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TRANSMISSION IN CALIFORNIA

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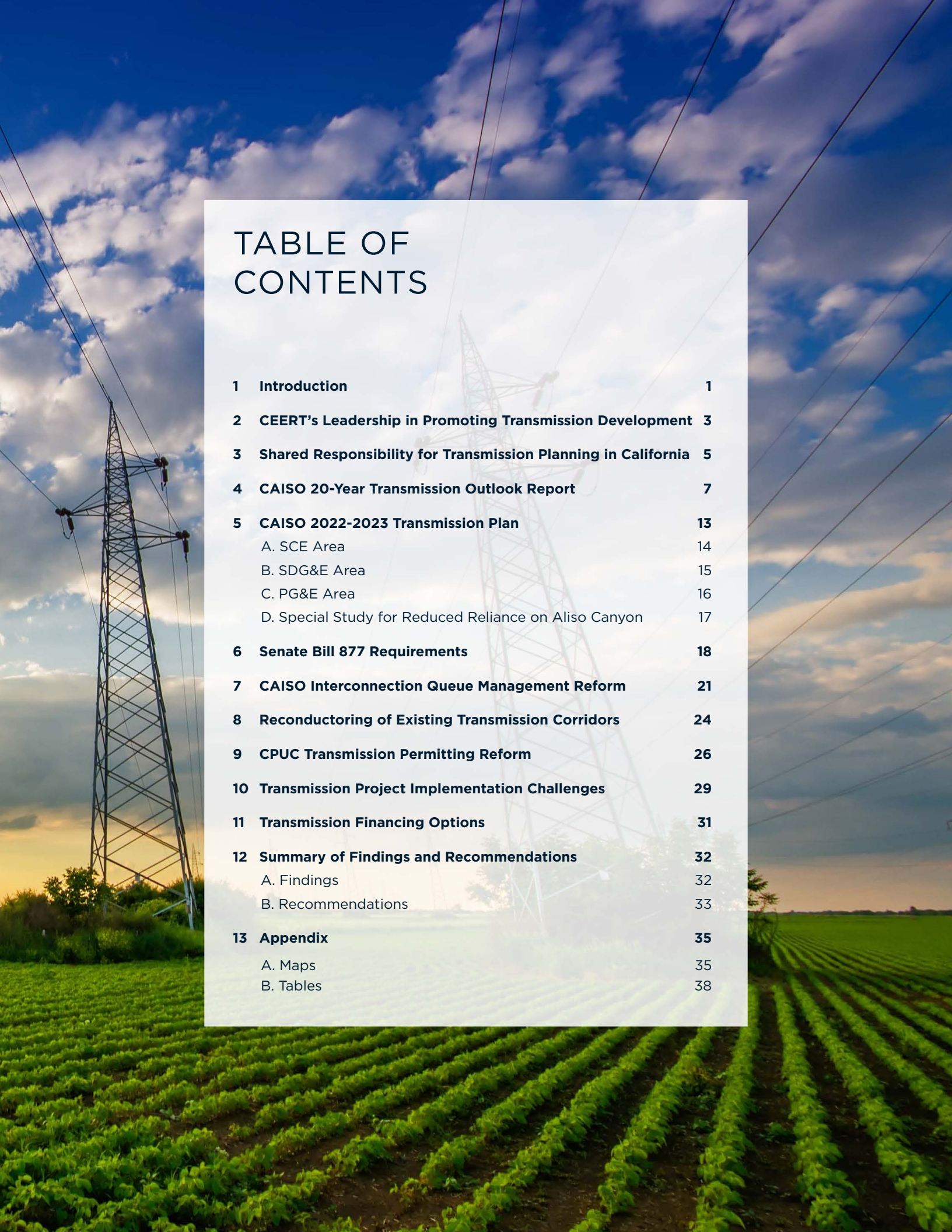

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1 INTRODUCTION

Upgrading existing and building new high voltage transmission projects is currently the key challenge facing energy policymakers. Overcoming this challenge is absolutely necessary to make substantial progress in the near future towards decarbonizing the electric system and the economy. Most of California's electric transmission system was built before 1980 to deliver electricity from fossil, nuclear and hydroelectric generation.

Over the past twenty years the costs of clean energy technologies including wind, solar and battery storage have declined with remarkable speed as the industries that manufacture these technologies have scaled up. These technologies are now replacing fossil fuels as a source of electricity. Geothermal and other energy storage technologies, including green sources of hydrogen, are expected to follow the downward cost trajectory over the next decade.

Suitable geographical locations where these technologies can be located have also expanded with the declines in technology costs. Solar and wind projects paired with battery storage are now cost competitive with operating natural gas power plants throughout most of the Western United States. This wider geographical range where clean energy technologies can be located creates the potential for rapid reductions in greenhouse gas (GHG) emissions and improved electric system reliability as more diversity is built into the regional power system. To unlock that potential of geographical and technological diversity much more transmission is needed.

Major changes are beginning to occur in how customers use electricity to improve their lives. Electrification of mobility and of heating and of other end uses in buildings will rapidly increase the amount of electricity needed over the next decade and beyond. As the economy's dependence on electricity grows, the importance of multiple robust transmission pathways in and through California will increase.

The passage of the Inflation Reduction Act, coupled with recent decision of the California Public Utilities Commission (CPUC) to order the development of 15.5 gigawatts (GW) of firm, clean new sources of energy, has resulted in a surge of interconnection applications to tie these resources to the bulk power grid.

The quantity of applications in the California Independent System Operator's (CAISO) Cluster 14 is so great that the CAISO had to expand the period of time it needs to study the need for transmission expansion to provide deliverability. California is fortunate that there is such a high-level interest among independent power developers in building clean energy resources to help the State meet its GHG reduction goals. However, California will need to ensure sufficient transmission capacity is available in order to leverage this competitive market. Bottlenecks on the transmission system can be very costs as the need for clean energy grows rapidly.

2
CEERT'S LEADERSHIP IN PROMOTING TRANSMISSION DEVELOPMENT

The Center for Energy Efficiency and Renewable Technologies (CEERT) has been a leader in promoting the expansion of California's transmission system going back to the 1990s, as the opportunity for large scale wind development emerged. The CEERT Board and its staff were instrumental in advocating for the Tehachapi Renewable Transmission Project (TRTP).[1] This innovative project consisted of new and upgraded high-voltage electric transmission lines and substations that can carry 4,500 megawatts (MW) of electricity from renewable generators in Kern County south to the Los Angeles basin.

The TRTP, built by Southern California Edison (SCE), included two new gathering substations (Whirlwind and Windhub) and 173 miles of transmission lines. The substations and lines were fully energized at the end of 2016, twelve years after SCE submitted its initial application to the CPUC for authorization to construct the transmission facilities.

Another initiative that CEERT led under contract with the California Energy Commission (CEC) was the Renewable Energy Transmission Initiative (RETI 1.0). RETI was set up by state policymakers to identify competitive renewable energy zones, to identify transmission corridors to facilitate the development of transmission projects and to expedite siting and permitting of renewable generation and transmission lines.

RETI 1.0 involved transmission owners/operators, renewable energy developers, utilities and other load serving entities, state and federal permitting agencies, tribal governments and environmental and public interest organizations as well as state agencies and the CAISO. The RETI 1.0 report informed transmission planning at the CAISO and the U.S. Department of Interior through the Desert Renewable Energy Conservation Plan. Thirty competitive renewable energy zones (CREZs) were identified with 80,000 MW of renewable potential across the state.

1 Long-time CEERT colleagues David Olson and Rich Ferguson were deeply engaged in the planning process that resulted in the approval of the TRTP project.

The CEC followed up with the RETI 2.0 report in 2017. The report examined multiple resource portfolios and concluded that continued growth in solar generation would likely lead to curtailment of solar production during high solar periods and could result in a shortage of flexible capacity during the evening hours to meet net peak loads.

It recommended creating transmission access to low-cost wind and geothermal resources both within and outside California that had complementary generation profiles. The report examined transmission constraints in the San Joaquin Valley[2], the Mojave Desert area[3], the Imperial Valley[4], and the High Desert area north of the Lugo substation[5]. It also examined the potential for increased imports across the California-Oregon intertie[6].

2 The report concluded that if a large quantity of new generation could be geographically concentrated then it could be connected to the 500 kV system, which would offer lower cost and greater system benefits.

3 The Desert Area transmission constraint affects the deliverability of new renewable generations across a vast area that includes Victorville-Barstow, Eastern Riverside County, and the Imperial Valley, as well as imports from the Eldorado hub in Nevada and the Palo Verde hub in Arizona.

4 The report identified the Imperial Valley as a location where high voltage direct current (HVDC) might be an appropriate solution.

5 Generation development north of the Kramer substation (San Bernardino County) could result in constraints between Kramer, Lugo, and Calcite substations.

6 The California-Oregon Intertie consists of three 500 kV transmission lines with a rate capacity of 4,800 MW. The report concluded there was no capacity for new fully deliverable resources from the Pacific Northwest. However, scheduling coordination and dynamic line rating could increase the utilization of existing capacity.

3
SHARED RESPONSIBILITY FOR TRANSMISSION PLANNING IN CALIFORNIA

As California's renewable portfolio standard began implementation, the CAISO and the CPUC recognized that the transmission planning process needed to be revised to achieve the State's legislative renewable energy targets, such as achieving 33 percent renewable generation by 2020.[7] To achieve that goal and maintain system reliability, the CAISO and the CPUC adopted a memorandum of understanding (MOU) in 2010 regarding coordinated transmission planning.

The CPUC and the CAISO agreed that beginning with the 2011-2012 transmission plan the CAISO would review resource scenarios provided by the CPUC. The CAISO would then provide the CPUC and other stakeholders with a formal assessment of the transmission needs for the CPUC-provided resource scenarios. The final annual transmission plan would identify specific transmission facilities, which would be categorized as Category 1 facilities, that merited unconditional approval based on the concept of least regrets, and Category 2 facilities that may be needed depending on the course of future generation development.

Least regret (Category 1) transmission projects would be specified with sufficient detail to allow eligible parties to submit competitive proposals to develop the projects that included a detailed construction schedule and cost estimates. For Category 2 projects, parties were encouraged to propose alternative solutions that would be evaluated in subsequent annual transmission plans.

