Transmission Planning Process Overview
Draft 2023-2024 Transmission Plan

Agenda - Stakeholder Meeting

2023-2024 Transmission Planning Process

April 9, 2024

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

- If you are connected to audio through your computer or used the “call me” option, select the raise hand icon located on the bottom of your screen.

  Note: #2 only works if you dialed into the meeting.

- Please remember to state your name and affiliation before making your comment

2023-2024 Transmission Planning Process Stakeholder Call – Agenda

Topic	Presenters
Agenda	Yelena Kopylov-Alford
Introduction	Neil Millar
Overview	Jeff Billinton
Reliability-driven Projects Recommended for Approval - PG&E Planning Area - SDG&E Planning Area	Preethi Rondla Uriel Rangel Diaz Rene Romo de Santos
Frequency Response	Chris Fuchs
Maximum Import Capability (MIC) – Expansion Requests	Catalin Micsa
Policy-driven Projects Recommended for Approval - Northern Area - Southern Area	Nebiyu Yimer Binaya Shrestha Meng Zhang Rene Romo de Santos
Economic Assessment	Yi Zhang
Wrap-up	Yelena Kopylov-Alford

Introduction
Draft 2023-2024 Transmission Plan

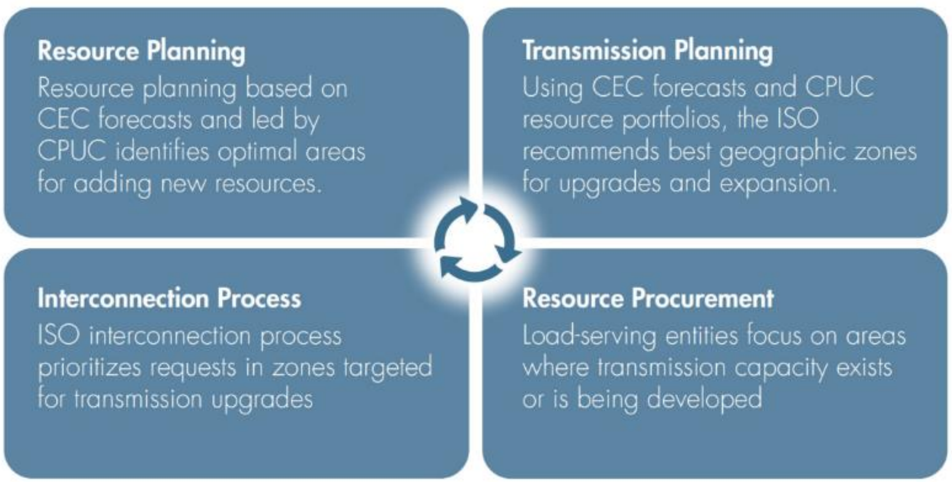
Neil Millar

Vice-President, Infrastructure & Operations Planning

2023-2024 Transmission Planning Process Stakeholder Meeting

April 9, 2024

Transmission Planning and Generation Interconnection are two of four fundamental and interwoven 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

Transmission Planning Process Overview
Draft 2023-2024 Transmission Plan

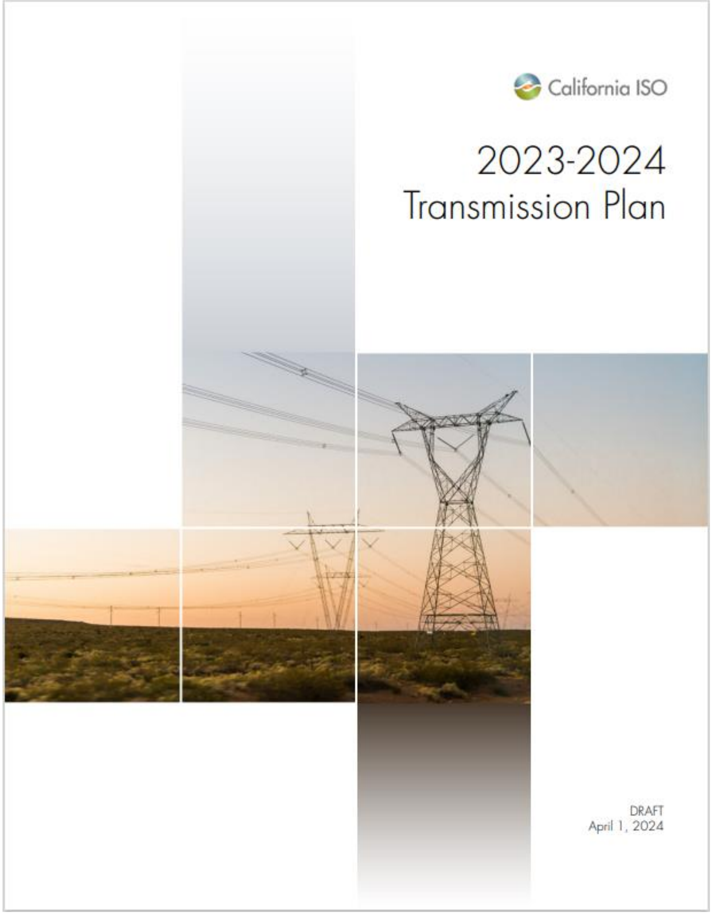
Jeff Billinton
Director, Transmission Infrastructure Planning

2023-2024 Transmission Planning Process Stakeholder Meeting
April 9, 2024

2023-2024 Draft Transmission Plan

- The 2023-2024 Draft Transmission Plan was posted on April 1, 2024. https://www.caiso.com/InitiativeDocuments/DRAFT_2023-2024_TransmissionPlan.pdf

- The Draft Transmission Plan represents the CAISO's identification of system needs over the next 12-years and offers an opportunity for stakeholder input before the final recommendations are presented to the CAISO Board of Governors in May.



Considerations in the 2023-2024 Transmission Planning Process

- This years transmission plan is based on state projections provided that California needs to add more than 85 GW of capacity by 2035. Particular considerations in this planning cycle include,
  - Offshore Wind Development
  - Out of State Wind and Geothermal Development
  - Increased access and distribution for Solar and Battery projects

- 26 new Reliability and Policy driven projects were found to be needed, totaling an estimated $6.1 billion.

2023-2024 Transmission Planning Process

January 2023 — **April 2023** — **May 2024**

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

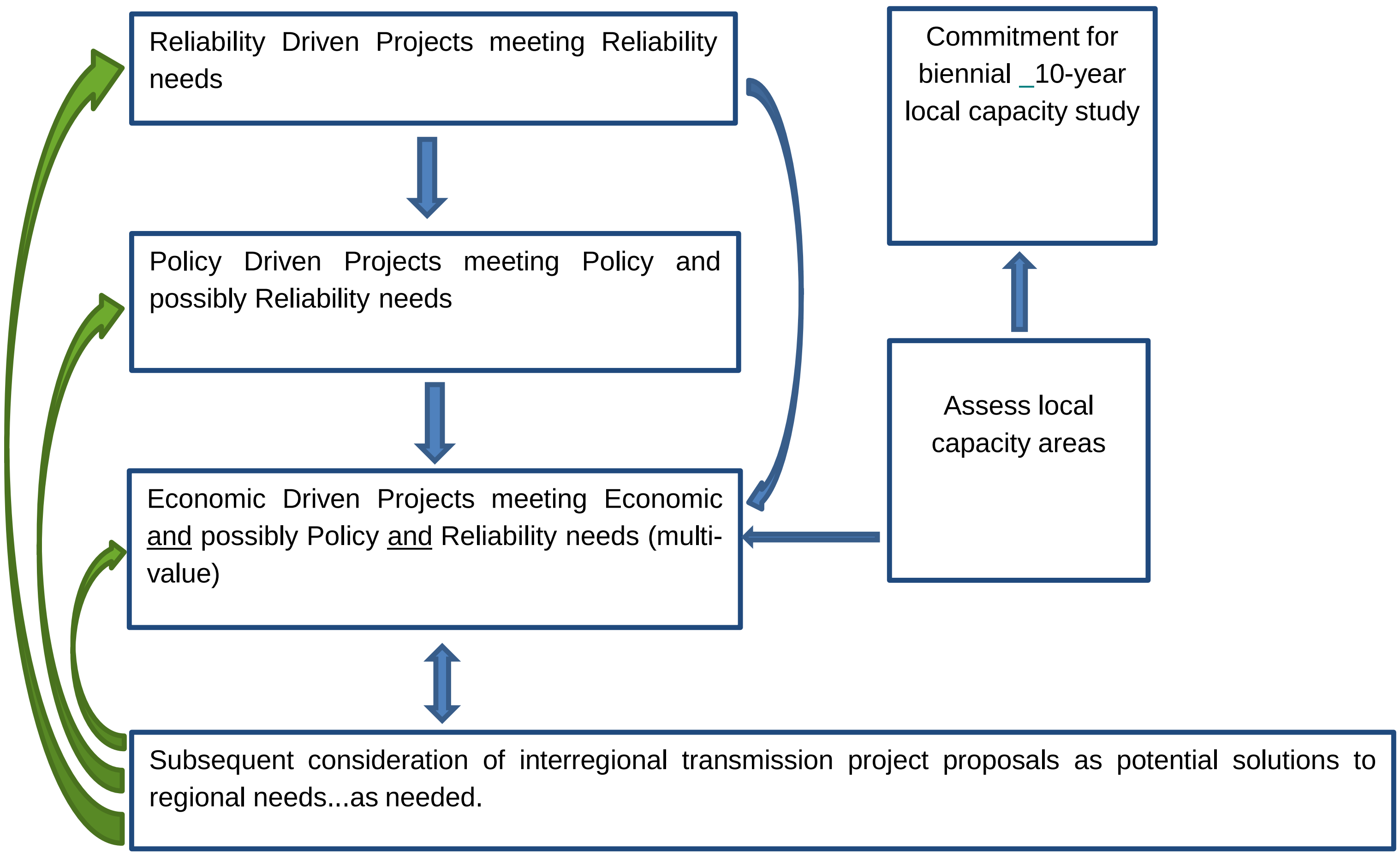
CAISO Board for approval of transmission plan

California ISO

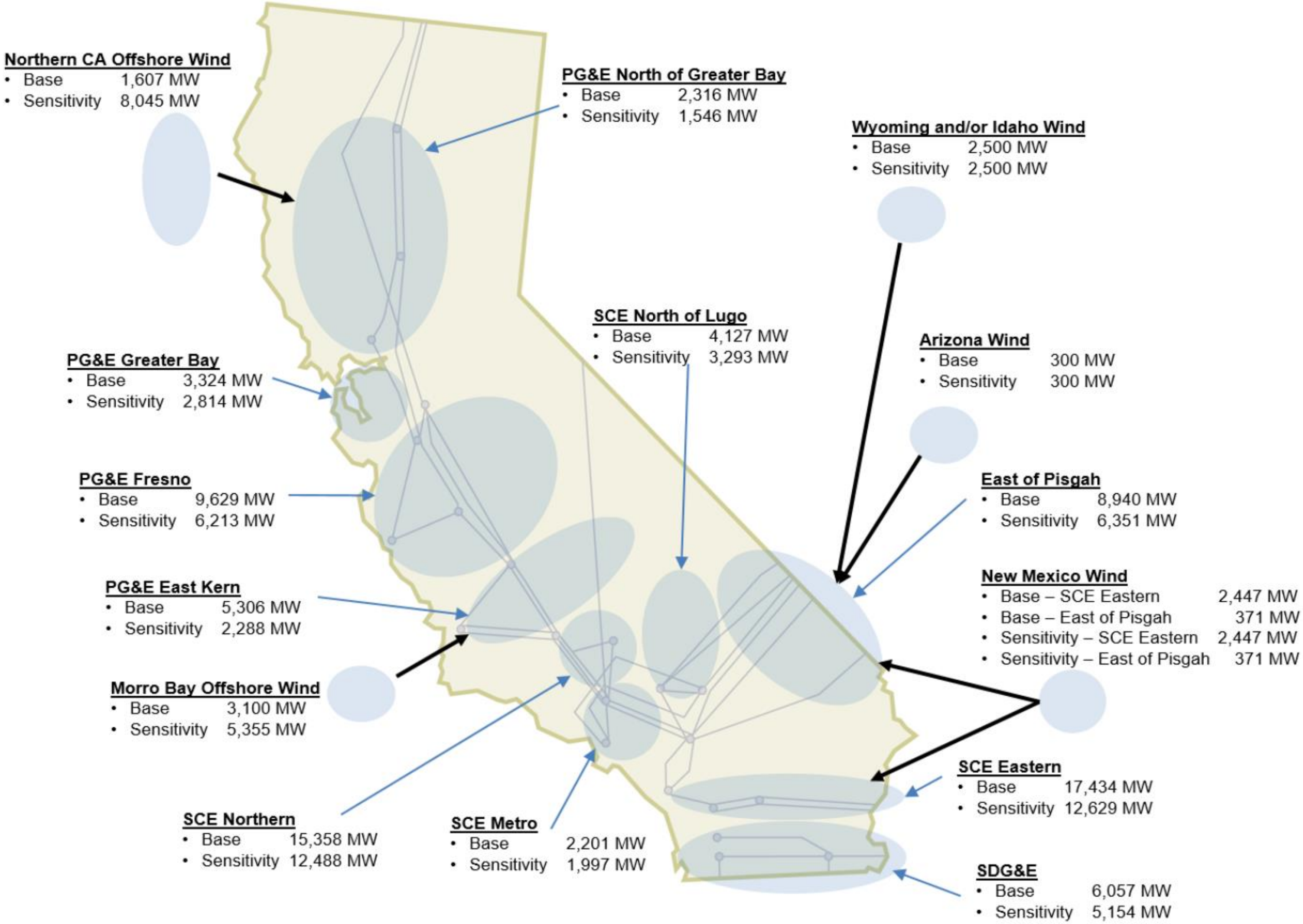
2023-2024 Transmission Plan Milestones

- Draft Study Plan posted on February 23, 2023
- Stakeholder meeting on Draft Study Plan on February 28, 2023
  - Comments submitted by March 14, 2023
- Final Study Plan posted on August 16, 2023
- Preliminary reliability study results posted on August 15, 2023
- Stakeholder meeting on September 26 and 27, 2023
  - Comments submitted by October 11, 2023
- Request window closed October 15, 2023
- Preliminary policy and economic study results on November 16, 2023
  - Comments to be submitted by November 30, 2023
- Draft transmission plan to be posted on April 1, 2024
- Stakeholder meeting on April 9, 2024
  - Comments to be submitted by April 23, 2024
- Revised draft for approval at May Board of Governor meeting

Studies are coordinated as a part of the transmission planning process



Zonal Approach: Transmission Planning Zones and Capacity



California ISO

Grid-Enhancing Technologies (GETs)

- Includes a range of technologies that offer specific benefits and opportunities that are considered on a case-by-case basis.

- The ISO has considered several Grid Enhancing Technologies as potential alternatives.

- In the 2023-2024 plan a phase-shifting transformer that provides flow control has been recommended for approval.

Reliability-Driven Recommended Projects

- 19 reliability projects driven by load growth and evolving grid conditions as the generation fleet transitions to increased renewable generation have been recommended, totaling $1.542 billion

No.	Project Name	PTO Area	Planning Area	Est. Cost ($M)
1	Covelo 60 kV Voltage Support[7]	PG&E	North Coast / North Bay	22
2	Martin-Millbrae 60 kV Area Reinforcement[7]	PG&E	Greater Bay Area	40
3	Atlantic High Voltage Mitigation[7]	PG&E	Central Valley	40
4	Mira Loma 500 kV Bus SCD Mitigation[7]	SCE	SCE Bulk	5
5	Inyo 230 kV Shunt Reactor[7]	SCE	North of Lugo	20
6	Etiwanda 230 kV Bus SCD Mitigation[7]	SCE	SCE Eastern	15
7	Eldorado 230 kV Short Circuit Duty Mitigation[7]	SCE	East of Lugo	48.8
8	Valley Center System Improvement	SDG&E	SDG&E	51
9	Camden 70 kV Reinforcement	PG&E	Greater Fresno	100
10	Gates 230/70 kV Transformer Addition	PG&E	Greater Fresno	72
11	Reedley 70 kV Capacity Increase	PG&E	Greater Fresno	98
12	Diablo Canyon Area 230 kV High Voltage Mitigation	PG&E	Central Coast & Los Padres	70
13	Crazy Horse Canyon - Salinas - Soledad #1 and #2 115 kV Line Reconductoring	PG&E	Central Coast & Los Padres	108
14	Vaca-Plainfield 60 kV Line Reconductoring	PG&E	Central Valley	68
15	Rio Oso - W. Sacramento Reconductoring	PG&E	Central Valley	97.4
16	Cortina #1 60 kV Line Reconductoring	PG&E	Central Valley	94.3
17	Salinas Area Reinforcement	PG&E	Central Coast & Los Padres	452.3
18	Tejon Area Reinforcement	PG&E	Kern	56
19	French Camp Reinforcement	PG&E	Central Valley	84.2
			Total	**1,542**

7 These projects have already been approved by ISO Management, ahead of the rest of the Plan being approved 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.

Policy-Driven Recommended Projects

- To meet the renewable generation requirements established in the CPUC-developed renewable generation portfolios, an additional 7 transmission projects that are policy driven have been recommended, totaling $4.586 billion

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

Economic-Driven Recommended Projects

- The ISO conducted several economic studies investigating opportunities to reduce total costs to ratepayers through transmission upgrades not otherwise needed for reliably accessing renewables and serving load.

- No projects driven solely by economic considerations are being recommended in the 2023-2024 plan.

