

Docket No.: Application 24-07-018

Exhibit No. _____

Date June 5, 2026

Witness: Diwakar Tewari

ALJ: Robert Haga

**REBUTTAL TESTIMONY OF DIWAKAR TEWARI
ON BEHALF OF LS POWER GRID CALIFORNIA, LLC**

1 **I. Introduction**

2 **Q. Please state your name and title.**

3 A. My name is Diwakar Tewari. I am Vice President of Transmission Planning at LS Power.

4 **Q. On whose behalf are you testifying?**

5 A. I am testifying on behalf of LS Power Grid California, LLC (“LSPGC”).

6 **Q. Please describe your background and expertise as relevant to your testimony in this**
7 **proceeding.**

8 A. I am a licensed Professional Engineer and Senior Member of the Institute of Electrical and
9 Electronics Engineers (“IEEE”) with over 26 years of technical and leadership experience in
10 electrical engineering, with a focus on transmission planning, power system studies, and grid
11 interconnection.

12 I hold a Bachelor of Science in Electrical Engineering from the Indian Institute of Technology
13 and a Master of Science in Electrical Engineering from Arizona State University. I am currently
14 Vice President of Transmission Planning at LS Power, based in Folsom, California, where I am
15 responsible for transmission planning for LS Power’s transmission assets across multiple
16 regional transmission organizations (“RTOs”), including the California Independent System
17 Operator (“CAISO”), the Electric Reliability Council of Texas (“ERCOT”), the Midcontinent
18 Independent System Operator (“MISO”), PJM Interconnection, and the New York Independent
19 System Operator.

20 My technical expertise spans reliability planning studies, resource interconnection, CAISO
21 transmission planning process and North American Electric Reliability Council (“NERC”)
22 reliability compliance.

23 Prior to joining LS Power, I served as Director of Transmission Planning at Leidos from 2012 to
24 2021, where I managed a team of transmission planning engineers conducting studies for clients
25 nationwide and internationally, with particular emphasis on renewable generation
26 interconnection and grid integration. Before that, I was a Manager of Operations Engineering at
27 the CAISO, where I provided real-time engineering support to system operators and managed the
28 Western Electricity Coordinating Council (“WECC”) seasonal operating studies process. Earlier
29 in my career, I spent eight years at MISO, where I led transmission access planning and
30 generator interconnection queue management, including playing a key technical role in MISO’s
31 queue reform process in 2008.

1 Throughout my career, I have participated in IEEE technical committees and working groups,
2 NERC, North American Transmission Forum (“NATF”), Electric Power Research Institute
3 (“EPRI”) and other industry forums, and advised clients and stakeholders on transmission
4 planning standards, Federal Energy Regulatory Commission and NERC compliance, and
5 renewable energy integration. This breadth of experience across ISO/RTO markets, consulting,
6 and transmission development provides the foundation for my testimony in this proceeding.

7 **Q. Please briefly describe the purpose of your testimony.**

8 **A.** The purpose of my testimony is to respond to the assertion presented in the Prepared
9 Testimony of Expert Deborah Galimba on behalf of California Forever that the Collinsville
10 500/230 kV Substation Project (“Collinsville Project”), the subject of this proceeding, is
11 dependent on, or was initiated, sited, sized, or configured for, the future New Humboldt 500 kV
12 Substation, with a 500/115 kV Transformer, and a 500 kV line to Collinsville [HVDC operated
13 as AC] (“Humboldt Project”). My testimony explains why that assertion is not supported by the
14 facts. In particular, I describe the separate CAISO planning histories for the Collinsville Project
15 and the Humboldt Project, the independent need for and utility of the Collinsville Project, and
16 the fact that the current Collinsville Project scope does not include the equipment or facilities
17 required to interconnect the Humboldt-Collinsville transmission line.

18 **Q. Do you have any attachments to your testimony?**

19 **A.** Yes. For convenient reference, I am attaching the relevant excerpts from documents I refer to
20 in this testimony, as shown in the following table:

Attachment	Title or Description
A	CAISO 2021-2022 Transmission Plan (excerpts)
B	CAISO 2023-2024 Transmission Plan (excerpts)
C	CAISO 2024-2025 Transmission Plan (excerpts)
D	CAISO 2022-2023 Transmission Plan (excerpts)
E	Appendix A to the Approved Project Sponsor Agreement for the Collinsville 500/230 kV Substation Project

21 **Q. What issue are you addressing in this portion of your rebuttal testimony?**

22 **A.** I am addressing Ms. Galimba’s assertion that the Collinsville Project was initiated, sited,
23 sized, or configured because of the future Humboldt-Collinsville transmission line and Humboldt
24 offshore wind development. I disagree with that assertion. The facts show that the Collinsville
25 Project was approved in the 2021-2022 CAISO Transmission Plan for independent Greater Bay

1 Area and Solano-area transmission needs, while the Humboldt Project facilities were evaluated
2 separately and approved later in the 2023-2024 CAISO Transmission Plan.¹

3 **Q. What is Ms. Galimba’s contention?**

4 **A.** Ms. Galimba asserts that in the absence of an influx of new generation and the associated
5 transmission from the Humboldt offshore wind projects, “there is no independent reliability
6 driver for the HVDC Line or the Collinsville Substation. The Substation and the transmission
7 infrastructure that feeds into it were designed, sized, and sited for one purpose: to receive 1.6
8 GW of Humboldt offshore wind generation and deliver it to the California grid by June 1,
9 2034.”² She states that the strategic placement of the Collinsville Substation was “wholly
10 predicated” on serving as the receiving terminus for the Humboldt HVDC line.³

11 **Q. Do you agree with that contention?**

12 **A.** No. Ms. Galimba’s contention reverses the chronology and conflates separate CAISO
13 planning decisions. The need for the Collinsville Project was identified first, in the 2021-2022
14 Transmission Plan, to address base-portfolio transmission constraints and to provide an
15 additional 500 kV supply into the northern Greater Bay Area required in 2028.⁴ The Humboldt
16 Project was approved two years later, in the 2023-2024 Transmission Plan, as part of a separate
17 transmission plan to accommodate North Coast offshore wind resources with a required in
18 service date of 2034.⁵ The fact that a later Humboldt transmission project *may* use Collinsville as
19 a termination point does not mean the original Collinsville Project was caused by, dependent on,
20 or approved for Humboldt offshore wind. Further, an earlier in-service date project is never
21 dependent on a later in-service date project in my experience. In addition, the Approved Project
22 Sponsor Agreement (“APSA”) between LSPGC and CAISO that defines the project details for
23 the Collinsville Project does not include the facilities needed to interconnect the future Humboldt
24 Project.⁶

25 **Q. What is your overall conclusion?**

26 **A.** The Collinsville Project is not currently designed to interconnect with the Humboldt project

¹ Attachment A, p. 193; Attachment B, pp. 6, 72-73.

² “Prepared Testimony of Expert Deborah Galimba on Behalf of California Forever,” May, 13, 2026 (“Galimba Testimony”), p. 18.

³ Galimba Testimony, p. 25.

⁴ Attachment A, pp. 192-196.

⁵ Attachment B, pp. 72-74.

⁶ Attachment E, pp. 36-37.

1 and has independent CAISO-approved utility and need. It was approved in the 2021-2022
2 Transmission Plan to address the base-portfolio 230 kV constraints and for an additional 500 kV
3 source into the northern Greater Bay Area.⁷ In the 2024-2025 Transmission Plan, CAISO later
4 confirmed that Collinsville may provide a termination for the proposed Humboldt-Collinsville
5 transmission line, but “is not dependent on the Humboldt-Collinsville project.”⁸

6 **II. The CAISO’s Approval of the Collinsville Project Was Not Dependent on the**
7 **Humboldt Project**

8 **Q. What is the evidence that Collinsville Project is not dependent on the Humboldt**
9 **Project?**

10 **A.** The most direct evidence is CAISO’s own statement in the 2024-2025 Transmission Plan:
11 “By 2028, an additional 500/230 kV supply source will be established at
12 Collinsville, located in the northeastern part of the Bay Area. This new facility
13 will provide stronger support for the East Bay and alleviate stress on the 230 kV
14 lines, particularly in the Contra Costa region. This source was approved in the
15 ISO’s 2021-2022 transmission plan, and while it may also provide a termination
16 for the proposed Humboldt-Collinsville transmission line subsequently proposed
17 in the ISO’s 2023-2024 transmission plan, it is not dependent on the Humboldt-
18 Collinsville project.”⁹

19 **Q. Why is that statement important?**

20 **A.** It directly refutes Ms. Galimba’s notion that the sole purpose of the Collinsville Project is to
21 receive 1.6 GW from North Coast offshore wind projects. CAISO recognized both facts: first,
22 that the Collinsville Project has an independent function as a 500/230 kV substation providing
23 support to 230 kV lines in the East Bay and Contra Costa region; and second, that *if* North Coast
24 offshore wind achieves its potential, Collinsville may also be used later as a termination for the
25 Humboldt-Collinsville transmission line.¹⁰ CAISO’s statement confirms that later potential use is
26 not the same as dependency.

27 **Q. Does the current Collinsville Project have independent utility?**

28 **A.** Yes. Collinsville provides a new 500/230 kV supply source into the northern Greater Bay

⁷ Attachment A, p. 193.

⁸ Attachment C, p. 69.

⁹ Attachment C, p. 69.

¹⁰ Attachment C, p. 69.

1 Area, supports the East Bay and Contra Costa region, addresses 230 kV constraints identified in
2 CAISO’s base-portfolio studies, and enables deliverability of renewable and energy storage
3 resources in the Solano and northern Greater Bay Area. That independent utility exists regardless
4 of whether the later Humboldt Project proceeds.

5 **Q. Are existing substations frequently used to connect later-developed transmission lines?**

6 **A.** Yes. For example, in the 2024-2025 Transmission Plan, the CAISO authorized a new
7 Manning-Metcalf transmission line, connecting two existing substations that were constructed to
8 meet other transmission needs and not just to serve as termination points for the new line.¹¹ The
9 proposed Humboldt-Fern Road is another example of a new transmission line that will connect to
10 a substation that was constructed for other purposes. To my knowledge, it hasn’t been suggested
11 that the Fern Road substation was authorized solely as a termination point for North Coast
12 offshore wind generation.

13 **Q. Does Ms. Galimba’s own testimony recognize that the Collinsville Project and**
14 **Humboldt Project are separate projects?**

15 **A.** Yes. Ms. Galimba states that the Collinsville transmission corridor involves “two legally and
16 operationally separate projects approved in different CAISO planning cycles.”¹² She identifies
17 the Collinsville Project as the project currently before the Commission from the 2021-2022
18 planning cycle, and the 260-mile Humboldt-Collinsville line as a later project identified in the
19 2023-2024 planning cycle. That admission is consistent with the CAISO transmission plans, the
20 APSA for the Collinsville Substation,¹³ this application for a Certificate of Public Convenience
21 and Necessity (“CPCN”), and the Final Environmental Impact Report (“Final EIR”) on the
22 Collinsville Project.¹⁴

23 **Q. Does that admission resolve the issue?**

24 **A.** It is highly relevant, but Ms. Galimba draws the wrong conclusion from it. The fact that the
25 projects are legally and operationally separate, were approved by the CAISO in different
26 planning cycles, have different in-service dates, and have different scopes confirms that the
27 current Collinsville Project should not be treated as if it were dependent on the Humboldt
28 Project.

¹¹ Attachment C, pp. 69-71.

¹² Galimba Testimony, p. 19.

¹³ Attachment E .

¹⁴ Final EIR, ES-1 to ES-4.

1 **III. Correct Planning Framework**

2 **Q. Ms. Galimba refers to the lack of an “independent reliability driver” for the Collinsville**
3 **Project. Is that the correct framing?**

4 **A.** No. The correct question is whether the Collinsville Project was approved to address an
5 independent CAISO-identified transmission need. The Collinsville Project was approved as a
6 policy-driven transmission project, but the 2021-2022 Transmission Plan also identifies the
7 reliability, deliverability, and economic benefits of the Collinsville Project.¹⁵ A policy-driven
8 project may provide reliability benefits even if it is not classified solely as a reliability-driven
9 project. CAISO’s 2021-2022 plan authorized the Collinsville Project to address base-portfolio
10 deliverability constraints and to provide an additional 500 kV source into the northern Greater
11 Bay Area; both functions will improve reliability.

12 **Q. Why does your framing of the issue matter?**

13 **A.** It matters because Ms. Galimba’s “reliability driver” framing attempts to impose the wrong
14 test and fails to recognize the full benefits of the Collinsville Project. The Collinsville Project
15 does not need to be justified solely as a reliability-driven project. The relevant question is
16 whether the Collinsville Project has independent benefits and meets an independent CAISO-
17 identified need. The Collinsville Project meets both tests: CAISO approved the Collinsville
18 Project as a policy-driven project with additional reliability and deliverability benefits.

19 **IV. The CAISO’s Transmission Plans Consistently Recognize the Distinction Between**
20 **the Collinsville Project and the Humboldt Project**

21 **A. 2021-2022 Transmission Plan**

22 **Q. When was the Collinsville Project approved by CAISO?**

23 **A.** The Collinsville Project was approved by the CAISO Board of Governors in the 2021-2022
24 Transmission Plan. The approved project was a new Collinsville 500/230 kV substation, with the
25 Vaca Dixon-Tesla 500 kV line looped into the substation, two 500/230 kV transformers with
26 1,500 MVA ratings, and two 230 kV cables between Collinsville and the Pittsburg Substation.¹⁶

27 **Q. What need did CAISO identify for resolution by the Collinsville Project in the 2021-**
28 **2022 Transmission Plan?**

¹⁵ Attachment A, pp. 193, 300-301.

¹⁶ Attachment A, p. 193.

1 A. CAISO stated that the Collinsville Project would address constraints within the base
2 portfolio, including the Cayetano-North Dublin 230 kV line, the Lone Tree-USWP-JRW-
3 Cayetano 230 kV line, and the Las Positas-Newark 230 kV line. CAISO also stated that the
4 project would provide an additional supply from the 500 kV system into the northern Greater
5 Bay Area to increase reliability and advance additional renewable generation in the northern
6 area.¹⁷

7 **Q. Did that approved 2021-2022 scope include the Humboldt-to-Collinsville transmission**
8 **line?**

9 A. No. The 2021-2022 approved Collinsville Project scope included the Collinsville 500/230 kV
10 substation, the Vaca Dixon-Tesla 500 kV loop, two 500/230 kV transformers, and two 230 kV
11 cables between Collinsville and Pittsburg.¹⁸ It did not include the Humboldt-to-Collinsville
12 transmission line or the facilities to interconnect a Humboldt-related 500 kV line at the
13 Collinsville Substation.

14 **Q. Were the constraints identified in the 2021-2022 Transmission Plan that the Collinsville**
15 **Project will resolve dependent on Humboldt offshore wind?**

16 A. No. The Collinsville Project constraints were identified in the policy-driven analysis that
17 used the base portfolio developed by the Commission,¹⁹ which did not include offshore wind.²⁰
18 Offshore wind was studied in a separate sensitivity analysis.²¹

19 **Q. Didn't the 2021-2022 Transmission Plan identify transmission upgrades that would be**
20 **needed for North Coast offshore wind generation?**

21 A. Humboldt offshore wind was studied separately in the offshore wind sensitivity as part of the
22 2021-2022 Transmission Plan. The Commission specifically transmitted a sensitivity portfolio to
23 the CAISO to test transmission needs associated with 8 GW of offshore wind and stated that the
24 purpose was to obtain inputs for future portfolio development, not to identify that sensitivity
25 portfolio as the optimal portfolio overall.²²

¹⁷ Attachment A, p. 193.

¹⁸ Attachment A, p. 193.

¹⁹ Attachment A, pp. 28-29, 166-167.

²⁰ Decision ("D.") 21-02-002, pp. 17-24.

²¹ Attachment A, pp. 220-235.

²² D.21-02-002, pp. 26-28.

1 **Q. Why is the distinction between the base portfolio and the offshore wind sensitivity study**
2 **important?**

3 **A.** The distinction matters because a base-portfolio mitigation is part of the transmission plan’s
4 approved need determination, while a sensitivity study tests possible *future* conditions. The
5 Collinsville Project was approved to address base-portfolio constraints. Humboldt offshore wind
6 was evaluated separately as part of a sensitivity study. That distinction undermines the contention
7 that Humboldt offshore wind and the related Humboldt transmission line was the justification for
8 the Collinsville Project.