Least regret transmission projects that were identified by the CAISO in its annual transmission plan would then proceed to the CPUC for review under the California Environmental Quality Act (CEQA) and other permitting requirements and for issuance of a Certificate of Public Convenience and Necessity (CPCN).

The purpose of the MOU was to clarify and streamline the planning and permitting processes for necessary transmission. However, few policy-driven transmission projects were approved since the 2010 MOU was adopted by the CPUC and the CAISO (see Table A1 in the appendix).

7 SB 100 now requires that California obtain at least 60% of its electricity requirements from qualified renewable energy resources by 2030.

To remedy that deficiency and to take account of the escalating need for new clean energy resource development, the parties, now including the CEC, updated and amended the 2010 MOU in December 2022. The 2022 MOU recognizes the importance of the electricity demand forecast that is regularly developed and updated by the CEC. The CEC is also responsible for the development of long-term multi-decade forecasts to estimate the impact of the state's decarbonization goals under SB 100.

The new 2022 MOU also recognized that the CPUC will continue to develop forward-looking resource portfolios that set the direction for procurement authorizations for load serving entities regulated by the Commission.[8] The MOU requires the CEC, CPUC, and the CAISO to coordinate and implement a joint work plan during the CEC's Integrated Energy Policy Report proceedings. Importantly, the parties agree to use a single demand forecast for both transmission planning and resource procurement.

The parties also agreed to work together on longer-term informational planning exercises to provide the CPUC and the public with an assessment of transmission planning needs over a longer time horizon. The CAISO in 2022 prepared a 20-Year Transmission Outlook report which investigated long-term grid requirements and options for meeting the State's GHG reduction goals.

The CPUC will use transmission information from the CAISO to map its resource portfolios to specific electrical locations (busbars) through a joint effort with the CEC and the CAISO. Precise busbar mapping will enable improved transmission planning through power flow analysis and other technical studies.

Importantly, the 2022 MOU commits the CPUC to giving substantial weight in its permitting process to projects selected in the CAISO's annual transmission plans. In other words, the determination of need for transmission will rely on the studies, stakeholder processes, and competitive solicitations administered by the CAISO.

The CAISO also agrees in the MOU to prioritize interconnection process activities to support resources with the operational characteristics and geographic locations consistent with the resource planning conducted by the CPUC and CEC.

8 SB 350 (de Leon – 2015) initiated a comprehensive Integrated Resource Planning process that, among other things, required the Commission to set a greenhouse gas reduction target.

4
CAISO 20-YEAR TRANSMISSION OUTLOOK REPORT

In June 2022 the CAISO adopted and promulgated a 20-Year Transmission Outlook report to support the CPUC's Integrated Resource Planning process, the CEC's Integrated Policy Report and the joint agencies' SB 100 planning efforts. The CAISO acknowledged in initiating this report that resource requirements to meet state policy goals and reliability needs will accelerate sharply over the next 10 years compared to the last five years.[9] In addition, the CAISO is anticipating that, in response to a proposed federal Proposed Notice of Rulemaking, a longer-term planning horizon for transmission will be recognized as a best practice.[10]

For the 20-Year Transmission Outlook Report the CAISO staff used a specific resource portfolio developed by the CEC for its SB 100 analysis and then assumed natural gas power plant retirements of 15,000 MW by 2040. This scenario was referred to as the Starting Point Scenario. Table 1 (below) provides the resource assumptions in the 2021-2022 transmission planning process for 2031 and the SB 100 Starting Point Scenario for 2040.

TABLE 1. *Comparison of Resource Scenarios*

RESOURCE TYPE	2021-2022 TP BASE PORTFOLIO FOR 2031 (MW)	STARTING POINT SCENARIO FOR 2040 (MW)
Natural gas power plants	0	(15,000)
Battery energy storage	9,368	37,000
Long-duration storage	627	4,000
Utility-scale solar	13,044	53,212
In-state wind	1,918	2,237
Offshore wind	0	10,000
Out-of-state wind	2,087	12,000
Geothermal	651	2,332

9 The Base Case resource portfolio used in the 2022-2023 Transmission Plan assumes a buildout of 2,700 MW of renewable resources annually. The new resource portfolio with a GHG goal of 30 MMT in 2030 and assumes high transportation electrification requires a buildout of 4,000 MW per year.

10 FERC Docket No. RM21-17-000

The Starting Point Scenario identified 53,212 MW of utility-scale solar in 2040. In allocating the utility scale solar to geographical locations, the Starting Point Scenario utilized commercial interest together with environmental screens to determine where solar might be suitably located. Table 2 lists geographical regions where 1,000 MW or more of solar may be sited.

TABLE 2. *Solar Resource Allocation by Region*

RESOURCE LOCATION	CAPACITY (MW)
Imperial Valley	6,407
North of Kramer	2,162
Kern County	6,154
Tehachapi (Whirlwind, Windhub)	9,544
Westlands (Central Valley)	12,655
East Riverside	4,922
Los Banos (Central Valley)	1,079
Tehachapi (Vincent, Moorpark)	2,066
Southern Nevada	2,024
Western Arizona	2,352

The CAISO power flow studies specifically looked at transmission line overloads from the Westlands and Kern areas in the Central Valley to Bay Area load centers assuming only 2,000 MW of available local gas generation in the Bay Area. One reason for these studies is the southern Central Valley is an area where the SB 100 planning effort and Starting Point Scenario expect a significant build-out of solar and storage resources, creating an important new area for clean energy resource development that must then reach major load centers. Table 3 shows transmission elements that are overloaded during normal operating conditions in early afternoon summer conditions.

TABLE 3. *Peak Summer Overloads During Normal Operations*

OVERLOADED ELEMENT	BASE CASE OVERLOAD
Manning – Gates 500 kilovolt (kV) line	163%
Lugo 500/230 kV Transformer Banks #1 and #2	161%
Los Banos – Manning #1 and #2 500 kV lines	152%
Los Banos – Tesla 500 kV line	138%
Los Banos – Tracy 500 kV line	117%
Los Banos – Moss Landing 500 kV line	116%
Moss Landing – Las Aguilas 230 kV line	133%
Westley – Los Banos 230 kV line	119%
Panoche – Los Banos 230 kV line	119%
Collinsville – Pittsburg 230 kV line	116%
Lighthipe – Mesa 230 kV line	108%

For the Los Angeles Basin area, the CAISO analyzed electricity deliverability during evening summer conditions after the sun has set. Electricity will mostly likely be supplied by battery storage, wind generation, imported power and hydro units. Table 4 shows transmission elements that are overloaded during these evening summer conditions.

TABLE 4. *Net Peak Summer Overloads During Normal Operations*

OVERLOADED ELEMENT	BASE CASE OVERLOAD
Lighthipe – Mesa 230 kV line	128%
Serrano 500/230 kV Transmission Banks #1, #2 and #3	119%
North Gila – Imperial Valley 500 kV line	113%
Diablo – Gates 500 kV line	113%
Devers – Red Bluff 500 kV #1 and #2 lines	112%
Hassayampa – North Gila #2 500 kV lines	110%
Barre – Lewis 230 kV line	113%
Barre – Ellis #1, #2, #3 and #4 230 kV lines	105%

The CAISO also analyzed off-peak conditions for deliverability. Off-peak conditions are in the middle of the day in the spring when demand is about 50% of the peak load and generation from behind-the-meter solar generation is high. The study assumes that all battery storage units (40 GW) are in charging mode. It is also assumed the CAISO system is exporting 5 GW of energy to neighboring systems. Table 5 shows transmission elements that are overloaded during these conditions.

TABLE 5. *Off Peak Overloads During Normal Operations*

OVERLOADED ELEMENT	BASE CASE OVERLOAD
Lugo 500/230 kV Transformer Banks #1 and #2	155%
Table Mountain 500/230 kV Transformer Bank #1	126%
Gates – Mustang 230 kV #1 and #2 lines	115%

In addition to analyzing overloads during normal operating conditions, the CAISO also analyzed overloads during N-1 contingencies and N-1-1 contingencies.

Based on its deliverability analysis, the CAISO identified specific transmission projects that will be needed to integrate the resources in the SB 100 Starting Point Scenario. Table 6 identifies projects located within the existing CAISO footprint.

TABLE 6. *Transmission Projects to Integrate Starting Point Scenario Resources*

TRANSMISSION PROJECT	DESCRIPTION
Eldorado – Lugo 500 kV line	180 miles of 500 kV line, series compensation in various locations
Manning or new 500 kV substation in Fresno County to Moss Landing or Metcalf	Consistent with the 20-year transmission outlook
Gates II to Vincent 500 kV line	Consistent with the 20-year transmission outlook
Colorado River – Devers 500 kV line	Devers to Red Bluff 500 kV line, Red Bluff to Colorado River 500 kV line
North Gila – Imperial Valley 500 kV line	85 miles 500 kV line, series compensation
Westland 500/230 kV substation	New 500/230 kV substation with two transformers, 50 miles of 500 kV line
2nd Los Banos to Tracy or to new Manning or other new 500 kV substation in Fresno County 500 kV line	67 miles of 500 kV line
3rd Collinsville – Pittsburg 230 kV line	230 kV cable
Manning – Moss Landing 500 kV line	78 miles of 500 kV line, new 500/230 kV substation with two transformers
Devers – La Fresa HVDC	100 miles of DC cables, Two VSC converters
Lugo – LA Basin HVDC	80 miles of DC cables, Two VSC converters
Sycamore – Alberhill HVDC	82 miles of DC cables, Two VSC converters
Diablo – South HVDC	250 miles HVDC cables, 4 VSC converters
Diablo – North HVDC	200 miles HVDC cables, 4 VSC converters
Round Mountain 500/230 kV Transformer	Add one 500/230 kV transformer
Lugo 500/230 kV transformer	Add one 500/230 kV transformer

Table 7 identifies transmission projects needed to integrate out-of-state wind resources identified in the Starting Point Scenario.

