



California ISO


# 2024-2025 Transmission Planning Process: Draft Transmission Plan

*April 15, 2025 Stakeholder Meeting*

# Housekeeping Reminders

- Stakeholder calls and meetings related to Transmission Planning are not recorded.
  - Given the expectation that documentation from these calls will be referred to in subsequent regulatory proceedings, we address written questions through written comments, and enable more informal dialogue at the call itself.
  - Minutes are not generated from these calls, however, written responses are provided to all submitted comments.
- Calls are structured to stimulate an honest dialogue and engage different perspectives.
- Please keep comments professional and respectful.

# Instructions for raising your hand to ask a question

- Open the Participant and Chat panels from the bottom right.
- If you are connected to audio through your computer or used the “call me” option, select the raise hand icon  located at the bottom of the chat panel
  - **Note:** If you dialed in outside of webex, press \*3 to get into the question queue
- Please remember to state your name and affiliation before making your comment.
- If you need technical assistance during the meeting, please send a chat to the event producer @Intellor events
- You may also send your question via chat to all panelists.

# 2024-2025 Transmission Planning Process

## Stakeholder Call – Agenda

Topic	Presenters
Welcome and Introductions	Yelena Kopylov-Alford
Overview	Jeff Billinton
Reliability-driven Projects Recommended for Approval <ul style="list-style-type: none"><li>PG&amp;E Planning Area</li><li>SCE Planning Area</li><li>VEA Planning Area</li><li>SDG&amp;E Planning Area</li></ul>	Preethi Rondla Uriel Rangel Diaz Frank Chen Rick Torres Nikitas Zagoras Rene Romo de Santos
Frequency Response	Chris Fuchs
Maximum Import Capability (MIC) – Expansion Requests	Catalin Micsa
Policy-driven Projects Recommended for Approval	Lindsey Thomas
Economic Assessment	Yi Zhang
Wrap-up/Next steps	Yelena Kopylov-Alford



# Transmission Planning Process Overview

## Draft 2024-2025 Transmission Plan

Jeff Billinton

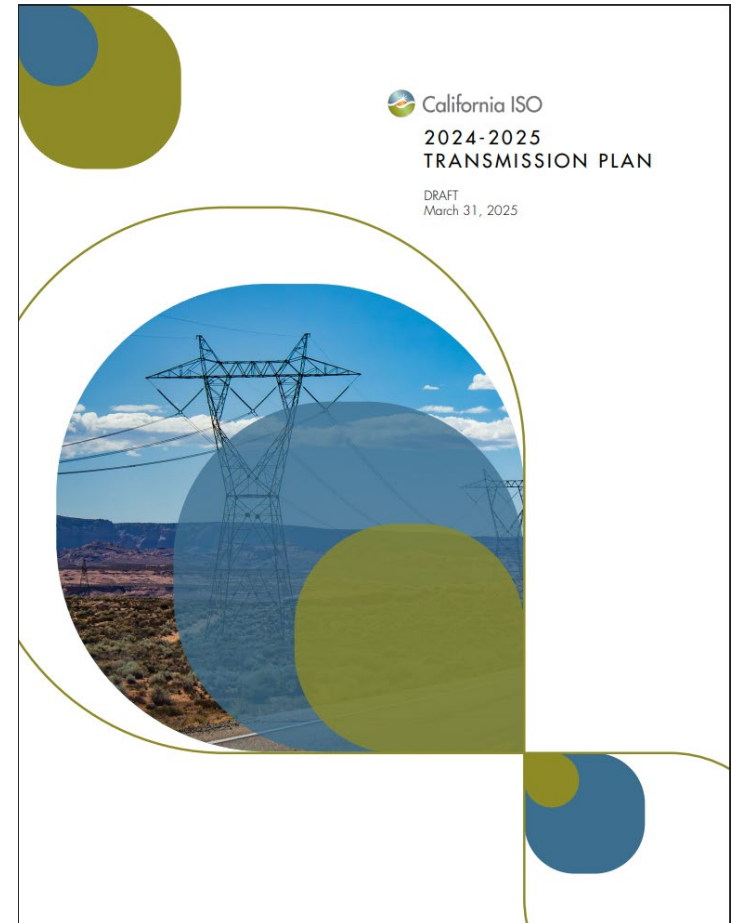
*Director, Transmission Infrastructure Planning*

2024-2025 Transmission Planning Process Stakeholder Meeting

*April 15, 2025*

# 2024-2025 Draft Transmission Plan

- The 2024-2025 Draft Transmission Plan was posted on March 31, 2025.  
<https://stakeholdercenter.caiso.com/InitiativeDocuments/Draft-2024-2025-Transmission-Plan.pdf>
- The Draft Transmission Plan represents the CAISO's identification of system needs over the next 15 years and offers an opportunity for stakeholder input before final recommendations are presented to the CAISO Board of Governors in May.



# Draft Transmission Plan Project Recommendations

- This year's Plan identified 31 transmission projects, with a total capital cost estimate of \$4.8 billion, as needed to maintain the reliability of the ISO transmission system and unlock access to renewable generation resources to meet state energy needs
- The ISO will present the Plan to the ISO Board of Governors at the May, 2025 meeting for approval
- Subject to approval, the ISO will initiate the competitive solicitation process for the two eligible projects

# 2024-2025 Transmission Planning Process

January 2024

April 2024

May 2025

## Phase 1 – Develop detailed study plan

State and federal policy  
CEC - Demand forecasts  
CPUC - Resource forecasts and common assumptions with procurement processes  
Other issues or concerns

## Phase 2 - Sequential technical studies

- Reliability analysis
- Renewable (policy-driven) analysis
- Economic analysis

Publish comprehensive transmission plan with recommended projects

## Phase 3 Procurement

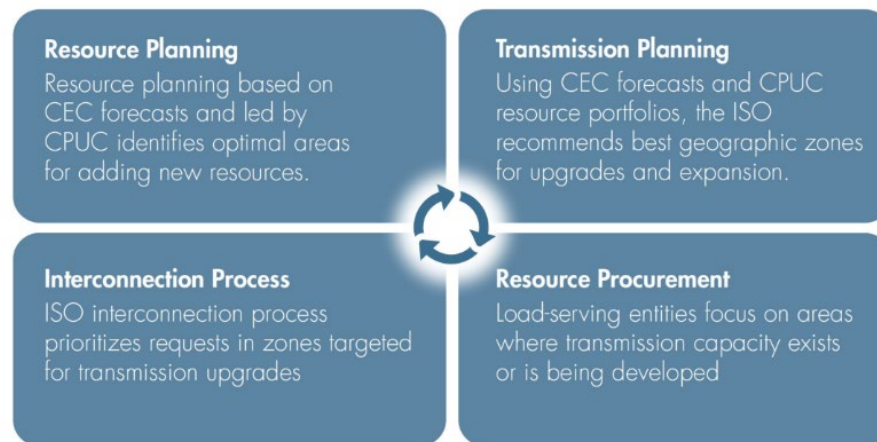
CAISO Board for approval of transmission plan



# 2024-2025 Transmission Plan Milestones

- Draft Study Plan posted on February 21
- Stakeholder meeting on Draft Study Plan on February 28
  - Comments to be submitted by March 13
- Final Study Plan to be posted in April
- Preliminary reliability study results to be posted on August 15
- Stakeholder meeting on September 23 and 24
  - Comments to be submitted by October 8
- Request window closes October 15
- Preliminary policy and economic study results on November 13
  - Comments to be submitted by November 27
- Long-Term LCR Study Stakeholder Meeting December 9
- Draft transmission plan to be posted on March 31, 2025
- Stakeholder meeting: Draft Transmission Plan, April 15, 2025
  - Comments to be submitted within two weeks (April 29) after stakeholder meeting
- Revised draft for approval at May 2025 Board of Governor meeting

# Transmission Planning and Generation Interconnection are two of four fundamental and interwoven resource development processes:



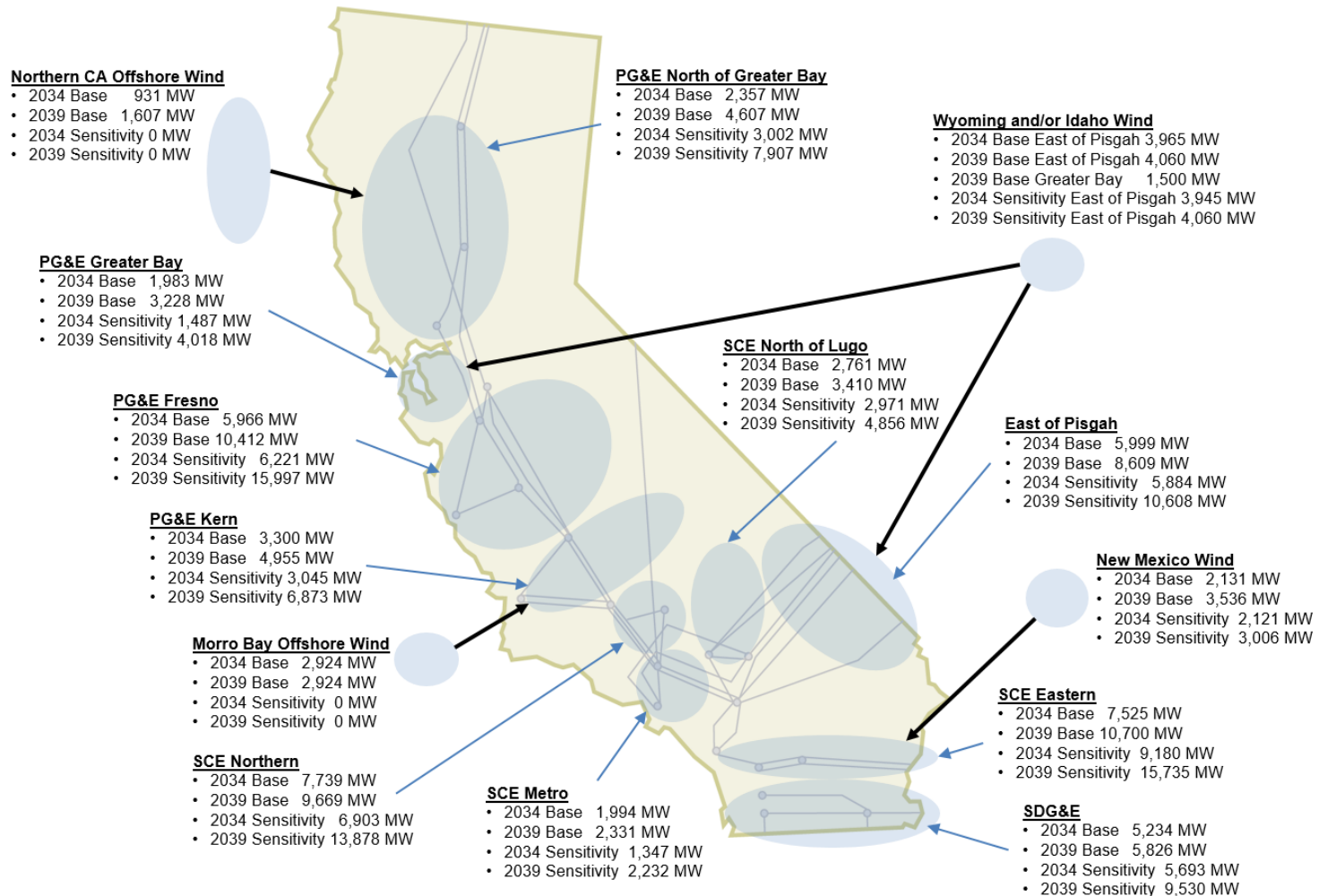
The strategic direction for transformational change was established in the CPUC/CEC/ISO Memorandum of Understanding signed in December, 2022 to:

- Tighten the linkage between resource and transmission planning, procurement direction, and the ISO interconnection process to the greatest extent possible.
- Create formal linkage between CEC SB 100/IEPR activities and the ISO and CPUC processes
- Reaffirm the existing state agency and single forecast set coordination
- Update references to current processes and set direction to updating process documentation

# Considerations in the 2024-2025 Transmission Planning Process

- The CPUC base portfolio includes projections that California needs to add more than:
  - 54 GW of capacity by 2034
  - 76 GW of capacity by 2039
- CEC IEPR 2023 identifies an increase in year over year peak demand growth, particularly in the Greater Bay Area

# The 2024-2025 Transmission Plan continues to utilize the zonal approach for resource development



# Reliability-Driven Management Approved Projects

- 7 Reliability Driven projects were approved by CAISO management following the intent to approve as presented in the November TPP stakeholder meeting and review of stakeholder feedback.

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

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

# Reliability-Driven Recommended Projects

- 21 additional reliability projects have been recommended in the Draft Transmission Plan. These projects are driven by load growth and evolving grid conditions as the generation fleet transitions to increased renewable generation.
- Total of 28 Reliability projects included in the 2024-2025 Transmission Planning process, with an estimated cost of \$4.555 billion.

No.	Project Name	PTO Area	Planning Area	Est Cost (\$M)
8	Sloan Canyon Tertiary Reactors	GLW	VEA	15
9	Ames Distribution – Palo Alto 115 kV transmission line	PG&E	GBA	84
10	Cortina #3 60 kV Reconductoring	PG&E	CVLY	55.5
11	Gold Hill-El Dorado Reinforcement	PG&E	CVLY	127
12	Greater Bay Area 500 kV Transmission Reinforcement	PG&E	GBA	700
13	Metcalf Substation 500/230 kV Transformer Bank Addition	PG&E	GBA	182
14	Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade Re-scope	PG&E	GBA	135
15	North Oakland Reinforcement Project	PG&E	GBA	1127
16	San Jose B – NRS 230 kV line	PG&E	GBA	200
17	San Mateo 230/115 kV Transformer Bank Addition Project	PG&E	GBA	110
18	South Bay Reinforcement Project	PG&E	GBA	410
19	South Oakland Reinforcement Project	PG&E	GBA	250
20	West Fresno 115 kV Voltage Support	PG&E	Fresno	60
21	Alamitos 230 kV SCD Upgrade	SCE	SCE Main	5
22	Julian Hinds-Mirage 230 kV Advanced Reconductor	SCE	Eastern	76
23	Kramer-Coolwater 115 kV Line Looping into Tortilla 115 kV Substation	SCE	NOL	37
24	Serrano 230 kV SCD GIS Bus Split	SCE	SCE Main	28
25	Serrano 500 kV SCD Mitigation	SCE	SCE Main	183
26	Tortilla 115 kV Capacitor Replacement	SCE	NOL	5
27	Coronado Island Reliability Reinforcement Phase II	SDG&E	SDG&E	66
28	Downtown Reliability Reinforcement	SDG&E	SDG&E	500
			<b>Total</b>	<b>4555.2</b>

# Policy-Driven Recommended Projects

- To meet the renewable generation requirements established in the CPUC-developed renewable generation portfolios, an additional 3 transmission projects that are policy driven have been recommended, totaling \$289.5 million

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



# Economic-Driven Recommended Projects

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



# Projects Eligible for Competitive Solicitation

- The ISO federal tariff sets out a competitive solicitation process for eligible reliability-driven, policy-driven and economic-driven regional transmission facilities found to be needed in the plan.
- The following projects are eligible for competitive solicitation, and the ISO will provide a schedule for those processes in May, 2025:
  - San Jose B – NRS 230 kV line
  - Metcalf – Manning 500 kV line

# FERC Order 1000 Interregional Coordination Process

- The 2024-2025 Transmission Planning Process includes the first year of the two year Interregional Transmission Coordination planning process that the ISO conducts with its neighboring planning regions, WestConnect and NorthernGrid
- The submission period for interregional transmission projects was held between January 1<sup>st</sup> to March 31<sup>st</sup>, 2024. Five interregional transmission projects (ITPs) were submitted in this window
- Western Planning Regions:
  - WestConnect will not evaluate the submitted ITPs as it has determined that there are no regional transmission needs in its 2024-26 regional planning cycle
  - NorthernGrid has yet to make a regional need determination on the submitted ITPs

# Grid-Enhancing Technologies (GETs)

- GETs encompass a range of technologies with specific benefits and opportunities. Currently, the term is used to describe:
  - Advanced conductors – high temperature, low sag characteristics
  - Dynamic line ratings
  - Power Flow Controllers
  - Topology Optimizations
- The following reliability-driven reconductoring projects recommended for approval will utilize advanced conductors:
  - Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade Re-scope:
    - Piercy-Metcalf 115 kV line;
    - Swift-Metcalf 115 kV line;
    - Newark-Dixon Landing 115 kV line; and
    - McKee-Piercy 115 kV line;
  - Julian Hinds-Mirage 230 kV Advanced Reconductor .

# Policy Portfolio Sensitivity Study

- The CPUC resource portfolios included an informational sensitivity based on elevated levels of retirement of gas-fired generation.
- The ISO also assessed the sensitivity scenario in reliability, policy economic and the long-term local capacity technical analysis.
- The detailed analysis is included in the applicable Appendices B, G, F and J with the following observations were made:
  - In the Greater Bay area, the reliability constraints and resource deficiencies increase;
  - In the LA Basin area, the LCR requirements increase in the 15-year planning horizon. With increased storage resources in the portfolio in the LA Basin area, the constraint can be addressed with local dynamic voltage support; and
  - In the Moorpark area, thermal constraints were observed in the 15-year planning horizon.

# Deliverability Reservations for Long Lead-Time Resources

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

Resource type and Location	Base Portfolio		Deliverability reservation
	2034	2039	
Wyoming wind (Eldorado)	2,905 MW	3,000 MW	1,500 MW
Wyoming wind (Tesla)	0 MW	1,500 MW	0 MW
Idaho wind (Harry Allen)	1,060 MW	1,060 MW	1,060 MW
New Mexico Wind (Palo Verde)	2,131 MW	3,536 MW	3,536 MW
Offshore wind (North Coast)	931 MW	1,607 MW	1,607 MW
Offshore wind (Central Coast)	2,924 MW	2,924 MW	2,924 MW
Geothermal (Imperial Irrigation District)	950 MW	950 MW	950 MW

# Additional Policy Considerations

- The ISO considers a number of social, economic, and policy-related drivers in the transmission planning process, and will continue to adapt to the policy landscape in future processes.
  - FERC Orders No. 1920 and 1920-A
  - Engagement with Tribes
  - West-wide transmission planning
  - Planning for large loads
  - Transmission project execution and completion
  - Assignment of re-scoped, previously approved transmission projects
  - Grid-enhancing technologies and non-wires solutions
  - Relevant State legislation
- Appendix K also lists infrastructure-related submissions to the 2024 stakeholder policy catalog, with ISO responses to each submission.