9 **Q. Did CAISO’s sensitivity study evaluate multiple Humboldt interconnection options in**
10 **the 2021-2022 Transmission Plan?**

11 **A.** Yes. CAISO studied multiple Humboldt offshore wind interconnection alternatives, including
12 interconnections modeled at Fern Road, Collinsville, and Bay Hub.²³

13 **Q. What does the existence of multiple Humboldt interconnection options show?**

14 **A.** It shows that even when CAISO evaluated Humboldt offshore wind, Collinsville was not the
15 only possible interconnection point, and certainly not an indispensable or exclusive Humboldt
16 interconnection solution. The CAISO’s consideration of multiple interconnection options is
17 inconsistent with the claim that the Collinsville Project was initiated solely to receive Humboldt
18 offshore wind.

19 **B. 2022-2023 Transmission Plan**

20 **Q. What action did CAISO take in the 2022-2023 Transmission Plan regarding North**
21 **Coast offshore wind?**

22 **A.** CAISO did not approve North Coast offshore wind transmission in the 2022-2023 planning
23 cycle. CAISO stated that the base resource portfolio did not support the need for North Coast
24 transmission in that cycle because only 100 to 150 MW of offshore wind was mapped to
25 Humboldt.²⁴ CAISO identified the need for North Coast transmission only in the sensitivity
26 portfolio and stated that the sensitivity study was informational and would set the stage for future
27 planning.²⁵

²³ Attachment A, pp.220-228.

²⁴ Attachment D, p. 103.

²⁵ Attachment D, p. 103.

1 **Q. Why is the 2022-2023 plan relevant to Ms. Galimba’s contention?**

2 **A.** The 2022-2023 Transmission Plan confirms the separation between the Collinsville Project
3 and transmission for Humboldt offshore wind. If Collinsville had already been approved in 2021-
4 2022 as a Humboldt-dependent project, CAISO would not have needed to defer North Coast
5 transmission approval in 2022-2023 pending development of a later base portfolio. The 2022-
6 2023 plan shows that the North Coast/Humboldt transmission decision had not yet been made.

7 **C. 2023-2024 Transmission Plan**

8 **Q. What actions did CAISO take in the 2023-2024 Transmission Plan related to Humboldt**
9 **offshore wind?**

10 **A.** In the 2023-2024 Transmission Plan, CAISO approved a separate North Coast offshore wind
11 transmission package. The approved policy-driven projects included the Humboldt 500 kV
12 Substation with a 500 kV line to Collinsville, initially operated as AC; the Humboldt to Fern
13 Road 500 kV Line; the Humboldt 115/115 kV phase shifter with a 115 kV line to the existing
14 Humboldt 115 kV Substation; and downstream upgrades including North Dublin-Vineyard
15 reconductoring, Tesla-Newark reconductoring, and the Collinsville 230 kV Reactors.²⁶

16 **Q. Does the 2023-2024 Transmission Plan’s approval of the Humboldt-Collinsville line**
17 **mean that the earlier Collinsville Project was justified by or dependent on Humboldt**
18 **offshore wind?**

19 **A.** No. It shows the opposite. The Humboldt Project was approved two years later than the
20 Collinsville Project, in a separate planning cycle, for a different 2034 offshore wind integration
21 purpose. The original Collinsville Project remained a previously approved 2021-2022 project
22 with a different scope, schedule, and need determination.

23 **Q. Did CAISO evaluate alternatives to interconnect Humboldt offshore wind?**

24 **A.** Yes. In the 2023-2024 plan, CAISO considered multiple Humboldt interconnection options.
25 CAISO stated that the Humboldt area base portfolio included 1,607 MW of offshore wind and
26 that there was no existing bulk substation near the Humboldt offshore wind area. CAISO then
27 considered five options in the baseline portfolio to interconnect Humboldt offshore wind to the
28 rest of the system, three of which did not require a connection to the Collinsville Substation.²⁷

²⁶ Attachment B, p. 6.

²⁷ Attachment B, pp. 69-71.

1 **Q. What was Alternative E?**

2 **A.** Alternative E was the Humboldt offshore wind interconnection alternative CAISO
3 recommended in the 2023-2024 Transmission Plan. It included a new Humboldt 500 kV
4 substation, a 260-mile HVDC line initially operated as a 500 kV AC line to Collinsville, a 140-
5 mile 500 kV AC line to Fern Road, and a 115/115 kV phase-shifting transformer with a 115 kV
6 line from Humboldt 500 kV to the existing Humboldt 115 kV substation. CAISO stated that
7 Alternative E provided more flexibility and reduced stranded-cost risk if offshore wind
8 developed more slowly or shifted to a different call area. Alternative E also provided a parallel
9 path to the existing 500 kV lines from Round Mountain to Tesla, and had the lowest cost estimate
10 among the interconnection and mitigation combinations.²⁸

11 **Q. What in-service date did CAISO identify for Alternative E?**

12 **A.** CAISO identified Alternative E as having an estimated in-service date of 2034.²⁹

13 **Q. How does that compare to the in-service date of the Collinsville Project?**

14 **A.** The Collinsville Project has an in-service date of 2028. The Humboldt-Collinsville and
15 Humboldt-Fern Road facilities are 2034 projects. That six-year separation supports the
16 conclusion that the Collinsville Project has near-term independent utility and was not approved
17 merely as part of a later Humboldt transmission project.

18 **V. Response to Ms. Galimba’s Other Contentions**

19 **Q. Ms. Galimba points to earlier offshore wind studies and CAISO presentations that**
20 **discussed Collinsville as a possible Humboldt terminus. Does that prove that the**
21 **Collinsville Project was justified by the Humboldt transmission line?**

22 **A.** No. It proves at most that Collinsville was one possible future Humboldt interconnection
23 option that CAISO and others studied. It does not prove that the 2021-2022 Collinsville Project
24 was justified by the Humboldt transmission line. The 2021-2022 Transmission Plan approved
25 Collinsville to address the base-portfolio constraints, while Humboldt offshore wind was studied
26 separately in a sensitivity with multiple possible interconnection points.

27 **Q. The 2021-2022 Transmission Plan states that the Collinsville Project will “advance**
28 **additional renewable generation in the northern area.” Does that phrase refer to**
29 **Humboldt offshore wind specifically?**

²⁸ Attachment B, p. 72.

²⁹ Attachment B, p. 73.

1 A. No. That phrase appears in the context of CAISO’s 2021-2022 base-portfolio need for the
2 Collinsville Project.³⁰ It refers to the broader deliverability of renewable and energy storage
3 resources in the northern area, which includes Solano County and the Sacramento Valley. In fact,
4 Humboldt offshore wind was not even modeled in the base portfolio. It does not convert the
5 base-portfolio Collinsville approval into a Humboldt offshore wind project.

6 **Q. Ms. Galimba argues that federal headwinds for Humboldt offshore wind require
7 reconsideration of the Collinsville Project. Do you agree?**

8 A. No, not as to the LSPGC’s proposed Collinsville Project. Those issues may be relevant to the
9 future Humboldt Project, but they do not eliminate the independent need for the Collinsville
10 Project. CAISO has expressly stated that the Collinsville Project is not dependent on the
11 Humboldt Project.

12 **Q. Does the possibility that Humboldt may later interconnect at Collinsville change the
13 purpose of the current Collinsville Project?**

14 A. No. A later project may use an earlier-approved substation without changing the original
15 cause or purpose of that substation. Collinsville may be useful to a future Humboldt project, but
16 the facts show that the Collinsville Project was not initiated for that project and is not dependent
17 on it.

18 **VI. Conclusion**

19 **Q. What is your conclusion regarding Ms. Galimba’s contention that the Collinsville
20 Project was “designed, sized, and sited for one purpose: to receive 1.6 MW of Humboldt
21 offshore wind generation”?**

22 A. Ms. Galimba’s contention is not supported by the facts. The facts show the following
23 sequence:

- 24 • First, CAISO approved the Collinsville Project in the 2021-2022 Transmission Plan to
25 address the base-portfolio 230 kV constraints and provide additional 500 kV supply into
26 the northern Greater Bay Area.³¹

³⁰ Attachment A, p. 193.

³¹ Attachment A, p. 193.

- 1 • Second, CAISO separately studied Humboldt offshore wind in the 2021-2022 offshore
2 wind sensitivity, including multiple interconnection options, only one of which connected
3 at Collinsville.³²
- 4 • Third, CAISO did not approve North Coast offshore wind transmission in the 2022-2023
5 Transmission Plan because the base portfolio did not support that need in that cycle.³³
- 6 • Fourth, CAISO later approved separate Humboldt offshore wind transmission projects in
7 the 2023-2024 Transmission Plan, including a new Humboldt 500 kV Substation with a
8 line to Collinsville and a separate line to Fern Road.³⁴
- 9 • Fifth, CAISO expressly stated in the 2024-2025 Transmission Plan that Collinsville may
10 provide a termination for the later Humboldt-Collinsville line but is not dependent on the
11 Humboldt-Collinsville project.³⁵
- 12 • Sixth, the APSA defines the current Collinsville Project without the additional 500 kV
13 line terminal facilities needed to interconnect a Humboldt-Collinsville transmission
14 line.³⁶

15 In addition, the facts demonstrate that the justification for the Collinsville Project is independent
16 of North Coast offshore wind. The Collinsville Project provides a new 500/230 kV supply source
17 into the northern Greater Bay Area, supports the East Bay and Contra Costa region, addresses
18 230 kV constraints identified in CAISO’s base-portfolio studies, and increases deliverability of
19 renewable and energy storage resources in the Solano and northern Greater Bay Area. That
20 independent utility exists regardless of whether the later Humboldt Project proceeds.

21 As explained in this testimony, the Commission should reject Ms. Galimba’s allegation of a
22 relationship between Humboldt and the Collinsville Project.

23 **Q. What should the Commission conclude regarding the alleged relationship between**
24 **Humboldt and Collinsville?**

25 **A.** The Commission should reject Ms. Galimba’s Humboldt contention. The Collinsville Project
26 was approved in 2021-2022 for independent CAISO-identified transmission needs. The
27 Humboldt Project was approved later, in 2023-2024, as part of a separate offshore wind

³² Attachment A, pp. 220-228.

³³ Attachment D, p. 103.

³⁴ Attachment B, pp. 6, 72-76.

³⁵ Attachment C, p. 69.

³⁶ Attachment E, p. 37.

1 transmission package. The facts therefore support the conclusion that Collinsville is not caused
2 by or dependent on the Humboldt Project.

3 **Q. Does that complete your testimony?**

4 **A.** Yes.

ATTACHMENT A

CAISO 2021-2022 Transmission Plan (excerpts)



2021-2022 TRANSMISSION PLAN

 California ISO

March 17, 2022
Board Approved

The CPUC subsequently issued a proposed decision⁴⁰ on December 22, 2021 and the ISO is now reviewing the details of the proposed decision and its impact on the earlier findings.

The above sequence of planning activities demonstrates the rapid escalation of resource requirements over a few short years, particularly storage, responding to the pressures described earlier.

1.4.2.1 Resource Portfolios provided via the Integrated Resource Planning Process

As noted above, the CPUC provided to the ISO via Decision 21-02-008⁴¹ released on February 11, 2021 base case and sensitivity portfolios for use in this planning cycle.

The Decision transmitted to the ISO for its 2021-2022 Transmission Planning Process the reliability and policy-driven base case portfolio that meets the 46 million metric ton (MMT) greenhouse gas (GHG) emissions target by 2031. The Decision also transferred two policy-driven sensitivity portfolios for study purposes:

- 1) A portfolio that meets a 38 MMT GHG emissions target by 2031; and,
- 2) A portfolio to test transmission needs associated with 8 GW of offshore wind, which was accommodated by further lowering the greenhouse gas emissions target to a 30 MMT range. The CPUC stressed that the purpose of the study of this portfolio was to obtain key inputs for capacity expansion modeling to inform future portfolio development, not to suggest that the portfolio used for this study was seen as part of an optimal portfolio overall. Rather, this study is designed to test the transmission implications if barriers were to be removed to large-scale development of offshore wind.

These portfolios also took into account the announced retirements of approximately 3700 MW of gas-fired generation to comply with state requirements for thermal generation relying on coastal water for once-through cooling, and the announced retirement of the Diablo Canyon Power Plant.

Unlike the portfolios provided to the ISO for the 2020-2021 transmission plan, the CPUC acknowledged that utilizing the electric resource portfolio that meets the 46 MMT GHG emissions target as a reliability and policy-driven base case in the transmission planning process would likely result in the need for new transmission investment to make the portfolio deliverable.⁴²

The portfolios provided to the ISO also provided specific direction regarding the treatment of out-of-state wind resources, particularly for the base case. The ISO was requested to study the

⁴⁰ Proposed Decision, DECISION ADOPTING 2021 PREFERRED SYSTEM PLAN, Rulemaking 20-05-003, December 22, 2021: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M434/K547/434547053.PDF>

⁴¹ Decision 21-02-008 released on February 11, 2021 for the purposes of the CAISO/ISO 2021-22 transmission planning cycle. Page 41 <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF>

⁴² id. Page 39

potential requirements and implications of 1062 MW being injected into the ISO system from each of Idaho/Wyoming or New Mexico in the base case, but not both simultaneously. The ISO recognized that the approval of any identified needs to accommodate either injection would hinge on the analysis and subsequent stakeholder comments⁴³. Further, the CPUC acknowledged that out-of-state transmission would be needed to deliver these volumes to the existing ISO boundary, but those were outside the scope of the policy-driven transmission study request. Accordingly, the policy-driven analysis (see chapter 3) was conducted on this basis. In subsequent comments in the ISO's stakeholder process, CPUC staff comments later requested the ISO consider, time permitting, possible out-of-state requirements for information purposes only⁴⁴. The ISO undertook additional analysis of out-of-state issues in its economic study process that also considered a related economic study request (see chapter 4).

1.4.2.2 Additional considerations supplementing Resource Portfolios

Other relevant information and input augmented the portfolios provided by the CPUC. These considerations support more extensive system upgrades in several areas beyond what the resource portfolios provided by the CPUC support.

This will allow several low-risk projects to proceed and enable the ISO to focus its 2022-2023 planning efforts on the expected growth in requirements.

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

In developing the base portfolio for the 2021-2022 transmission planning cycle, the CPUC's modeling showed that while no new natural gas-fired power plants are identified in the 2031 new resource mix, existing gas-fired plants – other than those relying on once-through-cooling and scheduled for retirement - are needed in 2031 as operable and operating resources, providing a renewable integration service. Accordingly, to align with the CPUC's assumptions, the ISO has not assumed retirement regardless of age. This is a change from the 2020-2021 transmission plan, where generation was assumed to retire at 40 years for study purposes, but the resources were added back in if a reliability issue was triggered.

Notwithstanding the strong indications that the existing gas-fired generation fleet will be needed into the foreseeable future for system-wide supply adequacy, the ISO has over a number of years conducted additional studies on a largely informational basis to provide better insights and understandings of the opportunities and issues associated with gas-fired generation retirement. Study efforts focusing on reducing costs to consumers by reducing local capacity requirements and shifting away from reliance on gas-fired generation for those needs will need to take into

⁴³ Page 34, D.21-02-008 that transferred the portfolios to the ISO. "The CAISO, in reply comments, suggested that they could study separately the injection of the full amount of energy at both the El Dorado substation representing resources from Wyoming, Idaho, or potentially other locations, and the Palo Verde substation, presentation resources from New Mexico or other Southwest locations, delivering results for further consideration at the end of this TPP cycle. We understand this to be a unique situation where the CAISO may be able to offer optionality within the base case analysis, and therefore we will take the CAISO up on this offer and work with them to understand better the transmission buildout requirements associated with generation siting in both locations." <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF>

⁴⁴ CPUC Staff Comments dated March 11, 2021 re ISO February 25, 2021 stakeholder meeting: "We encourage the CAISO's review of possible opportunities for such an informational study of transmission needs outside the CAISO system, whether it might be conducted solely by the CAISO or jointly with another agency." <http://www.caiso.com/InitiativeDocuments/CPUCComments-2021-2022TransmissionPlanningProcess-Feb252021StakeholderCall.pdf>

Off-peak deliverability assessment

The off-peak deliverability assessment is performed to identify potential transmission system limitations that may cause excessive renewable energy curtailment. The ISO performed the assessment following the Off-Peak Deliverability Assessment Methodology¹¹⁷.