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, 2024:
  - New Humboldt 500 kV Substation, with a 500/115 kV transformer, and 500 kV line to Collinsville (HVDC operated as AC)
  - New Humboldt to Fern Road 500 kV Line

Comments

- Comments due by end of day April 23, 2024
- Submit comments through the ISO's commenting tool, using the template provided on the process webpage:
- https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2023-2024-Transmission-planning-process

Reliability Assessment Recommendations – PG&E Area
Draft 2023-2024 Transmission Plan

Preethi Rondla

Lead Engineer, Regional Transmission – North

2023-2024 Transmission Planning Process Stakeholder Meeting

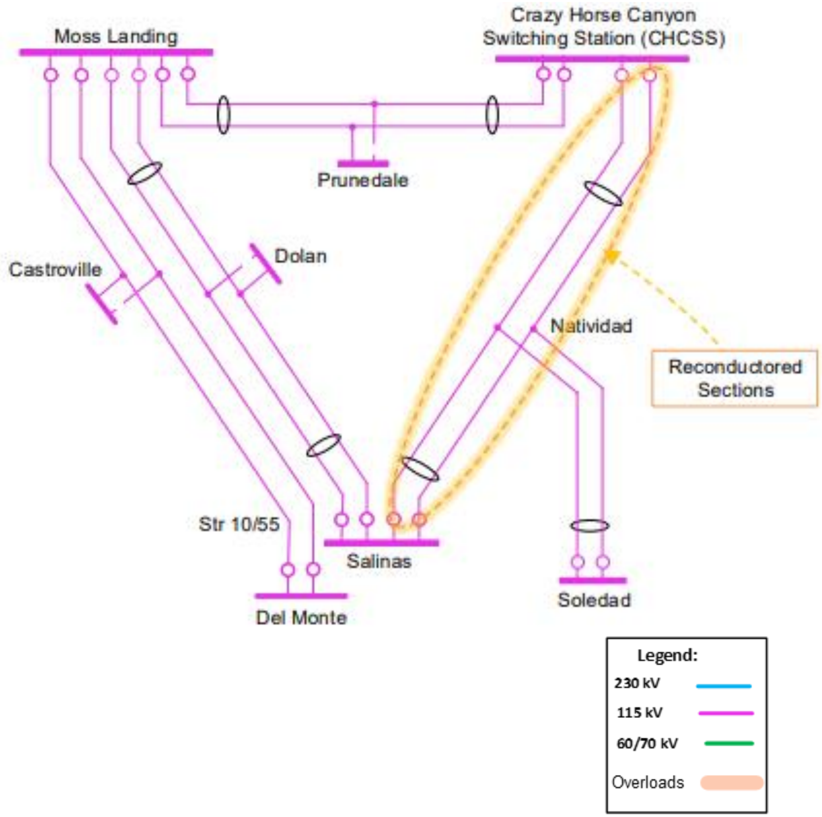
April 9, 2024

New Reliability Projects Recommended for Approval in 2023-2024 TPP - PG&E Area

Projects	Planning Area	Status
Crazy Horse Canyon - Salinas - Soledad #1 and #2 115 kV Line Reconductoring	Central Coast & Los Padres	Recommended for Approval
Diablo Canyon Area 230 kV High Voltage Mitigation	Central Coast & Los Padres	Recommended for Approval
Salinas Area Reinforcement	Central Coast & Los Padres	Recommended for Approval
Cortina #1 60 kV Line Reconductoring	Central Valley	Recommended for Approval
French Camp Reinforcement	Central Valley	Recommended for Approval
Rio Oso - W. Sacramento Reconductoring	Central Valley	Recommended for Approval
Vaca-Plainfield 60 kV Line Reconductoring	Central Valley	Recommended for Approval
Camden 70 kV Reinforcement	Greater Fresno	Recommended for Approval
Gates 230/70 kV Transformer Addition	Greater Fresno	Recommended for Approval
Reedley 70 kV Capacity Increase	Greater Fresno	Recommended for Approval
Tejon Area Reinforcement	Kern	Recommended for Approval
Oakland Transmission Reinforcement	Greater Bay Area	Work in Progress

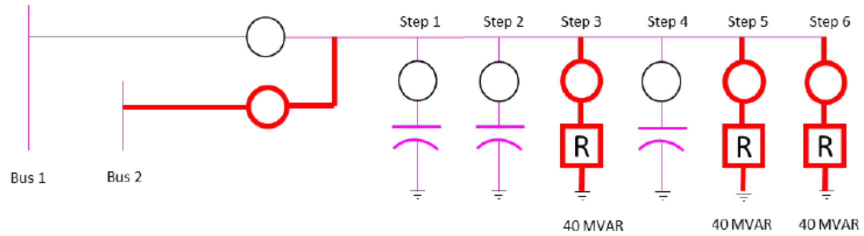
Crazy Horse Canyon - Salinas - Soledad #1 and #2 115 kV Line Reconductoring

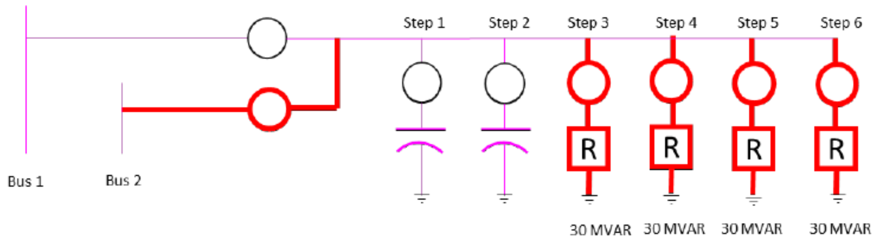
- Reliability Assessment Need
  - The near-term issues driven by P7 category contingencies and long-term issues driven by P2.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductor the CHCSS-Natividad section and Natividad-Salinas sections of CHCSS-Salinas #1 and #2 lines, and remove any limiting elements on these line sections and associated bus connections to achieve full conductor rating.
- Estimated Project Cost
  - $54M - $108M
- Estimated In-service Date
  - 2030
- Alternatives Considered
  - Status quo
  - Looping in Moss landing-Del Monte #1 and #2 115 kV double circuit into Salinas but not recommended due to space constraints at Salinas
  - RAS not recommended to due violating ISO RAS guidelines
- Recommendation
  - Approval



Diablo Canyon Area 230 kV High Voltage Mitigation Project

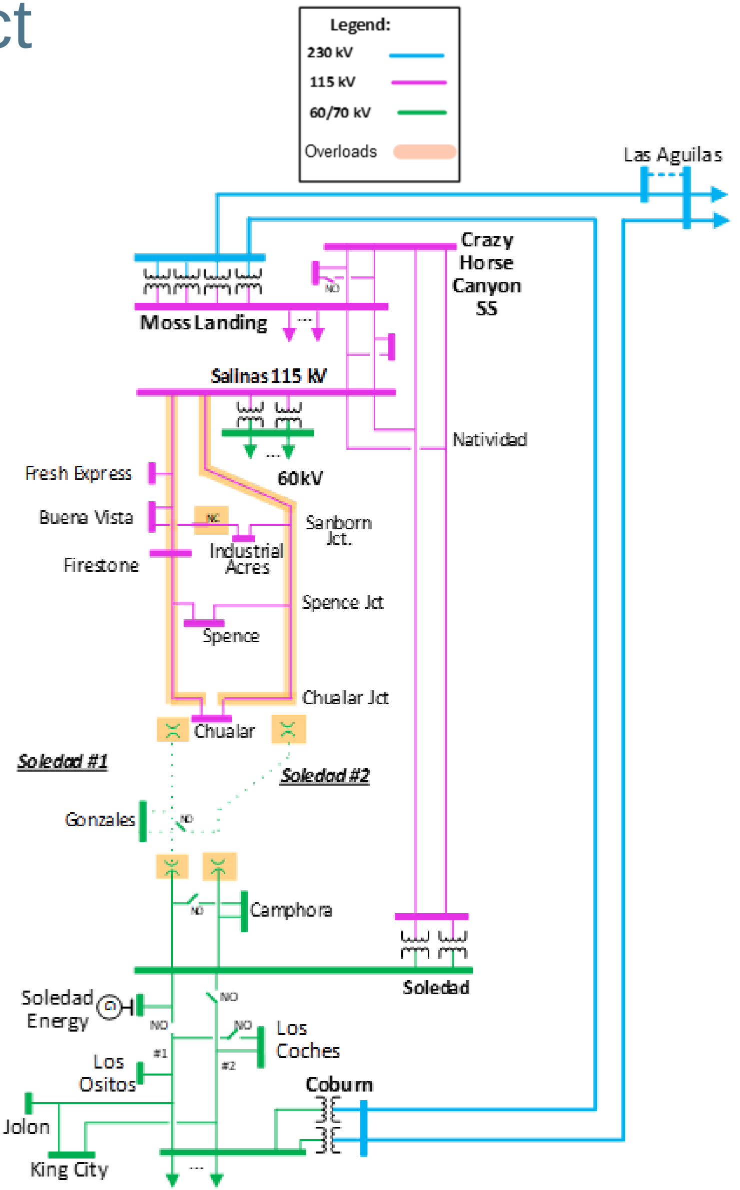
- Reliability Assessment Need
  - Real time HV issues in off-peak during midnight
- Project Submitter
  - PG&E
- Project Scope
  - Install a total of 120 MVAR (3x40 Mvar or 4x30 MVar) shunt reactors along with existing shunt capacitors at Mesa 115 kV
- Estimated Project Cost
  - $35M - $70M
- Estimated In-service Date
  - 2027
- Alternatives Considered
  - Statcom installations at Mesa 230kV, Morro Bay 230kV Diablo Canyon 230 kV or Mesa 115 KV but others not recommended due to high costs
- Recommendation
  - Approval





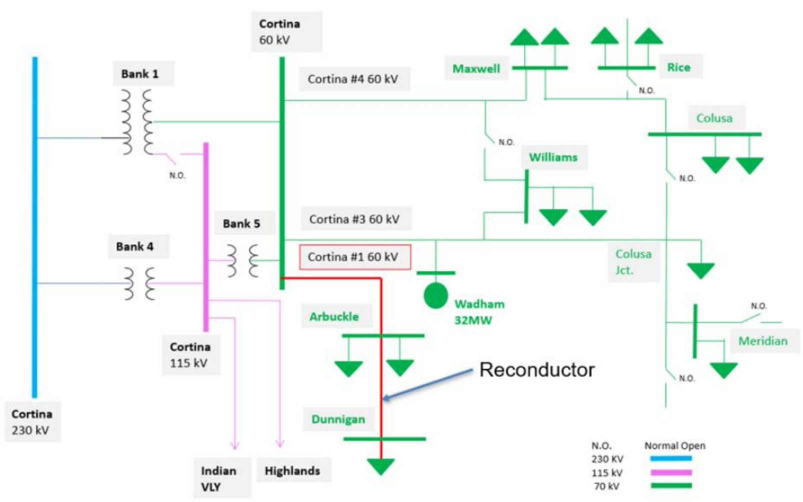
Salinas Area Reinforcement Project

- Reliability Assessment Need
  - The near-term issues driven by P0-P7 category contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Build a new 115kV Chaular station to carry load from Gonzales which will be decommissioned
  - Re-build existing 60 kV Salinas –Firestone and Firestone-Spence line sections to achieve 1400A and 800A respectively and operate at 115 kV
  - Spence-Chaular and Spence Jct-Chaular to have a min rating of 500A. Sanborn Jct-Industrial Acres to have a min rating of 950A
  - Replace transformer and other HV side equipment to allow 115 kV operation
  - Existing Salinas-Firestone #1 and #2 60 kV line reconductoring project will be cancelled
- Estimated Project Cost
  - $226.1M - $452.3M
- Estimated In-service Date
  - 2035
- Alternatives Considered
  - Alternatives such as re-conductoring entire 60kV path, adding new bank at Salinas, loop in CCHCS-Natividad-Salinas 115kV into Soledad, loop in LasAguilas-Coburn 230kV into CCHCS-Natividad were considered but not considered due to a combination of cost, future scalability, space issues.
- Recommendation
  - Approval



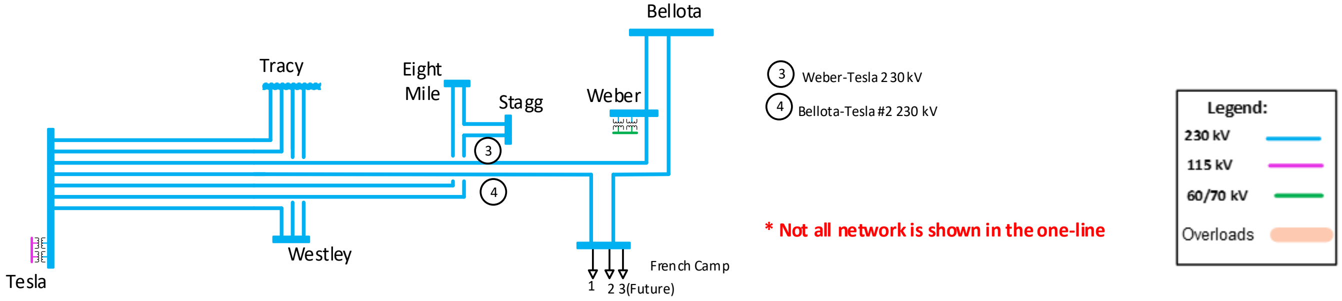
Cortina #1 60 kV Line Reconductoring Project

- Reliability Assessment Need
  - Addressing overloads and low voltage criteria violations within the 60 kV transmission system connecting Dunnigan, Arbuckle and Cortina substations under NERC Category P0 contingencies.
  - Driven by large load interconnection project and associated studies.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductor ~15.4 circuit miles between the Cortina substation and Arbuckle substation (From Cortina to 015/259) on the Cortina #1 60 kV line with a larger conductor to achieve at least 818 Amps during normal conditions.
  - Reconductor ~10.8 circuit miles between the Arbuckle Substation and Dunnigan substation (From 015/260 to Dunnigan) on the Cortina #1 60 kV line with a larger conductor to achieve at least 818 Amps during normal conditions.
  - Remove any limiting components as necessary to achieve full conductor capacity.
- Estimated Project Cost
  - $47.1M - $94.3M
- Estimated In-service Date
  - May 2028
- Alternatives Considered
  - N/A.
- Recommendation
  - Approval



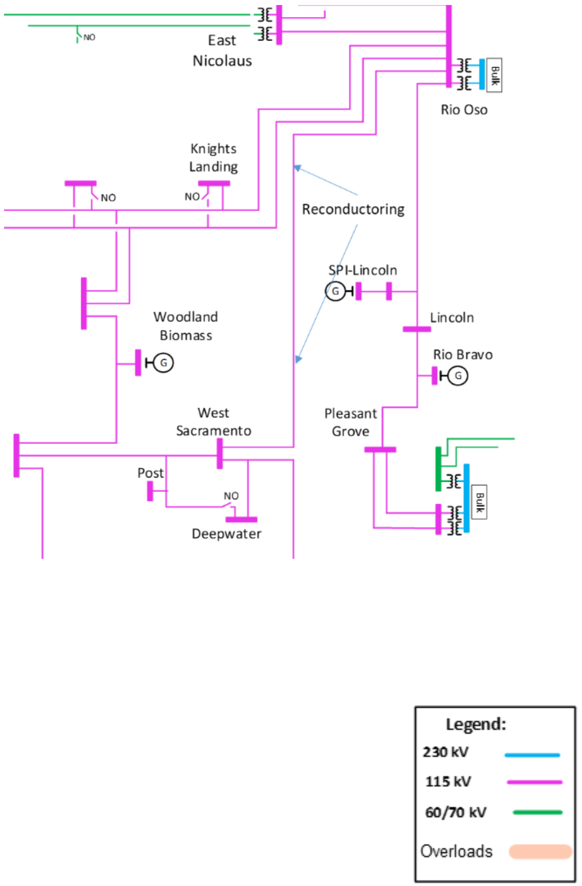
French Camp Reinforcement

- Reliability Assessment Need
  - The near-term issues driven by P1 category contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Loop Bellota-Tesla #2 230 kV line into French Camp substation, add a new 230 kV bus at French Camp. The total length of transmission circuit is about 4.4 miles.
- Estimated Project Cost
  - $42.1M - $84.2M
- Estimated In-service Date
  - May 2030 or Earlier
- Alternatives Considered
  - Various alternatives such as re-conductoring French Camp-Weber 60 kV lines and few 230 kV and 115 kV lines were considered to be looped into French Camp Substation. Due to combination of future scalability and cost issues, these alternatives are not recommended.
- Recommendation
  - Approval



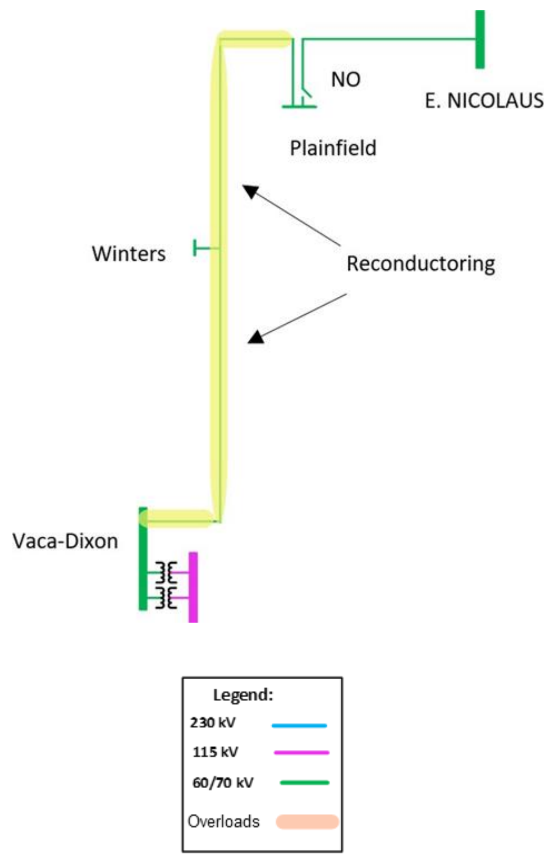
Rio Oso - W. Sacramento Reconductoring

- Reliability Assessment Need
  - Addressing overloads and voltage criteria violations within the 115 kV and 60 kV transmission system connecting Vaca Dixon, Davis, Rio Oso, and Brighton substations under NERC Category P0 - P7 contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductoring the Rio Oso – West Sacramento 115 kV line from 040/291 to 013/095A (about 26 miles)
- Estimated Project Cost
  - $48.7M - $97.4M
- Estimated In-service Date
  - 2030
- Alternatives Considered
  - Previously approved as re-rate project, but due to ageing infrastructure, that's no longer feasible.
- Recommendation
  - Approval

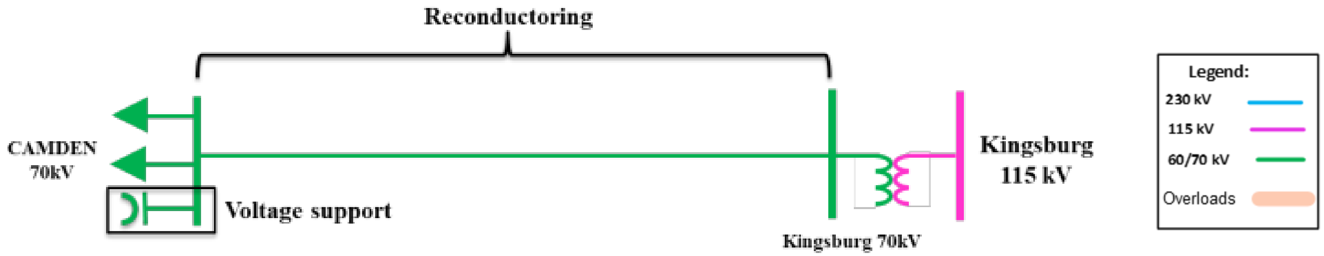


Vaca-Plainfield 60 kV Line Reconductoring

- Reliability Assessment Need
  - Addressing the near-term overloads on the Vaca-Plainfield 60 kV line resulting from NERC Category P0 and P1 contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductor Vaca-Plainfield 60 kV (about 30 miles) to achieve minimum conductor rating of 635A for summer normal and 741A for summer emergency rating.
- Estimated Project Cost
  - $34M - $68M
- Estimated In-service Date
  - May 2030 or earlier
- Alternatives Considered
  - Battery isn’t recommended due to space limitation at Winters substation.
  - Voltage conversion was considered but has higher cost.
  - Constructing a second Vaca-Plainfield 60 kV line was considered but has higher cost
- Recommendation
  - Approval



