante 230/115 kV Transformer Bank #1 & #2 under Basecase conditions as shown in Table F.7-14. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.7-15, 42 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint can be mitigated by adding an additional 230/115 kV bank # 3

Table F.7-14: Sobrante 230/115 kV Transformer Bank #1 & #2 on-peak deliverability constraint

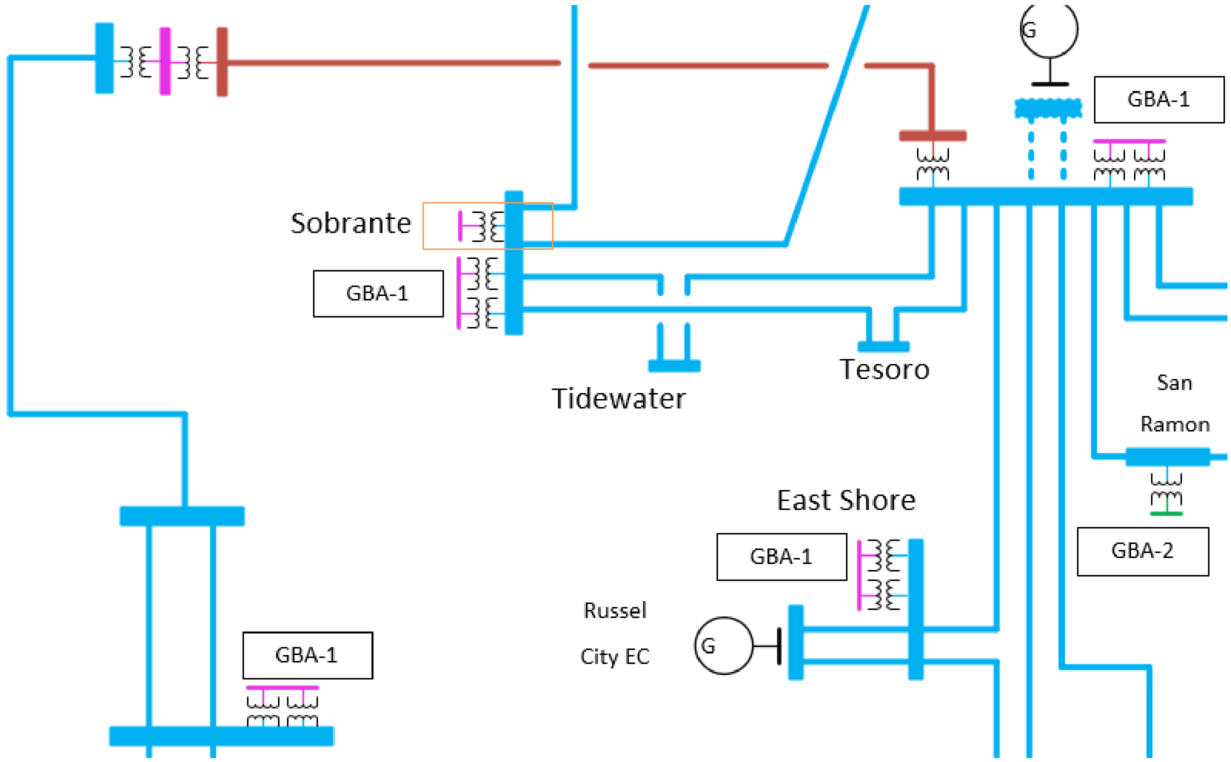
Overloaded Facility	Contingency	Scenario	Loading	
			BASE	SENS-01
Sobrante 230/115 kV Transformer Bank #1	SOBRANTE 230/115KV TB 2	HSN	112%	117%
Sobrante 230/115 kV Transformer Bank #2	SOBRANTE 230/115KV TB 1	HSN	112%	117%

Table F.7-15: Sobrante 230/115 kV Transformer Bank #1 & #2 on-peak deliverability constraint summary

Affected transmission zones: PG&E Greater Bay Area			
		Base	**Sensitivity**
Generic Portfolio MW behind the constraint (installed FCDS capacity)		142	98
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		25	25
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		395	655
Mitigation Options	RAS	N/A	N/A
	Re-locate generic portfolio battery storage (MW)	N/A	N/A
	Transmission upgrade including cost	New 230/115 kV Bank ($20M-$40M)	New 230/115 kV Bank ($20M-$40M)
Recommended Mitigation		New 230/115 kV Bank ($20M-$40M)	

To mitigate overloads identified in the on peak baseline deliverability study the ISO is recommending for approval the addition of a new 230/115 kV bank at Sobrante. The Project will cost $20M-$40M. The estimated in service year will be 2034. The scope includes a new 230/115 kV Bank at Sobrante Substation with 420 MVA rating. It will also include any bus upgrades and limiting equipment upgrades to achieve the full transformer rating.

Figure F.7-2: New Sobrante 230/115 kV Bank #3



F.7.2 Off-peak results

In the off-peak deliverability assessment of the Greater Bay and North of Greater Bay interconnection there was one constraint identified for the base portfolio. The constraint observed are listed in Table F.7-16.

Table F.7-16: Greater Bay and North of Greater Bay Interconnection Area On-Peak Deliverability Constraints in only the Sensitivity Portfolio

Constraint	Contingency	Loading	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
TESLA 500 kV - LOSBANOS 500 kV Line	TRACY-LOS BANOS 500KV	122%	7743	3739	3767	Reconductor if economic

Critical constraints identified in off peak study have been evaluated as part of the economic study. For mitigation please refer to the economic study process.

F.8 PG&E Greater Fresno Interconnection Area

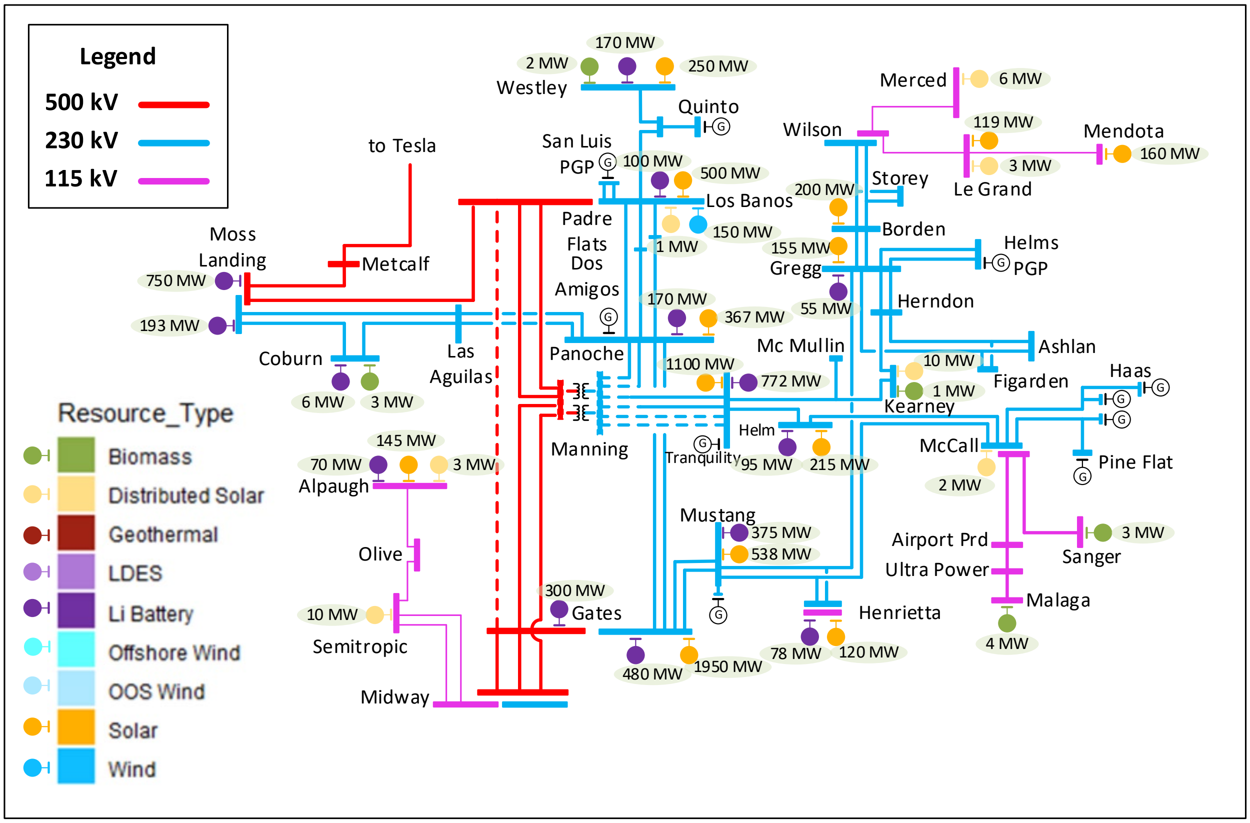
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E Greater Fresno interconnection area are listed in Table F.8-1. The portfolios are comprised of solar, wind (in-state), battery storage, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table F.8-1: PG&E Greater Fresno Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	1,462	1,714	**3,167**	1,047	818	**1,865**
Wind – In State	249	-	**249**	249	-	**249**
Wind – Out-of-State (Existing TX)	-	-	**-**	-	-	**-**
Wind – Out-of-State (New TX)	-	-	**-**	-	-	**-**
Li Battery	2,704	-	**2,704**	1,878	-	**1,878**
Geothermal	-	-	**-**	-	-	**-**
Long Duration Energy Storage (LDES)	-	-	**-**	-	-	**-**
Biomass/Biogas	12	-	**12**	12	-	**12**
Distributed Solar	37	-	**37**	37	-	**37**
Total	**4,464**	**1,714**	**6,178**	**3,223**	**818**	**4,041**

The resources as identified in the CPUC busbar mapping for the PG&E Greater Fresno interconnection area are illustrated on the single-line diagram in Figure F.8-1. No adjustments were made to the portfolios in this area to account for allocated TPD and additional in-development resources identified. No adjustments were made to the portfolios in this area to account for allocated TPD and additional in-development resources identified.

Figure F.8-1: PG&E Greater Fresno Interconnection Area – Mapped Base Portfolio



F.8.1 On-peak results

Mccall 230/115 kV Bank #1 and #3 on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Mccall 230/115 kV Bank #1 and #3 under N-1 conditions as shown in Table F.8-2. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.8-3, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint would be considered an LDNU and therefore will be addressed through the GIP.

Table F.8-2: Mccall 230/115 kV Bank #1 and #3 on-peak deliverability constraint

Overloaded Facility	Contingency	Scenario	Loading	
			BASE	SENS-01
Mccall 230/115kV Bank 1	MC CALL 230/115KV TB 3	HSN	103%	<100%
Mccall 230/115kV Bank 3	MC CALL 230/115KV TB 1	HSN	101%	<100%

Table F.8-3: Mccall 230/115 kV Bank #1 and #3 on-peak deliverability constraint summary

Affected transmission zones: PG&E Fresno Area			
		Base	**Sensitivity**
Generic Portfolio MW behind the constraint (installed FCDS capacity)		7	N/A
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		95	N/A
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		0	N/A
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		149	N/A
Mitigation Options	RAS	N/A	N/A
	Re-locate generic portfolio battery storage (MW)	N/A	N/A
	Transmission upgrade including cost	New Bank ($30M-$60M)	N/A
Recommended Mitigation		This constraint would be considered a local constraint and therefore will be addressed in the GIP.	

McCall-Sanger #2 115 kV Line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Fresno area is limited by thermal overloading of the McCall-Sanger #2 115 kV Line under N-2 conditions as shown in Table F.8-4. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.8-5, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint would be considered an LDNU and therefore will be addressed through the GIP.

Table F.8-4: McCall-Sanger #2 115 kV Lineon-peak deliverability constraint

Overloaded Facility	Contingency	Scenario	Loading	
			BASE	SENS-01
McCall-Sanger #2 115 kV Line	MCCALL-REEDLEY 115KV & MCCALL-SANGER #3 115KV	HSN	114%	112%

Table F.8-5: McCall-Sanger #2 115 kV Lineon-peak deliverability constraint summary

Affected transmission zones: PG&E Fresno Area			
		Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)		0.2	161
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		0	0
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		292	161
Mitigation Options	RAS	N/A	N/A
	Re-locate generic portfolio battery storage (MW)	N/A	N/A
	Transmission upgrade including cost	Reconductor($25M-$50M)	Reconductor($25M-$50M)
Recommended Mitigation		This constraint would be considered a local constraint and therefore will be addressed in the GIP.	

Herndon-Woodward 115 kV Line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Fresno area is limited by thermal overloading of the Herndon-Woodward 115 kV Line under N-2 conditions as shown Table F.8-6. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.8-7, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint would be considered an LDNU and therefore will be addressed through the GIP.

Table F.8-6: Herndon-Woodward 115 kV Line. on-peak deliverability constraint

Overloaded Facility	Contingency	Scenario	Loading	
			BASE	SENS-01
Herndon-Woodward 115 kV Line	HERNDON-BARTON 115KV & HERNDON-MANCHESTER 115KV	HSN	125%	<100%

Table F.8-7: Herndon-Woodward 115 kV Line. on-peak deliverability constraint summary

Affected transmission zones: PG&E Fresno Area			
		Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)		7	N/A
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		55	N/A
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		0	N/A
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		225	N/A
Mitigation Options	RAS	N/A	N/A
	Re-locate generic portfolio battery storage (MW)	N/A	N/A
	Transmission upgrade including cost	Reconductor ($57M-$114M)	N/A
Recommended Mitigation		This constraint would be considered a local constraint and therefore will be addressed in the GIP.	

F.8.2 Off-peak results

Table F.8-8: PG&E Greater Fresno Interconnection Area Off-Peak Deliverability Constraints

Constraint	Contingency	Loading	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
Huron-Calflax 70 kV line	GATES-PANOCHE #1 230KV & GATES-PANOCHE #2 230KV	101%	0	20	20	Portfolio energy storage in charging mode
Henrietta-Kingsburg 115 kV line	HELM-MCCALL 230KV & HENTAP2-MUSTANGSS #1 230KV	191%	90	68	270	Reconductor if economic.
Kingsburg 115 kV bustie	HELM-MCCALL 230KV & HENTAP2-MUSTANGSS #1 230KV	143%	90	68	276	Reconductor if economic.
Sanger-McCall 115 kV line	MCCALL-SANGER #1 115KV & MCCALL-SANGER #2 115KV	173%	1.4	0	33	Reconductor if economic.
Sanger-Herndon 115 kV line	HENTAP1-MUSTANGSS #1 230KV & TRANQLTYSS-MCMULLN1 #1 230KV	166%	1.4	0	1.4	Reconductor if economic.

Constraint	Contingency	Loading	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
LeGrand-Wilson 115 kV line	WILSON-BORDEN 230KV #1 & #2	133%	96	0	96	Reconductor if economic.
Chowchilla-Kerckhoff 115 kV line	WILSON-BORDEN 230KV #1 & #2	118%	1.42	0	1.42	Reconductor if economic.
Gregg-Mustang 230 kV line	HELM-MCCALL 230KV & HENTAP2-MUSTANGSS #1 230KV	123%	975	628	628	Portfolio energy storage in charging mode
Wilson-Melones 230 kV line	WARNERVILLE-WILSON 230KV	115%	381	75	377	Reconductor if economic.
Wilson-Storey 230 kV line	WILSON-BORDEN #2 230KV	126%	551	123	953	Reconductor if economic.
Las Aguilas-Panoche 230 kV line	LAS AGUILAS SW STA-PANOCHE #1 230KV	128%	290	170	344	Reconductor if economic.
Panoche-Gates 230 kV line	GATES-MANNING 500KV	NCONV	0	181	283	Reconductor if economic.
Los Banos-Panoche 230 kV line	LOS BANOS-PADRE FLAT SW STA 230KV	117%	290	170	623	Reconductor if economic.
Quinto-Los Banos 230 kV line	TESLA-LOS BANOS #1 500KV	NCONV	918	822	926	Reconductor if economic.
Quinto-Fink SS 230 kV line	TESLA-LOS BANOS #1 500KV	NCONV	918	822	926	Reconductor if economic.
Fink SS-Westley 230 kV line	TESLA-LOS BANOS #1 500KV	NCONV	968	1076	810	Reconductor if economic.
Moss Landing-Las Aguilas 230 kV line	Base Case	160	290	170	408	Reconductor if economic.
Warnerville-Wilson 230 kV line	COTTLE-MELONES 230KV	137%	381	75	377	Reconductor if economic.
Gates-Midway 500 kV line	MIDWAY-MANNING 500KV	NCONV	933	1233	2592	Reconductor if economic.
Gates Bank	MUSTANGSS-GATES #1 230KV & MUSTANGSS-GATES #2 230KV	113%	2246	1407	5428	Reconductor if economic.
Manning-Midway 500 kV line	GATES-MANNING 500KV	NCONV	4294	1283	6636	Reconductor if economic.
Manning-Gates 500 kV line	MIDWAY-MANNING 500KV	NCONV	5109	2337	8977	Reconductor if economic.
Los Banos-Manning 500 kV line	LOSBANOS-MANNING 500KV	206%	5867	3014	11128	Reconductor if economic.
Metcalf-Moss Landing 500 kV line	TESLA-LOS BANOS #1 500KV	NCONV	1565	296	1861	Reconductor if economic.
Tesla-Los Banos 500 kV line	Base Case	180%	5856	1484	9459	Reconductor if economic.
Tracy-Los Banos 500 kV line	Base Case	153%	5109	1295	9032	Reconductor if economic.

Critical constraints identified in off peak study have been evaluated as part of the economic study. For mitigation please refer to the economic study process.

F.9 PG&E East Kern Interconnection Area

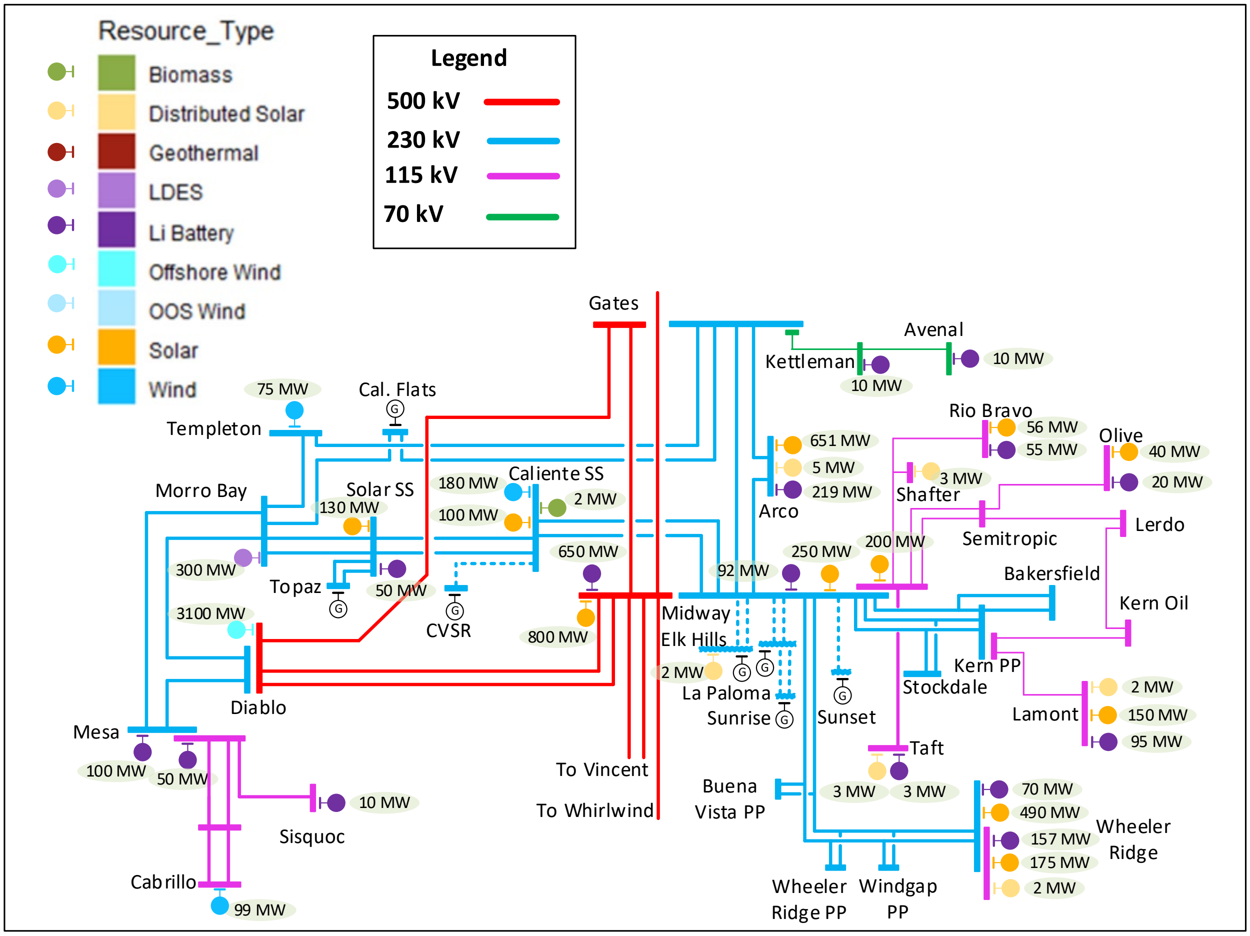
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the PG&E East Kern interconnection area are listed in Table F.9-1. The portfolios in the interconnect area are comprised of solar, wind (in-state and offshore), battery storage, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table F.9-1: PG&E East Kern Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	1,361	2,374	3,735	1,031	843	1,874
Wind – In State	255	-	255	255	-	255
Wind – Out-of-State (Existing TX)	-	-	-	-	-	-
Wind – Out-of-State (New TX)	-	-			-	-
Wind – Offshore	3,100	-	3,100	5,355	-	5,355
Li Battery	2,021	-	2,021	953	-	953
Geothermal	-	-	-	-	-	-
Long Duration Energy Storage (LDES)	300	-	300	-	-	-
Biomass/Biogas	2	-	2	2	-	2
Distributed Solar	15	-	15	15	-	15
Total	**7,053**	**2,374**	**9,428**	**7,611**	**843**	**8,454**

The resources as identified in the CPUC busbar mapping for the PG&E East Kern interconnection area are illustrated on the single-line diagram in Figure F.9-1. No adjustments were made to the portfolios in this area to account for allocated TPD and additional in-development resources identified.

Figure F.9-1: PG&E East Kern Interconnection Area – Mapped Base Portfolio



F.9.1 On-peak results

Wheeler 115/70 kV bank 2 on-peak deliverability constraint

The deliverability of renewable portfolio resources in the East Kern area is limited by thermal overloading of the Wheeler 115/70 kV bank 2 under basecase conditions as shown in Table F.9-2. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.9-3, 54 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint can be mitigated by relocating policy generation to high side of 115/70 kV transformer.

Table F.9-2: Wheeler 115/70 kV bank 2 on-peak deliverability constraint

Overloaded Facility	Contingency	Scenario	Loading	
			BASE	SENS-01
Wheeler 115/70 kV bank 2	Basecase	HSN	155%	<100%
	WHEELER RIDGE-ADOBE SWSTA 115KV	HSN	127%	<100%

Table F.9-3: Wheeler 115/70 kV bank 2 on-peak deliverability constraint summary

Affected transmission zones: PG&E Kern Area			
		Base	**Sensitivity**
Generic Portfolio MW behind the constraint (installed FCDS capacity)		0.2	NA
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		87	NA
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		54	NA
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		34	NA
Mitigation Options	RAS	N/A	N/A
	Re-locate generic portfolio battery storage (MW)	34 MW	N/A
	Transmission upgrade including cost	Bank upgrade	N/A
Recommended Mitigation		Relocate Generation	

F.9.2 Off-peak results

Table F.9-4: PG&E Greater Kern Interconnection Area Off-Peak Deliverability Constraints

Constraint	Contingency	Loading	Renewable Portfolio MW behind Constraint	Energy Storage Portfolio MW behind Constraint	Renewable curtailment without mitigation	Potential Mitigation
San Miguel-Union 70 kV line	TEMPLETON-GATES 230KV & GATES-CALFLATSSS #1 230KV	116%	77	161	161	Portfolio energy storage in charging mode
Casa Loma-Arvin J2 115 kV line	CASALOMA-LAMONT 115KV	135%	111	95	95	Portfolio energy storage in charging mode
Casa Loma-Lamont 115 kV line	CASALOMA-LAMONT 115KV (2)	135%	111	95	95	Portfolio energy storage in charging mode
Smyrna-Olive 115 kV line	Base Case	149%	147	90	90	Portfolio energy storage in charging mode
Smyrna-Ganso 115 kV line	Base Case	141%	147	90	90	Portfolio energy storage in charging mode
Arco-Midway 230 kV Line	GATES-ARCO & GATES-MIDWAY 230 KV LINES	162%	516	205	312	Reconductor if economic
Gates-Arco 230 kV line	ARCO-MIDWAY 230KV	160%	516	205	935	Reconductor if economic

Critical constraints identified in off peak study have been evaluated as part of the economic study. For mitigation please refer to the economic study process.