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. The PCM with the sensitivity portfolios 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 2021-2022 transmission planning process study plan. Details of PCM modeling assumptions and approaches are provided in chapter 4.

3.4 Resource Portfolios

As mentioned in Section 3.1, a base portfolio and two sensitivity portfolios were transmitted by the CPUC for study in the ISO 2021-2022 transmission planning process policy-driven assessment. The three portfolios complete with the final busbar mapping results for non-battery and battery resources as well as a retirement list for the sensitivity portfolios are available at the CPUC website.

Final busbar mapping results for non-battery resources for the base and sensitivity portfolios – https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/mappingsummary_bystation_allportfolios_2021_22tpp_ver2.xlsx

Final busbar mapping results for battery storage for the base and sensitivity portfolios – ftp://ftp.cpuc.ca.gov/energy/modeling/Battery_Mapping_Dashboard_All_Portfolios_Final.xlsx

Retirement list for the policy-driven sensitivity portfolios – ftp://ftp.cpuc.ca.gov/energy/modeling/Retirement_List_for_Sensitivity_Portfolios.xlsx

The composition of each of the portfolios by resource type is provided in Table 3.4-1. The table includes resources selected with Full Capacity Deliverability Status (FCDS) as well as those selected as Energy Only (EO). The portfolios are comprised of solar, wind, pumped hydro, geothermal and battery storage resources. While the base portfolio assumes all of the existing gas-fired generation is retained, the sensitivity portfolios assume some of the existing gas-fired generation fleet will be retired by 2031. All portfolio resources are modeled in policy-driven assessments except in the on-peak deliverability assessment, where only FCDS resources are modeled.

¹¹⁷ <http://www.caiso.com/Documents/Off-PeakDeliverabilityAssessmentMethodology.pdf>

Table 3.4-1: Portfolio composition – FCDS+EO resources (MW)

	Base	Sensitivity-1	Sensitivity-2
Solar	13,044	13,817	9,807
Wind	4,005	7,955	16,039
Pumped Hydro	627	1,843	1,495
Geothermal	651	105	0
Battery storage	9,368	9,447	7,604
Gas Retirements	0	(1,319)	(1,718)
Total (FC+EO)	27,695	31,848	33,227

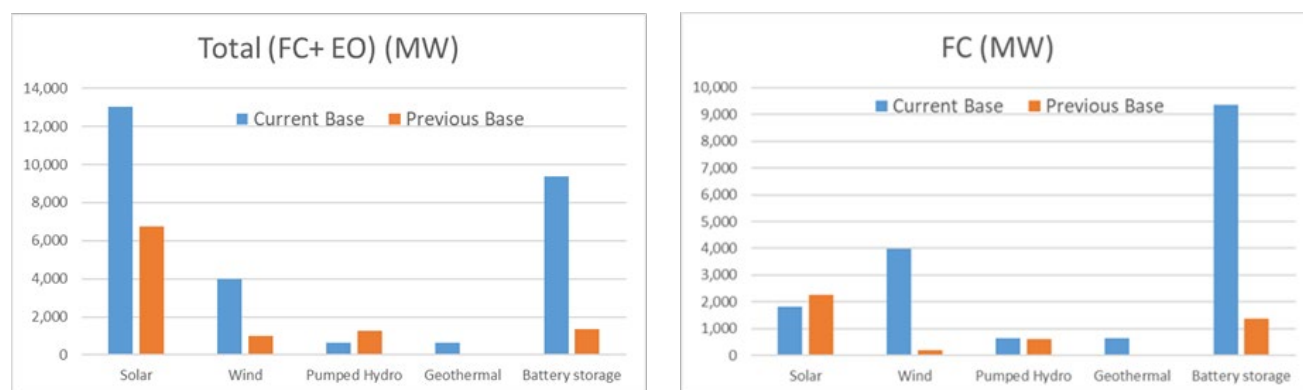
Table 3.4-2 below provides the composition of the portfolio resources selected with Full Capacity Deliverability Status (FCDS).

Table 3.4-2: Portfolio composition – FCDS resources (MW)

	Base	Sensitivity-1	Sensitivity-2
Solar	1,832	2,422	1,332
Wind	3,971	6,451	13,250
Pumped Hydro	627	1,843	1,495
Geothermal	651	57	0
Battery storage	9,368	9,447	7,604
Gas Retirements	0	1,319	1,718
Total FC	16,448	18,901	21,963

Compared to the base portfolio studied in the 2020-2021 transmission planning process, the current base portfolio includes significantly more resources, both in total amount and FCDS amount as shown in Figure 3.4-1

Figure 3.4-1: Comparison of current and 2020-21 TPP base portfolios



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

The deliverability of renewable and energy storage portfolio resources in the Solano area is limited by thermal overloading of the Cayetano-North Dublin 230 kV line under N-2 conditions as shown in Table 3.5-24. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table 3.5-25, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. RAS was ruled out due to the complexity. The RAS would need to encompass the larger area and requires remote monitoring. The new Collinsville 500 kV substation has been identified as the mitigation.

Table 3.5-24: Cayetano-North Dublin 230 kV line on-peak deliverability constraint

Overloaded Facility	Contingency		Loading				
			BASE	SENS-01	SENS-02		
					Option 1	Option 2	Option 3
Cayetano-North Dublin 230 kV line	Contra Costa-Morago #1 and #2 230 kV lines	HSN	106%	107%	110%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%

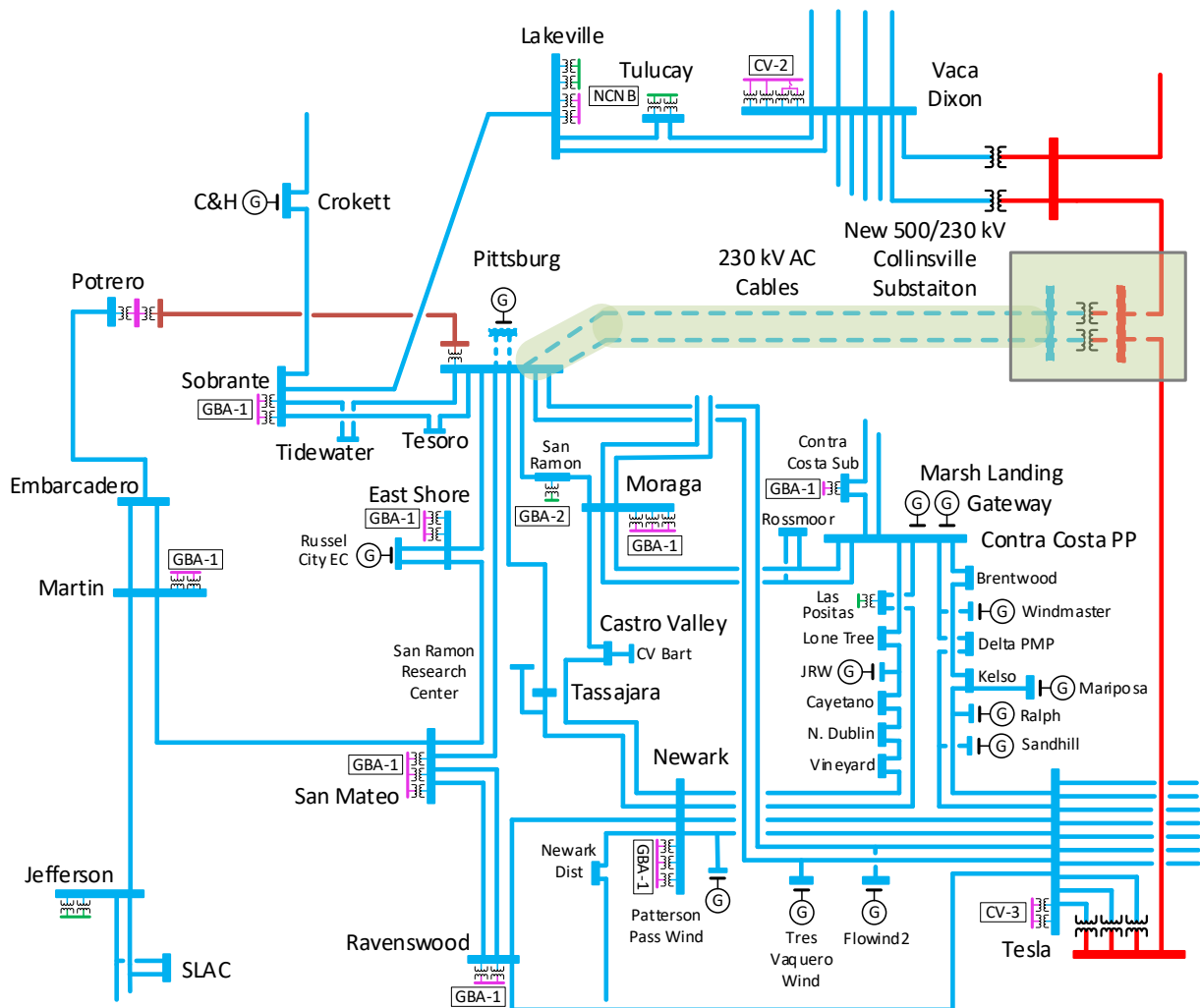
Table 3.5-25: Cayetano-North Dublin 230 kV line on-peak deliverability constraint summary

Affected transmission zones		Solano				
		Base Portfolio	S1 Portfolio	S2 Portfolio		
				Option 1	Option 2	Option 3
Renewable portfolio MW behind the constraint (installed FCDS capacity)		102 Wind	102 Wind	102 Wind	102 Wind	102 Wind
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		5.4	0	0	0	0
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0	0	102	102
Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)		260	299	422	0	0
Mitigation Options	RAS	No, remote monitoring (RAS Guideline violation)				
	Re-locate portfolio battery storage (MW)	Not applicable				
	Transmission upgrade including cost	Reconductor the line (\$42.4M – \$55.1M) or New Collinsville 500 kV substation (\$475M – \$675M)				
Recommended Mitigation		New Collinsville 500 kV substation (\$475M – \$675M)				

Collinsville 500/230 kV substation project

The Collinsville 500/230 kV substation project will address a number of identified transmission constrains within the base portfolio (Cayetano-North Dublin 230 kV line, Lone Tree-USWP-JRW-Cayetano 230 kV line, and Las Positas-Newark 230 kV line) and provide an additional supply from the 500 kV system into the northern Greater Bay Area to increase reliability to the area and advance additional renewable generation in the northern area.

Figure 3.5-1: Collinsville 500/230 kV substation project interconnection



The scope of the Collinsville 500/230 kV substation project is as follows:

- A new Collinsville 500/230 kV substation looping in Vaca Dixon – Tesla 500 kV line
- Two 500/230 kV transformers with 1,500 MVA ratings
- Two 230 kV cables between Collinsville and Pittsburg 230 kV.

- The series capacitor on the Vaca Dixon – Tesla 500 kV line is currently all at Vaca Dixon substation. As part of the project, the series capacitor at Vaca Dixon will be reduced and new series caps will be installed on the Collinsville – Tesla 500 kV line at Collinsville substation to keep the compensation level on each line section the same as what is currently between Vaca Dixon and Tesla (~%75)

The estimated cost of the Collinsville 500/230 kV substation project is \$475-675 million with an expected in-service date of 2028.

Lone Tree-USWP-JRW-Cayetano 230 kV line on-peak deliverability constraint

The deliverability of renewable and energy storage portfolio resources in the Solano-Sacramento River area is limited by thermal overloading of the Lone Tree-USWP-JRW-Cayetano 230 kV line under N-0 conditions as shown in Table 3.5-26. This constraint was identified in the baseline portfolio under HSN conditions. As shown in Table 3.5-27, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. RAS was ruled out due to N-0 overloads. The new Collinsville 500 kV substation has been identified as the mitigation.

Table 3.5-26: Lone Tree-USWP-JRW-Cayetano 230 kV line on-peak deliverability constraint

Overloaded Facility	Contingency		Loading				
			BASE	SENS-01	SENS-02		
					Option 1	Option 2	Option 3
Lone Tree-USWP-JRW-Cayetano 230 kV line (Lonetree-USWP JRW)	Contra Costa-Morago #1 and #2 230 kV lines (also Base Case overload)	HSN	100%	101%	105%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
Lone Tree-USWP-JRW-Cayetano 230 kV line (USWP JRW-Cayetano)	Base Case	HSN	101%	101%	103%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
Lone Tree-USWP-JRW-Cayetano 230 kV line (USWP JRW-Cayetano)	Contra Costa-Las Positas 230 kV Line	HSN	104%	104%	106%	<100%	100%
		SSN	<100%	<100%	<100%	<100%	<100%
Lone Tree-USWP-JRW-Cayetano 230 kV line (USWP JRW-Cayetano)	Contra Costa-Morago #1 and #2 230 kV lines	HSN	111%	112%	115%	105%	104%
		SSN	<100%	<100%	<100%	<100%	<100%

Table 3.5-27: Lone Tree-USWP-JRW-Cayetano 230 kV line on-peak deliverability constraint summary

Affected transmission zones		Solano				
		Base Portfolio	S1 Portfolio	S2 Portfolio		
				Option 1	Option 2	Option 3
Renewable portfolio MW behind the constraint (installed FCDS capacity)		102 Wind	102 Wind	102 Wind	102 Wind	102 Wind
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		5.4	0	0	0	0
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0	0	0	0
Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)		500	533	642	218	201
Mitigation Options	RAS	No, N-0 overloads				
	Re-locate portfolio battery storage (MW)	Not applicable				
	Transmission upgrade including cost	Reconductor the line (\$55.1M – \$71.6M) New Collinsville 500 kV substation (\$475M – \$675M)				
Recommended Mitigation		New Collinsville 500 kV substation (\$475M – \$675M)				

Las Positas-Newark 230 kV line on-peak deliverability constraint

The deliverability of renewable and energy storage portfolio resources in the Solano-Sacramento River area is limited by thermal overloading of the Las Positas-Newark 230 kV line under N-2 conditions as shown in Table 3.5-28. This constraint was identified in baseline portfolio under HSN conditions. As shown in Table 3.5-29, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. RAS was ruled out due to the complexity. The RAS would need to encompass the larger area and requires remote monitoring. The new Collinsville 500 kV substation has been identified as the mitigation.

Table 3.5-28: Las Positas-Newark 230 kV line on-peak deliverability constraint

Overloaded Facility	Contingency		Loading				
			BASE	SENS-01	SENS-02		
					Option 1	Option 2	Option 3
Las Positas-Newark 230kV line	Contra Costa-Delta Switchyard 230kV Line	HSN	103%	101%	106%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
Las Positas-Newark 230kV line	Contra Costa-Morago #1 and #2 230kV lines	HSN	116%	115%	121%	102%	107%
		SSN	<100%	<100%	<100%	<100%	<100%

Table 3.5-29: Las Positas-Newark 230kV line on-peak deliverability constraint summary

Affected transmission zones		Solano				
		Base Portfolio	S1 Portfolio	S2 Portfolio		
				Option 1	Option 2	Option 3
Renewable portfolio MW behind the constraint (installed FCDS capacity)		102 Wind	102 Wind	102 Wind	102 Wind	102 Wind
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		5.4	0	0	0	0
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0	0	0	0
Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)		510	476	638	116	253
Mitigation Options	RAS	No, remote monitoring (RAS Guideline violation)				
	Re-locate portfolio battery storage (MW)	Not applicable				
	Transmission upgrade including cost	Reconductor the line (\$47.65M – \$62M) New Collinsville 500 kV substation (\$475M – \$675M)				
Recommended Mitigation		New Collinsville 500 kV substation (\$475M – \$675M)				

Rio Oso-SPI Jct-Lincoln 115 kV line on-peak deliverability constraint

The deliverability of renewable portfolio resources in the Sacramento River area is limited by thermal overloading of the Rio Oso-SPI Jct-Lincoln 115kV line under N-2 conditions as shown in Table 3.5-30. This constraint was identified in the baseline portfolio under HSN conditions. As

3.7 Sensitivity 2 – Offshore Wind Study

3.7.1 Introduction

The offshore wind sensitivity 2 study included the following offshore wind resources:

- Humboldt Bay: 1,607 MW
- Diablo Canyon: 4,419 MW
- Morro Bay: 2,324 MW

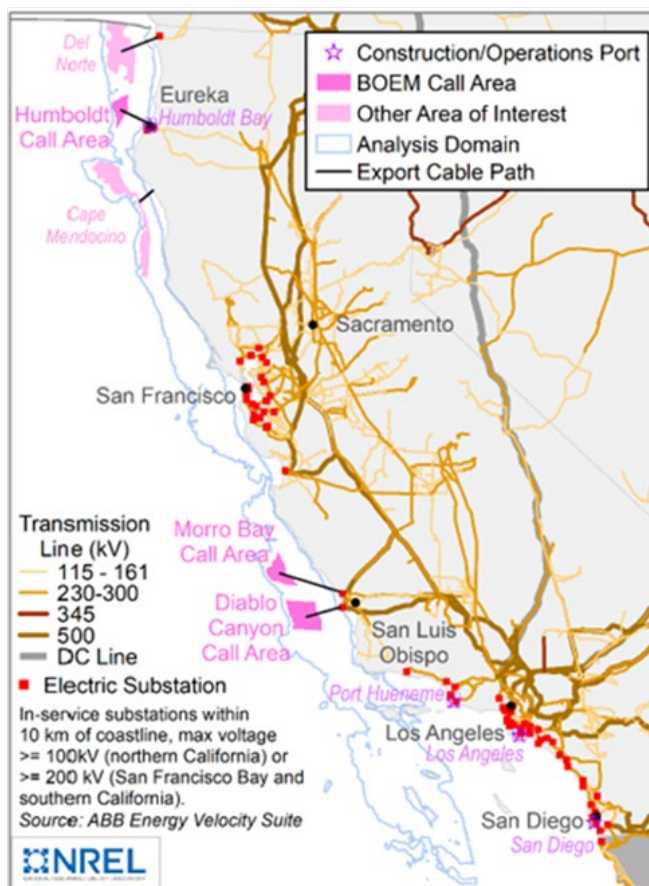
Other resources in the sensitivity 2 portfolio were similar to base portfolio and are discussed in section 3.4. Detailed studies were performed to identify the transmission upgrades required to address reliability and deliverability constraints. In addition, an offshore wind outlook assessment with the following resources was also included to evaluate the impact of accommodating the remaining offshore wind resource potential in California, at high level:

- Del Norte: 6,605 MW
- Cape Mendocino: 6,216 MW

The total offshore wind resources in the wind outlook assessment is 21,171 MW from which 14,428 MW is in the north coast and 6,743 MW is in the central coast. Figure 3.7-1 provides an approximate location of the offshore wind sites considered in this study.