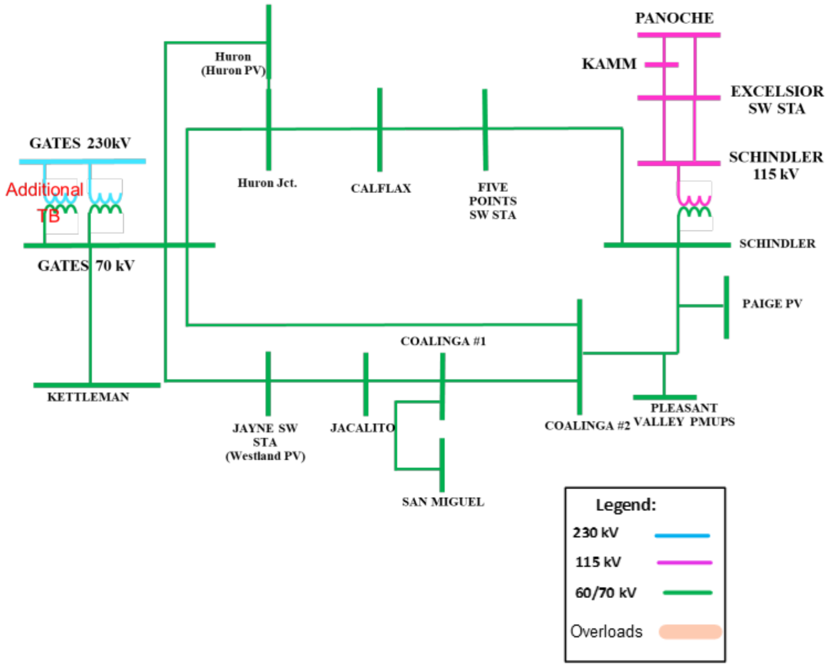
Camden 70 kV Reinforcement Project



- Reliability Assessment Need
  - The near-term issues driven by P0-P7 category contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Install 30 Mvar voltage support and
  - Remove any limiting elements and Reconductor the Camden-Kingsburg 70 kV line to achieve a minimum rating of 800 during Summer Normal
- Estimated Project Cost
  - $50M - $100M
- Estimated In-service Date
  - 2030
- Alternatives Considered
  - Energy storage and voltage support alternative is not recommended due to space constraints and the new unit will be a P1 violation that needs mitigation
- Recommendation
  - Approval

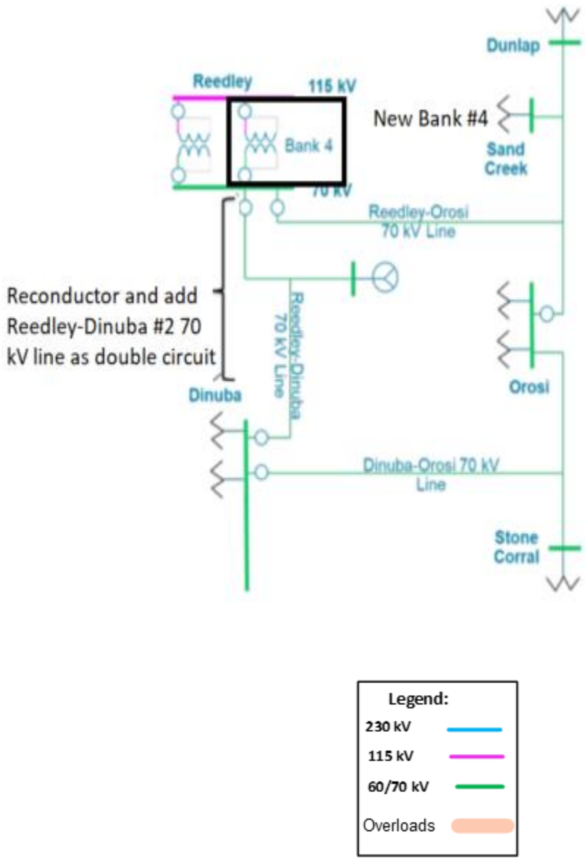
Gates 230/70 kV Transformer Addition Project

- Reliability Assessment Need
  - The near-term issues driven by P0-P7 category contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Install an additional 230/70 kV bank at Gates substation
  - Gates 70 kV bus conversion
  - Upgrade limiting elements to achieve full bank capacity
- Estimated Project Cost
  - $36M - $72M
- Estimated In-service Date
  - 2030
- Alternatives Considered
  - BESS but it will be a next limiting P3 issue and there are charging capacity issues
- Recommendation
  - Approval



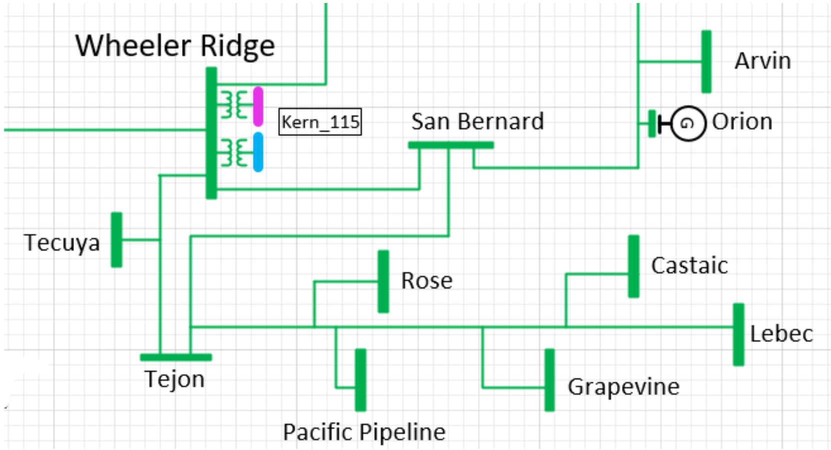
Reedley 70 kV Capacity Increase Project

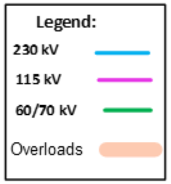
- Reliability Assessment Need
  - The near-term issues driven by P0-P7 category contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Upgrade 115/70 kV bank 4 at Reedley substation
  - Reconductor existing Reedley-Dinuba #1 70 kV line to achieve min rating of 800 A and 1000 A SN and SE
  - Add a double circuit Reedley-Dinuba #2 70 kV line to have a min rating of 800A and 1000 A SN and SE
- Estimated Project Cost
  - $49M - $98M
- Estimated In-service Date
  - 2030
- Alternatives Considered
  - Additional BESS capacity not possible due to space constraints and charging limitations
  - Remove limiting elements on Reedley-Orosi 70 kV, Reconductor Reedley-Dinuba #1 70 kV and Orosi-Orosi Jct 70 kV along with 12 MW battery which is still insufficient for 2035 loading and beyond.
- Recommendation
  - Approval



Tejon Area Reinforcement Project

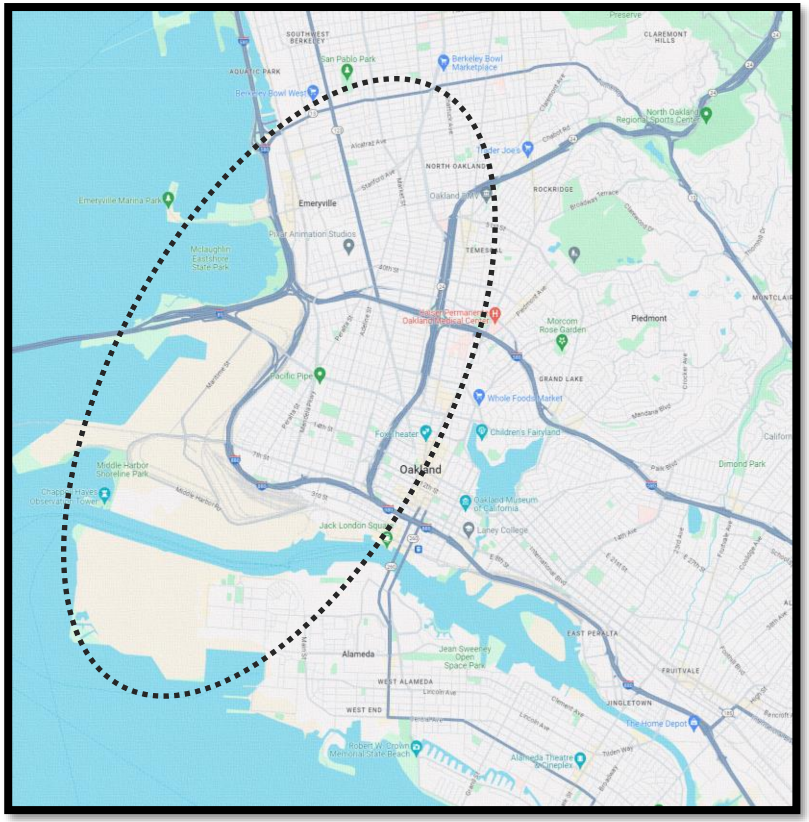
- Reliability Assessment Need
  - Addressing overloads on the Wheeler Ridge – San Bernard and Wheeler Ridge – Tejon 70 kV lines under NERC Category P3 contingencies in near term.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductor the Wheeler Ridge – San Bernard, Wheeler Ridge – Tejon, and Tejon - San Bernard 70kV lines (Approximately 18 miles)
- Estimated Project Cost
  - $28M - $56M
- Estimated In-service Date
  - 2029
- Alternatives Considered
  - Build a new 115 kV source from Wheeler Ridge to Tejon substation and reconductor the Wheeler Ridge – Tejon 70 kV line
  - Build a new 230 kV source from Wheeler Ridge to Tejon substation and reconductor the Wheeler Ridge – Tejon 70 kV line
- Recommendation
  - Approval





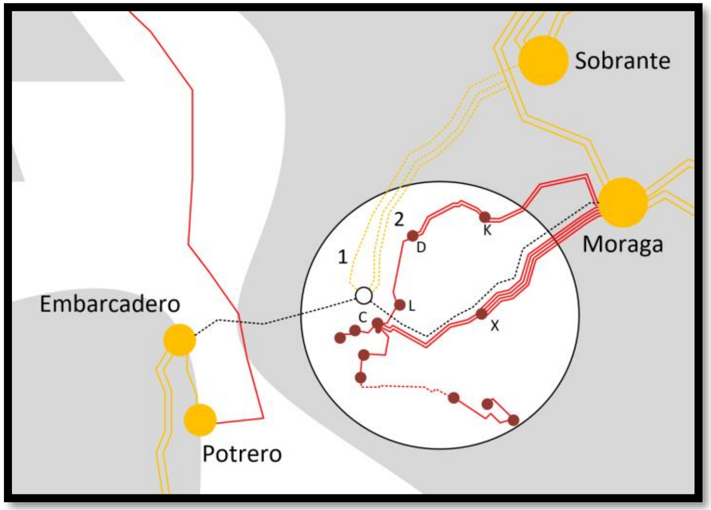
Oakland transmission reinforcement project

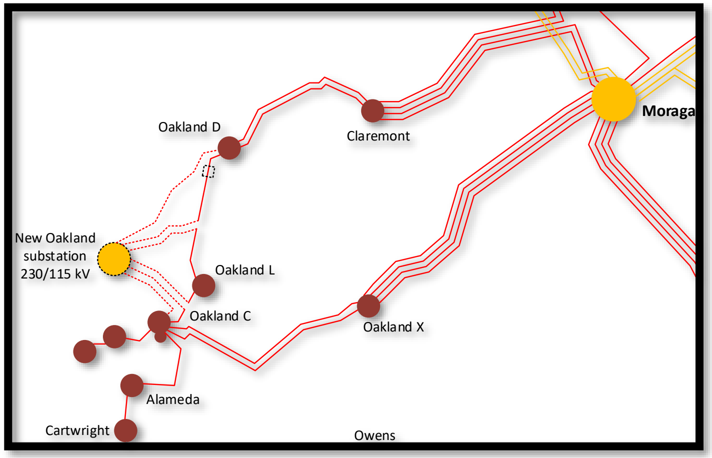
- Reliability assessment need
  - Number of overloads were observed on most of the 115 kV lines serving this area due to increased load forecast in the Oakland area. The previously approved OCEI project is not sufficient to mitigate these overloads. The previously approved OCEI project and the local thermal units will be relied upon while the additional transmission upgrades are being developed and implemented.
- Project Status
  - Under study
- Alternatives being considered
  - Existing 115 kV network upgrade
    - Rebuild or reconductor majority of lines/cables in the Northern Oakland pocket
  - New 230 kV source into Northern Oakland area with a new 230/115 kV substation and new 115 kV cables to connect to existing stations.
    - 230 kV source could include connection from: Moraga, Sobrante, Embarcadero, or Collinsville 230 kV station or Moraga-Parkway 230 kV line.
    - 115 kV connections could include looping-in some of the existing cables into the new 230/115 kV substation, new cables to the existing D, L and C substations or a combination of both.



Oakland transmission reinforcement project

- On-going activities
  - Feasibility investigation:
    - Feasibility of reconductoring / rebuilding of existing 115 kV network and ultimate ratings that can be achieved.
    - Location for new 230/115 kV substation in the Northern Oakland area and amount of load that can be transferred from the existing stations.
    - Bus positions availability in the potential 230 kV sources for connection to the new substation.
    - High-level feasibility of building new 230 kV lines to connect to the new substation, including alternative routes and undergrounding needs.
    - Space availability for new 115 kV connections in the Oakland North substations and feasibility of options to loop-in the existing 115 kV cables.
- Next steps
  - Load serving capability calculation of feasible alternatives.
  - Cost estimation
  - Approval recommendation





Reliability Assessment Recommendations – SDG&E Area Draft 2023-2024 Transmission Plan

Rene Romo de Santos
Regional Transmission - South

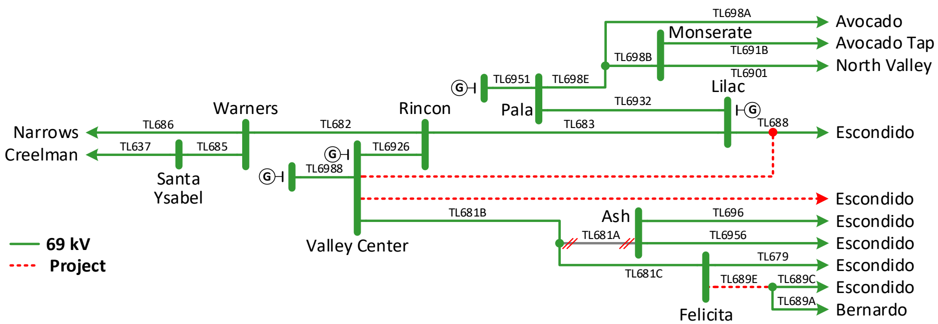
2023-2024 Transmission Planning Process Stakeholder Meeting
April 9, 2024

New Reliability Project Recommended for Approval in 2023-2024 TPP – SDG&E Area

Projects	Planning Area	Status
Valley Center System Improvement	SDG&E	Recommended for Approval

Valley Center System Improvement

- Reliability Assessment Need
  - P0, P1, P3 and P6 contingencies in the near-term and long-term planning assessments resulted in several thermal overloads in the 69 kV transmission system.
- Project Submitter
  - SDG&E
- Project Scope
  - New 5-mile double circuit 69 kV line (one pole structure) to create two new lines that will connect to Valley Center substation.
    - One circuit will connect to a de-energized line TL99901 to form a new Valley Center – Escondido 69 kV line.
    - One circuit will tap into TL688 to create Valley Center – Escondido – Lilac 3-terminal 69 kV line.
  - De-energize TL681A Ash – Ash Tap.
  - Reconductor 0.1 miles of TL689E Felicita – Felicita Tap.
  - Reconductor the underground section of the existing TL99901.
- Estimated Project Cost
  - $51M
- Estimated In-service Date
  - 2028
- Alternatives Considered
  - Status Quo: Not recommended since there are thermal overloads that occur in P0 conditions which trigger existing Valley Center RAS; not allowing its retirement. Conflicting with ISO S-RAS2 standard.
- Recommendation
  - Approval



Frequency Response Assessment and Data Requirements
Draft 2023-2024 Transmission Plan

Chris Fuchs
Regional Transmission North

2023-2024 Transmission Planning Process Stakeholder Meeting
April 9, 2024

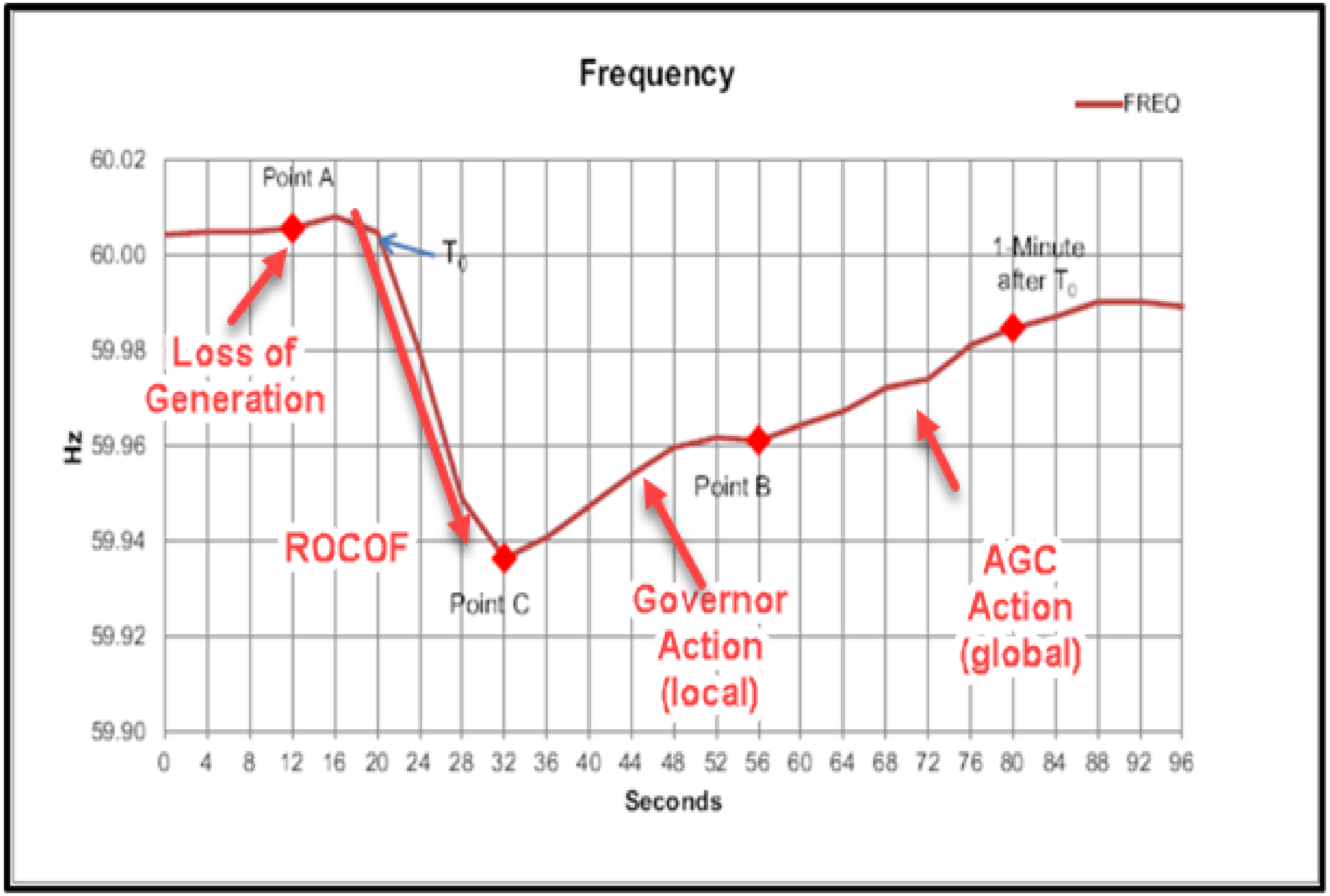
Overview

- Basics of frequency
- ISO frequency response study results in previous TPPs
- ISO frequency response study results 2023-2024 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

