California ISO

Agenda
Draft 2022-2023 Transmission Plan

Kaitlin McGee

Sr. Stakeholder Engagement and Policy Specialist

2022-2023 Transmission Planning Process Stakeholder Meeting

April 11, 2023

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.
- To ask a question, press #2 on your telephone keypad. Please state your name and affiliation first.
- Calls are structured to stimulate an honest dialogue and engage different perspectives.
- Please keep comments friendly and respectful.

2022-2023 Transmission Planning Process Stakeholder Call – Agenda

Topic	Presenters
Introduction	Neil Millar
Overview	Jeff Billinton
Reliability-driven Projects Recommended for Approval - PG&E Planning Area - SCE Planning Area - SDG&E Planning Area	 - Preethi Rondla - Meng Zhang and Frank Chen - 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	 - Binaya Shrestha - Meng Zhang, Amanda Wong, Nebiyu Yimer and Luba Kravchuk
Economic Assessment	Yi Zhang
Wrap-up	Kaitlin McGee

Introduction
Draft 2022-2023 Transmission Plan

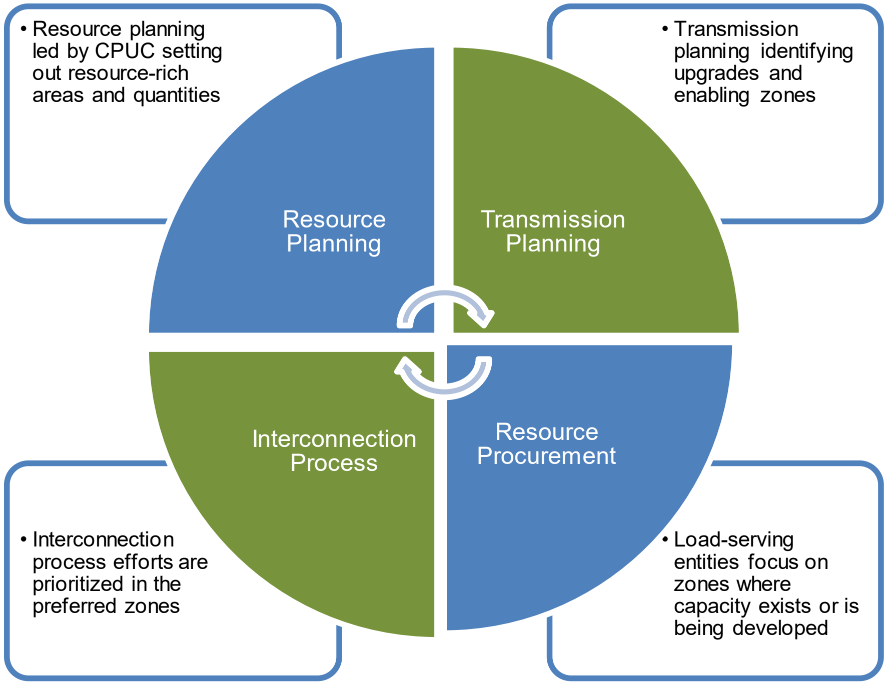
Neil Millar

Vice-President, Infrastructure & Operations Planning

2022-2023 Transmission Planning Process Stakeholder Meeting

April 11, 2023

The 2022-2023 Transmission Plan addresses rapidly escalating need for new resources and sets the foundation for a focused zonal approach to resource development

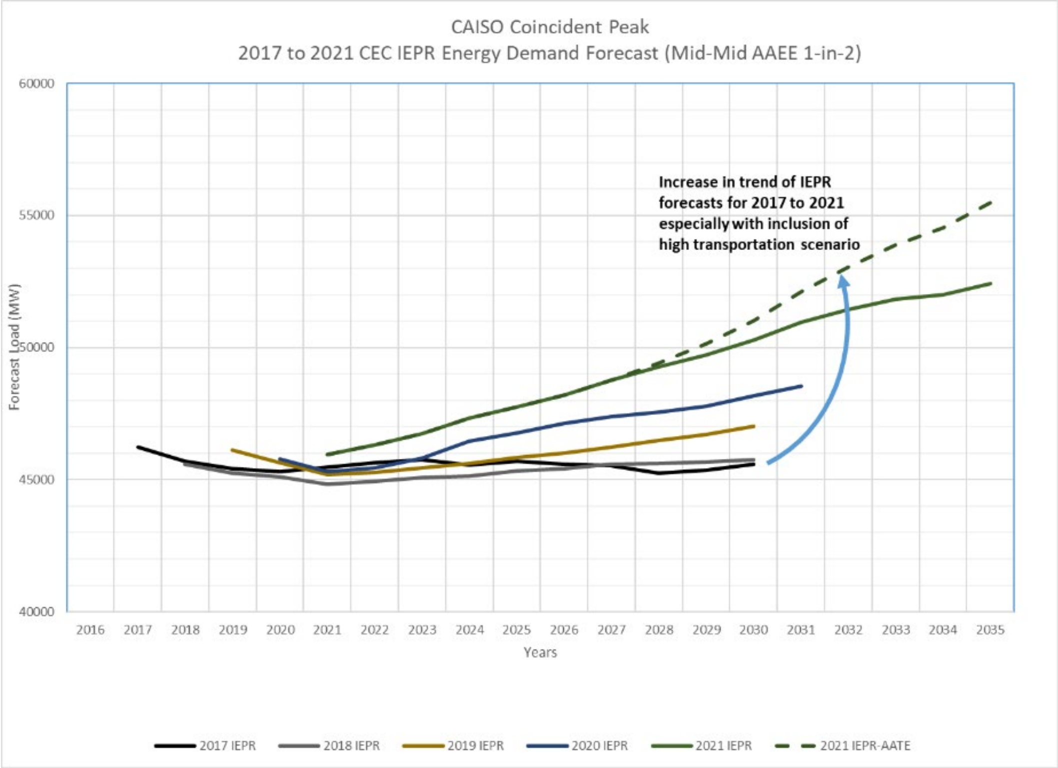


The strategic direction for transformational change was established in the CPUC/CEC/ISO Memorandum of Understanding signed in December, 2022 to:

- 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

California's climate change goals are driving escalating load forecasts

The CEC's load forecast is used in both the CPUC's Integrated Resource Planning process and the ISO's transmission planning process.