The following aspects of offshore wind scenario were evaluated in this study that will be discussed in this section:

- Interconnection of the offshore wind generation to the rest of the ISO system
- On-peak deliverability assessment results
- Off-peak deliverability assessment results
- Mitigation measures to address deliverability constraints
- High level cost estimate
- High level assessment of the wind outlook with 21,171 MW of wind generation.

Figure 3.7-1: Offshore Wind Development Location Assumptions¹³⁴

3.7.2 System Interconnection Options

Considering the CPUC offshore wind modelling assumptions¹³⁵, the offshore wind projects were assumed to be connected with export cables to a substation located approximately 3 miles inland. The objective of this study was to study interconnection options to connect the assumed inland substation to the rest of the ISO system.

3.7.2.1 Diablo and Morro Bay Offshore Wind Interconnection

The initial mapping of resources to substations discussed in section 3.4.1, maps the 4,419 MW Diablo Canyon offshore wind to Diablo 500 kV substation. The same assumption is used in this study. The initial mapping however maps the 2,324 MW Morro Bay offshore wind to the Morro Bay 230 kV substation. A high-level evaluation indicated that the Morro Bay 230 kV substation does not have the required capacity and therefore the Morro Bay offshore wind was connected to a new 500 kV substation at Morro Bay looping in the Diablo – Gates 500 kV line. A schematic diagram of the interconnection of the Diablo and Morro Bay offshore wind projects to the system is provided in Figure 3.1-2.

¹³⁴ [The Cost of Floating Offshore Wind Energy in California Between 2019 and 2032 \(nrel.gov\)](#) (Page 39)

¹³⁵ http://ftp.cpuc.ca.gov/energy/modeling/Modeling_Assumptions_2021_22_TPP_Final.pdf

The advantages of AC transmission include the following:

- It is very common. The majority of bulk power transfer is done on AC line
- It doesn't need converter stations
- It can be easily looped into a new substation.

Potential challenges of AC transmission include the following:

- It requires series compensation for high-power transfers over longer distance applications
- With the same power transfer capacity, it may require a wider right-of-way compared to other technologies
- Power flow on the line is determined by the network topology and load/generation patterns and cannot be easily controlled
- Long-distance AC cables are not feasible or practical. Cable applications of 500 kV AC lines are very limited and only for very short distances.

Conventional (LCC) HVDC

The HVDC transmission technology has been used under special circumstances around the world for more than 60 years. In California, PDCI and IPPDC are two ± 500 kV Bipole LCC HVDC links connecting California to neighboring systems. PDCI transmits power over more than 850 miles and is rated at 3,210 MW N-S with evaluations performed to increase it to 3,800 MW N-S. Much higher ratings are in operation around the world.

The advantages of LCC HVDC include the following:

- Transmission over long distances with overhead lines or underground/subsea cables; there is no practical limit on how far power could be transmitted with HVDC lines
- Potentially requires smaller rights-of-way
- Power flow on the line is set by the operator
- Overload capability

Potential challenges of LCC HVDC transmission include the following:

- Requires a converter station at each end of the line; for high-power applications, the converter station may require a significant area
- The AC system the HVDC convertors are connected to should have short-circuit levels above a certain threshold, especially at the receiving end
- Most of the schemes in the world are point-to-point interconnections. "Looping in" the line for other interconnections (Multi-terminal HVDC applications) are rare
- HVDC convertors consume reactive power which is around 50-60% of the operating real power

Voltage Source Converter Based HVDC (VSC-HVDC)

VSC-HVDC technology has been used for certain DC applications for more than 20 years. Trans Bay Cable is a 400 MW VSC-HVDC link that went into service in California in 2010.

Most high-power installations of VSC-HVDC are around 1000 MW, with new projects planned for 2,000 MW. Siemens is planning a number of 2,000 MW VSC-HVDC links that will go in service in the 2026-2028 timeframe with multi-terminal capability for some of the projects¹³⁶. Higher capacity VSC-HVDC projects exist around the world but are not common.

The advantages of VSC-HVDC transmission over LCC HVDC include the following:

- The AC system the VSC-HVDC converters are connected to does not need specific minimum short circuit levels
- The converter stations are physically smaller compared to LCC HVDC stations and therefore more suitable to deliver power to urban centers
- Does not require reactive power support at the converter station
- Multi-terminal configuration is less complicated

Potential challenges of VSC-HVDC includes the following:

- The power rating is lower than LCC HVDC
- It is challenging to design schemes with overhead lines; the majority of existing applications are cable connections
- The converter station losses are higher

ISO Generation Trip/Drop Limits

The ISO Planning Standard sets the following limits with regards to generation tripping following contingencies:

- The generation drop following N-1 contingency should be limited to 1,150 MW
- The generation drop following N-2 (DCTL) contingency should be limited to 1,400 MW

These limits should be taken into account in designing a concept for interconnecting large generators to the ISO system.

Interconnection Concept for 14,428 MW of North Coast Offshore Wind

High-voltage AC lines are the most common technology for bulk power transfers. If only AC transmission lines are used, five to six 500 kV AC lines would be required to reliably transfer 14,428 MW power.

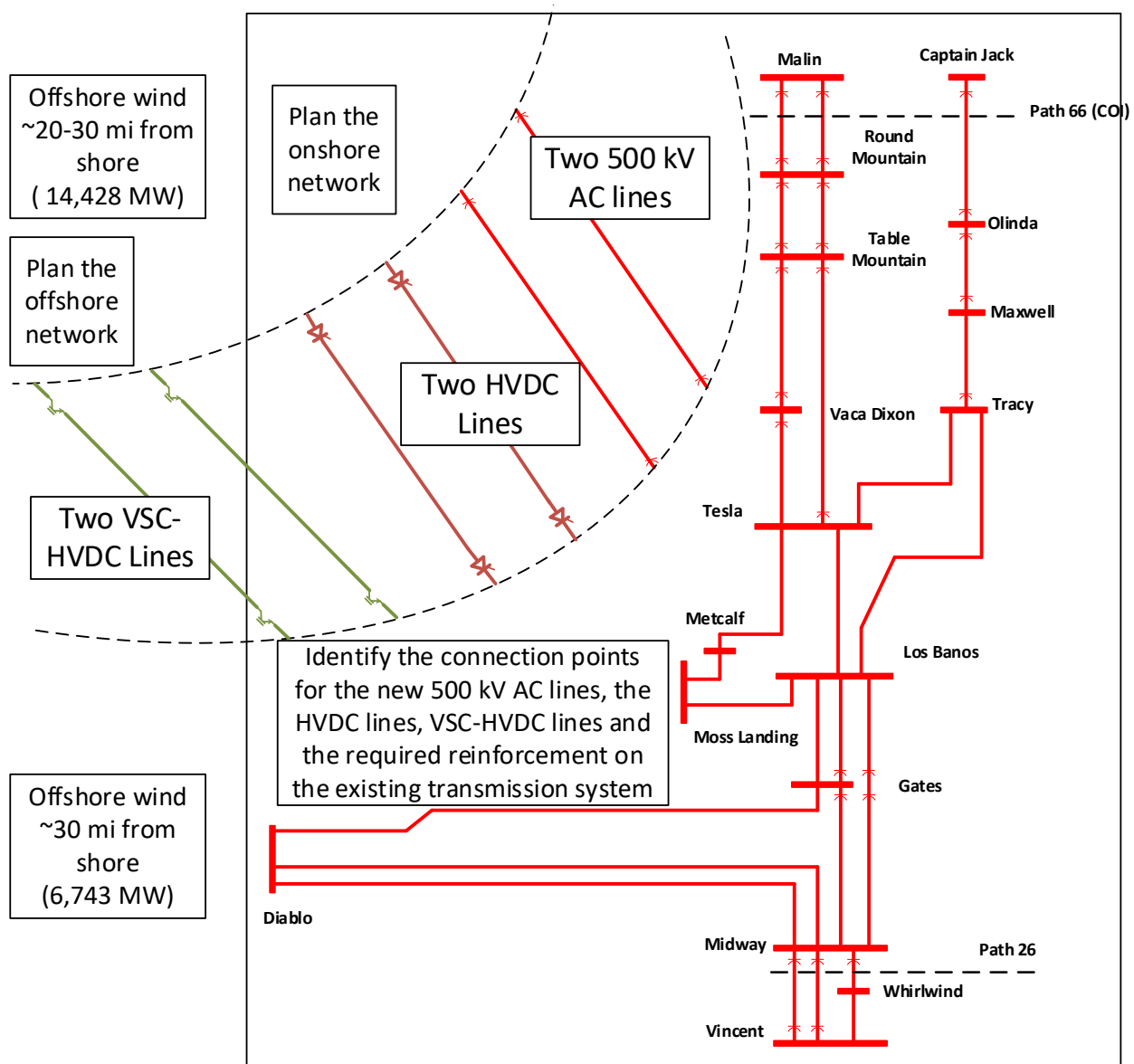
Four high-capacity LCC HVDC bipoles with short-term overload capability would have the capacity to transfer power and to meet the ISO generation drop limits.

¹³⁶ [Siemens Energy · Technical document · DIN A4 landscape – Template \(siemens-energy.com\)](#)

VSC-HVDC is suitable for delivering power to urban areas and systems with low short-circuit levels. Considering 2,000 MW maximum rating, seven or eight underground/subsea cable schemes would be required to reliably transfer the required power in this application.

Considering the advantages and challenges of each transmission technology, potentially a hybrid AC and HVDC solution concept could be explored as the preferred concept to connect the 14,428 MW of north coast offshore wind in the outlook assessment. A schematic diagram of such a hybrid system is provided in Figure 3.1-3. As shown in the figure, two high-capacity links from each technology would be required to reliably transfer 14,428 MW of power while meeting the ISO standard on generation trip limits following N-1 and N-2 contingencies.

Figure 3.7-3: Hybrid AC and HVDC Interconnection Option for North Coast Offshore Wind



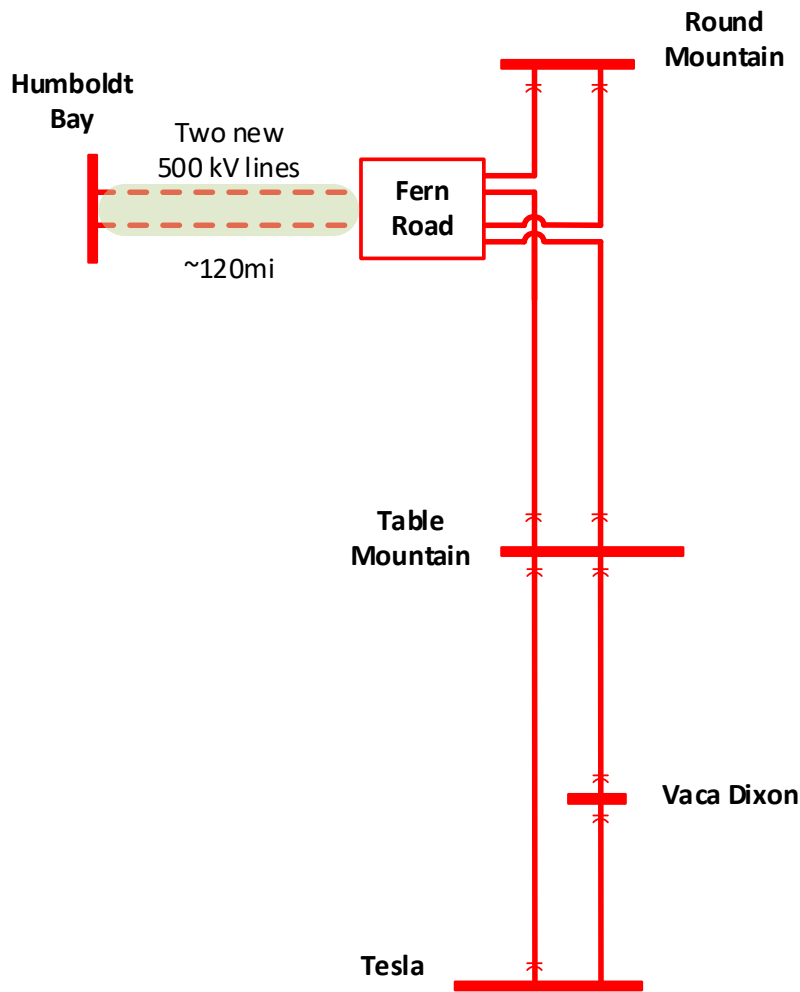
Interconnection Options for 1,607 MW Humboldt Bay Offshore Wind

Considering the overall interconnection concept for 14,428 MW of north coast offshore wind (Figure 3.7-3), three interconnection options, one for each technology, were selected for detailed deliverability studies for interconnecting just 1,607 MW of Humboldt Bay offshore wind.

Option 1: 500 kV AC line 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 DRS project that is located approximately 11 miles south of the Round Mountain substation. In this option, it is assumed two approximately 120-mile, 500-kV AC lines will interconnect the project to the Fern Road substation (Figure 3.1-4). The cost estimate for option 1 is \$1.2B.