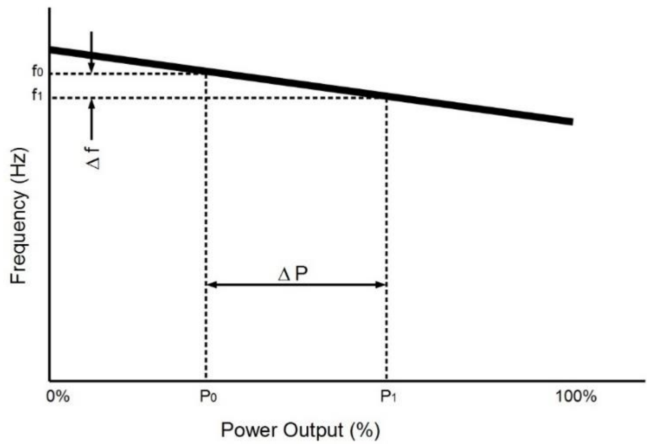
Nadir needs to be higher than the 1st set-point for Under Frequency Load Shedding (59.5 Hz)

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 1st 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 headroom=pmax-pmin. With pmax=-pmin, can have this much headroom=2*pmax

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

$$FRO_{BA} = FRO_{Int}\frac{Pgen_{BA} + Pload_{BA}}{Pgen_{Int} + Pload_{Int}}$$

- 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 DER and BESS
- Assess the CAISO system frequency response in the year 2028 & 2035 and identify any performance issues related to frequency response.
- The starting base case was the Spring off-Peak case for 2028 & 2035. 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

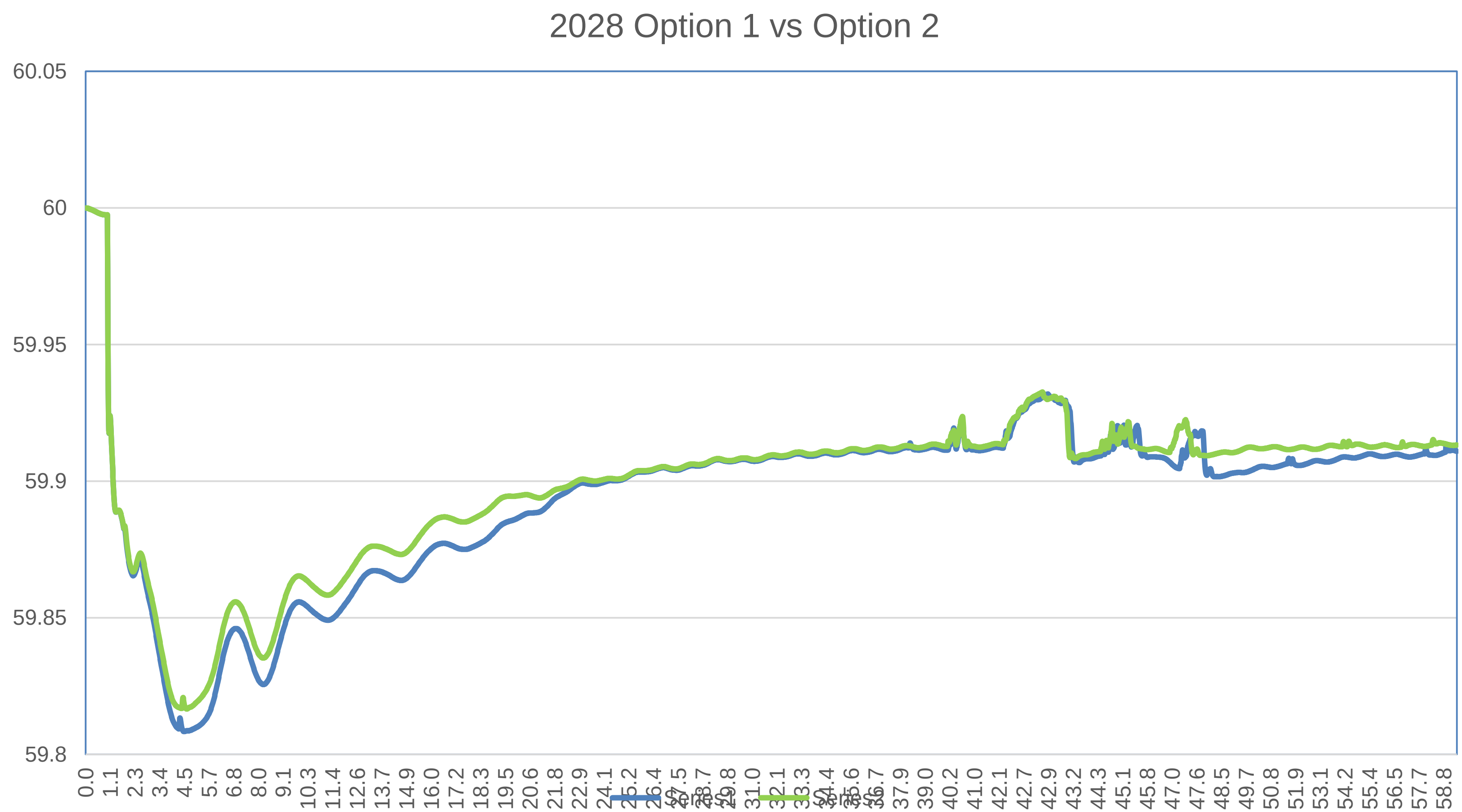
- Cases: Base case 2028/2035 Spring off-Peak and the selected case with reduced headroom.
- BESS are mostly in charging mode except for high spinning reserve scenarios

Scenarios
IBR Frequency Control is switched off
IBR Frequency Control is switched on
Frequency Control for system at 10%
IBR Frequency Control at 10% for system & BESS

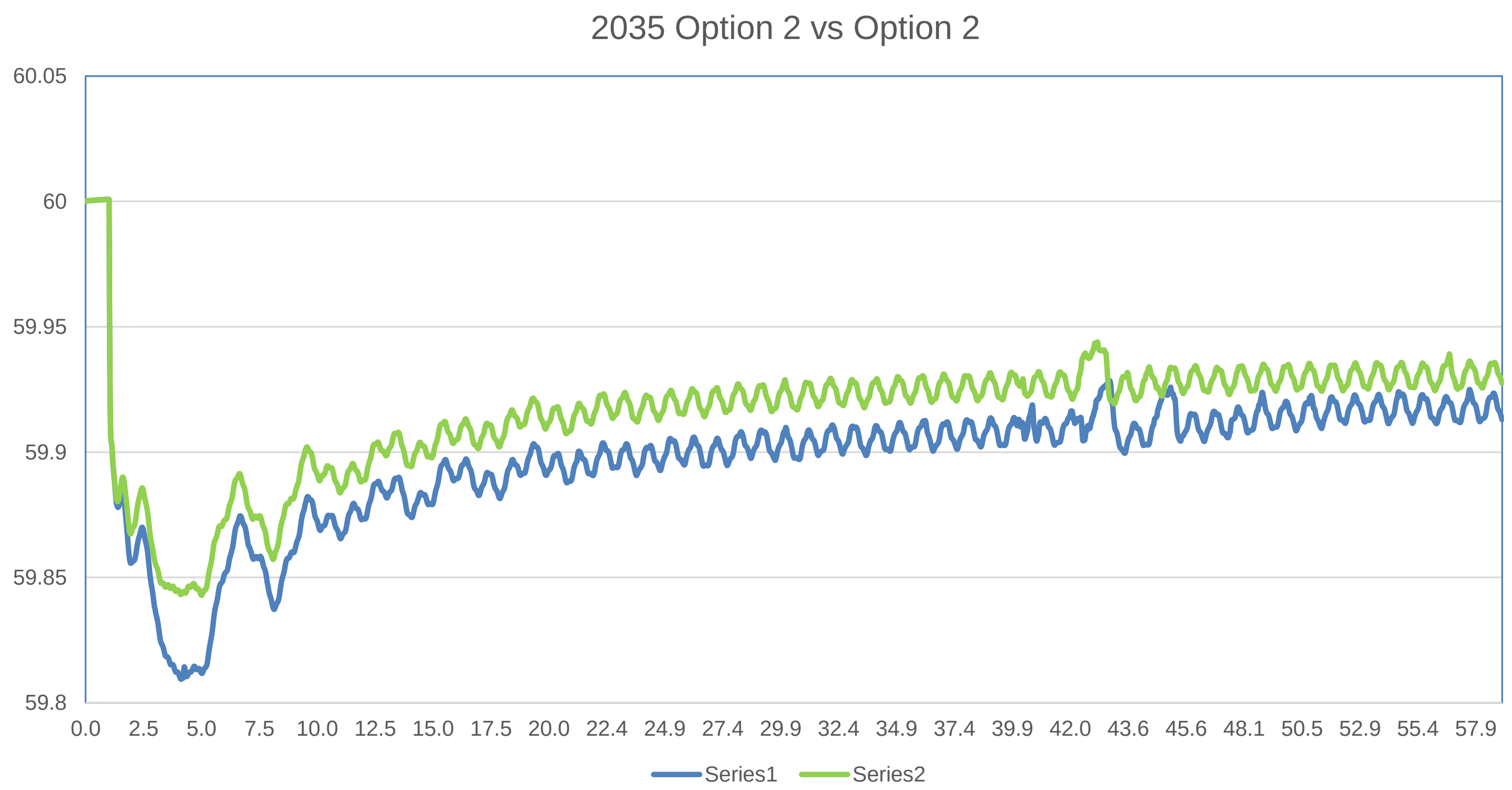
Monitored Values

- 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.
- Rate of Change of Frequency (ROCOF)

Scenario #1&2: 2028 All IBR On & Off

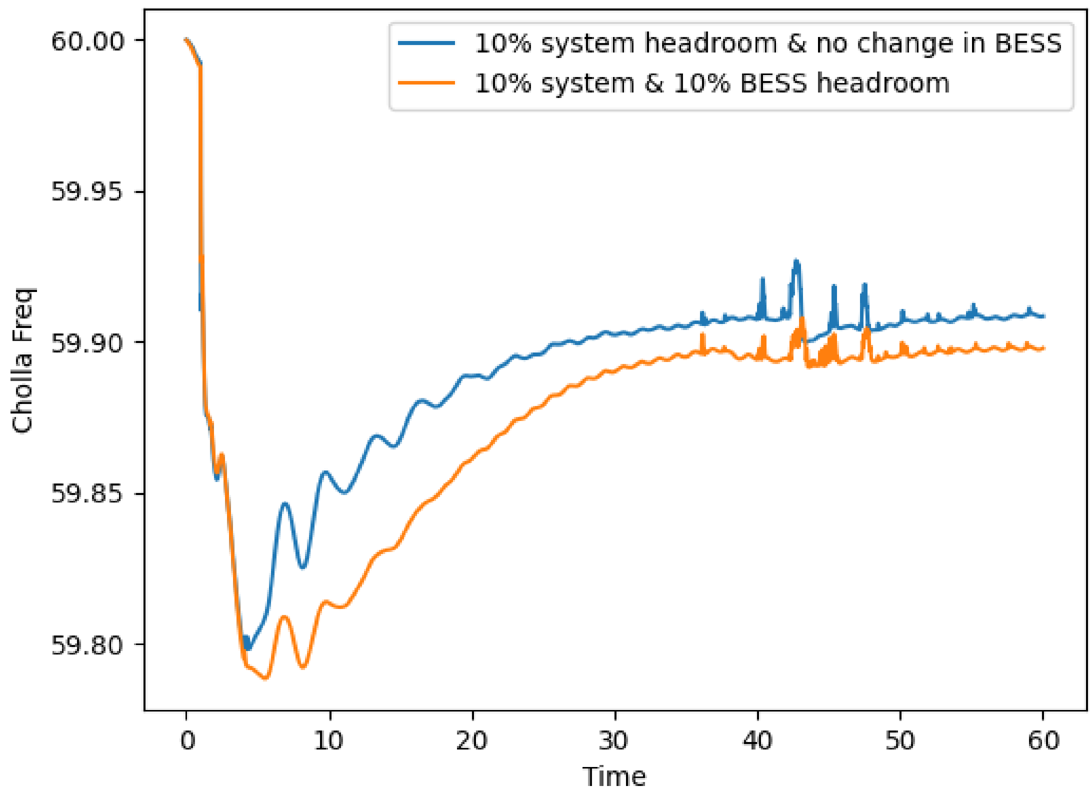


Scenario #1&2: 2035 All IBR On & Off

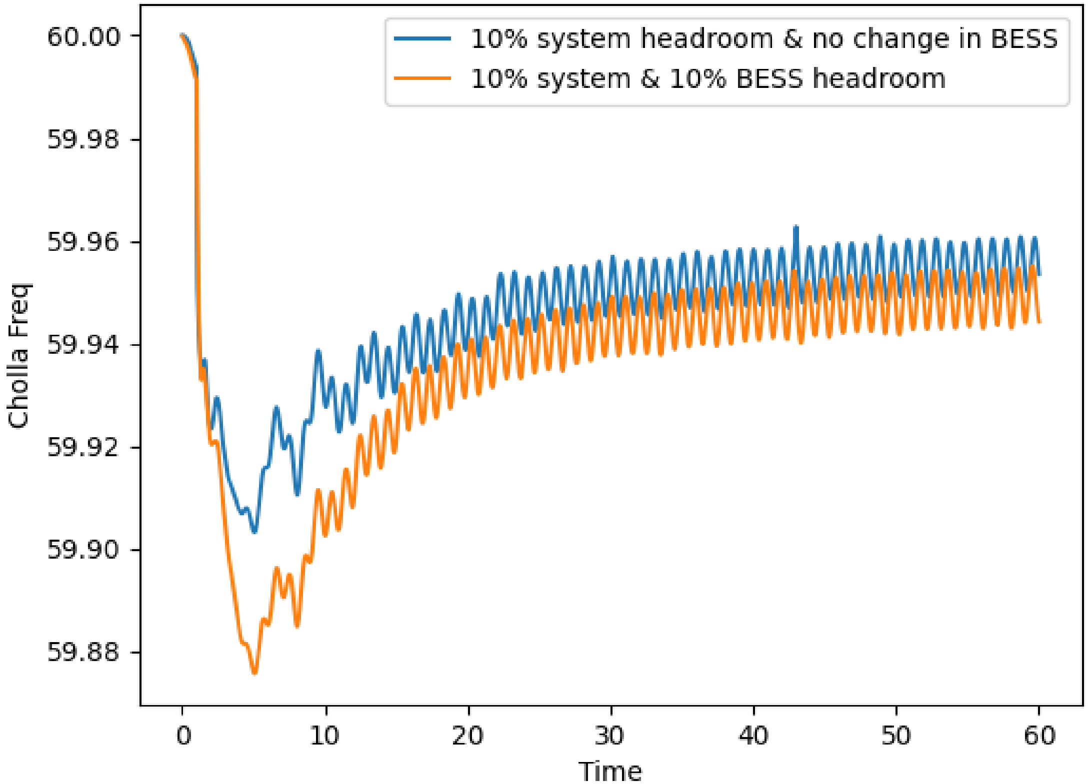


California ISO

Scenario #3&4: 2028 10% System Headroom vs Same+10%BESS Headroom



Scenario #3&4: 2035 10% System Headroom vs Same+10%BESS Headroom



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 2035 scenarios is > than the 2028 scenarios
- BESS units have a much higher impact in 2035 due to the higher overall proportional of them in the system compared to 2028.

2023-2024 TPP Study Conclusions

- IBR units with frequency response significantly improve the system frequency performance and will allow the ISO to fulfill its FRO

Future Considerations

- Adequate synchronizing torque for future years – will the system have it or not?
- Related is the ROCOF (rate of chng of freq) – how much higher will this be? And what point should we be concerned.
- Checking the benefit of GFM (grid forming IBRs).
- Following development of solar & wind technology for added system frequency response benefits.
- State of Charge considerations.

2023 MIC Expansion Requests

Catalin Micsa
Senior Advisor, Transmission Infrastructure Planning

2023-2024 Transmission Planning Process Stakeholder Meeting
April 9, 2024

2023 Valid MIC expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Resource type
1-2	Southern California Edison	BLYTHE_ITC (BLYTHE161)	23	Hydro
3	Marin Clean Energy	GONDIPPDC_ITC (GONIPP)	20	Geothermal
		MONAIPPDC_ITC (MDWP)		
4-6	California Community Power	GONDIPPDC_ITC (GONIPP)	38.5	Geothermal
		SILVERPK_ITC (SILVERPEAK55)		
		SUMMIT_ITC (SUMMIT120)		
		IID-SDGE_ITC (IVLY2)	40	
		GONDIPPDC_ITC (GONIPP)	13	
		SILVERPK_ITC (SILVERPEAK55)		
7	Fervo Energy Cal Choice Energy Authority Clean Energy Alliance Desert Energy Community	IPPDCADLN_ITC (IPP & IPPUTAH)	20	Geothermal
8	Fervo Energy Clean Power Alliance	IPPDCADLN_ITC (IPP & IPPUTAH)	33	Geothermal
9	Clean Power Alliance	MEAD_ITC (MEAD230)	119	Wind

Not all MIC expansion requests trigger an actual need for expansion

- First the CAISO checks is 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 2023 MIC expansion requests

No	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Triggers expansion	Comments
1-2	Southern California Edison	BLYTHE_ITC (BLYTHE161)	23	Yes	Partial
3	Marin Clean Energy	GONDIPPDC_ITC (GONIPP)	20	In CPUC Portfolio	CPUC portfolio triggers MIC expansion.
		MONAIPPDC_ITC (MDWP)			
4-6	California Community Power	GONDIPPDC_ITC (GONIPP)	38.5	In CPUC Portfolio	CPUC portfolio triggers MIC expansion.
		SILVERPK_ITC (SILVERPEAK55)			Active as back-up location only.
		SUMMIT_ITC (SUMMIT120)			
		IID-SDGE_ITC (IVLY2)	40		No expansion needed.
		GONDIPPDC_ITC (GONIPP)	13		CPUC portfolio triggers MIC expansion.
		SILVERPK_ITC (SILVERPEAK55)			
7	Fervo Energy Cal Choice Energy Authority Clean Energy Alliance Desert Energy Community	IPPDCADLN_ITC (IPP & IPPUTAH)	20	Yes	Full
8	Fervo Energy Clean Power Alliance	IPPDCADLN_ITC (IPP & IPPUTAH)	33	Yes	Full
9	Clean Power Alliance	MEAD_ITC (MEAD230)	119	In CPUC Portfolio	CPUC portfolio triggers MIC expansion.

MIC expansion requests currently being assessed (not already part of the CPUC portfolio)

No.	Year	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Resource type
1-2	2022	San Diego Community Power	ELDORADO_ITC (WILLOWBEACH)	90	Wind
3-5	2022	Valley Electric Association	MEAD_ITC (MEAD 230)	33	Hydro
6	2022	Valley Electric Association	MEAD_ITC (MEAD 230)	90	Hybrid (Solar/Battery)
7-8	2023	Southern California Edison	BLYTHE_ITC (BLYTHE161)	7	Hydro
9	2023	California Community Power	SUMMIT_ITC (SUMMIT120) * SILVERPK_BG (SILVERPEAK55) *	39	Geothermal
10	2023	Fervo Energy Cal Choice Energy Authority Clean Energy Alliance Desert Energy Community	IPPDCADLN_ITC (IPP & IPPUTAH)	20	Geothermal
11	2023	Fervo Energy Clean Power Alliance	IPPDCADLN_ITC (IPP & IPPUTAH)	33	Geothermal

* = As back-up locations only – main delivery point included as GONDIPPDC_ITC (GONIPP) and part of the CPUC portfolio

California ISO

NQC Deliverability Study (2024)

Intertie Name (Scheduling Point)	Status	Comments:
GONDIPPDC_ITC (GONIPP)	Failed	
BLYTHE_ITC (BLTHE161)	Failed	
ELDORADO_ITC (WILLOWBEACH)	Failed	Includes both CPUC portfolio and MIC expansion requests.
MEAD_ITC (MEAD 230)	Failed	Includes both CPUC portfolio and MIC expansion requests.
SILVERPK_ITC (SILVERPEAK55)	Pass	Included in the CPUC portfolio. Temporary expansion included in 2024 MIC.