# Comments

- Comments due by end of day April 29, 2025
- Submit comments through the ISO's commenting tool, using the template provided on the process webpage:

<https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2024-2025-Transmission-planning-process>



# Reliability Assessment Recommendations – PG&E Area Draft 2024-2025 Transmission Plan

*Preethi Rondla and Uriel Rangel Diaz*

Regional Transmission – North

*2024-2025 Transmission Planning Process Stakeholder Meeting*

*April 15, 2025*

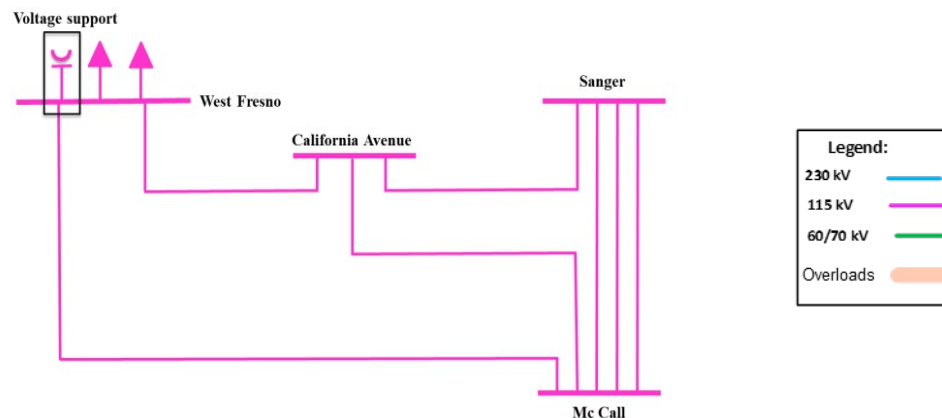


# New Reliability Projects Recommended for Approval in 2024-2025 TPP - PG&E Area

Projects	Planning Area	Status
Konocti – Eagle Rock 60 kV Line Reconductoring	North Coast / North Bay	Management Approved in December
San Miguel New 70kV Line Project	Los Padres	Management Approved in December
Pittsburg-Kirker 115 kV Line Section Limiting Elements Upgrade Project	Greater Bay Area	Management Approved in December
Sobrante 230 kV Bus Upgrade Project	Greater Bay Area	Management Approved in December
Jefferson-Stanford 60 kV Recabling Project	Greater Bay Area	Management Approved in December
Moraga 230/115 kV Transformer Bank Addition Project	Greater Bay Area	Management Approved in December
West Fresno 115 kV Voltage Support	Greater Fresno Area	Recommended for Approval
Cortina #3 60 kV Reconductoring	Central Valley	Recommended for Approval
Gold Hill-El Dorado Reinforcement	Central Valley	Recommended for Approval
Ames Distribution – Palo Alto 115 kV transmission line	Greater Bay Area	Recommended for Approval
Greater Bay Area 500 kV Transmission Reinforcement	Greater Bay Area	Recommended for Approval
Metcalf Substation 500/230 kV Transformer Bank Addition	Greater Bay Area	Recommended for Approval
Metcalf-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade Rescope	Greater Bay Area	Recommended for Approval
North Oakland Reinforcement Project	Greater Bay Area	Recommended for Approval
San Jose B – NRS 230 kV line	Greater Bay Area	Recommended for Approval
San Mateo 230/115 kV Transformer Bank Addition Project	Greater Bay Area	Recommended for Approval
South Bay Reinforcement Project	Greater Bay Area	Recommended for Approval
South Oakland Reinforcement Project	Greater Bay Area	Recommended for Approval

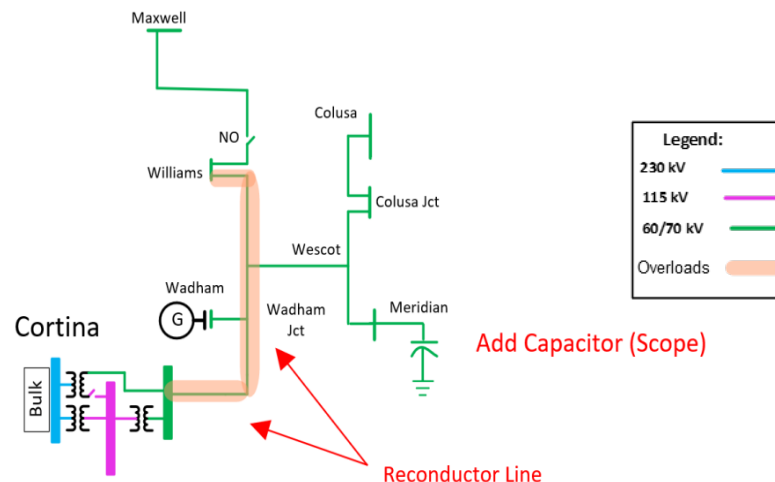
# West Fresno 115 kV Voltage Support

- Reliability Assessment Need
  - Real time issues driven by P0 category contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Install 75 MVAR voltage support and
  - Expand West Fresno 115 kV bus as needed for voltage support interconnection.
- Estimated Project Cost
  - \$30M - \$60M
- Estimated In-service Date
  - 2031
- Alternatives Considered
  - Energy storage is not recommended due to higher interconnection cost.
- Recommendation
  - Approval



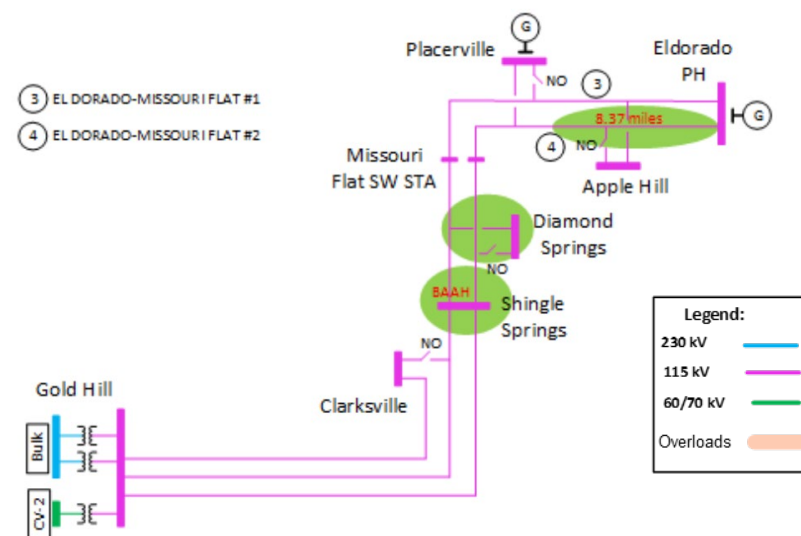
# Cortina #3 60 kV Reconductoring

- Reliability Assessment Need
  - Addressing overloads within the 60 kV transmission system connecting Williams, Colusa, Meridian substations under NERC Category P0 and P1 contingencies.
  - Driven by EV distribution load projects.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductor Cortina #3 60 kV line to achieve minimum conductor rating of 1014 Amps for summer normal rating and 1127 Amps for summer emergency rating.
  - Install a 15 MVAR shunt capacitor at Meridian 60 kV substation.
  - Remove any limiting components as necessary to achieve full conductor capacity.
- Estimated Project Cost
  - \$27.8M - \$55.5M
- Estimated In-service Date
  - May 2031
- Alternatives Considered
  - Power Flow Control Device or RAS.  
Not applicable for radial systems
  - Energy storage is not recommended due to limited charging window
- Recommendation
  - Approval



# Gold Hill – El Dorado Reinforcement

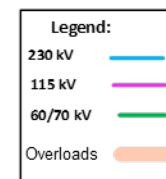
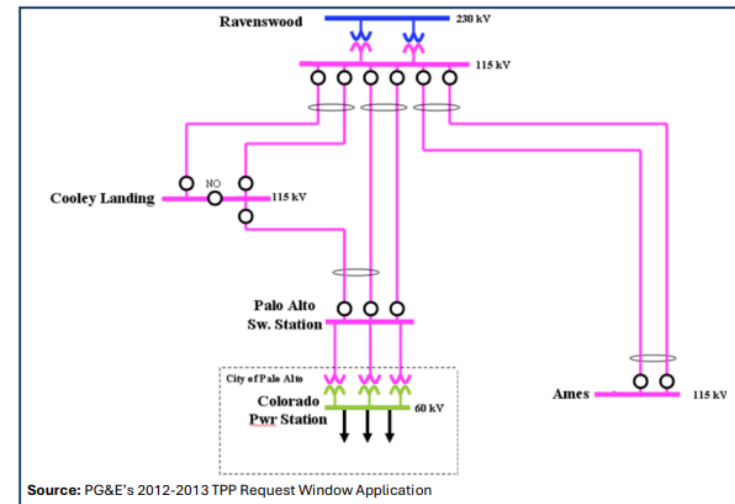
- Reliability Assessment Need
  - To addressing near-term overloads in 115 kV system under NERC Category P2-1 contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Serve Diamond Springs 115 kV Substation from Missouri Flat – Gold Hill #1 115 kV Line
  - Convert Shingle Springs Substation 115 kV bus to BAAH
  - Reconductor ~8.8 circuit miles between El Dorado and 008/062 of the El Dorado – Missouri Flat #2 115 kV Line with larger conductor to achieve minimum 577 Amps of summer emergency rating.
  - Remove any limiting components as necessary to achieve full conductor capacity
- Estimated Project Cost
  - \$63.5M - \$127M
- Estimated In-service Date
  - May 2032
- Alternatives Considered
  - Serve Apple hill from line 2 and Placerville and Diamond springs from line 1 with shunt caps and re-conductoring Eldorado-Missouri flat line1 which has higher cost.
  - BESS addition needs bus upgrades at both Diamond springs and Shingle springs which has higher cost without offering higher load serving capability
- Recommendation
  - Approval



# Ames Distribution – Palo Alto 115 kV transmission line

- Reliability Assessment Need
  - Addressing long-term overloads in the Ravenswood – Palo Alto 115 kV lines under NERC Category P6 and P7 contingencies.
  - Improve system reliability by diversifying the sources serving the load at Palo Alto
- Project Scope
  - Construct a new Ames Distribution – Palo Alto 115 kV line using existing vacant tower positions and idle lines, with a minimum capacity requirement of 1500 Amps;
  - Expand the Ames Distribution Station to allow for one additional 115 kV connection. It requires the upgrade Ames Distribution to ring bus station; and expand the Palo Alto Switching Station to allow for one additional 115 kV connection.
- Estimated Project Cost
  - \$42M - \$84M
- Estimated In-service Date
  - May 2034
- Alternatives Considered
  - Adding a new distribution substation and connect it radial to Ames or looped into the Palo Alto – Ames line. It is not recommended due to higher cost.
  - Power Flow Control Device or RAS. Not applicable for radial systems
  - BESS. Not feasible due to land availability limitations.
  - Reconductoring. It is not recommended due to higher cost.

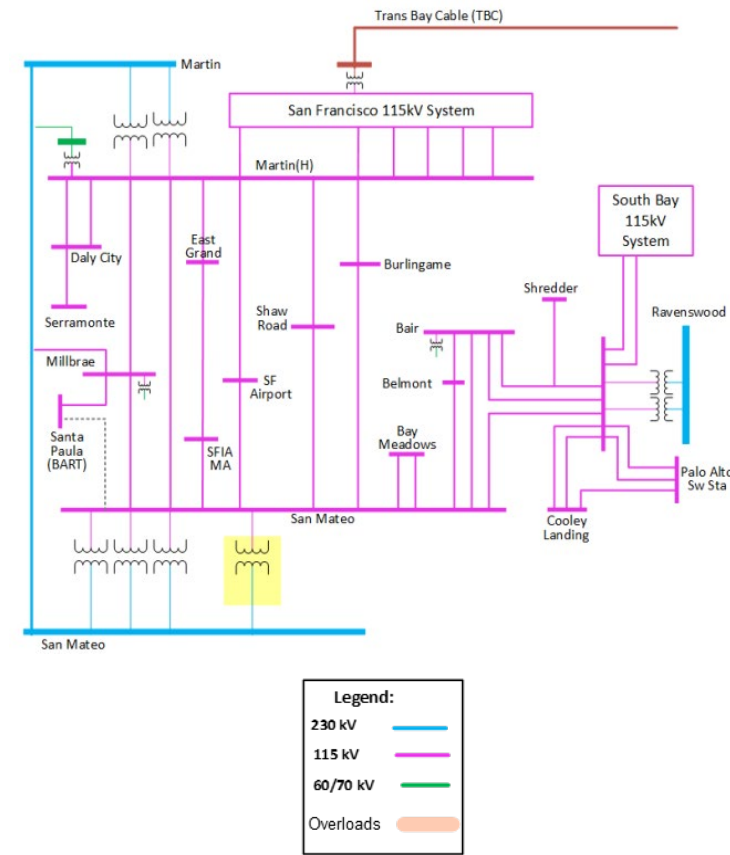
- Project Submitter
  - CPAU
- Recommendation
  - Approval



# San Mateo 230/115 kV Transformer Bank Addition Project

- Reliability Assessment Need
  - Addressing overloads in the San Mateo 230/115 kV transformer banks under NERC Category P6 contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Install a new 230/115 kV transformer bank at San Mateo Substation with minimum 420 MVA for summer normal rating and 462 MVA for summer emergency rating.
  - Upgrade San Mateo 115 kV bus and any limiting elements to achieve full bank capacity
- Estimated Project Cost
  - \$55M - \$110M
- Estimated In-service Date
  - May 2032
- Alternatives Considered
  - Increasing the transformer capacity in other existing or new substation. It is not recommended due to higher cost and reduced effectiveness.
  - BESS. Not recommended due to insufficient capacity in the charging window.
  - Power Flow Control Device. Not recommended due to the multiple power flow controllers required

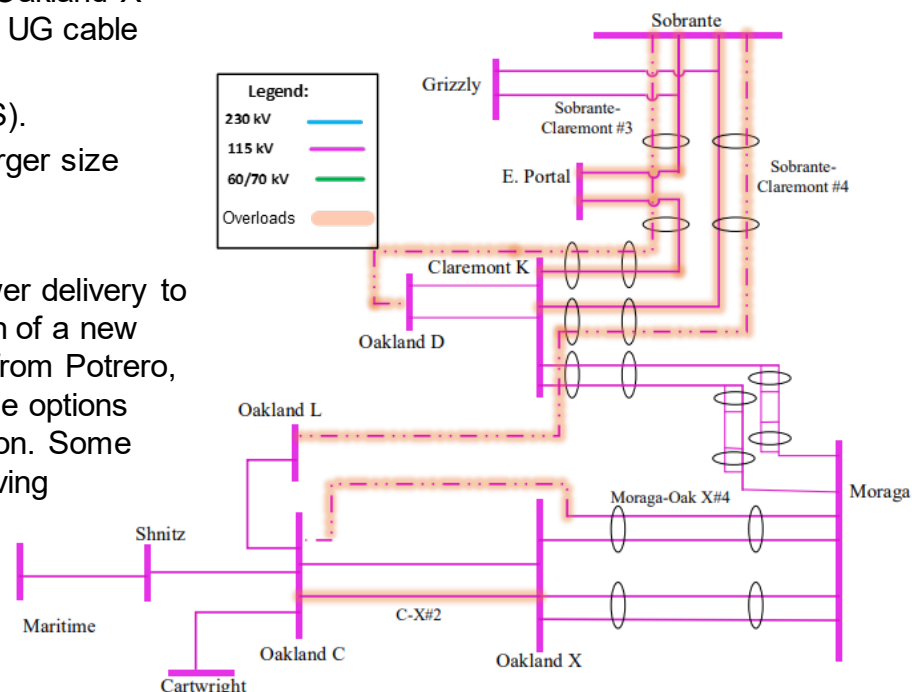
- Recommendation
  - Approval



# North Oakland Reinforcement Project

- Reliability Assessment Need
  - Addressing overloads in the 115 kV transmission system in the Northern Oakland area under NERC Category P2 and P6 contingencies.
- Project Scope
  - Rebuilding the two Sobrante-Grizzly-Clairemont #1 and #2 115 kV lines into four lines, each with a summer normal rating of at least 1714 Amps.
  - Rerouting the Moraga-Oakland X #4 line to bypass the Oakland X Substation and instead connect to Oakland C via a new UG cable section.
  - Converting Oakland C to Gas-Insulated Switchgear (GIS).
  - Replacing the Oakland C-Oakland X UG cable with a larger size cable.
- Alternatives Considered
  - Several alternatives were considered for increasing power delivery to the north Oakland area. These included the construction of a new 230/115 kV substation, a new 115 kV transmission line from Potrero, and upgrades to the existing 115 kV grid. However, these options were found to be less effective than the proposed solution. Some alternatives had similar costs but offered lower load serving capabilities.
- Recommendation
  - Approval

- Project Submitter
  - PG&E
- Estimated Project Cost
  - \$564M - \$1,127M
- Estimated In-service Date
  - May 2032

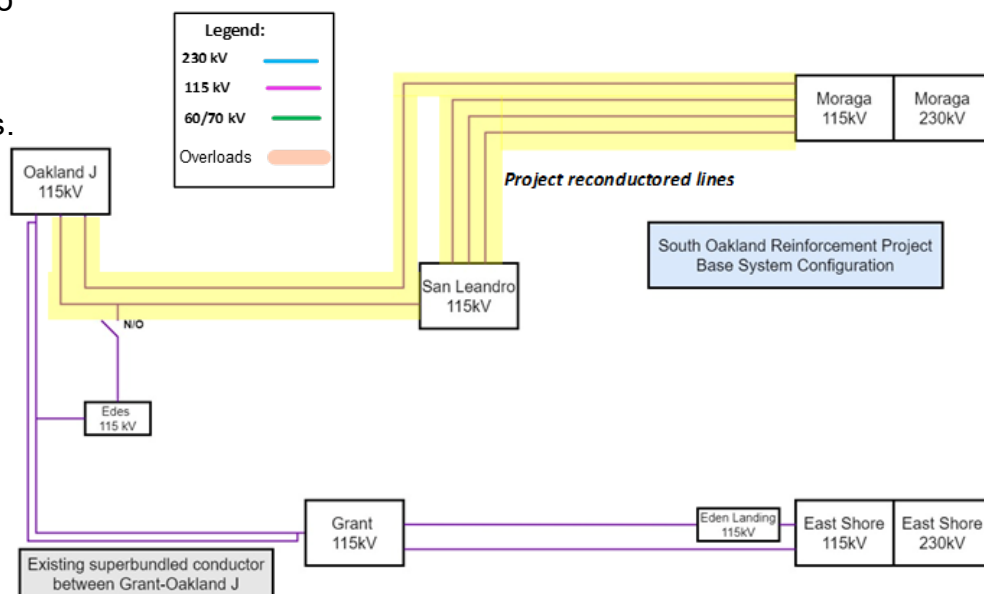




# South Oakland Reinforcement Project

- Reliability Assessment Need
  - Addressing overloads in the 115 kV transmission system in the South of Oakland under NERC Category P1 to P7 contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductor the Moraga-San Leandro #1, #2, and #3 115 kV lines to achieve a minimum capacity of 1500 Amps;
  - Reconductor the Moraga-Oakland J 115 kV line to achieve a minimum capacity of 2000 Amps; and
  - Reconductor the San Leandro-Oakland J 115 kV line to achieve a minimum capacity of 2000 Amps.
- Estimated Project Cost
  - \$125M - \$250M
- Estimated In-service Date
  - May 2032
- Recommendation
  - Approval

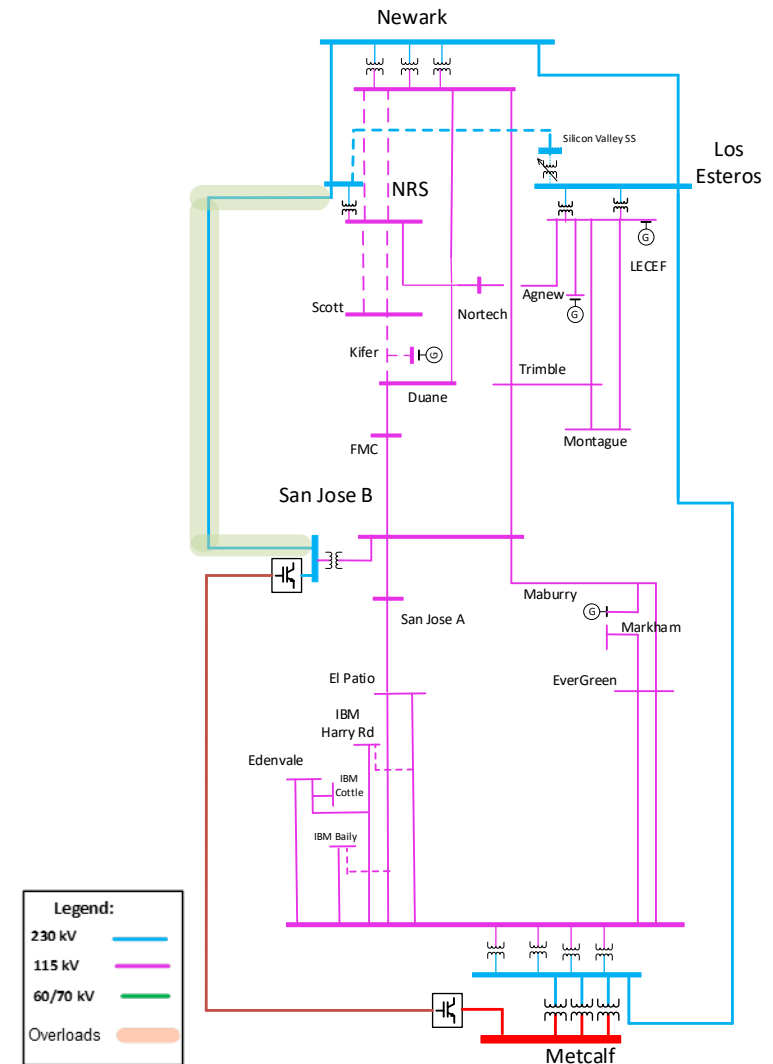
- Alternatives Considered
  - Considering the projected load growth and the topology of the Oakland South area, a new 230 kV supply from various sources was evaluated alongside with other alternatives. However, this type of solution does not avoid the reconductoring need in the region, particularly for the lines running from Moraga and San Leandro to Oakland J.