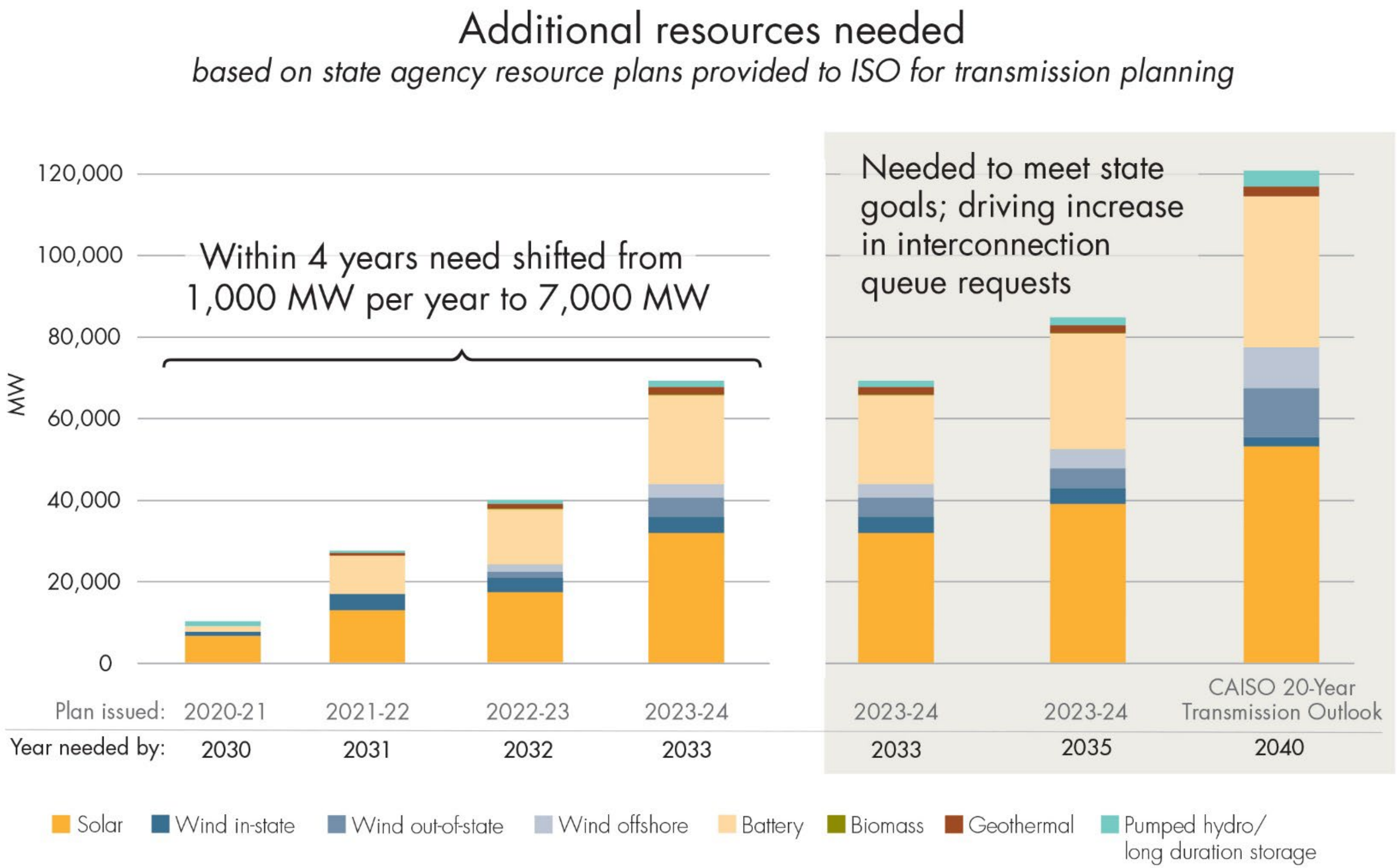
The ISO uses:

- The 1-in-10 weather event forecast for local reliability studies
- The 1-in-5 weather event forecast for bulk system reliability-driven and policy-driven studies
- The 1-in-2 weather event forecast for economic (market efficiency) studies

California ISO

California's climate change goals and escalating load forecasts lead to unprecedented resource needs

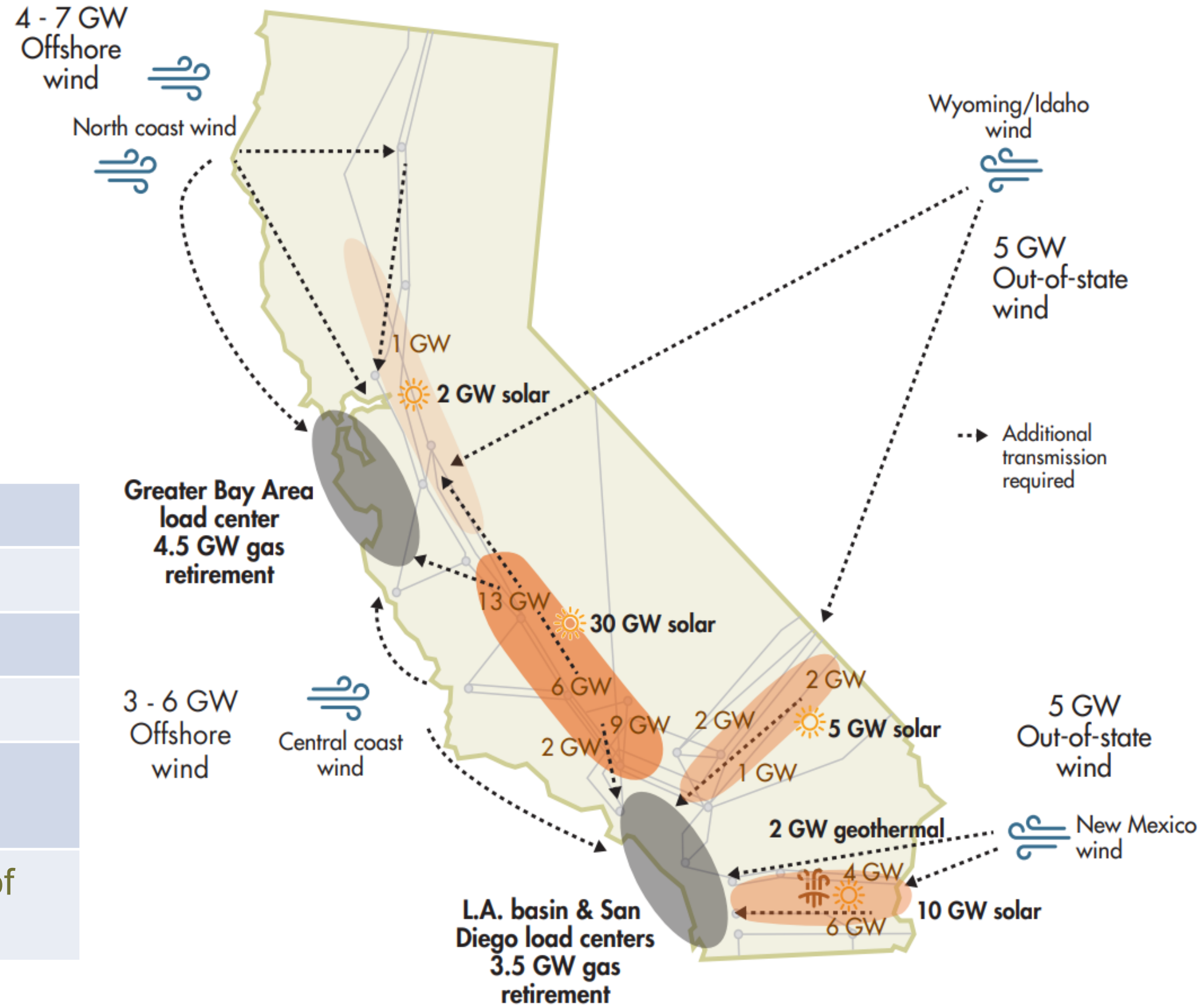
The resource portfolios provided by the CPUC for transmission planning reflect the acceleration in new resource requirements



California ISO

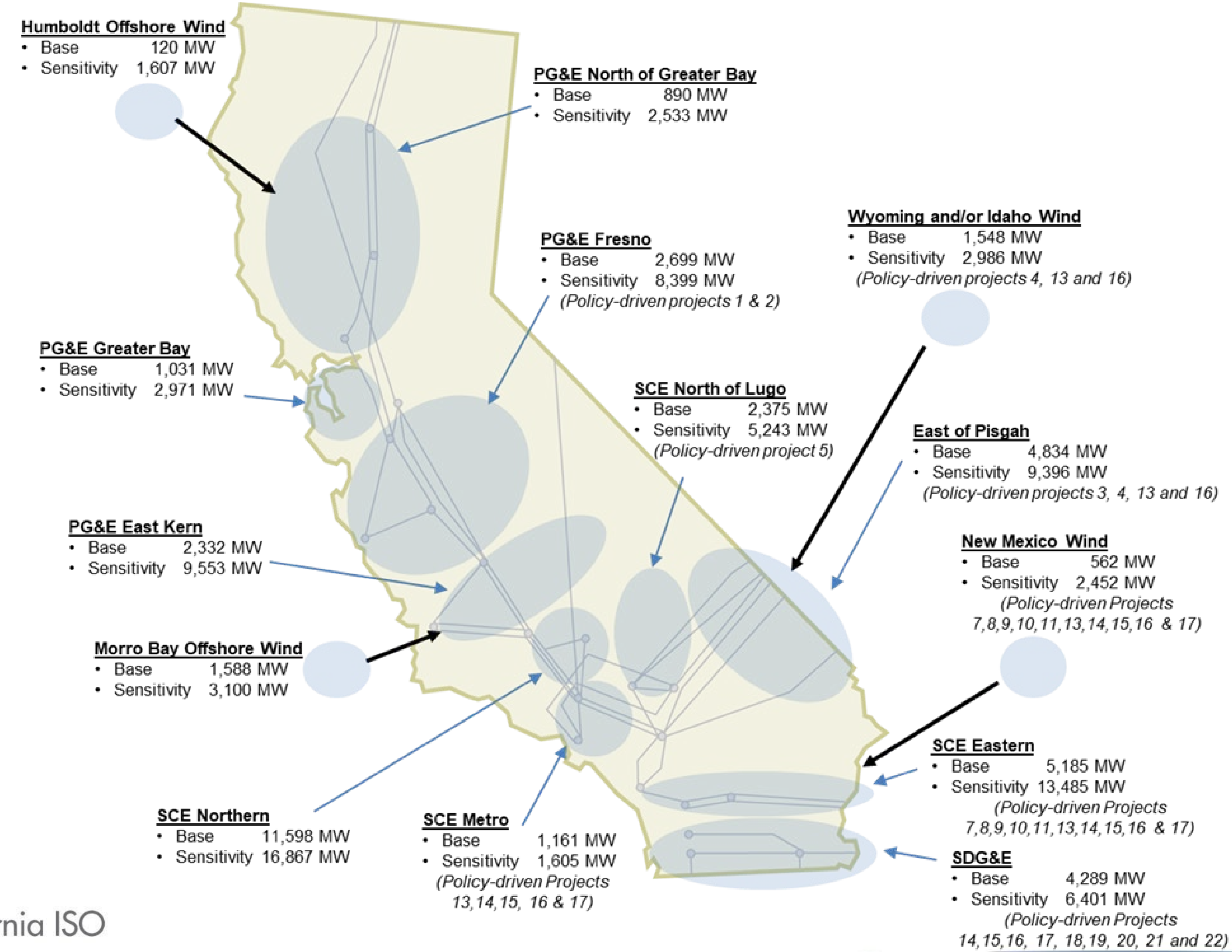
The plan also aligns with the 20-Year Transmission Outlook – and puts us on the right trajectory to meet 2045 goals