F.10East of Pisgah area

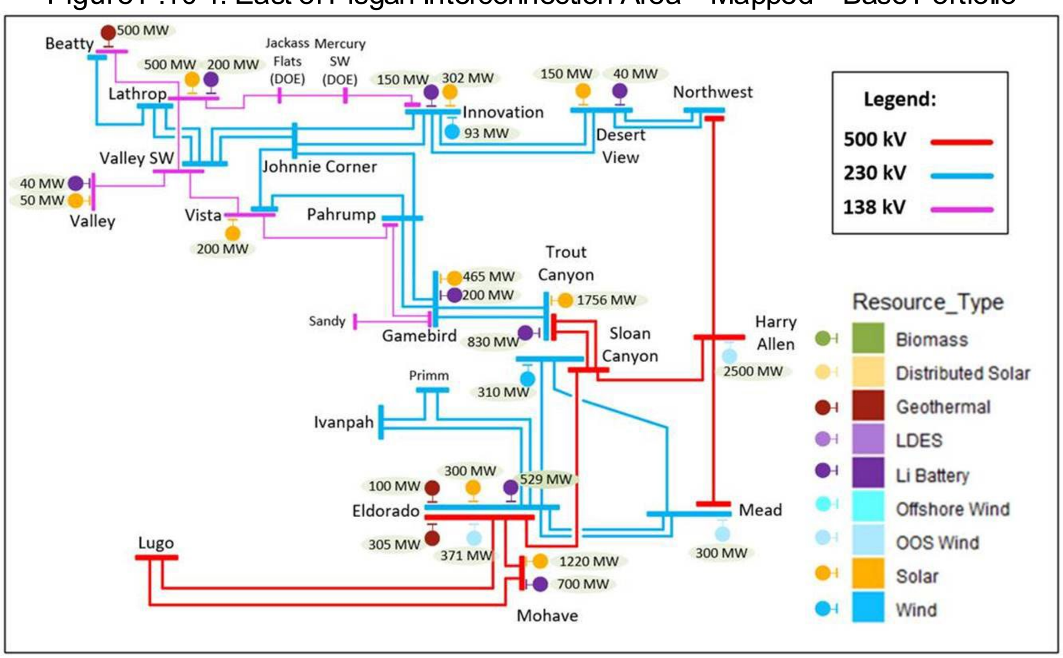
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the East of Pisgah interconnection area are listed in Table F.10-1. The portfolios in the interconnection area are comprised of solar, wind (in-state and out-of-state), battery storage and geothermal resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table F.10-1: East of Pisgah Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS	EO	Total	FCDS	EO	Total
Solar	2,157	2,786	**4,943**	Not applicable for EOP area		
Wind – In State	403	-	**403**			
Wind – Out-of-State (Existing TX)	571	100	**671**			
Wind – Out-of-State (New TX)	2,500	-	**2,500**			
Wind – Offshore	-	-	**-**			
Li Battery	2,689	-	**2,689**			
Geothermal	905	-	**905**			
Long Duration Energy Storage (LDES)	-	-	**-**			
Biomass/Biogas	-	-	**-**			
Distributed Solar	-	-	**-**			
Total	**9,225**	**2,886**	**12,111**			

The resources as identified in the CPUC busbar mapping for the East of Pisgah interconnection area are illustrated on the single-line diagram in Figure F.10-1.

Figure F.10-1: East of Pisgah Interconnection Area – Mapped[18] Base Portfolio



18 Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the East of Pisgah Interconnection Area to account for allocated TPD and additional in-development resources identified.

F.10.1 On-peak results

Sloan Canyon – Eldorado 500 kV Constraint

MIC expansion request on the ELDORADO_ITC, MEAD_ITC, and SILVERPK_BG interties are subject to curtailment due to normal loading limitation on the Sloan Canyon – Eldorado 500 kV Line as shown in Table F.10-2. As indicated in Table F.10-3, there are 7,509 MW portfolio resources behind this constraint. However, this constraint can be mitigated by curtailing MIC expansion request and wouldn't impact portfolio resources deliverability.

Table F.10-2: Sloan Canyon – Eldorado 500 kV on-peak deliverability constraints

Overloaded Facility	Contingency	Condition	Loading (%)	
			Base	Sensitivity
Sloan Canyon – Eldorado 500 kV line	Base Case	HSN	100.4%	N/A

Table F.10-3: Sloan Canyon – Eldorado 500 kV constraint summary

Affected transmission zones		East of Pisgah area	
		Base	**Sensitivity**
Portfolio MW behind constraint		7,509 MW	N/A
Portfolio battery storage MW behind constraint		2,186 MW	
Deliverable portfolio MW w/o mitigation		7,509 MW	
Total undeliverable baseline and portfolio MW		0 MW	
Mitigation Options	RAS	N/A	
	Reduce generic battery storage (MW)	Not needed	
	Transmission upgrade	Not Needed	
Recommended Mitigation		Curtail MIC expansion request	

Affected interties	ELDORADO_ITC, MEAD_ITC, SILVERPK_BG	
	Base	**Sensitivity**
MIC expansion request MW behind constraint	252	N/A
Deliverable MIC expansion request MW	53	

VEA-GLW Area Constraint

The deliverability of full capacity portfolio resources in the VEA and GLW area is limited by thermal overloading of multiple 138 kV lines following Category P7 contingencies as shown in Table F.10-4. This constraint was identified in base portfolio under HSN condition. As shown in Table F.10-5, 3,412 MW of renewable and energy storage resources are behind the constraint and 297 MW would be undeliverable. The constraint can be mitigated by the future Trout Canyon RAS as proposed in the GIDAP process.

Table F.10-4: VEA-GLW on-peak deliverability constraints

Overloaded Facility	Contingency	Condition	Loading (%)	
			Base	Sensitivity
VEA PST-IS Tap 138kV line	Trout Canyon – Sloan Canyon 500kV Nos. 1&2 lines	HSN	127.4%	N/A
IS Tap – Northwest 138kV line	Trout Canyon – Sloan Canyon 500kV Nos. 1&2 lines	HSN	118.7%	
Sandy – Amargosa 138kV line	Trout Canyon – Sloan Canyon 500kV Nos. 1&2 lines	HSN	117.1%	
Gamebird – Sandy 138kV line	Trout Canyon – Sloan Canyon 500kV Nos. 1&2 lines	HSN	102.3%	

Table F.10-5: VEA-GLW constraint summary

Affected transmission zones		VEA and GLW	
		Base	**Sensitivity**
Portfolio MW behind constraint		3,412 MW	N/A
Portfolio battery storage MW behind constraint		1,417 MW	
Deliverable portfolio MW w/o mitigation		3,115 MW	
Total undeliverable baseline and portfolio MW		297 MW	
Mitigation Options	RAS	New Trout Canyon RAS	
	Reduce generic battery storage (MW)	Not needed	
	Transmission upgrade	Not Needed	
Recommended Mitigation		New Trout Canyon RAS	

<u>Lugo – Victorville 500 kV Constraint</u>

The CAISO presented the initial policy study result in the November stakeholder meeting where the Lugo – Victorville 500 kV line was loaded to 98.2% following the Eldorado – Lugo 500 kV line outage and the Eldorado – McCullough 500 kV line was loaded to 110.4%. Following the stakeholder meeting, the CAISO further refined the generation dispatch in the EOP area deliverability cases. These refinements were to ensure that effective generation capacity on both sides of the Lugo-Victorville area constraint were predispatched to 80% of their study amount prior to running the deliverability study tool. With the updated deliverability case, the Lugo – Victorville 500 kV line was loaded to 101.8% following the Eldorado – Lugo 500 kV line outage. The existing Lugo – Victorville RAS would mitigate the overload and no transmission upgrade is required at this time.

The deliverability of full capacity portfolio resources in the East of Pisgah area is limited by thermal overloading of Eldorado – McCullough and Lugo – Victorville 500 kV lines following Category P1 contingency as shown in Table F.10-6. This constraint was identified in base portfolio under HSN condition. As shown in Table F.10-7, 9,074 MW of renewable and energy storage resources are behind the constraint and 1,036 MW would be undeliverable. MIC expanstion request on the ELDORADO_ITC, MEAD_ITC, BLYTHE_ITC, SILVERPK_BG AND IPPDCADLN_ITC interties are behind this constraint and none of the 312 MW MIC expansion request is deliverable.The constraint can be mitigated by expanding the existing Lugo – Victorville RAS and cut MIC expansion request. The potential Eldorado 500 kV SCD mitigation project discussed in Chapter 2 and Appendix B would eliminate the Eldorado – McCullough 500 kV line overload as a long term solution.

Table F.10-6: Lugo - Victorville 500 kV on-peak deliverability constraints

Overloaded Facility	Contingency	Condition	Loading (%)	
			Base	Sensitivity
Eldorado – McCullough 500 kV line	Eldorado – Lugo 500 kV line	HSN	111.0%	N/A
Lugo – Victorville 500 kV line	Eldorado – Lugo 500 kV line	HSN	101.8%	N/A

Table F.10-7: Lugo – Victorville 500 kV constraint summary

<table>
<tr><td colspan="2">Affected transmission zones</td><td colspan="2">East of Pisgah</td></tr>
<tr><td colspan="2"></td><td>Base</td><td>Sensitivity</td></tr>
<tr><td colspan="2">Portfolio MW behind constraint</td><td>9,074 MW</td><td rowspan="8">N/A</td></tr>
<tr><td colspan="2">Portfolio battery storage MW behind constraint</td><td>3,131 MW</td></tr>
<tr><td colspan="2">Deliverable portfolio MW w/o mitigation</td><td>7,978 MW</td></tr>
<tr><td colspan="2">Total undeliverable baseline and portfolio MW</td><td>1,096 MW</td></tr>
<tr><td rowspan="3">Mitigation Options</td><td>RAS</td><td>Lugo – Victorville RAS</td></tr>
<tr><td>Reduce generic battery storage (MW)</td><td>Not needed</td></tr>
<tr><td>Transmission upgrade</td><td>Eldorado 500 kV SCD mitigation project[19]</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td>Lugo – Victorville RAS
Eldorado 500 kV SCD mitigation project</td></tr>
</table>

[19] Short circuit duty concerns have been identified on the Eldorado 500 kV bus. SCE has proposed a mitigation plan to deloop lines from either McCullough or Eldorado. These proposals would mitigate the identified Eldorado-McCullough 500 kV line overload, but are under discussion with SCE and LADWP.

Affected interties	ELDORADO_ITC, MEAD_ITC, BLYTHE_ITC, SILVERPK_BG, IPPDCADLN_ITC	
	Base	**Sensitivity**
MIC expansion request MW behind constraint	312	N/A
Deliverable MIC expansion request MW	0	

F.10.2 Off-peak results

<u>VEA-GLW Area Constraint</u>

The solar and wind portfolio resources in the VEA and GLW area are subject to curtailment due to the thermal overloading of multipled 138 kV lines following Category P7 contingencies as shown in Table F.10-8. As shown in Table F.10-9, the constraint can be mitigated by the future Trout Canyon RAS as proposed in GIDAP process or by charging 1,002 MW portfolio energy storage resources after fully utilizing all baseline battery storage.

Table F.10-8: VEA-GLW off-peak deliverability constraints

Overloaded Facility	Contingency	Loading (%)	
		Base	Sensitivity
VEA PST-IS Tap 138kV Line	Trout Canyon – Sloan Canyon 500kV Nos. 1&2 lines	161.6%	N/A
	Northwest – Desert View 230kV Nos. 1&2 lines	129.3%	
	Innovation – Desert View 230kV Nos. 1&2 lines	115.9%	
IS Tap – Northwest 138kV Line	Trout Canyon – Sloan Canyon 500kV Nos. 1&2 lines	154.4%	
	Northwest – Desert View 230kV Nos. 1&2 lines	123.6%	
	Innovation – Desert View 230kV Nos. 1&2 lines	110.2%	
Sandy – Amargosa 138kV Line	Trout Canyon – Sloan Canyon 500kV Nos. 1&2 lines	159.7%	
Gamebird – Sandy 138kV Line	Trout Canyon – Sloan Canyon 500kV Nos. 1&2 lines	136.0%	
Amargosa 230/138kV Transformer	Trout Canyon – Sloan Canyon 500kV Nos. 1&2 lines	121.0%	
Innovation – VEA PST 138kV Line	Trout Canyon – Sloan Canyon 500kV Nos. 1&2 lines	108.1%	

Table F.10-9: VEA-GLW off-peak deliverability constraint summary

Affected renewable transmission zones		GLW and VEA area	
		Base	**Sensitivity**
Portfolio solar and wind MW behind the constraint		3,506 MW	N/A
Energy storage portfolio MW behind the constraint		1,466 MW	
Renewable curtailment without mitigation		1,240 MW	
Mitigation Options	Portfolio ES (in charging mode)	1,002 MW	
	RAS	New Trout Canyon RAS	
	Transmission upgrades	Not needed	
Recommended Mitigation		New Trout Canyon RAS and/or battery charging	

Eldorado – McCullough 500 kV Constraint

The solar and wind portfolio resources in the East of Pisgah area are subject to curtailment due to the thermal overloading of Eldorado – McCullough 500 kV line following Category P1 contingency as shown in Table F.10-10. As shown in Table F.10-11, the constraint can be mitigated by charging 350 MW portfolio energy storage resources after fully utilizing all baseline battery storage. The Eldorado 500 kV SCD mitigation project discussed in Chapter 2 and Appendix B would eliminate this constraint in the long term.

Table F.10-10: Eldorado – McCullough 500 kV off-peak deliverability constraints

Overloaded Facility	Contingency	Loading (%)	
		Base	Sensitivity
Eldorado – McCullough 500 kV line	Eldorado – Lugo 500 kV Line	105.5 %	N/A

Table F.10-11: Eldorado – McCullough 500 kV off-peak deliverability constraint summary

<table>
<tr><td colspan="2">Affected transmission zones</td><td colspan="2">East of Pisgah</td></tr>
<tr><td colspan="2"></td><td>Base</td><td>Sensitivity</td></tr>
<tr><td colspan="2">Portfolio solar and wind MW behind constraint</td><td>8,175 MW</td><td rowspan="7">N/A</td></tr>
<tr><td colspan="2">Energy storage portfolio MW behind constraint</td><td>2,695 MW</td></tr>
<tr><td colspan="2">Renewable curtailment without mitigation</td><td>500 MW</td></tr>
<tr><td rowspan="3">Mitigation Options</td><td>Portfolio ES (in charging mode)</td><td>350 MW</td></tr>
<tr><td>RAS</td><td>Not needed</td></tr>
<tr><td>Transmission upgrade</td><td>Eldorado 500 kV SCD mitigation project</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td>Charge portfolio energy storage
Eldorado 500 kV SCD mitigation project</td></tr>
</table>

F.10.3 Conclusion and recommendation

The SCE and GLW East of Pisgah area base portfolio deliverability assessment identifies on peak and off-peak deliverability constraints. These constraints can be mitigated by curtailing MIC expansion request, by expanding the existing RAS and the future planned RAS. The off-peak deliverability constraints can also be mitigated by charging the portfolio battery storage. As such, transmission upgrades are not found to be needed in this planning cycle.

MIC expanstion request on the ELDORADO_ITC, MEAD_ITC, BLYTHE_ITC, SILVERPK_BG AND IPPDCADLN_ITC interties are behind the Lugo – Victorville constraint and none of the 312 MW of MIC expansion request are deliverable.

F.11SCE Northern Area

The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE Northern interconnection area are listed in Table F.11-1. The portfolios in the interconnection area are comprised of solar, wind (in-state), battery storage, long duration energy storage, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table F.11-1: SCE Northern Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio
	FCDS	EO	Total	
Solar	3,763	5,022	**8,784**	Not applicable for southern areas
Wind – In State	345	-	**345**	
Wind – Out-of-State (Existing TX)	-	-	**-**	
Wind – Out-of-State (New TX)	-	-	**-**	
Wind – Offshore	-	-	**-**	
Li Battery	5,714	-	**5,714**	
Geothermal	-	-	**-**	
Long Duration Energy Storage (LDES)	500	-	**500**	
Biomass/Biogas	8	-	**8**	
Distributed Solar	6	-	**6**	
Total	**10,336**	**5,022**	**15,358**	

Table F.11-2 shows adjustments to the base portfolio in the SCE Northern Interconnection Area made by CPUC staff to account for adjustments to in-development resources identified.

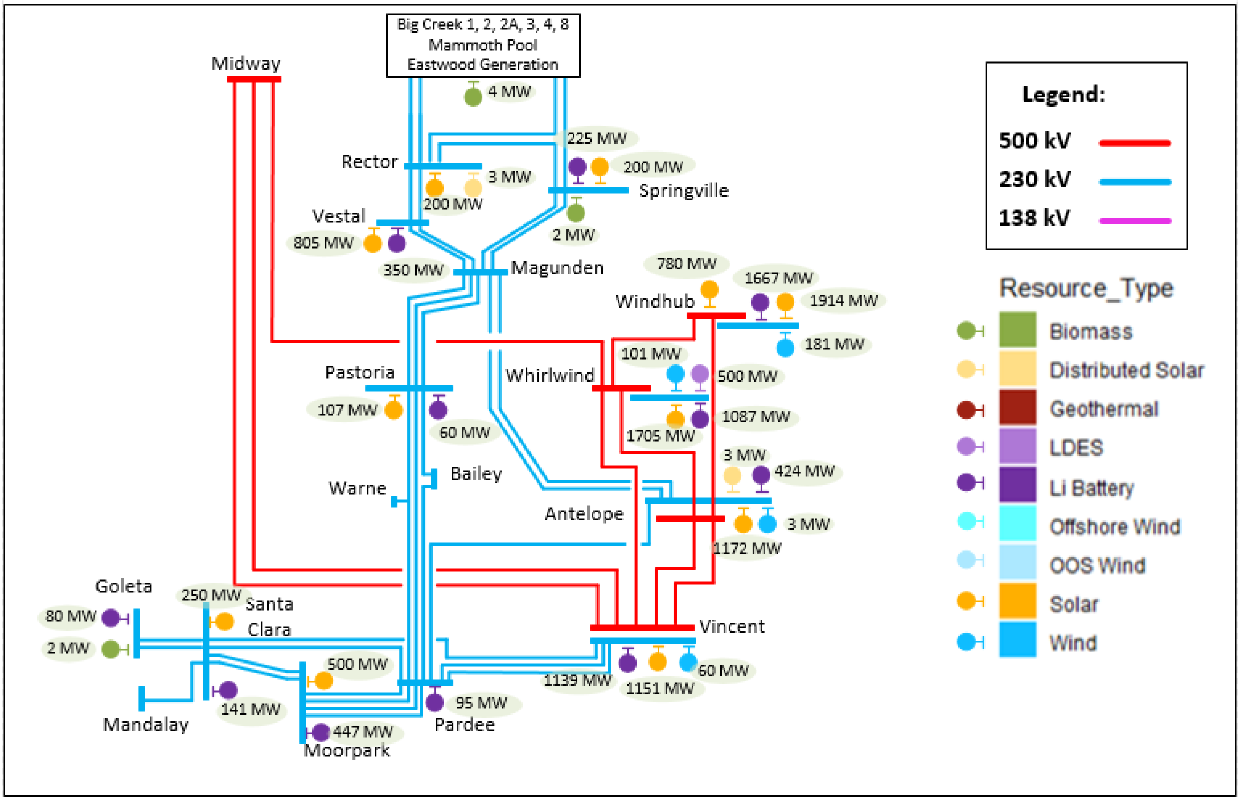
Table F.11-2: SCE Northern Interconnection Area – Adjustments to the base portfolio to account for adjustments to in-development resources[20]

CAISO Substation	Voltage	Resource Type	Adopted Base Portfolio Resources (2035)			Post Decision Adjustments			Updated Base Portfolio Resources (2035)		
			FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Windhub	500	Li Battery	412	-	412	-412	-	-412	-	-	-
	230	Li Battery	1,255	-	1,255	412	-	412	1,667	-	1,667
	500	Solar	780	-	780	-	-	-	780	-	780
	230	Solar	846	1,068	1,914	-	-	-	846	1,068	1,914
Total			**3,293**	**1,068**	**4,361**	**-**	**-**	**-**	**3,293**	**1,068**	**4,361**

[20] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/busbardashboard2035_30mmt_hebase_vd2_08-11-23.xlsx

The resources as identified in the CPUC busbar mapping for the SCE Northern interconnection area are illustrated on the single-line diagram in Figure F.11-1.

Figure F.11-1: SCE Northern Interconnection Area – Mapped[21] Base Portfolio



F.11.1 On-peak results

Windhub 500/230 kV Transformer Constraint

The deliverability of FC resources interconnecting at Windhub 230 kV buses is limited by thermal overloading of the 500/230 kV transformers under Category P1 conditions as shown in Table F.11-3. The constraint is identified in the base portfolio under the HSN condition, where 633 MW and 208 MW of capacity resources interconnected at Bus A and Bus B, respectively, will be undeliverable without mitigation as shown in Table F.11-4 and Table F.11-6. The constraint can be mitigated by the planned Windhub CRAS.

[21] Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the SCE Northern Interconnection Area to account for additional in-development resources identified.

Table F.11-3: Windhub 500/230 kV transformer deliverability constraint

Overloaded Facility	Contingency	Condition	Loading (%)	
			Base	Sensitivity
Windhub #1 500/230 kV transformer*	Windhub #2 500/230 kV transformer	HSN	140%	N/A
Windhub #2 500/230 kV transformer*	Windhub #1 500/230 kV transformer	HSN	140%	N/A
Windhub #3 500/230 kV transformer*	Windhub #4 500/230 kV transformer	HSN	115%	N/A
Windhub #4 500/230 kV transformer*	Windhub #3 500/230 kV transformer	HSN	115%	N/A

* The loading on the transformers depends on which Windhub 230 kV bus, Bus A or Bus B, generic portfolio resources are mapped to.

Table F.11-4: Windhub #1 and #2 500/230 kV transformer constraint summary

Affected transmission zones		Tehachapi area – Windhub 230 kV Bus A	
		Base	Sensitivity
Portfolio MW behind the constraint		1163 MW	N/A
Portfolio battery storage MW behind the constraint		1033 MW	
Deliverable portfolio MW w/o mitigation		530 MW	
Total undeliverable baseline and portfolio MW		633 MW	
Mitigation Options	RAS	Planned Windhub CRAS	
	Re-locate portfolio battery storage (MW)	Not applicable or needed	
	Transmission upgrade including cost	Not Needed	
Recommended Mitigation		Planned Windhub CRAS	

Table F.11-5: Windhub #1 and #2 500/230 kV transformer constraint affected interties

Affected interties	N/A	
	Base	Sensitivity
MIC expansion request MW behind constraint	N/A	N/A
Deliverable MIC expansion request MW		

Table F.11-6: Windhub #3 and #4 500/230 kV transformer constraint summary

Affected transmission zones		Tehachapi area – Windhub 230 kV Bus B	
		Base	**Sensitivity**
Portfolio MW behind the constraint		1603 MW	N/A
Portfolio battery storage MW behind the constraint		761 MW	
Deliverable portfolio MW w/o mitigation		1395 MW	
Total undeliverable baseline and portfolio MW		208 MW	
Mitigation Options	RAS	Planned Windhub CRAS	
	Re-locate portfolio battery storage (MW)	Not applicable or needed	
	Transmission upgrade including cost	Not Needed	
Recommended Mitigation		Planned Windhub CRAS	

Table F.11-7: Windhub #3 and #4 500/230 kV transformer constraint affected interties

Affected interties	N/A	
	Base	**Sensitivity**
MIC expansion request MW behind constraint	N/A	N/A
Deliverable MIC expansion request MW		

Windhub Area Export Constraint

The deliverability of FC resources interconnecting at Windhub Substation is limited by the simultaneous or overlapping outage of Antelope – Windhub 500kV Line and Whirlwind – Windhub 500 kV Line without time for system adjustments, which results in islanding of the Windhub System and the consequential loss of 3000 to 6000 MW of generation.

The loss of one Windhub 500 kV line results in exposing the entire ISO and surrounding areas to voltage collapse-driven cascading outages for loss of the second Windhub 500 kV line in the Cluster 13 and Cluster 14 studies. This results in the need to immediately curtail up to 5000 MW of generation, or cascading outages if the second contingency occurs before the generation can be curtailed. Therefore, an area deliverability constraint has been enforced to address this voltage collapse and loss of resource issue.

Under the HSN condition, the constraint was exceeded with the base portfolio. Therefore, the ISO revaluated the maximum generation amount that can be islanded at Windhub Substation before a voltage collapse occurs in the system.

- **Assumptions for the Post Transient Study**

The post transient analysis was performed using PSLF SSTools were governor power flow (inertial generation pickup) was assumed for all WECC units to account for the generation lost at Windhub Substation during a simultaneous or overlapping outage of Antelope – Windhub 500 kV Line and Whirlwind – Windhub 500 kV Line without time for system adjustments. Base-load units were blocked from responding to the event. Furthermore, the post-contingency adjustment of controllable shunt (SVD) was allowed with the exception of SVDs type 3 and 4, which do not have a continuous element.

The 2028 SCE Main Summer Peak reliability base case was selected for the assessment and the dispatch was adjusted by increasing generation in the Pacific Northwest area and reducing generation in SCE area, with the objective to maintain a 4,800 MW real power flow, pre-contingency, through Path 66 California – Oregon Intertie (COI) in the North to South (N>S) direction.

Several sensitivity cases were created by increasing the dispatch of the resources connected at Windhub substation and reducing the dispatch of energy storage resources in the rest of SCE area to maintain a 4,800 MW N>S power flow on Path 66. Additionally, for these sensitivity cases, the swing bus generator was interchanged between Northwest (Area 40), B.C. Hydro (Area 50), and SRP (Area 15) to test if there were any significant differences in the results, since the additional post-contingency losses are assigned to the swing bus generator and not distributed between all the generators participating in the redispatch.

- **Post Transient Analysis**

The post transient analysis was conducted to determine if the system was in compliance with the WECC Post Transient Voltage Deviation Standard and ISO Planning Standards in the Bulk Electric System (BES) and if there were thermal overloads on the BES.

Table F.11-8 summarizes the sensitivity cases studied, showing the Windhub Export and Windhub generation MW amounts, the location of the swing bus generator, simulation convergence, presence of thermal overloads or voltage violations, and the post-contingency real power flow of the main Paths under study. It can be noted that when the swing bus generator was located at Northwest and B.C. Hydro areas the results are similar and a dispatch of 3,290 MW of Windhub generation can be islanded before having divergence in the simulation. When the swing bus generator was located at SRP area, the results differ considerably, as the simulation converges up to a Windhub generation dispatch of 5,069 MW.

The fundamental reason for this difference is a tool limitation, as the additional post-contingency system losses are not considered in the redispatch, thus, they are assigned to the swing bus generator. For that reason, Table F.11-8 shows that the N>S path flows were higher when the swing bus generator was located at Northwest and B.C. Hydro areas compared to when it was located at SRP area, and in particular, Path 66 flow was between 400 MW to 500 MW higher. Similarly, East to West (E>W) path flows were higher with the swing bus generator located at SRP area.