# San Jose B – NRS 230 kV line

- Reliability Assessment Need
  - Complementary project of the revised San Jose HVDC area project to prevent overloads in the 115 kV transmission system in the South Bay area under NERC Category P1 to P7 contingencies.
- Project Scope
  - Build a new 230 kV line from the new San Jose B 230 kV to NRS
  - One new 230 kV connection at both ends of the proposed line
- Estimated Project Cost
  - \$150M - \$200M
- Estimated In-service Date
  - 2028 – 2030
- Alternatives Considered
  - N/A. Since this is a complementary project, the alternative analysis was evaluated together with the previously approved revised scope of the San Jose area HVDC lines project.
- Recommendation
  - Approval

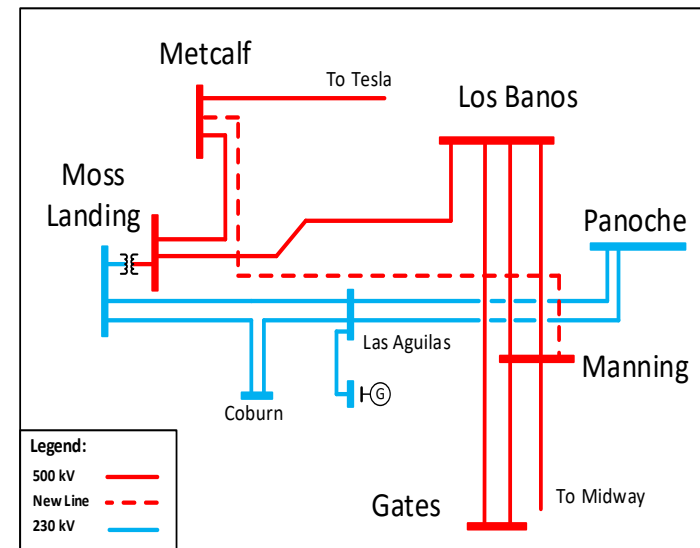


Slide 33

# Greater Bay Area 500 kV Transmission Reinforcement

- Reliability Assessment Need
  - Addressing long-term overloads in the 500 and 230 kV system in the South Bay under NERC Category P6 contingencies.
  - Supporting the increased supply needs in the Bay Area and LCR needs
- Project Scope
  - Build a new 500 kV line from Manning to Metcalf. Build a new 500 kV line from Manning to Metcalf.
  - One new 500 kV connection at both ends of the proposed line
- Estimated Project Cost
  - \$500M - \$700M
- Estimated In-service Date
  - May 2034
- Alternatives Considered
  - Other alternatives to bring an additional supply to the Greater Bay Area, such as: Warnerville – Newark 230 kV HVDC or new 500 kV from Tesla to the Newark area. These alternatives proved to be less effective in alleviating the loading on the multiple overloaded lines and also showed minimal benefit in relieving congestion on the Panoche-Las Aguilas-Moss Landing 230 kV path.

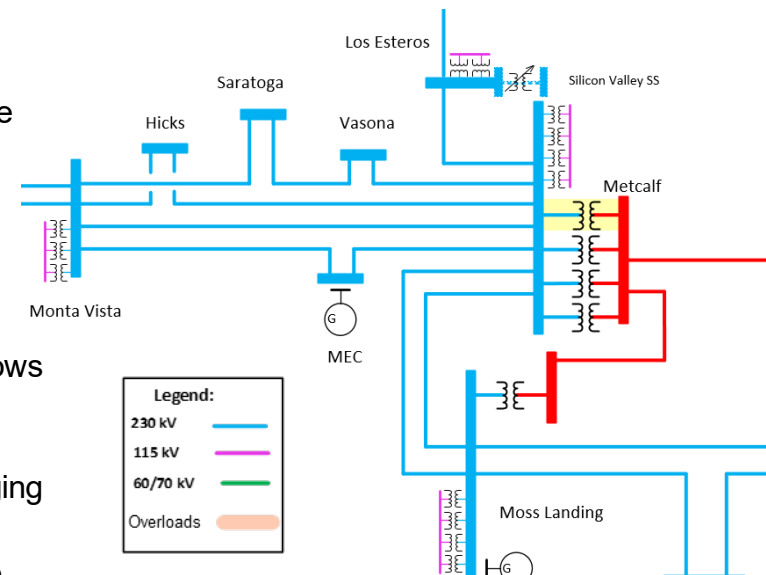
- Recommendation
  - Approval



# Metcalf Substation 500/230 kV Transformer Bank Addition

- Reliability Assessment Need
  - Addressing overloads in the Metcalf 500/230 kV transformer banks under NERC Category P6 contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Install a new (4th) 500/230 kV transformer at the Metcalf Substation to achieve at least 1122 MVA summer emergency rating;
  - Upgrade any limiting components as necessary to achieve full transformer capacity; and
  - Relocate existing equipment within the substation to accommodate the new transformer.
- Alternatives Considered
  - Increasing the transformer capacity in other existing or new substation. It is not recommended due to higher cost and reduced effectiveness
  - Adding a 500/115 kV TB. Not recommended due to unbalanced flows on the 230/115 kV side, leading to increased overload issues downstream and raising the short circuit duty on the 115 kV grid.
  - BESS. Not recommended due to insufficient capacity in the charging window.
  - Power Flow Control Device. Not recommended due to the multiple power flow controllers required

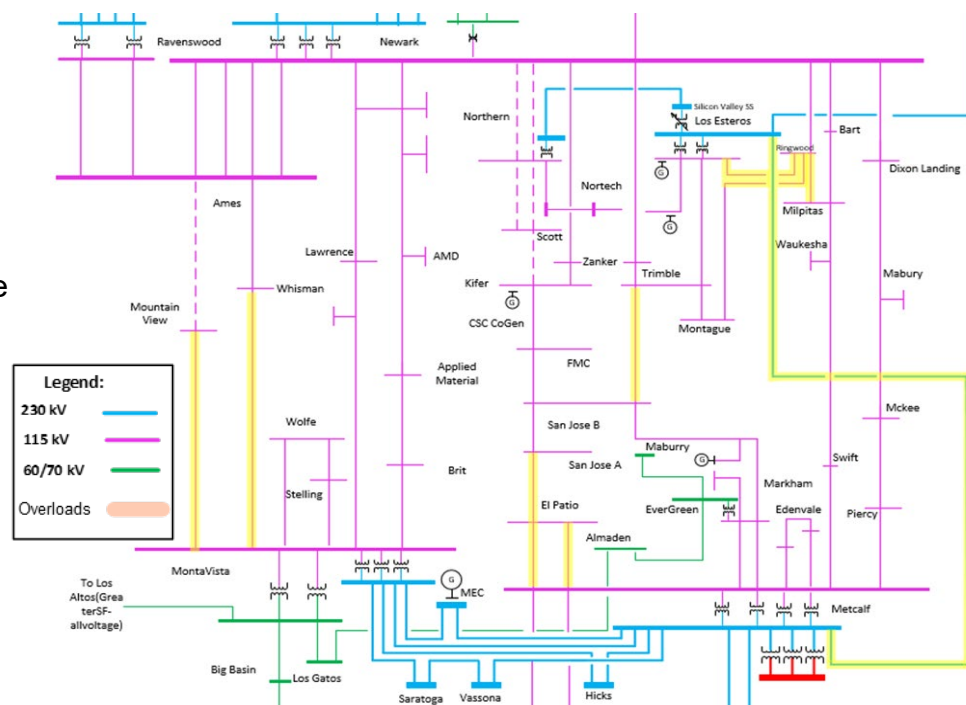
- Estimated Project Cost
  - \$91M - \$182M
- Estimated In-service Date
  - May 2034
- Recommendation
  - Approval



# South Bay Reinforcement Project

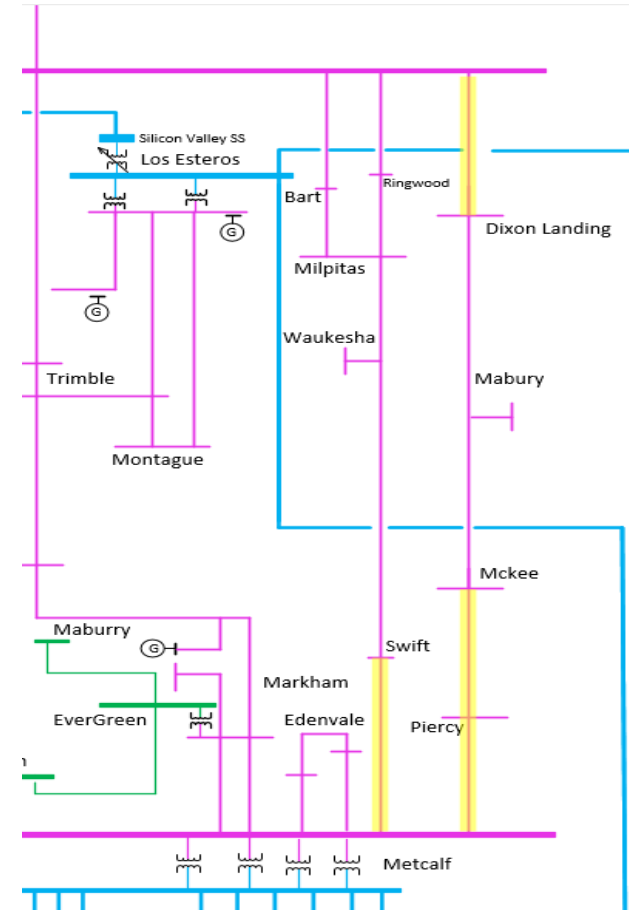
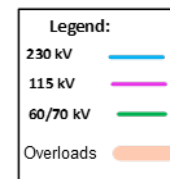
- Reliability Assessment Need
  - Addressing overloads in the 115 kV transmission system in the South Bay area under NERC Category P1 to P7 contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductor the following 115 kV lines/sections: El Patio – San Jose A, Trimble – San Jose B 115 kV, Mountain View – Monta Vista, Whisman – Monta Vista, and Ringwood – Milpitas with a larger conductor to achieve at least 3000 Amps during summer emergency conditions;
  - Remove the limiting elements at the Metcalf Substation on the Los Esteros – Metcalf 230 kV line to achieve at least 725 MVA during summer emergency conditions;
  - Loop Ringwood onto the Los Esteros-Montague 115 kV line.
- Estimated Project Cost
  - \$205M - \$410M
- Estimated In-service Date
  - May 2032
- Recommendation
  - Approval

- Alternatives Considered
  - Given the high complexity of constructing new transmission assets or upgrading the existing grid in a densely populated urban environment, the lines identified for re-conductoring do not have feasible alternatives for comparison.



# Metcalfe-Piercy & Swift and Newark-Dixon Landing 115 kV Upgrade Re-scope

- Reliability Assessment Need
  - Addressing overloads in the 115 kV transmission corridor Newark – Metcalf under NERC Category P1, P2, P6, and P7 contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Original. The project originally proposed to re-conductor the following 115 kV lines to 795 ACSS conductors or an equivalent: Piercy-Metcalf, Swift-Metcalf, and Newark-Dixon Landing.
  - Proposed. Reconductor the following 115 kV lines using advanced conductors to achieve a summer emergency rating of 3,000 Amps or higher: Piercy-Metcalf, Swift-Metcalf, Newark-Dixon Landing, and McKee-Piercy.
- Estimated Project Cost
  - Current estimate of original scope: \$92M - \$184M
  - Estimate for revised scope: \$124M - \$248M
- Estimated In-service Date
  - May 2028
- Alternatives Considered
  - NA
- Recommendation
  - Approval





# Reliability Assessment Recommendations – SCE Area Draft 2024-2025 Transmission Plan

*Rick Torres and Frank Chen  
Regional Transmission – South*

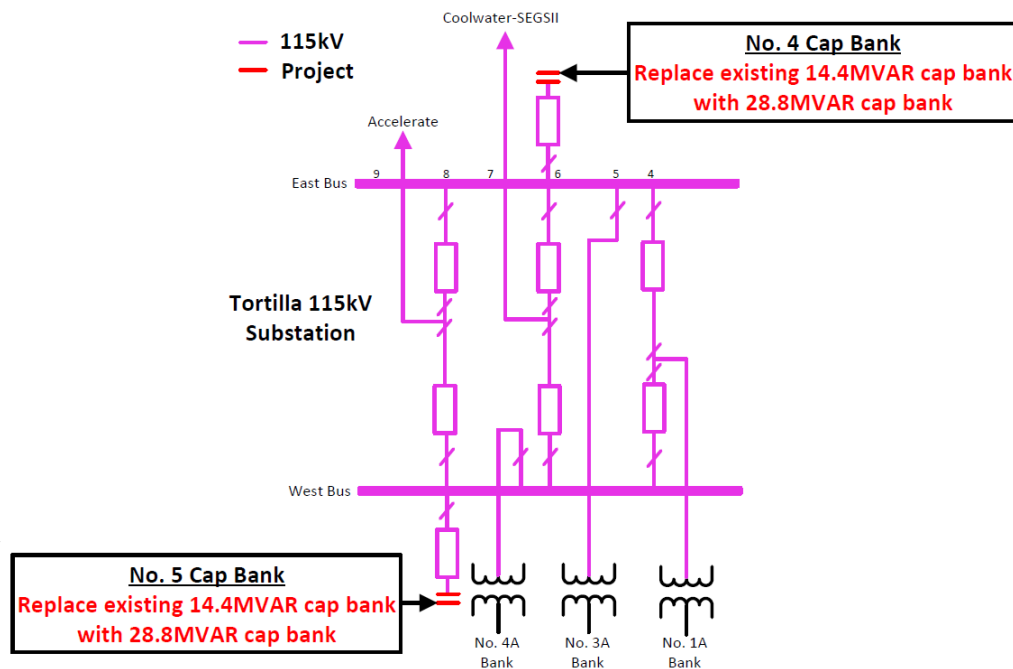
*2024-2025 Transmission Planning Process Stakeholder Meeting  
April 15, 2025*

# New Reliability Projects Recommended for Approval in 2024-2025 TPP - SCE Area

Projects	Planning Area	Status
Tortilla 115 kV Capacitor Replacement	North of Lugo	Recommended for Approval
Kramer-Coolwater 115 kV Line Looping Tortilla 115 kV Sub.	North of Lugo	Recommended for Approval
Julian Hinds-Mirage 230 kV Advanced Reconductor Project	Eastern	Recommended for Approval
Serrano 500 kV SCD Mitigation	SCE Metro	Recommended for Approval
Serrano 230 kV GIS Bus Split	SCE Metro	Recommended for Approval
Alamitos 230 kV SCD Upgrade	SCE Metro	Recommended for Approval

# Tortilla 115 kV Capacitor Replacement

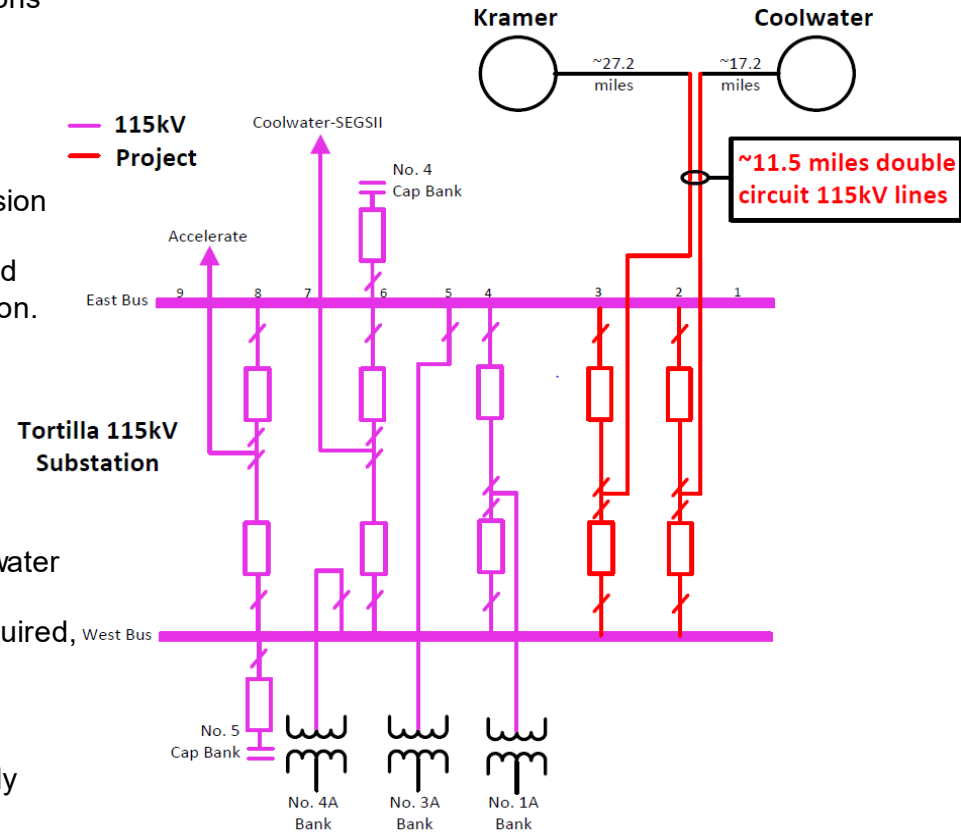
- Reliability Assessment Need
  - To mitigate low voltage and voltage collapse issues in the near-term and long-term planning horizons under category P1, P3, P5 and P6 contingencies.
- Project Submitter
  - SCE
- Project Scope
  - Replace the existing two (2) 14.4 MVAR 115 kV capacitors at the Tortilla 115/33 kV substation with two (2) new 28.8 MVAR 115 kV capacitors.
- Estimated Project Cost
  - \$5M
- Estimated In-service Date
  - June 30, 2029
- Alternatives Considered
  - Looping the Kramer-Coolwater 115 kV line into the Tortilla 115 kV substation – This option provides additional VAR support but does not fully resolve the low voltage issues identified.
  - An 80 MW BESS – Low voltages were identified when charging the large BESS which would likely prohibit fully recharging the batteries during extended transmission contingency conditions.
- Recommendation
  - Approval