53 GW	Solar
22.2 GW	Wind
2.3 GW	Geothermal
37 GW	Battery
4 GW	Long-duration Storage
$30.5B	Estimated cost of transmission



California ISO

The zonal approach emphasized in this year's plan enables clearer direction and prioritization in other processes



Overview
Draft 2022-2023 Transmission Plan

Jeff Billinton
Director, Transmission Infrastructure Planning

2022-2023 Transmission Planning Process Stakeholder Meeting
April 11, 2023

2022-2023 Transmission Planning Process

December 2021 | April 2022 | May 2023

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

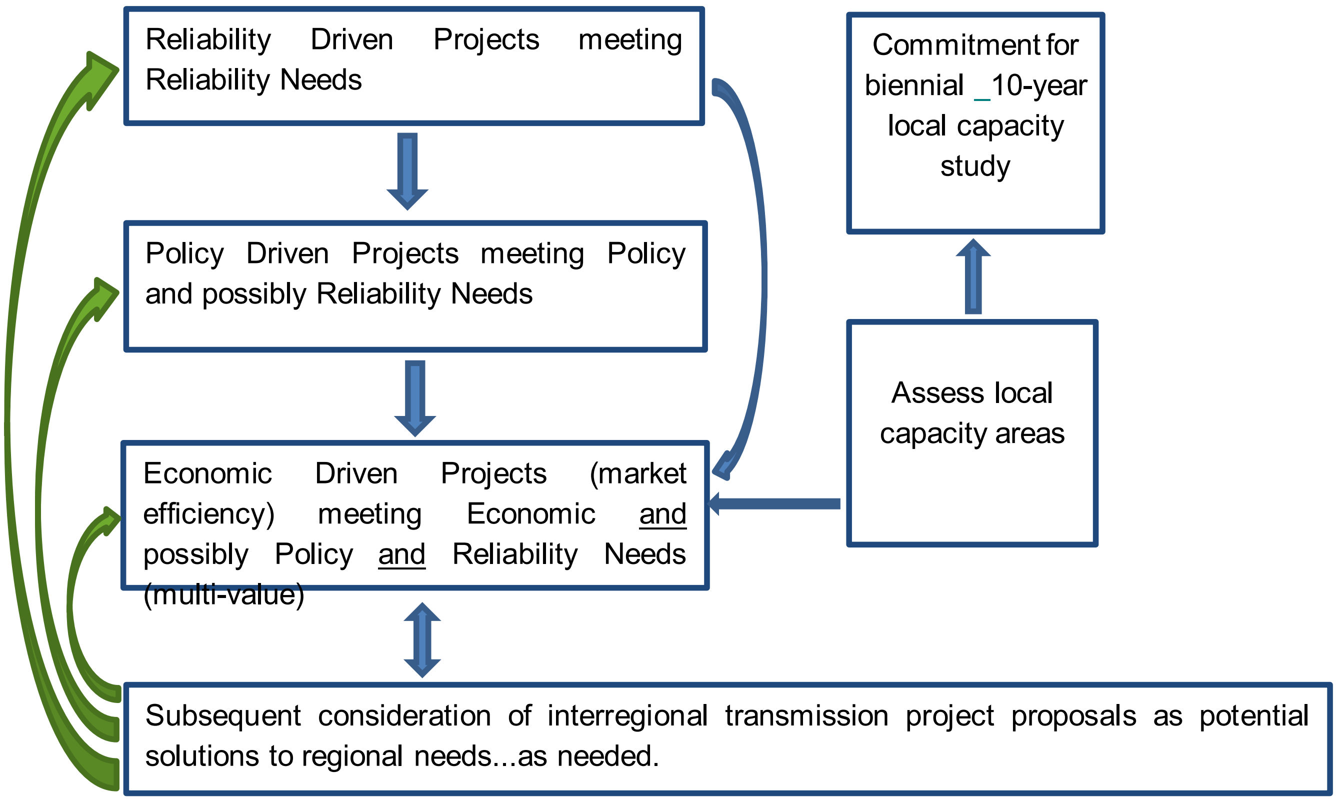
Phase 3 Procurement

CAISO Board for approval of transmission plan

2022-2023 Transmission Plan Milestones

- Draft Study Plan posted on February 18
- Stakeholder meeting on Draft Study Plan on February 28
- Final Study Plan posted on March 31
- Stakeholder meeting July 6
- Preliminary reliability study results posted and open Request Window on August 15
- Stakeholder meeting on September 27 and 28
  - Comments to be submitted by October 12
- Request window closes October 15
- Preliminary policy and economic study results on November 17
- Comments to be submitted by December 5
- Draft transmission plan to be posted on April 3, 2023
- Stakeholder meeting on April 11, 2023
  - Comments to be submitted by April 25, 2023
- Revised draft for approval at May 17-18 Board of Governor meeting

Studies are coordinated as a part of the transmission planning process



Reliability-Driven Projects

- 24 reliability projects driven by load growth and evolving grid conditions as the generation fleet transitions to increased renewable generation have been recommended, totaling $1.76 billion

Project Name	PTO Area	Planning Area	Cost ($M)
Banta ring bus[8]	PG&E	Central Valley	17.5
Metcalf 230/115 kV Transformers Circuit Breaker Addition[8]	PG&E	Greater Bay Area	15.0
South Bay Area Limiting Elements Upgrade[8]	PG&E	Greater Bay Area	11.0
Equipment Upgrade at CCSF Owned Warnerville 230 kV Substation[8]	PG&E	Greater Fresno	1.6
Barre 230 kV Switchrack Conversion to Breaker-and-a-Half [8]	SCE	Main	45
Mira Loma 500 kV Circuit Breaker Upgrade[8]	SCE	Main	10
Garberville area reinforcement project	PG&E	Humboldt	204.0
Tulucay-Napa #2 60 kV line resonductoring project	PG&E	North Coast & North Bay	4.6
Santa Rosa 115 kV lines reconductoring project	PG&E	North Coast & North Bay	74.0
Tesla 115 kV Bus Reconfiguration Project	PG&E	Central Valley	55.0
Lone Tree – Cayetano – Newark Corridor Series Compensation	PG&E	Greater Bay Area	25.0
Los Banos 70 kV Area Reinforcement Project	PG&E	Fresno	60.0
Redwood City Area 115 kV System Reinforcement	PG&E	Greater Bay Area	110.8
Pittsburg 115 kV Bus Reactor project	PG&E	Greater Bay Area	26
Los Banos 230 kV Circuit Breaker Replacement	PG&E	Fresno	66
Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project	PG&E	Fresno	184
North East Kern 115 kV Line Reconductoring Project	PG&E	Kern	256.0
Mesa Spare Transformer Installation	PG&E	Central Coast & Los Padres	24
Coolwater 1A 230/115 kV Bank Project	SCE	North of Lugo	47
Control 115 kV Shunt Reactor	SCE	North of Lugo	4
Serrano 4AA 500/230 kV Transformer Bank Addition	SCE	Main	120
Sylmar Transformer Replacement	SCE	Main	23
Antelope-Whirlwind 500 kV Line Upgrade Project	SCE	Main	6
Miguel-Sycamore Canyon 230 kV line Loop-in to Suncrest Projec	SDG&E	SDG&E	375
		Total	**1,764.5**