Table F.11-8: Summary of the Windhub Sensitivity Cases

Sensitivity Case	Windhub Export (MW)	Windhub Generation (MW)	Swing Bus Generator	Convergence	Thermal Overload	Post Transient Voltage Violation	Path 66 N>S (MW)	Path 65 N>S (MW)	Path 26 N>S (MW)	Path 15 N>S (MW)	Path 46 E>W (MW)	Southern CA Imports (MW)
1a	2927	3083	40296 GND_COULE_22	Yes	No	No	6235	3101	3874	3388	7007	15218
1b	2927	3083	50645 REV 16G2	Yes	No	No	6233	3101	3873	3387	7008	15218
1c	2927	3083	15971 CORONAD1	Yes	No	No	5814	3101	3577	3087	7250	15174
2a	3030	3186	40296 GND_COULE_22	Yes	No	No	6305	3101	3922	3437	7065	15301
2b	3030	3186	50645 REV 16G2	Yes	No	No	6302	3101	3921	3436	7066	15301
2c	3030	3186	15971 CORONAD1	Yes	No	No	5852	3101	3614	3125	7307	15255
3a	3132	3290	40296 GND_COULE_22	Yes	No	No	6357	3101	3970	3486	7101	15392
3b	3132	3290	50645 REV 16G2	Yes	No	No	6359	3101	3971	3487	7104	15393
3c	3132	3290	15971 CORONAD1	Yes	No	No	5889	3101	3650	3162	7360	15345
4a	3208	3367	40296 GND_COULE_22	No	N/A							
4b	3208	3367	50645 REV 16G2	No	N/A							
4c	3208	3367	15971 CORONAD1	Yes	No	No	5894	3101	3660	3171	7391	15387
5c	3539	3703	15971 CORONAD1	Yes	No	No	6012	3101	3775	3288	7548	15638
6c	3868	4039	15971 CORONAD1	Yes	No	No	6154	3101	3909	3423	7710	15865
7c	4170	4349	15971 CORONAD1	Yes	Yes	No	6252	3101	4007	3522	7893	16143
8c	4471	4659	15971 CORONAD1	Yes	Yes	No	6334	3101	4086	3603	8064	16389
9c	4794	4994	15971 CORONAD1	Yes	Yes	No	6406	3101	4146	3664	8283	16632
10c	4869	5069	15971 CORONAD1	Yes	Yes	No	6424	3101	4157	3675	8362	16684
11c	4944	5144	15971 CORONAD1	No	N/A							

As the generation amount islanded at Windhub increases, losses also grow exponentially for two main reasons: 1) increase in the Southern California imports and 2) reduction in voltage profiles that result in higher i^2R losses. Since the sensitivity cases were adjusted to consider a stressed Path 66 flow, losses are higher in the cases were the swing bus generator was located at Northwest or B.C. Hydro areas.

In sensitivity cases 7c to 10c, thermal overloads of Windhub 500/230 kV Banks #1 and #2 were observed in P0 conditions. In consequence, available generation capacity at Windhub substation beyond 4,350 MW may be subject to congestion management to avoid thermal overloads under normal operating conditions.

During the simulations, no post transient voltage violations were identified in the BES but high voltage deviation was observed in several 500 kV buses in PG&E and Northwest areas. As a result, the ISO performed a steady state voltage stability analysis to identify if these voltage concerns were real or if they were mainly a product of the swing bus generator exceeding its P_{max} limit.

Figure F.11-2 to Figure F.11-4 present PV curves that show the N>S real power flow through Path 66 versus the 500 kV voltages in SCE, PG&E and Northwest areas, respectively. The simulation was performed by increasing Northwest and B.C. Hydro generation and reducing Windhub Substation generation.

In Figure F.11-2 it is shown that the reduction of Windhub generation does not produce a significant variation in the 500 kV voltages in SCE area, even some of the voltages slightly increased due to the reduction of real power transfer in SCE Northern area.

Figure F.11-2: PV curve – Path 66 vs. SCE 500 kV voltages

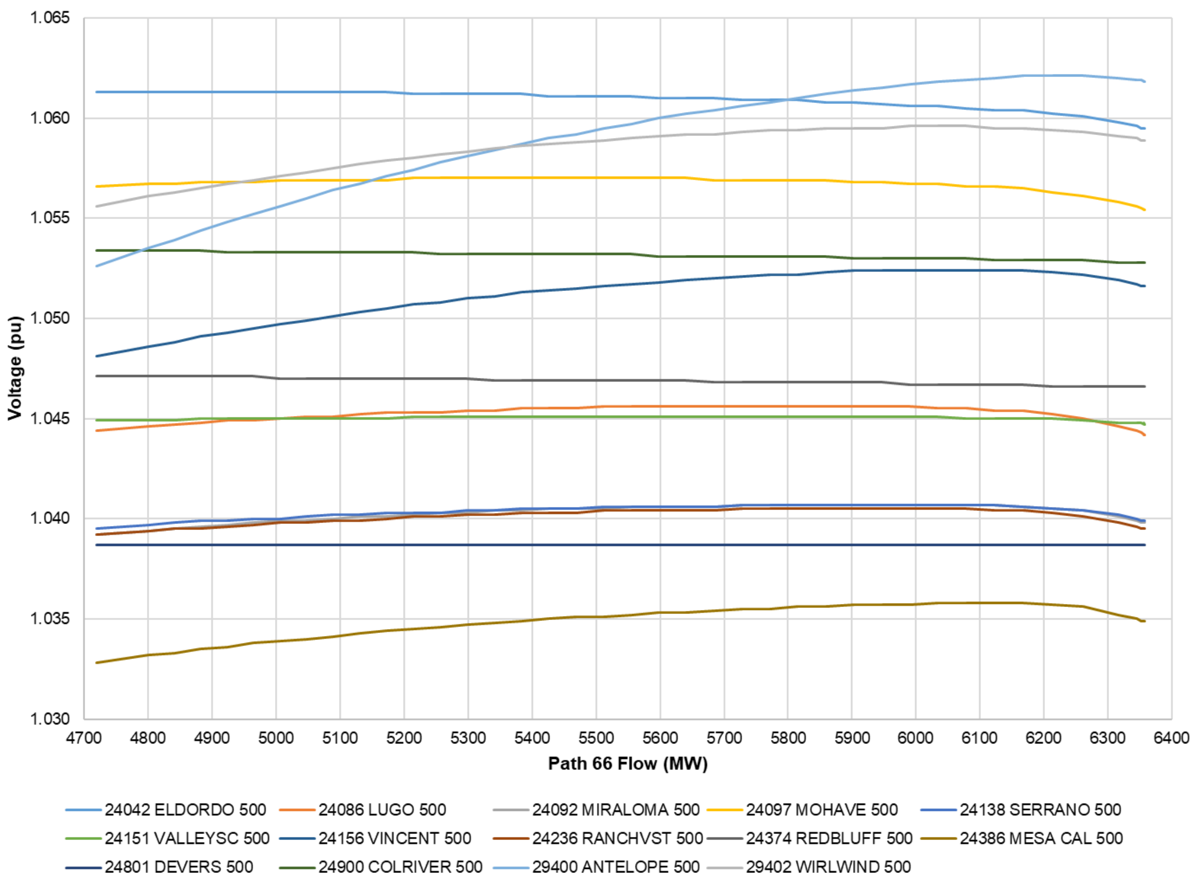
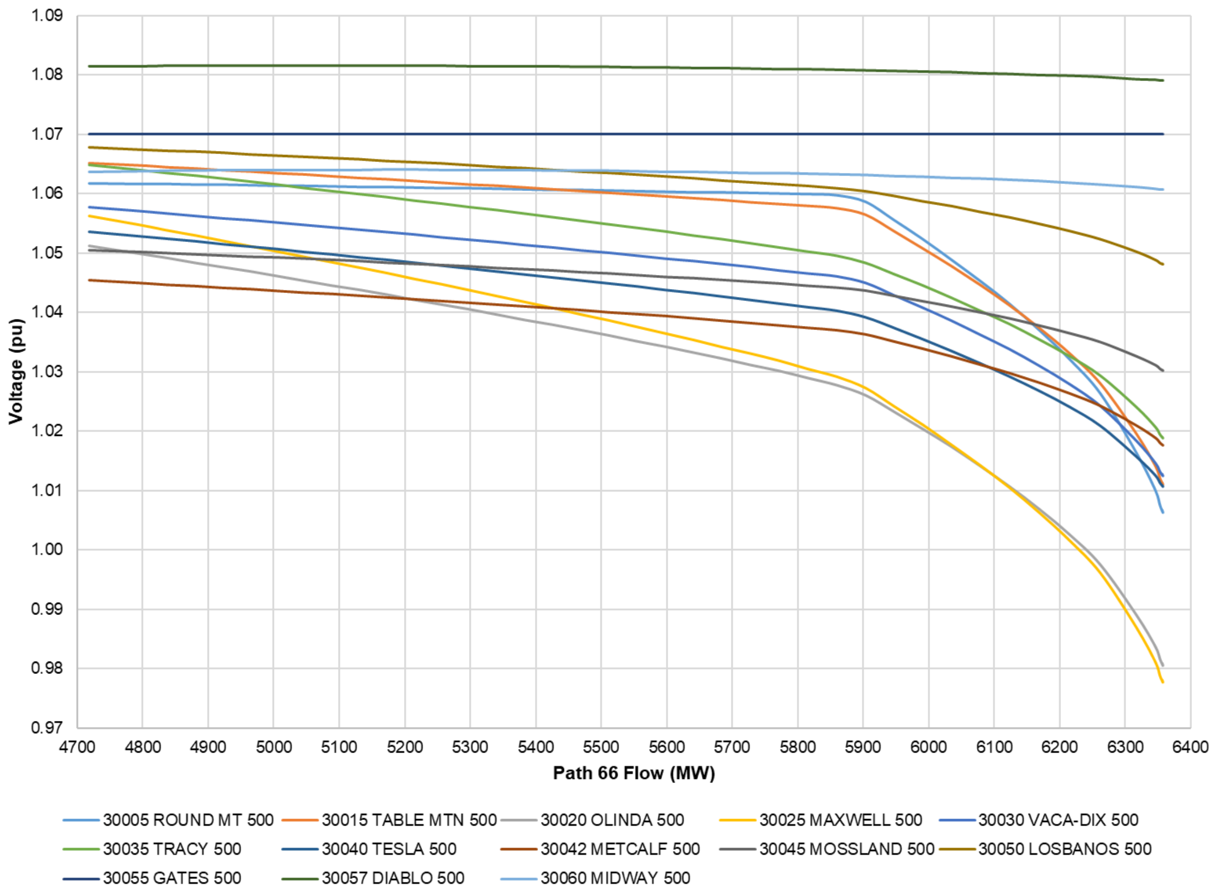


Figure F.11-3 displays that several of the northernmost 500 kV buses in PG&E system have a significant voltage deviation and the knee point of the PV curves occur with a post contingency N>S real power flow through Path 66 of around 6,350 MW, which is consistent with the results shown in Table F.11-8. Therefore, the swing bus generator exceeding its P_{max} limit in the post transient simulation is not the reason for the divergence and it is an actual steady state voltage stability issue.

Figure F.11-3: PV curve – Path 66 vs. PG&E 500 kV voltages



In a similar way, Figure F.11-4 illustrates the 500 kV voltages in Northwest area, were most of them exhibit a high voltage deviation near the knee point of the PV curve.

It is relevant to mention that with a post contingency N>S real power transfer of around 5,900 MW through Path 66, the slope of the PV curves change since voltage control at Fern Road substation (new substation that will loop-in Round Mountain – Table Mountain 500 kV lines) is lost, as the new ±2x265.4 MVAr STATCOMs would operate at its Q_{max} value. This is depicted in Figure F.11-5, which shows the reactive power production/absorption of Fern Road and Orchard (Gates) STATCOMs.

Figure F.11-4: PV curve – Path 66 vs. Northwest 500 kV voltages

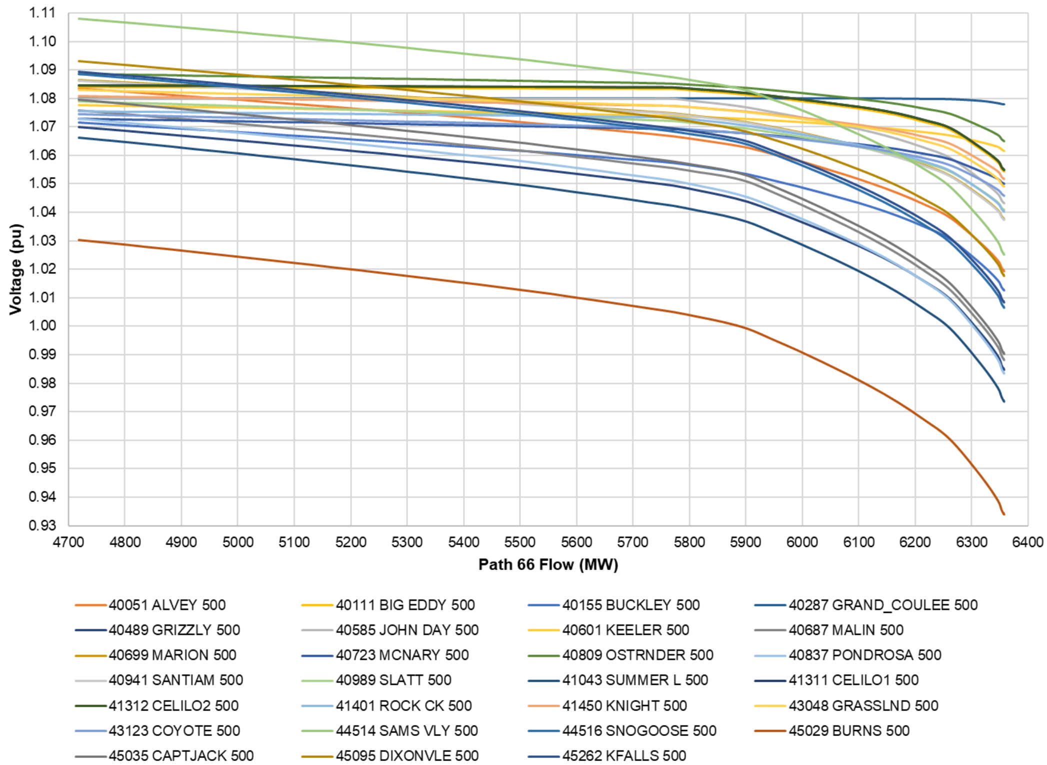
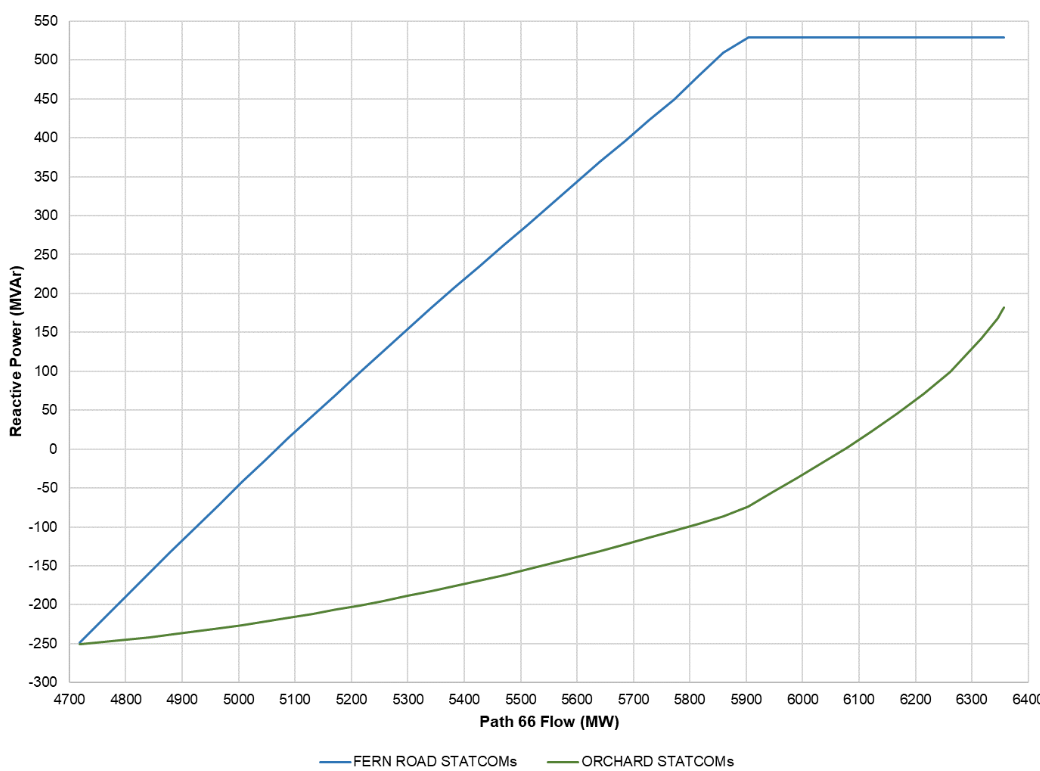


Figure F.11-5: PQ curve – Path 66 vs. Fern Road and Orchard STATCOMs



- **Transient Stability Analysis**

Additional to the post transient assessment, a transient stability analysis was performed to determine if the system was stable and exhibited positive damping of oscillations and if transient stability criteria were met as per WECC criteria and ISO Planning Standards.

Sensitivity cases 3a, 5c, 6c, and 7c, defined in Table F.11-8, were selected for the assessment and three contingencies were evaluated:

- A solid three-phase fault was applied at Windhub 500 kV bus that was cleared after 4-cycles. As a result of the fault, Antelope – Windhub 500 kV Line and Whirlwind – Windhub 500 kV Line were tripped simultaneously (N-2).
- With Antelope – Windhub 500 kV Line out-of-service and without any system adjustments, a solid three-phase fault was applied at Windhub 500 kV bus that was cleared after 4-cycles. As a result of the fault, Whirlwind – Windhub 500 kV Line was tripped (N-1-1 [A]).
- With Whirlwind – Windhub 500 kV Line out-of-service and without any system adjustments, a solid three-phase fault was applied at Windhub 500 kV bus that was cleared after 4-cycles. As a result of the fault, Antelope – Windhub 500 kV Line was tripped (N-1-1 [B]).

Simulations showed that transient stability criteria were met as per WECC criteria and ISO Planning Standards for all sensitivity cases. The main reason for this difference compared to the post transient analysis is that a significant amount of composite load dropped during the event, as shown in Table F.11-9. It can be noted that the load reduction for the N-2 outage was higher compared to the N-1-1 outages without system adjustments since the fault seen by the rest of system is more severe because the equivalent impedance is lower as it is propagated through two 500 kV lines compared to one transmission line for the N-1-1 outages. For example, in case 3a there is only a 1,090 MW net load-resource imbalance for the N-2 outage and about 1,300 MW for the N-1-1 outages without system adjustments.

Table F.11-9: Composite Load reduction in the transient stability simulations

Sensitivity Case	Contingency N-2 (MW)	Contingency N-1-1 [A] (MW)	Contingency N-1-1 [B] (MW)
3a	2200	1940	1998
5c	2706	2145	2077
6c	2482	2025	2023
7c	2837	2633	2535

The lower amount of composite load dropped in the N-1-1 outages results in a more severe post-fault voltage recovery, even requiring the operation of under voltage load shedding (UVLS) relays in Northwest area in cases 5c, 6c and 7c. Therefore, in the transient stability timeframe, the amount of generation that can be islanded at Windhub substation is dependent on the accuracy of the composite load models.

Figure F.11-6 presents the bus voltage plots for Burns (Northwest), Maxwell (PG&E) and Mesa (SCE) 500 kV buses in case 5c. In general, these 500 kV buses were the ones that exhibit a higher voltage deviation pre and post event. It can be seen that during the fault, the voltages were lower for the N-2 outage (red), but since more composite load was dropped during the event, as previously described, the post-contingency voltages were higher in Northwest and PGE areas compared to the N-1-1 outages (blue and green). In SCE area, the post event voltages were almost identical, and even higher than the pre-contingency state due to the important amount of composite load reduction.

Figure F.11-6: Transient voltages in case 5c – a) Burns 500 kV, b) Maxwell 500 kV, and c) Mesa 500 kV substations

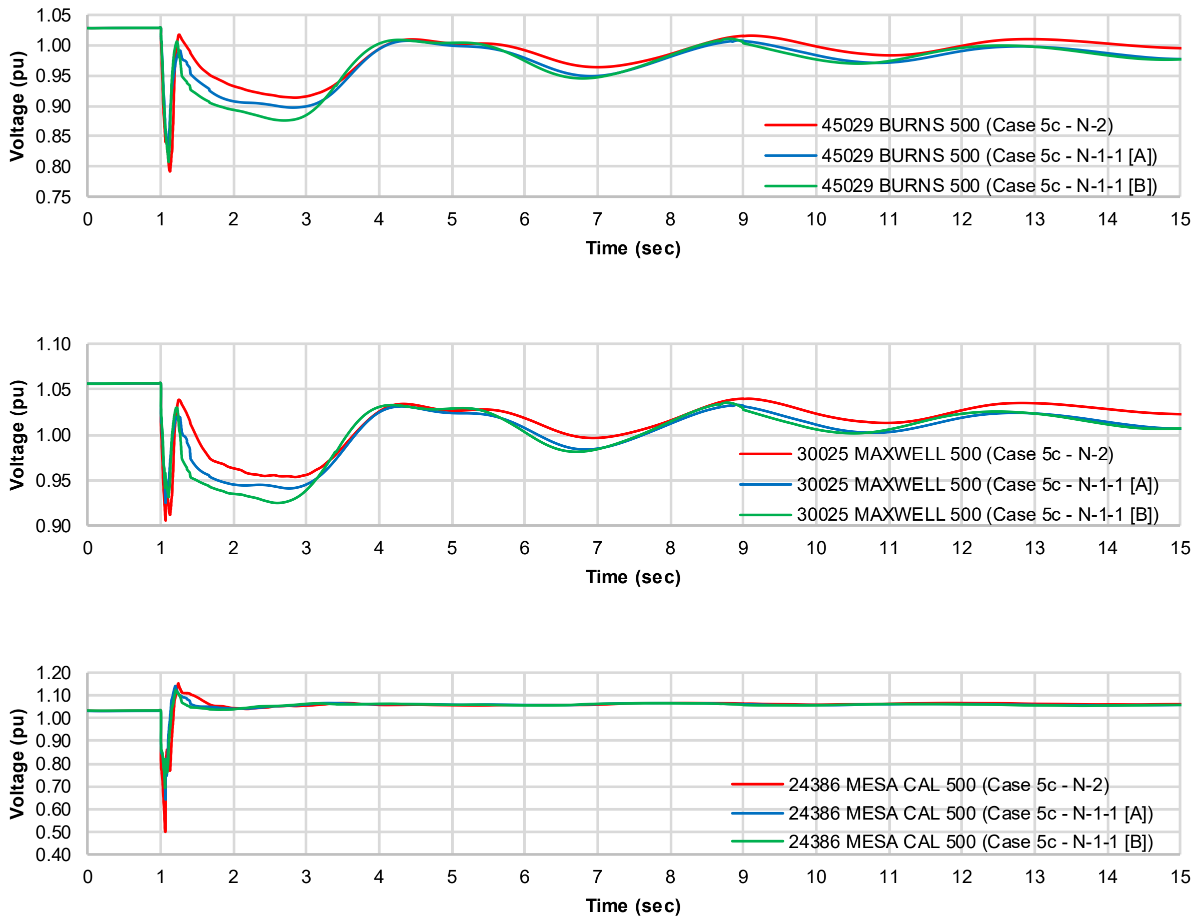


Figure F.11-7 shows the frequency plots for Rio Hondo 66 kV bus in case 5c. This substation in SCE area reached the lowest frequency during the transient event. Similarly to the voltage plots, the N-2 outage (red) outage reached a lower frequency during the fault compared to the N-1-1 outages (blue and green).

Figure F.11-7: Transient frequency in case 5c – Rio Hondo 66 kV substation

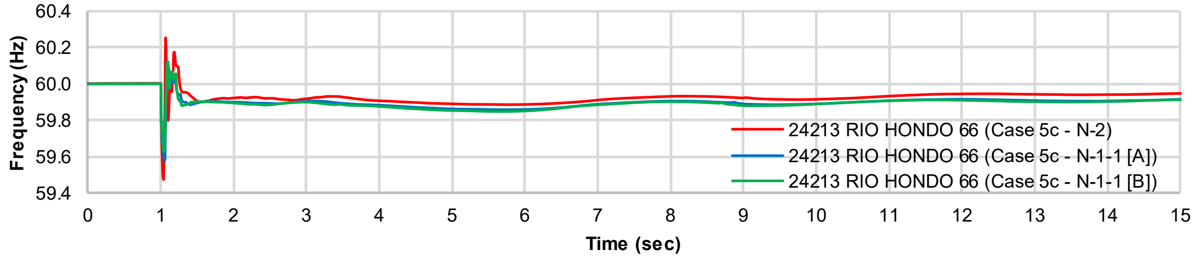
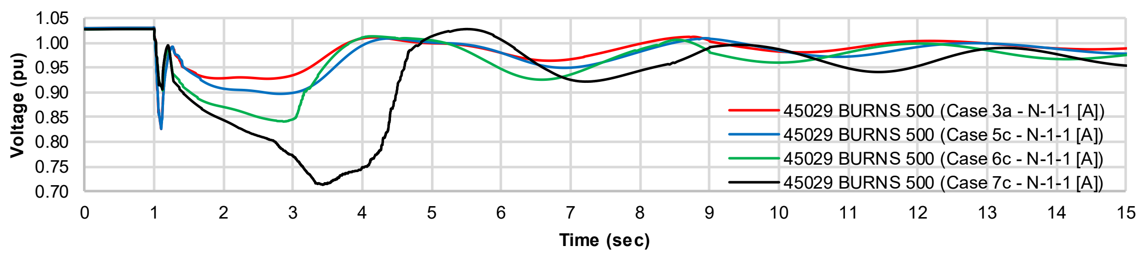
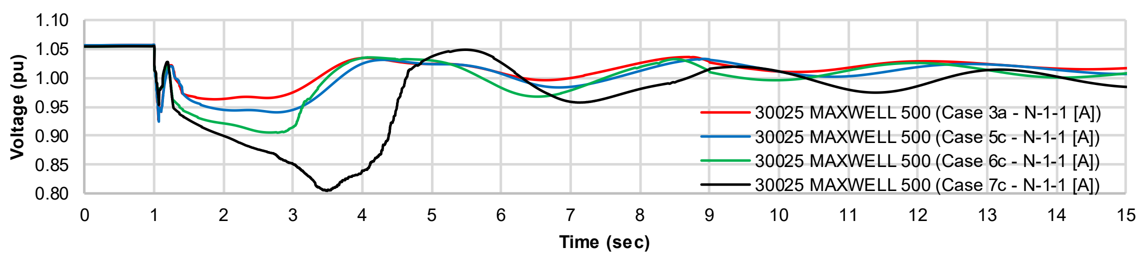


Figure F.11-8 also presents the bus voltage plots for Burns, Maxwell and Mesa 500 kV buses but comparing cases 3a, 5c, 6c, and 7c for the N-1-1 [A] outage. It can be seen that as the amount of generation islanded at Windhub substation increases, the voltage profiles in Burns and Maxwell significantly decrease once the fault was cleared, particularly in case 7c. In addition, even if the oscillations showed a positive damping, it is possible that the post-contingency steady state could be achieved after 30 seconds or more. For SCE area, the amount of generation dropped at Windhub substation did not exhibit a major different impact.