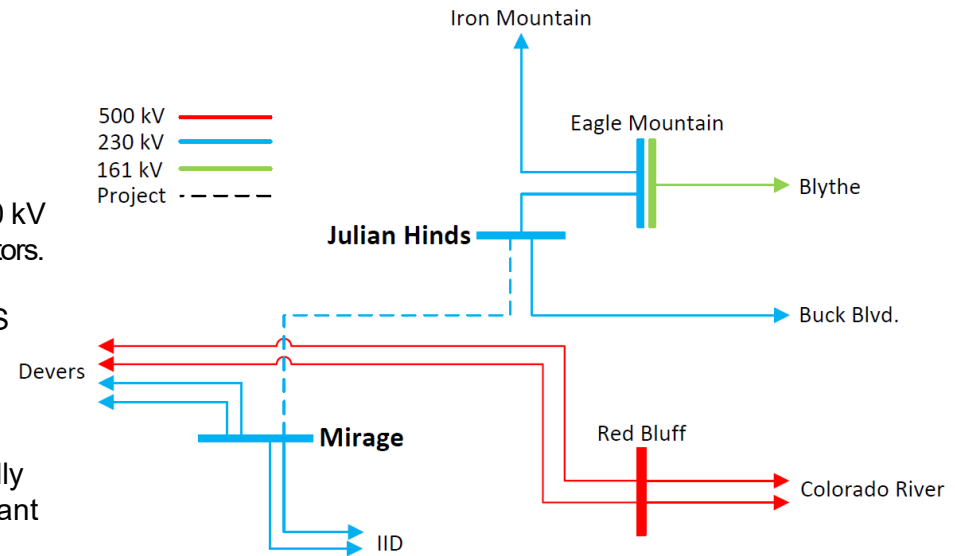
# Kramer-Coolwater 115 kV Line Looping Tortilla 115 kV Substation

- Reliability Assessment Need
  - To mitigate thermal overloads and reduce the risk of voltage collapse in the near-term and long-term planning horizons under category P1, P3, P5 and P6 contingencies.
- Project Submitter
  - SCE
- Project Scope
  - Utilize the existing Kramer-Coolwater 115 kV transmission line to loop in the Tortilla 115/33 kV substation via an approximate 11.5-mile double-circuit line extension and switchrack expansion at the Tortilla 115/33 kV substation.
- Estimated Project Cost
  - \$37M
- Estimated In-service Date
  - June 30, 2034
- Alternatives Considered
  - Constructing a new 11.4-mile 115 kV circuit from Coolwater to Tortilla – Tortilla would be supported by only 3 lines instead of 4, additional work at Coolwater would be required, Coolwater-SEGS-Tortilla 115 kV line would face long outages during construction.
  - An 80 MW BESS – Low voltages were identified when charging the large BESS which would likely prohibit fully recharging the batteries during extended transmission contingency conditions.
- Recommendation
  - Approval



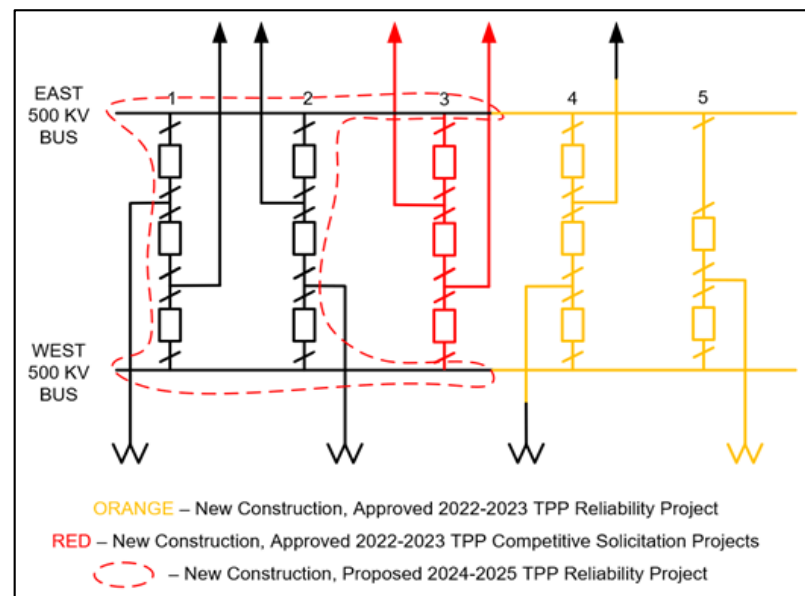
# Julian Hinds-Mirage 230kV Advanced Reconductor Project

- Reliability Assessment Need
  - To address the thermally constrained Julian Hinds-Mirage 230 kV line, which has been subject to the Blythe Energy RAS and has activated ten times between 2019 and 2023. Additionally, this line was identified as a near-term and long-term issue under category P1 and P6 contingencies which would trigger the Blythe Energy RAS.
- Project Submitter
  - SCE
- Project Scope
  - Reconductor ~47 miles of the Julian Hinds-Mirage 230 kV line with high-temperature, low-sag advanced conductors. Select towers will be upgraded to support the new conductor and modifications to the existing Blythe RAS will be necessary to accommodate the increased line rating.
- Estimated Project Cost
  - \$76M (These upgrade costs are expected to be partially subsidized by the U.S. Department of Energy GRIP grant funding awarded through the CHARGE 2T project.)
- Estimated In-service Date
  - April 1, 2030
- Alternatives Considered
  - Continue using the Blythe Energy RAS.
- Recommendation
  - Approval



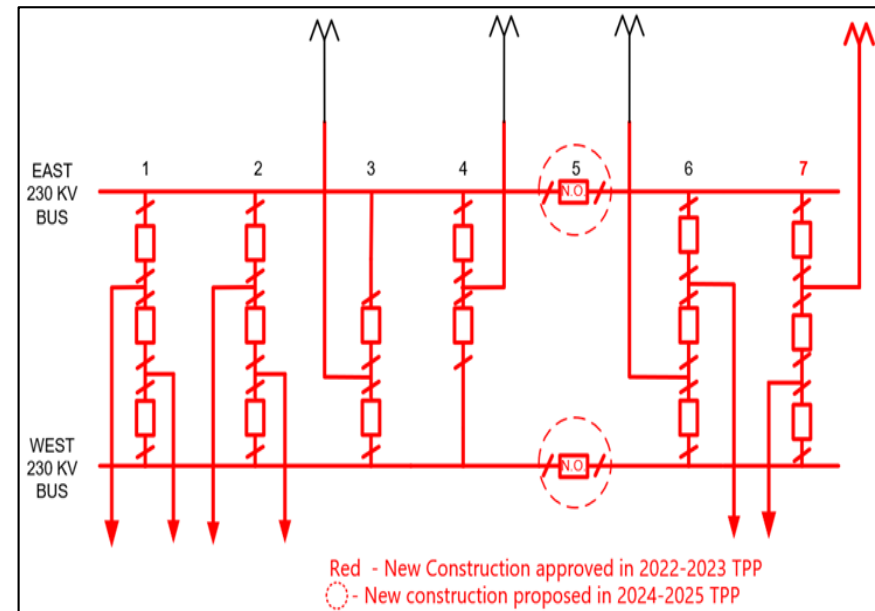
# Serrano 500 kV SCD Mitigation

- Reliability Assessment Need
  - The 2022-2023 TPP CAISO approved upgrades aggravates short-circuit duty (SCD) level at the Serrano 500 kV bus, causing the 40 kA circuit breaker loading to exceed 95% in the near-term planning case of 2029 and 100% in the long-term planning case of 2034
- Project Submitter
  - SCE
- Project Scope
  - Replace the 500 kV GIS bus positions 1 through 3 with 63 kA-rated equipment
- Estimated Project Cost
  - \$183M
- Estimated In-service Date
  - 12/31/2029
- Alternatives Considered
  - None
- Recommendation
  - Approval



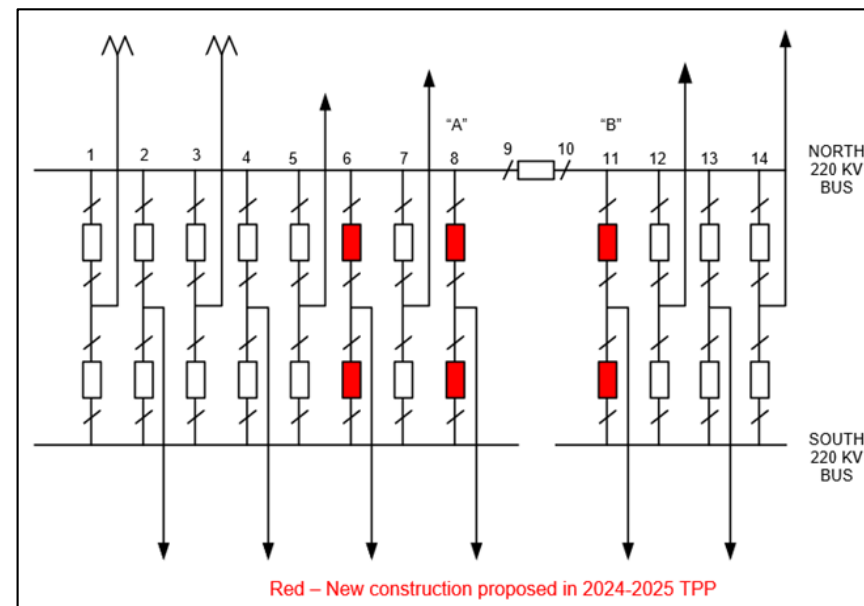
# Serrano 230 kV GIS Bus Split

- Reliability Assessment Need
  - The 2022-2023 TPP CAISO approved upgrades aggravates short-circuit duty (SCD) level at the neighboring Villa Park 230 kV substation, causing the circuit breaker loading to exceed 100% in the long-term planning case of 2039
- Project Submitter
  - SCE
- Project Scope
  - Split the Serrano 230 kV bus by installing two 230 kV sectionalizing circuit breakers
  - Perform the construction work with the previously ISO-approved fourth 500/230 kV transformer and 230 kV GIS rebuild to 80 kA capability at Serrano to gain cost saving efficiencies
- Estimated Project Cost
  - \$28M
- Estimated In-service Date
  - 12/31/2029
- Alternatives Considered
  - De-looping 230 kV lines
- Recommendation
  - Approval



# Alamitos 230 kV SCD Upgrade

- Reliability Assessment Need
  - The 2022-2023 TPP CAISO approved the Serrano – Del Amo – Mesa 500 kV Transmission Reinforcement Project aggravates the SCD level at the Alamitos 230 kV Substation, resulting in the Alamitos A and B 230 kV switchracks exceeding 100% of the 40 kA rated circuit breaker capacity in the long-term planning cases of 2034 and 2039
- Project Submitter
  - SCE
- Project Scope
  - Replace the six (6) 40 kA circuit breakers at Alamitos 230 kV Substation to 63 KA, four (4) CBs at the Alamitos A 230 kV switchrack and two (2) CBs at the Alamitos B 230 kV switchrack
- Estimated Project Cost
  - \$5M
- Estimated In-service Date
  - 12/31/2032
- Alternatives Considered
  - De-looping 230 kV lines
- Recommendation
  - Approval





# Reliability Assessment Recommendations – VEA Area Draft 2024-2025 Transmission Plan

*Nikitas Zagoras*

*Regional Transmission – South*

*2024-2025 Transmission Planning Process Stakeholder Meeting*

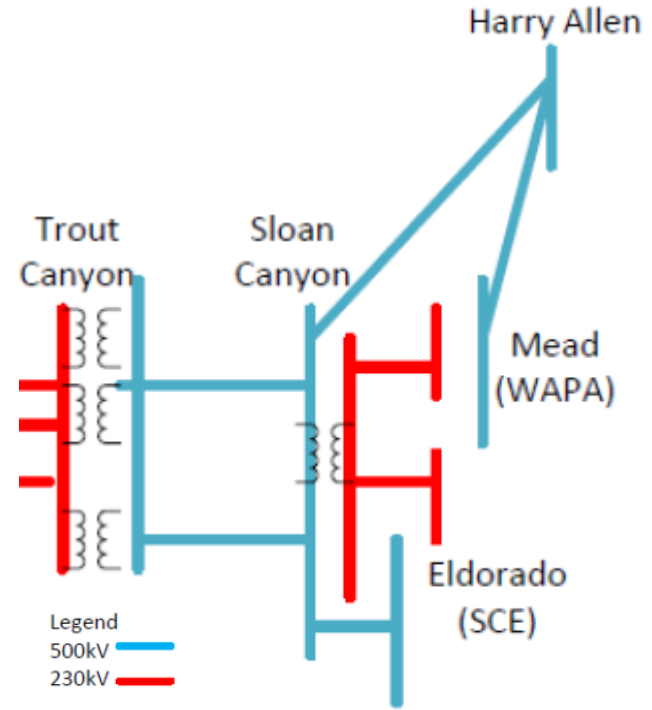
*April 15, 2025*

## New Reliability Projects Recommended for Approval in 2024-2025 TPP - VEA Area

Projects	Planning Area	Status
Sloan Canyon Tertiary Reactors	VEA	Recommended for Approval

# Sloan Canyon Tertiary Reactors

- Reliability Assessment Need
  - To address high voltage under contingency conditions. During the P6 contingency the Harry Allen-Sloan Canyon 500 kV and Sloan Canyon-Eldorado 500 kV lines the 500 kV bus voltage at Sloan Canyon was 560 kV in the 2029 summer peak base case which exceeds the 550 kV high voltage limit.
- Project Submitter
  - GLW
- Project Scope
  - The scope of this project is to install three 66 MVAR shunt reactors on the 24.9 kV tertiary of the Sloan Canyon 500/230 kV transformer.
- Estimated Project Cost
  - \$5M – 10M
- Estimated In-service Date
  - December 31, 2027
- Alternatives Considered
  - GLW identified the potential for high voltages with all lines in-service, so de-energizing the lines is not a feasible option due to potential daily operation of the breakers, increased maintenance costs and breaker failure rates.
- Recommendation
  - Approval







# Reliability Assessment Recommendations – SDG&E Area Draft 2024-2025 Transmission Plan

*Rene Romo de Santos*  
*Regional Transmission - South*

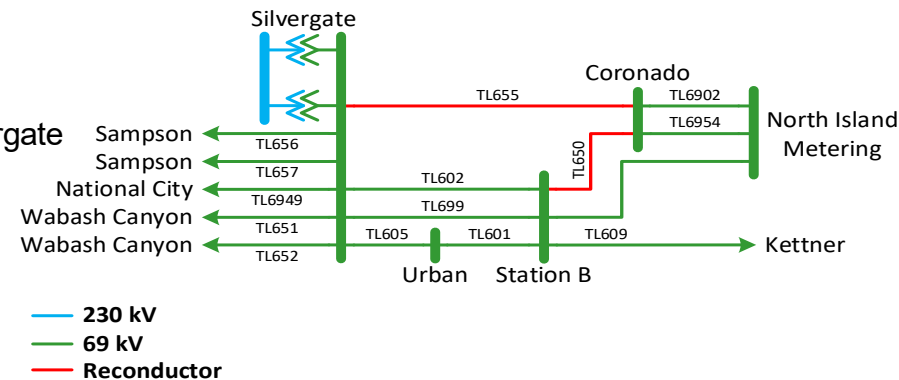
*2024-2025 Transmission Planning Process Stakeholder Meeting*  
*April 15, 2025*

# New Reliability Projects Recommended for Approval in 2024-2025 TPP – SDG&E Area

<b>Projects</b>	<b>Planning Area</b>	<b>Status</b>
Coronado Island Reliability Reinforcement Phase I	SDG&E	Management Approved
Coronado Island Reliability Reinforcement Phase II	SDG&E	Recommended for Approval
Downtown Reliability Reinforcement	SDG&E	Recommended for Approval

# Coronado Island Reliability Reinforcement Phase II

- Reliability Assessment Need
  - This project was proposed by SDG&E as a reliability transmission solution to the overload of the existing cables that serve Coronado Island even after the construction of the third 69 kV line identified in Coronado Island Reliability Reinforcement Phase I, due to additional US Navy load blocks.
  - The need date of the project is 2035 based on the reliability assessment, but SDG&E requested an in-service date of Q4 2028 to avoid the risk of potential load drop during the construction process as the reconductoring of each 69 kV line could take between nine to 12 months. The ISO evaluated this assumption and confirmed that once the first block of additional US Navy load comes into service, there would be no time window during the year where the reconductoring could take place without the risk of potential load drop, which is contrary to the ISO Planning Standards.
- Project Submitter
  - SDG&E
- Project Scope
  - Reconductor TL650 Station B – Coronado and TL655 Silvergate
  - Coronado to increase their normal rating to 150 MVA
- Estimated Project Cost
  - \$66M
- Estimated In-service Date
  - Q4 2028
- Alternatives Considered
  - Addition of series reactors/flow control devices** to TL650 and TL655 or a **series capacitor/flow control device** to the new 69 kV line to redistribute the power flow during P1 contingencies. This alternative is unfeasible due to space limitations at existing Station B, Coronado, North Island Metering, and Silvergate substations and the lack of land to expand them.
  - Energy Storage.** Not applicable due to energy storage charging limitations.
  - RAS.** Not suitable per ISO RAS Guidelines where involuntary load tripping is not allowed due to critical US Navy load.
- Recommendation
  - Approval



# Downtown Reliability Reinforcement

## Reliability Assessment Need

- This project was proposed by SDG&E as a reliability transmission solution to address the thermal overload of Old Town 230/69 kV banks and TL604 Old Town – Vine 69 kV line, due to P1, P3 and P4 contingencies, in the near-term and long-term horizons.

## Project Submitter

- SDG&E

## Project Scope

- Energize Silvergate 230/69 kV spare bank (\$10-15M);
- Upgrade Sampson 69 kV circuit breakers (\$10-15M);
- Expand existing Vine 69/12 kV substation to 230/69/12 kV, loop TL23029 Old Town – Mission into Vine substation; and install a 230/69 kV 350 MVA bank at Vine substation (\$385-475M).

## Estimated Project Cost

- \$400-500M

## Estimated In-service Date

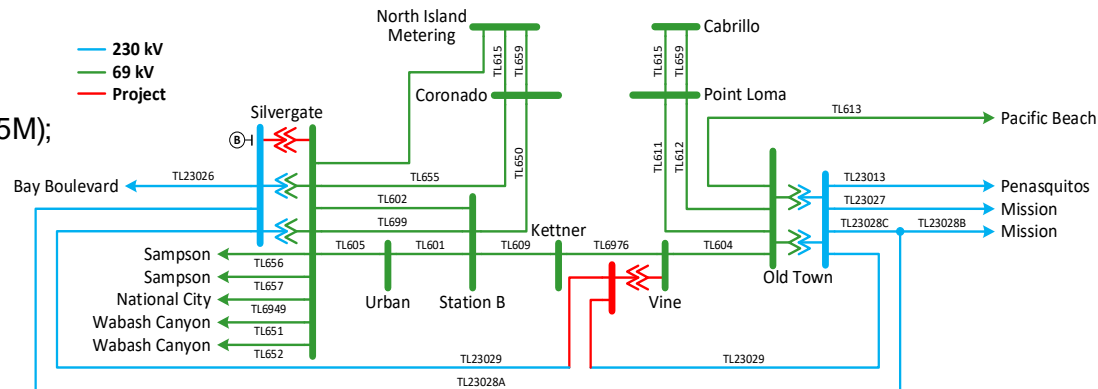
- The first two upgrades have a targeted in-service date of 2029 while the Vine expansion is targeted for 2037

## Alternatives Considered

- Energize Silvergate 230/69 kV spare bank, upgrade Sampson 69 kV CBs, rebuild Old Town substation to GIS and replace the existing Old Town 230/69 kV banks with 350 MVA banks. (\$400-500M). This alternative would be difficult to build since it is not expected to have a time window during the year to perform the scheduled outages at Old Town substation, which would be contrary of the ISO Planning Standards.
- **Addition of flow control devices** in series with the Old Town 230/69 kV banks, rebuild Old Town substation to GIS, energize Silvergate 230/69 kV spare bank, upgrade Sampson 69 kV CBs, reconductor TL602 Silvergate – Station B, and TL699 Silvergate – Station B. (\$512-630M)
- **Installation of energy storage** in the 69 kV load pocket, but this alternative is not appropriate due to energy storage charging limitations and also could lead to downstream 69 kV transmission line overloads while discharging.