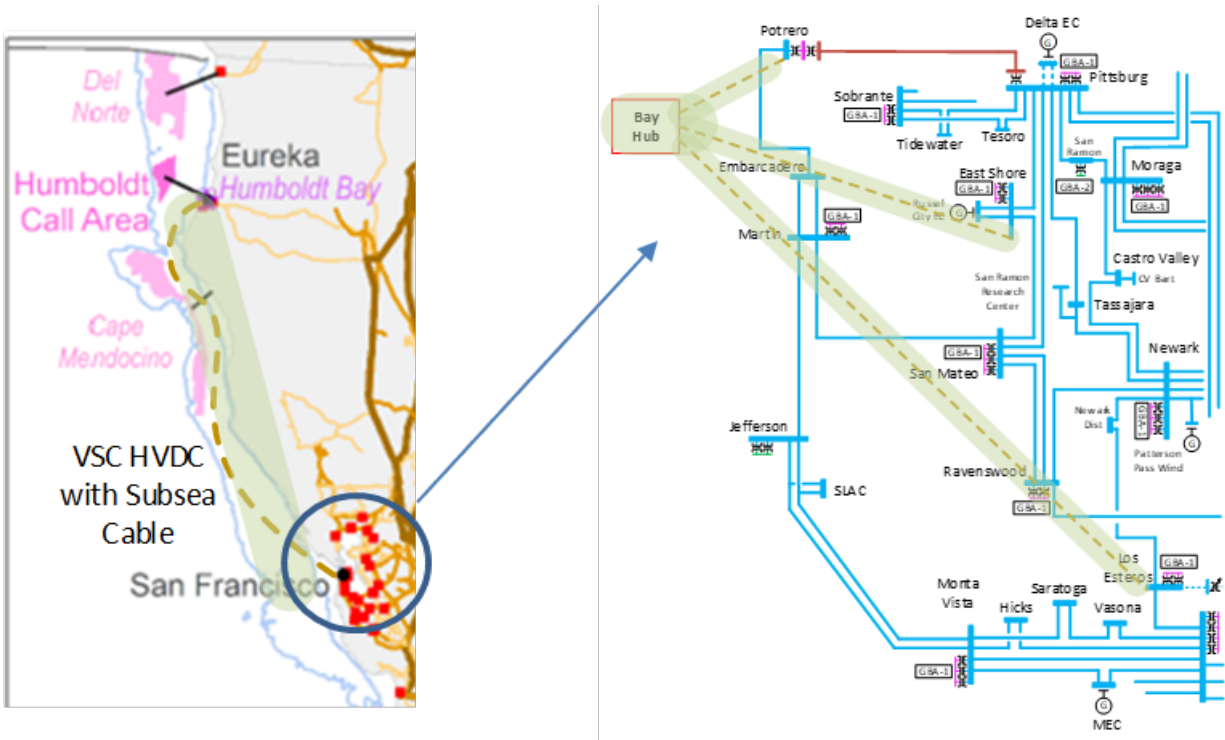
Figure 3.7-4: AC Option to Interconnect Humboldt Bay Offshore Wind (Option 1)



Option 2: 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 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 3.1-5). The cost estimate for option 2 is \$4B.

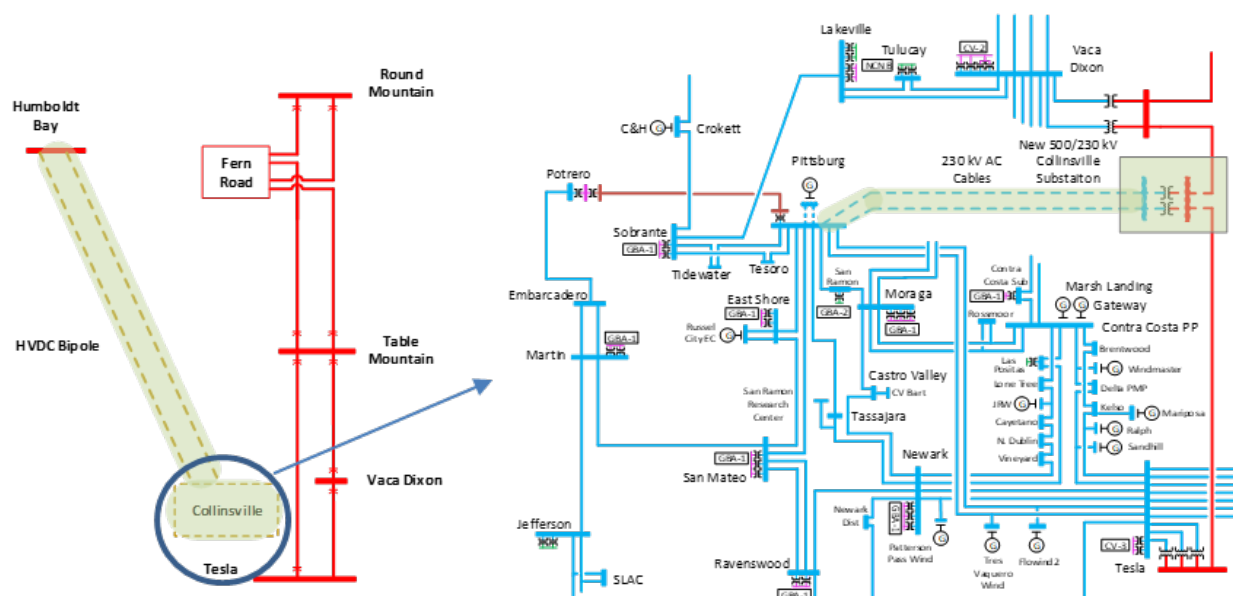
Figure 3.7-5: VSC-HVDC Option to Interconnect Humboldt Bay Offshore Wind (Option 2)



Option 3: LCC HVDC Bipole to Collinsville 500/230 kV substation

Collinsville substation is studied in prior transmission planning cycles to reduce reliance on gas generation in the Bay area. Vaca Dixon – Tesla 500 kV line is looped into it with two 230 kV connections to Pittsburg 230 kV substation. In this study it is assumed that the Humboldt Bay offshore wind will be connected to Collinsville substation with an HVDC bipole link (Figure 3.1-6). The cost estimate for option 3 is \$3B.

Figure 3.7-6: LCC HVDC Option to Interconnect Humboldt Bay Offshore Wind (Option 3)



A base case was developed for the deliverability studies for each of the above three options for the Humboldt Bay offshore wind interconnection. In all three cases, the Diablo and Morro Bay offshore wind were interconnected to the system as described earlier in this chapter. The results of the on-peak and off-peak deliverability studies are provided in the following sections.

3.7.3 On-Peak Deliverability Assessment Results

Fern Road-Table Mountain #1, #2, and Table Mountain-Vaca Dixon 500 kV line constraints

The deliverability of renewable portfolio resources in the Northern California and Humboldt Bay Offshore wind area is limited by thermal overloading of the Fern Road – Table Mountain 500kV and Table Mountain – Vaca Dixon 500 kV lines under normal (N-0) and contingency (N-1) conditions as shown in Table 3.1-1. This constraint was identified only under sensitivity 2, option 1 under HSN conditions. As shown in Table 3.1-2, 0 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint can be mitigated by building a new 500 kV line from Fern Road to Tesla.

Table 3.7-1: Fern Road-Table Mountain #1 and #2 and Table Mountain – Vaca Dixon 500kV lines on-peak deliverability constraint

Overloaded Facility	Contingency		Loading				
			BASE	SENS-01	SENS-02		
					Option 1	Option 2	Option 3
Fern Road-Table Mountain #1 and #2 500kV lines	Base Case	HSN	<100%	<100%	112%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
Table Mountain-Vaca Dixon 500 kV Line	Base Case	HSN	<100%	<100%	116%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
Fern Road-Table Mountain #1 and #2 500kV lines	Fern Road-Table Mountain #2 or #1 500kV lines	HSN	<100%	<100%	138%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
Table Mountain-Rio Oso 230 kV Line	Table Mountain-Vaca Dixon 500 kV Line	HSN	<100%	<100%	112%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
Round Mountain-Cottonwood #3 230 kV Line	Table Mountain-Vaca Dixon 500 kV Line	HSN	<100%	<100%	101%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%
North Dublin-Vineyard 230 kV line	Contra Costa-Moraga #1 and #2 230kV lines	HSN	<100%	<100%	101%	<100%	<100%
		SSN	<100%	<100%	<100%	<100%	<100%

Table 3.7-2: Fern Road-Table Mountain #1 and #2 and Table Mountain – Vaca Dixon 500kV lines on-peak deliverability constraint summary

Affected transmission zones		Northern California and Humboldt Bay Off-Shore Wind (Fern Road)				
		Base Portfolio	S1 Portfolio	S2 Portfolio		
				Option 1	Option 2	Option 3
Renewable portfolio MW behind the constraint (installed FCDS capacity)		N/A	N/A	437 Wind 1607 OSW	N/A	N/A
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		N/A	N/A	0	N/A	N/A
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		N/A	N/A	0	N/A	N/A
Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)		N/A	N/A	2,305	N/A	N/A
Mitigation Options	RAS	Not Needed		N/A, N-0 Overload	Not Needed	
	Re-locate portfolio battery storage (MW)	Not Needed		N/A	Not Needed	
	Transmission upgrade including cost	Not Needed		Build a new 500 kV line from Fern Road to Tesla (\$1.1B)	Not Needed	
Recommended Mitigation		Not Needed		Build a new 500 kV line from Fern Road to Tesla	Not Needed	

Diablo-Midway #2, #3 and Morro Bay-Gates 500 kV line constraints

The deliverability of renewable portfolio resources in the Diablo/Morro Bay Offshore wind area is limited by thermal overloading of the Diablo-Midway #2, #3 and Morro Bay-Gates 500 kV lines under normal (N-0) and contingency (N-1) conditions as shown in Table 3.1-3. This constraint was identified only for sensitivity 2 under HSN conditions. As shown in Table 3.1-4, more than 5,300 MW of renewable and energy storage would be deliverable without any transmission upgrades. The constraint can be mitigated by a number of alternatives which all will add to power transfer capacity out of the area. The recommended mitigation for the purpose of this study is to build a new 500 kV AC line from Diablo to Gates substations.

Table 3.7-3: Diablo – Morro Bay #2 and #3 and Morro Bay – Gates 500kV lines on-peak deliverability constraint

Overloaded Facility	Contingency		Loading				
			BASE	SENS-01	SENS-02		
					Option 1	Option 2	Option 3
Diablo-Midway 500 kV Lines	Base Case	HSN	<100%	<100%	112%	112%	112%
		SSN	<100%	<100%	<100%	<100%	<100%
	Remaining Diablo-Midway 500 kV Line	HSN	<100%	<100%	114%	114%	114%
		SSN	<100%	<100%	<100%	<100%	<100%
Morro Bay-Gates 500 kV Line	Base Case	HSN	<100%	<100%	125%	125%	125%
		SSN	<100%	<100%	<100%	<100%	<100%
	Diablo-Midway 500 kV Line	HSN	<100%	<100%	136%	136%	136%
		SSN	<100%	<100%	<100%	<100%	<100%

Table 3.7-4: Diablo – Morro Bay #2 and #3 and Morro Bay – Gates 500kV lines on-peak deliverability constraint summary

Affected transmission zones		Northern California and Diablo/Morro Bay Off-Shore Wind				
		Base Portfolio	S1 Portfolio	S2 Portfolio		
				Option 1	Option 2	Option 3
Renewable portfolio MW behind the constraint (installed FCDS capacity)		0	0	6,743 OSW	6,743 OSW	6,743 OSW
Energy storage portfolio MW behind the constraint (installed FCDS capacity)		0	0	0	0	0
Deliverable Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0	5,355	5,379	5,380
Total undeliverable baseline and portfolio resources, MW (Installed FCDS capacity)		0	0	1,388	1,364	1,363
Mitigation Options	RAS	Not Needed		N/A, N-0 Overload		
	Re-locate portfolio battery storage (MW)	Not Needed		N/A		
	Transmission upgrade including cost	Not Needed		<ul style="list-style-type: none"> • Diablo – North HVDC (\$1.6B) • Diablo – South HVDC (1.85B) • Second Diablo – Gates 500 kV line (\$0.4B) 		
Recommended Mitigation		Not Needed		Second Diablo – Gates 500 kV line		

3.7.4 Off-Peak Deliverability Assessment Results

Diablo-Midway #2, #3 and Morro Bay-Gates 500 kV line constraints

Portfolio resources in the Diablo/Morro Bay Offshore wind area are subject to up to around 1,350 MW of curtailment due to thermal overloading of the Diablo-Midway #2, #3 and Morro Bay-Gates lines under normal (N-0) and contingency (N-1) conditions as shown in Table 3.1-5 and Table 3.1-6. The overload can be mitigated by a number of alternatives which all will add to power transfer capacity out of the area. Building a new 500 kV AC line from Diablo to Gates substation that was recommended to mitigate on-peak deliverability constraint will also address the overload identified in the off-peak assessment.

Table 3.7-5: Diablo – Morro Bay #2 and #3 and Morro Bay – Gates 500kV lines off-peak deliverability constraint

Overloaded Facility	Contingency	Loading				
		BASE	SENS-01	SENS-02		
				Option 1	Option 2	Option 3
Diablo-Midway 500 kV Lines	Base Case	<100%	<100%	106%	121%	121%
	Remaining Diablo-Midway 500 kV Line	<100%	<100%	109%	121%	121%
Morro Bay-Gates 500 kV Line	Base Case	<100%	<100%	127%	121%	121%
	Either Diablo-Midway 500 kV Line	<100%	<100%	131%	121%	121%

Table 3.7-6: Diablo – Morro Bay #2 and #3 and Morro Bay – Gates 500kV lines off-peak deliverability constraint summary

Affected transmission zones		Northern California and Diablo/Morro Bay Offshore Wind				
		Base Portfolio	S1 Portfolio	S2 Portfolio		
				Option 1	Option 2	Option 3
Renewable portfolio MW behind the constraint		0	0	6,743 OSW	6,743 OSW	6,743 OSW
Energy storage portfolio MW behind the constraint		0	0	0	0	0
Renewable MW curtailment		0	0	1,333	1,349	1,219
Portfolio energy storage MW re-dispatched in charging mode		0	0	0	0	0
Mitigation Options	RAS	Not Needed		N/A, N-0 Overload		
	Re-locate portfolio battery storage (MW)	Not Needed		N/A		
	Transmission upgrade including cost	Not Needed		<ul style="list-style-type: none"> • Diablo – North HVDC (\$1.6B) • Diablo – South HVDC (1.85B) • Second Diablo – Gates 500 kV line (\$0.4B) 		
Recommended Mitigation		Not Needed		Second Diablo – Gates 500 kV line that was recommended to address on-peak deliverability constraints.		

3.7.5 Deliverability Assessment Summary for 8,350 MW of Offshore Wind

The study results indicated that the following transmission alternatives will facilitate the interconnection and will address any constraints and overload identified in the studies for north coast (Humboldt Bay) and central cost (Diablo and Morro Bay) offshore wind areas with a total of 8,350 MW of wind generation capacity.

Humboldt Bay (1,607 MW)

- Option 1: 500 kV AC connection to Fern Road substation and a new 500 kV line from Fern Road to Tesla. The overall cost estimate for option 1 is \$2.3B
- Option 2: VSC-HVDC connection to a Bay Hub substation with three connections to load centers in the Bay area. The overall cost estimate for option 2 is \$4.0B
- Option 3: LCC-HVDC connection to Collinsville substation, recommended for approval in this planning cycle in section 3.5.7. The cost estimate for option 3 is \$2.1B

Diablo and Morro Bay (6,743 MW)

- Connect Diablo offshore wind to Diablo 500 kV substation.
- Connect Morro Bay offshore wind to a new Morro Bay 500 kV substation with the cost estimate of \$110M.
- Without mitigation, around 5,300 MW of the Diablo/Morro Bay area offshore wind will be deliverable. Any of the following transmission projects will make the entire 6,753 MW deliverable:
 - Diablo – North HVDC with a cost estimate of \$1.6B
 - Diablo – South HVDC with a cost estimate of \$1.85B. The source of the cost estimate is the Pacific Transmission Expansion Project (PTE) submission.
 - Second Diablo – Gates 500 kV line with a cost estimate of \$0.4B

3.7.6 Outlook Assessment with 21,171 MW of Offshore Wind

The following topics are discussed at a high level for the outlook wind scenario with 21,171 MW of offshore wind development of which 14,428 MW are in the north coast of California:

- Interconnection to the ISO System
- Offshore Grid Considerations
- Increased Transfer Capacity between California and Pacific Northwest

Interconnection to the ISO System

As discussed earlier, a concept based on two high-capacity AC lines, two LCC HVDC lines, and two VSC-HVDC lines would have enough capacity to transfer 14,428 MW of north coast offshore wind out of the area. However, further reliability, deliverability, and production cost simulation studies are required to determine the optimum configuration, capacity, interconnection points, and staging of different components of required system enhancements. An optimum system enhancement plan developed in close coordination with the gas retirement and the long-term renewable resource development plans across the state.

Offshore Grid Considerations

One option for offshore wind connection to the system on the shore is to interconnect each wind project with the system through a dedicated cable. In this configuration, there would be no power flow between different offshore wind projects. An alternative approach is to have an offshore grid to interconnect a number of projects offshore and bring the aggregated power to shore. The potential advantage of such a configuration is to have fewer cables coming to the shore and to also increase the overall reliability of supply under contingency conditions. The idea has been explored in other systems such as New York¹³⁷ and Denmark¹³⁸.