- Only applicable to MIC expansion request for RA year 2024
- Permanent expansion depends on the TPP and GIP deliverability study results

TPP Deliverability Study

Intertie Name (Scheduling Point)	Status	Comments:
GONDIPPDC_ITC (GONIPP)	Pass with upgrade	Fully included in the CPUC portfolio. Waiting for the Lugo-Victorville line upgrade and the expansion of the Lugo-Victorville RAS.
IPPDCADLN_ITC (IPP & IPPUTAH)	Failed/ Denied	Mitigation for Lugo-Victorville (Eldorado-McCullough) 500 kV constraint (expansion of the Lugo-Victorville RAS) does no create additional capability for MIC expansion requests.
BLYTHE_ITC (BLYTHE161)		
ELDORADO_ITC (WILLOWBEACH)	Failed/ Denied	Part not in the CPUC portfolio. Mitigation for Lugo-Victorville (Eldorado-McCullough) 500 kV constraint (expansion of the Lugo-Victorville RAS) does no create additional capability for MIC expansion requests and Sloan Canyon-Eldorado 500 kV constraint has no mitigation required for reliability, economic or policy needs.
MEAD_ITC (MEAD 230)		
SILVERPK_BG (SILVERPEAK55)	Failed/ Denied	Used as back-up only – main in the CPUC portfolio. The Control-Silver Peak 55 kV constraint allows for 4 MWs of deliverability however the mitigation for Lugo-Victorville (Eldorado-McCullough) 500 kV constraint (expansion of the Lugo-Victorville RAS) does no create additional capability for MIC expansion requests and Sloan Canyon-Eldorado 500 kV constraint has no mitigation required for reliability, economic or policy needs.
SUMMIT_ITC (SUMMIT120)	Failed/ Denied	Used as back-up only – main in the CPUC portfolio. The Drum-Higgins 115 kV constraint has no mitigation required for reliability, economic or policy needs.
IID-SDGE_BG (IVLY2)	N/A	Included in the CPUC portfolio. No need for additional expansion.

Policy-driven Assessment Recommendations
Draft 2023-2024 Transmission Plan

Transmission Infrastructure Planning

2023-2024 Transmission Planning Process Stakeholder Meeting
April 9, 2024

Overview

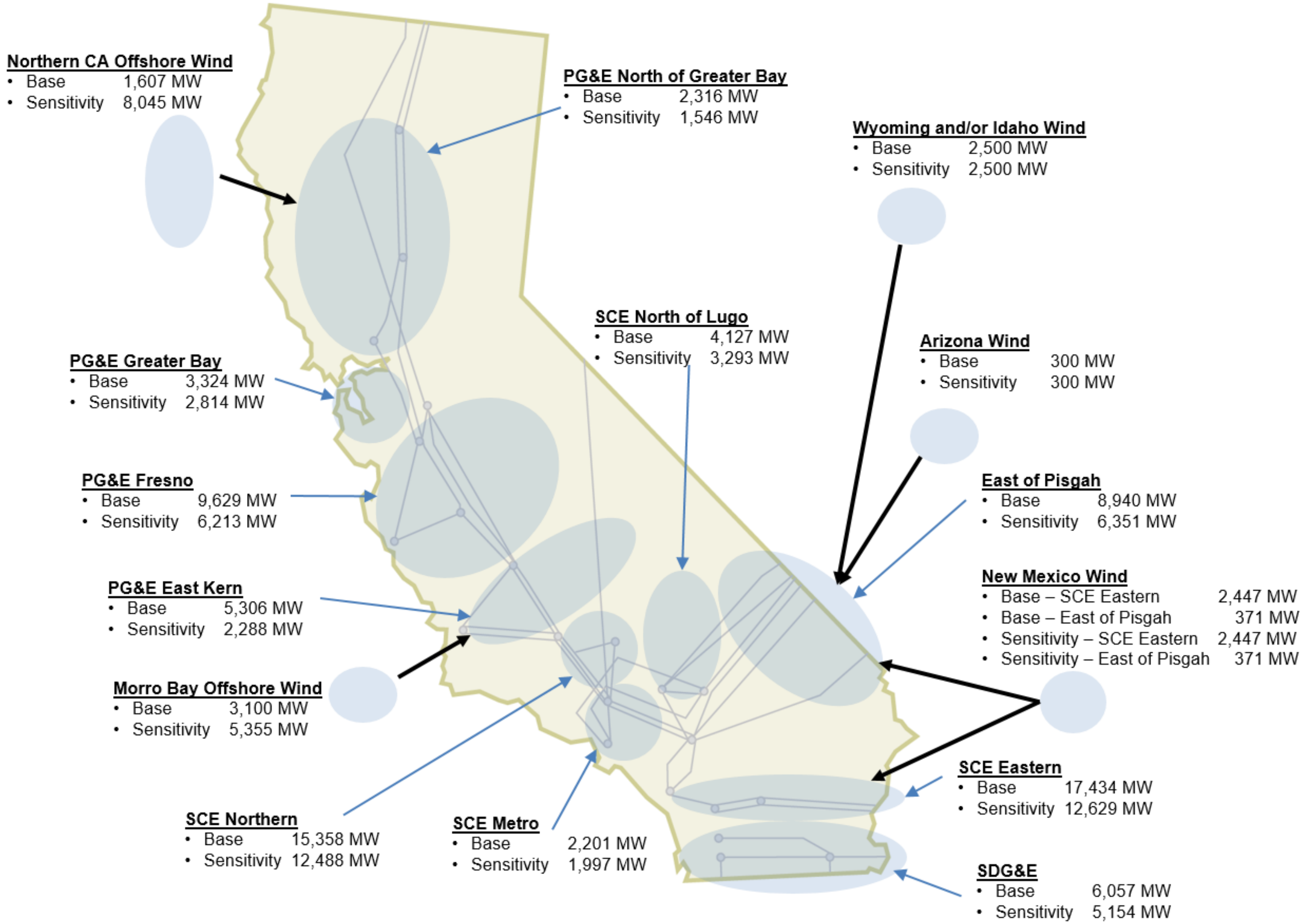
- The 2023-2024 TPP policy-driven deliverability assessment is based on the base and OSW sensitivity portfolios transmitted by CPUC for year 2035
  - Base Portfolio based on a 30 MMT by 2030 GHG target
  - Sensitivity Portfolio based on the same GHG target intended to test the transmission needs of 13.4 GW of offshore wind
- The PG&E area was the focus of the OSW sensitivity portfolio assessment
- MIC expansion requests were also assessed as part of the studies (conclusions covered in an earlier presentation)
- This presentation provides
  - The policy-driven projects recommended for approval along with supporting deliverability assessment results
  - Conclusions regarding mitigation for the Lugo–Victorville Constraint and the Windhub export constraint

Adopted Base and Sensitivity Portfolios by Resource Type and Deliverability Status (2035)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	15,636	23,311	38,947	11,442	14,304	25,746
Wind – In State	2,511	564	3,074	2,511	564	3,074
Wind – Out-of-State (Existing TX)	690	100	790	690	100	790
Wind – Out-of-State (New TX)	4,828	0	4,828	4,828	0	4,828
Wind - Offshore	4,546	161	4,707	13,239	161	13,400
Li Battery	28,374	0	28,374	23,545	0	23,545
Geothermal	2,037	0	2,037	1,149	0	1,149
Long Duration Energy Storage (LDES)	2,000	0	2,000	1,000	0	1,000
Biomass/Biogass	134	0	134	134	0	134
Distributed Solar	125	0	125	125	0	125
Total	**60,880**	**24,135**	**85,015**	**58,663**	**15,129**	**73,791**

- Per CPUC guidance a total of 477 MW additional battery storage was added in SCE Eastern and EOP Areas to account for TPD allocations

Adopted Base and OSW Sensitivity Portfolios (2035)



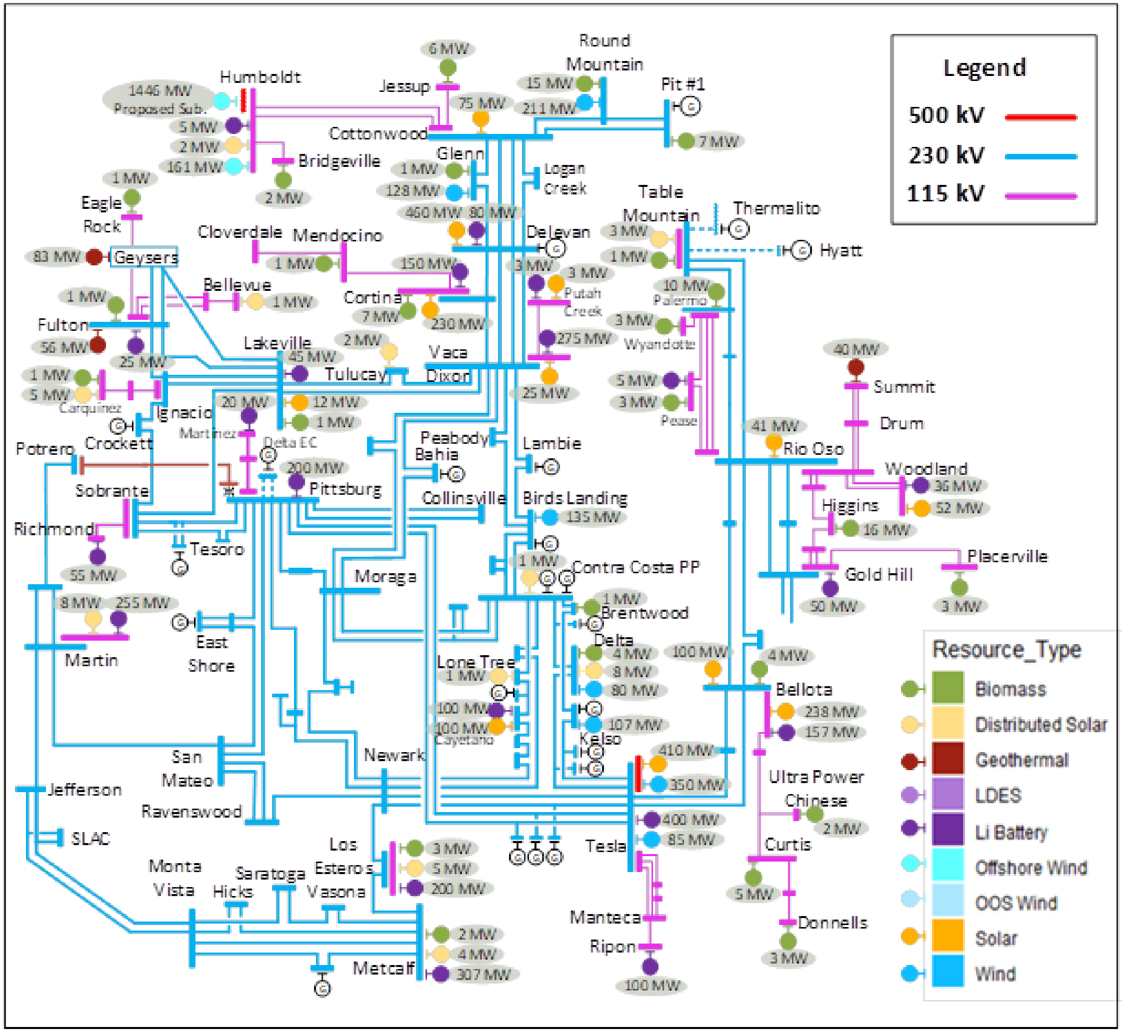
Policy-driven Projects Recommended for Approval

- Humboldt offshore wind is the major trigger for new transmission this year
- A total of seven new projects including two new 500 kV lines are recommended in the PG&E area
- Estimated total cost $3.1–$4.6 million

Project Name	PTO	Planning Area	Cost($M)
Sobrante 230/115 kV Transformer Bank Addition	PG&E	GBA	20 - 40
New Humboldt 500 kV Substation with 500 kV line to Collinsville [HVDC operated as AC]	PG&E	NGBA	1,913 - 2,740
New Humboldt to Fern Road 500 kV Line	PG&E	NGBA	980 - 1,400
New Humboldt 115/115 kV Phase Shifter with 115 kV line to Humboldt 115kV Substation	PG&E	NGBA	40 - 57
North Dublin -Vineyard 230 kV Reconductoring	PG&E	NGBA	116 - 233
Tesla - Newark 230 kV Line No. 2 Reconductoring	PG&E	NGBA	29 - 58
Collinsville 230 kV Reactor	PG&E	NGBA	39 - 58
		Total	**3,137 - 4,586**

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

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



PG&E Greater Bay and North of Greater Bay On-Peak Constraints

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

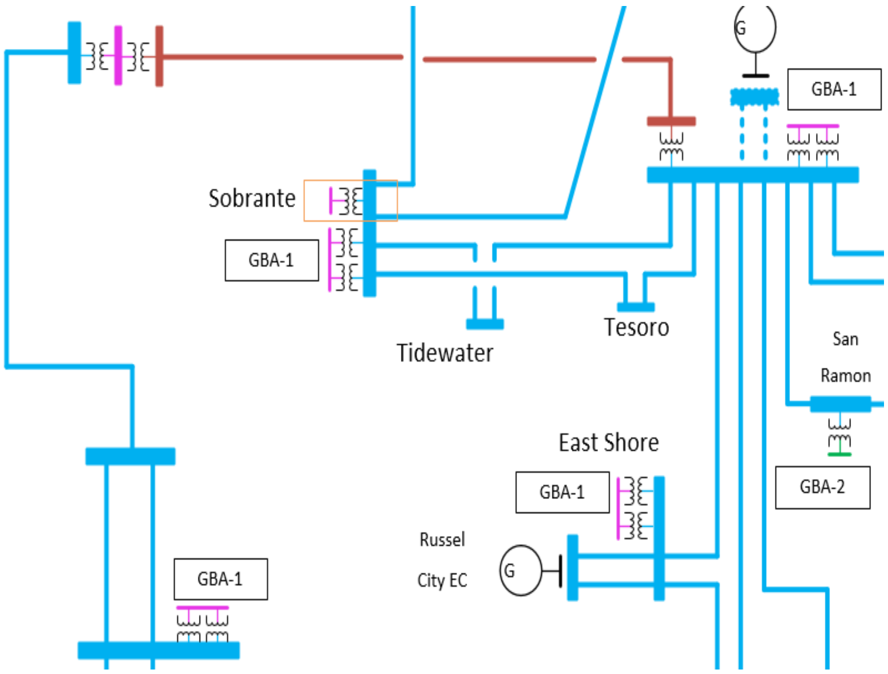
Affected transmission zones: PG&E Greater Bay Area

		Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)		142	0
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		25	0
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		395	0
Mitigation Options	RAS	RAS criteria violation	N/A
	Re-locate generic portfolio battery storage (MW)	Not effective	N/A
	Transmission upgrade including cost	New 230/115 kV Bank ($20M-$40M)	N/A
Recommended Mitigation		New 230/115 kV Bank ($20M-$40M)	

California ISO

New Sobrante 230/115 kV Bank #3

- Policy Assessment Need
  - Base and sensitivity HSN scenario
- Project Scope
  - New 230/115 kV Bank at Sobrante Substation with 420 MVA rating. It will also include any bus upgrades and limiting equipment upgrades to achieve this transformer rating.
- Estimated Project Cost
  - $20M - $40M
- Estimated In-service Date
  - 2034
- Alternatives Considered
  - RAS. Not selected due to RAS criteria violation.
  - Upgrading existing transformers was considered, but ruled out as it would not entirely mitigate the issue.
- Recommendation
  - Approval



PG&E Greater Bay and North of Greater Bay On-Peak Constraints – Offshore Wind

Overloaded Facility	Contingency	Loading (%)			
		Base A	Base B/E	Base C	Base D
Table Mountain – Vaca Dixon 500kV line	Base Case	122%	<100%	103%	101%
	TABLE MTN-TESLA 500KV	129%	103%	106%	105%
Fern Rd – Table Mountain 500 kV line #1	Base Case	107%	<100%	<100%	<100%
	OLINDA-TRACY 500KV	106%	<100%	<100%	<100%
Fern Rd – Table Mountain 500 kV line #2	Base Case	107%	<100%	<100%	<100%
	OLINDA-TRACY 500KV	107%	<100%	<100%	<100%
Table Mountain – Tesla 500 kV line	TABLE MTN-VACA 500KV	114%	<100%	<100%	<100%
Vaca – Collinsville 500 kV line	TABLE MTN-TESLA 500KV	106%	<100%	<100%	<100%

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

PG&E Greater Bay and North of Greater Bay On-Peak Constraints – Offshore Wind

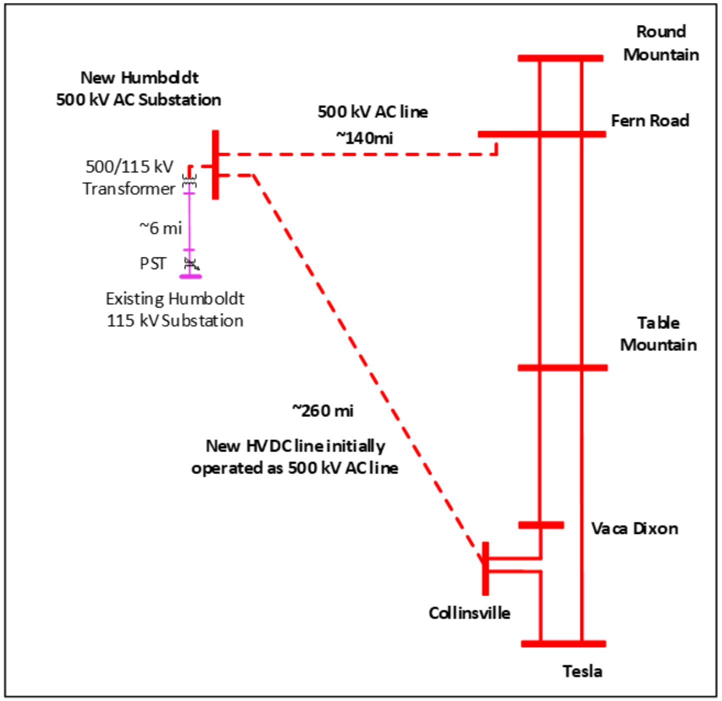
Overloaded Facility	Contingency	Loading (%)			
		Base A	Base B/E	Base C	Base D
Collinsville – PittsburgE 230kV line	Base Case	106%	112%	<100%	<100%
Collinsville – PittsburgF 230kV line	Base Case	<100%	110%	<100%	<100%
	COLLINSVILLE-PITTSBURG-E #1 230KV	124%	130%	<100%	106%
North Dublin -Vineyard 230 kV	CONTRA COSTA-LAS POSITAS 230KV	<100%	103%	100%	<100%
Tesla - Newark 230 kV Line No. 2	TESLA-NEWARK #1 230KV & TESLA-RAVENSWOOD 230KV	<100%	107%	104%	<100%
Henrietta-GWF 115 kV Line	HELM-MCCALL 230KV & HENTAP2-MUSTANGSS #1 230KV	<100%	<100%	<100%	103%
Eastshore 230/115kV Transformer #1	E. SHORE 230/115KV TB 2	<100%	<100%	<100%	107%
Eastshore 230/115kV Transformer #2	E. SHORE 230/115KV TB 1	<100%	<100%	<100%	108%
Fulton - Hopland 60 kV (Geyser Jct to Fitch Mt. Tap)	GEYSERS #9-LAKEVILLE & EAGLE ROCK-FULTON-SILVERADO LINES	<100%	<100%	<100%	100%