## Recommendation

- Approval





# Frequency Response Assessment and Data Requirements Draft 2024-2025 Transmission Plan

*Chris Fuchs*

*Regional Transmission North*

*2024-2025 Transmission Planning Process Stakeholder Meeting*

*April 15, 2025*

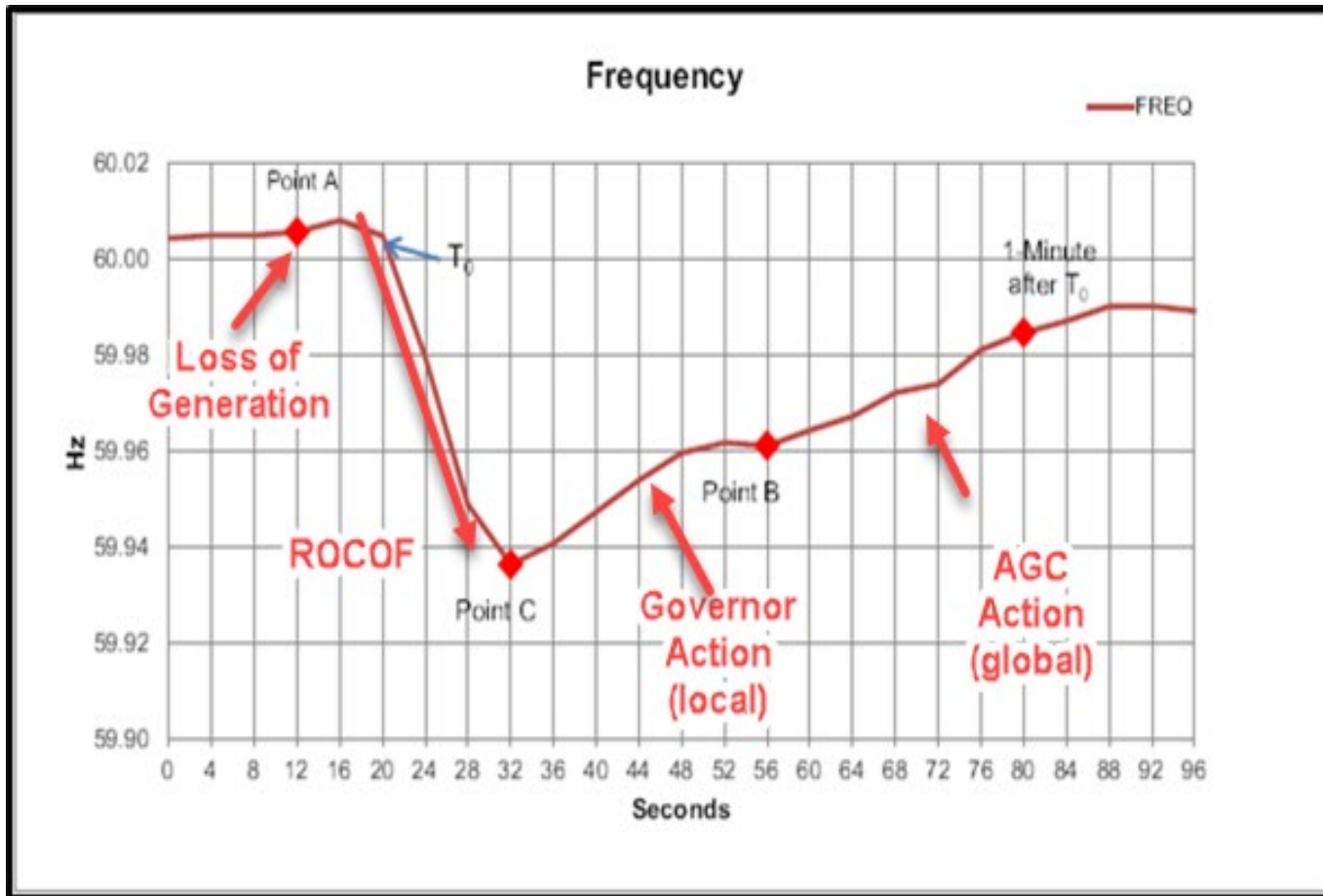
# Overview

- Basics of frequency
- ISO frequency response study results 2024-2025 TPP - impact of frequency response from Inverter Based Resources (IBRs) and Battery Energy Storage Systems (BESS)

# Continuous Supply and Demand Balance

- Load-Resource balance must be maintained at all time scales:  $\sum Load = \sum Generation + \Delta$
- During system disturbances/outages frequency goes outside of allowable tolerances
- $\sum Load > \sum Generation$  results in and under-frequency
- $\sum Load < \sum Generation$  results in and over-frequency
- Over frequency are easy enough to remediate
- Under frequency requires bringing generation on-line

# Standard Frequency Event Progression



Point C – nadir  
Point B – settling frequency

Nadir needs to be higher than the 1<sup>st</sup> set-point for Under Frequency Load Shedding (59.5 Hz)

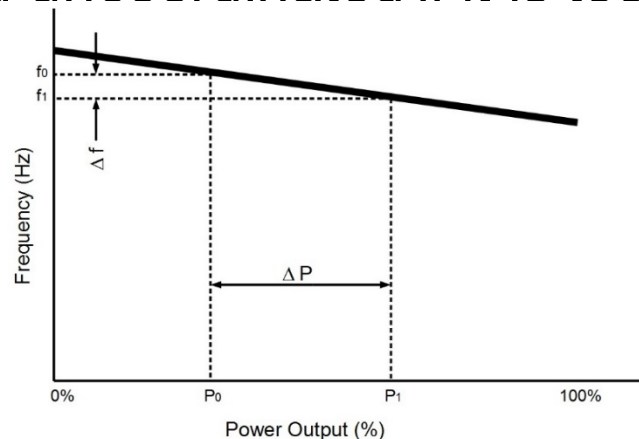


# Generator Response to Frequency Events

- Generating units play a major role in controlling system frequency through their governors and for IBRs via their Governors are the 1<sup>st</sup> line of defense for system frequency control.
- A governor controls the generator MW output to a preset output subject to a deliberate steady state error called droop control.
- Droop is a means of getting all system generators to proportionally share an increase in output power to frequency excursions based on the capacity of the contributing machines
- Droop is **completely independent** of system/generator inertia – so IBR based system can, and as shown later do, contribute to frequency restoration.

# Governor Droop Curve

- Droop was used with the first integrated power systems.
- Droop is the ratio of the frequency change to generator output change. The smaller the droop, the higher the individual response, but system-wide generation response becomes erratic and uncoordinated if it is too small. Droop is typically in the 3%



- *Example: for a drop in system frequency to 59.9 Hz, with 5% droop setting, unit responds with  $([60-59.9]/60)/0.05 = 3.33\%$  increase of the machines' rated power*

# Generator/BESS Headroom

- Headroom is the difference between the maximum capacity of the unit and the unit's output. Units that don't respond to changes in frequency are considered not to have headroom.
- Solar and Wind plants are designed to extract as much energy from the environment as possible and prefer to operate at capacity if possible. ➡ minimal headroom.
- Battery Energy Storage Systems (BESS) plants when charging have a large headroom for under-frequency events.
- In effect  $\text{headroom} = p_{\text{max}} - p_{\text{min}}$ . With  $p_{\text{max}} = -p_{\text{min}}$ , can have this much  $\text{headroom} = 2 * p_{\text{max}}$  assuming they are enabled for freq response during charging.

# Frequency Response Characterization

- For studies of off-nominal frequency events, it is essential to properly characterize the response of each generator
- System inertia and determines how fast the frequency will decrease with loss of generation. As the penetration of inverter-based resources increases, on-line synchronous inertia may decrease and rate-of-change of frequency (ROCOF) may continue to increase
- Frequency response of all units in the system determines at which value frequency will settle before the AGC action engages.

# Frequency Response Obligation (FRO) and Measure (FRM)

- Frequency Response (FR), or Frequency Response Measure (FRM)

- $$FR = \frac{\Delta P}{\Delta f} \left[ \frac{MW}{0.1Hz} \right]$$

- FRO for the Interconnection is established in NERC BAL-003-2 Frequency Response & Frequency Bias Setting Standard
- For WECC, FRO is 858 MW/0.1Hz
- Balancing Authority FRO allocation

$$FRO_{BA} = FRO_{Int} \frac{P_{gen_{BA}} + P_{load_{BA}}}{P_{gen_{Int}} + P_{load_{Int}}}$$

- For the CAISO, FRO is approximately 30% of WECC FRO (257.4 MW/0.1Hz)

## Study Methodology and Objective

- Evaluate primary frequency response with high IBR penetration, including separate DER enabled runs.
- Assess the CAISO system frequency response in the year 2029 (mid) & 2034 (far) and identify any performance issues related to frequency response.
- The starting base case was the Spring off-Peak case for 2029 & 2034. The cases studied had different assumptions on the generation dispatch and the headroom and on frequency response provided by IBRs and the battery energy storage devices.
- An outage of two Palo Verde nuclear units at full output was studied.
- Dynamic stability simulations were run for up to 60 seconds.

# Study Scenarios

- Cases: Base case 2029/2034 Spring off-Peak and the selected case with reduced headroom.
- BESS are in full charging mode – usually at  $p_{gen} = -p_{max}$

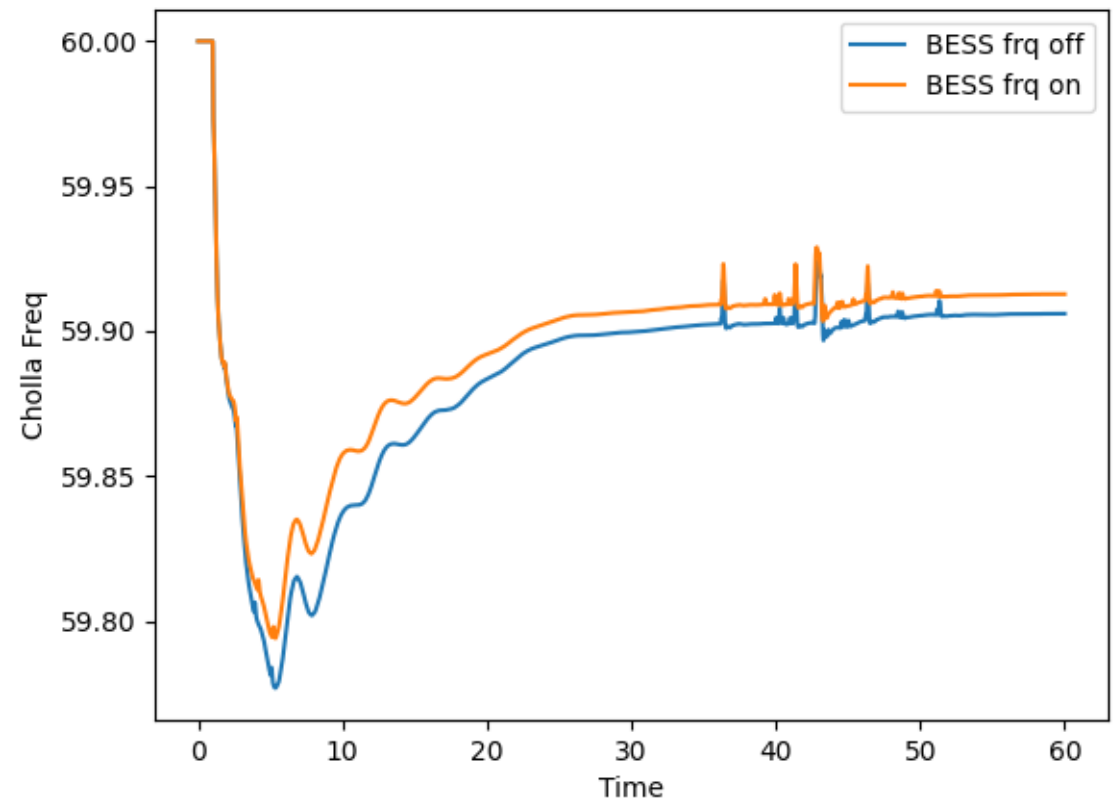
Scenarios
IBR Frequency Control is switched off
IBR Frequency Control is switched on
Frequency Control for system at 10%
IBR Frequency Control for system with minimal headroom

# Monitored Values

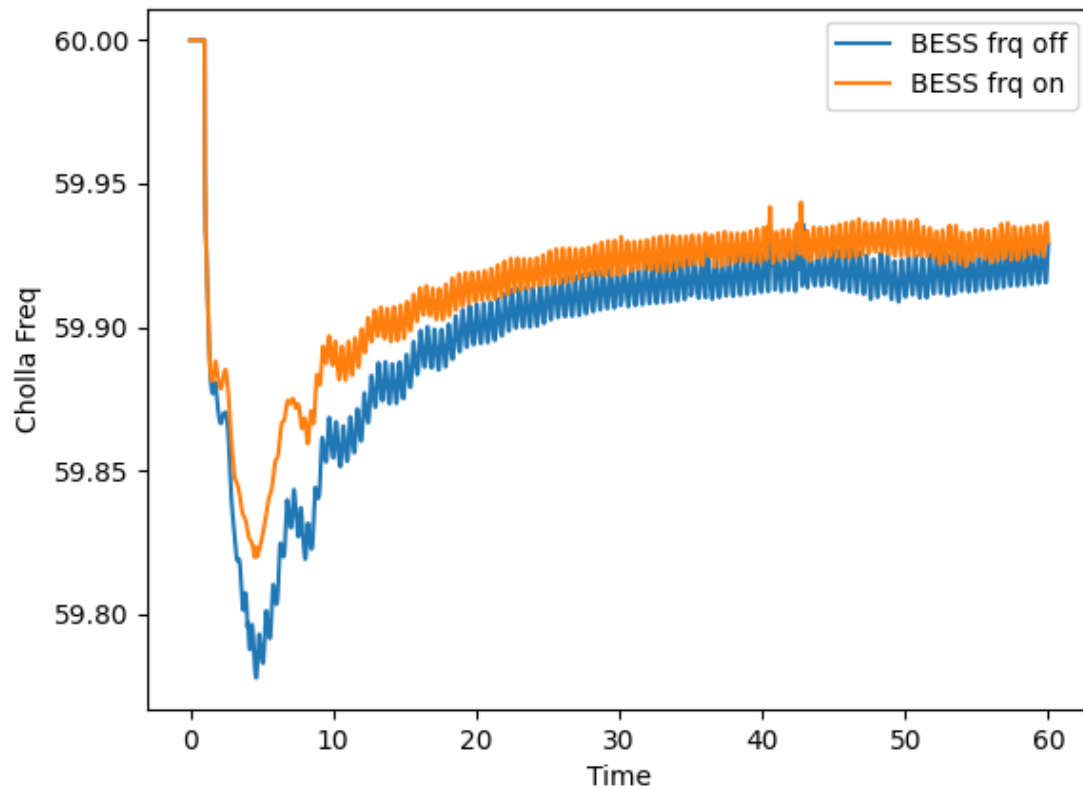
- System frequency including frequency nadir and settling frequency after primary frequency response
- The total new IBR output
- The total output of all other CAISO generators
- The major path flows
- Frequency Response Measures of the WECC and CAISO (MW/0.1 Hz)
- Frequency response from each unit in MW and in percent of the maximum output.
- Noticeably absent: Rate of Change of Frequency (ROCOF).