TABLE 7. *Transmission Projects to Integrate Out-of-State Wind*

TRANSMISSION PROJECT	DESCRIPTION
SWIP-North	275 mile 500 kV line from Midpoint to Robinson with upgrade from Robinson to Harry Allen to access Idaho wind
Cross-Tie	214 mile 500 kV line from Robinson to Mona/Clover to access Wyoming wind
Robinson – Eldorado	500 kV line from Robinson to Eldorado
TransWest Express	732 mile system consisting of HVDC and 500 kV facilities to access Wyoming wind
SunZia	530 mile HVDC line and 35 mile 500 kV line to access New Mexico wind
Additional transmission for additional Wyoming/Idaho wind resources	HVDC transmission line from the wind resource to northern California (Tesla)
Additional transmission for additional New Mexico wind resources	HVDC transmission line from the wind resources to southern California (Lugo)

The CAISO has also done some initial scoping of transmission projects needed to integrate 10 GW of offshore wind. For the 2023-2024 TPP the CPUC is recommending that the CAISO conduct a more detailed analysis of the transmission resources needed to integrate 13 GW of offshore wind.

The 20-Year Transmission Outlook was revelatory and much appreciated by stakeholders involved in transmission planning. It clearly laid out options for meeting California's GHG reduction and renewable energy development goals in a reliable manner. It provides clear longer-term context for the framing of transmission needs that should be further elaborated in actionable CAISO transmission plans beginning with the 2022-2023 Transmission Plan.

5
CAISO 2022-2023 TRANSMISSION PLAN

The CAISO's 2022-2023 Transmission Plan is in the final stages of development with final approval expected in May following another round of public review and comment. The Plan examines the impact of two resource portfolios developed by the CPUC. First is the preferred system portfolio with a GHG reduction target of 38 million metric tons (MMT) by 2030. It is the base case portfolio that will be used to recommend least regrets (Category 1) transmission projects. A second sensitivity portfolio with a 30 MMT GHG target by 2030 and with high electrification will also be analyzed to examine longer term needs through 2035. The sensitivity portfolio is expected to become the base case portfolio in the 2023-2024 Transmission Plan. Table 8 compares the resource additions in the two portfolios.[11]

TABLE 8. *Total Resource Additions in Transmission Planning Scenarios*

RESOURCES (MW)	BASE SCENARIO (2032)	SENSITIVITY SCENARIO (2035)
Solar	11,271	33,640
Wind	5,778	12,301
Battery Storage	7,299	20,673
Long Duration Storage	1,000	2,000
Geothermal	1,119	1,746
Bio	129	129
Total	26,597	70,489

The difference in the amount of resources that needs to be developed in the two scenarios is striking. Since the sensitivity scenario is expected to become the base scenario for the subsequent transmission plan, many stakeholders have advised the CAISO to heavily weigh the constraints arising in the sensitivity scenario in recommending "least regret" transmission projects for development.

11 The resource additions use nameplate capacity. It is expected that many battery storage systems will be paired with renewable sources of generation so that the megawatts at points of interconnection will be less than the sum of the resources.

At the November 17, 2022 stakeholder meeting, the CAISO staff provided preliminary deliverability assessment results for three broad regions of the CAISO footprint: the SCE area[12], the SDG&E area, and the PG&E area. Transmission constraints under both scenarios were identified for each of the areas as well as alternative transmission projects that mitigated the constraints.

A. SCE AREA

The CAISO transmission deliverability studies for the SCE service area analyzed deliverability in specific sections of the SCE service area as well as specific constraints on key elements of their high voltage transmission system. The areas that are studied include the SCE Metro Area, the North of Lugo Area (portions of San Bernardino and Kern Counties), the SCE Eastern Area (Riverside County and parts of San Bernardino County), and the SCE Northern Area (Ventura and a portion of the San Joaquin Valley). Key transmission constraints that are analyzed are the Lugo-Victorville constraint and the Lugo-Calcite constraint.

Three large-scale transmission projects emerge from the studies of the SCE area. The first addresses overloads between the Red Bluff substation and the Devers substation in Riverside County and between the Devers substation and the Mira Loma substation in San Bernardino County. An additional 500 kV transmission line along this corridor would mitigate deliverability constraints in both the base case scenario and the sensitivity scenario and enable large amounts of solar and battery projects in the interconnection queue to be developed. In addition, it will increase the import capability into California from projects developed in Arizona and New Mexico (see Map X1 in the appendix for the location of the 500 kV transmission line).

The second large-scale transmission project is intended to address the Lugo-Victorville constraint which is driven by power coming through Nevada to the Lugo and Victorville substations in San Bernardino County. The CAISO system overloads are parallel to constraints that the Los Angeles Department of Water and Power (LADWP) faces on its transmission system from the McCullough substation in Nevada to the Victorville substation in San Bernardino County. The CAISO is analyzing three alternatives to mitigate the constraint. One involves building a second 180-mile 500 kV line between the Eldorado and Lugo substations along with series compensation for system stability. The other two alternatives involve the construction of new 500 kV lines as well as new substations. It is expected that the CAISO will recommend a preferred alternative in the final 2022-2023 transmission plan. A solution is needed to overcome this constraint to enable more power to be imported from solar and battery projects in Southern Nevada and for wind imports from Wyoming and/or Idaho. There are clear advantages of the CAISO working together with LADWP to find a mutually beneficial solution that avoids excessive loop flow on

12 The CAISO includes within the SCE study area parts of Nevada served by Valley Electric Association and the Gridliance high voltage electric system. The focus of this summary is on the SCE portion of the area.

either system[13] (see Map X2 in the appendix for the locations of the transmission option addressing the Lugo-Victorville constraint).

The third set of projects are in the SCE Metro area which includes portions of Los Angeles, Riverside, and San Bernardino Counties. The CAISO has identified two alternative project designs that consist of multiple elements. The proposed projects are intended to address constraints identified from the base case. Many additional constraints show up in the sensitivity portfolio that are not addressed. Common elements of the two alternatives are an additional 500 kV underground cable between the Mesa and Mira Loma substations and a new 500 kV line from the Mesa to Serrano substations. A third needed element consists of building three 500/230 kV transformer banks at the Del Amo substation, and then linking the Del Amo substation to the Mesa substation with two new 500 kV lines or looping through the new Mesa-Serrano 500 kV line through the Del Amo substation (see Map X3 in the appendix for the locations of the SCE Metro projects).

B. SDG&E AREA

Transmission project alternatives located in the San Diego area are to a certain extent contingent on decisions made in the SCE Eastern Area. Also, the transmission solutions chosen for the San Diego area will be influenced by the degree to which the CAISO decides to be proactive and address the need for transmission for projects included in the sensitivity scenario. Imperial County is one of the state's premier locations for the development of geothermal power. The sensitivity scenario assumes that 900 MW of geothermal generation would be developed by 2035. It also assumes that 653 MW of solar and 375 MW of battery storage would be developed in Imperial County. However, the lack of transmission limits the delivery of power from the Imperial Valley to the San Diego urban area and/or into the SCE area.

The CAISO identifies six alternative transmission project options for the San Diego area. Two of the options are focused on upgrades to the 230 kV system serving urban San Diego and the northern parts of San Diego County. Four of the options include a new 500 kV line from the Imperial Valley (IV) substation across the coastal mountains to the Serrano substation in Orange County. This new line is estimated to cost approximately $3.3 billion. Three of the options with the new IV-Serrano 500 kV line also include a second 500 kV line that would run between the North Gila substation at the Arizona border to the Imperial Valley substation. This line would follow an existing transmission right of way. However, the second North Gila to Imperial Valley 500 kV line is only needed in the sensitivity case and would enable more imports from Arizona renewable projects (see Map X4 in the appendix for the locations of the Imperial Valley to Serrano and North Gila to Imperial Valley 500 kV projects).

13 LADWP presented to its Board on December 13, 2022 an update on its Strategic Transmission Plan (STP). See A2 in the appendix for an excerpt from that presentation summarizing Stage 1 of the STP.

Clearly, additional transmission capacity is needed to better connect the resource rich Imperial Valley to San Diego and to the greater Southern California region. It is expected that further refinement of Imperial Valley transmission options will be made for the final 2022-2023 Transmission Plan. SDG&E noted in their December comments on the draft plan that the options under consideration provide multiple benefits including 1) addressing existing and future reliability issues, 2) reducing local capacity requirements in the San Diego area, 3) enabling the deliverability of future policy-driven projects, and 4) lessening dependence on Aliso Canyon gas storage.

C. PG&E AREA

The PG&E area includes the locations where offshore wind projects would land for delivery to the state's load centers. The transmission needs for offshore wind will be examined in more detail with the sensitivity scenario in the 2023-2024 Transmission Planning Process. The focus of this report is on the transmission needed to enable the development of solar and battery projects in the South Area (Southern Central Valley) of PG&E's territory.

The South PG&E area includes Fresno and Kings Counties and parts of Tulare and Kern counties. There is a dramatic difference between the CPUC base case scenario and the sensitivity scenario as to the quantity of solar and battery storage that is forecasted for development in this area. Table 9 compares the resources included in the two scenarios.

TABLE 9. *Comparison of Resource Portfolios in the South PG&E Area*

RESOURCE (MW)	BASE SCENARIO (2032)	SENSITIVITY SCENARIO (2035)
Solar	1,817	9,989
Battery Storage	1,107	5,556
Total	2,924	15,545

As might be expected, given the difference in the magnitude of the resources added in the sensitivity scenario, most constraints show up in the sensitivity case. The constraints that do show up in the base case are in very local parts of PG&E's 70 kV and 115 kV system. To mitigate the need for reconductoring lower voltage lines, the CAISO recommends that generators be re-mapped to higher voltage points of interconnection (230 kV). Many transmission constraints show up in the analysis of off-peak conditions since solar generation in this area cannot be fully absorbed by nearby load. As mitigation, the CAISO recommends that additional batteries be located in the South Area and operated in charging mode during light-load conditions.

CEERT is concerned about the divergence between the base case scenario being used in the 2022-2023 Transmission Plan and the 20-Year Transmission Outlook Starting Point scenario, which identified over 20 GW of solar being developed in the San Joaquin Valley

near the Los Banos, Manning, and Gates substations. Most of these projects would be expected to be paired with battery storage.[14] At a minimum, the CAISO should use the results of the sensitivity portfolio in the 2022-2023 portfolio for the South PG&E area. In the future the CAISO needs to re-examine the need for a new Westlands substation that was identified as a needed transmission project in the 20-Year Transmission Outlook report.

The CAISO should also examine the opportunity to cost-effectively reconductor or convert to HVDC portions of Paths 15 and 26 to enable the delivery of even larger amounts of clean energy from the Central Valley to the Bay Area and Southern California.