It should be noted that offshore wind developments in California and other systems might have a major difference considering the depth of the water which may require solutions that are specifically designed for deep-water applications.

Increased Transfer Capacity between California and Pacific Northwest

The interconnection solution along with the mitigation measures studied in the assessment will potentially create two strong connection points in California that enable more interconnections between California and the Pacific Northwest. One strong point would be the Fern Road 500 kV substation, which —with the addition of the Fern Road–Tesla 500 kV line —will have capacity available for another connection to the Pacific Northwest similar to the Malin – Round Mountain 500 kV lines. Another strong point could be either the offshore or the onshore grid required for the 14,428 MW of north coast wind development. This will also require coordination with the offshore wind potential in the Pacific Northwest and would need to further explore the concept of an offshore grid, as indicated above, to collect the resources from the offshore wind farms off the California coast and connect to offshore wind developments in the Pacific Northwest that could also increase the transfer capabilities between the regions.

¹³⁷ [The Benefit and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York \(brattle.com\)](https://brattle.com)

¹³⁸ [A132994-2-4 Elektriske systemer for Bornholm I + II, Nordsøen II + III og Området vest for Nordsøen II + III \(ens.dk\)](#) (in Danish)

summer months only. The Panoche – Gates reactors did not show benefit for ISO ratepayers in one of the two scenarios, which was worth further investigating in future planning cycles.

4.9.4 PG&E Manning and Collinsville Upgrades

The Manning 500 kV Upgrade and the Collinsville 500 kV Upgrade were identified as policy upgrades in Chapter 3 to address transmission constraints identified in the policy on-peak deliverability assessment in the PG&E Fresno and Greater Bay areas, respectively, as well as to allow advancement of renewable generation, in the PGE& Westland/San Joaquin and Northern areas, respectively. The detailed policy assessment for the PG&E areas can be found in section 3.5.7. The production benefits of the Manning Upgrade and the Collinsville Upgrade were assessed based on the ISO TEAM methodology, as set out in this section. It should be noted that the purpose of the production benefit assessment in this section was to examine whether there is potential economic impact of the upgrades on ISO ratepayers. As the Manning and Collinsville Upgrades had been identified as policy upgrades in this planning cycle, economic justification is not needed for the approval of these two upgrades. The economic assessment results showed that these two upgrades can provided incremental production benefits for the ISO's ratepayers.

Production benefits of Manning Upgrade

The production benefits for ISO ratepayers and the production cost savings of the Manning Upgrade are shown in Table 4.9-20.

The results showed that the production benefits for ISO ratepayers of the Manning Upgrade is \$15 million per year. The present value of the production benefit is about \$218 million, assuming 7% discount rate and 50-year project life.

Table 4.9-20: Production Benefits of Manning Upgrade

	Base case	Manning Upgrade	
	(\$M)	Post project (\$M)	Savings (\$M)
ISO load payment	9,265	9,198	67
ISO generator net revenue benefiting ratepayers	4,206	4,157	-49
ISO transmission revenue benefiting ratepayers	484	480	-4
ISO Net payment	4,575	4,561	15
WECC Production cost	13,184	13,187	-3

Note that ISO ratepayer "savings" are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide "Savings" are a decrease in overall production cost. A negative saving is an incremental cost or loss.

Production benefits of Collinsville Upgrade

The production benefits for ISO ratepayers and the production cost savings of the Collinsville Upgrade are shown in Table 4.9-21.

The results showed that the production benefits for ISO ratepayers of the Collinsville Upgrade is \$10 million per year. The present value of the production benefit is about \$145 million, assuming 7% discount rate and 50-year project life.

Table 4.9-21: Production Benefits of Collinsville Upgrade

	Base case	Collinsville Upgrade	
	(\$M)	Post project (\$M)	Savings (\$M)
ISO load payment	9,265	9,251	14
ISO generator net revenue benefiting ratepayers	4,206	4,192	-14
ISO transmission revenue benefiting ratepayers	484	494	10
ISO Net payment	4,575	4,565	10
WECC Production cost	13,184	13,181	3

Note that ISO ratepayer “savings” are a decrease in load payment, but an increase in ISO generator net revenue benefiting ratepayers and an increase in ISO transmission revenue benefiting ratepayers. WECC-wide “Savings” are a decrease in overall production cost. A negative saving is an incremental cost or loss.

4.10 Out-of-State Wind Study

In the 2021-2022 planning cycle, the CPUC provided a base portfolio and two sensitivity portfolios to the ISO. The CPUC IRP Base portfolio and the Sensitivity 1 portfolio included out-of-state (OOS) resources, particularly the out-of-state wind resources in the New Mexico, Wyoming and/or Idaho areas.

The ISO wished to address the request from CPUC staff to investigate potential out-of-state implications of wind development and also be responsive in assessing the economic benefits of potential out-of-state transmission upgrades to access out-of-state wind resources, as well as to address the economic study request from LS Power for the SWIP North project (see section 4.8.4). This study addresses both topics. In this analysis, the resources have been modeled at out-of-state locations together with the appropriate transmission upgrade intended to access those resources. The benefits therefore comingle the impacts of the transmission upgrades themselves as well as the benefits of the differences in resource characteristics as well.

In contrast, as requested by the CPUC¹⁴⁸, the ISO considered only the potential impact on transmission upgrades inside the ISO footprint in assessing the potential for approval of in-state policy-driven transmission projects, as set out in chapter 3. Accordingly, the ISO modeled those

¹⁴⁸ Page 34, D.21-02-008 that transferred the portfolios to the ISO. “The CAISO, in reply comments, suggested that they could study separately the injection of the full amount of energy at both the El Dorado substation representing resources from Wyoming, Idaho, or potentially other locations, and the Palo Verde substation, presentation resources from New Mexico or other Southwest locations, delivering results for further consideration at the end of this TPP cycle. We understand this to be a unique situation where the CAISO may be able to offer optionality within the base case analysis, and therefore we will take the CAISO up on this offer and work with them to understand better the transmission buildout requirements associated with generation siting in both locations.” <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K426/366426300.PDF>

ATTACHMENT B

CAISO 2023-2024 Transmission Plan (excerpts)

2023-2024 Transmission Plan



BOARD APPROVED
May 23, 2024

Policy-Driven Projects: The ISO found the need for 7 transmission projects that are policy-driven. These total \$4.59 billion and are listed in Table ES-2. They are needed to meet the renewable generation requirements established in the CPUC-developed renewable generation portfolio's.

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

No.	Project Name	PTO Area	Geographic Area	Cost (\$M)
1	Sobrante 230/115 kV Transformer Bank Addition	PG&E	GBA	40
2	New Humboldt 500 kV Substation with 500 kV line to Collinsville [HVDC operated as AC]	PG&E	NGBA	2740
3	New Humboldt to Fern Road 500 kV Line	PG&E	NGBA	1400
4	New Humboldt 115/115 kV Phase Shifter with 115 kV line to Humboldt 115kV Substation	PG&E	NGBA	57
5	North Dublin -Vineyard 230 kV Reconductoring	PG&E	NGBA	233
6	Tesla - Newark 230 kV Line No. 2 Reconductoring	PG&E	NGBA	58
7	Collinsville 230 kV Reactor	PG&E	NGBA	58
			Total	4,586

- The ISO has included in the above transmission projects (No. 2, 3 and 4 in Table ES-2) its transmission system requirements necessary to interconnect the offshore wind resources in the Humboldt call area as well as the downstream transmission upgrades (No. 5, 6 and 7 in Table ES-2) necessary to facilitate deliverability to the loads.

Economic-Driven Projects: The ISO conducted several economic studies investigating opportunities to reduce total costs to ratepayers through transmission upgrades not otherwise needed for reliably accessing renewables and serving load. No projects driven solely by economic considerations are being recommended in this plan.

Competitive Transmission Procurement: The ISO federal tariff sets out a competitive solicitation process for eligible reliability-driven, policy-driven and economic-driven regional transmission facilities found to be needed in the Plan. The following projects – included in Table ES-2 above – are eligible for competitive solicitation, and the ISO will provide a schedule for those processes in May, 2024:

- New Humboldt 500 kV Substation with 500 kV line to Collinsville (HVDC operated as AC); and
- New Humboldt to Fern Road 500 kV Line

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

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Hopland 115/60 kV transformer bank	Base	2	0	0	62	Maintenance Project
	Sensitivity	1	22	0	466	
Geysers56-MPE Tap 115 kV	Base	1	0	0	119	This constraint is a local constraint and therefore will be addressed in the GIP.
	Sensitivity	0	0	0	0	
Ukiah-Hopland-Cloverdale 115 kV (Ukiah sub 115kv to Hopland Jct 115kv)	Base	1	0	0	217	This constraint is a local constraint and therefore will be addressed in the GIP.
	Sensitivity	206	432	614	34	
Cascade-Deschutes 60 kV Line	Base	6	5	0	28	This constraint is a local constraint and therefore will be addressed in the GIP.
	Sensitivity	1	22	0	29	
Fulton - Hopland 60 kV (Hopland Jct 60 kV to Cloverdale Jct 60 kV to Geysers Jct 60 kV)	Base	2	232	84	151	Existing LDNU
	Sensitivity	206	432	614	34	

Based on the constraints identified in Table 3.5-2, there are no policy-driven upgrades identified in the North of Greater Bay interconnection planning areas. There is an existing maintenance project for the Hopland 115/60 kV bank. There is an existing LDNU that will address the Fulton-Hopland 60 kV line.

Off-Shore Wind Deliverability Baseline Assessment

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 is no existing bulk substation in the vicinity of Humboldt offshore wind. Eight options in the baseline and sensitivity portfolios were considered to interconnect Humboldt offshore wind to the rest of the system (Figure 3.5-2). These options along with the study results are detailed in the following sections.

Figure 3.5-2: Interconnection options considered for 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

Table 3.5-3: Humboldt Offshore Wind related On-Peak Deliverability Constraints in Base Portfolio

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%
Fern Rd – Table Mountain 500 kV line #1	Base Case	107%	<100%	<100%	<100%
	OLINDA-TRACY 500KV	106%	<100%	<100%	<100%
Fern Rd – Table Mountain 500 kV line #2	Base Case	107%	<100%	<100%	<100%
	OLINDA-TRACY 500KV	107%	<100%	<100%	<100%
Table Mountain – Tesla 500 kV line	TABLE MTN-VACA 500KV	114%	<100%	<100%	<100%
Vaca – Collinsville 500 kV line	TABLE MTN-TESLA 500KV	106%	<100%	<100%	<100%
Collinsville – PittsburgE 230kV line	Base Case	106%	112%	<100%	<100%
Collinsville – PittsburgF 230kV line	Base Case	<100%	110%	<100%	<100%
	COLLINSVILLE-PITTSBURG-E #1 230KV	124%	130%	<100%	106%
North Dublin -Vineyard 230 kV	CONTRA COSTA-LAS POSITAS 230KV	<100%	103%	100%	<100%
Cayetano-Lone Tree (USWP-Cayetano) 230kV Line	TESLA-NEWARK #1 230KV & TESLA-RAVENSWOOD 230KV	100%	<100%	<100%	<100%
Tesla - Newark 230 kV Line No. 2	TESLA-NEWARK #1 230KV & TESLA-RAVENSWOOD 230KV	<100%	107%	104%	<100%
Henrietta-GWF 115 kV Line	HELM-MCCALL 230KV & HENTAP2-MUSTANGSS #1 230KV	<100%	<100%	<100%	103%
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%
Cortina - Mendocino 115 kV Line (Indian Valley – Lucern)	EAGLE ROCK-CORTINA & EAGLE ROCK-REDBUD LINES (2)	<100%	<100%	101%	<100%
Eagle Rock - Cortina 115 kV (Cortina to Highland)	CORTINA-MENDOCINO #1 115KV	<100%	<100%	100%	<100%
Fulton - Hopland 60 kV (Geyser Jct to Fitch Mt. Tap)	GEYSERS #9-LAKEVILLE & EAGLE ROCK-FULTON-SILVERADO LINES	<100%	<100%	104%	100%

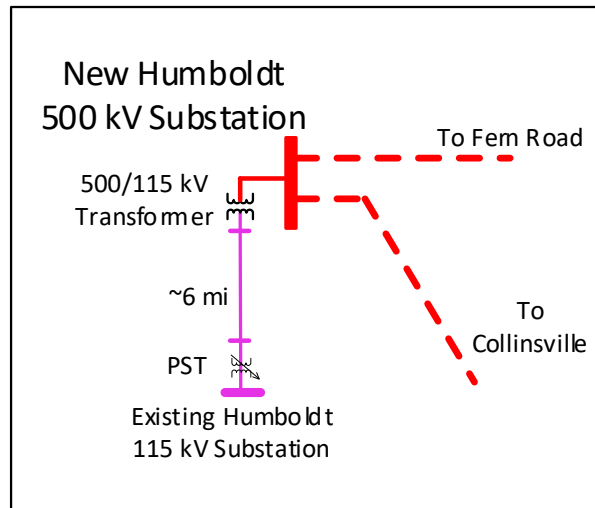
Table 3.5-4: Summary of potential mitigations and cost estimates

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 lines from Cottonwood substation around 120 miles away. To enhance the resiliency of the Humboldt 115 kV system and allow for the retirement of gas generation in the long term, in all alternatives the ISO is proposing to provide another supply to the area from the Humboldt 500 kV substation. The interconnection includes a 500/115 kV transformer at Humboldt 500 kV substation, a 115 kV line from Humboldt 500 kV to existing Humboldt 115 kV substation, and a 115kV/115 kV phase shifting transformer (PST) at Humboldt 115 kV substation. The PST will help to control the flow and prevent overload as the amount of offshore wind generation varies in real time operation. The schematic diagram of the interconnection is provided in Figure 3.5-2

Figure 3.5-2: 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 3.5-3, 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 115 kV/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 an estimated in-service date of 2034⁴⁷.

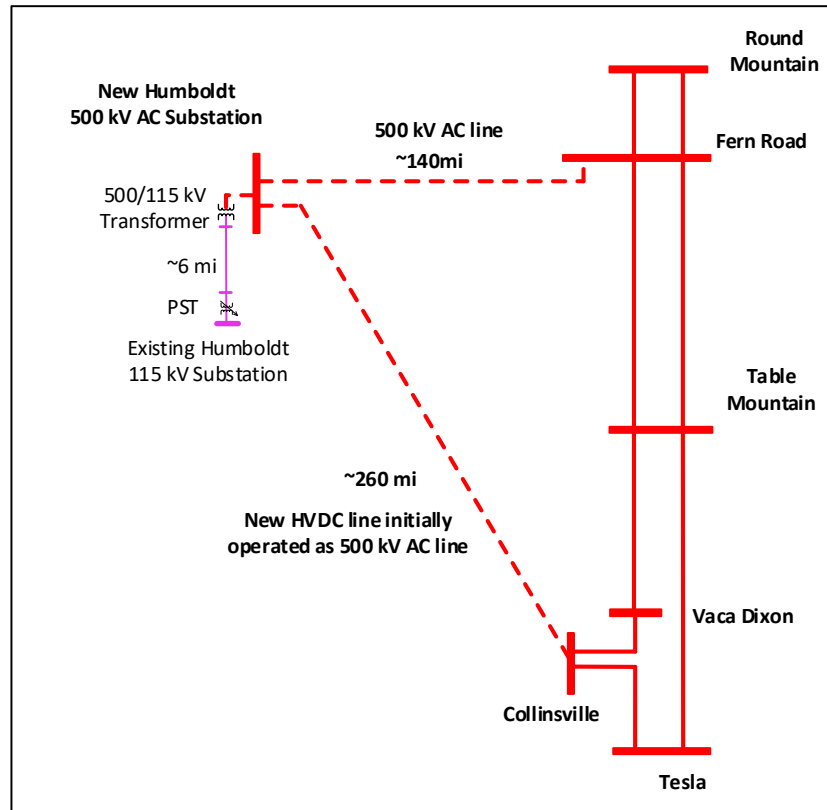
The ISO acknowledges and appreciates stakeholder concerns expressed through the transmission planning stakeholder process regarding the inherent uncertainty with the development of new technologies such as floating offshore wind off the California coast. In balancing the need to engage promptly on long lead time transmission yet remain in step with the numerous other parallel development paths needed to enable offshore wind to develop, the ISO is committed to both seeking to prudently manage expenditures that could be the subject of cost recovery processes, as well as providing industry transparency on the pace of transmission development activities and associated cost exposure. Accordingly, the functional specifications for these projects set out additional informational expectations to facilitate these efforts, and the ISO will explore how best to provide industry transparency once a project sponsor has been selected through the ISO's competitive process.