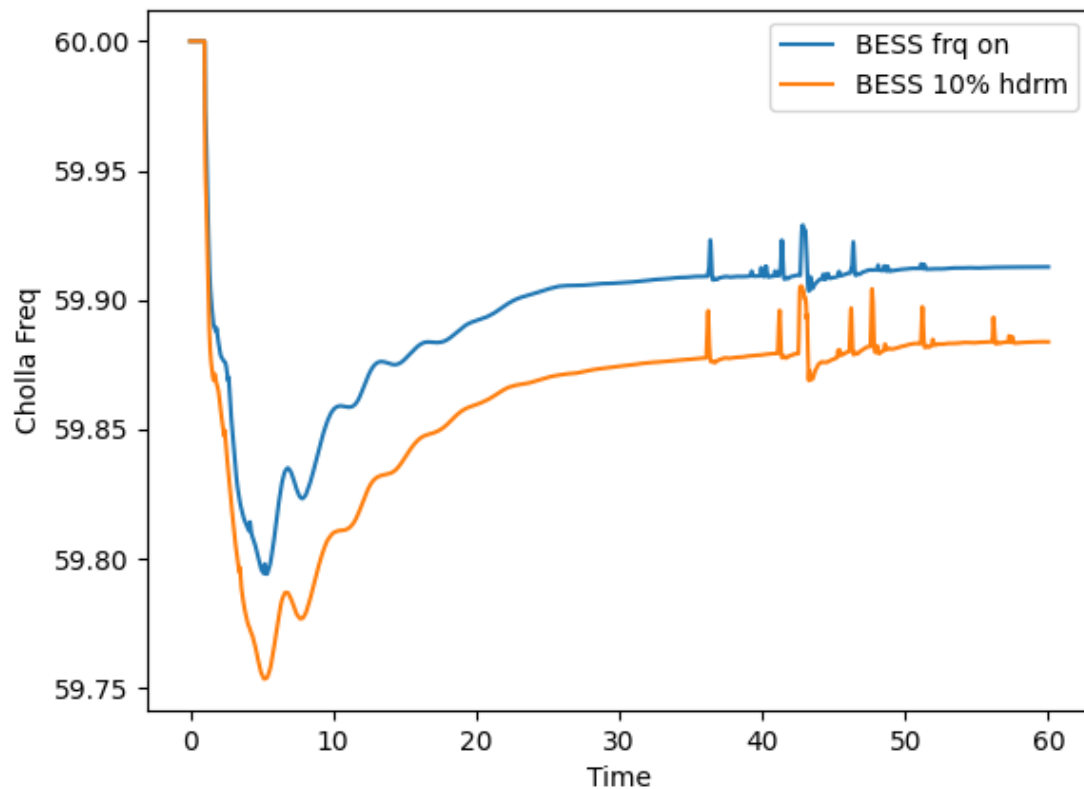
# Scenario #1&2: 2029 All IBR On & Off



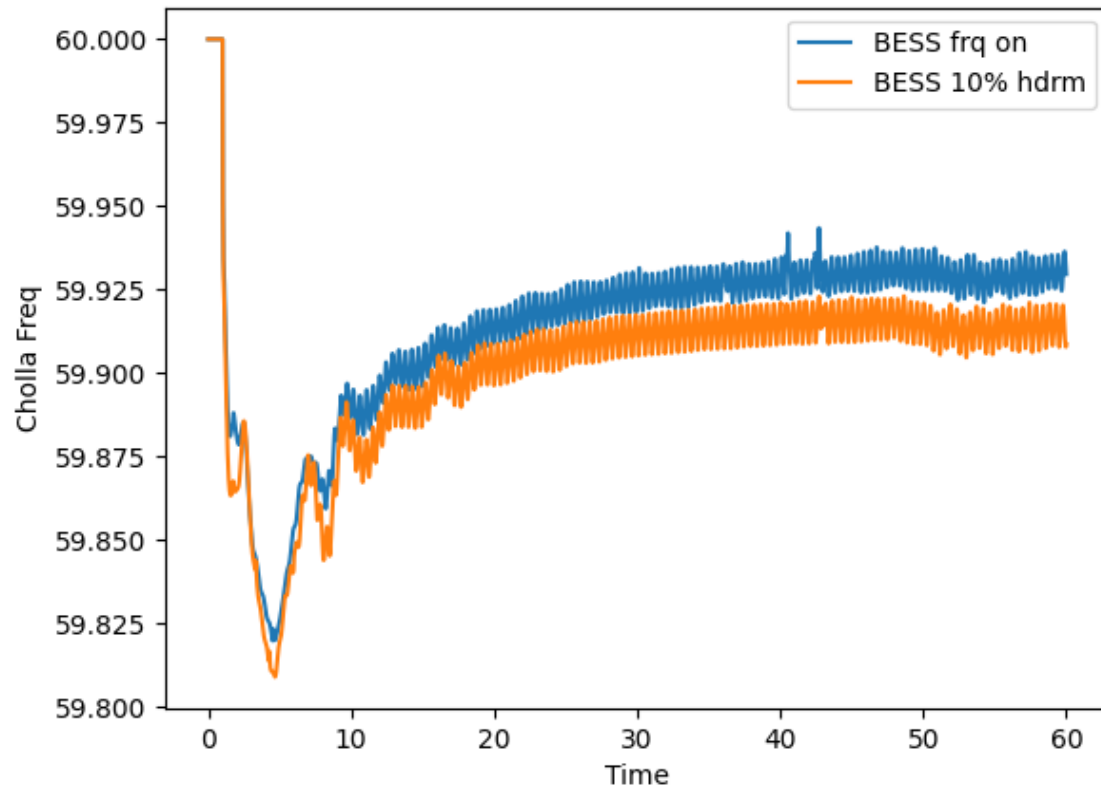
## Scenario #1&2: 2034 All IBR On & Off



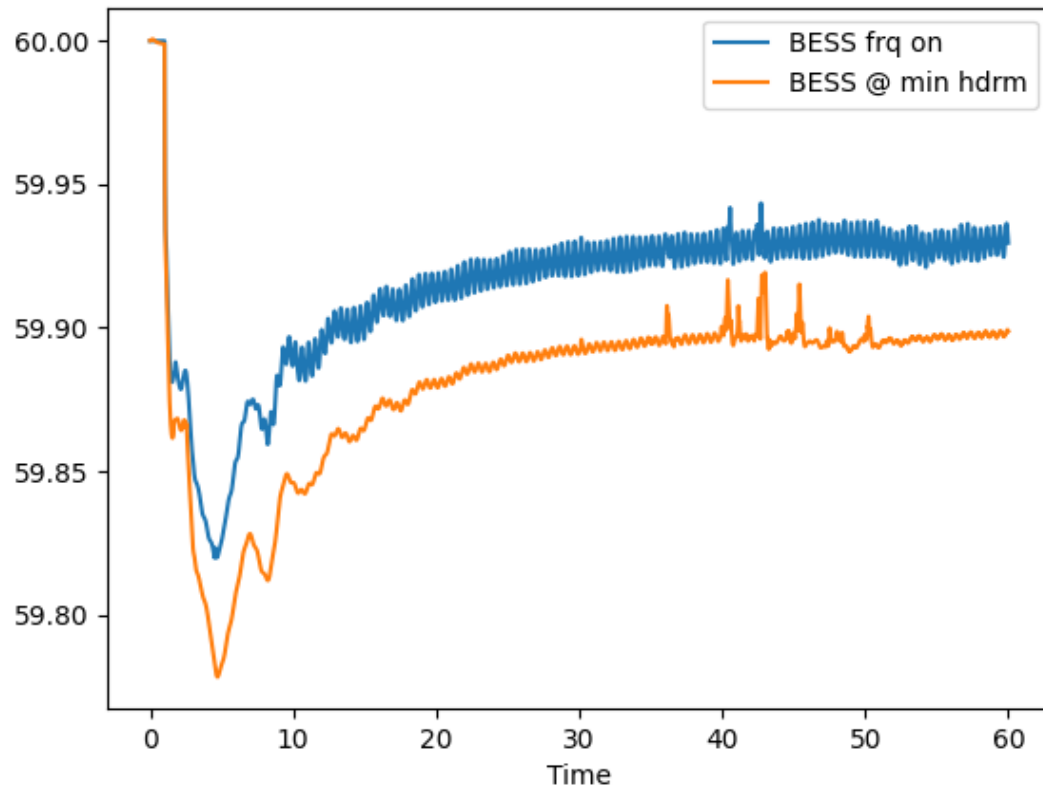
# Scenario #3&1: 2029 10% System Headroom vs System Normal (All BESS On)



# Scenario #3&2: 2034 Target 10% System Headroom vs System Normal (All BESS On)



## Scenario #5&2: 2034 min BESS Headroom vs System Normal (All BESS On)



# System Frequency Observations

- Having frequency response from the BESS improves frequency performance
- The frequency nadir was above the first block of under-frequency relay settings of 59.5 Hz for all scenarios surveyed
- The frequency nadir for 2034 scenarios is comparable to the 2028 scenarios – due to the higher # of generators in 2034
- BESS units have a much higher impact in 2034 due to the higher overall proportional of them in the system compared to 2029.

## 2024-2025 TPP Study Conclusions

- IBR units with frequency response significantly improve the system frequency performance and should allow the ISO to fulfill its FRO
- IBR units with frequency response enabled provide a response that acts in a similar manner to synchronous machines.

# Future Considerations

- Localize redispatch whenever possible
- Harmonize BESS initial settings across PTOs
- Different case construction approaches
  - Headroom via BESS->0 and/or Dispatch gen->0
- Differential check between GFL (Grid Following) and GFM (Grid Forming).
- Output power response investigation for when:
  - pgen goes up with the event but downwards afterwards (see this on the system)
  - pgen goes down requires additional investigation





# 2024 MIC Expansion Requests

Catalin Micsa

Senior Advisor, Transmission Infrastructure Planning

2024-2025 Transmission Planning Process Stakeholder Meeting

April 15, 2025

# 2024 Valid MIC expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Resource type
1-2	Southern California Edison	BLYTHE_ITC (BLYTHE161)	22.7	Hydro
3	Clean Power Alliance	IPPCADLN_ITC (IPP & IPPUTAH)	33	Geothermal
4		MEAD_ITC (MEAD230)	118.95	Wind
5-6	Valley Electric Association	MEAD_ITC (MEAD230)	24	Hydro
7			90	Solar/Battery
8	California Community Power	SUMMIT_ITC (SUMMIT120)	18	Geothermal
		MERCHANT_ITC (ELDORADO230) Back-up		
9		IID-SDGE_ITC (IMLY2)	107	
		IID-SCE_ITC (MIR2) Back-up		
10		SILVERPK_ITC (SILVERPEAK55)	13	
11	Ava Community Energy	PALOVRDE_ITC (PWEST)	99.13	Wind
12			42.5	Solar/Battery
13	San Diego Community Power	ELDORADO_ITC (WILLOWBEACH)	20.22	Wind
14-15		PALOVRDE_ITC (PWEST)	79.70	
16		IID-SCE_ITC (MIR2)	145.5	Solar/Battery
17		IID-SDGE_ITC (IMLY2)	35	
18		BLYTHE_ITC (BLYTHE161)	160	

## Not all MIC expansion requests trigger an actual need for expansion

- First the CAISO checks if these resources were included in the base portfolio in order to avoid duplicate entries.
- Second the CAISO calculates if a MIC expansion is needed (see methodology in RR BPM section 6.1.3.5).
- If MIC expansion is needed, the increase in MIC needs to be modeled and tested through deliverability studies
  - NQC deliverability study (if applicable in year one)
  - TPP deliverability study
  - GIP deliverability study
- One or multiple of these studies can limit the deliverability and therefore the MIC expansion.

# Assessment of valid 2024 MIC expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW Quantity	Triggers Expansion	Comments
1-2	Southern California Edison	BLYTHE_ITC (BLYTHE161)	22.7	Yes	Partial
3	Clean Power Alliance	IPPD CADLN_ITC (IPP & IPPUTAH)	33	In CPUC portfolio	
4		MEAD_ITC (MEAD230)	118.95		
5-6	Valley Electric Association	MEAD_ITC (MEAD230)	24	Yes	Full
7			90		
8	California Community Power	SUMMIT_ITC (SUMMIT120)	18	In CPUC portfolio	Active as back-up location only
		MERCHANT_ITC (ELDORADO230) Back-up			No need for expansion
IID-SDGE_ITC (IMLY2)		107			
IID-SCE_ITC (MIR2) Back-up					
10		SILVERPK_ITC (SILVERPEAK55)	13		Active as back-up location only
11	Ava Community Energy	PALOVRDE_ITC (PWEST)	99.13	In CPUC portfolio	
12			42.5	No	No need for expansion
13	San Diego Community Power	ELDORADO_ITC (WILLOWBEACH)	20.22	In CPUC portfolio	
14		PALOVRDE_ITC (PWEST)	20.22		
15			59.48		
16		IID-SCE_ITC (MIR2)	145.5		
17		IID-SDGE_ITC (IMLY2)	35	Yes	Full
18		BLYTHE_ITC (BLYTHE161)	160	Yes	Full

# 2024 MIC Expansion Requests Being Assessed (not already part of the CPUC portfolio)

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Resource type
1-2	Southern California Edison	BLYTHE_ITC (BLYTHE161)	8	Hydro
3-4	Valley Electric Association	MEAD_ITC (MEAD 230)	24	Hydro
5			90	Hybrid (Solar/Battery)
6-7	California Community Power	SUMMIT_ITC (SUMMIT120) *	18	Geothermal
		SILVERPK_ITC (SILVERPEAK55) **	13	Geothermal
8-9	San Diego Community Power	IID-SDGE_ITC (ILY2)	35	Hybrid (Solar/Battery)
		BLYTHE_ITC (BLYTHE161)	160	Hybrid (Solar/Battery)

\* = As back-up locations only – main delivery point included as MEAD\_ITC (MEAD230) and part of the CPUC portfolio.

\*\* = As back-up locations only – main delivery point included as MONAIPPDC\_ITC (MDWP) and part of the CPUC portfolio.

# 2025 NQC Deliverability Study Results For MIC Expansion Requests Being Assessed

Intertie Name (Scheduling Point)	Status	Comments:
BLYTHE_ITC (BLTHE161)	Pass	Temporary expansion included in 2025 MIC.
MEAD_ITC (MEAD 230)	Pass	Includes both CPUC portfolio and MIC expansion requests. Temporary expansion included in 2025 MIC.

- Only applicable to MIC expansion request across RA year 2025
- Permanent expansion depends on the TPP and GIP deliverability study results

# TPP Deliverability Study Results

## For MIC Expansion Requests Being Assessed

Intertie Name (Scheduling Point)	Status	Comments:
BLYTHE_ITC (BLYTHE161)	Failed/ Denied	Additional mitigation for Lugo-Victorville 500 kV constraint is not proposed in this expansion cycle and therefore no additional capability exists for MIC expansion requests.
IID-SDGE_ITC (IVLY2)	Pass/ Move forward	Subject to various mitigations already in place including, but not limited to, Southern Area Reinforcement and Lugo-Victorville line upgrade. First expected RA year 2036
MEAD_ITC (MEAD 230)	Failed/ Denied	Part not in the CPUC portfolio. Additional mitigation for Lugo-Victorville and Eldorado-McCullough 500 kV constraints is not proposed in this expansion cycle and therefore no additional capability exists for MIC expansion requests.
SILVERPK_BG (SILVERPEAK55)	Failed/ Denied	Used as back-up only – main in the CPUC portfolio. Additional mitigation for Control-Inyokern 115 kV lines (Control-Silver Peak) and Lugo-Victor #1 & #2 230 kV lines constraints is not proposed in this expansion cycle and therefore no additional capability exists for MIC expansion requests.
SUMMIT_ITC (SUMMIT120)	Pass/ Move forward	Used as back-up only – main in the CPUC portfolio. Waiting for Humboldt-Fern Road 500 kV & Humboldt-Collinsville 500 kV. First expected RA year 2035.

**For a comprehensive view of future MIC increases (including due to main CPUC portfolio) please read chapter 6.1.2 Resource adequacy import capability of the 2024-2025 Transmission Plan.**



# Policy-driven Assessment Recommendations Draft 2024-2025 Transmission Plan

Lindsey Thomas  
*Regional Transmission Engineer Lead*

*2024-2025 Transmission Planning Process Stakeholder Meeting*  
April 15, 2025



# Policy-driven Projects Recommended for Approval

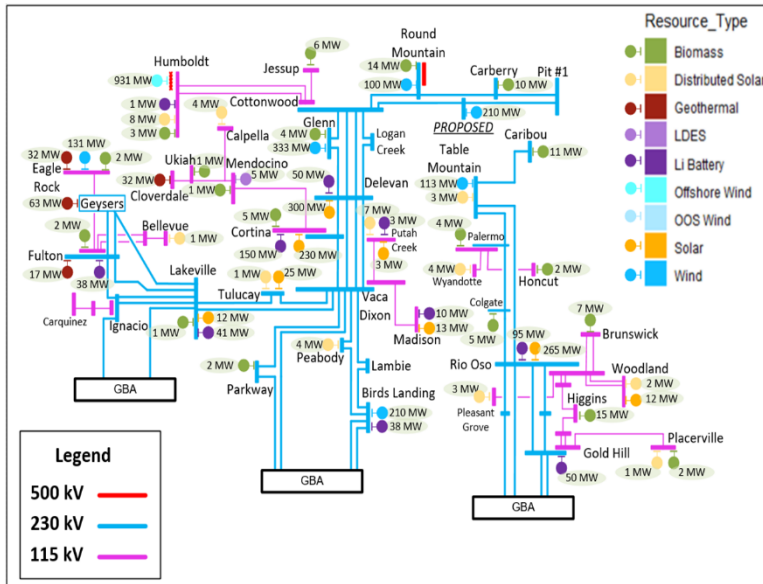
- A total of 3 new projects are recommended in the PG&E area

Project Name	PTO	Planning Area	Cost(\$M)
Eagle Rock- Fulton- Silverado 115 kV Line Reconductor	PG&E	NGBA	92.9
Reconductor of GWF-Kingsburg 115 kV Line	PG&E	Fresno	81.6
New Helm 230/70 kV Bank #2	PG&E	Fresno	115
		<b>Total</b>	<b>289.5</b>

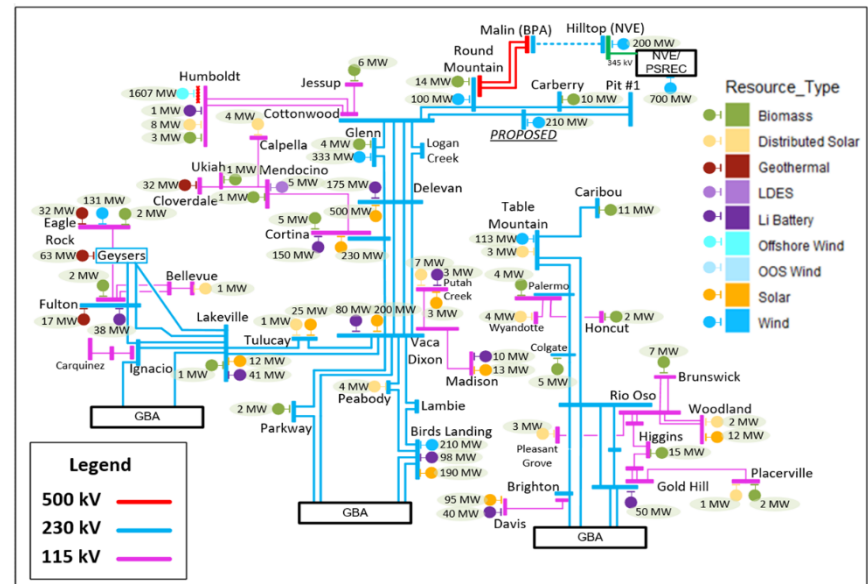
# PG&E Greater Bay and North of Greater Bay Interconnection Areas

# PG&E North of Greater Bay Interconnection Area Mapped Base Portfolio

## 2034 Base Portfolio



## 2039 Base Portfolio



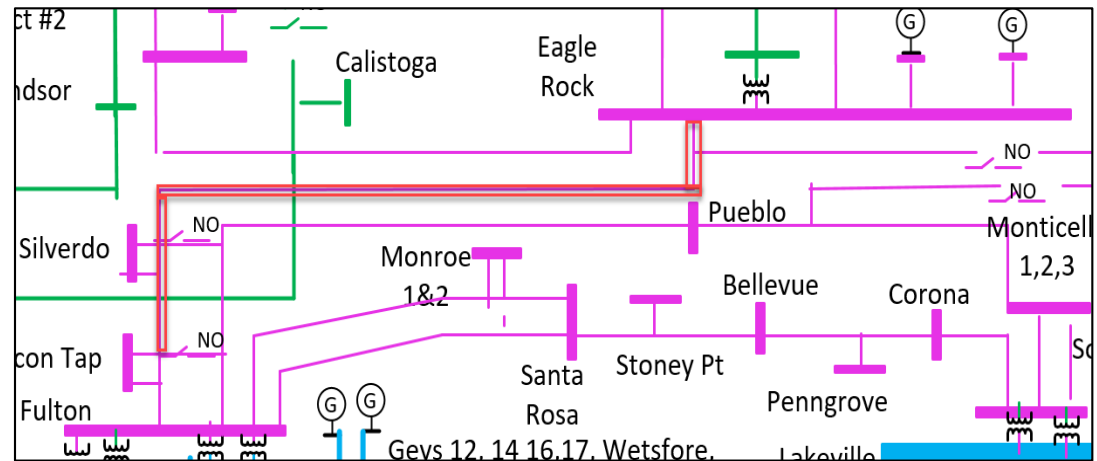
# Eagle Rock- Fulton- Silverado 115 kV (Eagle rock sub to Ricon Jct 115 kV) on-peak deliverability constraint summary

Overloaded Facility	Contingency	Scenario	Loading	
			HSN	SSN
Eagle Rock- Fulton- Silverado 115 kv (Eagle rock sub to Ricon Jct Jct2 115 kV)	Tulucay-Vaca 230 kV Line & Vaca-Lakeville #1 230 kV Line	HSN	124.45%	<100%

Affected transmission zones		North of Greater Bay Area
Portfolio resources behind the constraint (Installed FCDS capacity)		282
Portfolio battery storage behind the constraint (Installed FCDS capacity)		150
Deliverable portfolio resources w/o mitigation (Installed FCDS capacity)		147
Total undeliverable baseline and portfolio resources (Installed FCDS capacity)		290
Mitigation Options	RAS	N/A
	Reduce generic battery storage (MW)	N/A
	Transmission upgrade including cost	Reconductor (\$92.9M)
Recommended Mitigation		Reconductor

# Eagle Rock- Fulton- Silverado 115 kV Line Reconductor

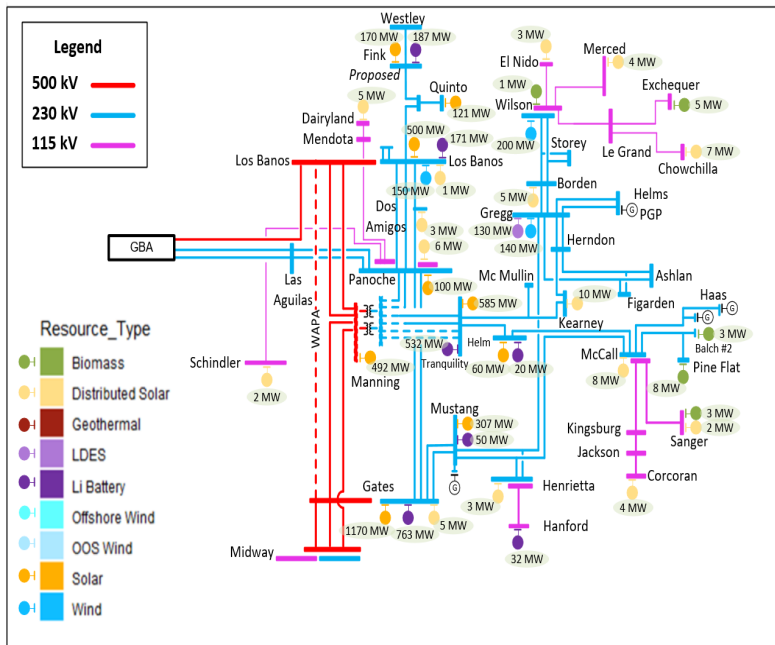
- Policy Assessment Need
  - Base HSN scenario
- Project Scope
  - Reconductor Eagle Rock-020/087A with minimum rating of 1236 Amps or higher and update any limiting components at the substation (if any). Reconductor 020/87A-037/191A with minimum rating of 1687 Amps or higher and update any limiting components at the substation (if any)..
- Estimated Project Cost
  - \$92.9M
- Estimated In-service Date
  - 2034
- Alternatives Considered
  - RAS. Not selected due to RAS criteria violation.
- Recommendation
  - Approval