D. SPECIAL STUDY FOR REDUCED RELIANCE ON ALISO CANYON

As part of the 2022-2023 Transmission Plan, the CAISO conducted a local reliability assessment for the LA Basin and San Diego-Imperial Valley areas, assuming Aliso Canyon gas storage was not available for approximately 3,700 MW of gas-fired generation.[15] The study identified 25 transmission facilities that would be impacted by the curtailment of the 3,700 MW from gas-fired power plants in the SCE and SDG&E areas. To mitigate the impact on these facilities the CAISO developed 13 alternative transmission scenarios. The CAISO's analysis of the effectiveness of the scenarios narrowed down the options to three.

Each of the three options included as an anchoring element a High Voltage Direct Current (Diablo South HVDC) subsea cable that ran from Diablo Canyon to two terminals in the greater Los Angeles region. The options also include various upgrades in the SCE and SDG&E areas, including the North Gila to Imperial Valley #2 500 kV line. By adding the delivery of energy from the north into the Los Angeles basin, the Diablo South HVDC cable also provides relief for Path 26 under contingency conditions.

While the addition of Diablo South HVDC cable may not allow for the immediate closure of the Aliso Canyon gas storage facility it would significantly decrease the use of fossil generation in the LA Basin and increase system reliability by providing an alternative path to Southern California from Path 26. For these reasons, CEERT strongly recommends that the CAISO include a Diablo South HVDC cable as a least regrets transmission project (see Map X5 in the appendix for the recommended Diablo South HVDC subsea cable).

14 Vistra, in its December comments on the 2022-2023 Transmission Plan, noted that it intended to develop an additional 350 MW of battery storage at Moss Landing and that it expected the charging requirements to drive the need for additional transmission from the Central Valley to Moss Landing.

15 The CPUC is studying the possible retirement of the Aliso Canyon facility as part of I.17-02-002.

6
SENATE BILL 877 REQUIREMENTS

During the 2022 legislative session, the Legislature enacted and the Governor signed Senate Bill 877. This legislation requires the CPUC to request the CAISO to identify the highest priority transmission facilities needed to deliver renewable energy or zero-carbon energy from projects that are expected to be developed by 2035 to load pockets that currently require the operation of local fossil fuel power plants.

The objective of SB 887 was to encourage the CAISO to consider approval of high priority transmission projects in its 2022-2023 transmission planning process. The law required the CPUC to transmit this expectation to the CAISO by January 15, 2023. CPUC President Alice Reynolds sent a letter setting forth the requirements of SB 887 to CAISO President and CEO Elliot Mainzer on January 13, 2023.

One of the purposes of this transmission report is to highlight specific high priority transmission projects that were initially identified in the CAISO 20-Year Outlook and in the draft 2022-2023 Transmission Plan. CEERT considers the following transmission projects to be the highest priority projects that will enable the development of renewable and zero-carbon energy that can be delivered to areas of the state that currently rely on locally sited fossil fuel generation:

1. A third 500 kV transmission line is needed that extends from the Red Bluff Substation in Eastern Riverside County through the Devers substation near Palm Springs to the Mira Loma substation in San Bernardino County. This transmission project will enable new solar and battery projects developed in Riverside County and Western Arizona as well as wind generation developed in New Mexico to be delivered into the Southern California region and lessen the use of fossil fuel generation in load pockets in the SCE and SDG&E areas.
2. A third underground 500 kV cable is needed in the SCE Metro area that will run from the Mira Loma substation to the Mesa substation as well as a new 500 kV transmission line that will run from the Mesa substation to the Serrano substation. In addition, three new 500/230 kV transformer banks will be needed at the Del Amo substation. The Del Amo and Mesa substations will need to be linked together either by two new 500 kV lines or by looping the new Mesa-Serrano 500 kV line through the Del Amo substation. These transmission lines will relieve significant constraints in the greater Los Angeles region and enable the delivery of renewable and zero-carbon energy from the east.
3. Significant 500 kV infrastructure is needed (transmission, series compensation and possibly a new substation) between Southern Nevada and the Hesperia area in San Bernardino County to overcome the Lugo-Victorville constraint. One alternative would be the construction of a new 180-mile 500 kV transmission line from the Eldorado substation in Southern Nevada to the Lugo substation near Hesperia. Two alternative projects have also been proposed in the draft 2022-2023 transmission plan that included new 500 kV substations. LADWP also has high voltage transmission lines in this area which extend from the McCullough substation in Southern Nevada to the Victorville substation in San Bernardino County. CEERT believes that a cooperative project between the two balancing authorities could result in a more optimal solution for ratepayers in Southern California. A transmission solution that overcomes the Lugo-Victorville constraint will enable substantial wind, solar/battery and geothermal energy to be imported from neighboring states including Nevada, Idaho and Wyoming.
4. New transmission is needed in Imperial County to enable the development of geothermal potential in the region near the Salton Sea and to advance solar and battery development in Imperial County and Western Arizona. One project that has been identified, the second 500 kV line from the North Gila substation in Arizona to the Imperial Valley substation west of El Centro will partially improve the deliverability of these resources and lessen the need for fossil fuel resources in the SCE and SDG&E areas. An additional 500 kV or HVDC line is needed that

will strengthen the link between the transmission system running through Imperial County and the electric grid to the north. The CAISO has identified a 500 kV line that would link the Imperial Valley substation to the Serrano substation in Orange County. Other alternatives need to be examined.

5. One of the major constraints to the development of new cost-effective renewable generation that can be used in both the northern and southern parts of the state is Path 26, which runs from the Midway substation in Kern County to the Vincent substation in Los Angeles County. A new transmission pathway between the north and the south would greatly improve system reliability and the economic performance of the grid. The most obvious solution that has been put forward is a subsea HVDC cable between the Diablo Canyon substation and the greater Los Angeles area. Various options for what are called the Diablo South HVDC cable were highlighted in CAISO's 20-Year Outlook report. That report identified several potential terminals in Southern California where the cable could land. CEERT believes that the CAISO and LADWP should work together to optimize the value of a new link between Diablo and Los Angeles that could add 2000 MW or more of transfer capability. An HVDC cable would go a long way to reducing Southern California's dependence on fossil generation and the Aliso Canyon gas storage facility. It could also serve as a pathway for future offshore wind development.
6. The lower Central Valley from Merced County in the north to Kern County in the south has the potential for the development of 30 GW or more of solar and battery projects. Projects in the Central Valley have the potential to deliver energy north into the Bay Area or south to the Los Angeles Basin based on the growing needs of both regions. Path 15 is the major backbone transmission system linking Northern and Southern California. There are four major substations in the lower Central Valley – Los Banos, Manning, Gates, and Midway. A fifth substation is needed between the Gates and Midway substations to enable the interconnection of significant new clean energy capacity. In addition, the Path 15 transmission lines will need to be upgraded to enable the delivery of that energy to load centers. One possibility is the conversion of one or more of the existing lines to an HVDC line. This is a solution that the CAISO should study in its 2023-2024 transmission planning process. In addition, there is a need in the Central Valley to upgrade the aging and weak 115 kV and 70 kV power lines.

7
CAISO INTERCONNECTION QUEUE MANAGEMENT REFORM

Transmission planning is closely related to the interconnection process for new generators. For renewable energy projects to be financed, they need to have a clear line of sight of when they can be connected to the grid and whether the power they produce can be reliably delivered to customers. The CAISO's interconnection process has recently slowed in part because of the lack of available transmission capacity for new generators to reliably deliver power to load centers. As transmission has become scarcer, there has also been an enormous increase in the number of interconnection applications, particularly for battery storage projects.

The CAISO interconnection process was overwhelmed by the Cluster 14 cycle, which saw a near tripling in the number of interconnection applications submitted by the April 2021 deadline. The CAISO responded to this flood of new interconnection applications by obtaining permission from FERC to delay the completion of the necessary interconnection technical studies for a year. Also, the timing of the Cluster 15 application process was delayed for a year.

An interconnection request includes several components: the selection by the developer of a specific point of interconnection, the determination by the CAISO whether there is sufficient transmission capacity to deliver power reliably from that location, and the construction of network upgrades by the transmission owner to assure energy deliverability.

Interconnection customers request a deliverability designation when they submit their interconnection applications. The choices are Full Capacity Deliverability Status (FCDS), Partial Capacity Deliverability Status (PCDS), or Energy Only (EO).

Interconnection customers are awarded FCDS or PCDS status to the extent that deliverability is available on the transmission system. Clarity in determining deliverability allocation is critically important to developers. Being designated FCDS or PCDS means that the grid can deliver a specific amount of capacity to the grid under peak load conditions. An EO designation, on the other hand, means that the generator's delivered output is subject to grid conditions.

Deliverability designations are key to supplying Resource Adequacy in California. An FCDS or PCDS designation qualifies the generator's output to count towards a load serving entity's resource adequacy requirement.

FCDS and PCDS generators are responsible for the financing costs of constructing Delivery Network Upgrades. These are upgrades designed to relieve transmission constraints. An EO designation means that the interconnection customer will not be responsible for deliverability upgrades. It also means the resource will be ineligible to count towards resource adequacy.

In the future, the CAISO will allocate deliverability to proposed generators in areas based on project development criteria. The CAISO will allocate deliverability in the following order: (A) to interconnection customers that have executed power purchase agreements and to load serving entities that are developing projects to serve their own load; (B) to interconnection customers that are on an active short list to receive a power purchase agreement; (C) to interconnection customers that have achieved Commercial Operation for the capacity seeking deliverability but have not executed a power purchase agreement; and (D) to other interconnection customers.

Once an interconnection customer has a deliverability allocation, it must make commercial progress in order to retain the allocation. Shortlisted interconnection customers

must execute a power purchase agreement, and interconnection customers that are not shortlisted must ultimately execute a power purchase agreement. In the future, the CAISO intends to be more aggressive in terminating interconnection agreements that do not meet project milestones.

While interconnection customers provide the initial financing for local delivery network upgrades, they eventually are reimbursed with the accumulative costs going to ratepayers that use the transmission system.