Figure F.11-8: Transient voltages in cases 3a, 5c, and 6c for N-1-1 [A] outage – a) Burns 500 kV, b) Maxwell 500 kV, and c) Mesa 500 kV substations





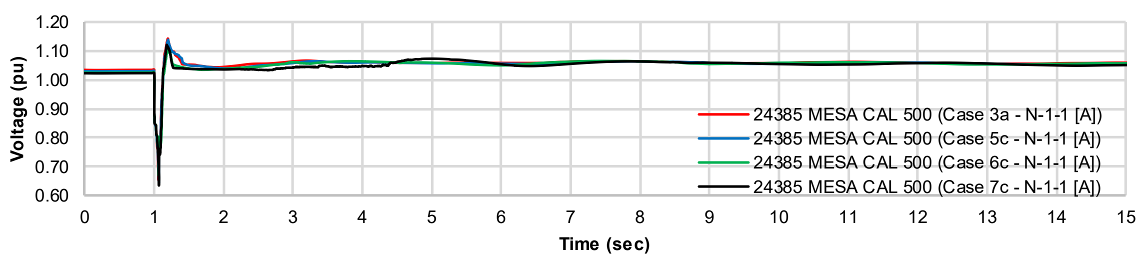


Figure F.11-9 shows the frequency plots for Rio Hondo 66 kV bus comparing cases 3a, 5c, 6c, and 7c for the N-1-1 [A] outage. It can be seen that during the fault, there was no significant difference in the frequency but the post-contingency frequency is lower as the load-resource imbalance increases.

Figure F.11-9: Transient frequency in cases 3a, 5c, and 6c for N-1-1 [A] outage – Rio Hondo 66 kV substation

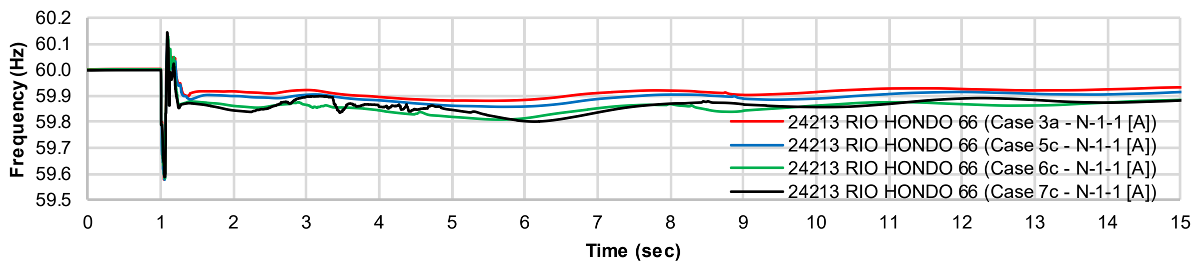
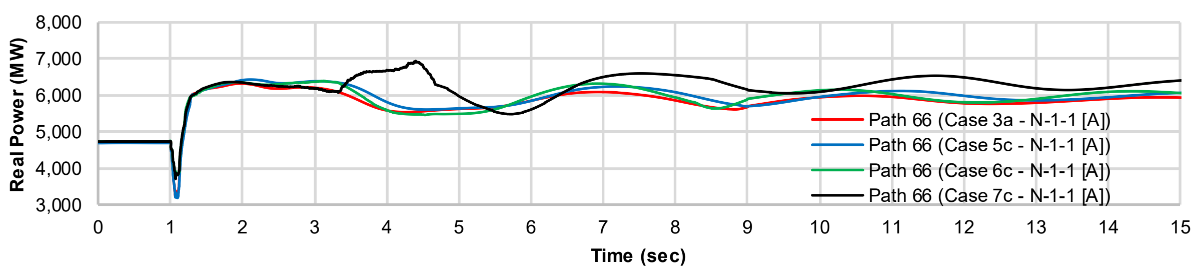


Figure F.11-10 presents a comparison Path 66 real power flow for cases 3a, 5c, 6c, and 7c for the N-1-1 [A] outage. In the first three cases, the peak value occurred during the first power swing with and average value of 6,400 MW. These simulations stabilized to a post-contingency real power flow around 6,000 MW. For case 7c, the maximum value occurred around 3.5 seconds, with a value of almost 7,000 MW (coincident with the voltage dip observed) and stabilized to a post-contingency value of 6,350 MW.

Figure F.11-10: Transient real power flow in cases 3a, 5c, and 6c for N-1-1 [A] outage – Path 66



- **Conclusions of the post transient and transient assessments**

The post transient assessment indicated that the maximum generation amount that can be islanded at Windhub substation is 3,290 MW before voltage collapse driven cascading outages occur in PG&E and Northwest areas for scenarios with high N>S power transfers through Path 66.

The transient stability assessment showed that generation amounts beyond 3,290 MW could be islanded at Windhub substation, but the validity of these results is directly related to the accuracy of the composite load models, which is difficult to validate. If a lower reduction of composite load would have been observed in the simulations, the results would have been closer to the ones in post transient assessment. Furthermore, even if the composite load models are adequate, this load would automatically return along with the voltage stability concern identified.

The constraint is identified in the base portfolio under the HSN condition, where 1063 MW of capacity resources would be undeliverable without mitigation as shown in Table F.11-10. However, the transmission capability estimate provided to the CPUC was approximately 400 MW higher in terms of the actual study amount level which is approximately equivalent to the 1000 MW of nameplate capacity that was found to be undeliverable. Given this inaccuracy in the estimate provided, during the development of the resource portfolio it was not anticipated that a transmission upgrade would be triggered for the Windhub Area Export constraint. In addition, with the updated estimate, the 2024-2025 TPP portfolio is not expected to require a transmission upgrade for this constraint. Therefore, an upgrade is not recommended for approval for this constraint.

Table F.11-10: Windhub Area Export constraint summary

<table>
<tr><td colspan="2">Affected transmission zones</td><td colspan="2">Tehachapi area – Windhub Substation</td></tr>
<tr><td colspan="2"></td><td>Base</td><td>Sensitivity</td></tr>
<tr><td colspan="2">Portfolio MW behind the constraint</td><td>3546 MW</td><td rowspan="8">N/A</td></tr>
<tr><td colspan="2">Portfolio battery storage MW behind the constraint</td><td>1795 MW</td></tr>
<tr><td colspan="2">Deliverable portfolio MW w/o mitigation</td><td>2483 MW</td></tr>
<tr><td colspan="2">Total undeliverable baseline and portfolio MW</td><td>1063 MW</td></tr>
<tr><td rowspan="3">Mitigation Options</td><td>RAS</td><td>Not applicable</td></tr>
<tr><td>Re-locate portfolio battery storage (MW)</td><td>Does not solve the issue</td></tr>
<tr><td>Transmission upgrade including cost</td><td>Not needed</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td>See discussion above</td></tr>
</table>

F.11.2 Off-peak results

Wind and solar resources in the SCE Northern area are subject to curtailment in the base portfolio due to loading constraints identified in Table F.11-11 under normal and/or contingency conditions, which are further discussed below.

Table F.11-11: SCE Northern area off-peak deliverability constraints

Overloaded Facility	Contingency	Loading (%)	
		Base	Sensitivity
Windhub #1 500/230 kV transformer*	Windhub #2 500/230 kV transformer	119%	N/A
Windhub #2 500/230 kV transformer*	Windhub #1 500/230 kV transformer	119%	N/A
Whirlwind #1 500/230 kV transformer	Whirlwind #3 or #4 500/230 kV transformer	100%	N/A
Whirlwind #3 500/230 kV transformer	Whirlwind #1 or #4 500/230 kV transformer	101%	N/A
Midway–Whirlwind 500 kV (PG&E)	Base Case	112%	N/A
Midway–Whirlwind 500 kV (SCE)	Vincent–Midway #1 and #2 500 kV line**	128%	N/A

* Depending on which Windhub 230 kV bus, Bus A or Bus B, generic portfolio resources are mapped to, could overload Banks #3 and #4 500/230 kV transformers.

** Operational always credible common corridor N-2 that is under review.

Windhub 500/230 kV transformers off-peak deliverability constraint

Wind and solar resources interconnecting to Windhub 230 kV Bus A are subject to curtailment in the base portfolio due to loading limitations of the Windhub 500/230 kV transformers under Category P1 conditions as shown in Table F.11-12. Pre-contingency curtailment can be avoided by relying on the planned Windhub CRAS.

Table F.11-12: Windhub 500/230 kV transformers off-peak deliverability constraint summary

Affected renewable transmission zones		Tehachapi area – Windhub 230 kV Bus A	
		Base	Sensitivity
Portfolio solar and wind MW behind the constraint		1216 MW	N/A
Energy storage portfolio MW behind the constraint		1033 MW	
Renewable curtailment without mitigation (MW)		371 MW	
Mitigation Options:	Portfolio ES (in charging mode) (MW)[22]	305 MW	
	RAS	Planned Windhub CRAS	
	Transmission upgrades	Not needed	
	Planned Windhub CRAS	Not needed	

22 The Portfolio energy storage (in charging mode) amount is the amount needed to mitigate the constraint after baseline battery storage is fully utilized.

Whirlwind 500/230 kV transformers off-peak deliverability constraint

Wind and solar resources interconnecting to Whirlwind 230 kV bus are subject to curtailment in the base portfolio due to loading limitations of the Whirlwind 500/230 kV transformers under Category P1 conditions as shown in Table F.11-13. Pre-contingency curtailment can be avoided by relying on the planned Whirlwind CRAS.

Table F.11-13: Whirlwind 500/230 kV transformers off-peak deliverability constraint summary

Affected renewable transmission zones		Tehachapi area – Whirlwind 230 kV	
		Base	**Sensitivity**
Portfolio solar and wind MW behind the constraint		1579 MW	N/A
Energy storage portfolio MW behind the constraint		1635 MW	
Renewable curtailment without mitigation (MW)		103 MW	
Mitigation Options:	Portfolio ES (in charging mode) (MW)[23]	36 MW	
	RAS	Planned Whirlwind CRAS	
	Transmission upgrades	Not needed	
Recommended Mitigation		Planned Whirlwind CRAS	

Midway–Whirlwind 500 kV line off-peak deliverability constraint

Wind and solar resources in southern California are subject to curtailment in the base portfolio due to loading limitations on PG&E's portion of the Midway–Whirlwind 500 kV line under normal conditions and on SCE's portion of the line under category P7 conditions as shown above. About 1042 MW of portfolio resources were curtailed to mitigate the overload as shown in Table F.11-14. The constraint occurs during periods of high renewable output and heavy south to north transfers on Path 26. Renewable curtailment can be avoided by reducing thermal generation and dispatching baseline energy storage in charging mode. Since the constraint occurs under normal system conditions, RAS is not a viable mitigation.

[23] The Portfolio energy storage (in charging mode) amount is the amount needed to mitigate the constraint after baseline battery storage is fully utilized.

Table F.11-14: Midway–Whirlwind 500 kV off-peak deliverability constraint summary

Affected renewable transmission zones		All of Southern California	
		Base	**Sensitivity**
Portfolio solar and wind MW behind the constraint		27047 MW	N/A
Energy storage portfolio MW behind the constraint		22582 MW	
Renewable curtailment without mitigation (MW)		1042 MW	
Mitigation Options:	Portfolio ES (in charging mode) (MW)[24]	Not needed	
	RAS	Not applicable for P0 overload	
	Transmission upgrades	Bypass the series capacitor of the Midway–Whirlwind 500 kV line	
Recommended Mitigation		Reduce thermal generation and dispatch baseline storage in charging mode	

1. Bypass the series capacitor of the Midway–Whirlwind 500 kV line

Bypassing the series capacitor of the Midway–Whirlwind 500 kV line is sufficient to address the off-peak deliverability constraint for both the base case condition without contingency and the outage of both Vincent – Midway 500 kV lines assuming a Path 26 south to north flow of 3,000 MW. Further reliability studies would be needed to determine if the series capacitor could be bypassed permanently, seasonally or if there is a requirement of constant switching dependent on changing system conditions.

F.11.3 Conclusion and recommendation

The SCE Northern area base portfolio deliverability assessment identified on-peak and off-peak deliverability constraints. All but one of the constraints can be addressed by using RAS or reducing thermal generation and dispatching energy storage in charging mode, as applicable.

For the Windhub Area Export Constraint, there was an inaccuracy in the transmission capability estimate provided to the CPUC during the development of the resource portfolio, thus, it was not anticipated that a transmission upgrade would be triggered. In addition, with the updated estimate, the 2024-2025 TPP portfolio is not expected to require a transmission upgrade for this constraint.

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

[24] The Portfolio energy storage (in charging mode) amount is the amount needed to mitigate the constraint after baseline battery storage is fully utilized.

F.12 SCE North of Lugo Area

Base portfolio resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE North of Lugo (NOL) interconnection area are listed in Table F.12-1. The portfolio in the interconnection area are comprised of solar, battery storage, geothermal, biomass/biogas and distributed solar resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table F.12-1: SCE North of Lugo Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio
	FCDS	EO	Total	
Solar	1,310	1,350	**2,660**	Not applicable for southern areas
Wind – In State	0	0	**0**	
Wind – Out-of-State (Existing TX)	0	0	**0**	
Wind – Out-of-State (New TX)	0	0	**0**	
Wind – Offshore	0	0	**0**	
Li Battery	1,404	0	**1,404**	
Geothermal	53	0	**53**	
Long Duration Energy Storage (LDES)	0	0	**0**	
Biomass/Biogas	3	0	**3**	
Distributed Solar	7	0	**7**	
Total	2,777	1,350	**4,127**	

The base portfolio resources as identified in the CPUC busbar mapping for the SCE North of Lugo interconnection area are illustrated on the single-line diagram in Figure F.12-1.

Figure F.12-1: SCE North of Lugo Interconnection Area – Mapped Base Portfolio

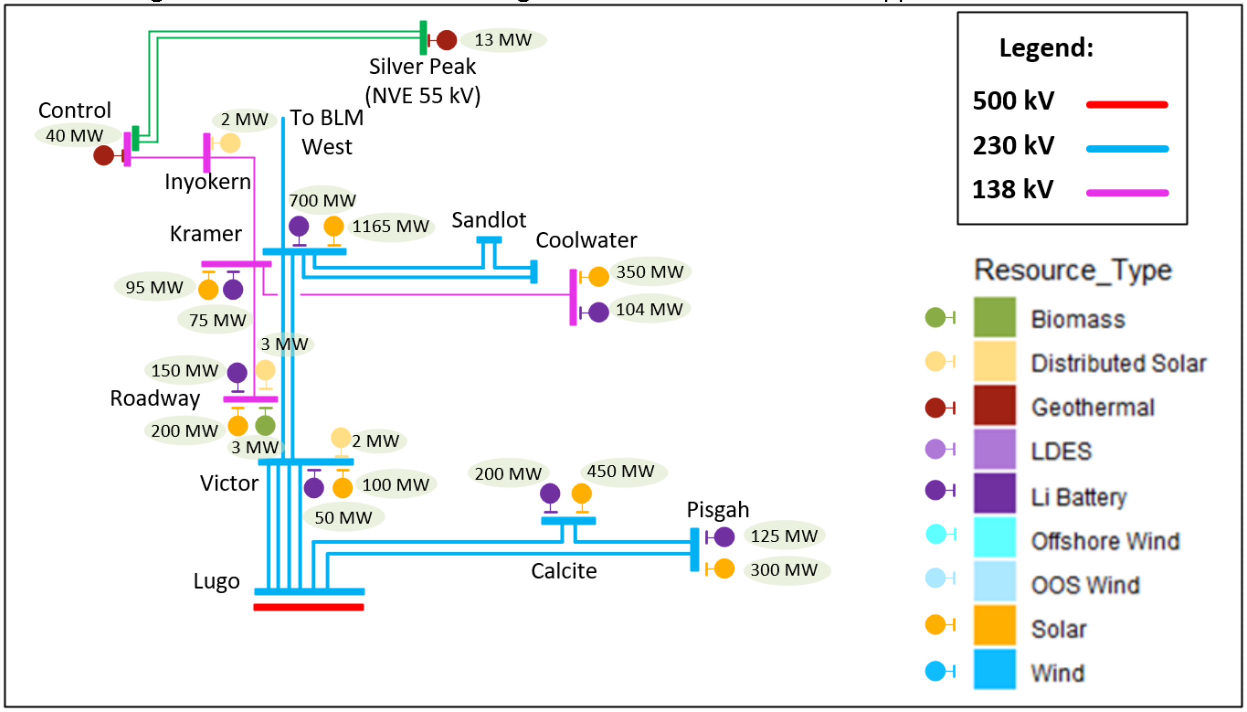


Table F.12-2 shows the MIC expansion requests that were assessed as part of the NOL area assessment.

F.12.1 On-peak results

Coolwater–Kramer Corridor Constraint

The Coolwater–Kramer corridor deliverability constraint, which is comprised of the constraints included in Table F.12-2, affect deliverability of capacity resources in the NOL area due to thermal overloading of the planned 230/115 kV transformer and 115 kV lines in the area under contingency conditions as shown in the table. Up to 439 MW of capacity resources in the base portfolio will be undeliverable without mitigation.

Table F.12-3 provides the constraint summary for the more limiting constraints.

Table F.12-2: Coolwater–Kramer corridor on-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)	
		HSN	SSN
Coolwater 230/115 kV Transformer (Planned)	Kramer–Coolwater & Kramer–Sandlot 230 kV lines	139.5%	162.4
	Kramer–Coolwater & Sandlot–Coolwater 230 kV lines	128.6%	120.3%
Tortilla–Coolwater 115 kV	Kramer–Coolwater & Kramer–Sandlot 230 kV lines	--	106.9%
Coolwater–Kramer 115 kV		--	106.9%

Table F.12-3: On-peak Coolwater–Kramer corridor constraint summary

Affected transmission zones		North of Lugo Area
		Base (SSN)
Portfolio MW behind constraint		1,186 MW
Portfolio battery storage MW behind constraint		376 MW
Deliverable portfolio MW w/o mitigation		747 MW
Total undeliverable baseline and portfolio MW		439 MW
Mitigation Options	RAS	Expanded Mohave Desert RAS
	Reduce generic battery storage (MW)	Not needed
	Transmission upgrade including cost	Not needed
Recommended Mitigation		Expanded Mohave Desert RAS

Remedial Action Schemes (RAS), reducing generic portfolio battery storage and transmission alternatives were considered to address the constraints. Since expanding the existing Mohave Desert RAS adequately mitigates the deliverability constraints, no other solution was found to be needed.

Control–Inyokern/Haiwee Tap 115 kV Constraint

Control–Inyokern/Haiwee Tap 115 kV deliverability constraint described in Table F.12-4 affects deliverability of capacity resources in the NOL area due to outage of Control–Coso–Inyokern 115 kV line. Up to 26 MW of capacity resources in the base portfolio will be undeliverable without mitigation. Table F.12-5 provides a summary of the constraint including affected resources and mitigation solutions.

Table F.12-4: Control–Inyokern/Haiwee Tap 115 kV on-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)	
		HSN	SSN
Control–Inyokern/Haiwee Tap 115 kV	Control–Coso–Inyokern 115 kV line	109.2%	106.7%

Table F.12-5: On-peak Control–Inyokern/Haiwee Tap 115 kV constraint summary

Affected transmission zones		North of Inyokern Area
		Base (HSN)
Portfolio MW behind constraint		54 MW
Portfolio battery storage MW behind constraint		0 MW
Deliverable portfolio MW w/o mitigation		54 MW
Total undeliverable baseline and portfolio MW		26 MW
Mitigation Options	RAS	Existing Bishop RAS
	Reduce generic battery storage (MW)	N/A
	Transmission upgrade including cost	Not needed
Recommended Mitigation		Existing Bishop RAS

RAS and transmission upgrades were considered to address the constraint. Since the existing Bishop RAS adequately mitigates the deliverability constraint, no further mitigation solution was found to be needed.

With the transmission upgrades approved in the NOL area in the 2022-2023 Transmission Plan and the Bishop RAS modeled, the constraint did not impact MIC expansion requests in the area as indicated in Table F.12-6.

Table F.12-6: MIC expansion requests impacted by the Control–Inyokern/Haiwee Tap constraint

Affected interties	SILVERPK_BG
	Base
MIC expansion request MW behind constraint	39 MW
Deliverable MIC expansion request MW with mitigation	39 MW

Control–Silver Peak 55kV corridor constraint

Control–Silver Peak 55 kV corridor deliverability constraint, which is comprised of the constraints included in Table F.12-7, affect deliverability of capacity resources in the Control and Silver Peak areas due to thermal overloading of the non-ISO controlled Silver Peak PST under normal conditions and 115 kV and 55 KV facilities in the area under contingency conditions. The most limiting constraint is the Silver Peak PST and the 17 MW rating of Path 52. The overload is due to the 53 MW MIC expansion request associated with the Silver Peak inter-tie which exceeds the rating of the 17 MVA PST. Reducing the MIC expansion request to be within the rating of the PST addresses all of the constraints. Table F.12-8 provides the Control–Silver Peak corridor constraint summary for the most limiting constraint.

Table F.12-7: Control–Silver Peak 55 kV corridor deliverability constraint

Overloaded Facility	Contingency	Base Portfolio Loading (%)	
		HSN	SSN
Silver peak PST (See Note)*	Base case	305%	305%
Control–Silver Peak C 55kV	Control–Silver Peak A 55kV line	140.6%	146.7%
Control–Silver Peak A 55kV	Control–Silver Peak C 55kV line	133.8%	138.7%

Note: The requested 53 MW Silver Peak BG MIC exceeds the 17 MVA normal rating of the non-ISO controlled Silver Peak PST and the 17 MW rating of Path 52. Reducing the requested MIC expansion to be within the rating of the PST addresses all of the overloads.

Table F.12-8: Control–Silver Peak 55 kV corridor constraint summary

Affected transmission zones		North of Control Area
		Base (HSN/SSN)
Portfolio MW behind constraint		13 MW
Portfolio battery storage MW behind constraint		0 MW
Deliverable portfolio MW w/o mitigation		13 MW
Total undeliverable baseline and portfolio MW		35 MW
Mitigation Options	RAS	Not applicable for N-0 overload
	Reduce generic battery storage (MW)	N/A
	Transmission upgrade including cost	Not needed
Recommended Mitigation		Reduce requested MIC expansion to 4 MW

Only 4 MW of the 39 MW MIC expansion request in the area will be deliverable as indicated in Table F.12-9 with the transmission upgrades approved in the NOL area in the 2022-2023 Transmission Plan modeled.

Table F.12-9: MIC expansion requests impacted by the Control–Silver Peak 55 kV constraint

Affected interties	None
	Base
MIC expansion request MW behind constraint	39 MW
Deliverable MIC expansion request MW	4 MW

Lugo–Calcite 230 kV Constraint

The overloading of the Lugo–Calcite 230 kV line under the contingency conditions indicated in Table F.12-10 affect deliverability of capacity resources connected to Calcite and Pisgah. Up to 103 MW of capacity resources in the base portfolio will be undeliverable without mitigation. Table F.12-11 provides a summary of Lugo–Calcite 230 kV Constraint.

Table F.12-10: Lugo–Calcite on-peak deliverability constraint

Overloaded Facility	Contingency	Base Portfolio Loading (%)	
		HSN	SSN
Calcite–Lugo 230 kV	Pisgah–Lugo 230 kV	117.3%	100.6%
	Lugo–Victorville 500 kV	105.4%	91.1%
	Eldorado–Lugo 500 kV	102.1%	--

Table F.12-11: On-peak Lugo–Calcite 230 kV constraint summary

Affected transmission zones		Pisgah and Calcite (Planned) 230 kV Substations
		Base (HSN)
Portfolio MW behind constraint		625 MW
Portfolio battery storage MW behind constraint		325 MW
Deliverable portfolio MW w/o mitigation		522 MW
Total undeliverable baseline and portfolio MW		103 MW
Mitigation Options	RAS	Planned Calcite RAS
	Reduce generic battery storage (MW)	Not needed
	Transmission upgrade including cost	Not needed
Recommended Mitigation		Planned Calcite RAS

Since the planned Calcite area RAS expanded to include portfolio resources and the Lugo–Victorville 500 kV and Eldorado–Lugo 500 kV contingencies can address the constraint, no further mitigation solution was found to be needed.

The Lugo–Calcite 230 kV constraint was not found to impact MIC expansion requests.