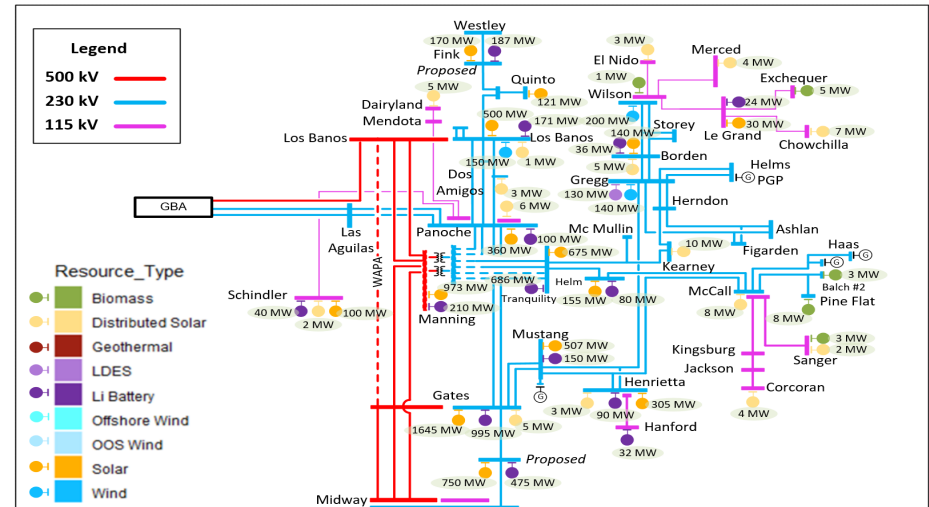
# PG&E Greater Fresno Interconnection Area

# PG&E Greater Fresno Interconnection Area Mapped Base Portfolio

## 2034 Base Portfolio



## 2039 Base Portfolio



# GWF-Kingsburg 115 kV Line on-peak deliverability constraint

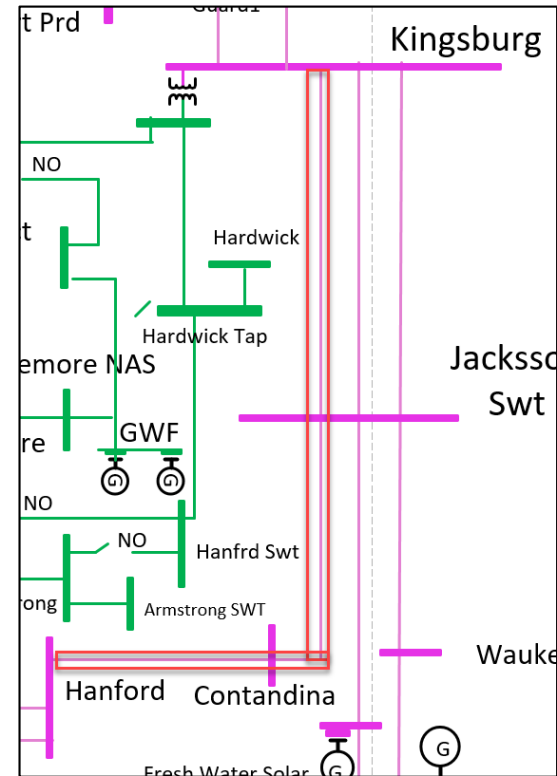
Overloaded Facility	Contingency	Scenario	Loading	
			HSN	SSN
GWF-Kingsburg 115 kV Line	HELM-MCCALL 230KV & HENTAP2-MUSTANGSS #1 230KV	HSN	122.18%	<100%

Affected transmission zones: PG&E Fresno Area			
			Base
Generic Portfolio MW behind the constraint (installed FCDS capacity)			314
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)			32
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)			314
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)			127
Mitigation Options	RAS		N/A
	Re-locate generic portfolio battery storage (MW)		N/A
	Transmission upgrade including cost		Reconductor (\$81.6M)
Recommended Mitigation			Reconductor



# Reconductor of GWF-Kingsburg 115 kV Line

- Policy Assessment Need
  - Base HSN scenario
- Project Scope
  - Reconductor the entire GWF-Kingsburg 115 kV Line with minimum summer emergency rating of 1500 Amps or higher and update the limiting components at the substations if there is any.
- Estimated Project Cost
  - \$81.6M
- Estimated In-service Date
  - 2034
- Alternatives Considered
  - RAS was considered as an alternative but was not selected due to not meeting the RAS guidelines
- Recommendation
  - Approval



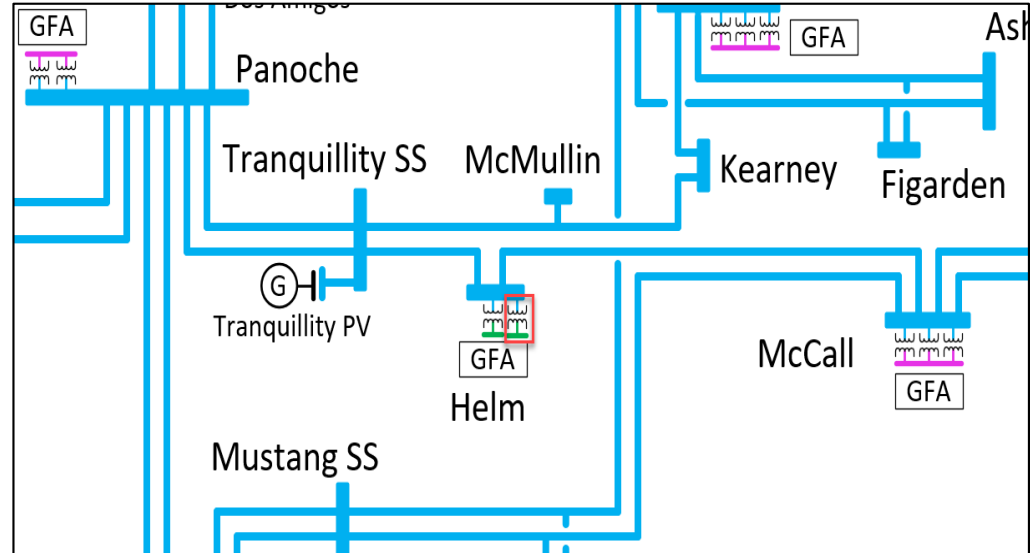
# Helm-Crescent 70 kV Line on-peak deliverability constraint summary

Overloaded Facility	Contingency	Scenario	Loading	
			HSN	SSN
Helm-Crescent 70 kV Line	HELM 230/70KV TB 1	HSN	280.2%	511.12%

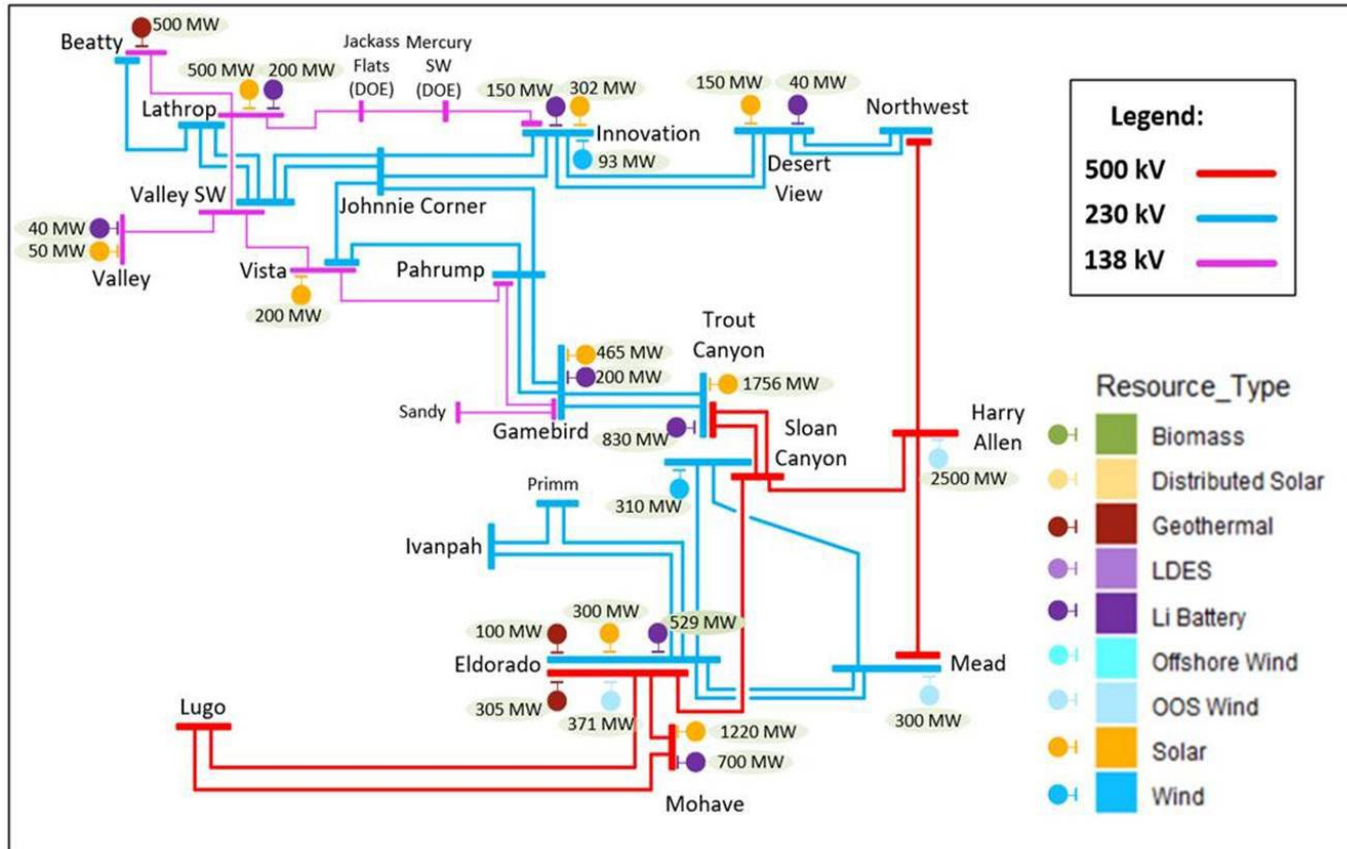
Affected transmission zones: PG&E Fresno Area		
		Base
Generic Portfolio MW behind the constraint (installed FCDS capacity)		200
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		81
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		184
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		97
Mitigation Options	RAS	N/A
	Re-locate generic portfolio battery storage (MW)	N/A
	Transmission upgrade including cost	Install new Helm 230/70kV Bank #2 (\$115M)
Recommended Mitigation		Install new Helm 230/70kV Bank #2

# New Helm 230/70 kV Bank #2

- Policy Assessment Need
  - Base HSN/SSN scenario
- Project Scope
  - The scope includes a new 230/70 kV Bank at Helm Substation with a 200 MVA rating. It will also include any bus upgrades and limiting equipment upgrades to achieve this transformer rating.
- Estimated Project Cost
  - \$115M
- Estimated In-service Date
  - 2034
- Alternatives Considered
  - RAS was considered as an alternative but was not selected due to not meeting the RAS guidelines
  - Helm – Schindler #1 and #2 line reconductoring, not considered due to cost
- Recommendation
  - Approval



# East of Pisgah Interconnection Area – Mapped Base Portfolio





# Economic Assessment and Production Cost Simulation Draft 2024-2025 Transmission Plan

*Yi Zhang*  
*Sr. Advisor Regional Transmission Engineer*

*2024-2025 Transmission Planning Process Stakeholder Meeting*  
*April 15, 2025*

## Key steps since November stakeholder session

- Modeled approved or recommended reliability upgrades that have impact on production cost simulation results
  - San Jose/Metcalf AC and DC hybrid upgrade
  - The fourth Metcalf 500/230 kV transformer
  - Manning – Metcalf 500 kV line upgrade
  - J.Hinds – Mirage 230 kV line upgrade
- Economic study requests evaluation
  - Total 17 economic study requests
- Cost estimate for transmission upgrades based on study requests or CAISO's transmission per unit cost
- Hitachi Energy's GridView v10.3.80 was used for simulation

# Comparing two alternatives of Manning – Metcalf upgrade

- Effectiveness of congestion mitigation and production cost savings are compared for two alternative:
  - Alternative 1:
    - Build a new Manning – Las aguilas – Moss Landing – Metcalf 500 kV line using the existing 230 kV right of way
  - Alternative 2:
    - Build a new Manning – Metcalf 500 kV line using new right of way

# Impact of Manning to Metcalf upgrade on congestion (2039 Base portfolio PCM)

Area or Branch Group	Congestion Cost (\$M)	Congestion Cost (\$M) with Manning - Metcalf upgrade Alternative 1	Congestion Cost (\$M) with Manning – Metcalf upgrade Alternative 2
Path 15 Corridor	391.71	468.49	521.80
PG&E Moss Landing - Las Aguilas 230 kV	289.89	0.00	0.00
Path 26 Corridor	171.79	194.06	206.28
SWIP North	66.56	58.14	51.61
PG&E GBA	14.36	6.96	5.79
PG&E Manning - Moss Landing 500 kV	0.00	5.47	0.00
PG&E Manning - Metcalf 500 kV	0.00	0.00	3.65

Both alternatives are effective to mitigate the Moss Landing – Las Aguilas 230 kV line congestion, but aggravate congestions on the Path 15 and Path 26 corridors



# Production cost savings comparison of the two alternatives of Manning to Metcalf upgrade (2039 Base portfolio PCM)

	2039 Base Portfolio without Manning - Metcalf upgrade	2039 Base Portfolio with Manning - Metcalf upgrade Alternative 1		2039 Base Portfolio with Manning - Metcalf upgrade Alternative 2	
	(\$M)	(\$M)	Savings (\$M)	(\$M)	Savings (\$M)
ISO load payment	19,053	18,841	212	18,823	230
ISO generator net revenue benefiting ratepayers	14,174	14,241	67	14,205	30
ISO transmission revenue benefiting ratepayers	1,838	1,642	-196	1,698	-140
ISO Net payment	3,040	2,957	83	2,920	120
WECC Production cost	23,942	23,872	70	23,874	68

# PCM assumption regarding Manning to Metcalf upgrade

- Production cost simulation results demonstrated that these two alternatives had similar impact on congestion and had similar economic benefit to the ISO's ratepayers
- The alternative 2 of the upgrade, i.e. building a new 500 kV line from Manning to Metcalf using new right of way, was recommended for approval as a reliability upgrade
  - It was also modeled in the PCM base cases in this planning cycle

# Aggregated congestion in the 2034 base portfolio PCM

No.	Aggregated congestion	Cost (\$M)	Duration (Hr)
1	Path 15 Corridor	389.42	5,468
2	Path 26 Corridor	241.10	4,503
3	SWIP North	51.29	716
4	East of Pisgah	35.61	1,378
5	Path 65 PDCI	28.53	1,679
6	SCE Northern	19.69	1,743
7	SCE Metro	16.05	179
8	PG&E North Valley 230 kV	15.05	1,863
9	Path 42	11.29	495
10	SDG&E/CFE	10.43	1,577
11	SCE North of Lugo	8.04	4,492
12	PG&E Kern 230kV	6.57	997
13	Path 41 Sylmar transformer	4.72	298
14	SDG&E 230 kV	3.74	634
15	SDG&E Bulk	3.67	374
16	COI Corridor	2.93	70
17	SCE Antelope 66kV	2.71	1,098
18	Path 46 WOR	2.37	45
19	PG&E Sierra	1.95	475
20	PG&E GBA	1.10	186

- Only listed congestions with congestion cost greater than \$1 million per year. More details can be found in the draft TPP report
- Reliability upgrades modeled in the PCM are the main reasons of congestion changes from the preliminary results presented in the November 13<sup>th</sup> stakeholder meeting

# Aggregated congestion in 2039 base portfolio PCM

No.	Aggregated congestion	Cost (\$M)	Duration (Hr)
1	Path 15 Corridor	521.80	7,343
2	Path 26 Corridor	206.28	4,197
3	East of Pisgah	86.87	3,334
4	SCE Northern	78.62	3,348
5	SCE Metro	67.89	1,328
6	SWIP North	51.61	748
7	SCE North of Lugo	32.55	6,531
8	Path 42	24.13	594
9	Path 65 PDCI	22.99	1,380
10	Path 46 WOR	19.53	308
11	SDG&E/CFE	18.03	2,101
12	PG&E North Valley 230 kV	16.63	1,485
13	SDG&E 230 kV	12.34	1,293
14	PG&E Kern 230kV	11.58	1,548
15	SCE Eastern	9.63	171
16	PG&E Morro Bay 230 kV	9.51	1,169
17	PG&E Sierra	8.39	1,053
18	Path 41 Sylmar transformer	7.93	397
19	SCE Antelope 66kV	6.76	1,619
20	PG&E GBA	5.79	459
21	COI Corridor	4.96	52
22	PG&E Fresno 115 kV	4.55	227
23	SDG&E Bulk	3.99	447
24	PG&E Manning - Metcalf 500 kV	3.65	116
25	PG&E Fresno 230 kV	1.23	182

- Only listed congestions with congestion cost greater than \$1 million per year. More details can be found in the draft TPP report
- Reliability upgrades modeled in the PCM are the main reasons of congestion changes from the preliminary results presented in the November 13<sup>th</sup> stakeholder meeting

# Detailed economic assessments

Detailed investigation	Alternative	Reason for receiving detailed assessment
East of Pisgah and Path 46 congestion	The Trout Canyon to Lugo project to build a new Trout Canyon – Lugo 500 kV line with 70% compensation	<p>Recurring congestion on the Path 61 corridor under both contingency and normal condition when the flow was from Victorville to Lugo was observed. Large congestions on the Eldorado – McCullough 500 kV line and the Sloan Canyon – Eldorado 500 kV line, and the Path 46, were also observed.</p> <p>The congestion in this area is mainly attributed to renewable generation in the SCE's East of Pisgah area, GridLiance West/VEA area, and the out of state wind generation delivered to the Harry Allen and Eldorado area. Solar generation in Arizona and New Mexico wind generation in the CPUC portfolios also contributed to the Path 46 congestion.</p>
	The Marketplace to Adelanto project to convert the Marketplace-Adelanto 500 kV line to HVDC, and build a 500 kV line from Adelanto to Lugo and a 500 kV line from Marketplace to Eldorado	
	Build the second Sloan Canyon – Eldorado 500 kV line	
	Build a new Adelanto – Lugo 500 kV line	
	Build the third Colorado River – Red Bluff 500 kV line and a new Red Bluff – Mira Loma 500 kV line	

## Detailed economic assessments (cont.)

Detailed investigation	Alternative	Reason for receiving detailed assessment
LA Basin and Path 26 corridor congestion	The PTE project	Path 26 congestion is a recurring congestion with large congestion cost. La Fresa – La Cienega 230 kV congestion was also observed.  Some of these alternatives can help to reduce local capacity requirements.
	The K-SEL project (Midway – El Nido 2000 MW HVDC)	
	The DelAmo – El Nido underground HVDC project	
	The DelAmo – El Nido underground 230 kV AC line project	
	Build the third Midway – Vincent 500 kV line	