Ultimately, the purpose of deliverability assignment is to allocate deliverability to projects that will provide energy to the grid during stressed conditions. Since incremental deliverability on the transmission system is severely limited, it is important that delivery network upgrades be used to meet procurement portfolios provided by load serving entities. However, given the strong demand for deliverability by new generators, there is little risk that network upgrades that are built will not eventually be used to meet customer load. The strong demand and limited supply indicates the necessity of new, upsized transmission facilities to increase deliverability across the system and facilitate the interconnection of new deliverable resources.

The CAISO's initial proposed changes to improve the interconnection process have merit but will need to undergo further stakeholder discussion. However, interconnection reform alone is not sufficient to ensure that the electric system will be ready to deliver the vast amount of renewable and zero-carbon energy required to meet California's climate and clean energy goals. The CAISO has recognized that the transmission planning process, and especially the development of policy-driven transmission, will need to accelerate and be more closely coordinated with the interconnection process and the procurement plans of load serving entities.

Given the long-lead times required for developing new transmission projects, planning for new transmission will need to be initiated well in advance of procurement of the clean energy projects that will eventually use the lines to deliver renewable and zero-carbon energy to customers. And with CAISO's desire to enhance the relationship of transmission planning with generator interconnection, part of the goal of proactive transmission planning should be to value the locations in which the transmission will guide future resource development (especially for solar development that involves a lot of acreage and nameplate capacity).

8 RECONDUCTORING OF EXISTING TRANSMISSION CORRIDORS

Developing new transmission can take over ten years to plan, permit, construct, and commission. Longer distance interstate lines frequently take more than 15 years to complete. California's goal of reducing GHG emissions in the electric system to 30 MMT by 2030 will require substantial improvements in the schedules for siting and building high-voltage transmission. Making this goal more challenging, most new transmission corridors often face aesthetic and environmental opposition from members of the public.

An alternative to building new high-voltage power lines is to reconductor existing transmission lines. Wires with higher ampacity can increase the carrying capacity of an alternating current (AC) transmission line by up to 50 percent. However, there are new alternative reconductoring approaches which can further increase the amount of energy that can be safely and reliably delivered.

According to researchers at the Lawrence Berkeley National Laboratory (LBNL), high voltage direct current (HVDC) conversion is becoming cost competitive for shorter distance transmission lines.[16] Historically, HVDC lines have been built over long distances or used for subsea electric transmission.

One of the first HVDC lines developed in the United States was the Pacific DC Intertie (Path 65), which transmits power from the Pacific Northwest to Los Angeles. The line's capacity is 3.1 GW and represents a significant portion of the peak capacity needed by the Los Angeles Department of Water and Power. The project was completed in 1970 after concerns expressed by investor-owned electric utilities concerns were overcome.[17] Another important California HVDC line was installed in 2010, that connected San Francisco to a substation in Pittsburg across the San Francisco Bay. The Trans Bay Cable improved reliability by allowing two-way power flows in the Bay Area and allowing the retirement of two older fossil fuel power plants in San Francisco.

16 Earlier research indicated that DC lines less than 200 miles were not economic compared to AC lines.

17 The Pacific DC Intertie was approved in 1961 by the Bonneville Power Administration. Technical objections were resolved at a 1963 meeting of the Institute of Electrical and Electronics Engineers.

A major advantage of DC lines over AC lines is that DC current penetrates the entire conductor and allows for more power to be transmitted for the same size conductor. HVDC lines can also help stabilize the power grid from cascading blackouts since the overhead power flow is controllable. Converter stations are located at each end of the DC line, one to convert AC power to DC and the other to convert DC power to AC. The Pacific DC Intertie uses line-commuted converters, while the Trans Bay cable uses more modern voltage-sourced converters (VSC).

An advantage of HVDC conversion is that it can use existing towers and conductors. LBNL researchers estimate that HVDC conversion using existing lines can increase the total power in a transmission corridor by as much as 3.5 times. High voltage AC conversion to HVDC has not yet been widely considered by transmission planners. As a result, the potential economic advantages of conversion are not well understood.

An even greater opportunity to increase transmission capacity could result from combining HVDC conversion with an upgrade of the electrical conductor to ACSS or ACCR conductors. According to the LBNL researchers, this option has not been studied. They believe that the combination of DC conversion with an upgrade of the conductors could result in as much as an 8-fold increase in transmission line carrying capacity with only minor modifications to existing support structures.

Given the multiple challenges to developing new transmission lines, there appears to be a significant opportunity to use existing rights of way for cost effective reconductoring with either AC or DC technology.

The projects that have been identified above in this report might be good candidates for an economic analysis of reconductoring options. CEERT encourages the CAISO to take this opportunity into consideration, both in the current 2022-2023 Transmission Plan and in the subsequent 2023-2024 Transmission Plan (see Map X6 in the appendix for reconductoring opportunities).

9 CPUC TRANSMISSION PERMITTING REFORM

Once the CAISO determines that a transmission project is needed, the selected project developer is then required to obtain a Certificate of Public Convenience and Necessity (CPCN) or a Permit to Construct (PTC) from the CPUC under Public Utilities Code sections 1001 and 1002.[18]

According to the code, the CPUC is required to give consideration to 1) community values, 2) recreation and park areas, 3) historical and aesthetic values and 4) influence on the environment. Influence on the environment has been interpreted to require compliance with the California Environmental Quality Act (CEQA).

To meet these statutory requirements, a transmission developer, be it a regulated utility or a third-party developer, must submit a Proponents Environmental Assessment (PEA) and either an application for a CPCN, which applies to transmission lines above 200 kV, or a PTC, which applies to transmission projects between 50 kV and 200 kV and for any substation above 50 kV. The environmental review and the CPCN review by the CPUC happen concurrently.

18 Public Utilities Section 1001 states "No railroad corporation whose railroad is operated primarily by electric energy, street railroad corporation, gas corporation, electrical corporation, telegraph corporation, telephone corporation, water corporation, or sewer system corporation shall begin the construction of a street railroad, or of a line, plant, or system, or of any extension thereof, without having first obtained from the commission a certificate that the present or future public convenience and necessity require or will require such construction."

The CPUC's review process is set forth in CPUC General Order 131-D. The CPUC analyzes the need for the project and the economics of the project, in addition to the environmental impact. The CPUC's "needs determination" is on top of the CAISO's determination of need.

Both the CPCN and PTC processes are subject to a public hearing, should a member of the public submit a protest within 30 days of the application's filing. The protest process is led by an Administrative Law Judge (ALJ) and consists of a series of conferences and/or hearings, similar to a court case.

Once the CPUC reviews are complete, the ALJ submits a proposed decision to the Commission. The Commissioners will then vote to approve permits for the project at a meeting of the full Commission.

The Clean Air Task Force (CATF), a public interest non-profit organization, recently analyzed the timelines of thirteen transmission projects approved in CAISO Transmission Plans between 2012 and 2019.[19] Of the thirteen projects reviewed, two projects were completed but experienced considerable delays, two projects were canceled or put on hold by the CAISO, eight projects had yet to be completed and were delayed past their anticipated online date, and one project is yet to be completed but is still on track to be constructed on time.

The CATF noted the following trends in transmission permitting: 1) the CAISO's competitive solicitation process is regularly completed within one year and is the only phase of project development that is consistent in duration, 2) delays are particularly acute during the period needed for the developer to prepare a project application for the CPUC and during the CPUC environmental review process.[20] Of the ones reviewed, projects developed by an incumbent transmission owner took much more time to submit applications to the CPUC than those developed by a third party or jointly developed by the incumbent transmission owner and a third party.

The CATF concluded that the permitting status quo is unsuited to the scale of transmission expansion needed to meet California's climate goals. They recommended that the transmission permitting process be accelerated. They observed that the need for major transmission projects is currently reviewed twice and recommended consolidating the review into a single process at the CAISO. They also recommend that the State Legislature consider streamlining the permitting process as was done for non-fossil power plants in AB 205.

AB 205, which was enacted into law in 2022, established a new certification process for solar photovoltaic, terrestrial wind, geothermal and other non-fossil power plants with a generating capacity of 50 MW or more, for energy storage systems capable of storing 200 megawatt hours or more of electricity, and for transmission lines from those facilities

19 Clean Air Task Force (CATF) and Environmental Defense Fund (EDF), "Growing the Grid: A Plan to Accelerate California's Clean Energy Transition", October 2022. https://www.catf.us/resource/growing-grid-plan-accelerate-californias-clean-energy-transition/

20 It took between one to six years for incumbent utility transmission owners to submit CPCN or PTC applications and PEAs to the CPUC. Environmental reviews lasted between 16 months and four years.

to a point of connection with an electrical transmission system. The law requires the CEC to review the project application and to determine whether to issue certification within a specified time period. The law designates the CEC as the lead agency for purposes of CEQA review for these projects.

AB 205 permits the CEC to certify a project as a leadership project under the Jobs and Economic Improvement Through Environmental Leadership Act of 2021. The law requires the State Judicial Council, the policymaking body of the California courts, to establish procedures that require actions or proceedings related to the certification of an environmental impact report or the issuance of the certification for a designated facility be resolved within 270 days.

CEERT recommends that the Legislature consider extending the provisions of AB 205 to transmission projects of over 200 kV that are determined to be needed by the CAISO to meet California's GHG reduction and clean energy goals. Two recent bills seek to streamline the transmission permitting process in California: SB 619 (Padilla)[21] and SB 420 (Becker)[22].

21 https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320240SB619

22 https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320240SB420

10 TRANSMISSION PROJECT IMPLEMENTATION CHALLENGES

Once transmission projects have been permitted, they need to be built. While recently large transmission projects have been competitively bid and development awarded to independent transmission developers, the majority of projects that are currently under construction, particularly those identified in the interconnection study process, are the responsibility of incumbent utility transmission owners, i.e. PG&E, SCE, and SDG&E in California, and Valley Electric Association in Nevada.

With the increasing quantities of renewable energy projects being developed in California, renewable energy developers have expressed a need for more transparency in tracking the progress of utility transmission projects. Better visibility regarding their completion timelines is required so that new clean energy generation projects can be brought online in a timely manner and power reliability delivered to load.

In response to the need for improved visibility, the CAISO, at the beginning of 2022, established a quarterly Transmission Development Forum. Its purpose was to create a single forum to track the status of transmission network upgrade projects that affect generators as well as all other transmission projects approved in the CAISO's transmission planning process.