8 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 Projects

- To meet the renewable generation requirements established in the CPUC-developed renewable generation portfolios, an additional 22 transmission projects that are policy driven have been recommended, totaling $7.53 billion

No.	Project Name	PTO Area	Geographic Area	Cost ($M)
1	Borden-Storey 230 kV 1 and 2 Line Reconductoring	PG&E	Fresno	50
2	Henrietta 230/115 kV Bank 3 Replacement	PG&E	Fresno	20
3	Beatty 230 kV	VEA/GLW	East of Pisgah	155
4	Trout Canyon-Lugo 500 kV Line	GLW/SCE	East of Pisgah	2,000
5	Lugo–Victor–Kramer 230 kV Upgrade	SCE	North of Lugo	482
6	Colorado River-Red Bluff 500 kV 1 Line Upgrade	SCE	SCE Eastern	50
7	Devers-Red Bluff 500 kV 1 and 2 Line Upgrade	SCE	SCE Eastern	140
8	Devers-Valley 500 kV 1 Line Upgrade	SCE	SCE Eastern	40
9	Serrano-Alberhill-Valley 500 kV 1 Line Upgrade	SCE	SCE Eastern	60
10	San Bernardino-Etiwanda 230 kV 1 Line Upgrade	SCE	SCe Eastern	65
11	San Bernardino-Vista 230 kV 1 Line Upgrade	SCE	SCE Eastern	18
12	Vista-Etiwanda 230 kV 1 Line Upgrade	SCE	SCE Eastern	13
13	Mira Loma-Mesa 500 kV Underground Third Cable	SCE	SCE Metro	35
14	Imperial Valley–North of SONGS 500 kV Line and Substation	SDG&E	SDG&E	2,288
15	North of SONGS–Serrano 500 kV line	SDG&E / SCE	SDG&E and SCE Metro	503
16	Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement	SCE	SCE Metro	1,125
17	North Gila–Imperial Valley 500 kV line	SDG&E	SDG&E (Potential Joint Project with IID)	340
18	Upgrade series capacitors on HW-NG and HA-NG to 2739 MVA	APS	APS	27
19	Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento	SDG&E	SDG&E	21
20	Reconductor TL680C San Marcos-Melrose Tap	SDG&E	SDG&E	28
21	3 ohm series reactor on Sycamore-Penasquitos 230 kV line	SDG&E	SDG&E	8
22	Upgrade TL13820 Sycamore-Chicarita 138 kV	SDG&E	SDG&E	60
			Total	**7,528**

Economic-Driven (Market Efficiency) 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 market efficiency considerations are being recommended in this 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, 2023:
  - Trout Canyon-Lugo 500 kV line;
  - Imperial Valley–North of SONGS 500 kV Line and Substation;
  - North of SONGS–Serrano 500 kV line; and
  - North Gila–Imperial Valley 500 kV line.

North Coast Offshore Wind

- Based on the sensitivity portfolio provided by the CPUC, the ISO studied the need for transmission capacity from the North Coast for offshore wind.
- As the study was only informational and set the stage for future planning, no projects were recommended for approval in this 2022-2023 Plan.
- Given the growing volumes already identified in the North Coast in the renewable generation portfolios provided for the 2023-2024 planning cycle, the ISO expects to make a decision on North Coast transmission in next year's transmission plan.

The ISO continues to assess the SWIP-North project

- Accessing Idaho wind identified in CPUC portfolios
  - 1,000 MW from Idaho in the 2022-2023 sensitivity portfolio and 2023-2024 base portfolio
- SWIP-North is a near-shovel ready project enabling transmission between Idaho and California
  - The CAISO is interested primarily in north-to-south transfer capability
- Interest from Idaho Power on a joint project with CAISO
  - Idaho Power currently analyzing SWIP-North in its 2023 IRP process
  - South-North direction, may not need 1,000 MW
- Development of a recommendation for SWIP-North as a potential regional policy-driven project will be as an extension to the 2022-2023 TPP

Consideration of state policy direction in SB 887

- CPUC to provide by March 31, 2024, resource projections expected to reduce the need to rely on non-preferred resources in local capacity areas by 2035
  - these projections are not yet reflected in the CPUC portfolios
- The ISO has identified 12 reliability-driven and policy-driven projects recommended for approval that also reduce gas-fired generation local capacity requirements
- The Pacific Transmission Expansion Project, a multi-terminal HVDC project from Diablo Canyon 500 kV substation to multiple 230 kV substations in the LA Basin area was reviewed in this planning cycle. The ISO will continue to explore opportunities, both leading up to presenting this Plan to the ISO Board of Governors for approval, and after the Plan has been approved.

FERC Order 1000 Interregional Coordination Process

- Seven potential projects were submitted into the ISO's 2023 interregional transmission project (ITP) submission window in the first quarter of 2022
- Only the North Gila – Imperial Valley No. 2 project met the requirements of an interregional transmission project in the submission validation process and received further detailed review by WestConnect and the ISO.
- Although WestConnect's subsequent review did not find a need for the project, it was determined to be necessary by the ISO and is recommended for approval as a regional ISO project

Comments

- Comments due by end of day April 25, 2023
- Submit comments through the ISO’s commenting tool, using the template provided on the process webpage:
- https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2022-2023-Transmission-planning-process

Reliability Assessment Recommendations – PG&E Area
Draft 2022-2023 Transmission Plan

Preethi Rondla
Regional Transmission - North

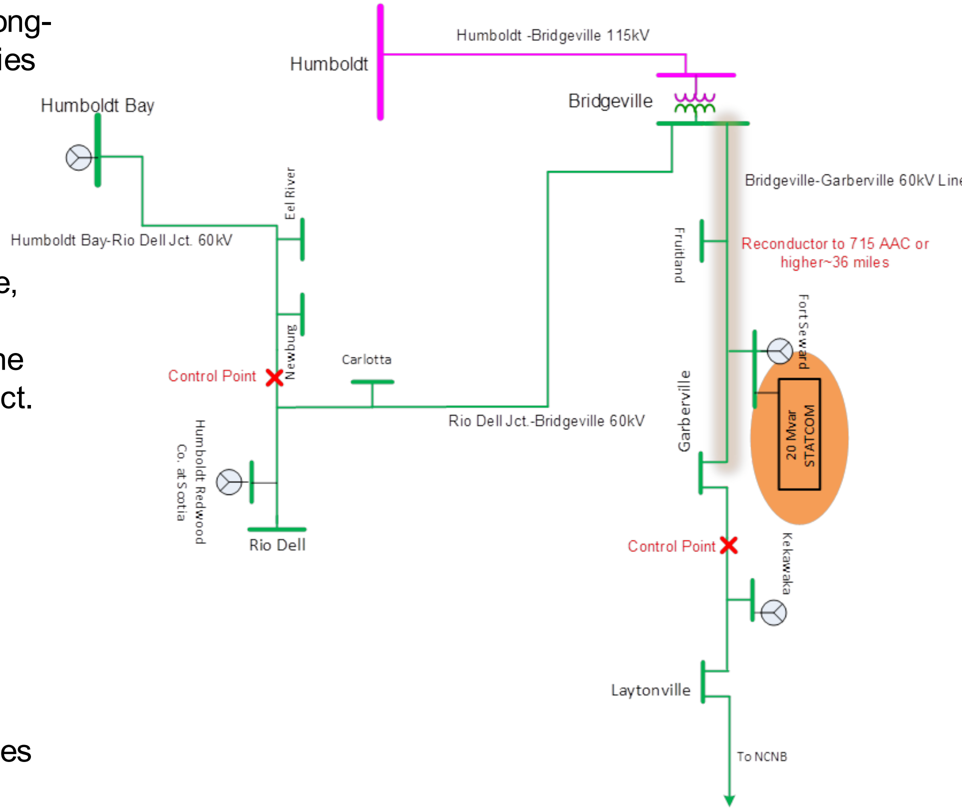
2022-2023 Transmission Planning Process Stakeholder Meeting
April 11, 2023