Summary of offshore wind mitigations with costs

Potential Mitigation	Base A	Base B	Base C	Base D	Base E
Interconnection	$2.1B-$3.0B	$3.2B-$4.6B	$4.6B-$6.7B	$4.9B-$7.0B	$2.9B-$4.2B
North Dublin -Vineyard 230 kV Reconductor		$116M-$233M	$116M-$233M		$116M-$233M
Tesla - Newark 230 kV Line No. 2 Reconductor		$29M-$58M	$29M-$58M		$29M-$58M
Henrietta-GWF 115 kV Line Reconductor				$107M-$215M	
New Fern Road- Tesla 500 kV Line	$1.4B-2.0B				
Reinstate 500 kV Line Rerates		PG&E maintenance	PG&E maintenance	PG&E maintenance	PG&E maintenance
New Eastshore 230/115kV Transformer #3				$120M-$240M	
Fulton - Hopland 60 kV (Geyser Jct to Fitch Mt. Tap) Reconductor			existing LDNU	existing LDNU	
Collinsville 230 kV Reactor	$39-58M	$39-58M		$39-58M	$39-58M
Total Mitigation Cost	$1.4B- $2.1B	$184M-$349M	$145M-$291M	$266M-$513M	$184M-$349M
Total Mitigation and Interconnection Costs	$3.5B – $5.1B	$3.3B- $4.9B	$4.6B- $6.9B	$5.1B- $7.5B	$3.1B - $4.5B

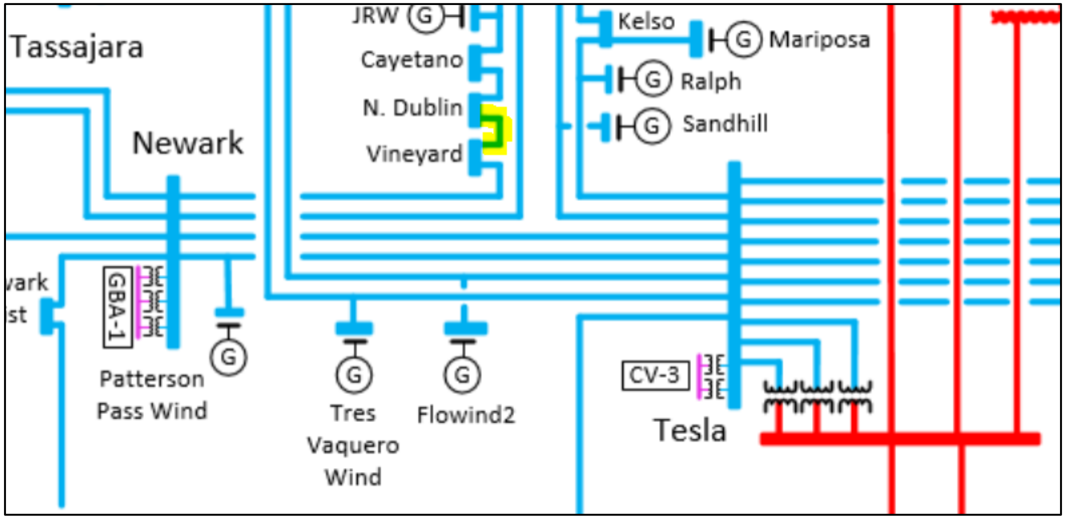
Recommended Option (Option E) to Interconnect Humboldt to Fern Road and Collinsville

- Policy Assessment Need
  - Base and sensitivity HSN scenario
- Project Scope
  - Humboldt 500 kV substation complete with a 500/115 kV transformer.
  - Building approximately 260 mile HVDC line, initially operated as 500 kV AC line to interconnect Humboldt 500 kV to the Collinsville substation.
  - Building approximately 140 mile, 500 kV AC line to interconnect Humboldt 500 kV to the Fern Road substation.
  - A 115 kV line from Humboldt 500 kV to existing Humboldt 115 kV substation, and a 115kV/115 kV phase shifting transformer (PST) at Humboldt 115 kV substation.
- Estimated Project Cost
  - $2.9B - $4.2B
- Estimated In-service Date
  - 2034
- Alternatives Considered
  - Several other options were considered. Please refer to Appendix F of the Transmission Plan for additional details.
- Recommendation
  - Approval



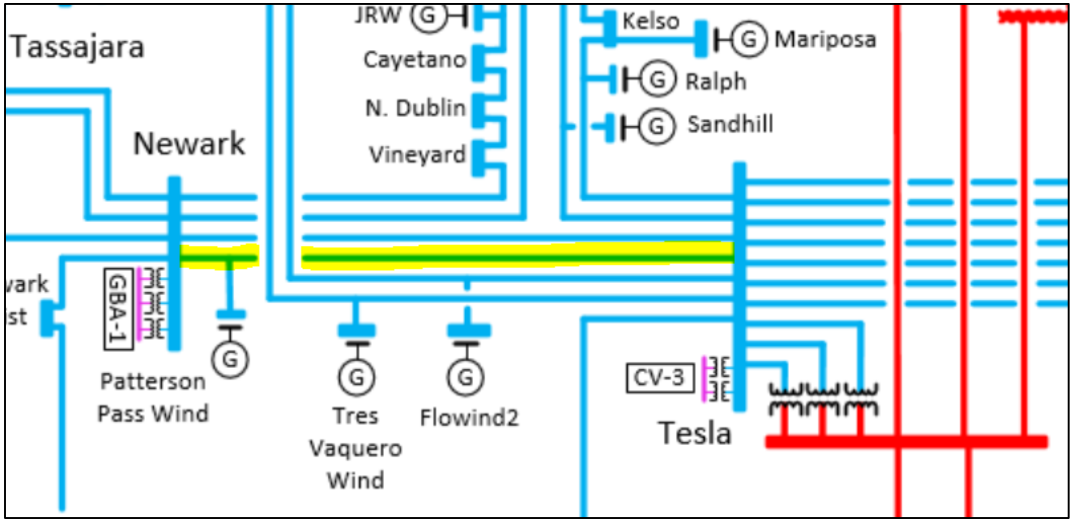
North Dublin – Vineyard 230 kV Reconductor

- Policy Assessment Need
  - Base and sensitivity HSN scenario
- Project Scope
  - Reconductor North Dublin - Vineyard 230 kV line with minimum summer emergency rating of 1350 Amps or highest conductor feasible with existing structure and will include any other limiting elements upgrade to achieve the new line rating.
- Estimated Project Cost
  - $116M - $232M
- 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



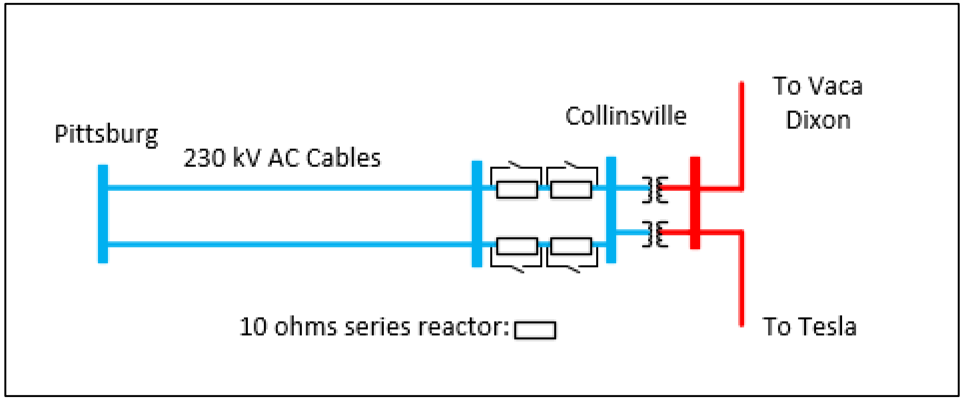
Tesla – Newark 230 kV line No 2 Reconductor

- Policy Assessment Need
  - Base and sensitivity HSN scenario
- Project Scope
  - Reconductor Tesla –Newark #2 230 kV line - From 024/148 to Newark (~4.28 miles), with minimum summer emergency rating of 3428 AMPS, matching other sections of the line or highest conductor feasible with existing structure. Will also include any other limiting element upgrades to achieve this line rating.
- Estimated Project Cost
  - $29M - $58M
- 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



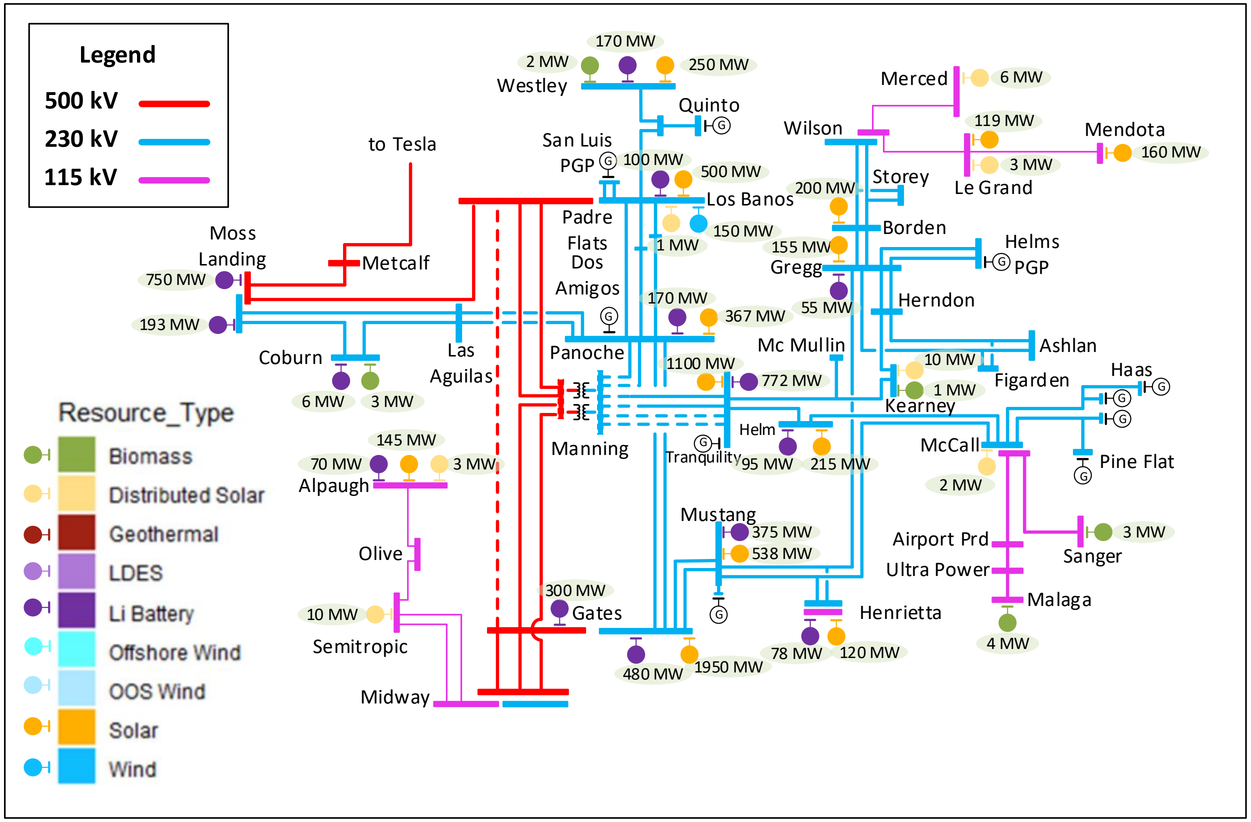
Collinsville 230 kV Reactor

- Policy Assessment Need
  - Base and sensitivity HSN scenario
- Project Scope
  - Add 20 ohm reactors on the Collinsville – Pittsburg 230 kV lines.
- Estimated Project Cost
  - $39M - $58M
- Estimated In-service Date
  - Concurrently with New Collinsville Substation project
- Alternatives Considered
  - Additional lines out of Collinsville but eliminated due to large cost.
- Recommendation
  - Approval



PG&E Greater Fresno Interconnection Area

PG&E Greater Fresno Interconnection Area Mapped Base Portfolio



California ISO

PG&E Greater Fresno Interconnection Area On-Peak Constraints

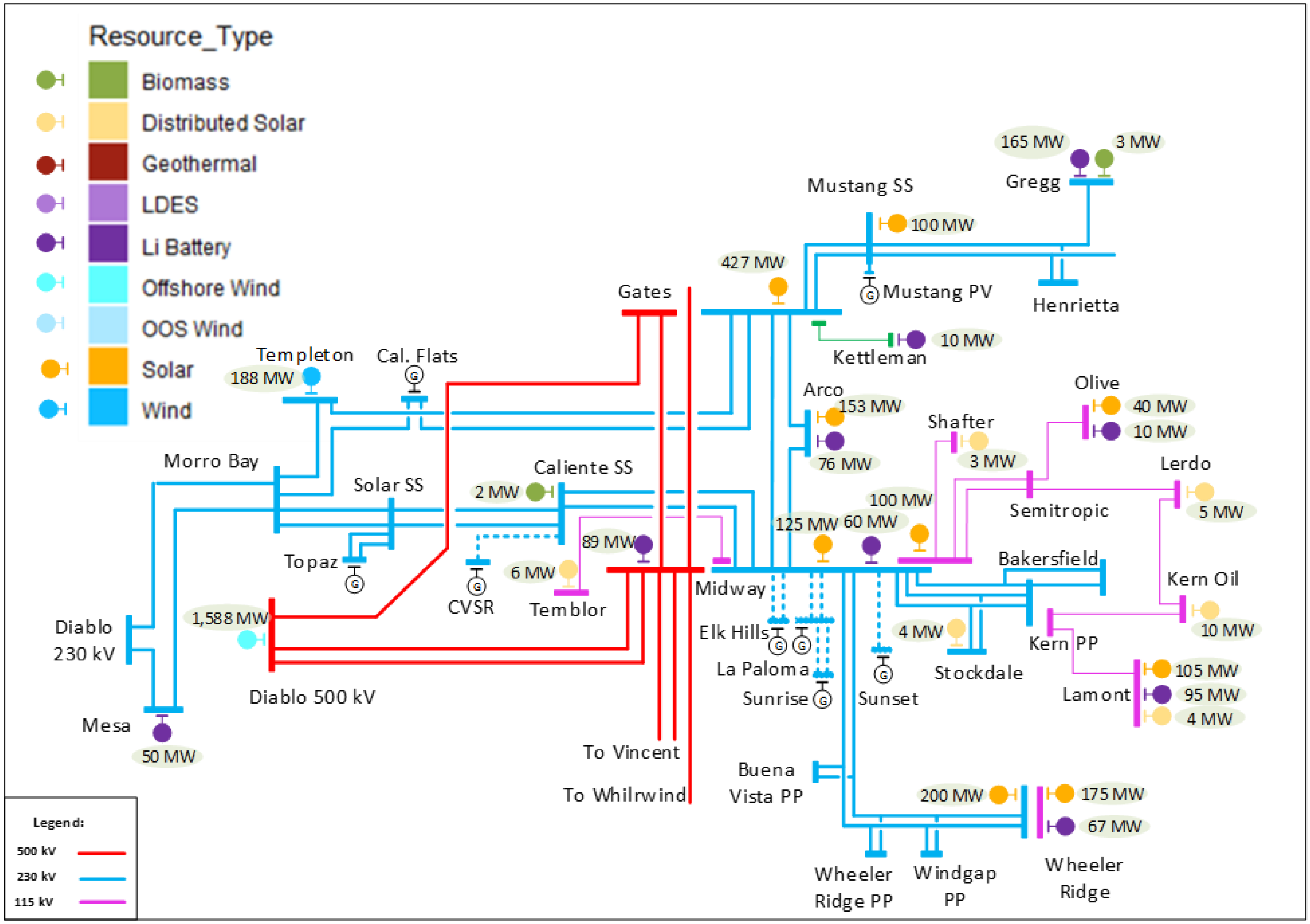
Overloaded Facility	Contingency	Scenario	Loading	
			BASE	SENS-01
Mccall 230/115kV Bank 1	MC CALL 230/115KV TB 3	HSN	103%	<100%
Mccall 230/115kV Bank 3	MC CALL 230/115KV TB 1	HSN	101%	<100%
McCall-Sanger #2 115 kV Line	MCCALL-REEDLEY 115KV & MCCALL-SANGER #3 115KV	HSN	114%	112%
Herndon-Woodward 115 kV Line	HERNDON-BARTON 115KV & HERNDON-MANCHESTER 115KV	HSN	125%	<100%

PG&E Greater Fresno Mitigation Plan

- There are no policy-driven upgrades identified in the Fresno interconnection planning area.
- All Identified constraints are local and will therefore be addressed though the GIP.