The Forum tracks projects approved through the CAISO transmission planning process and network upgrades identified in the generator interconnection process. Each utility provides a workbook that includes approved transmission projects and network upgrades. The status of projects in the workbooks are updated on a quarterly basis. Five Transmission Development Forums have been held since the inception in January 2022. Project developer participants have found them to be helpful and have offered comments suggesting how they can be improved.

A reoccurring theme among stakeholders over the past year has been concern about delays by PG&E in their management of transmission projects and network upgrades. For instance, battery storage developer, Broad Reach Power has noted that in PG&E's most recent presentation regarding 14 transmission projects, two showed a modest schedule

improvement, three showed an in-service delay of 3 or more months, and nine projects showed a delay of 6 or more months. Likewise, for generation interconnection network upgrades, PG&E lists 42 projects in its workbook. In the Broad Reach Power notes, PG&E has only provided information on 23 projects during the five meetings with 7 projects showing a schedule improvement and 16 showing a delay in the project's In-Service Date. The average delay is 18 months.

Broad Reach Power states that PG&E's performance in constructing network upgrades has gotten demonstrably worse over the past year and the utility has not offered a plan to get back on course. Broad Reach Power recommended that the CAISO take the following actions to remedy PG&E's performance:

1. Report to FERC and the CPUC specific information on transmission network upgrade delays. They recommend that delays measured from the in-service date be included in Phase 2 interconnection studies or in executed generation interconnection agreements.
2. Take enforcement actions when a transmission owner fails to meet reasonable performance standards in completing transmission project upgrades.
3. Allow third parties to complete network upgrades when it is demonstrated that a transmission owner cannot perform in a timely manner.

Westlands Solar Park (WSP) reports that they are constructing several solar and storage projects in the Central Valley that are to become operational in Q3 of 2023 and Q1 of 2024. They have indicated they are concerned that these projects could be detrimentally impacted by delays in PG&E's transmission network upgrade work. WSP has provided written comments to the CAISO that it needs more timely information from PG&E on reliability network upgrades in order to plan for near-term work to make the project ready for interconnection.

WSP has emphasized to the CAISO that renewable project developers need to closely coordinate their project construction schedules with the schedules for reliability network upgrades. They informed the CAISO that while the Transmission Development Forum has benefits, more timely information is needed from PG&E on delays than quarterly forums.

The CPUC Public Advocates Office (Cal Advocates) has also taken notice of PG&E's deteriorating performance, siting a massive backload of 83 CAISO approved transmission projects. Cal Advocates has asked the CAISO to re-evaluate the need for PG&E's 13 severely delayed projects that were approved prior to the 2011 TPP. They also have recommended that the CAISO consider market alternatives within the context of its tariff to help remedy PG&E's challenges in the timely completion of necessary transmission projects.

CEERT believes that a more comprehensive review of PG&E's performance is needed that looks at all of PG&E's approved but not yet built transmission and interconnection projects. The Legislature should consider convening a special hearing on the impact of delays in transmission construction in meeting the state's climate and clean energy goals.

11 TRANSMISSION FINANCING OPTIONS

The CAISO estimated in its 20-Year Transmission Outlook report that approximately $30 billion will need to be invested in new transmission over the next two decades to meet California's GHG targets. While this estimate represents a significant level of investment, it is reasonable given the magnitude of the transition to a decarbonized economy. It is also worth noting that transmission projects have a useful operating life of 60 to 80 years. It is vitally important that large-scale transmission projects be implemented in as cost-effective a manner as possible to manage ratepayer impacts.

California investor-owned utilities have credit ratings that range from moderate to poor. According to Fitch, the SDG&E credit rating is BBB+ and SCE's is BBB-, which indicates a moderate level of default risk and is considered investment grade. PG&E, on the other hand, has a BB credit rating, which indicates an elevated level of default risk. California's public power agencies generally have a better credit rating, as does the State of California.[23]

CEERT recommends that policymakers should consider providing financial support or credit enhancement for transmission projects that have been identified as being necessary to meet California's public policy objectives. Alternative sources of funding could include the State General Fund, the Greenhouse Gas Reduction Fund, or state financing[24], as well as support from multiple federal programs (see Table A4 in the appendix for DOE funding programs).

23 SMUD's Fitch credit rating is AA and LADWP Fitch credit rating is AA-. The State of California's credit rating is AA.

24 The California Infrastructure and Economic Development Bank (IBank) was created to finance infrastructure that promotes jobs and improves the quality of life in California communities. IBank has the authority to issue tax-exempt and taxable revenue bonds, and provide credit enhancements.

12
SUMMARY OF FINDINGS AND RECOMMENDATIONS

A. FINDINGS

1. California's aging electric transmission system was built to bring energy from fossil fuel, nuclear, and hydroelectric projects to load centers where energy is used.
2. Clean energy technologies have rapidly declined in cost to the point where new projects are competitive with existing fossil fuel plants.
3. New transmission is needed to unlock the potential for the large-scale development of clean energy technologies. And as CAISO pushes transmission planning to be more proactive, it is critical that transmission planning consider the land implications of the clean energy resources they are unlocking (especially for solar).
4. California has examples of successfully planning for and developing large-scale policy-driven transmission projects in the past (eg., Tehachapi).
5. Transmission planning and development in California have not kept pace over the past decade. The modest transmission that has been approved has developed slowly, and there have not been large-scale policy-driven transmission and generation projects that have been jointly planned since the Tehachapi Regional Transmission Project.
6. Developing new transmission projects is a shared responsibility among the CPUC, CEC, CAISO, transmission owners and developers, and the public.
7. The most recent update to a Memorandum of Understanding between the CPUC, CEC, and CAISO offers an effective framework for transmission planning.
8. The CAISO 20-Year Transmission Outlook report was an informative and comprehensive look at longer term transmission needs through 2040. It identified 14 in-state transmission projects which would integrate high levels of clean energy and allow for the retirement of a portion of the state's fossil fuel power plants. However, CAISO's development of the 20-Year Transmission Outlook did not directly trigger transmission project approval.
9. The CAISO 2022-2023 Transmission Plan could be the document that identifies least regrets transmission projects that need to be developed to meet the resource scenarios developed by the CPUC, if strong consideration is given to the sensitivity portfolio.

10. The CAISO 2022-2023 Transmission Plan should identify significant transmission constraints in the SCE, SDG&E, and PG&E areas.
11. Three key constraints in the SCE area show up in the SCE Metro area, the North of Lugo area (parts of San Bernardino and Kern Counties), and the SCE Eastern area (Riverside County and part of San Bernardino County).
12. The major constraints in the SDG&E area are in delivering power from the Imperial Valley into urban San Diego and north to the SCE service area.
13. For the PG&E area, major transmission constraints are observed in the South Area where significant solar and storage development is expected, particularly under the CPUC sensitivity scenarios.
14. The special study for reduced reliance on Aliso Canyon gas storage facility suggested several options, all of which included an HVDC subsea cable between Diablo Canyon and the Los Angeles basin.
15. Senate Bill 877 requires the CPUC to request the CAISO to identify the highest priority transmission facilities that are needed to deliver clean energy from projects expected to be built by 2035.
16. The CAISO has proposed interconnection queue management reform that will prioritize reliability and deliverability network upgrades for projects committed to load serving entities. However, interconnection reform is not sufficient to accelerate the quantity of clean energy projects required by California's Integrated Resource Planning process and the joint agency SB 100 planning process.
17. Reconductoring of existing transmission corridors with high voltage direct current technology has considerable promise but has not been widely studied.
18. California's transmission permitting process has not kept pace with the need for new transmission projects. Permitting reform is urgently needed.
19. PG&E has experienced recent challenges in making progress on necessary transmission projects and network upgrades that are required to timely interconnect clean energy projects to the grid.
20. The CAISO has estimated that approximately $30 billion will need to be invested in larger transmission projects to meet California's decarbonization goals.

B. RECOMMENDATIONS

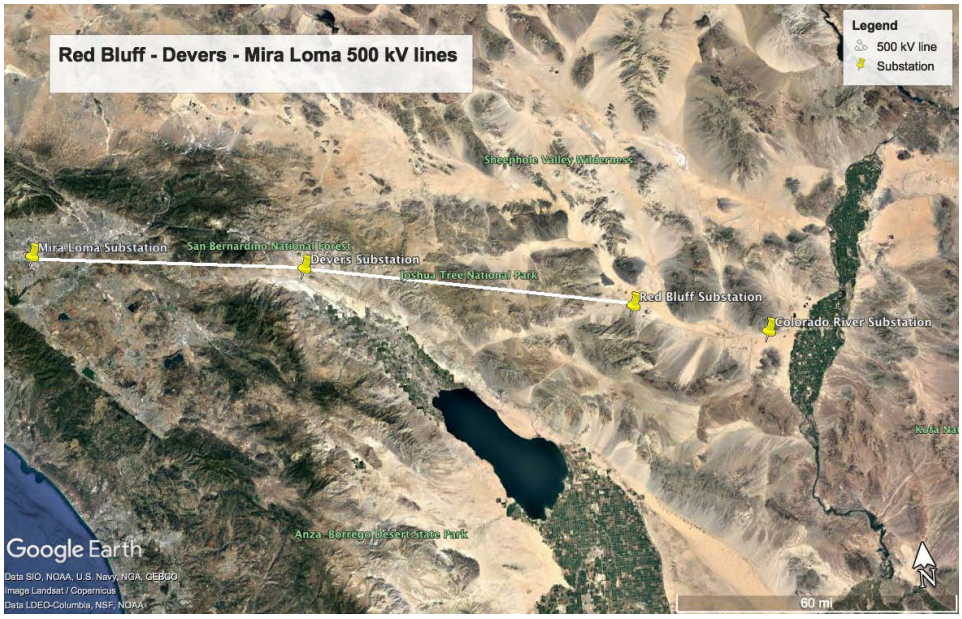
1. The California state government needs to adopt a unified approach to prioritize transmission development to meet the state's decarbonization goals.
2. The CAISO should be the lead agency on transmission need determination, which should drive the necessary permitting and development processes.
3. A longer-term planning horizon (20 years) is needed for resource planning by state agencies and by the CAISO for the development of needed transmission projects.