The CEC has posted under its AB525 Reports webpage⁴⁸ a high-level corridor assessment related to the development of potential electric transmission infrastructure needed to access wind energy in federal waters offshore Humboldt County.

⁴⁷ 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.

⁴⁸ <https://www.energy.ca.gov/data-reports/reports/ab-525-reports-offshore-renewable-energy>

Figure 3.5-3: Overall Recommended Alternative to Interconnect Humboldt to Fern Road and Collinsville

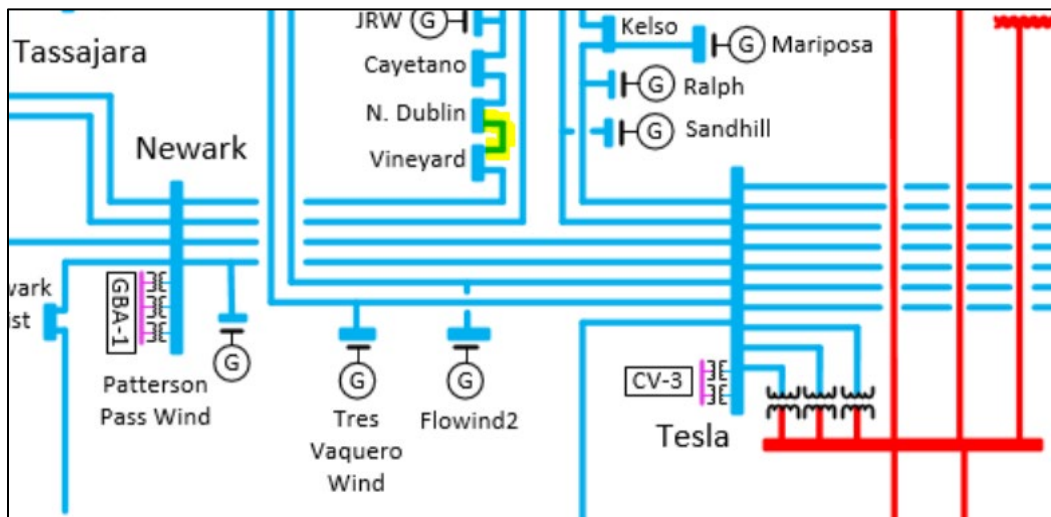


Recommended additional downstream mitigations needed for the Alternative E are identified below.

North Dublin -Vineyard 230 kV Reconductor

To mitigate P1 overloads identified as part of Interconnection Alternative E, the ISO is recommending approval of the North Dublin – Vineyard 230 kV reconductoring project. This project will cost \$116M - \$232M and take an estimated 24 months to complete. The scope includes reconductor the 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 upgraded to achieve the new line rating.

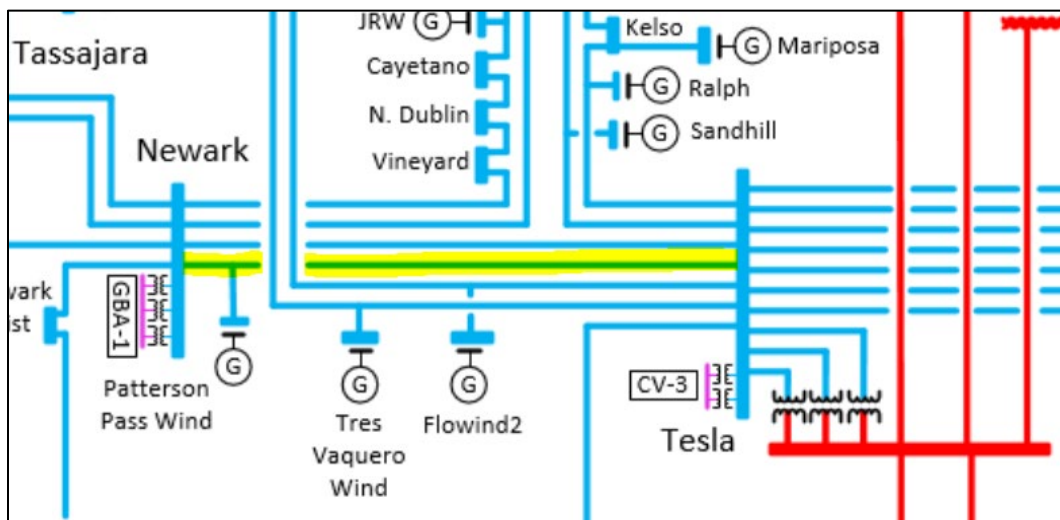
Figure 3.5-4: Recommended North Dublin – Vineyard 230 kV Reconductor



Tesla - Newark 230 kV Line No. 2 Reconductor

To mitigate overloads identified as part of Interconnection Alternative E, the ISO is recommending approval of the Tesla - Newark 230 kV line No 2 reconductoring project. The project will cost \$29M - \$58M and take an estimated 54 months to complete. The scope includes reconductoring of the Tesla –Newark #2 230 kV line - From 024/148 to Newark (approximately 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.

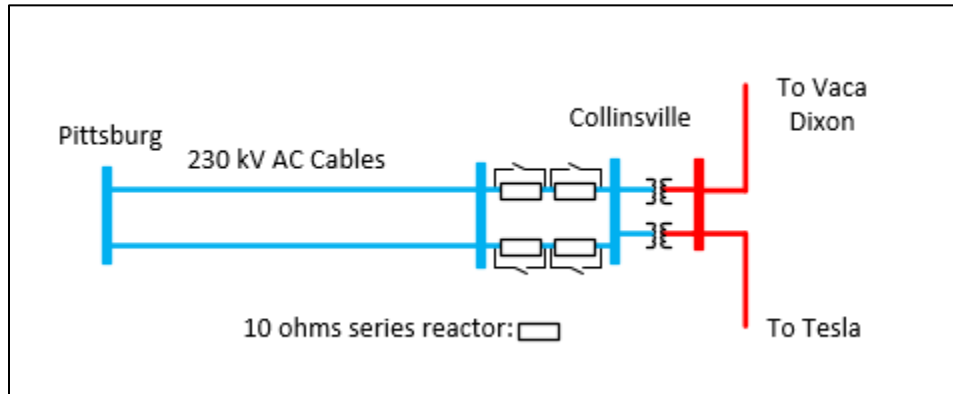
Figure 3.5-5: Recommended Tesla – Newark 230 kV line No 2 Reconductor



Collinsville 230 kV Reactor

To mitigate overloads identified as part of Interconnection Alternative 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 3.5-6: Collinsville 230 kV Reactor



ATTACHMENT C

CAISO 2024-2025 Transmission Plan (excerpts)



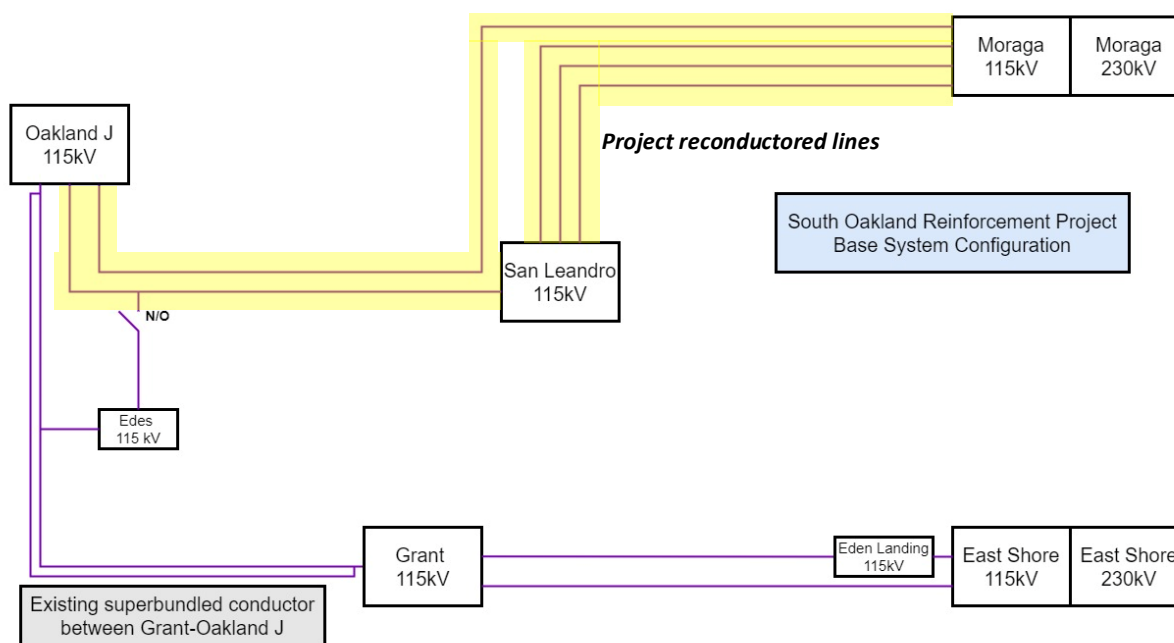
California ISO

2024-2025 TRANSMISSION PLAN

BOARD APPROVED
May 30, 2025



Figure 2.5-24: South Oakland Reinforcement



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

Greater Bay Area 500 kV Transmission Reinforcement

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

Recent planning cycles have shown a significant increase in load demand, driven by factors such as transportation electrification, fuel substitution, and anticipated large load

interconnections in various areas within the GBA. According to load forecasts, a major ramp-up in demand is expected in the long-term, particularly in scenarios beyond 2034. The anticipated increase in load significantly surpasses the available transmission resources and internal generation capacity. The latest long-term Local Capacity Requirement (LCR) study indicates a deficiency of nearly 5,000 MW in the 2039 scenario.

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

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

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

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

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

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

ATTACHMENT D

CAISO 2022-2023 Transmission Plan (excerpts)



2022-2023 TRANSMISSION PLAN



BOARD APPROVED
May 18, 2023

Morro Bay area offshore wind. The ISO will continue to coordinate with PG&E and the offshore resource developers, which were the successful federal Bureau of Ocean Energy Management (BOEM) lease bidders, for the interconnection point for the Morro Bay area offshore wind.

The base resource portfolio provided by the CPUC for the 2022-2023 Transmission Plan does not support the need for transmission capacity from the North Coast in this year's studies, with 100-150 MW of offshore wind mapped to the Humboldt area. The need for new transmission from the North Coast area was identified in studying the sensitivity portfolio. The ISO also notes that the base portfolio for the 2023-2024 transmission plan will necessitate new transmission, with 1.6 GW of offshore wind mapped to the north coast/Humboldt area.⁶⁸

Given the resource portfolios provided for this year's transmission planning studies and the state's progress of resource development planning activities (supply chains, harbors, etc.) with the CEC AB 525 report due in June 2023, the ISO is not recommending approval of transmission solutions in this planning cycle and will look instead to advancing upgrades in the next planning cycle. The assessment of alternatives in this planning cycle was conducted on the sensitivity portfolio and documented in Appendix F and will assist in being positioned to make a decision for the recommended transmission for the North Coast in the 2023-2024 Transmission Plan.

3.8 CPUC Request to CAISO in Accordance with SB 887

The CPUC submitted a letter⁶⁹ to the ISO on January 13, 2023 in accordance with SB 887 indicating the following.

“Pursuant to Senate Bill 887 (Becker, 2022), this letter requests the California Independent System Operator to (1) identify, based as much as possible on studies and projections completed before January 1, 2023, by the CAISO, the CPUC and the California Energy Commission, the highest priority transmission facilities that are needed to allow for increased transmission capacity into local capacity areas to deliver renewable energy resources or zero-carbon resources that are expected to be developed by 2035, and (2) consider whether to approve such transmission projects as part of the CAISO's 2022–23 transmission planning process.”

The ISO addressed this request, by considering the following sources of relevant information:

- The two-year study process conducted through the 2018-2019 and the 2019-2020 transmission plan specifically undertaken to explore options and opportunities to reduce reliance on – primarily gas-fired – local capacity requirements in the ISO's local capacity areas and sub-areas. That work specifically prioritized areas relying on natural gas and/or petroleum, risk of retirement, and proximity to disadvantaged communities;
- Economic planning studies conducted in the 2020-2021 Transmission Plan (where detailed economic studies explored reducing local capacity requirements in the Greater

⁶⁸ CPUC Decision (D.) 23-02-040 adopted on February 23, 2023.

⁶⁹ <http://www.caiso.com/InitiativeDocuments/Letter-2022-2023-Transmission-Planning-Process-Jan%2013,%202023.pdf>

ATTACHMENT E

**Appendix A to the Approved Project Sponsor Agreement for the
Collinsville 500/230 kV Substation Project**

Appendix A

Project Details

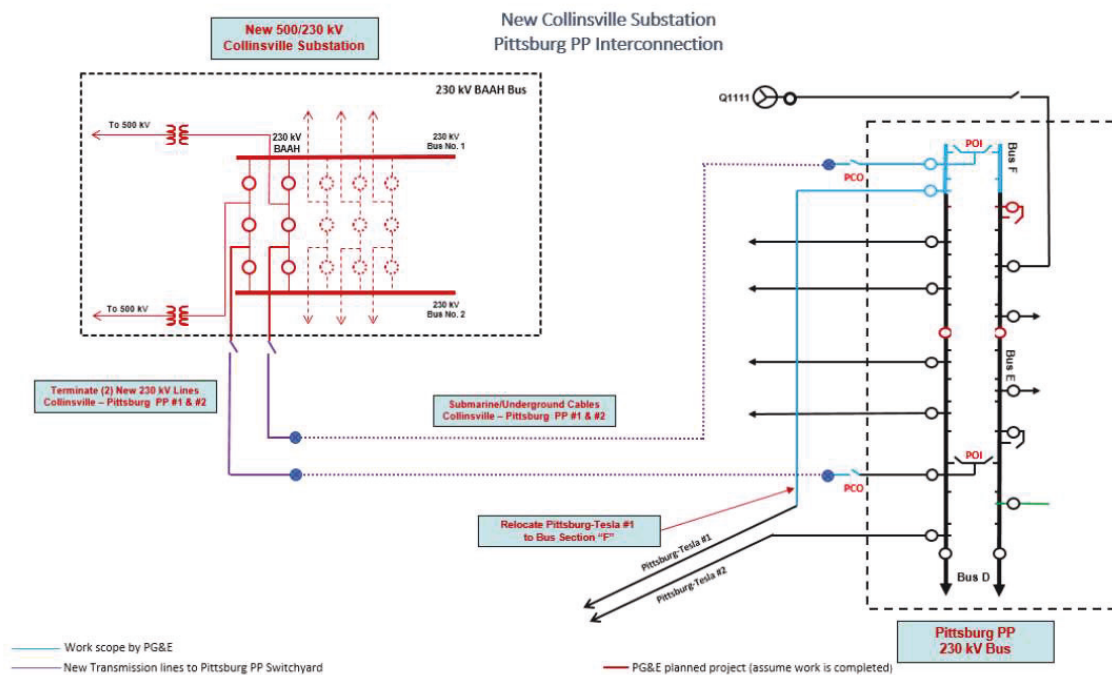
1. Description

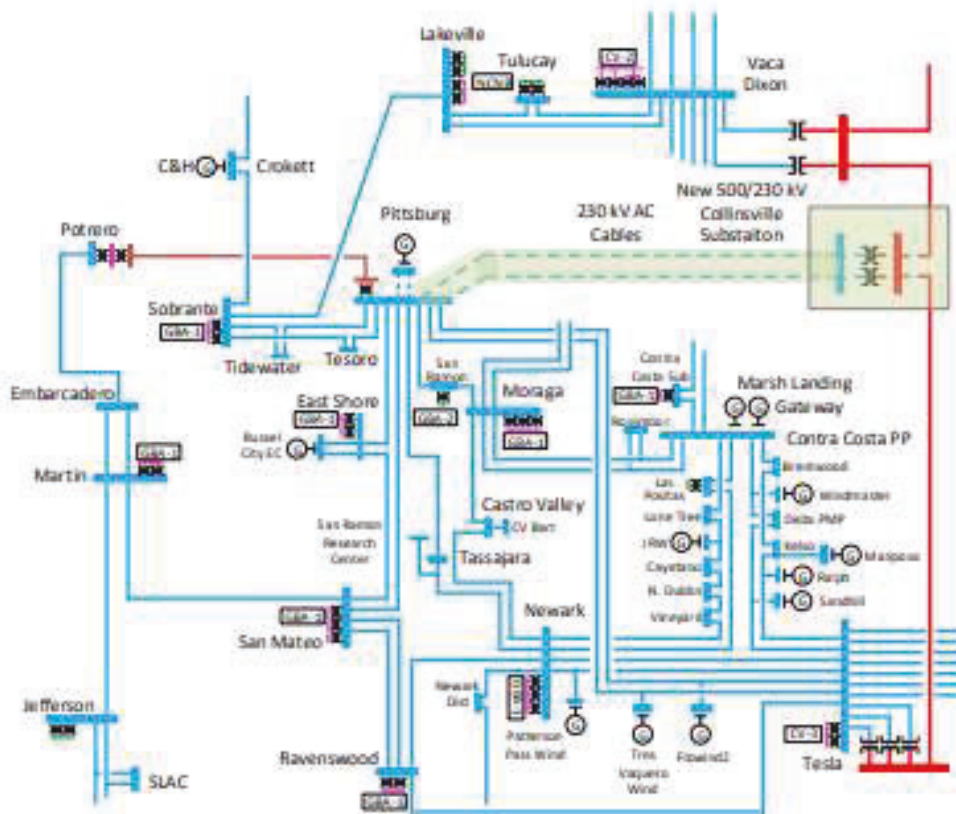
In the 2021-2022 Transmission Plan, CAISO identified a policy-driven need for the Collinsville 500/230 kV Substation Project to address multiple overloads on the 230 kV corridor between Contra Costa and Newark under normal, N-1 and N-2 contingency conditions. This Project provides additional supply from the 500 kV system into the northern Greater Bay Area to increase reliability and advance additional renewable generation.