F.12.2 Off-peak results

Coolwater–Kramer Corridor Constraint

Wind and solar resources in the Kramer-Coolwater area are subject to curtailment due to loading limitations on 230 and 115 kV facilities in the area under contingency conditions as shown in Table F.12-12. Table F.12-13 provides a summary of the constraints including mitigation alternatives considered. The constraints can be mitigated by expanding Mojave Desert RAS or dispatching portfolio battery storage in charging mode.

Table F.12-12: Coolwater–Kramer 230/115 kV corridor off-peak deliverability constraints

Overloaded Facility	Contingency	Base Loading (%)
Coolwater–Kramer 115 kV	Kramer–Coolwater & Kramer–Sandlot 230 kV (Loading results are based on DC solution as the AC solution diverged)*	152.9%
Coolwater 230/115 kV Tr.		183.3%
Tortilla–Coolwater 115 kV		137.8%
Kramer 230/115 kV #1 & #2 Tr.		129.6%
Tortilla–Kramer 115 kV		133.4%
Kramer–Sandlot 230 kV	Kramer–Coolwater 230 kV	120.7%
Kramer–Coolwater 230 kV	Kramer–Sandlot 230 kV	112.7%

* The Kramer–Coolwater & Sandlot–Coolwater 230 kV line outage also causes overloads on the same lines but is not reported because it is less limiting.

Table F.12-13: Coolwater–Kramer off-peak deliverability constraint summary

Affected renewable transmission zones		Sandlot-Coolwater area
		Base Portfolio
Portfolio solar and wind MW behind the constraint		987 MW
Energy storage portfolio MW behind the constraint		617 MW
Renewable curtailment without mitigation (MW)		456 MW
Mitigation Options:	Portfolio ES (in charging mode) (MW)[25]	376 MW
	RAS	Expanded Mojave desert RAS
	Transmission upgrades	Not needed
Recommended Mitigation		Expanded Mojave desert RAS

[25] The Portfolio energy storage (in charging mode) amount is the amount needed to mitigate the constraint after baseline battery storage is fully utilized.

Victor–Kramer 230 kV Constraint

Wind and solar resources north of the Victor–Kramer corridor will be subject to curtailment due to loading limitations on Victor-Kramer No. 1 & No. 2 230 kV lines under contingency conditions as shown in Table F.12-14. Table F.12-15 provides a summary of the constraint including mitigation alternatives considered. The constraints can be mitigated by expanding Mojave Desert RAS or dispatching portfolio battery storage in charging mode.

Table F.12-14: Victor–Kramer 230 kV off-peak deliverability constraints

Overloaded Facility	Contingency	Base Loading (%)
Kramer–Victor #1 and #2 230 kV	Kramer–Victor #3 & #4 230 kV (Planned)	117.4%

Table F.12-15: Victor–Kramer 230 kV off-peak deliverability constraint summary

Affected renewable transmission zones		North of the Victor–Kramer corridor
		Base Portfolio
Portfolio solar and wind MW behind the constraint		1,792 MW
Energy storage portfolio MW behind the constraint		1,242 MW
Renewable curtailment without mitigation (MW)		377 MW
Mitigation Options:	Portfolio ES (in charging mode) (MW)[26]	255 MW
	RAS	Expanded Mojave desert RAS
	Transmission upgrades	Not needed
Recommended Mitigation		Expanded Mojave desert RAS

Lugo–Calcite–Pisgah 230 kV Corridor Constraint

Wind and solar resources at Pisgah and Calcite (planned) will be subject to curtailment due to loading limitations on the Calcite–Pisgah–Lugo 230 kV corridor under normal and contingency conditions as shown in Table F.12-16. Table F.12-17 provides summary of the constraints including mitigation alternatives considered. The constraints can be mitigated by dispatching generic portfolio battery storage in charging mode.

[26] The Portfolio energy storage (in charging mode) amount is the amount needed to mitigate the constraint after baseline battery storage is fully utilized.

Table F.12-16: Lugo–Calcite–Pisgah 230 kV corridor off-peak deliverability constraint

Overloaded Facility	**Contingency**	**Base Loading (%)**
Calcite–Lugo 230 kV	Pisgah–Lugo 230 kV	152.8%
	Eldorado–Lugo 500 kV	133.1%
	Base case	125.8%
Pisgah–Lugo 230 kV	Calcite–Lugo 230 kV	114.2%
Calcite–Pisgah 230 kV		121.2%

Table F.12-17: Lugo–Calcite–Pisgah 230 kV corridor off-peak deliverability constraint summary

Affected renewable transmission zones		Calcite and Pisgah Substations
		Base Portfolio
Portfolio solar and wind MW behind the constraint		750 MW
Energy storage portfolio MW behind the constraint		325 MW
Renewable curtailment without mitigation (MW)		200 MW
Mitigation Options	Portfolio ES (in charging mode) (MW)[27]	200 MW
	RAS	Not applicable for N-0
	Transmission upgrades	Not needed
Recommended Mitigation		Dispatch portfolio battery storage in charging mode

F.12.3 Conclusion and recommendation

The following conclusion can be made based on the North of Lugo Area deliverability assessment:

- All portfolio resources in the NOL area are deliverable with existing or expanded Remedial Action Schemes (RAS). Off-peak deliverability constraints can be addressed using RAS or dispatching portfolio battery storage in charging mode;
- Out of the 39 MW of California Community Power's SILVERPK_BG MIC expansion request, only about 4 MW is deliverable with the transmission upgrades approved for the NOL Area in the 2022-2023 Transmission Plan modeled.

[27] The Portfolio energy storage (in charging mode) amount is the amount needed to mitigate the constraint after baseline battery storage is fully utilized.

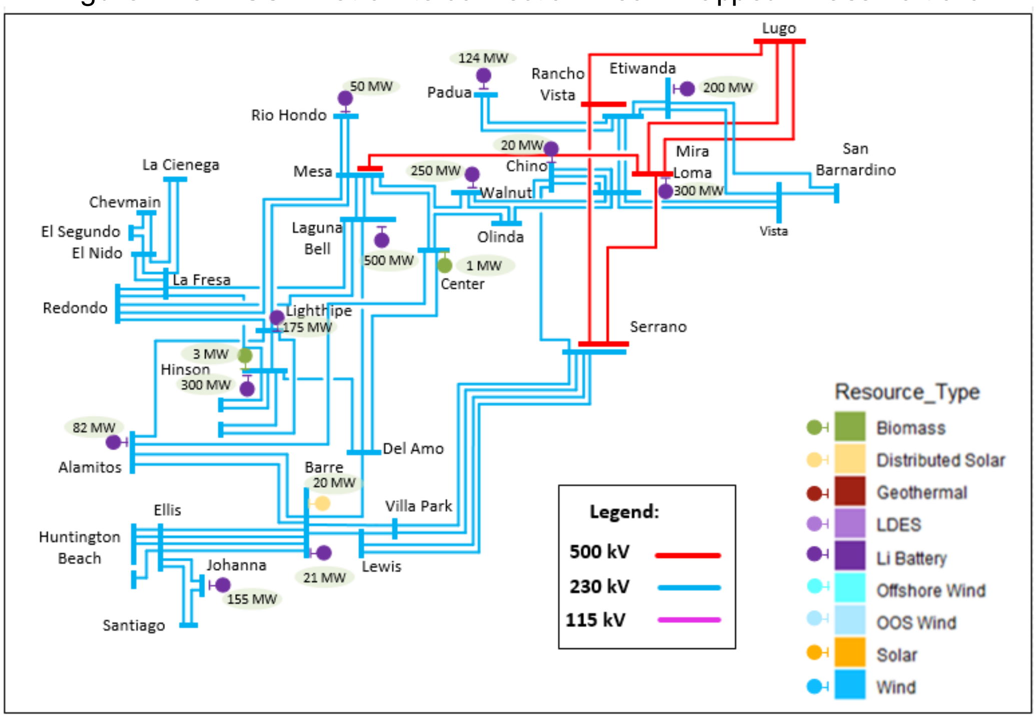
F.13SCE Metro Area

The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE Metro interconnection area, are listed in Table F.13-1. The portfolios in the interconnection area are comprised of battery storage resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table F.13-1: SCE Metro Interconnection Area – Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio
	FCDS	EO	Total	
Solar	-	-		Not applicable for southern areas
Wind – In State	-	-		
Wind – Out-of-State (Existing TX)	-	-		
Wind – Out-of-State (New TX)	-	-		
Wind – Offshore	-	-		
Li Battery	2,177	-	2,177	
Geothermal	-	-	-	
Long Duration Energy Storage (LDES)	-	-	-	
Biomass/Biogas	4	-	4	
Distributed Solar	20	-	20	
Total	2,201	-	2,201	

Figure F.13-1: SCE Metro Interconnection Area – Mapped[28] Base Portfolio



[28] Mapped base portfolio includes the adjustments to the base portfolio made by CPUC staff in the SCE Metro Interconnection Area to account for allocated TPD and additional in-development resources identified.

F.13.1 On-peak results

The SCE Metro area deliverability assessment did not identify any base portfolio on-peak deliverability constraints that require transmission upgrades.

F.13.2 Off-peak results

The SCE Metro area deliverability assessment did not identify any base portfolio off-peak deliverability constraints that require transmission upgrades.

F.13.3 Summary of Metro area results

The SCE Metro area deliverability assessment did not identify any base portfolio (on-peak or off-peak) deliverability constraints that require transmission upgrades.

F.14SCE Eastern

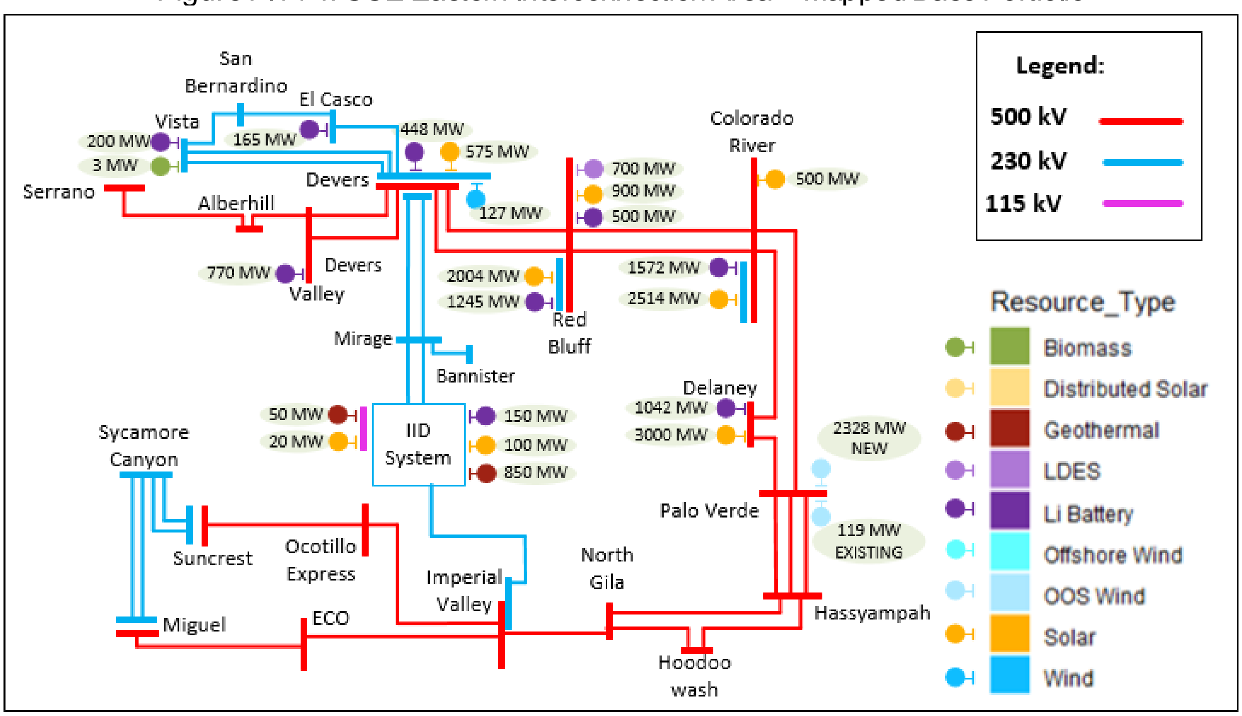
The total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SCE Eastern interconnection area are listed in Table F.14-1. The portfolios are comprised of solar, wind (in-state and out-of-state), battery storage and biomass/biogas resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table F.14-1: SCE Eastern Interconnection Area – Base Portfolio by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio
	FCDS	EO	Total	
Solar	6,092		**6,092**	Not applicable for southern areas
Wind – In State	107	20	**127**	
Wind – Out-of-State (Existing TX)	119	-	**119**	
Wind – Out-of-State (New TX)	2,328	-	**2,328**	
Wind – Offshore	-	-	**-**	
Li Battery	6,092	-	**6,092**	
Geothermal	900	-	**900**	
Long Duration Energy Storage (LDES)	700	-	**700**	
Biomass/Biogas	3	-	**3**	
Distributed Solar	-	-	**-**	
Total	**13,198**	**6,684**	**19,881**	

The resources as identified in the CPUC busbar mapping for the SCE Eastern interconnection area are illustrated on the single-line diagram in Figure F.14-1.

Figure F.14-1: SCE Eastern Interconnection Area – Mapped Base Portfolio



F.14.1 On-peak results

Eastern Area: Colorado River 500/230 kV constraint

The deliverability of FC resources interconnecting at the Colorado River 230 kV bus is limited by thermal overloading of the 500/230 kV transformers under Category P1 conditions as shown in Table F.14-2. The constraint was identified in the base portfolio, with the highest loadings being observed under the HSN scenario. The constraint can be mitigated by the planned West of Colorado River CRAS.

Table F.14-2: Colorado River 500/230 kV Deliverability Constraint

Overloaded Facility	Contingency	More Limiting Condition	Loading (%)	
			Base	Sensitivity
Colorado River 500/230 kV Transformer No.1	Colorado River 500/230 kV Transformer No.2	HSN	122	N/A
Colorado River 500/230 kV Transformer No.2	Colorado River 500/230 kV Transformer No.1	HSN	122	N/A

Table F.14-3: Colorado River 500/230 kV Deliverability Constraint Summary

<table>
<tr><td colspan="2">Affected transmission zones</td><td colspan="2">Colorado River</td></tr>
<tr><td colspan="2"></td><td>Base</td><td>Sensitivity</td></tr>
<tr><td colspan="2">Portfolio MW behind the constraint</td><td>2530 MW</td><td rowspan="8">N/A</td></tr>
<tr><td colspan="2">Portfolio battery storage MW behind the constraint</td><td>1499 MW</td></tr>
<tr><td colspan="2">Deliverable portfolio MW w/o mitigation</td><td>2052 MW</td></tr>
<tr><td colspan="2">Total undeliverable baseline and portfolio MW</td><td>478 MW</td></tr>
<tr><td rowspan="3">Mitigation Options</td><td>RAS</td><td>West of Colorado River CRAS</td></tr>
<tr><td>Re-locate portfolio battery storage (MW)</td><td>Not needed</td></tr>
<tr><td>Transmission upgrade including cost</td><td>Not needed</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td>West of Colorado River CRAS</td></tr>
</table>

F.14.2 Off-peak results

Eastern Area: Colorado River 500/230 kV off-peak deliverability constraint

Wind and solar resources interconnecting at the Colorado River 230 kV bus are subject to curtailment in the base and sensitivity portfolios due to loading limitations on the transformers as shown in Table F.14-4. Pre-contingency curtailment can be avoided by dispatching portfolio energy storage in charging mode and/or utilizing the planned West of Colorado River CRAS.

Table F.14-4: Colorado River 500/230 kV off-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)	
		Base	Sensitivity
Colorado River 500/230 kV Transformer No.1	Colorado River 500/230 kV Transformer No.2	183	N/A
Colorado River 500/230 kV Transformer No.2	Colorado River 500/230 kV Transformer No.1	183	N/A
Colorado River 500/230 kV Transformer No.1	Base Case	109	N/A
Colorado River 500/230 kV Transformer No.2	Base Case	109	N/A

Table F.14-5: Colorado River 500/230 kV off-peak deliverability constraint summary

<table>
<tr><td colspan="2">Affected renewable transmission zones</td><td colspan="2">Colorado River</td></tr>
<tr><td colspan="2"></td><td>Base</td><td>Sensitivity</td></tr>
<tr><td colspan="2">Portfolio solar and wind MW behind the constraint</td><td>2262 MW</td><td rowspan="7">N/A</td></tr>
<tr><td colspan="2">Energy storage portfolio MW behind the constraint</td><td>1563 MW</td></tr>
<tr><td colspan="2">Renewable curtailment without mitigation (MW)</td><td>1501 MW</td></tr>
<tr><td rowspan="3">Mitigation Options:</td><td>Portfolio ES (in charging mode) (MW)[29]</td><td>1135 MW</td></tr>
<tr><td>RAS</td><td>West of Colorado River CRAS</td></tr>
<tr><td>Transmission upgrades</td><td>Not needed</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td>West of Colorado River CRAS and/or batteries in charging mode</td></tr>
</table>

[29] The Portfolio energy storage (in charging mode) amount is the amount needed to mitigate the constraint after baseline battery storage is fully utilized.

Eastern Area: Red Bluff 500/230 kV off-peak deliverability constraint

Wind and solar resources interconnecting at the Red Bluff 230 kV bus are subject to curtailment in the base and sensitivity portfolios due to loading limitations on the transformers as shown in Table F.14-6. Pre-contingency curtailment can be avoided by utilizing the planned West of Colorado River CRAS.

Table F.14-6: Red Bluff 500/230 kV off-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)	
		Base	Sensitivity
Red Bluff 500/230 kV Transformer No.1	Red Bluff 500/230 kV Transformer No.2	147	N/A
Red Bluff 500/230 kV Transformer No.2	Red Bluff 500/230 kV Transformer No.1	147	N/A

Table F.14-7: Red Bluff 500/230 kV off-peak deliverability constraint summary

<table>
<tr><td colspan="2">Affected renewable transmission zones</td><td colspan="2">Red Bluff</td></tr>
<tr><td colspan="2"></td><td>Base</td><td>Sensitivity</td></tr>
<tr><td colspan="2">Portfolio solar and wind MW behind the constraint</td><td>2168 MW</td><td rowspan="7">N/A</td></tr>
<tr><td colspan="2">Energy storage portfolio MW behind the constraint</td><td>1280 MW</td></tr>
<tr><td colspan="2">Renewable curtailment without mitigation (MW)</td><td>906 MW</td></tr>
<tr><td rowspan="3">Mitigation Options:</td><td>Portfolio ES (in charging mode) (MW)[30]</td><td>674 MW</td></tr>
<tr><td>RAS</td><td>West of Colorado River CRAS</td></tr>
<tr><td>Transmission upgrades</td><td>Not needed</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td>West of Colorado River CRAS and/or batteries in charging mode</td></tr>
</table>

[30] The Portfolio energy storage (in charging mode) amount is the amount needed to mitigate the constraint after baseline battery storage is fully utilized.

F.15SDG&E area

F.15.1 On-peak results

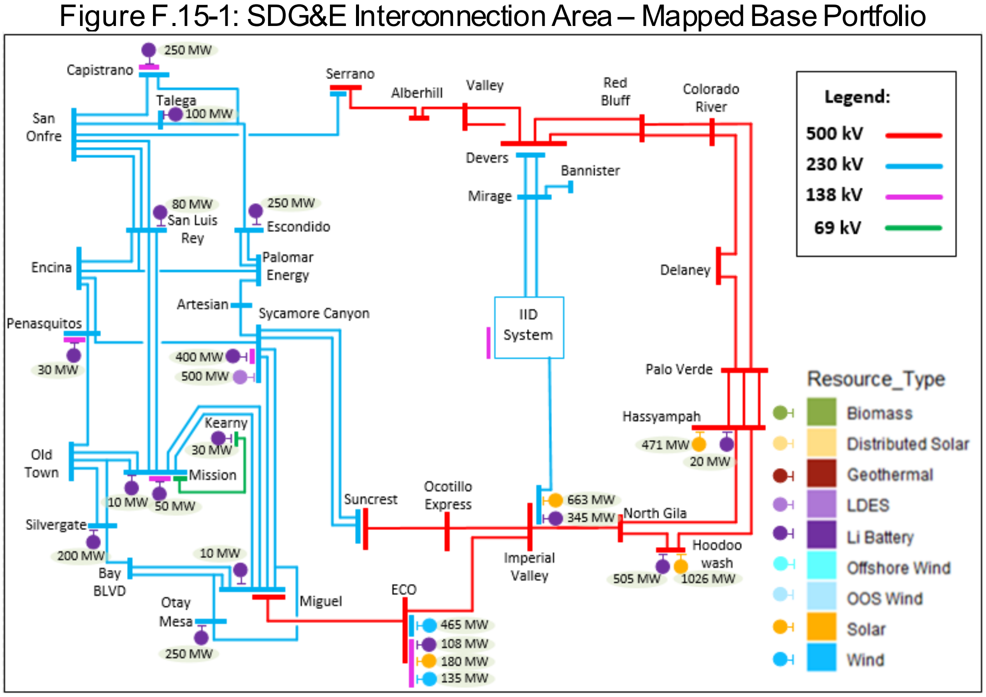
Table F.15-1 includes the total capacity of resources, by resource type, selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO) in the SDG&E interconnection area. The portfolios in the interconnection area are comprised of solar, wind (instate), battery storage, geothermal, and long duration energy storage resources. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment in which only FCDS resources are modeled.

Table F.15-1: SDG&E Interconnection Area – Base Portfolio by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio
	FCDS	EO	Total	
Solar	650	1,690	**2,340**	Not applicable for southern areas
Wind – In State	240	360	**600**	
Wind – Out-of-State (Existing TX)	-	-	**-**	
Wind – Out-of-State (New TX)	-	-	**-**	
Wind – Offshore	-	-	**-**	
Li Battery	2,617	-	**2,617**	
Geothermal	-	-	**-**	
Long Duration Energy Storage (LDES)	500	-	**500**	
Biomass/Biogas	-	-	**-**	
Distributed Solar	-	-	**-**	
Total	**4,007**	**2,050**	**6,057**	

The resources as identified in the CPUC busbar mapping for the SDG&E interconnection area are illustrated on the single-line diagram in Figure F.15-1.

Figure F.15-1: SDG&E Interconnection Area – Mapped Base Portfolio



Bay Boulevard-Silvergate constraint

The deliverability of portfolio resources in the Bay Boulevard-Silvergate area is limited by thermal overloading of the Bay Boulevard-Silvergate 230 kV line as shown in Table F.15-2. These overloads were identified for the base portfolio. The constraints were seen in both the HSN and SSN scenarios, with the higher loadings being in the HSN scenario. Table F.15-3 shows the amount of portfolio generation that would be deliverable without any transmission upgrades.

The constraint can be mitigated by using the 2-hour emergency rating of the Bay Boulevard-Silvergate 230 kV line.

Table F.15-2: Bay Boulevard-Silvergate constraints

		Highest Loading (%) (HSN)	
Overloaded Facility	**Contingency**	**Base**	**Sensitivity**
Bay Boulevard-Silvergate 230 kV	Miguel-Mission 230 kV #1 and #2	104	N/A
Bay Boulevard-Silvergate 230 kV	Imperial Valley-NSONGS 500 kV	106	N/A

Table F.15-3: Bay Boulevard-Silvergate deliverability constraint summary

Affected transmission zones		ECO, Imperial Valley, Hoodoo Wash, SDGE Internal	
		Base	**Sensitivity**
Portfolio MW behind constraint		2,133 MW	N/A
Portfolio battery storage MW behind constraint		695 MW	
Deliverable portfolio MW w/o mitigation		863 MW	
Total undeliverable baseline and portfolio MW		1,270 MW	
Mitigation Options	RAS	None	
	Reduce generic battery storage (MW)	Not needed	
	Transmission upgrade including cost	Not needed	
Recommended Mitigation		Use 2 hour emergency rating	

Affected interties	N/A	
	Base	**Sensitivity**
MIC expansion request MW behind constraint	N/A	N/A
Deliverable MIC expansion request MW		

Silvergate-Old Town constraint

The deliverability of portfolio resources in the Silvergate-Old Town area is limited by thermal overloading of the Silvergate-Old Town 230 kV lines as shown in Table F.15-4. These overloads were identified for the base portfolio. The constraints were seen in both the HSN and SSN scenarios, with the higher loadings being in the HSN scenario. Table F.15-5 shows the amount of portfolio generation that would be deliverable without any transmission upgrades.

The constraint can be mitigated by using the 30 minute rating of the overloaded lines.

Table F.15-4: Silvergate-Old Town constraints

		Highest Loading (%) (HSN)	
Overloaded Facility	**Contingency**	**Base**	**Sensitivity**
Silvergate-Old Town Tap 230 kV	Silvergate-Old Town 230 kV	134	N/A
Silvergate-Old Town 230 kV	Silvergate-Mission-Old Town 230 kV	133	N/A
Silvergate-Old Town 230 kV	Silvergate-Mission-Old Town 230 kV and Old Town-Mission 230 kV	124	N/A
Silvergate-Old Town 230 kV	Imperial Valley-NSONGS 500 kV	105	N/A
Silvergate-Old Town 230 kV	Miguel-Mission 230 kV #1 and #2	105	N/A
Silvergate-Old Town Tap 230 kV	Imperial Valley-NSONGS 500 kV	102	N/A
Silvergate-Old Town Tap 230 kV	Miguel-Mission 230 kV #1 and #2	102	N/A

Table F.15-5: Silvergate-Old Town deliverability constraint summary

<table>
<tr><td colspan="2">Affected transmission zones</td><td colspan="2">ECO, SDGE Internal</td></tr>
<tr><td colspan="2"></td><td>Base</td><td>Sensitivity</td></tr>
<tr><td colspan="2">Portfolio MW behind constraint</td><td>1,017 MW</td><td rowspan="8">N/A</td></tr>
<tr><td colspan="2">Portfolio battery storage MW behind constraint</td><td>417 MW</td></tr>
<tr><td colspan="2">Deliverable portfolio MW w/o mitigation</td><td>586 MW</td></tr>
<tr><td colspan="2">Total undeliverable baseline and portfolio MW</td><td>431 MW</td></tr>
<tr><td rowspan="3">Mitigation Options</td><td>RAS</td><td>None</td></tr>
<tr><td>Reduce generic battery storage (MW)</td><td>Not needed</td></tr>
<tr><td>Transmission upgrade including cost</td><td>Not needed</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td>Use 30 minute emergency rating</td></tr>
</table>

F.15.2 Off-peak results

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

F.16Offshore Wind

F.16.1 Morro Bay Area

In the Morro Bay area the base portfolio included 3,100 MW and the sensitivity portfolio included 5,355 MW of offshore wind. For the interconnection of the offshore wind, the existing Diablo 500 kV substation has been identified and is where current offshore wind interconnection requests in the ISO queue are primarily located. The ISO has also considered the alternative of creating a new 500 kV substation on the Diablo-Gates 500 kV for the interconnection of the Morro Bay area offshore wind. The ISO will continue to coordinate with PG&E and the offshore resource developers, which were the successful BOEM lease bidders, for the interconnection point for the Morro Bay area offshore wind.