PG&E East Kern Interconnection Area

PG&E East Kern Interconnection Area Mapped Base Portfolio



PG&E East Kern Interconnection Area On-Peak Constraints

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

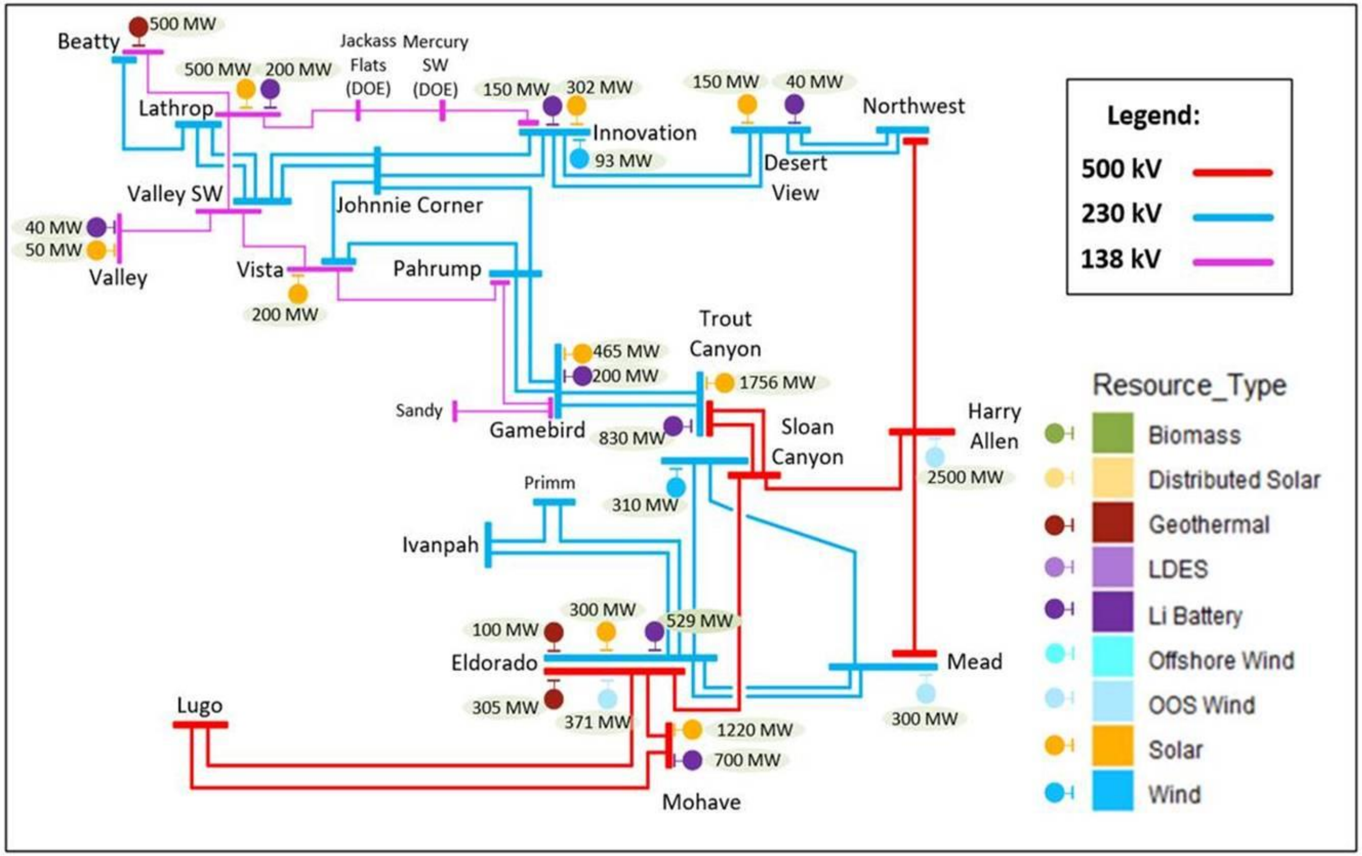
California ISO

PG&E East Kern Interconnection Area Mitigation Plan

- There are no policy-driven upgrades identified in the East Kern interconnection planning area.
- For the Wheeler 115/70 kV Bank 2 constraint, the ISO recommends relocating approximately 34 MW of generic BESS.

East of Pisgah Interconnection Area

East of Pisgah Interconnection Area – Mapped Base Portfolio



California ISO

Lugo – Victorville 500 kV On-peak Deliverability Constraints

- In the November stakeholder meeting, the CAISO presented the initial policy study result where the Lugo – Victorville 500 kV line was loaded to 98.2% following the Eldorado – Lugo 500 kV line outage and the Eldorado – McCullough 500 kV line was loaded to 110.4%.
- Following the stakeholder meeting, the CAISO refined the generation dispatch in the EOP area deliverability cases. These refinements were to ensure that effective generation capacity on both sides of the Lugo – Victorville area constraint were predispatched to 80% of their study amount prior to running the deliverability study tool.
- With the updated deliverability case, the Lugo – Victorville 500 kV line was loaded to 101.8% following the Eldorado – Lugo 500 KV line outage and the Eldorado – McCullough 500 kV line was loaded to 111.0%.
- The existing Lugo – Victorville RAS would mitigate the overloads and no transmission upgrade is required at this time.

Lugo – Victorville 500 kV On-peak Deliverability Constraints Summary

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

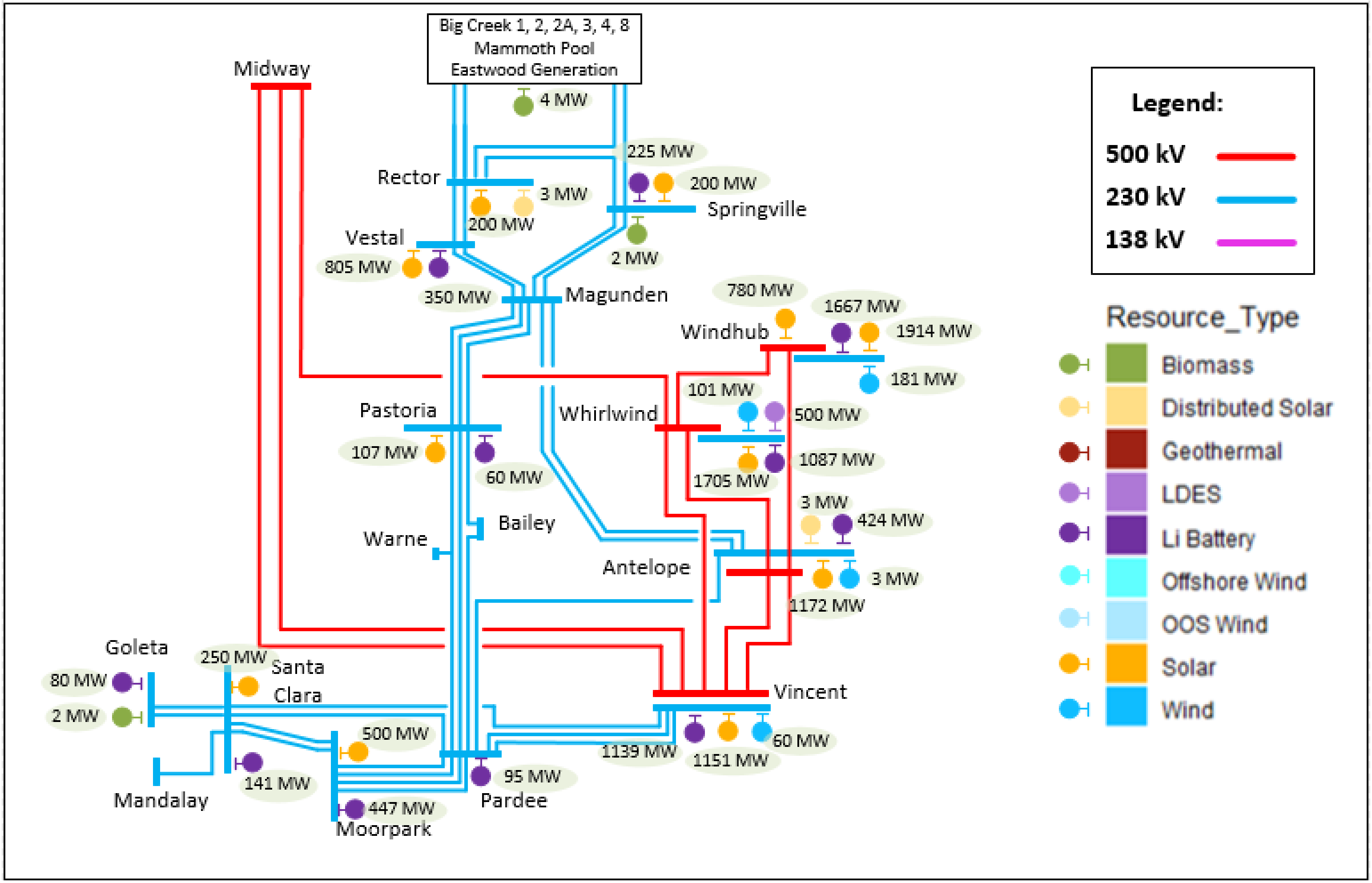
Affected transmission zones		East of Pisgah	
		Base	Sensitivity
Portfolio MW behind constraint		9,074 MW	N/A
Portfolio battery storage MW behind constraint		3,131 MW	
Deliverable portfolio MW w/o mitigation		7,978 MW	
Total undeliverable baseline and portfolio MW		1,096 MW	
Mitigation Options	RAS	Lugo – Victorville RAS	
	Reduce generic battery storage (MW)	Not needed	
	Transmission upgrade	Eldorado 500 kV SCD mitigation project	
Recommended Mitigation		Lugo – Victorville RAS Eldorado 500 kV SCD mitigation project	

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

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

SCE Northern Interconnection Area

Base Portfolio: SCE Northern Area



FCDS
10,336 MW

Total
15,358 MW

SCE Northern Interconnection Area

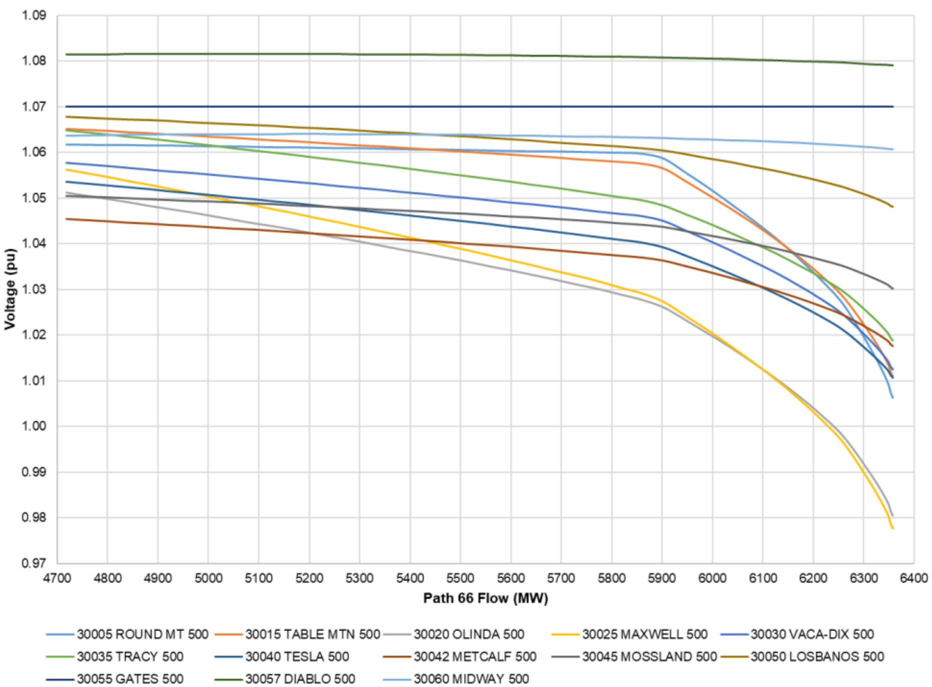
On-peak Windhub area export constraint

- In the November stakeholder meeting, the ISO mentioned that it was re-evaluating the maximum generation amount that can be islanded at Windhub Substation before cascading occurs and based on that information identify if a policy-driven transmission mitigation was needed.
- The ISO performed a post transient analysis where governor response was assumed for all WECC units to account for the generation lost at Windhub Substation during a simultaneous or overlapping outage of Antelope – Windhub 500 kV Line and Whirlwind – Windhub 500 kV Line without time for system adjustments.
- The 2028 SCE Main Summer Peak reliability base case was selected for the assessment and the dispatch was adjusted by increasing generation in the Pacific Northwest area and reducing generation in SCE area, with the objective to maintain a 4,800 MW real power flow, pre-contingency, through Path 66 California – Oregon Intertie (COI) in the North to South (N>S) direction.
- Sensitivity cases were created by increasing the dispatch of the resources connected at Windhub substation and reducing the dispatch of energy storage resources in the rest of SCE area to maintain a 4,800 MW N>S power flow on Path 66.
- The post transient analysis was conducted to determine if the system was in compliance with the WECC Post Transient Voltage Deviation Standard and ISO Planning Standards in the Bulk Electric System (BES) and if there were thermal overloads on the BES.

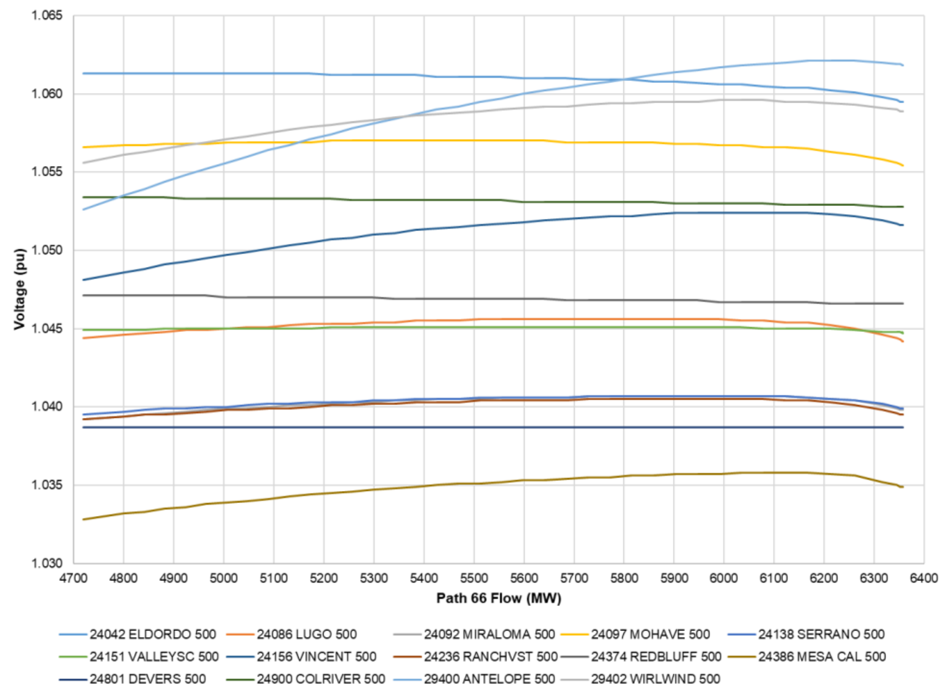
SCE Northern Interconnection Area

On-peak Windhub area export constraint

PV curve – Path 66 vs. PG&E 500 kV voltages



PV curve – Path 66 vs. SCE 500 kV voltages



- Several of the northernmost 500 kV buses in PG&E system and most of the 500 kV buses in Northwest area have a significant voltage deviation and the knee point of the PV curves occur with a post contingency N>S real power flow through Path 66 of around 6,350 MW, which is consistent with the divergence observed in the post transient assessment.
- There is no significant voltage deviation in SCE area 500 kV buses during the event.

SCE Northern Interconnection Area

On-peak Windhub area export constraint

- The transmission capability estimate provided to the CPUC was approximately 400 MW higher in terms of the actual study amount level which is approximately equivalent to the 1000 MW of nameplate capacity that was found to be undeliverable. Given this inaccuracy in the estimate provided, during the development of the resource portfolio it was not anticipated that a transmission upgrade would be triggered for the Windhub Area Export constraint. In addition, with the updated estimate, the 2024-2025 TPP portfolio is not expected to require a transmission upgrade for this constraint. Therefore, an upgrade is not recommended for approval for this constraint.

Affected transmission zones		Tehachapi area – Windhub Substation	
		Base	**Sensitivity**
Portfolio MW behind constraint		3546 MW	N/A
Portfolio battery storage MW behind constraint		1795 MW	
Deliverable portfolio MW w/o mitigation		2483 MW	
Total undeliverable baseline and portfolio MW		1063 MW	
Mitigation Options	RAS	Not applicable	
	Reduce generic battery storage (MW)	Does not solve the issue	
	Transmission upgrade including cost	Not needed	
Recommended Mitigation		See discussion above	

Economic Assessment and Production Cost Simulation
Draft 2022-2023 Transmission Plan

Yi Zhang

2023-2024 Transmission Planning Process Stakeholder Meeting
April, 2023

Key steps in database development since November stakeholder session

- Modeled SCE Eldorado 230 kV and 500 kV reconfiguration
  – Short circuit duty mitigations
- Relaxed PG&E Helm – MCCALL and Mustangs – Henrietta Tap2 – MCCALL 230 kV N-2 contingency
  – Conditional P7 in CAISO real time operation
- Hitachi Energy's GridView v10.3.72 was used for simulation

Base Portfolio - summary of congestions

	Aggregated congestion	Cost ($M)	Duration (Hr)
1	COI Corridor	159.61	1,903
2	Path 26 Corridor	61.06	3,220
3	Path 61 (Victorville-Lugo)	54.64	1,247
4	PG&E Moss Landing-Las Aguilas 230 kV	27.00	1,115
5	SDG&E/CFE	23.95	1,218
6	PG&E Collinsville corridor	22.97	1,075
7	Path 15 Corridor	21.77	1,140
8	SCE North of Lugo	18.29	3,613
9	Path 46 WOR	17.26	19
10	PG&E Panoche/Oro Loma area	9.53	1,973
11	PG&E Kern 230kV	9.21	1,381
12	PG&E Sierra	8.29	1,686
13	SDG&E 230 kV	6.19	1,080
14	GridLiance/VEA	4.61	1,076
15	Path 65 PDCI	2.41	153
16	SCE J.Hinds-Mirage	2.18	296
17	Path 49 EOR	1.45	4
18	PG&E Fresno Los Banos 230 kV	1.39	213
19	PG&E POE-RIO OSO 230 kV	1.18	147

- Only listed congestions with congestion cost greater than $1 million per year. More details can be found in the draft TPP report
- No significant changes from the preliminary results in the November stakeholder meeting
  - Except for the PG&E Fresno Henrietta 115 kV congestion and SCE East of Pisgah congestion due to the modeling updates

Detailed investigation and economic assessment

Detailed investigation	Alternative	Proposed by	Reason
Mead S – Sloan Canyon 230 kV line congestion	Add the second Mead S – Sloan Canyon 230 kV line	ISO	Mead S – Sloan Canyon 230 kV line remained a bottleneck for local renewable resources to connect to the system.
SCE East of Pisgah and Path 61 corridor congestion	Add the Trout Canyon – Lugo 500 kV line with 70% compensation	ISO	Significant congestion on the Path 61 corridor under both contingency and normal condition when the flow was from Victorville to Lugo was observed, mainly attributed to renewable generation in the SCE's East of Pisgah area, GridLiance West/VEA area, and the out of state wind generation
	Marketplace to Adelanto project with converting the Marketplace-Adelanto 500 kV line to HVDC, and adding a 500 kV line from Adelanto to Lugo and a 500 kV line from Marketplace to Eldorado		
Path 26 corridor congestion	PTE project	California Western Grid	Recurring congestion with large congestion cost. The mitigation alternatives are expected to help to mitigate the congestion, and to reduce local capacity requirements.
Path 15 corridor and Mosslanding – Las Aguilas 230 kV line congestion	Alternative 1: Manning – Moss Landing 500 kV line and Moss Landing – Metcalf 500 kV line reconductoring, removing the existing Moss Landing – Las Aguilas 230 kV line	ISO	Path 15 corridor congestion and Moss Landing – Las Aguilas 230 kV 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. These two corridors were selected to be assessed together in this planning cycle because the power flows of these two corridors impact each other, hence the individual mitigations for one corridor may also impact the other corridor. Comprehensive mitigations may be needed. Note: Alternative 1 assumed that the new Manning – Moss Landing 500 kV line will use the right of way of the existing Moss Landing – Las Aguilas 230 kV line.
	Alternative 2: Moss Landing – Las Aguilas 230 kV reconductoring, keep the series reactor		
	Alternative 3: Moss Landing – Las Aguilas 230 kV reconductoring, not keep the series reactor		
	Alternative 4: Midway–Gates–Manning 500 kV line		
	Alternative 5: Manning-Los Banos-Tracy 500 kV line		
	Alternative 6: Alternative 1 plus Alternative 4		
	Alternative 7: Alternative 3 plus Alternative 4		
	Alternative 8: Alternative 4 plus Alternative 5		

GridLiance West/VEA Mead S – Sloan Canyon congestion and mitigation

Constraint Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
MEAD S-SLOAN CANYON 230 kV line #1	0	0	1,348	474	1,348	474

The mitigation is to add the second Mead S – Sloan Canyon 230 kV line. This alternative can effectively mitigate the congestion on the existing Mead S – Sloan Canyon 230 kV line.