The Collinsville 500/230 kV Substation Project was approved by the CAISO Board of Governors on March 17, 2022. CAISO selected LS Power Grid California, LLC as the Approved Project Sponsor on January 23, 2023. The Project is to be in service by June 1, 2028.

As depicted in the schematic diagrams below, the Project scope includes the following facilities:

- A new Collinsville 500/230 kV substation 500/230 kV Transformers
- Two new 230 kV circuits from Collinsville to Pittsburg
- The Collinsville substation shall be configured to permit the installation of a 20 ohm series reactor on each 230 kV circuit in the future.





The Approved Project Sponsor will design, install, own and maintain the 500/230 kV Collinsville substation and the two new 230 kV transmission lines connecting the Collinsville and Pittsburg substations. Subject to the definition of Excluded Costs herein, the Approved Project Sponsor will be responsible for owning and maintaining the protection equipment located within the Collinsville substation that is designated for the protection of the incoming transmission lines, will coordinate with PG&E regarding the specifications and the details of the associated line protection (e.g., current differential, directional comparison, etc.), and will work with PG&E to develop relay logic and detailed relay settings.

The Approved Project Sponsor will be responsible for installing (and will own and maintain) 15 – 17 ohms¹ series capacitors on the Collinsville – Tesla line to be installed at Collinsville.

As the Project includes building new transmission facilities with voltage level over 200 kV, the Approved Project Sponsor will be responsible for completing the WECC Progress Report and other WECC processes that may be required for this Project to consider effects to other systems. All incremental costs incurred by the Approved

¹ Note: Proposal basis was 15 ohms. After Interconnecting PTO determines what impedance is required at Collinsville, incremental costs incurred by the Approved Project Sponsor associated with a design modification required by Interconnecting PTO shall be Excluded Costs as defined in Appendix E.

Project Sponsor associated with such studies and processes shall be Excluded Costs as defined in Appendix E.

The Collinsville Substation will be designed to accommodate future expansion, it being understood that the items labeled as “Ultimate” in the functional specification in Section 2 below are informative for such future expansion but are not part of the Project.

To enable interconnection of the Project, the Interconnecting PTO will be responsible for:

- Looping in the Vaca Dixon – Tesla 500 kV line into Collinsville substation.
- In post Project configuration, series capacitors may need to be added/modified to ensure:
 - (a) no 500 kV line section is compensated above 75% to meet PG&E protection standards, and
 - (b) the overall compensation on Vaca Dixon – Tesla path will remain the same as the existing system at 75%.
 PG&E will adjust the existing series capacitors at Vaca Dixon to meet the above two requirements.
- In addition, PG&E will also upgrade the terminal equipment that is currently limiting the line rating.

The facilities that are the responsibility of the Interconnecting PTO are further described in Sections 3, 4 and 5 below.

2. Functional Specifications

Collinsville Substation

Nominal Phase to Phase Voltage: 500 kV and 230 kV

Typical Phase to Phase Operating Voltage: 535 kV and 235 kV

500 kV and 230 kV Initial Bus Configuration: Breaker and a half (BAAH)

500 kV and 230 kV Ultimate Bus Configuration: BAAH

Initial Number of 500 kV Lines: 2 Ultimate Number of 500 kV Lines: 6

Initial Number of 500 kV CBs: 6 Ultimate Number of 500 kV CBs: 12

Initial Number of 230 kV Lines: 2 Ultimate Number of 230 kV Lines: 6

Initial Number of 230 kV CBs: 6 Ultimate Number of 230 kV CBs: 15

Initial Minimum Bus Ampacity: 4000A Ultimate Bus Ampacity: 4000A

Minimum CB Ampacity: 3000A

Minimum CB Interrupting Capability: 63 kA

Transfer Bus Required (SBSB only): N/A

Station Minimum BIL: 900 kV for 230 kV and 1,800 kV for 500 kV side.

Initial Reactive Power Requirements: None

Ultimate Reactive Power Requirements: None

Telemetry Requirements: Install necessary equipment, including RTUs to monitor the typical bulk power elements such as MW, MVar, and phase currents (Amps) at each line and also voltages (kV)² at lines and buses and all circuit breaker (CB) status/control, protection relays statuses and alarms. The installed equipment must be capable of transmitting information to the appropriate control center.

Latest In Service Date: June 1, 2028

Low Profile Required: Subject to local permitting requirements

Gas Insulation Required: No, but if proposed shall be enclosed

Initial Number of Transformers: Two 3-phase banks with an installed spare, single phase units are permissible with one single phase spare

Ultimate Number of Transformers: Two 3-phase banks with an installed spare, single phase units are permissible with one single phase spare

Transformer Nominal Low Winding Phase to Phase Voltage: 235 kV to match PG&E operation

Tertiary Winding Required: No

Nominal Voltage Rating: N/A

Primary Voltage Winding (wye, grounded wye, delta, etc): Grounded Wye

Secondary Voltage Winding: Grounded Wye

Tertiary Voltage Winding: Corner Grounded Delta

Maximum Transformer % IZ: 19% Minimum Transformer %IZ: 15%

Minimum Transformer Normal Rating: 1500 MVA

Minimum Transformer 4-hour Emergency Rating: 1800 MVA

LTC Required: No

No Load Taps Required: 5 NLTs with two 2.5% taps above & below nominal voltage of 235 kV

CIP 14 requirement: The substation perimeter shall be fenced by a solid wall

Minimum Series Capacitor Continuous Ampacity - Summer: 2700 A

Minimum Series Capacitor Continuous Ampacity – Winter: 3000 A

Minimum Series Capacitor 30 Minute Emergency Ampacity – Summer: 3600 A

Minimum Series Capacitor 30 Minute Emergency Ampacity – Winter: 4000 A

² [California ISO - Metering and telemetry \(caiso.com\)](http://caiso.com)

230 kV Transmission Line Functional Specifications - Collinsville – Pittsburg lines

Line Terminus 1: Collinsville 230 kV Bus

Line Terminus 2: Pittsburg Substation 230 kV Bus

Nominal Phase to Phase Voltage: 230 kV

Minimum Line Continuous Ampacity - Summer: 2100 Amps per circuit

Minimum Line Continuous Ampacity – Winter: 2100 Amps per circuit

Minimum Line 4 Hour Emergency Ampacity – Summer: 3500 Amps per circuit

Minimum Line 4 Hour Emergency Ampacity – Winter: 3500 Amps per circuit

Approximate Line Impedance: $(0.000016 \text{ to } 0.00002) + j(0.00026 \text{ to } 0.00032)$ pu/mile
(100 MVA base).

Approximate Line Length: TBD depending on the location of the Collinsville substation

Latest In Service Date: June 1, 2028

Transmission Line Minimum BIL: 900 kV with solidly grounded systems

Minimum ROW Width: Per applicable codes

Governing Design and Construction Standards: (GO 95, NESC Code, applicable municipal codes)

Overhead Line Construction Requirements

Support Structures: Single or double circuit structures

Shield Wire Required: Optical ground wire (minimum 6 pairs of fibers)

Failure Containment Loading Mitigation (anti-cascade structures, etc.): Per applicable codes

Shield Wire Ground Fault Withstand Ampacity: Coordinate with interconnecting entities

Aeolian Vibration Control (Conductor and Shield Wire): Vibration dampers must be installed on all conductors and overhead shield wires, with the exception of slack spans.

Underground / Submarine Line Construction Requirements

Duct Bank: With the exception of the submarine portion, the underground cable shall be located in a duct bank with a minimum of one additional spare conduit per circuit.

Design Ambient Air Temperature: 40°C

3. Transmission Interconnection Facilities

On February 2, 2023, the Approved Project Sponsor submitted its request to the Interconnecting PTO (“PG&E”) to interconnect its new facilities to the Pittsburg 230 kV substation and to the Vaca Dixon - Tesla 500 kV transmission line.

For the interconnection to the existing Vaca Dixon - Tesla 500 kV line, PG&E will be responsible for bringing the new transmission line extensions up to a point within 100 feet of the new Collinsville substation fence. The new line extensions will terminate on a dead end structure(s) to be owned by PG&E. The Approved Project Sponsor will be responsible for (and will own and maintain) the facilities from this last dead end structure(s) into the Collinsville substation.

For the interconnection of the new Collinsville – Pittsburg 230 kV lines to the Pittsburg 230 kV substation, PG&E will be responsible for installing the new transmission line segments from the Pittsburg 230 kV bus up to a point within 100 feet of the Pittsburg substation property line. These new line segments will terminate on a dead end structure(s) to be owned by PG&E. The Approved Project Sponsor will be responsible for (and will own and maintain) the facilities from this last dead end structure(s) back to the Collinsville substation.

Deviations on the location and ownership of the aforementioned dead end structures may be modified by mutual agreement between CAISO, PG&E and Approved Project Sponsor.

4. Network Upgrades

For the adjustment of the existing series capacitors on the Vaca Dixon– Tesla 500 kV line, PG&E will be responsible for adjusting the series capacitors to be in the range of 10-12 ohms depending on the location of the Collinsville substation. The series capacitors may need to be added or modified to ensure (a) no 500 kV line section is compensated above 75% to meet PG&E protection standards, and (b) the overall compensation on Vaca Dixon – Tesla path will remain the same as the existing system at 75%. In addition, PG&E will also upgrade the terminal equipment that is currently limiting the line rating.

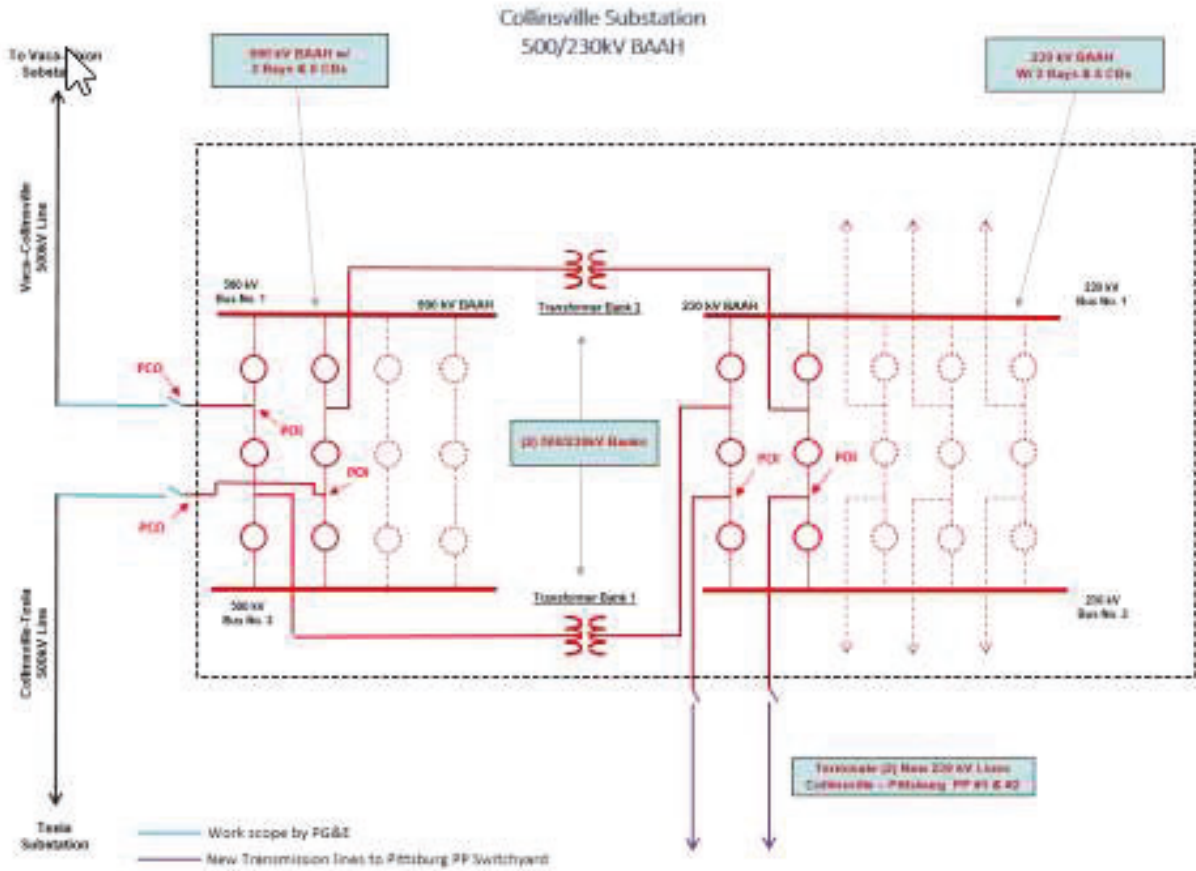
If system studies identify any required Network Upgrades, the cost of such Network Upgrades shall be Excluded Costs as defined in Appendix E.

5. Distribution Upgrades

If any Distribution Upgrades are determined to be required to support the Project, the Transmission Interconnection Facilities, or any Network Upgrades, the cost of such Distribution Upgrades shall be Excluded Costs as defined in Appendix E.

6. Diagram of Project

A preliminary Collinsville Substation schematic and general location diagram for the Project are given below. Dashed lines inside the substation boundary are future expansions and are not part of the Project..





7. Project Team

Approved Team Members:

LS Power Grid California, LLC:

- Paul Thessen – Executive Management
- Mark Milburn – Project Director
- David Wilson – Regulatory, Environmental, and Compliance Manager
- Andrew Scott – Engineering and Procurement Manager

Major Equipment Suppliers/Contractors:



8. Affected System

Pacific Gas and Electric Company

9. Additional Understandings

- a. CAISO acknowledges that its standard practice is to treat all materials received from an approved project sponsor pursuant to an Approved Project Sponsor Agreement as confidential, and will apply that standard practice to the Approved Project Sponsor with respect to this Agreement. Notwithstanding Article 19 of this Agreement, documents will not need to be marked or designated as Confidential Information for this practice to apply.
- b. CAISO acknowledges that for the purposes of Section 5.5.5 and Section 12.5 of this Agreement, the applicable team members or vendors subject to the requirements of Section 5.5.5 and Section 12.5 are those team members and vendors identified in Section 7 of Appendix A only. In the event the Approved Project Sponsor notifies CAISO pursuant to Section 5.5.5 of a change to a team member identified in Section 7 of Appendix A, CAISO shall not unreasonably withhold approval of such change. If CAISO does not object to any change noticed under Section 5.5.5 or 12.5 within ten (10) calendar days of receiving such notice, the change shall be deemed approved.
- c. CAISO shall cooperate with any assignment for collateral security by reasonably responding to reasonable requests for estoppel certificates, consents, and acknowledgements.
- d. Except to the extent the provisions of this Section 9 of Appendix A are also included in the Transmission Control Agreement, the provisions of this Section 9 of Appendix A shall survive termination of this Agreement.