New Reliability Projects Recommended for Approval in 2022-2023 TPP - PG&E Area

Projects	Planning Area	Status
Banta 60 kV Bus Voltage Conversion	Central Valley	Management Approved in December
Metcalf 230/115 kV Transformer Circuit Breaker Addition	Greater Bay Area	Management Approved in December
South Bay Area Limiting Elements Upgrade	Greater Bay Area	Management Approved in December
Bellota-Warnerville 230kV reconductor	Greater Fresno Area	Management Approved in December
Garberville Area Reinforcement Project	Humboldt	Recommended for Approval
Tulucay-Napa #2 60 kV line Reconductoring Project	North Coast North Bay	Recommended for Approval
Santa Rosa 115 kV line Reconductoring Project	North Coast North Bay	Recommended for Approval
Tesla 115 kV Bus Reconfiguration Project	Central Valley	Recommended for Approval
Redwood City Area 115 kV System Reinforcement	Greater Bay Area	Recommended for Approval
LoneTree-Cayetano-Newark Corridor Series Compensation	Greater Bay Area	Recommended for Approval
Pittsburg 115kV Bus Reactor project	Greater Bay Area	Recommended for Approval
Los Banos 70 kV Area Reinforcement Project	Greater Fresno Area	Recommended for Approval
Los Banos 230 kV Circuit Breaker Replacement	Greater Fresno Area	Recommended for Approval
Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade project	Greater Fresno Area	Recommended for Approval
North East Kern 115 kV Line Reconductoring Project	Kern	Recommended for Approval
Wheeler Ridge Junction Project	Kern	Recommended to release from Hold
Mesa 230/115kV spare transformer	Central Coast Los Padres	Recommended for Approval

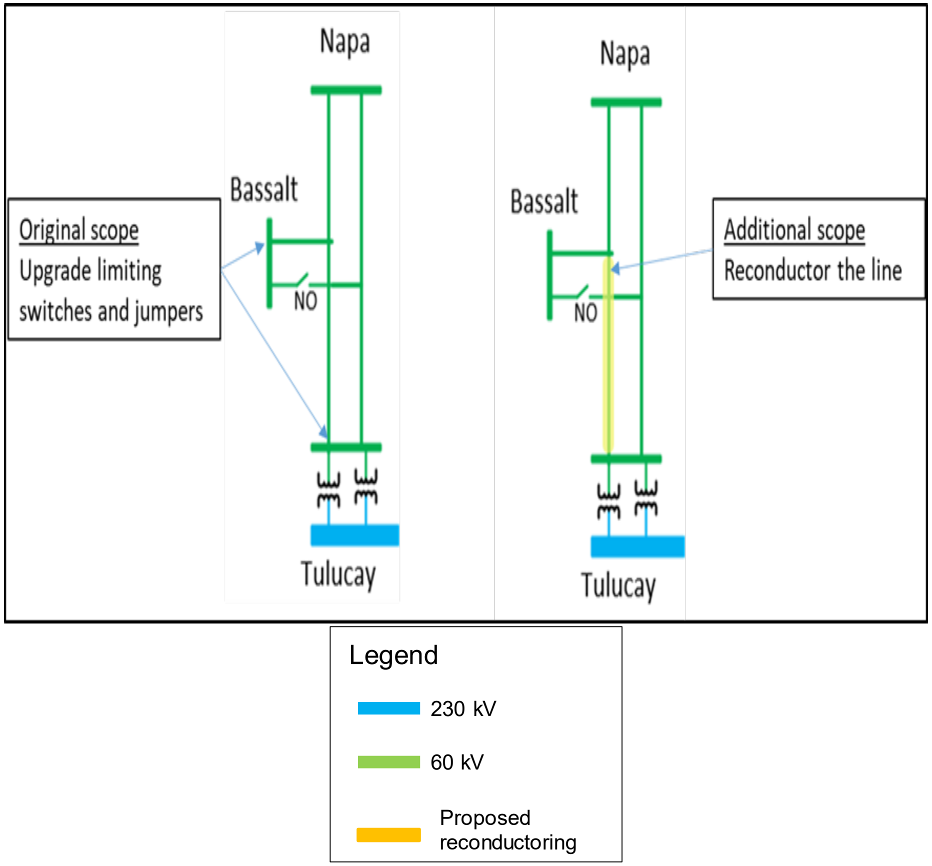
Garberville Area Reinforcement

- Reliability Assessment Need
  - The near-term issues driven by P2, P6 and P7 category contingencies and multiple the mid and long-term issues driven by various category contingencies including P1.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductor the Bridgeville – Garberville 60kV line, install a 20MVAR statcom at Fort Seward 60kV substation, and install two control points to open the Garberville – Kekawaka and Newburg – Rio Dell Jct. – Carlotta 60kV line sections.
- Estimated Project Cost
  - $102M - $204M
- Estimated In-service Date
  - 2032
- Alternatives Considered
  - Additional Control Points: This alternative is not recommended as it does not fully mitigate the issues in the Garberville area.
- Recommendation
  - Approval



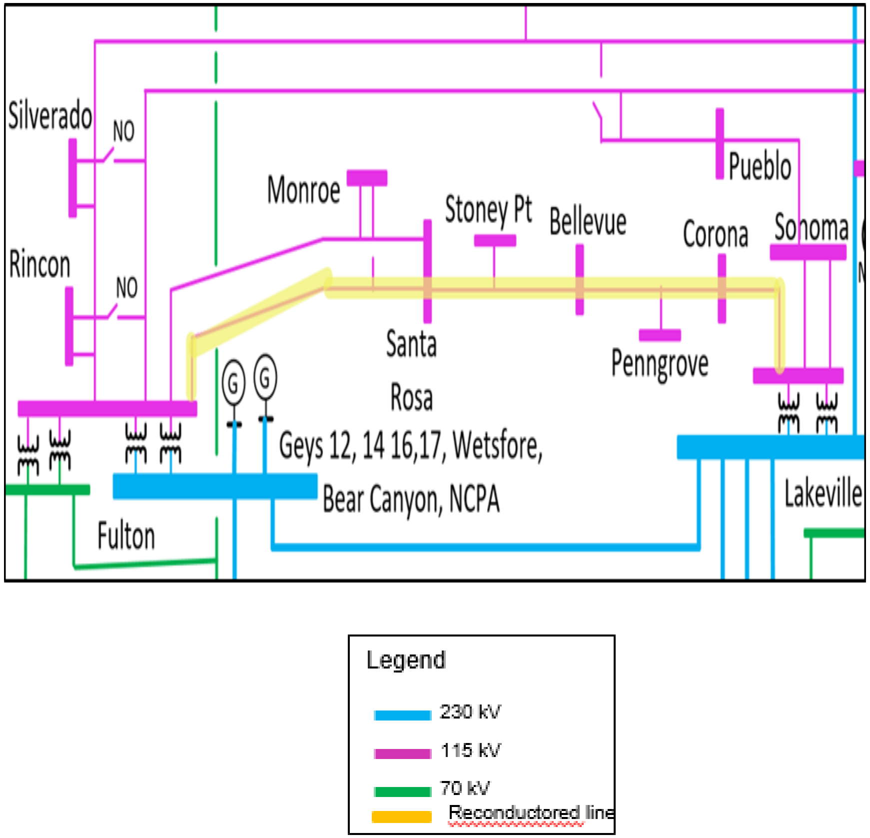
Tulucay-Napa #2 60 kV line Reconductoring Project