F.16.2 Humboldt off shore wind interconnection

In the Humboldt area the base portfolio included 1,607 MW (1,446 MW FCDS and 161 MW EO) and the sensitivity portfolio included 8,045 MW of offshore wind. There are no existing bulk substation in the vicinity of Humboldt offshore wind. Eight total options in the baseline and sensitivity portfolios were considered to interconnect Humbold offshore wind to the rest of the system (Figure F.16-1). These options along with the study results are detailed in the following sections.

Figure F.16-1: Options to Interconnect Humboldt Bay Offshore Wind

Concept/ Alternative	500 kV AC	Onshore HVDC	Offshore HVDC
Base_A	2 Fern Road	0	0
Base_B	0	1 Collinsville	0
Base_C	0	0	1 Moss Landing
Base_D	0	0	1 Bay Hub

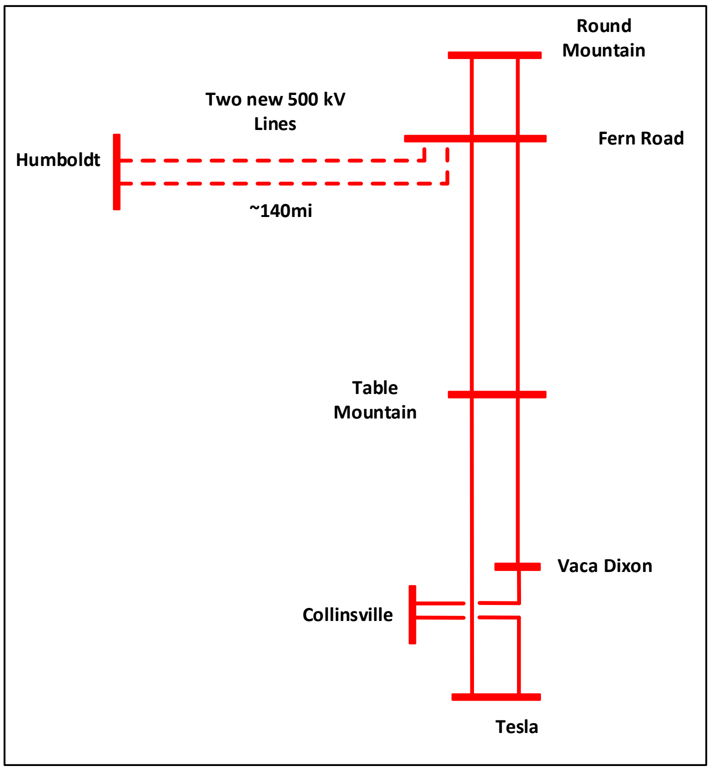
Concept/ Alternative	500 kV AC	Onshore HVDC	Offshore HVDC
Sen _A_1	1 Fern Road	1 Collinsville	1 Bay Hub
Sen _A_2	1 Fern Road	1 Collinsville	1 Moss Landing
Sen_B	1 Fern Road	2 Collinsville	0
Sen_C	2 Fern Road	0	1 Bay Hub

F.16.3 Humboldt off shore wind Baseline results

Option A: 500 kV AC lines to Fern Road 500 kV substation

Fern Road 500 kV substation is planned to be in service in 2024 as part of the Round Mountain Dynamic Reactive Support (DRS) project that is located approximately 11 miles south of Round Mountain substation. In this option, it is assumed that two, approximately 140 mile, 500 kV AC lines will interconnect the project to the Fern Road substation (Figure F.16-2). The cost estimate for this interconnection option-A is $2.1B-$3.0B.

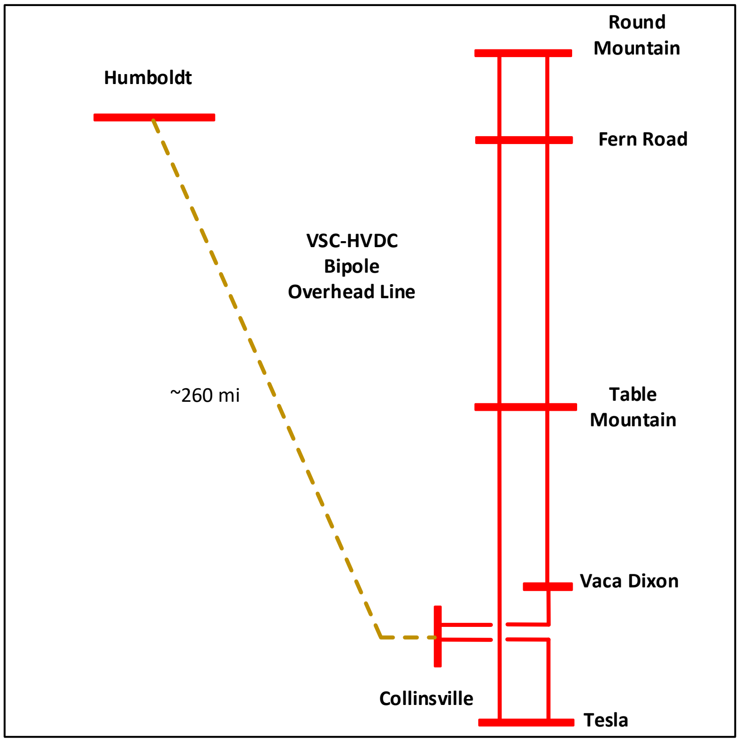
Figure F.16-2: AC Option to Interconnect Humboldt Bay Offshore Wind (Option-A)



Option B: LCC HVDC Bipole to Collinsville 500/230 kV substation

The new Collinsville 550/230 kV substation project was approved as a policy project in 2021-2022 TPP. The project includes looping of the Vaca Dixon – Tesla 500 kV line with two new 230 kV connections to the existing Pittsburg 230 kV substation. In this study it is assumed that the Humboldt Bay offshore wind will be connected to the new Collinsville substation with an HVDC bipole link (Figure F.16-3). The cost estimate for this interconnection option B is $3.1B-4.5B.

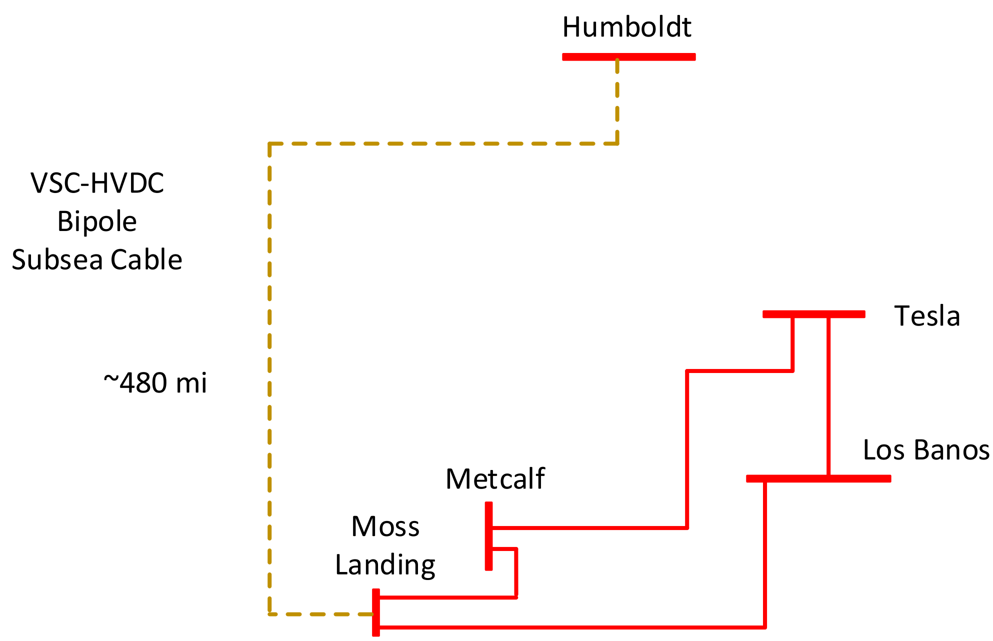
Figure F.16-3: LCC HVDC Option to Interconnect Humboldt Bay Offshore Wind (Option B)



<u>Option C: VSC-HVDC subsea cable connection to Moss Landing 500/230 kV substation</u>

In this option, it is assumed that a VSC-HVDC link will connect the Humboldt offshore wind to a Moss Landing 500/230 kV Substation. (Figure F.16-4). The cost estimate for interconnection option C is $4.4B-$6.5B.

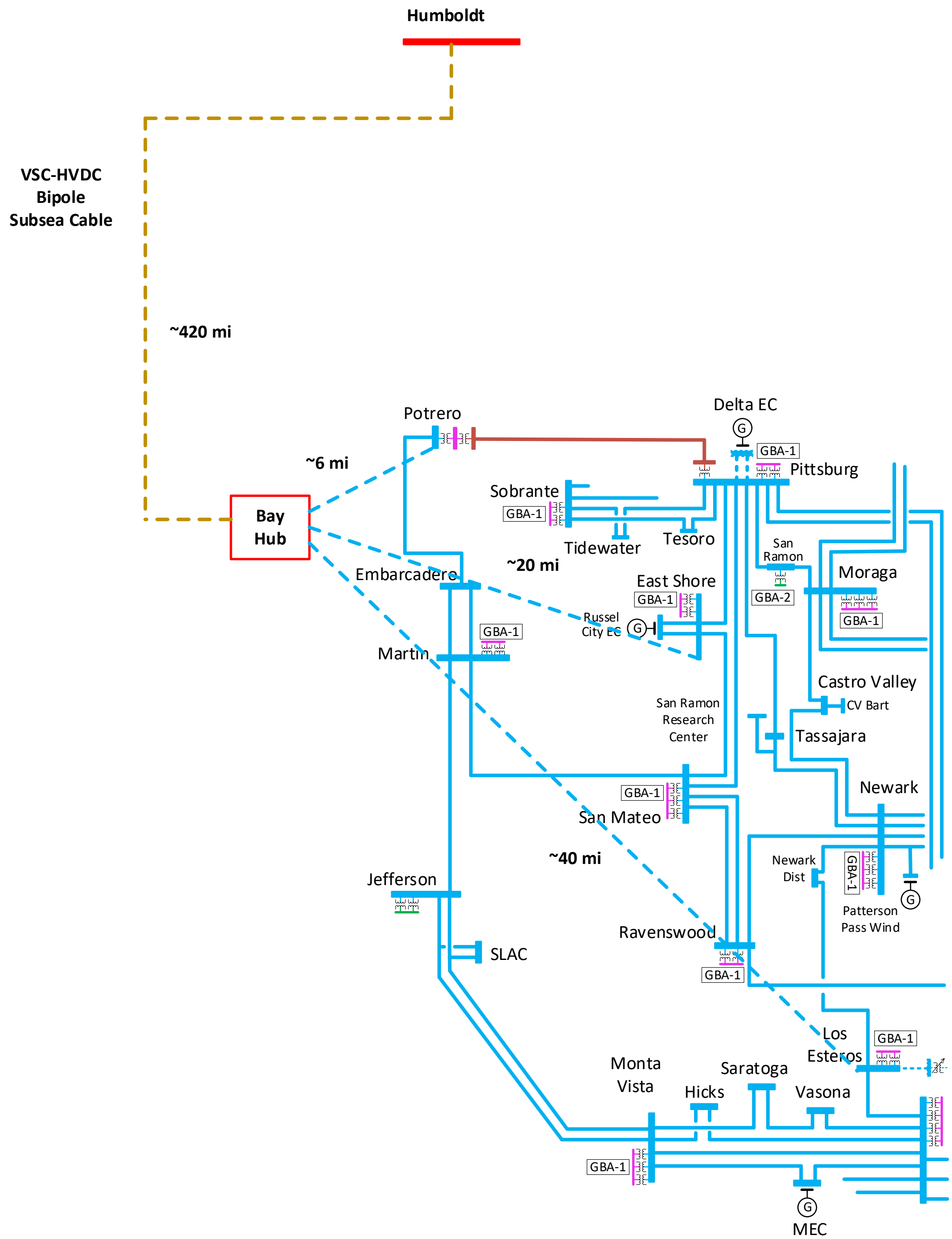
Figure F.16-4: VSC-HVDC Option to Interconnect Humboldt Bay Offshore Wind (Option C)



Option D: VSC-HVDC subsea cable connection to a converter station in the Bay area

In this option, it is assumed that a VSC-HVDC link will connect the Humboldt offshore wind to a new Bay Hub substation in the Bay area through a subsea cable. Three cables will then connect the Bay Hub 230 kV substation to major load centers in the area (Figure F.16-5). Currently the three load centers selected are Potrerro, East Shore and Los Esteros 230 kV substations. These injection locations need to be fine tuned to address any potential constraints associated with this interconnection option if this option is considered for further evaluation. The cost estimate for interconnection option D is $4.8B-6.9B.

Figure F.16-5: VSC-HVDC Option to Interconnect Humboldt Bay Offshore Wind (Option D)



<u>Option E: 500 kV AC Line to Fern Road and HVDC Line to Collinsville Initially Operated at 500 kV AC</u>

In this option, it is assumed that one, approximately 140 mile, 500 kV AC line will interconnect Humboldt 500 kV to the Fern Road substation and one, approximately 260 mile HVDC line, initially operated at 500 kV AC will interconnect Humboldt 500 kV to the Collinsville substation (Figure F.16-6). The cost estimate for interconnection Option E is $2.9B-$4.1B.

Figure F.16-6: Option E to Interconnect Humboldt Offshore Wind

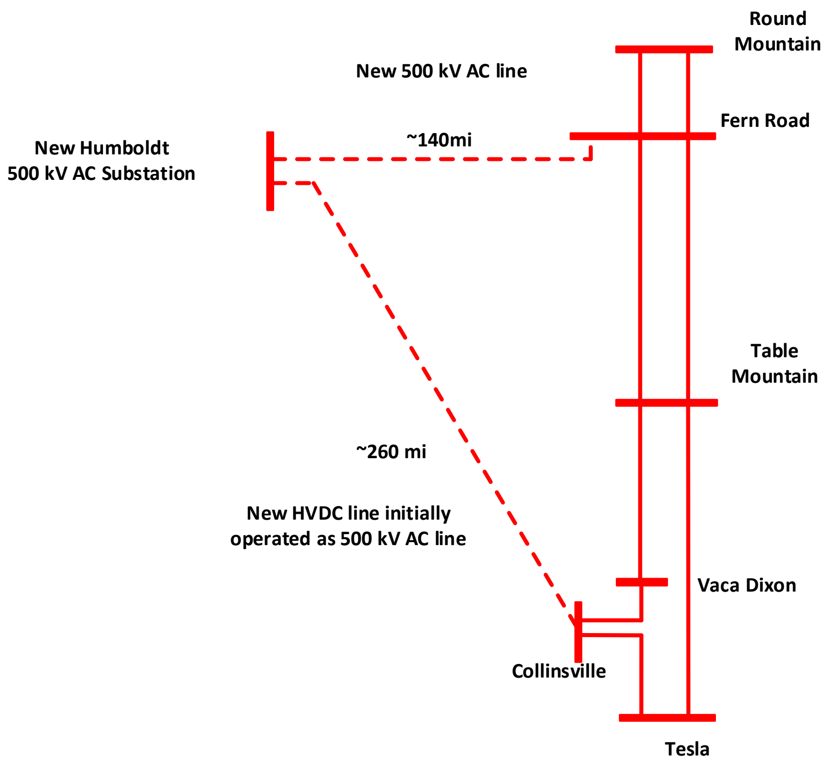


Table Mountain – Vaca Dixon 500kV line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Table Mountain – Vaca Dixon 500kV line under N-0 and N-1 conditions as shown in Table F.16-1. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.16-2, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades

Table F.16-1: Table Mountain – Vaca Dixon 500kV line peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)			
		Base A	Base B	Base C	Base D
Table Mountain – Vaca Dixon 500kV line	Base Case	122%	<100%	103%	101%
	TABLE MTN-TESLA 500KV	129%	103%	106%	105%

Table F.16-2: Table Mountain – Vaca Dixon 500 kV line #1 on-peak deliverability constraint summary

		Base A	Base B	Base C	Base D
Portfolio MW behind constraint		1407.5	207	207	207
Portfolio battery storage MW behind constraint		79	79	79	79
Deliverable portfolio MW w/o mitigation		0	0	0	0
Total undeliverable baseline and portfolio MW		1989.9	346	575	514
Mitigation Options	RAS	N/A	N/A	N/A	N/A
	Reduce generic battery storage (MW)	N/A	N/A	N/A	N/A
	Transmission upgrade including cost	New Fern Road-Nikola 500 kV Line($970M)	Reinstate 500 kV Line Rerates ($0)	Reinstate 500 kV Line Rerates ($0)	Reinstate 500 kV Line Rerates ($0)

Fern Rd – Table Mountain 500 kV line #1 on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Fern Rd – Table Mountain 500 kV line #1 under N-0 and N-1 conditions as shown in Table F.16-3. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.16-4, 993 MW of renewable and energy storage would be deliverable without any transmission upgrades.

Table F.16-3: Fern Rd – Table Mountain 500 kV line #1 on-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)			
		Base A	Base B	Base C	Base D
Fern Rd – Table Mountain 500 kV line #1	Base Case	107%	<100%	<100%	<100%
	OLINDA-TRACY 500KV	106%	<100%	<100%	<100%

Table F.16-4: Fern Rd – Table Mountain 500 kV line #1 on-peak deliverability constraint summary

		Base A	Base B	Base C	Base D
Portfolio MW behind constraint		1370	N/A	N/A	N/A
Portfolio battery storage MW behind constraint		85			
Deliverable portfolio MW w/o mitigation		993			
Total undeliverable baseline and portfolio MW		462			
Mitigation Options	RAS	N/A			
	Reduce generic battery storage (MW)	N/A			
	Transmission upgrade including cost	Reinstate 500 kV Line Rerates ($0)			

Fern Rd – Table Mountain 500 kV line #2 on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Fern Rd – Table Mountain 500 kV line #2 under N-0 and N-1 conditions as shown in Table F.16-5. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.16-6, 993 MW of renewable and energy storage would be deliverable without any transmission upgrades.

Table F.16-5: Fern Rd – Table Mountain 500 kV line #2 on-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)			
		Base A	Base B	Base C	Base D
Fern Rd – Table Mountain 500 kV line #2	Base Case	107%	<100%	<100%	<100%
	OLINDA-TRACY 500KV	107%	<100%	<100%	<100%

Table F.16-6: Fern Rd – Table Mountain 500 kV line #2 on-peak deliverability constraint summary

		Base A	Base B	Base C	Base D
Portfolio MW behind constraint		1370	N/A	N/A	N/A
Portfolio battery storage MW behind constraint		85			
Deliverable portfolio MW w/o mitigation		993			
Total undeliverable baseline and portfolio MW		521			
Mitigation Options	RAS	N/A			
	Reduce generic battery storage (MW)	N/A			
	Transmission upgrade including cost	Reinstate 500 kV Line Rerates ($0)			

Table Mountain – Tesla 500 kV line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Table Mountain – Tesla 500 kV line under N-1 conditions as shown in Table F.16-7. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.16-8, 568 MW of renewable and energy storage would be deliverable without any transmission upgrades.

Table F.16-7: Table Mountain – Tesla 500 kV line on-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)			
		Base A	Base B	Base C	Base D
Table Mountain – Tesla 500 kV line	TABLE MTN-VACA 500KV	114%	<100%	<100%	<100%

Table F.16-8: Table Mountain – Tesla 500 kV line on-peak deliverability constraint summary

		Base A	Base B	Base C	Base D
Portfolio MW behind constraint		1408	N/A	N/A	N/A
Portfolio battery storage MW behind constraint		79			
Deliverable portfolio MW w/o mitigation		568			
Total undeliverable baseline and portfolio MW		958			
Mitigation Options	RAS	N/A			
	Reduce generic battery storage (MW)	N/A			
	Transmission upgrade including cost	Reinstate 500 kV Line Rerates ($0)			

Vaca – Collinsville 500 kV line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Vaca – Collinsville 500 kV line under N-1 conditions as shown in Table F.16-9. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.16-10, 2000 MW of renewable and energy storage would be deliverable without any transmission upgrades.

Table F.16-9: Vaca – Collinsville 500 kV line on-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)			
		Base A	Base B	Base C	Base D
Vaca – Collinsville 500 kV line	TABLE MTN-TESLA 500KV	106%	<100%	<100%	<100%

Table F.16-10: Vaca – Collinsville 500 kV line on-peak deliverability constraint summary

		Base A	Base B	Base C	Base D
Portfolio MW behind constraint		1606	N/A	N/A	N/A
Portfolio battery storage MW behind constraint		864			
Deliverable portfolio MW w/o mitigation		2000			
Total undeliverable baseline and portfolio MW		508			
Mitigation Options	RAS	N/A			
	Reduce generic battery storage (MW)	N/A			
	Transmission upgrade including cost	Reinstate 500 kV Line Rerates ($0)			

Collinsville – PittsburgE 230kV line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Collinsville – PittsburgE 230kV line under N-0 conditions as shown in Table F.16-11. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.16-12, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades.

Table F.16-11: Collinsville – PittsburgE 230kV line on-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)			
		Base A	Base B	Base C	Base D
Collinsville – PittsburgE 230kV line	Base Case	106%	112%	<100%	<100%

Table F.16-12: Collinsville – PittsburgE 230kV line on-peak deliverability constraint summary

		Base A	Base B	Base C	Base D
Portfolio MW behind constraint		1200	1200	N/A	N/A
Portfolio battery storage MW behind constraint		0	0		
Deliverable portfolio MW w/o mitigation		0	0		
Total undeliverable baseline and portfolio MW		1200	1200		
Mitigation Options	RAS	N/A	N/A		
	Reduce generic battery storage (MW)	N/A	N/A		
	Transmission upgrade including cost	Collinsville 230 kV Reactor ($39-58M)	Collinsville 230 kV Reactor($39-58M)		

Collinsville – PittsburgF 230kV line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Collinsville – PittsburgF 230kV line under N-0 and N-1 conditions as shown in Table F.16-13. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.16-14, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades.

Table F.16-13: Collinsville – PittsburgF 230kV line on-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)			
		Base A	Base B	Base C	Base D
Collinsville – PittsburgF 230kV line	Base Case	<100%	110%	<100%	<100%
	COLLINSVILLE-PITTSBURG-E #1 230KV	124%	130%	<100%	106%

Table F.16-14: Collinsville – PittsburgF 230kV line on-peak deliverability constraint summary

		Base A	Base B	Base C	Base D
Portfolio MW behind constraint		1363	1363	N/A	162
Portfolio battery storage MW behind constraint		0	0		0
Deliverable portfolio MW w/o mitigation		0	0		0
Total undeliverable baseline and portfolio MW		3785	3785		1178
Mitigation Options	RAS	N/A	N/A		N/A
	Reduce generic battery storage (MW)	N/A	N/A		N/A
	Transmission upgrade including cost	Collinsville 230 kV Reactor($39-58M)	Collinsville 230 kV Reactor ($39-58M)		Collinsville 230 kV Reactor ($39-58M)

North Dublin -Vineyard 230 kV line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the North Dublin -Vineyard 230 kV line under N-1 conditions as shown in Table F.16-15. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.16-16, 76-123 MW of renewable and energy storage would be deliverable without any transmission upgrades.

Table F.16-15: North Dublin -Vineyard 230 kV line on-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)			
		Base A	Base B	Base C	Base D
North Dublin -Vineyard 230 kV	CONTRA COSTA-LAS POSITAS 230KV	<100%	103%	100%	<100%

Table F.16-16: North Dublin -Vineyard 230 kV line on-peak deliverability constraint summary

		Base A	Base B	Base C	Base D
Portfolio MW behind constraint		N/A	41	41	N/A
Portfolio battery storage MW behind constraint			101	101	
Deliverable portfolio MW w/o mitigation			76	123	
Total undeliverable baseline and portfolio MW			67	20	
Mitigation Options	RAS		N/A	N/A	
	Reduce generic battery storage (MW)		N/A	N/A	
	Transmission upgrade including cost		Reconducor ($116.3M-$232.6M)	Reconducor ($116.3M-$232.6M)	

Tesla - Newark 230 kV Line No. 2 on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Tesla - Newark 230 kV Line No. 2 under N-2 conditions as shown in Table F.16-17. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.16-18, 10-172 MW of renewable and energy storage would be deliverable without any transmission upgrades.

Table F.16-17: Tesla - Newark 230 kV Line No. 2 on-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)			
		Base A	Base B	Base C	Base D
Tesla - Newark 230 kV Line No. 2	TESLA-NEWARK #1 230KV & TESLA-RAVENSWOOD 230KV	<100%	107%	104%	<100%

Table F.16-18: Tesla - Newark 230 kV Line No. 2 on-peak deliverability constraint summary

		Base A	Base B	Base C	Base D
Portfolio MW behind constraint		N/A	50	50	N/A
Portfolio battery storage MW behind constraint			401	401	
Deliverable portfolio MW w/o mitigation			10	172	
Total undeliverable baseline and portfolio MW			441	279	
Mitigation Options	RAS		N/A	N/A	
	Reduce generic battery storage (MW)		N/A	N/A	
	Transmission upgrade including cost		Reconducor($29M-$58M)	Reconducor ($29M-$58M)	

Henrietta-GWF 115 kV Line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Henrietta-GWF 115 kV Line under N-2 conditions as shown in Table F.16-19. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.16-20, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades.