4. The CAISO should continue to update its 20-Year Transmission Outlook as a regular process.
5. The CAISO should give substantial weight to the 30 MMT Resource Portfolio in determining which policy-driven transmission projects will be included in the 2022-2023 Transmission Plan.
6. Priority for transmission development should be given to the following areas:
    1) Eastern Riverside Area (Red Bluff to Devers to Mira Loma)
    2) North of Lugo Area from Nevada to Hesperia, through cooperative efforts of the CAISO, SCE and LADWP
    3) SCE Metro Area 500 kV system improvements (lines and transformers)
    4) Imperial Valley Area including upgrades to improve power deliverability to urban San Diego and SCE facilities in the north
    5) A HVDC cable connecting Northern California resources at the Diablo substation to the Los Angeles Basin
    6) Major transmission capacity expansion along Path 15 from the Tesla/Tracy substations to Midway in order to accommodate at least 30 GW of new clean energy in the Central Valley.
7. Policymakers should recognize that while changes to the CAISO interconnection process are necessary, they are not sufficient to rapidly improve transmission capacity needed to meet California's decarbonization goals. Transmission expansion as part of a comprehensive look at commercial interest can ease the interconnection process going forward.
8. State support should be provided to study the potential to use HVDC technologies for upgrading transmission carrying capacity in the Central Valley along Path 15.
9. CPUC transmission permitting reform is urgently needed. The Legislature should consider AB 205 as a model for streamlining and expediting the permitting of transmission projects in California.
10. Policymakers should investigate the causes and potential remedies to PG&E's challenges in completing necessary transmission and interconnection network upgrades projects.
11. Alternative transmission financing options should be investigated by California policymakers to lessen the impact of the sizeable investment needed in transmission expansion.

13 | APPENDIX

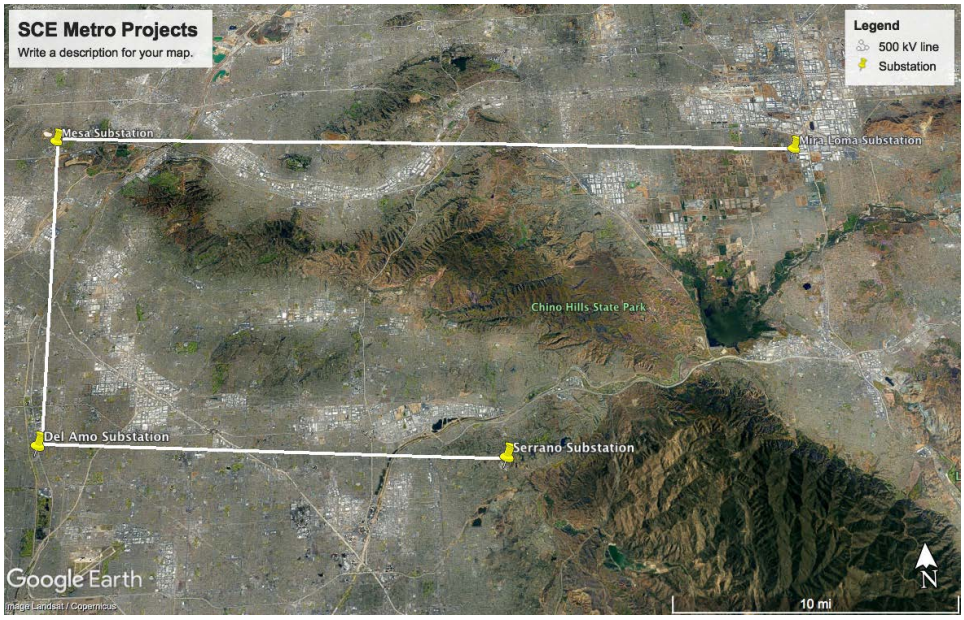
A. MAPS

MAP A1.



MAP A2.

MAP A3.


SCE Metro Projects
Write a description for your map.
Legend
500 kV line
Substation
Mesa Substation
Mira Loma Substation
Chino Hills State Park
Del Amo Substation
Serrano Substation
Google Earth
Image Landsat / Copernicus
10 mi
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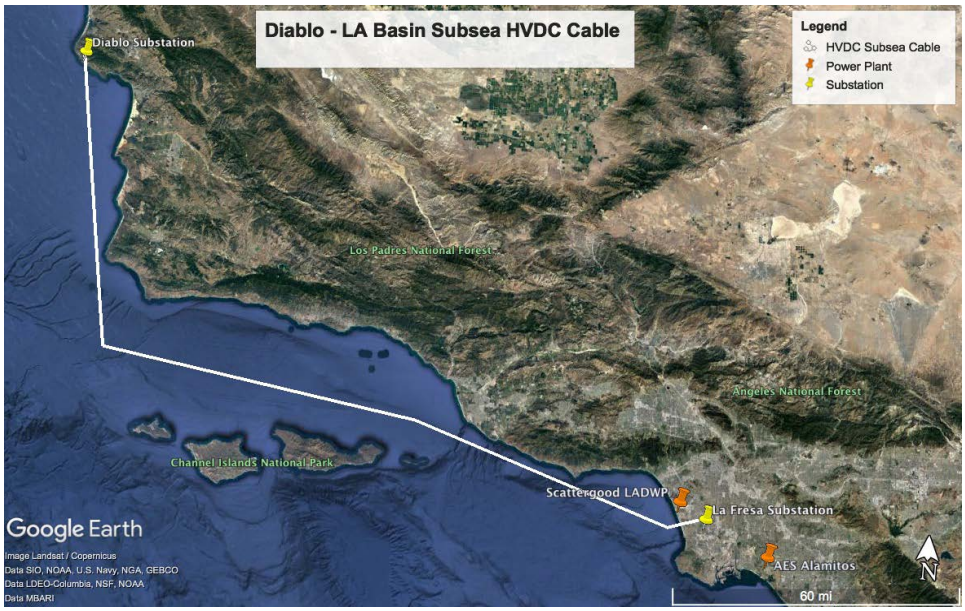
MAP A4.


Diablo - LA Basin Subsea HVDC Cable
Legend
HVDC Subsea Cable
Power Plant
Substation
Diablo Substation
Los Padres National Forest
Angeles National Forest
Channel Islands National Park
Scattergood LADWP
La Fresa Substation
AES Alamitos
Google Earth
Image Landsat / Copernicus
Data SIO, NOAA, U.S. Navy, NGA, GEBCO
Data LDEO-Columbia, NSF, NOAA
Data MBARI
60 mi
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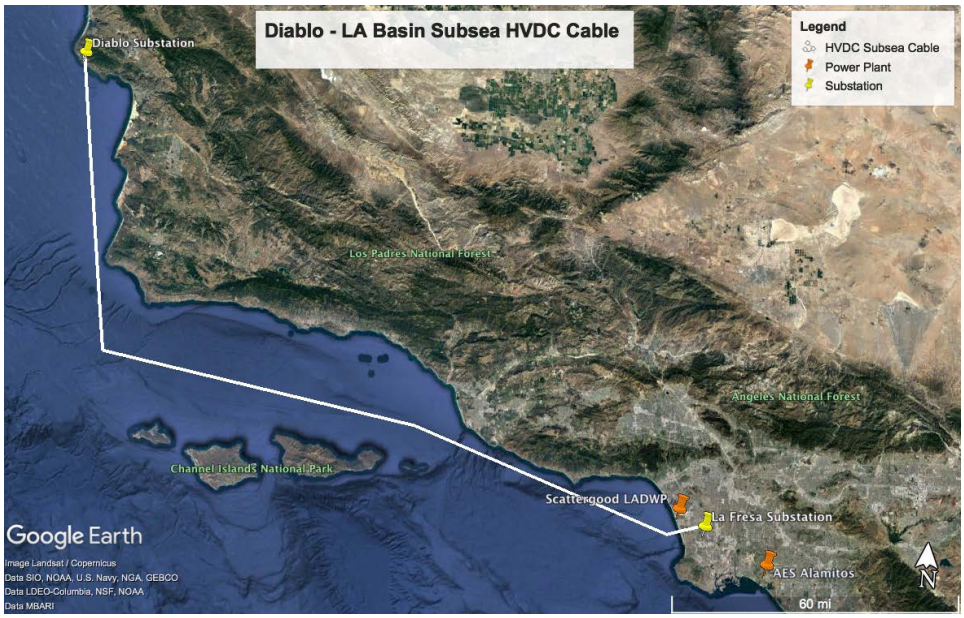
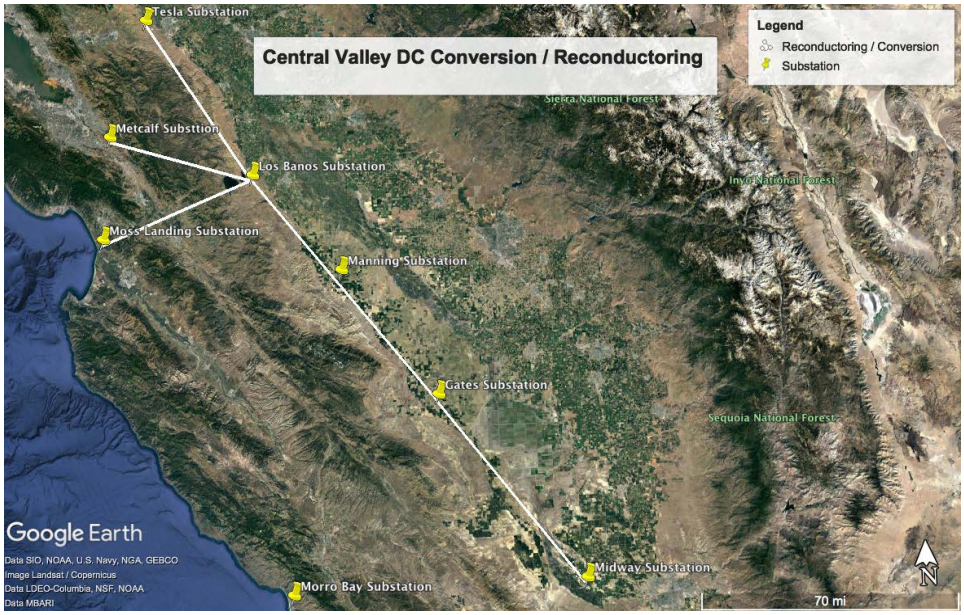
MAP A5.