- Reliability Assessment Need
  - The near-term issues driven by P1 and P3 category contingencies and multiple the mid and long-term issues driven by various category contingencies including P1.
- Project Submitter
  - CAISO
- Project Scope
  - To re-scope the previously approved project to include Reconductor the Tulucay-Napa #2 60 kV line from Tulucay to Basalt.
- Estimated Project Cost
  - $2.3M - $4.6M
- Estimated In-service Date
  - 2028
- Alternatives Considered
  - Previously approved project : This alternative is not recommended as overload is observed by 2032.
- Recommendation
  - Approval



Santa Rosa 115 kV line Reconductoring Project

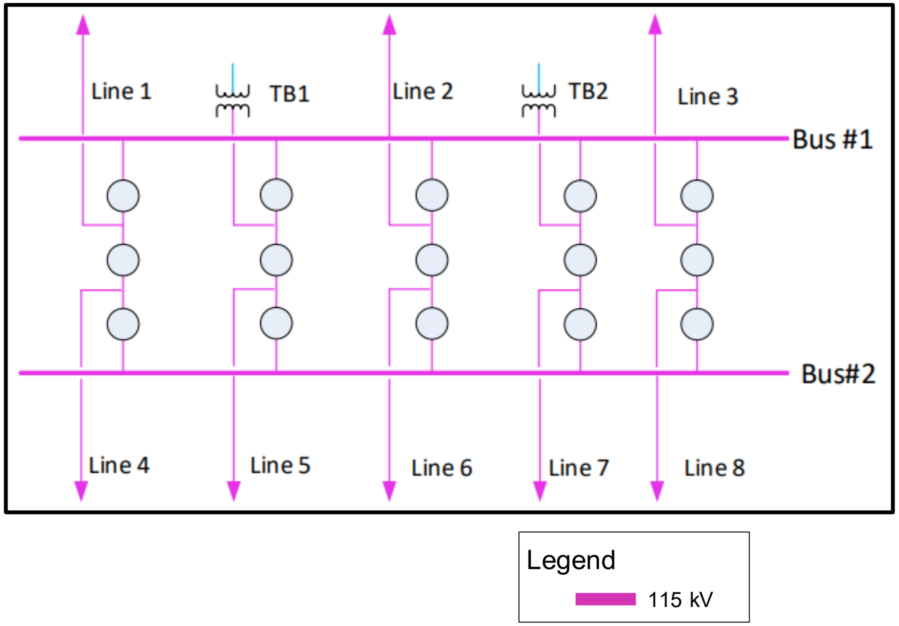
- Reliability Assessment Need
  - The near-term issues driven by P2, P6 and P7 category contingencies and multiple the mid and long-term issues driven by various category contingencies.
- Project Submitter
  - CAISO
- Project Scope
  - To reconductor the Fulton-Santa Rosa #1 and #2 115 kV lines; the Santa Rosa-Corona 115 kV line; and, the Corona-Lakeville 115 kV lines.
- Estimated Project Cost
  - $37M - $74M
- Estimated In-service Date
  - 2028
- Alternatives Considered
  - RAS: This alternative is not feasible as the number of required elements (both contingency and overloaded facilities) to be monitored will exceed the maximum per the ISO Planning Standard
- Recommendation
  - Approval



Tesla 115 kV Bus Reconfiguration Project

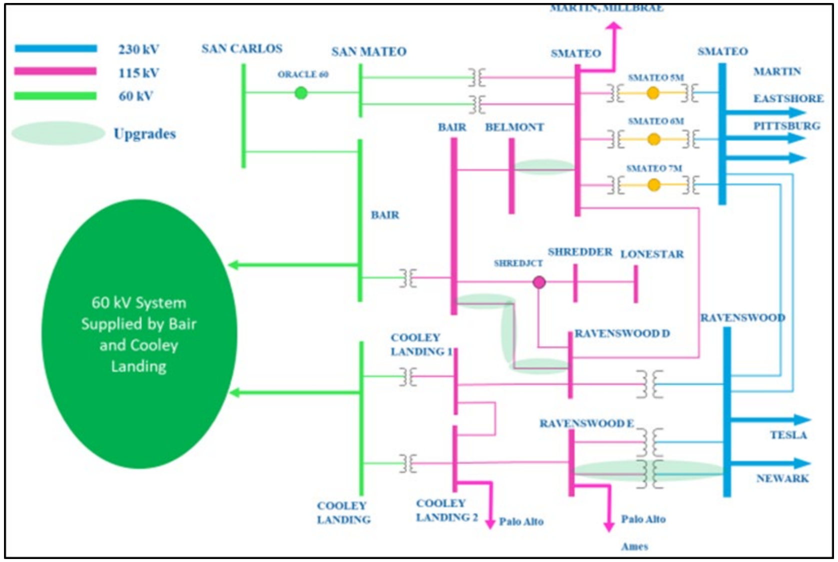
- Reliability Assessment Need
  - The near and long term issues driven by P2-4 category contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Convert the current Tesla 115 kV DBSB configuration to BAAH configuration
- Estimated Project Cost
  - $27.5M - $55M (AACE Level 5)
- Estimated In-service Date
  - May 2030
- Alternatives Considered
  - Alternative 1: Tesla 115 kV bus sectionalization. This alternative is not recommended due to space limitation.
  - Alternative 2: Install a Remedial Action Scheme (RAS). This alternative is not recommended due to the complexity of the RAS design, high requirement on the RAS reaction time, and requiring large amount of load to be dropped.
- Recommendation
  - Approval

Tesla 115 kV Post Project Configuration



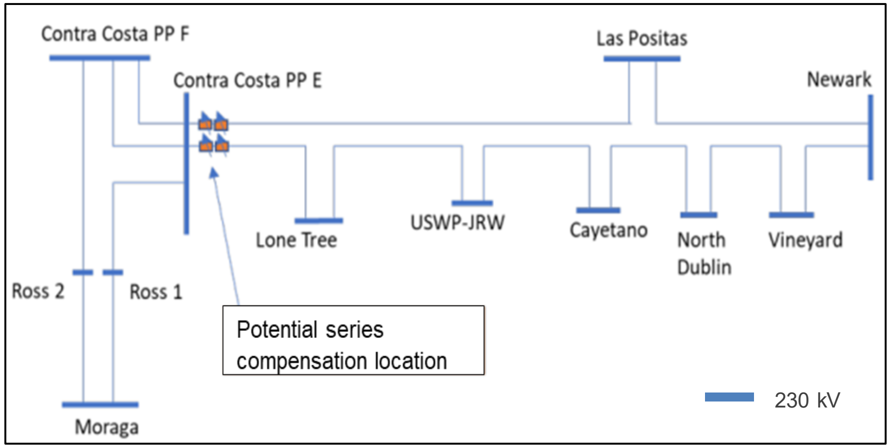
Redwood City Area 115 kV System Reinforcement

- Reliability Assessment Need
  - Identified contingencies (P6 and P7) which resulted in overloads on multiple 115 kV and 60 kV lines in Peninsula area in both the near-term and longer-term planning horizon. In addition, in the longer-term planning horizon only there were contingencies (P1, P3 and P6) which resulted in overloads on the Ravenswood 230/115 kV banks.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductoring the San Mateo-Belmont and Ravenswood-Bair 115 kV lines.
  - Adding a new 230/115 kV transformer at the Ravenswood substation.
- Estimated Project Cost
  - $55.4M - $110.8M
- Estimated In-service Date
  - 2030
- Alternatives Considered
  - Alt. 1 Reconductoring overloaded lines. This alternative is not recommended because in the long term a new transformer bank is needed.
  - Alt. 2 and 3 consider a new line and a 230/115 kV transformer bank at Ravenswood. This alternative is not recommended due to high cost and potential difficulties for constructing the new transmission line.
- Recommendation
  - Approval