# Detailed economic assessments (cont.)

Detailed investigation	Alternative	Reason for receiving detailed assessment
Path 15 corridor congestion	Alternative 1: Build a new Manning – Los Banos – Tesla 500 kV line	Path 15 corridor congestion showed significant increase in this planning cycle compared with the results in previous planning cycles, as the resource assumption changed in the CPUC IRP portfolio.
	Alternative 2: A1 plus a new Midway – Gates – Manning 500 kV line	
	Alternative 3: Monarch Option 1 Gates – Los Banos #3 500 kV line loops in new NewPoint 500 kV substation and build a new NewPoint to Tracy 500 kV line	
	Alternative 4: A3 plus NewPoint – Tracy looping in Tesla	
	Alternative 5: A4 plus build a new Midway – New Point 500 kV line	
	Alternative 6: Monarch Option 2 Build a new Manning – NewPoint – Tracy 500 kV line	
	Alternative 7: A6 plus NewPoint – Tracy looping in Tesla	
	Alternative 8: A7 plus build a new Midway – NewPoint 500 kV line	
	Alternative 9: Build a new 500 kV line from Midway to the new Gregg 500 kV substation to Tesla	
	Alternative 10: Install a 10 ohm series reactor on each of the two Panoche – Gates 230 kV lines	

# East of Pisgah area and Path 46 congestion mitigations

	Congestion Costs (\$K)					
	Base (2039 Base portfolio PCM)	A1: Trout Canyon - Lugo	A2: Marketplace- Adelanto HVDC	A3: Sloan Canyon - Eldorado	A4: Adelanto- Lugo	A5: Colorado River– Red Bluff– Mira Loma
LUGO-VICTORVL 500 kV line, subject to SCE N-1 Eldorado-Lugo 500 kV with RAS	40,639	13	0	42,019	0	21,288
ELDORDO-MCCULLGH 500 kV line, subject to SCE N-1 Eldorado-Lugo 500 kV with RAS	27,572	473	36,067	39,945	49,620	27,097
P46 West of Colorado River (WOR)	19,526	5,575	3,020	21,768	22,933	35,157
SLOAN_CYN_5-ELDORDO 500 kV line #1	17,778	79	22,453	0	11,789	17,436
P61 Lugo-Victorville 500 kV Line	306	1,883	2	616	0	794
GAMEBIRD-GAMEBIRD 230 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	12	19,237	13	16	14	11



# East of Pisgah area and Path 46 congestion mitigations – production cost savings

	Base (2039 Base portfolio PCM)	A1: Trout Canyon – Lugo 500 kV line		A2: Marketplace- Adelanto HVDC		A3: the second Sloan Canyon – Eldorado 500 kV line		A4: Adelanto-Lugo 500 kV line		A5: Colorado River – Red Bluff – Mira Loma 500 kV line	
	(\$M)	Post project (\$M)	Savings (\$M)	Post project (\$M)	Savings (\$M)	Post project (\$M)	Savings (\$M)	Post project (\$M)	Savings (\$M)	Post project (\$M)	Savings (\$M)
ISO load payment	18,823	19,021	-198	18,913	-90	18,822	1	18,864	-41	18,773	50
ISO generator net revenue benefiting ratepayers	14,205	14,335	130	14,272	68	14,199	-6	14,233	29	14,188	-16
ISO transmission revenue benefiting ratepayers	1,698	1,696	-2	1,644	-54	1,684	-13	1,652	-46	1,721	23
ISO Net payment	2,920	2,990	-70	2,997	-76	2,939	-18	2,978	-58	2,863	57
WECC Production cost	23,874	23,886	-12	23,816	58	23,869	5	23,848	26	23,841	33

## East of Pisgah and Path 46 congestion mitigations - summary

- Five transmission upgrades were study as alternatives for mitigating East of Pisgah and Path 46 congestions in this planning cycle
- Only the Colorado River to Red Bluff to Mira Loma 500 kV line upgrade showed positive benefit but its benefit to cost ratio was 0.245, still less than 1.0
  - The capital cost of this upgrade was estimated as about \$2.6 billion, based on the ISO transmission per unit cost
- No sufficient economic justification was found for these East of Pisgah and Path 46 congestion mitigation alternatives

# Path 26 corridor and LA Basin congestion mitigations

	Congestion Costs (\$K)					
	Base (2039 Base portfolio PCM)	A1: PTE	A2: K-SEL	A3: Del Amo – El Nido HVDC	A4: Del Amo – El Nido 230 kV AC	A5: the third Midway- Vincent line
P26 Northern-Southern California	173,557	62,850	138,873	174,109	173,500	69,092
LCIENEGA-LAFRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	67,364	0	0	0	0	65,736
MIDWAY-MN_WRLWND_31 500 kV line #3	31,897	20,048	39,060	30,335	29,847	25,994

# Path 26 corridor and LA Basin congestion mitigations – production cost savings

	Base (2039 Base portfolio PCM)	A1: PTE		A2: K-SEL		A3: Del Amo – El Nido HVDC		A4: Del Amo – El Nido 230 kV AC		A5: the third Midway-Vincent line	
	(\$M)	Post project (\$M)	Savings (\$M)	Post project (\$M)	Savings (\$M)	Post project (\$M)	Savings (\$M)	Post project (\$M)	Savings (\$M)	Post project (\$M)	Savings (\$M)
ISO load payment	18,823	18,725	98	18,808	15	18,828	-5	18,804	19	18,788	35
ISO generator net revenue benefiting ratepayers	14,205	14,303	99	14,286	82	14,271	67	14,257	52	14,178	-27
ISO transmission revenue benefiting ratepayers	1,698	1,459	-239	1,588	-110	1,633	-64	1,626	-72	1,677	-21
ISO Net payment	2,920	2,963	-42	2,933	-13	2,923	-3	2,921	-1	2,933	-12
WECC Production cost	23,874	23,785	89	23,843	31	23,867	7	23,859	15	23,824	50

# Path 26 corridor and LA Basin congestion mitigations – LCR reduction savings

- The PTE and K-SEL projects can potentially reduce LCR requirements in the LA Basin area, based on the assessment results in previous TPP cycles
- Following assumptions were used to assess the LCR reduction benefit for these projects in this planning cycle
  - LCR requirement reduction approximately equal to the transmission capacity of projects
  - The capacity requirements reduced in the local area will still be needed for system RA
- These assumptions were used only for screening purpose. Detailed LCR study will be needed if the results show economic benefit sufficient or close to compensate the cost of the projects

# Path 26 corridor and LA Basin congestion mitigations – LCR reduction savings (cont.)

Capacity costs in the CPUC Resource Adequacy Report were used to calculate the capacity value:

Area	Weighted average capacity cost (\$/kW-month) in CPUC 2022 RA report	In 2024 dollar
System	7.62	8.08
SP26	7.22	7.66
LA Basin	7.54	8.00

LCR reduction benefit can be negative as the LA Basin RA cost is less than the system RA cost

	PTE		K-SEL	
	Local vs System RA cost	Local vs SP 26 RA cost	Local vs System RA cost	Local vs SP 26 RA cost
LCR reduction benefit (Western LA Basin) (MW)	2,000		2,000	
Capacity value (\$/MW-year)	-1,018	4,073	-1,018	4,073
LCR Reduction Benefit (\$million/year)	-2.04	8.15	-2.04	8.15

# Path 26 corridor and LA Basin congestion mitigations – LCR reduction savings (cont.)

A sensitivity assessment for LCR reduction savings was conducted using the capacity costs proposed in the PTE economic study request

Area	Weighted average capacity cost (\$/kW-month) in 2024 dollar	Note
System	Low: 2.34, High: 2.74	The PTE economic study request assumed the system capacity marginal cost would be set by battery storage
LA Basin	Low: 5.15, High: 7.79	The PTE economic study request provided the LA Basin capacity cost

	PTE	K-SEL
	Local vs System RA cost	Local vs System RA cost
LCR reduction benefit (Western LA Basin) (MW)	2,000	2,000
Capacity value(\$/MW-year)	67,870	67,870
LCR Reduction Benefit (\$million/year)	135.74	135.74

# Path 26 corridor and LA Basin congestion mitigations – benefit to cost ratio

	PTE			K-SEL		
	Baseline study (CPUC capacity cost)		Sensitivity assessment	Baseline study (CPUC capacity cost)		Sensitivity assessment
	Local vs System RA cost	Local vs SP 26 RA cost	Local cost in CPUC report vs System cost (low) in PTE study request	Local vs System RA cost	Local vs SP 26 RA cost	Local cost in CPUC report vs System cost (low) in PTE study request
Production cost savings (\$million/year)	-42	-42	-42	-13	-13	-13
Capacity saving (\$million/year)	-2.04	8.15	135.74	-2.04	8.15	135.74
Capital cost (\$million)	2,200	2,200	2,200	2,424	2,424	2,424
Cost to Revenue Ratio	1.3	1.3	1.3	1.3	1.3	1.3
Discount Rate	7%	7%	7%	7%	7%	7%
Economic life (year)	50	50	50	50	50	50
PV of Production cost savings (\$million)	-620	-620	-620	-192	-192	-192
PV of Capacity saving (\$million)	-30	120	2,004	-30	120	2,004
Total benefit (\$million)	-650	-500	1,384	-222	-72	1,812
Total cost (Revenue requirement) (\$million)	2,860	2,860	2,860	3,152	3,152	3,152
Benefit-to-cost ratio (BCR)	-0.23	-0.17	0.48	-0.07	-0.02	0.58



## Path 26 corridor and LA Basin congestion mitigations – summary

- All five alternatives had negative production cost savings for the CAISO's ratepayers
- LCR reduction benefit was assessed for the PTE project and the K-SEL project
- No alternatives showed sufficient economic justification as economic-drive upgrade for Path 26 and LA Basin congestion mitigation
- The assumptions around the value of reducing capacity requirements and the capacity cost directly affect the value of the PTE and K-SEL projects
  - The LCR reduction benefit needs to be reassessed when such assumptions change

# Path 15 corridor congestion and mitigations – individual congestions in the 2039 Base portfolio PCM

Constraint Name	Cost Forward (\$K)	Duration Forward (Hrs)	Cost Backward (\$K)	Duration Backward (Hrs)	Costs Total (\$K)	Duration Total (Hrs)
MANNING-MN_GT_11 500 kV line #1	0	0	278,288	2,415	278,288	2,415
PANOCHÉ-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	85,856	1,628	85,856	1,628
MN_GT_11-GATES 500 kV line #1	0	0	54,304	475	54,304	475
MN_MW_21-MN_MW_22 500 kV line #2	0	0	38,600	559	38,600	559
MANNING-MN_MW_21 500 kV line #2	0	0	26,691	872	26,691	872
GT_MW_11-MIDWAY 500 kV line #1	0	1	11,029	234	11,030	235
MN_MW_23-MIDWAY 500 kV line #2	0	0	10,231	339	10,231	339
GATES-GT_MW_11 500 kV line #1	0	0	6,925	202	6,925	202
MN_MW_22-MN_MW_23 500 kV line #2	0	0	3,833	87	3,833	87
PANOCHÉ-GATES E 230 kV line, subject to PG&E N-2 LB-Gates and LB-Midway 500 kV	0	0	3,720	254	3,720	254
PANOCHÉ-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	1,061	151	1,061	151
FINKSWSTA-WESTLEY 230 kV line, subject to PG&E N-1 LosBanos-Tesla 500kV	657	21	0	0	657	21
PANOCHÉ-GATES E 230 kV line, subject to PG&E N-1 Panoche-Gates #1 230kV	0	0	599	105	599	105

# Path 15 corridor congestion and mitigations – impact on Path 15 and Path 26 congestions

	Path 15 corridor congestion		Path 26 corridor congestion		
	Congestion Cost (\$M)		Congestion Cost (\$M)		
2039 Base portfolio PCM case	521.80		206.28		
Alternatives	Congestion Cost (\$M)	Congestion Cost Change from Base (\$M)	Congestion Cost (\$M)	Congestion Cost Change from Base (\$M)	Note
Alternative 1: Build a new Manning – Los Banos – Tesla 500 kV line	574.52	52.72	212.03	5.75	Congestion on the Path 15 south of Manning segments increased, which contributed to the Path 15 corridor congestion increased
Alternative 2: A1 plus a new Midway – Gates – Manning 500 kV line	70.42	-451.37	289.95	83.67	Path 15 south of Manning congestion was significantly reduced. The remaining Path 15 congestion was mainly observed on the Panoche - Gates 230 kV lines. Path 26 congestion increased.
Alternative 3: Monarch Option 1 Gates – Los Banos #3 500 kV line loops in new NewPoint 500 kV substation and build a new NewPoint to Tracy 500 kV line	497.54	-24.26	215.59	9.31	The Gates - Los Banos #3 line looping-in to the NewPoint substation helps to reduce the flow and congestion on Gates - Manning 500 kV lines.
Alternative 4: A3 plus NewPoint – Tracy looping in Tesla	479.10	-42.70	220.51	14.23	Flow and congestion impact is similar to Alternative 3.
Alternative 5: A4 plus build a new Midway – New Point 500 kV line	211.25	-310.54	311.96	105.68	Adding the Midway - NewPoint 500 kV line can help to reduce Path 15 south of Manning congestion but the Path 26 congestion increased significantly.

# Path 15 corridor congestion and mitigations – impact on Path 15 and Path 26 congestions (cont.)

	Path 15 corridor congestion		Path 26 corridor congestion		
	Congestion Cost (\$M)		Congestion Cost (\$M)		
2039 Base portfolio PCM case	521.80		206.28		
Alternatives	Congestion Cost (\$M)	Congestion Cost Change from Base (\$M)	Congestion Cost (\$M)	Congestion Cost Change from Base (\$M)	Note
Alternative 6: Monarch Option 2 Build a new Manning – NewPoint – Tracy 500 kV line	594.39	72.60	212.22	5.95	Congestion on the Gates - Manning 500 kV lines significantly increased after modeling the Manning - NewPoint - Tracy 500 kV line.
Alternative 7: A6 plus NewPoint – Tracy looping in Tesla	607.81	86.01	215.70	9.42	Flow and congestion impact is similar to Alternative 6.
Alternative 8: A7 plus build a new Midway – NewPoint 500 kV line	217.84	-303.96	313.95	107.68	Adding the Midway - NewPoint 500 kV line can help to reduce Path 15 south of Manning congestion but the Path 26 congestion increased significantly.
Alternative 9: Build a new 500 kV line from Midway to new Gregg 500 kV substation to Tesla	137.77	-384.02	300.28	94.00	This alternative help to reduce the Path 15 congestion on both south of Manning segments and Panoche - Gates 230 kV lines, but increase the Path 26 congestion.
Alternative 10: Install a 10 ohm series reactor on each of the two Panoche – Gates 230 kV lines	516.87	-4.93	200.97	-5.31	Adding series reactors on the Panoche - Gates 230 kV lines helped to mitigate the congestion on the lines, but it aggravated the congestion on the Gates - Manning 500 kV lines.

# Path 15 corridor congestion and mitigations – production cost savings

Scenarios		ISO load payment (\$M)	ISO generator net revenue benefiting ratepayers (\$M)	ISO transmission revenue benefiting ratepayers (\$M)	ISO Net payment (\$M)	WECC Production cost (\$M)
Base case		18,823	14,205	1,698	2,920	23,874
Alternative 1: Build a new Manning – Los Banos – Tesla 500 kV line	Post project	18,831	14,182	1,759	2,890	23,874
	Savings	-8	-22	61	31	0
Alternative 2: A1 plus a new Midway – Gates – Manning 500 kV line	Post project	18,783	14,452	1,319	3,012	23,761
	Savings	40	247	-379	-91	113
Alternative 3: Monarch Option 1 Gates – Los Banos #3 500 kV line loops in NewPoint 500 kV and build NewPoint to Tracy 500 kV line	Post project	18,804	14,230	1,671	2,903	23,851
	Savings	19	25	-27	18	23
Alternative 4: A3 plus NewPoint – Tracy looping in Tesla	Post project	18,827	14,265	1,660	2,901	23,849
	Savings	-4	61	-37	19	24
Alternative 5: A4 plus build a new Midway – New Point 500 kV line	Post project	18,776	14,404	1,470	2,902	23,776
	Savings	47	199	-228	18	98
Alternative 6: Monarch Option 2 Build a new Manning – NewPoint – Tracy 500 kV line	Post project	18,855	14,191	1,779	2,885	23,878
	Savings	-32	-14	82	36	-4
Alternative 7: A6 plus NewPoint – Tracy looping in Tesla	Post project	18,861	14,186	1,800	2,876	23,885
	Savings	-38	-19	102	45	-12
Alternative 8: A7 plus Midway – New Point	Post project	18,782	14,402	1,482	2,898	23,761
	Savings	41	198	-215	23	113
Alternative 9: Build a new 500 kV line from Midway to new Gregg 500 kV to Tesla	Post project	18,777	14,449	1,385	2,943	23,769
	Savings	46	244	-312	-23	105
Alternative 10: Install 10 ohm series reactor on Panoche – Gates 230 kV lines	Post project	18,843	14,223	1,699	2,922	23,873
	Savings	-20	18	1	-1	1

# Path 15 corridor congestion and mitigations – benefit to cost ratio

	A1: new Manning – Los Banos – Tesla 500 kV line	A2: A1 plus a new Midway – Gates – Manning 500 kV line	A3: Monarch Option 1	A4: A3 plus NewPoint – Tracy looping in Tesla	A5: A4 plus new Midway – New Point 500 kV line	A6: Monarch Option 2	A7: A6 plus NewPoint – Tracy looping in Tesla	A8: A7 plus build a new Midway – NewPoint 500 kV line	A9: new 500 kV line from Midway to Tesla	A10: series reactor on Panoche – Gates 230 kV lines
Production cost savings (\$million/year)	31	-91	18	19	18	36	45	23	-23	-1
Capacity saving (\$million/year)	0	0	0	0	0	0	0	0	0	0
Capital cost (\$million)	888	2,018	950	1,164	2,068	851	1,065	1,933	1,781	109
Cost to Revenue Ratio	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Discount Rate	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Economic Life (year)	50	50	50	50	50	50	50	50	50	50
PV of Production cost savings (\$million)	452	-1,348	259	282	267	525	661	337	-335	-20
PV of Capacity saving (\$million)	0	0	0	0	0	0	0	0	0	0
Total benefit (\$million)	452	-1,348	259	282	267	525	661	337	-335	-20
Total cost (\$million)	1,155	2,624	1,235	1,513	2,688	1,107	1,385	2,513	2,315	142
Benefit-to-cost ratio (BCR)	0.39	-0.51	0.21	0.19	0.10	0.47	0.48	0.13	-0.14	-0.14

## Path 15 corridor congestion and mitigations - summary

- Multiple transmission alternatives for mitigating the congestion on the Path 15 corridor were assessed
- The benefit to cost ratio calculation was based on the assumptions:
  - all transmission upgrade alternatives are fully rate-based
  - capital costs of the projects were estimated based on the CAISO transmission per unit cost
- No alternatives showed sufficient economic justification as economic-driven upgrade for Path 15 corridor congestion mitigation

# Summary of economic assessment

- Congestion on the transmission system was assessed through detailed production cost modeling
- 20 transmission alternatives were assessed whether the benefits of alleviating congestion exceed the cost of transmission upgrades
  - LCR reduction benefit of possible transmission upgrades was also taken into account
- No projects driven solely by economic considerations are recommended in this planning cycle





# *Wrap-up*

## Draft 2024-2025 Transmission Plan

*Yelena Kopylov-Alford*  
*Stakeholder Engagement and Policy Specialist*

*2024-2025 Transmission Planning Process Stakeholder Meeting*  
*April 15, 2025*

# Comments

- Comments due by end of day April 29, 2025
- Submit comments through the ISO's commenting tool, using the template provided on the process webpage:  
<https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2024-2025-Transmission-planning-process>
- Questions? Email us at:  
[ISOStakeholderAffairs@caiso.com](mailto:ISOStakeholderAffairs@caiso.com)

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