Table F.16-19: Henrietta-GWF 115 kV Line on-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)			
		Base A	Base B	Base C	Base D
Henrietta-GWF 115 kV Line	HELM-MCCALL 230KV & HENTA P2-MUSTANGSS #1 230KV	<100%	<100%	<100%	103%

Table F.16-20: Henrietta-GWF 115 kV Line on-peak deliverability constraint summary

		Base A	Base B	Base C	Base D
Portfolio MW behind constraint		N/A	N/A	N/A	1
Portfolio battery storage MW behind constraint					68
Deliverable portfolio MW w/o mitigation					0
Total undeliverable baseline and portfolio MW					68
Mitigation Options	RAS				N/A
	Reduce generic battery storage (MW)				N/A
	Transmission upgrade including cost				Reconducor ($107.3M-$214.6M)

Eastshore 230/115kV Transformer #1 & #2 on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Eastshore 230/115kV Transformer #1 & #2 under N-1 conditions as shown in Table F.16-21. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.16-22, 918 MW of renewable and energy storage would be deliverable without any transmission upgrades.

Table F.16-21: Eastshore 230/115kV Transformer #1 & #2 on-peak deliverability constraint

Overloaded Facility	Contingency	Loading (%)			
		Base A	Base B	Base C	Base D
Eastshore 230/115kV Transformer #1	E. SHORE 230/115KV TB 2	<100%	<100%	<100%	107%
Eastshore 230/115kV Transformer #2	E. SHORE 230/115KV TB 1	<100%	<100%	<100%	108%

Table F.16-22: Eastshore 230/115kV Transformer#1 & #2 on-peak deliverability constraint summary

<table>
<tr><th colspan="2"></th><th>Base A</th><th>Base B</th><th>Base C</th><th>Base D</th></tr>
<tr><td colspan="2">Portfolio MW behind constraint</td><td rowspan="7">N/A</td><td rowspan="7">N/A</td><td rowspan="7">N/A</td><td>1200</td></tr>
<tr><td colspan="2">Portfolio battery storage MW behind constraint</td><td>250</td></tr>
<tr><td colspan="2">Deliverable portfolio MW w/o mitigation</td><td>918</td></tr>
<tr><td colspan="2">Total undeliverable baseline and portfolio MW</td><td>533</td></tr>
<tr><td rowspan="3">Mitigation Options</td><td>RAS</td><td>N/A</td></tr>
<tr><td>Reduce generic battery storage (MW)</td><td>N/A</td></tr>
<tr><td>Transmission upgrade including cost</td><td>New 230/115 Bank #3 ($120M-$240M)</td></tr>
</table>

Fulton - Hopland 60 kV (Geyser Jct to Fitch Mt. Tap)on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Northern California area is limited by thermal overloading of the Fulton - Hopland 60 kV (Geyser Jct to Fitch Mt. Tap) under N-2 conditions as shown in Table F.16-23. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table F.16-24, 225 MW of renewable and energy storage would be deliverable without any transmission upgrades

Table F.16-23: Fulton - Hopland 60 kV (Geyser Jct to Fitch Mt. Tap)on-peak deliverability constraint

<table>
<tr><th rowspan="2">Overloaded Facility</th><th rowspan="2">Contingency</th><th colspan="4">Loading (%)</th></tr>
<tr><th>Base A</th><th>Base B</th><th>Base C</th><th>Base D</th></tr>
<tr><td>Fulton - Hopland 60 kV (Geyser Jct to Fitch Mt. Tap)</td><td>GEYSERS #9-LAKEVILLE & EAGLE ROCK-FULTON-SILVERADO LINES</td><td><100%</td><td><100%</td><td><100%</td><td>100%</td></tr>
</table>

Table F.16-24: Fulton - Hopland 60 kV (Geyser Jct to Fitch Mt. Tap) on-peak deliverability constraint summary

		Base A	Base B	Base C	Base D
Portfolio MW behind constraint		N/A	N/A	N/A	2
Portfolio battery storage MW behind constraint					232
Deliverable portfolio MW w /o mitigation					225
Total undeliverable baseline and portfolio MW					9
Mitigation Options	RAS				N/A
	Reduce generic battery storage (MW)				N/A
	Transmission upgrade including cost				Reconductor (There is an exsisting LDNU for this project)

Below Table F.16-25 shows a cross compareison of potential mitigations for all options studied. The table shows estimated cost of each solution and provides cost totals by options.

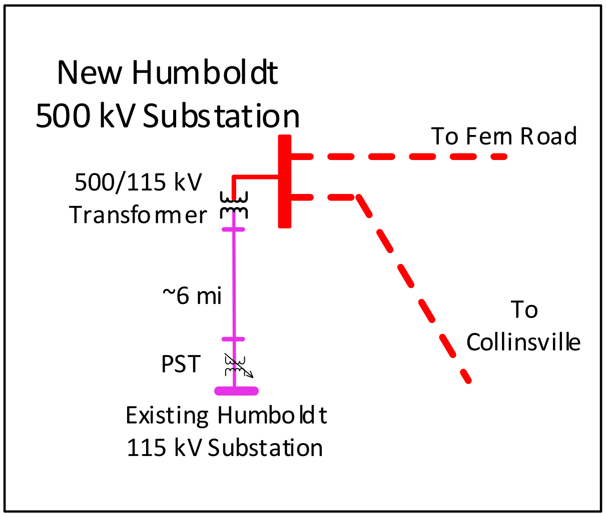
Table F.16-25: Summary of potential mitigations with costs

Potential Mitigation	Base A	Base B/E	Base C	Base D	Base E
Interconnection	**$2.1B-$3.0B**	**$3.2B-$4.6B**	**$4.5B-$6.6B**	**$4.9B-$7.0B**	**$2.9B-$4.2B**
North Dublin -Vineyard 230 kV Reconductor		$116M-$233M	$116M-$233M		$116M-$233M
Tesla - Newark 230 kV Line No. 2 Reconductor		$29M-$58M	$29M-$58M		$29M-$58M
Henrietta-GWF 115 kV Line Reconductor				$107M-$215M	
New Fern Road- Tesla 500 kV Line	$1.4B-2.0B				
Reinstate 500 kV Line Rerates		PG&E maintenance	PG&E maintenance	PG&E maintenance	PG&E maintenance
New Eastshore 230/115kV Transformer #3				$120M-$240M	
Fulton - Hopland 60 kV (Geyser Jct to Fitch Mt. Tap) Reconductor			existing LDNU	existing LDNU	
Collinsville 230 kV Reactor	$39-58M	$39-58M		$39-58M	$39-58M
Total Mitigation Cost	**$1.4B- $2.1B**	**$184M-$349M**	**$145M-$291M**	**$266M-$513M**	**$184M-$349M**
Total Mitigation and Interconnection Costs	**$3.5B – $5.1B**	**$3.3B- $4.9B**	**$4.6B- $6.9B**	**$5.1B- $7.5B**	**$3.1B - $4.5B**

Interconnection to Humboldt 115 kV System

Humboldt area is currently supplied by local gas generation and through two 115 kV line 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 F.16-7.

Figure F.16-7: Interconnecting Humboldt 500 kV substation to Humboldt 115 kV substation



In addition to Alternatives A, B, C and D, the ISO also considered a fifth alternative E, see Figure F.16-8, that the ISO is recommending for approval that provides more flexibility for implementation in the short term and for expansion in the long term. This option has all of the same downstream mitigation needs as for option B and:

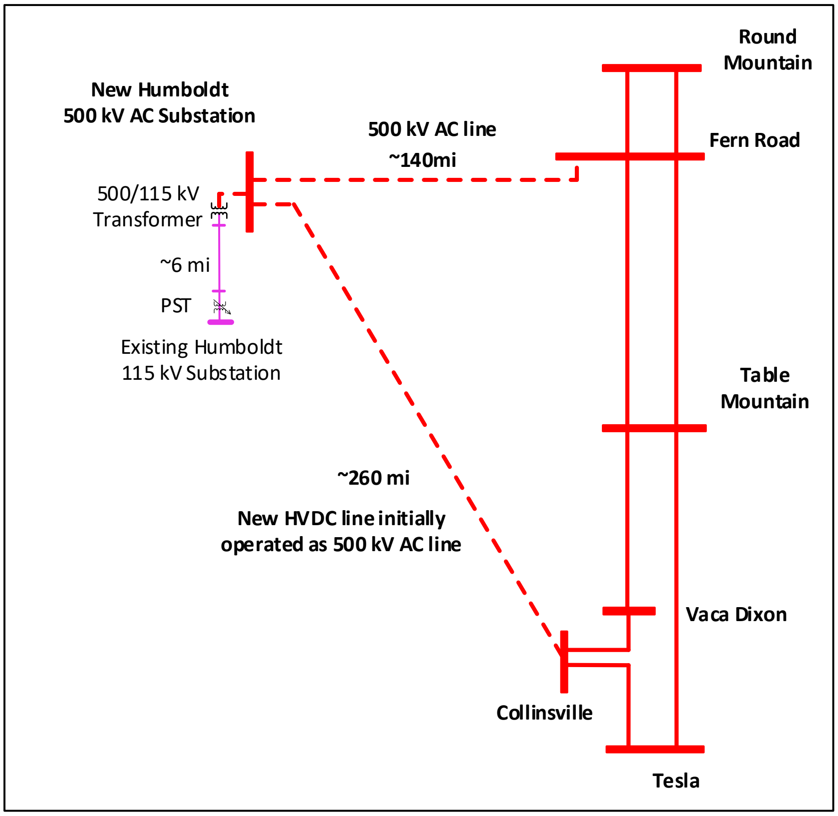
- Will provide more flexibility as offshore wind development progresses;
- Ensure transmission will not be stranded in the event that offshore wind does not get developed as quickly as anticipated or if it shifts to a different call area;
- Provides a parallel path to the existing 500 kV lines from Round Mountain to Tesla which provides an opportunity in the long term to reconductor/rebuild the existing lines rather than building new lines in new right of ways; and
- Has the lowest cost estimate compared to other combinations of interconnection and associated mitigations.

Given the overall cost estimates for the interconnection and associated mitigation solutions, the ISO is recommending Option E for approval, which includes:

- New Humboldt 500 kV substation, with a 500/115 kV transformer; and building approximately 260 mile HVDC line, initially operated as 500 kV AC line to interconnect Humboldt 500 kV to the Collinsville substation;
  - Estimated cost of $1,913 – $2,740 million;
- Building approximately 140 mile, 500 kV AC line to interconnect Humboldt 500 kV to the Fern Road substation;
  - Estimated cost of $980 – $1,400 million; and
- A 115kV/115 kV phase shifting transformer (PST) and a 115 kV line from Humboldt 500 kV to existing Humboldt 115 kV substation.
  - Estimated at $40 – $57 million.

The total estimated cost of Alternative E is \$3.1B to \$4.5 B with and estimated in-service date of 2034[31].

Figure F.16-8: Recommended Option (Option E) to Interconnect Humboldt to Fern Road and Collinsville

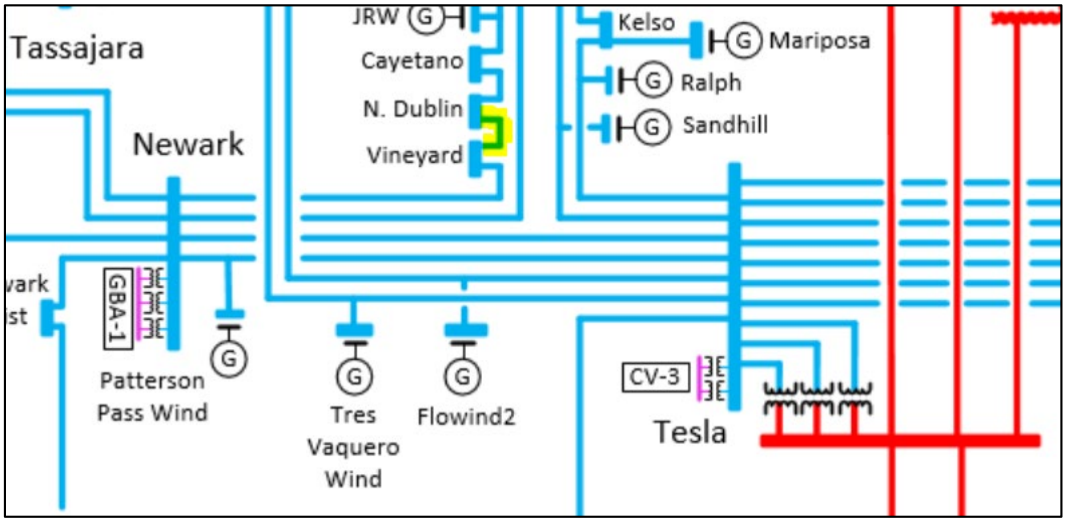


North Dublin -Vineyard 230 kV Reconductor

To mitigate P1 overloads identified as part of Interconnection option E the ISO is recommending approval of the North Dublin – Vineyard 230 kV reconductoring project. This project will cost \$116M-\$232M. The project will take an estimated 24 months to complete. The scope includes reconductor North Dublin -Vineyard 230 kV line with minimum summer emergency rating of 1350 AMPS or highest conductor feasible with existing structure and will include any other limiting elements upgrade to achieve the new line rating.

31 The CPUC base portfolio for 2023-2024 transmission planning process indicated 2035; however the CPUC has indicated 2034 for 900 MW of offshore wind in the Humboldt area in the base portfolio for the 2024-2025 transmission planning process.

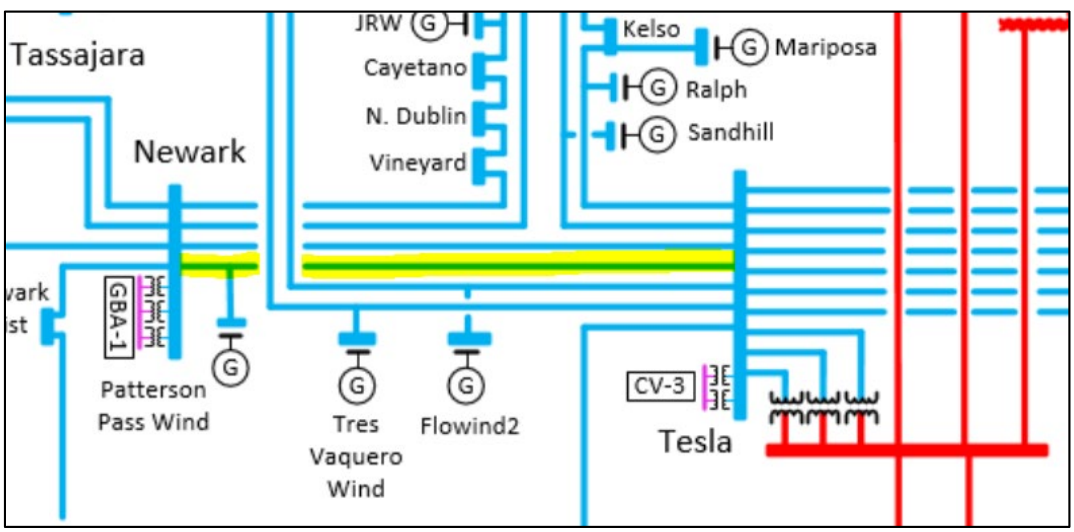
Figure F.16-9: Recommended North Dublin – Vineyard 230 kV Reconductor



Tesla - Newark 230 kV Line No. 2 Reconductor

To mitigate overloads identified as part of Interconnection option E the ISO is recommending approval of the Telsa - Newark 230 kV line No 2 reconductoring project. The project will cost $29M- $58M. The project will take an estimated 54 months to complete. The scope includes reconductor Tesla –Newark #2 230 kV line - From 024/148 to Newark (~4.28 miles), with minimum summer emergency rating of 3428 AMPS, matching other sections of the line or highest conductor feasible with existing structure. Will also include any other limiting element upgrades to achieve this line rating.

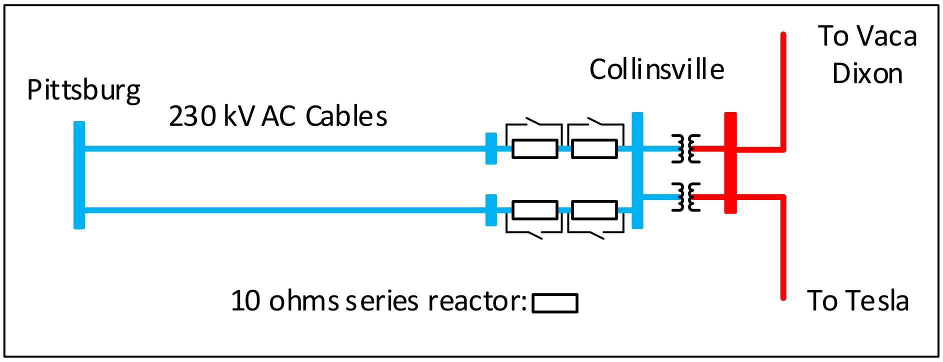
Figure F.16-10: Recommended Tesla – Newark 230 kV line No 2 Reconductor



Collinsville 230 kV Reactor

To mitigate overloads identified as part of Interconnection option E the ISO is recommending approval of the Collinsville 230 kV reactors. The project will cost $39M- $58M. The project will go into service congruently with the Collinsville project. The scope includes adding 20 ohm reactors on the Collinsville – Pittsburg 230 kV lines.

Figure F.16-11: Collinsville 230 kV Reactor



F.16.4 Humboldt offshore wind Sensitivity results

The sensitivity portfolio includes 8,045 MW offshore wind in the North Coast. The CPUC Modelling Assumptions for 2023-2024 TPP provided the following guidance:

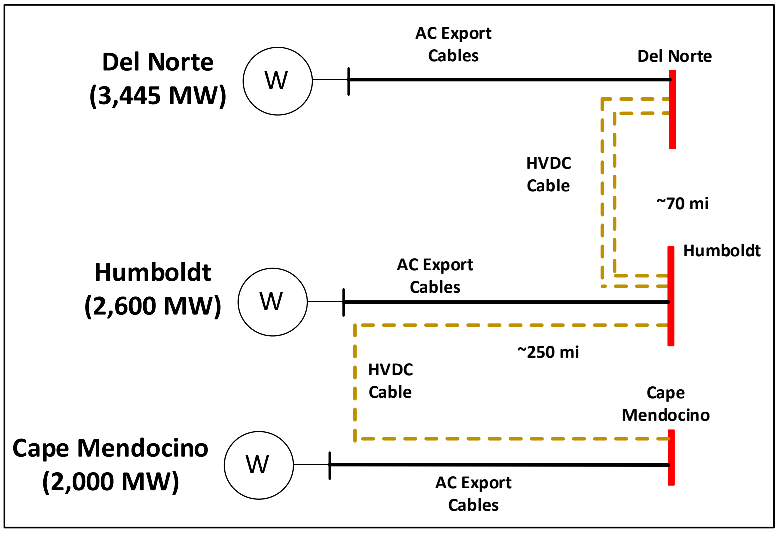
"... the 13.4 GW of offshore wind have been mapped to one location on the Central Coast (Morro Bay) and three separate locations on the North Coast (Humboldt, Del Norte, and Cape Mendocino) to allow CAISO to identify transmission upgrades and cost information necessary to further advance offshore wind planning in line with the state's offshore wind policy goals."

Based on a recent CEC report[32], the environmental analysis performed by Schatz center identifies significant environmental challenges to build overhead lines along the coast from Del Norte to Humboldt to Cape Mendocino. Therefore any transmission interconnecting Del Norte and Cape Mendocino Point of Interconnections to Humboldt is assumed to be VSC-HVDC with either underground or subsea HVDC cable. The selected option to interconnect the 3 substation is shown in Figure F.16-12. More details are provided in the 20-year Transmission Outlook Update[33].

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

[33] https://www.caiso.com/InitiativeDocuments/Presentation-20YearTransmissionOutlook-Apr18-2024.pdf

Figure F.16-12: Selected Interconnection Option

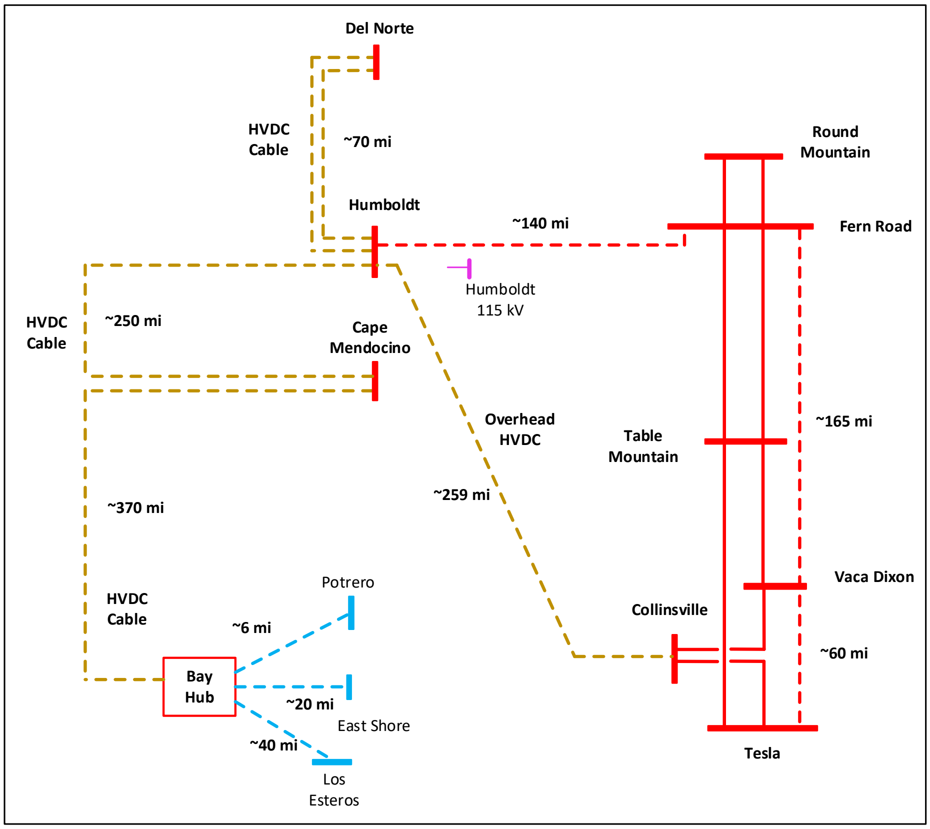


The transmission alternatives in the north coast for offshore wind sensitivity portfolio are discussed in the following sections.

Option A1: AC Fern Road, HVDC Collinsville, HVDC Bayhub

Figure F.16-13 provides a schematic diagram of Option A1. In this option, Humboldt substation is connected to Fern Road substation with a 500 kV AC line and to Collinsville substation through an overhead VSC-HVDC line. The Bay Hub Option discussed in the baseline analysis will interconnect Cape Mendocini to the Bay area. The Fern Road to Vaca Dixon to Tesla 500 kV line is assumed to be needed in all the sensitivity studies. The cost estimate for Option A1 is $13.6B-$19.7B.