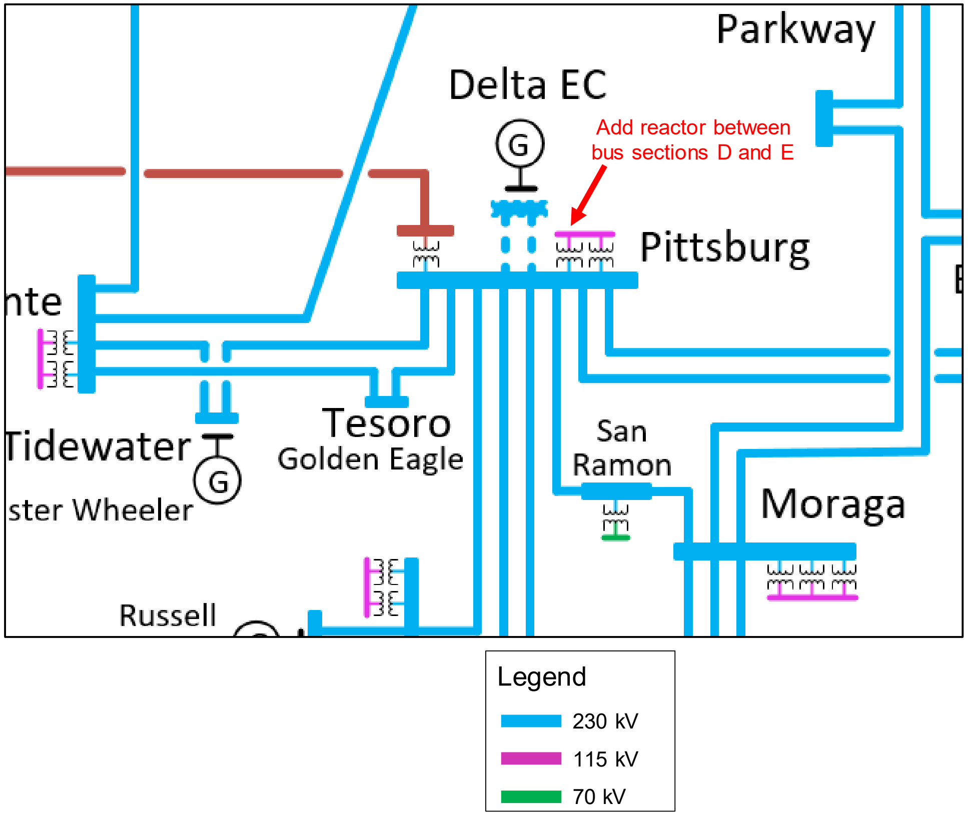
Lone Tree – Cayetano – Newark Corridor Series Compensation

- Reliability Assessment Need
  - Identified contingencies (P2, P3, P6 and P7) which resulted in overloads were on the Contra Costa-Newark corridor 230 kV lines in both the near-term and longer-term planning horizons.
- Project Submitter
  - Smart Wires
- Project Scope
  - Installing 6 to 8 ohm series compensation (reactance) devices on the Cayetano-Lone Tree and Las Positas-Newark 230 kV lines. The series compensation would only require to be switched in under system conditions that could potentially overload the Cayetano-Lone Tree and Las Positas-Newark 230 kV lines.
- Estimated Project Cost
  - \$15M - \$25M
- Estimated In-service Date
  - 2027
- Alternatives Considered
  - Reconductoring the Contra Costa-Newark 230 kV path. This alternative is not recommended due to the higher cost.
- Recommendation
  - Approval



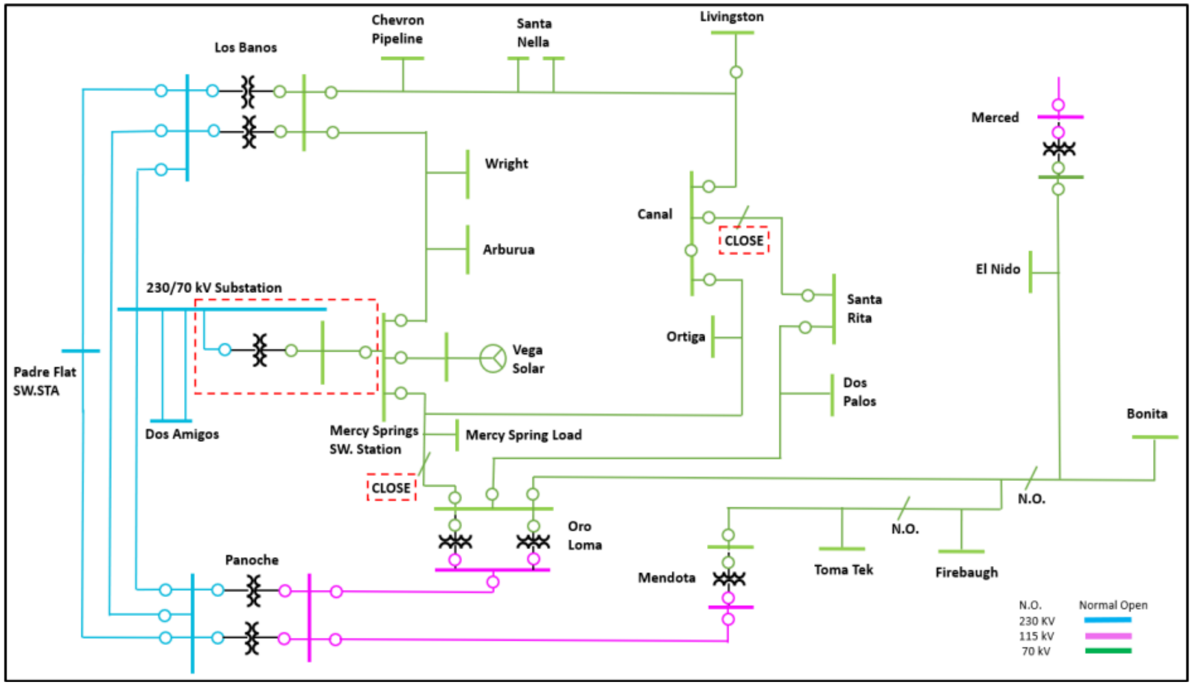
Pittsburg 115 kV Bus Reactor Project

- Reliability Assessment Need
  - Circuit Breaker overstressed in the 2032 scenario, caused by new Collinsville substation and contribution by portfolio resources.
- Project Submitter
  - CAISO
- Project Scope
  - Add 18-ohm reactors in parallel between Bus D and E of the Pittsburg 115kV substation;
  - One spare reactor unit; and
  - Associated switches and bus work.
- Estimated Project Cost
  - $13M - $26M
- Estimated In-service Date
  - Concurrently with the implementation of the new Collinsville substation
- Alternatives Considered
  - None
- Recommendation
  - Approval as an addition to the previously approved Collinsville 500/230 kV substation policy project



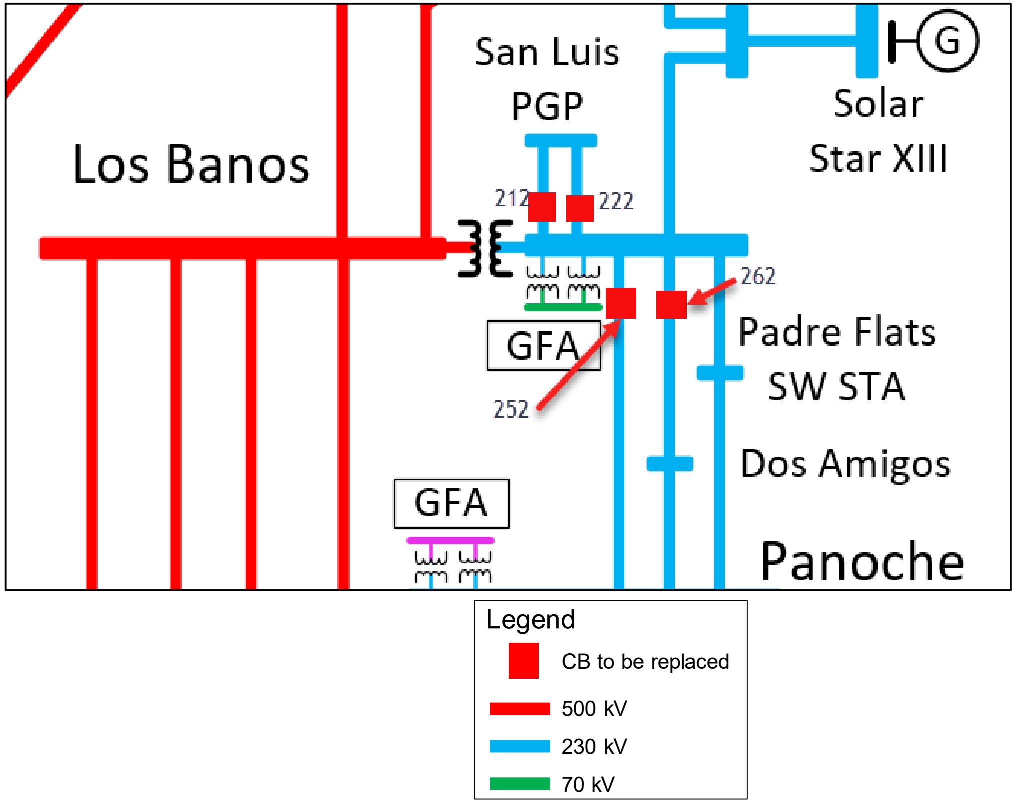
Los Banos 70 kV Area Reinforcement Project