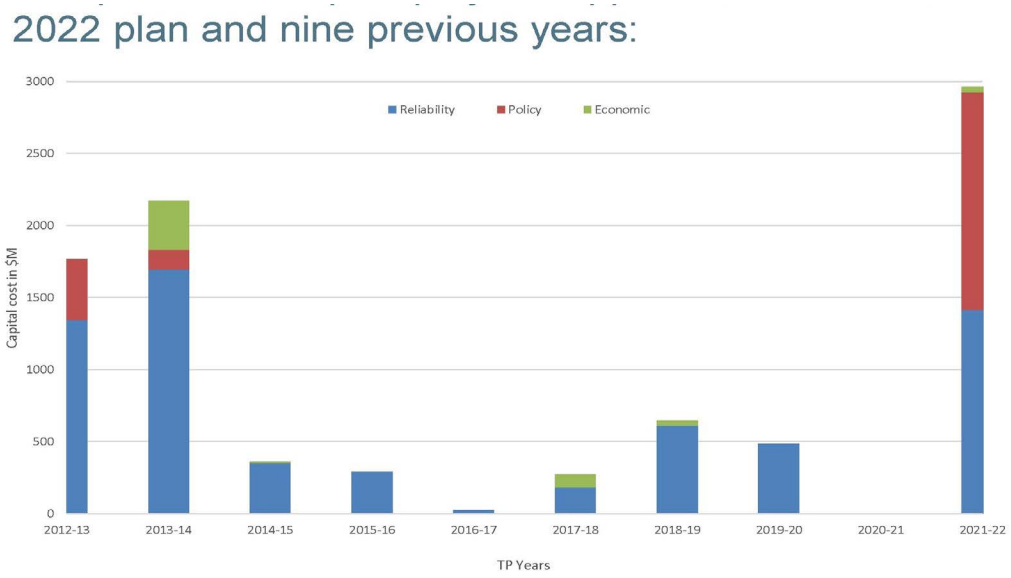

Diablo - LA Basin Subsea HVDC Cable
Legend
HVDC Subsea Cable
Power Plant
Substation
Diablo Substation
Los Padres National Forest
Angeles National Forest
Channel Islands National Park
Scattergood LADWP
La Fresa Substation
AES Alamitos
Google Earth
Image Landsat / Copernicus
Data SIO, NOAA, U.S. Navy, NGA, GEBCO
Data LDEO-Columbia, NSF, NOAA
Data MBARI
60 mi
N

MAP A6.


Central Valley DC Conversion / Reconductoring
Legend
Reconductoring / Conversion
Substation
Tesla Substation
Metcalf Substtion
Los Banos Substation
Moss Landing Substation
Manning Substation
Gates Substation
Midway Substation
Morro Bay Substation
Sierra National Forest
Inyo National Forest
Sequoia National Forest
Google Earth
Data SIO, NOAA, U.S. Navy, NGA, GEBCO
Image Landsat / Copernicus
Data LDEO-Columbia, NSF, NOAA
Data MBARI
70 mi
N

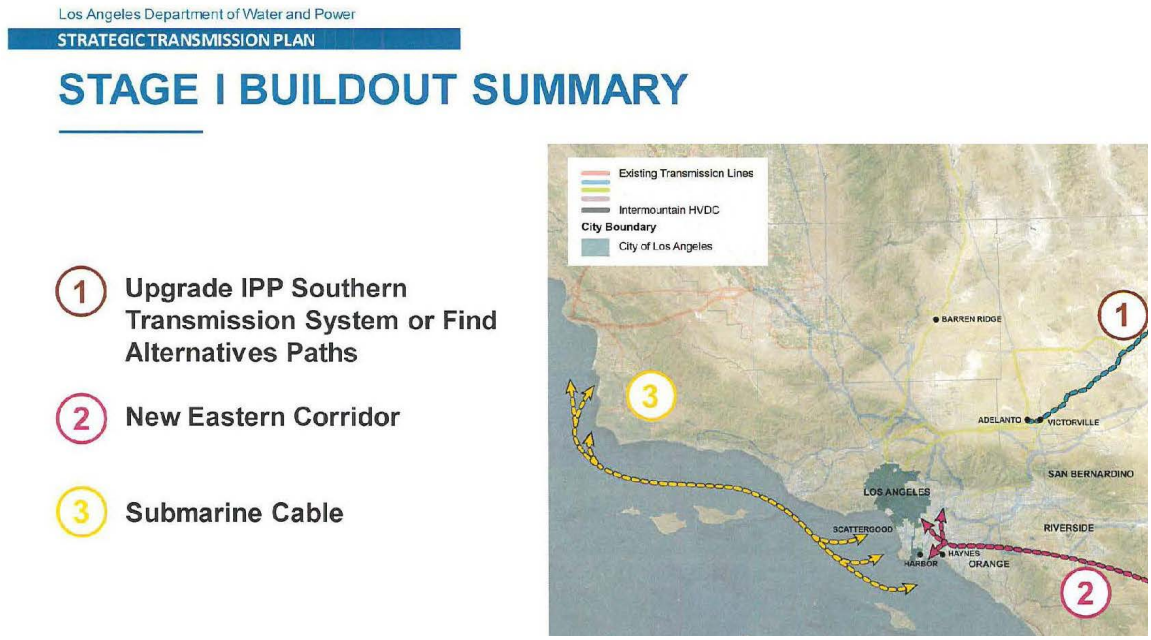
B. TABLES

TABLE A1.



Source: CAISO 2022-23 TPP Presentation September 28th, 2022.

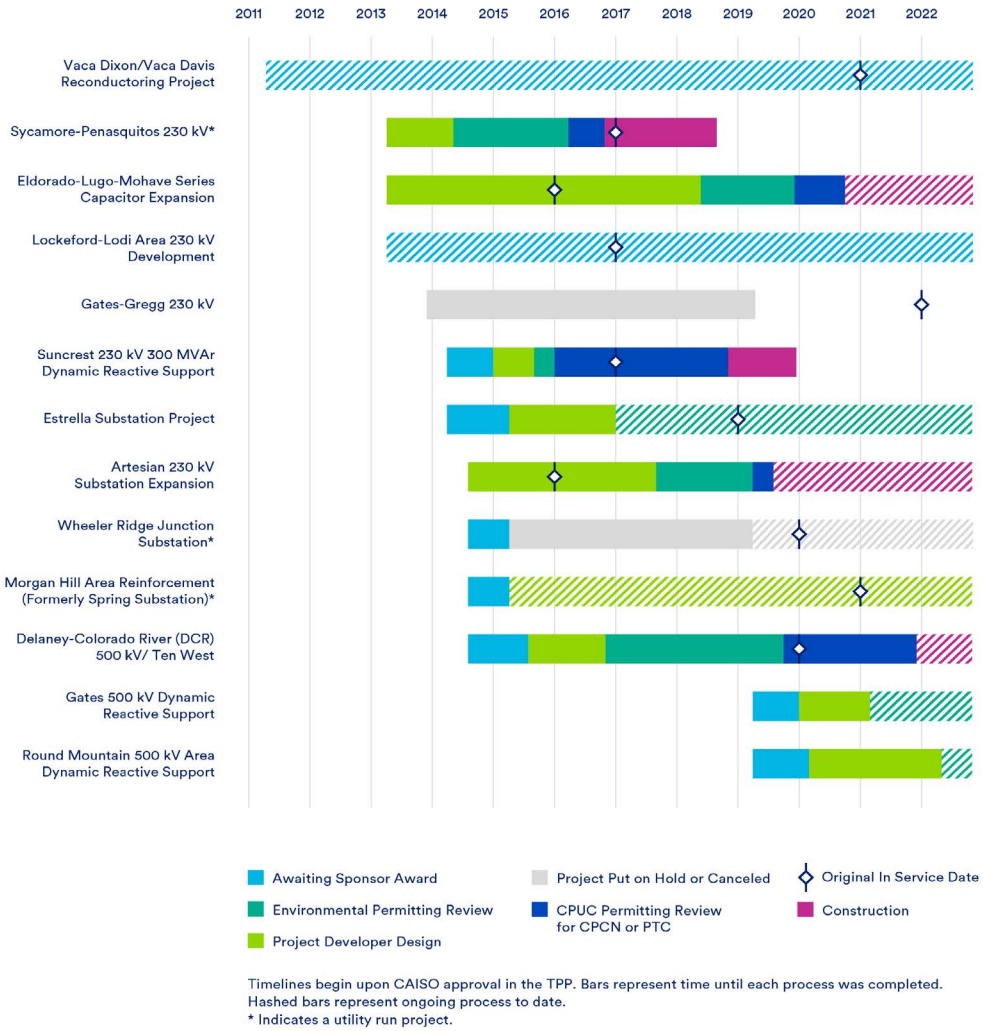
TABLE A2.



Source: "Power System Strategic Transmission Plan (STP) Update," LADWP December 13th, 2022

TABLE A3.

CAISO Approved Transmission Project Timelines



Timelines begin upon CAISO approval in the TPP. Bars represent time until each process was completed.
Hashed bars represent ongoing process to date.
* Indicates a utility run project.

Source: "Transmission Development in California—What's the Slowdown?" Clean Air Task Force, January 2023

TABLE A4. *DOE Programs Useful for Transmission Projects*

TRANSMISSION FACILITATION PROGRAM	LARGE SCALE TRANSMISSION	LOANS, CAPACITY CONTRACTS, TECHNICAL ASSISTANCE, OWNERSHIP	PROJECT DEVELOPER AND/OR OWNER
Grid Resilience	Transmission wildfire resilience	Grant	State, which would provide subaward to project owner
Upgrading Our Electric Grid	Innovative transmission for resilience	Grants	State and/or local government
Technologies to Enhance Grid Flexibility	Smart grid, advanced conductors, network topology (e.g., multi-terminal grids)	Grants	Utilities
Regional Clean Hydrogen Hubs	Network of hydrogen producers and consumers with "connectivity" infrastructure	Grants, other agreements	State and local government, utilities, technology developers, others
Loan Programs Office	Large transmission	Loan guarantees	Project developer/ owner
WAPA	Power and Transmission	Power and/or Transmission Service Purchase Contract	Project developer/ owner
Transmission Infrastructure Program	Transmission	Loans	Project developer/ owner
Public-Private Partnership Projects	Transmission	Partnership to develop and own transmission assets, including through WAPA, under the Transmission Facilitation Program authority	Project developer/ owner

Source: DOE, https://www.energy.gov/