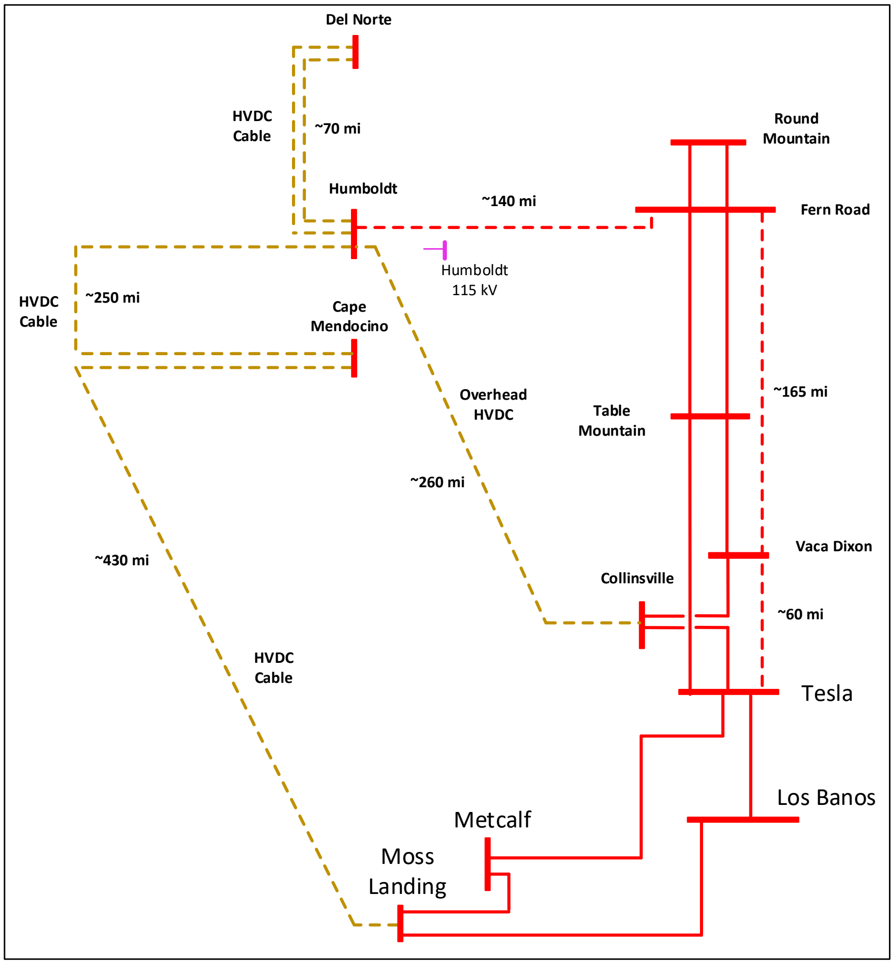
Figure F.16-13: Option A1 Diagram



Option A2: AC Fern Road, HVDC Collinsville, HVDC Moss Landing

Figure F.16-14 provides a schematic diagram of Option A2. In this option, Humboldt substation is connected to Fern Road substation with a 500 kV AC line and to Collinsville substation through an overhead VSC-HVDC line. The Cape Mendocino interconnects to Moss Landing substation with a subsea HVDC cable. The cost estimate for Option A2 is \$13.0B-\$19.0B

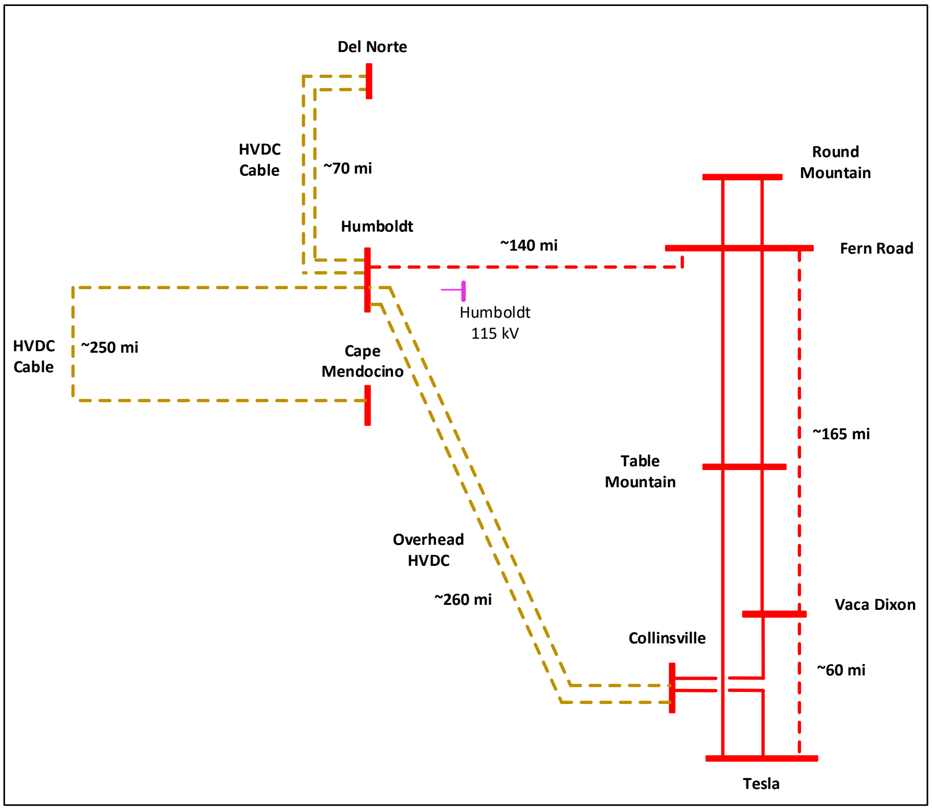
Figure F.16-14: Option A2 Diagram



Option B: AC Fern Road, 2 HVDC Collinsville

Figure F.16-15 provides a schematic diagram of Option B. In this option, Humboldt substation is connected to Fern Road substation with a 500 kV AC line and to Collinsville substation through two overhead VSC-HVDC lines. The cost estimate for Option B is $13.2B-$17.8B

Figure F.16-15: Option B Diagram



Option C: 2 AC Fern Road, HVDC Bayhub

Figure F.16-16 provides a schematic diagram of Option C. In this option, Humboldt substation is connected to Fern Road substation with two 500 kV AC lines. The Bay Hub Option discussed in the baseline analysis will interconnect Cape Mendocino to the Bay area. The Fern Road to Vaca Dixon to Tesla 500 kV line is assumed to be needed in all the sensitivity studies. The cost estimate for Option C is $11.6B-$16.8B.

Figure F.16-16: Option C Diagram

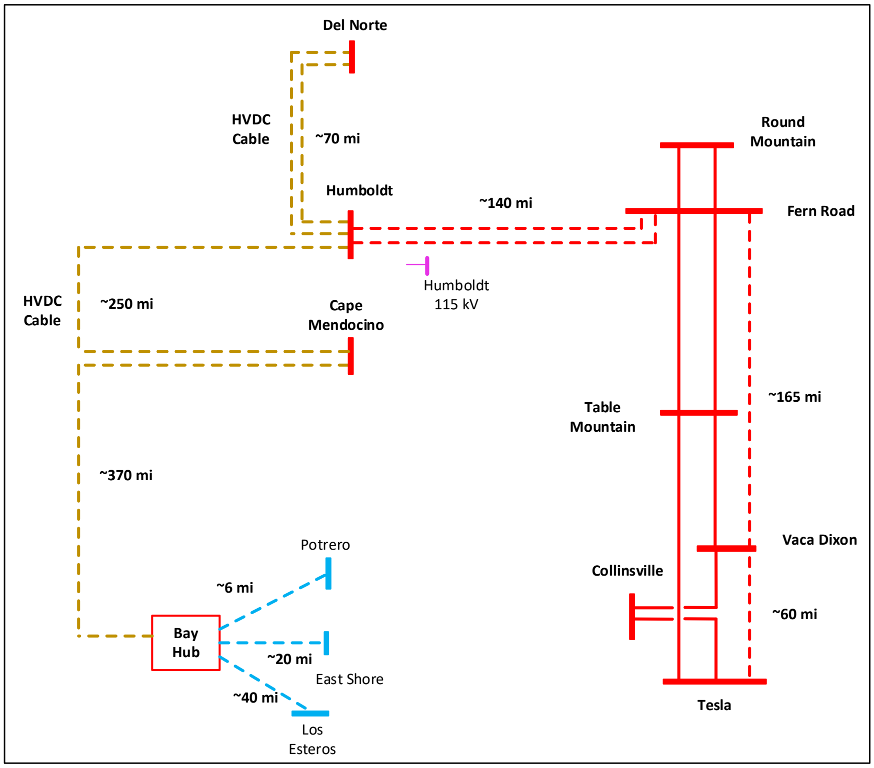


Table F.16-26: Table of Sensitivity Constraints

Overloaded Facility	Contingency	Sen A1	Sen A2	Sen B	Sen C
Table Mountain – Vaca Dixon #1 500kV line	Base Case	<100%	<100%	<100%	134%
	TABLE MTN-TESLA 500KV	101%	101%	<100%	142%
Vaca Dixon – Telsa 500kV line	P1-2:A0:26:_COLLINSVILLE-TESLA 500KV [0]	104%	<100%	131%	139%
Table Mountain – Tesla 500 kV	Base Case	<100%	<100%	<100%	102%
	P1-2:A0:4:_TABLE MTN-VACA 500KV [6090]	<100%	<100%	<100%	116%
Table Mountain – Vaca Dixon #2 500kV line	Base Case	<100%	<100%	<100%	119%
	Base Case	<100%	<100%	<100%	142%

Overloaded Facility	Contingency	Sen A1	Sen A2	Sen B	Sen C
Vaca Dixon – Collinsville #1 500kV line	P7-2:A99:1:_HUMBOLDT OSW-Collinsville HVDC Line [0]	<100%	<100%	<100%	102%
Fern Road – Table Mountain #1 500 kV	Fern Road – Table Mountain #2 500 kV	<100%	<100%	<100%	164%
Fern Road – Table Mountain #2 500 kV	Fern Road – Table Mountain #1 500 kV	<100%	<100%	<100%	164%
Fern Road – Table Mountain #3 500 kV	Base Case	<100%	<100%	<100%	135%
Collinsville – Tesla 500kV line	Base Case	<100%	<100%	109%	<100%
	P1-2:A0:33:_HUMBOLDT OSW-FERN ROAD #1 500KV [6020]	<100%	<100%	139%	<100%
Collinsville 500/230 kV Transformer Bank #1	Collinsville 500/230 kV Transformer Bank #2	<100%	<100%	104%	<100%
Collinsville 500/230 kV Transformer Bank #2	Collinsville 500/230 kV Transformer Bank #1	<100%	<100%	104%	<100%
Collinsville – PittsburgF 230kV line	COLLINSVILLE-PITTSBURG-E #1 230KV	122%	142%	155%	120%
Eastshore 230/115kV Transformer #1	E. SHORE 230/115KV TB 2	111%	<100%	<100%	113%
Eastshore 230/115kV Transformer #2	E. SHORE 230/115KV TB 1	112%	<100%	<100%	112%
Martinez-Sobrante 115kV Line	OLEUM-MARTINEZ 115KV	<100%	<100%	101%	<100%
Pease - Marysville - Harter 60 kV Line	PALERMO-NICOLAUS 115KV	<100%	<100%	<100%	101%
Tesla - Newark 230 kV Line No. 2	TESLA-NEWARK #1 230KV & TESLA-RAVENSWOOD 230KV	<100%	107%	113%	<100%
Cayetano-Lone Tree (USWP-Cayetano) 230kV Line	CONTRA COSTA-LAS POSITAS 230KV	<100%	101%	111%	<100%
North Dublin -Vineyard 230 kV	CONTRA COSTA-LAS POSITAS 230KV	<100%	101%	113%	<100%

Overloaded Facility	Contingency				
		Sen A1	Sen A2	Sen B	Sen C
Fulton - Hopland 60 kV (Hopland Jct to Cloverdale Jct)	GEYSERS #9-LAKEVILLE & EAGLE ROCK-FULTON-SILVERADO LINES	103%	<100%	<100%	101%
Round MT- Cottonwood 230 kV line	CAPTJACK-OLINDA 500KV	<100%	<100%	<100%	115%

Table F.16-27:Summary of Constraints for Humboldt Bay Offshore Wind Sensitivity study

Overloaded Facility	Contingency	Case	Loading	Portfolio (MW)			
				Behind constraint	Battery storage behind constraint	Deliverable w/o mitigation	Total undeliverable baseline and portfolio
Cascade-Deschutes 60 kV Line	Base Case	A1	106.83	5.5	0	0	27.95
		A2	106.61	5.5	0	0	25.4
		B	107.07	5.5	0	0	27.79
		C	109.41	0	0	0	0
Cayetano-Lone Tree (USWP-Cayetano) 230kV Line	TESLA-NEWARK #1 230KV & TESLA-RAVENSWOOD 230KV	A2	104.53	41.267	0	0	92.867
	CONTRA COSTA-LAS POSITAS 230KV	B	111.95	41.267	0	0	366.367
Collinsville - Pittsburg 230 kV Line	COLLINSVILLE-PITTSBURG-E #1 230KV	A1	126.35	6706.07	851.4	851.4	9099.45
		A2	146.47	6706.07	0	0	9127.61
		B	161.91	6706.07	0	0	9127.61
		C	121.82	0	0	0	0
Collinsville 500/230 kV Transformer Bank #1	COLLINSVILLE 500/230KV TB 2	B	109.21	7485.94	0	4491.59	2998.71
Collinsville 500/230 kV Transformer Bank #2	COLLINSVILLE 500/230KV TB 1	B	109.21	7485.94	0	4491.59	2998.71
Eastshore 230/115kV Transformer Bank #1	E. SHORE 230/115KV TB 2	A1	111.3	0.1	250	0	659.47
		C	111.53	0	0	0	0
Eastshore 230/115kV Transformer Bank #2	E. SHORE 230/115KV TB 1	A1	111.73	0.1	250	0	616.79
		C	111.82	0	0	0	0
Fern Road - Round Mountain 500 kV Line #1	Base Case	C	129.71	0	0	0	0
Fern Road - Round Mountain 500 kV Line #2	Base Case	C	130.79	0	0	0	0

Overloaded Facility	Contingency	Case	Loading	Portfolio (MW)			
				Behind constraint	Battery storage behind constraint	Deliverable w/o mitigation	Total undeliverable baseline and portfolio
Fern Road - Round Mountain 500 kV Line #3	Base Case	C	134.45	0	0	0	0
Fulton - Hopland 60 kV (Hopland Jct 60 kV to Cloverdale Jct 60 kV)	GEYSERS #9-LAKEVILLE & EAGLE ROCK-FULTON-SILVERADO LINES	A1	114.54	2	232.2	76.68	157.52
		A2	106.91	2	232.2	156.33	77.87
		B	105.94	2	232.2	166.56	67.64
	EGLE RCK-FULTON-SILVERDO 115KV	C	101.44	0	0	0	0
	GEYSERS #9-LAKEVILLE & EAGLE ROCK-FULTON-SILVERADO LINES	A1	102.5	2	232.2	199.19	35.01
		C	100.23	0	0	0	0
Fulton - Hopland 60 kV (Hopland Jct to Cloverdale Jct)	GEYSERS #9-LAKEVILLE & EAGLE ROCK-FULTON-SILVERADO LINES	A1	114.85	2	232.2	73.39	160.81
		A2	107.21	2	232.2	147.89	86.31
		B	106.24	2	232.2	163.4	70.8
	EGLE RCK-FULTON-SILVERDO 115KV	C	101.75	0	0	0	0
Geyser56-MPE Tap 115 kV	EAGLE ROCK - REDBUD & CORTINA-MENDOCINO #1 LINES	A1	102.61	1	0	0	111.79
		A2	103.77	1	0	0	109.88
		B	103.7	1	0	0	108.14
		C	102.68	0	0	0	0
Hopland 115/60 Transformer Bank #2	GEYSERS #9-LAKEVILLE & EAGLE ROCK-FULTON-SILVERADO LINES	A1	111.5	2	0	0	54.57
		A2	107.36	2	0	0	35.84
		B	106.92	2	0	0	33.87
	EGLE RCK-FULTON-SILVERDO 115KV	C	104.73	0	0	0	0
Las Positas - Newark 230 kV Line #1	Base Case	A2	136.83	41.267	0	0	904.097
Martinez - Alhambra 115 kV Line	OLEUM-MARTINEZ 115KV	B	103.07	0	20	13.04	6.96
McCall-Sanger #2 115 kV Line	MCCALL-REEDLEY 115KV & MCCALL-SANGER #3 115KV	A1	108.68	0.2	0	0	247.94
		A2	108.71	0.2	0	0	261.84
		B	107.98	0.2	0	0	209.42
		C	107.98	0	0	0	0
McCall-Sanger #3 115 kV Line	HENTAP1-MUSTANGSS #1	A1	128.67	0.2	0	0	490.9
		A2	129.99	0.2	0	0	490.9

Overloaded Facility	Contingency	Case	Loading	Portfolio (MW)			
				Behind constraint	Battery storage behind constraint	Deliverable w/o mitigation	Total undeliverable baseline and portfolio
	230KV & TRANQLTYSS-MCMULLN1 #1 230KV	B	128	0.2	0	0	490.9
		C	127.93	0	0	0	0
North Dublin -Vineyard 230 kV Line	TESLA-NEWARK #1 230KV & TESLA-RAVENSWOOD 230KV	A2	105.09	41.267	101.4	52.12	90.547
	CONTRA COSTA-LAS POSITAS 230KV	B	113.89	41.267	101.4	0	184.367
Pease - Marysville - Harter 60 kV Line	PALERMO-NICOLAUS 115KV MOAS OPENED ON PALERMO	C	101.18	0	0	0	0
Pittsburg-Eastshore 230kV Line	HUMBOLDT OSW-Bay Hub HVDC Line	A1	101.77	0	0	0	202.78
Round Mountain - Table Mountain 500 kV Line #1	Base Case	C	127.57	0	0	0	0
		C	109.29	0	0	0	0
Round Mountain - Table Mountain 500 kV Line #2	Base Case	C	128.65	0	0	0	0
Round MT- Cottonwood 230 kV Line #2	CAPTJACK-OLINDA 500KV	C	106.38	0	0	0	0
Round MT- Cottonwood 230 kV Line #3	CAPTJACK-OLINDA 500KV	C	116.09	0	0	0	0
San Leandro - Oakland J 115kV Line #1	MORAGA-OAKLAND J 115KV	B	108.08	0	55.65	0	70.16
Sobrante 230/115 kV Transformer Bank #1	SOBRANTE 230/115KV TB 2	A1	108.32	98	25	0	286.73
		A2	114.16	98	25	0	483.18
		B	118.23	98	25	0	655.4
		C	107.64	0	0	0	0
Sobrante 230/115 kV Transformer Bank #2	SOBRANTE 230/115KV TB 1	A1	108.37	98	25	0	288.21
		A2	114.22	98	25	0	484.6
		B	118.3	98	25	0	656.63
		C	107.69	0	0	0	0
Spring Gap-MI-WUK 115 kV Line	Base Case	A1	101.25	3	0	1.57	1.43
		A2	101.24	3	0	1.58	1.42
		B	101.25	3	0	1.58	1.42
		C	101.26	0	0	0	0
Table Mountain – Tesla 500 kV	Base Case	C	103.15	6741.378	318.1	6626.858	496.06
		C	100.85	0	0	0	0
		C	103.14	0	0	0	0

Overloaded Facility	Contingency	Case	Loading	Portfolio (MW)			
				Behind constraint	Battery storage behind constraint	Deliverable w/o mitigation	Total undeliverable baseline and portfolio
Table Mountain - Vaca Dixon #1 500 kV Line	Base Case	C	117.64	0	0	0	0
		C	116.33	0	0	0	0
Table Mountain - Vaca Dixon 500 kV Line #1	TABLE MTN-TESLA 500KV	A2	100.03	8844.598	50	8316.098	617.5
	Base Case	C	133.64	6735.87	50	3885.41	2939.46
		C	132.4	0	0	0	0
		C	120.25	0	0	0	0
Tesla - Newark 230 kV Line #2	TESLA-NEWARK #1 230KV & TESLA-RAVENSWOOD 230KV	A2	106.23	49.914	401.4	65.47	385.844
		B	112.3	49.914	401.4	0	492.314
Ukiah-Hopland-Cloverdale 115 kV (Ukiah sub 115kv to Hopland Jct 115kv)	EAGLE ROCK - REDBUD & CORTINA-MENDOCINO #1 LINES	A1	106.92	1	0	0	248.76
		A2	104.77	1	0	0	271.8
		B	105.94	1	0	0	271.8
		C	106.29	0	0	0	0
Vaca Dixon – Collinsville #1 500kV line	HUMBOLDT OSW-Collinsville HVDC Line	A2	102.12	7939.545	983.3	8001.295	960.55
	Base Case	C	129.04	0	0	0	0
Vaca Dixon – Collinsville 500kV line #1	HUMBOLDT OSW-Collinsville HVDC Line	A2	102.12	7939.545	983.3	8001.295	960.55
	Base Case	C	129.04	6777.545	679.5	4122.285	3373.76
Vaca Dixon – Telsa 500kV line	COLLINSVILLE-TESLA 500KV	A1	103.92	11384.47898	1399.65	12140.03898	683.09
		B	130.95	8995.765	1131.55	6644.615	3521.7
	VACA-DIX-COLLINSVILLE 500KV	C	136.66	0	0	0	0
	Base Case	C	117.64	6716.47	268.1	5209.08	1792.23
		B	112.94	8038.045	1025.05	7032.845	2069.25
	VACA-DIX-COLLINSVILLE 500KV	C	112.34	0	0	0	0

Table F.16-28 provides a summary of the estimated cost of transmission facilities to integrate the offshore wind in to the grid for the alternatives assessed. In addition to the interconnection facilities there would also be transmission upgrades required to mitigate the constaints identified in Table F.16-26.

Table F.16-28:Summary of Sensitivity Alternative Estimated Costs

Concept/ Alternative	500 kV AC	Lower Cost Range ($ million)	Higher Cost Range ($ million)
Sen _A_1	1 - 500 kV Line Fern Road 1 - HVDC On-land to Collinsville 1 - HVDC Sea cable to Bay Hub	13,615	19,700
Sen _A_2	1 - 500 kV Line Fern Road 1 - HVDC On-land to Collinsville 1 - HVDC Sea cable to Moss Landing	13,019	18,920
Sen_B	1 - 500 kV Line Fern Road 2 - HVDC On-land to Collinsville	12,236	17,830
Sen_C	2 - 500 kV Line Fern Road 1 - HVDC Sea cable to Bay Hub	11,622	16,767

F.17 Out-of-State Wind

The base portfolio includes 4,828 MW of out-of-state wind resources (1,500 MW from Wyoming, 1,000 MW from Idaho, and 2,328 MW from New Mexico). These resources have been identified by CPUC as requiring new transmission and were studied in detail under the 2022-2023 TPP in policy analysis and alternative analysis related to expanding the maximum import capability of the paths to determine the ISO internal transmission needs required to accommodate the out-of-state wind identified. Policy driven transmission projects recommended and approved by the ISO under the 2022-2023 TPP will support the integration of out-of-state wind resources identified in the base portfolio of the 2023-2024 TPP.

Two out-of-state subscriber transmission developments to accommodate the wind resources in Wyoming (TransWest Express) and New Mexico (Sunzia) are currently underway. The ISO filed the Subscriber PTO tariff for TransWest Express with FERC on September 22, 2023 under Docket No. ER23-2917-001 that was approved on March 12, 2024[34]. On January 24, 2024, the ISO received a PTO application from Sunzia to include its HVDC transmission facilities in New Mexico and certain transmission rights in Arizona under the ISO operational control as a Subscriber PTO.[35]

The ISO has been and continues to engage with Idaho Power on SWIP North as a regional policy-driven transmission project to take advantage of cost-sharing benefits. The ISO Board of Governors conditionally approved the SWIP North transmission project on December 14, 2023 as an extension of the 2022-2023 TPP to be consistent with Idaho Power's timelines.[36] The conditionally approved transmission project calls for the ISO's assumption of Great Basin Transmission's entitlements of 1,117.5 MW in the North to South direction and 572.5 MW in the South to North direction, with the remaining 500 MW in the South to North direction held by Idaho Power. SWIP North will facilitate the integration of Idaho wind resources consistent with the 2023-2024 TPP base portfolio and the CPUC approved decision regarding the 2024-2025 TPP base portfolio, on February 15, 2024. SWIP North is the sole known transmission project that would serve California Load Serving Entities (LSEs) in accessing wind resources in Idaho by 2027. The ISO's economic studies also demonstrate other economic benefits contributing to the overall value provided by the project, as set out in the 2021-2022 TPP and the 2022-2023 TPP. Concurrently, Idaho Power studied the value proposition that SWIP North delivers to Idaho to access power markets in the Desert Southwest and add resource diversity to its portfolio. Idaho Power has indicated the need for 500 MW in the South to North direction in its 2023 integrated resource plan which was submitted to public utility commissions in Idaho and Oregon on September 29, 2023.[37] The ISO expects Idaho Power to file a SWIP-related case with the Idaho Public Utilities Commission by end of March this year. The ISO also expects to conduct additional stakeholder sessions in 2024 on SWIP North as the project progresses in addressing conditions set by the ISO Board. Both the SWIP North project and the TransWest Express

[34] https://elibrary.ferc.gov/eLibrary/filedownload?fileid=99758347-4e9d-c034-90c3-8e348f000000

[35] SunZia Transmission, LLC Submits New Participating Transmission Owner application to California ISO (caiso.com)

[36] California ISO - Documents By Group (caiso.com)

[37] 2023 Integrated Resource Plan (idahopower.com)

project would deliver significant quantities of out-of-state wind into the Harry Allen-Eldorado area, and the combined impact on existing WECC Paths in the area will need to be studied.

F.18 Transmission Plan Deliverability with Approved Transmission Upgrades

As part of the coordination with other ISO processes and as set out in Appendix DD (GIDAP) of the ISO tariff, the ISO monitors the available transmission plan deliverability (TPD) in areas where the amount of generation in the interconnection queue exceeds the available deliverability, as identified in the generator interconnection cluster studies. In areas where the amount of generation in the interconnection queue is less than the available deliverability, the transmission plan deliverability is sufficient. An estimate of the generation deliverability supported by the existing system and approved upgrades is provided in the transmission capability estimates white paper the ISO published in June 2023[38]. The white paper considered queue clusters up to and including queue cluster 14. The transmission plan deliverability is estimated based on the area deliverability constraints identified in recent generation interconnection studies without considering local deliverability constraints.

F.19 Production cost model (PCM) results

The Base portfolio and the sensitivity portfolio were described in section F.4 were utilized for the PCM study in the policy-driven assessment in this planning cycle. Details of PCM assumptions and development can be found in Chapter 4. In this planning cycle, the Sensitivity portfolio PCM used the CEC 2021 IEPR 2035 load forecast with high electrification, while the Base portfolio PCM used the CEC 2021 IEPR 2032 load forecast with high electrification

As the Base portfolio PCM was used for the ISO economic assessment, the congestion and curtailment analysis of the Base portfolio PCM was discussed in Chapter 4. Only the Sensitivity portfolio PCM results were included in this section. Compared with the Base portfolio PCM congestin and curtailment results as set out in section 4.7, congestion and curtailment significantly increased in many areas, which was mainly due to the changes in resource portfolio. The change in load forecast in the Sensitivity portfolio 2035 PCM case also contributed to the increase in congestion in some areas, for example, SCE Western LA area and PG&E Greater Bay area.

Among all differences between the Base and the Sensitivity portfolios, there are incremental 1487 MW of Humboldt Bay offshore wind in the Sensitivity portfolio. Similar to the last planning cycle, three transmission interconnection alternatives for the incremental Humboldt Bay offshore wind were studied:

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

- Alternative 1 – The 1487 MW of Humboldt Bay offshore wind is injecting at the Fern Road 500 kV bus.
- Alternative 2 - The 1487 MW of Humboldt Bay offshore wind is injecting at the proposed BayHub 230 kV bus.
- Alternative 3 - The 1487 MW of Humboldt Bay offshore wind is injecting at the Collinsville 500 kV bus, which was a approved transmission upgrade in the last planning cycle.

Simulation results shows that the impacts on transmission congestion of these three alternatives are different. Among these three alternatives, the Alternative 1 has the largest COI corridor congestion, the Alternative 3 has the largest Collinsville-Pittsburg 230 kV corridor congestion, while the Alternative 2 has the Greater Bay area congestion increased. These three offshore wind transmission alternatives has similar impact on the overall system renewable curtailment, however, the Alternative 1 with the Humboldt offshore wind modeled at the Fernroad 500 kV bus has the lowest Humboldt offshore wind curtailment among all three alternatives. Detailed production cost simulation results are included in Appendix G.