GridLiance West/VEA Mead S – Sloan Canyon congestion and mitigation – production cost saving

	Base case	Second Mead S – Sloan Canyon 230 kV line	
	($M)	Post project ($M)	Savings ($M)
ISO load payment	9,765	9,699	66
ISO generator net revenue benefiting ratepayers	5,598	5,590	-8
ISO transmission revenue benefiting ratepayers	677	654	-24
ISO Net payment	3,490	3,455	35
WECC Production cost	13,070	13,068	2

Due to the limitation within the Mead Substation for adding another line position, further assessment for the feasibility and cost of adding the second Mead S – Sloan Canyon 230 kV line will be conducted in future planning cycle

SCE East of Pisgah area and Path 61 corridor congestion and mitigations

Constraint Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
LUGO-VICTORVL 500 kV line, subject to SCE N-1 ElDorado-Lugo 500 kV with RAS	0	0	51,400	169	51,400	169
P61 Lugo-Victorville 500 kV Line	0	0	3,237	1,078	3,237	1,078
ELDORDO-ELD_LUGO_11 500 kV line #1	12	3	0	0	12	3
ELDORDO-ELD_LUGO_11 500 kV line, subject to LADWP-SCE N-1 Victorville-Lugo 500kV	3	1	0	0	3	1
BAKER-MTN PASS 115 kV line #1	0	0	2	19	2	19

Two mitigation alternatives for the SCE East of Pisgah area and Path 61 corridor congestion were assessed:

1. Adding the new Trout Canyon – Lugo 500 kV line with 70% series compensation

2. Marketplace – Adelanto HVDC conversion project that includes converting the existing Marketplace to Adelanto 500 kV line to HVDC with 3,500 MW capacity, and building a 500 kV line from Adelanto to Vincent – Lugo 500 kV line and a 500 kV line from Marketplace to Eldorado.

SCE East of Pisgah area and Path 61 corridor congestion and mitigations - benefits

- The Trout Canyon – Lugo 500 kV line was effective to mitigate the Lugo – Victorville 500 kV line congestion under the Eldorado-Lugo 500 kV N-1 contingency, but the Path 61 congestion due to path rating binding was still observed.
- The Marketplace – Adelanto HVDC conversion project can mitigate both the Path 61 congestion and the congestion on the Lugo – Victorville 500 kV line
- Both alternatives showed positive production cost savings to ISO ratepayers

	Base case	Trout Canyon – Lugo 500 kV line		Marketplace – Adelanto project	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	9,765	9,571	194	9,566	199
ISO generator net revenue benefiting ratepayers	5,598	5,545	-53	5,550	-48
ISO transmission revenue benefiting ratepayers	677	599	-78	585	-92
ISO Net payment	3,490	3,427	63	3,431	59
WECC Production cost	13,070	13,106	-36	13,088	-18

SCE East of Pisgah area and Path 61 corridor congestion and mitigations – benefit to cost ratio

	Trout Canyon – Lugo 500 kV line	Marketplace – Adelanto project
Production cost savings ($million/year)	63	59
Capacity saving ($million/year)	0	0
Capital cost ($million)	2,000	1,525
Discount Rate	7%	7%
PV of Production cost savings ($million)	930	842
PV of Capacity saving ($million)	0	0
Total benefit ($million)	930	842
Total cost (Revenue requirement) ($million)	2,600	1,982
Benefit-to-cost ratio (BCR)	0.358	0.425

- The capital cost of Trout Canyon – Lugo was estimated based on the cost in the last TPP
- The capital cost of Marketplace – Adelanto project was based on the per unit cost

Path 26 corridor congestion

Constraint Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
P26 Northern-Southern California	9	11	35,606	1,753	35,615	1,764
MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	25,163	1,249	25,163	1,249
MW_WRLWND_31-MW_WRLWND_32 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	232	172	0	0	232	172
MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	17	18	2	5	19	23
MW_VINCNT_12-VINCENT 500 kV line #1	19	4	0	0	19	4
MW_VINCNT_22-VINCENT 500 kV line #2	14	8	0	0	14	8

Path 26 corridor congestion – PTE project

- The Pacific Transmission Expansion (PTE) project
  - An economic study request with offshore HVDC lines between the northern and southern California systems
  - Partially mitigated Path 26 congestion

Area or Branch Group	Congestion Cost ($M) Base case	Congestion Cost ($M) PTE-New	Change in Congestion Cost $M
Path 15 Corridor	21.77	26.59	4.83
COI Corridor	159.61	153.64	-5.97
Path 26 Corridor	61.06	32.59	-28.47

	Base case	PTE case	
	($M)	Post project ($M)	Savings ($M)
ISO load payment	9,765	9,778	-13
ISO generator net revenue benefiting ratepayers	5,598	5,636	38
ISO transmission revenue benefiting ratepayers	677	656	-21
ISO Net payment	3,490	3,486	3
WECC Production cost	13,070	13,034	36

Path 26 corridor mitigation – PTE LCR reduction benefit update

- Long term LCR was not assessed in this planning cycle. The LCR reduction results in previous planning cycles were used, but the LCR reduction benefit was updated using the latest capacity cost information provided in CPUC Resource Adequacy Report

Area	Weighted average capacity cost ($/kW-month) in CPUC 2021 RA report	In 2022 dollar
System	6.24	6.40
SP26	6.52	6.69
LA Basin	6.64	6.81

	Pacific Transmission Expansion HVDC Project	
	Local vs System RA cost	Local vs SP 26 RA cost
LCR reduction benefit (Western LA Basin) (MW)	1,889	
Capacity value ($/MW-year)	4,922	1,476
LCR Reduction Benefit ($million)	9.30	2.79

Path 26 corridor mitigation – PTE LCR reduction benefit update – different capacity cost

- Sensitivity assessment was conducted using different local and system capacity cost assumptions in the PTE economic study request

Area	Weighted average capacity cost ($/kW-month)	Note
System	Low: 2.21, High: 2.58	The PTE economic study request assumed the system capacity marginal cost would be set by battery storage
SP26	Low: 2.21, High: 2.58	The PTE economic study request did not provide the SP26 capacity cost. Assumed same as the system capacity cost in this assessment
LA Basin	Low: 4.86, High: 7.45	The PTE economic study request provided the LA Basin capacity cost

Path 26 corridor mitigation – PTE LCR reduction benefit update – different capacity cost

- Two scenarios that provides estimate for the upper bounds of the LCR reduction savings were selected to conduct sensitivity assessments:
  - Sensitivity 1: the local capacity cost in the CPUC report and the low system capacity cost ($2.21/kW-month) in the PTE economic study request were used
  - Sensitivity 2: the high local capacity cost and the low system capacity cost ($2.21/kW-month) in the PTE economic study request were used

	Pacific Transmission Expansion HVDC Project	
	Sensitivity 1 Local cost in CPUC report vs System cost (low) in PTE study request	Sensitivity 2 Local cost (high) in PTE study request vs System cost (low) in PTE study request
LCR reduction benefit (Western LA Basin) (MW)	1,889	1,889
Capacity value ($/MW-year)	55,177	62,900
LCR Reduction Benefit ($million)	104.23	118.82

Path 26 corridor mitigation – PTE benefit to cost ratio

	Baseline study (all capacity costs are based on CPUC 2021 Resource Adequacy Report)		Sensitivity studies	
	Local vs System RA cost	Local vs SP 26 RA cost	Sensitivity 1 Local cost in CPUC report vs System cost (low) in PTE study request	Sensitivity 2 Local cost (high) in PTE study request vs System cost (low) in PTE study request
Production cost savings ($million/year)	3.32	3.32	3.32	3.32
Capacity saving ($million/year)	9.30	2.79	104.23	118.82
Capital cost ($million)	1,950	1,950	1,950	1,950
Discount Rate	7%	7%	7%	7%
PV of Production cost savings ($million)	48.99	48.99	48.99	48.99
PV of Capacity saving ($million)	137.28	41.18	1,539.14	1,754.56
Total benefit ($million)	186.27	90.18	1,588.13	1,803.55
Total cost (Revenue requirement) ($million)	2,535	2,535	2,535	2,535
Benefit-to-cost ratio (BCR)	0.073	0.036	0.626	0.711

PG&E Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion and mitigations

Constraint Name	Cost Forward ($K)	Duration Forward (Hrs)	Cost Backward ($K)	Duration Backward (Hrs)	Costs Total ($K)	Duration Total (Hrs)
MOSSLNSW-LASAGLSRCTR 230 kV line, subject to PG&E N-1 Mosslanding-LosBanos 500 kV	0	0	27,000	1,115	27,000	1,115
P15 Midway-LosBanos	8,140	351	0	0	8,140	351
MN_GT_11-GATES 500 kV line #1	0	0	8,044	274	8,044	274
GATES-GT_MW_11 500 kV line #1	0	0	4,953	405	4,953	405
LB_MN_11-MANNING 500 kV line #1	0	0	486	46	486	46
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 LB-Gates and LB-Midway 500 kV	0	0	116	55	116	55
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	0	0	26	6	26	6
PANOCHE-GATES E 230 kV line, subject to PG&E N-2 Gates-Gregg and Gates-McCall 230 kV	0	0	2	3	2	3

PG&E Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion and mitigations

	Path 15 corridor congestion		Path 26 corridor congestion		PG&E Mosslanding-Las Aguilas 230 kV congestion		
	Congestion Cost ($M)		Congestion Cost ($M)		Congestion Cost ($M)		
Base portfolio PCM case	21.77		61.06		27.00		
Alternatives	Congestion Cost ($M)	Congestion Cost Change from Base ($M)	Congestion Cost ($M)	Congestion Cost Change from Base ($M)	Congestion Cost ($M)	Congestion Cost Change from Base ($M)	Note
Alternative 1: Manning – Mosslanding 500 kV line and Mosslanding – Metcalf 500 kV line reconductoring, removing the existing Mosslanding – Las Aguilas 230 kV line	40.65	18.88	74.77	13.71	0	-27.00	Assuming that the new Manning – Mosslanding 500 kV line will use the right of way of the existing Mosslanding – Las Aguilas 230 kV line. Congestion on the Gates-Manning 500 kV line increased, which contributed to the Path 15 corridor congestion increased
Alternative 2: Mosslanding – Las Aguilas 230 kV reconductoring, keep the series reactor approved in the 2021-2022 plannign cycle	26.89	5.13	63.04	1.98	0	-27.00	The Moss Landing-Las Aguilas 230 kV congestion was mitigated. Congestion on the Gates – Manning 500 kV line and the Path 26 corridor increased slightly. Minor congestion on the Moss Landing-Los Banos 500 KV line was observed
Alternative 3: Mosslanding – Las Aguilas 230 kV reconductoring, not keep the series reactor	26.24	4.47	61.05	-0.01	0	-27.00	The Moss Landing-Las Aguilas 230 kV congestion was mitigated. Congestion on the Gates – Manning 500 kV line increased slightly. Minor congestion on the Moss Landing-Los Banos 500 KV line was observed

PG&E Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion and mitigations

	Path 15 corridor congestion		Path 26 corridor congestion		PG&E Mosslanding-Las Aguilas 230 kV congestion		
	Congestion Cost ($M)		Congestion Cost ($M)		Congestion Cost ($M)		
Base portfolio PCM case	21.77		61.06		27.00		
Alternatives	Congestion Cost ($M)	Congestion Cost Change from Base ($M)	Congestion Cost ($M)	Congestion Cost Change from Base ($M)	Congestion Cost ($M)	Congestion Cost Change from Base ($M)	Note
Alternative 4: Midway – Gates – Manning new 500 kV line	11.4	-10.37	67.65	6.59	24.76	-2.24	Congestion on the Manning – Los Banos 500 kV line increased, although the overall Path1 15 corridor congestion reduced
Alternative 5: Manning-LosBanos-Tracy new 500 kV line	32.89	11.12	64.01	2.95	8.32	-18.68	Congestion on the Gates – Manning 500 kV line increased, which contributed to the Path 15 corridor congestion increased
Alternative 6: Manning – Mosslanding 500 kV line and Mosslaning – Metcalf 500 kV line reconductoring plus Midway – Gates – Manning new 500 kV line (alt 1 plus alt 4)	1.9	-19.87	90.27	29.21	0	-27.00	This is a combination of Alternative 1 and Alternative 4. Both path 15 corridor congestion and the Moss Landing-Las Aguilas 230 kV congestion can be mitigated, but the Path 26 corridor congestion increased.

PG&E Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion and mitigations

	Path 15 corridor congestion		Path 26 corridor congestion		PG&E Mosslanding-Las Aguilas 230 kV congestion		
	Congestion Cost ($M)		Congestion Cost ($M)		Congestion Cost ($M)		
Base portfolio PCM case	21.77		61.06		27.00		
Alternatives	Congestion Cost ($M)	Congestion Cost Change from Base ($M)	Congestion Cost ($M)	Congestion Cost Change from Base ($M)	Congestion Cost ($M)	Congestion Cost Change from Base ($M)	Note
Alternative 7: Mosslanding – Las Aguilas 230 kV reconductoring plus Midway – Gates – Mainning new 500 kV line (alt3 plus alt 4)	16.57	-5.20	68.37	7.31	0	-27.00	This is a combination of Alternative 3 and Alternative 4. Congestion on the Mosslanding – Las Aguilas, 230 kV line was mitigated, which is similar to Alternative 3. Path 15 corridor congestion was only partially mitigated and Path 20 corridor congestion increased, which are similar to Alternative 4.
Alternative 8: Manning-LosBanos-Tracy new 500 kV line, plus Midway-Gates-Manning new 500 kV line (alt 4 plus alt 5)	0.44	-21.33	79.7	18.64	13.55	-13.45	This is a combination of Alternative 4 and Alternative 5. Both path 15 corridor congestion and the Moss Landing-Las Aguila 230 kV congestion can be mitigated or partially mitigated, but Path 26 corridor congestion increased.

PG&E Path 15 corridor and Moss Landing – Las Aguilas 230 kV line congestion and mitigations – production cost benefit

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		9,765	5,598	677	3,490	13,070
Alternative 1: Manning – Moss Landing 500 kV line and Moss Landing – Metcalf 500 kV line reconductoring, removing the existing Moss Landing – Las Aguilas 230 kV line	Post project	9,765	5,612	685	3,467	13,065
	Savings	0	15	8	23	5
Alternative 2: Moss Landing – Las Aguilas 230 kV reconductoring, keep the series reactor approved in the 2021-2022 planning cycle	Post project	9,672	5,571	659	3,442	13,072
	Savings	93	-27	-18	48	-2
Alternative 3: Moss Landing – Las Aguilas 230 kV reconductoring, not keep the series reactor	Post project	9,739	5,616	649	3,475	13,067
	Savings	26	18	-28	15	3
Alternative 4: Midway – Gates – Manning new 500 kV line	Post project	9,739	5,610	654	3,475	13,058
	Savings	26	12	-23	15	12
Alternative 5: Manning-LosBanos-Tracy new 500 kV line	Post project	9,680	5,597	643	3,439	13,064
	Savings	86	-1	-35	50	6
Alternative 6: Manning – Moss Landing 500 kV line and Mosslaning – Metcalf 500 kV line reconductoring plus Midway – Gates – Manning new 500 kV line (alt 1 plus alt 4)	Post project	9,869	5,699	660	3,511	13,056
	Savings	-104	101	-18	-21	14
Alternative 7: Moss Landing – Las Aguilas 230 kV reconductoring plus Midway – Gates – Manning new 500 kV line (alt3 plus alt 4)	Post project	9,731	5,614	635	3,482	13,070
	Savings	34	16	-42	8	0
Alternative 8: Manning-Los Banos-Tracy new 500 kV line, plus Midway-Gates-Manning new 500 kV line (alt 4 plus alt 5)	Post project	9,877	5,685	671	3,521	13,065
	Savings	-112	88	-6	-31	5

PG&E Path 15 corridor and Mosslanding – Las Aguilas 230 kV line congestion and mitigations – benefit to cost ratio

	Alt 1: Manning-Moslanding 500 kV line and Moss-Metcalf reconductor	Alt2: Mosslanding-Las Aguilas reconductor, and keep reactor always in	Alt3: Mosslanding-Las Aguilas reconductor, and remove reactor	Alt4: Midway-Gates-Manning new 500 kV line	Alt5: Manning-Tracy	Alt6: Midway-Manning-Mosslanding-Metcalf (Alt1 plus Alt4)	Alt7: Midway-Manning and Reconductor Mosslanding - Las Aguilas (Alt3 plus Alt4)	Alt8: Midway-Gates-Manning-LosBanos-Tracy 500 kV line (Alt4 plus Alt5)
Production cost savings ($million/year)	23	48	15	15	50	-21	8	-31
Capacity saving ($million/year)	0	0	0	0	0	0	0	0
Capital cost ($million)	631	182	161	741	720	1,372	876	1,461
Cost to Revenue Ratio	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Discount Rate	7%	7%	7%	7%	7%	7%	7%	7%
Economic Life (year)	50	40	40	50	50	50	50	50
PV of Production cost savings ($million)	340	685	214	222	738	-310	118	-458
PV of Capacity saving ($million)	0	0	0	0	0	0	0	0
Total benefit ($million)	340	685	214	222	738	-310	118	-458
Total cost (Revenue requirement) ($million)	820	237	209	963	936	1,784	1,139	1,899
Benefit-to-cost ratio (BCR)	0.414	2.894	1.022	0.230	0.789	-0.174	0.104	-0.241

Summary of economic studies

- Several transmission solutions were found to have sufficient economic benefits based on the available cost estimate, however, the ISO decided to not recommend these transmission upgrades for approval as economic-driven projects in this planning cycle
  - The second Mead S – Sloan Canyon 230 kV line
  - Moss Landing – Las Aguilas 230 kV line reconductoring

Summary of economic studies: Mead S – Sloan Canyon 230 kV line

- There is potential limitation within the Mead Substation for adding a new line position
- Further assessment for the feasibility and cost of adding the second Mead S – Sloan Canyon 230 kV line is needed and will be conducted in future planning cycles

Summary of economic studies: Mosslanding – Las Aguilas 230 kV upgrades

- Moss Landing – Las Aguilas 230 kV line reconductoring showed benefit to cost ratio greater than 1.0
- 500 kV alternatives assessed in this planning cycle also showed meaningful production cost saving
- The congestion on Path 15 and the Moss Landing – Las Aguilas line is expected to change significantly as resource assumption changes in the new CPUC IRP
- Potential LCR reduction benefit were not assessed in this planning cycle due to a lack of clarity of gas-fired generator retirement and capacity cost information
- The ISO will continue to investigate congestion mitigations in the next planning cycles based on the new CPUC IRP resource assumption

Summary of economic studies: other transmission alternatives assessed

- Some transmission alternatives assessed in this planning cycle showed positive benefits to ISO’s ratepayers, but not showed sufficient economic justification
- Some alternatives showed effectiveness to mitigate or partially mitigate congestion on some corridors, but may aggravate congestion in other parts of the system.
  - Comprehensive mitigation plans, including combinations of multiple alternatives, may need to be evaluated in future transmission planning cycles

Wrap-up
Draft 2023-2024 Transmission Plan

Yelena Kopylov-Alford
Stakeholder Engagement and Policy Specialist

2023-2024 Transmission Planning Process Stakeholder Meeting
April 9, 2024

Comments

- Comments due by end of day April 23, 2024
- Submit comments through the ISO's commenting tool, using the template provided on the process webpage:
- https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2023-2024-Transmission-planning-process