- Reliability Assessment Need
  - The near and long term issues driven by P1, P2 and P6 category contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - To add new source to Los banos 70 kV area. This is by adding a new 230/70 kV bank connecting a generation driven substation next to Dos Amigos to Mercy Springs switching station.
- Estimated Project Cost
  - $30M - $60M
- Estimated In-service Date
  - 2029
- Alternatives Considered
  - Energy storage charging capability is limited by current equipment capacity.
  - Reconductoring and new bank: This alternative is not recommended due to higher cost.
- Recommendation
  - Approval



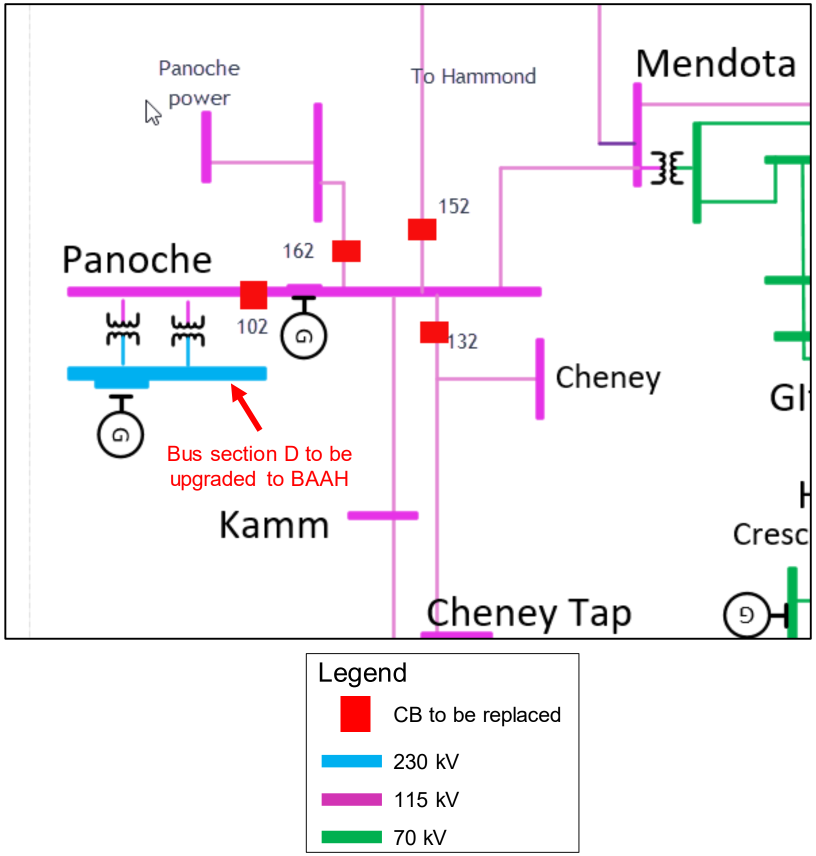
Los Banos 230 kV Circuit Breaker Replacement

- Reliability Assessment Need
  - Circuit Breaker overstressed in the 2032 scenario, caused by portfolio resources.
- Project Submitter
  - CAISO
- Project Scope
  - Breaker 212, 222: Replace in place with new SMP Relays. May replace foundations/structures as needed.
  - Breaker 252, 262: Replace with two new breaker-and-a-half bays in the new breaker-and-a-half bus section to meet the ultimate plan. T-Line relocations into new breaker-and-a-half positions.
- Estimated Project Cost
  - $33M - $66M
- Estimated In-service Date
  - 2032
- Alternatives Considered
  - None.
- Recommendation
  - Approval



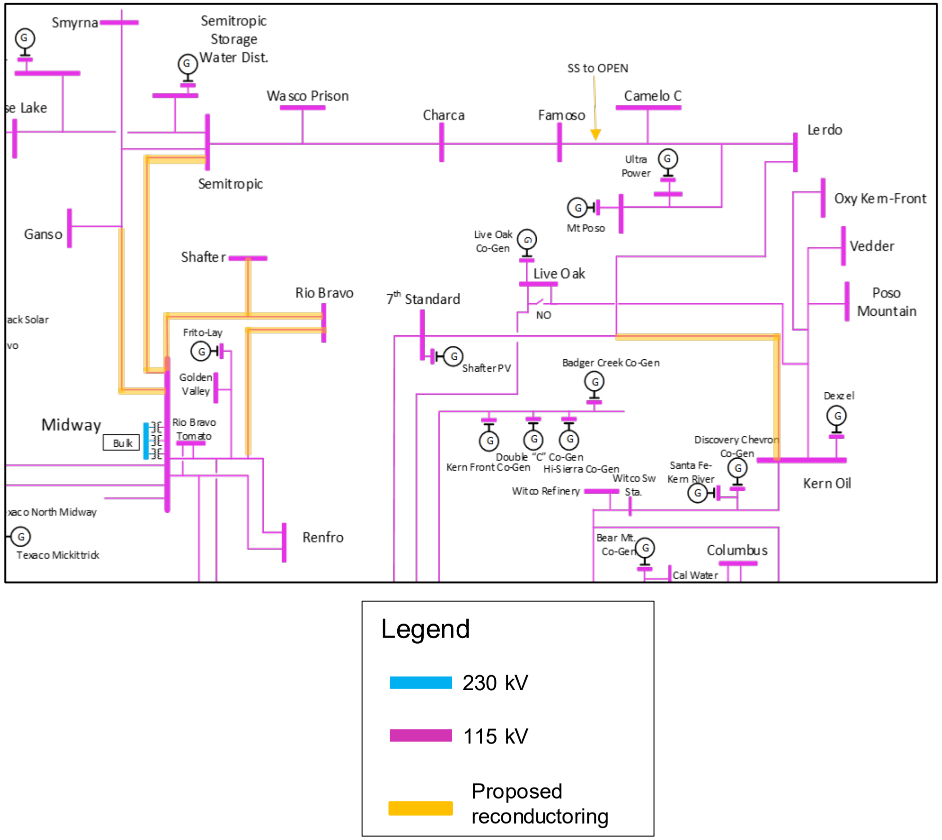
Panoche 115 kV Circuit Breaker Replacement and 230 kV Bus Upgrade Project

- Reliability Assessment Need
  - Circuit Breaker overstressed in the 2032 scenario, caused by new Manning substation and contribution by portfolio resources.
- Project Submitter
  - CAISO
- Project Scope
  - Replace the 115 kV circuit breakers 132, 152, 102 and 162;
  - Install a new MPAC building for the 115 kV bus section;
  - Convert 230 kV Bus Section D to breaker-and-a-half and replace overstressed breakers in Bus E to 63 kA at Panoche substation.
- Estimated Project Cost
  - $22M - $44M for 115 kV CB replacements
  - $70M - $140M for 230 kV bus upgrade
- Estimated In-service Date
  - Concurrently with the implementation of the new Manning substation
- Alternatives Considered
  - None
- Recommendation
  - Approval as an addition to the previously approved Manning 500/230 kV substation policy project



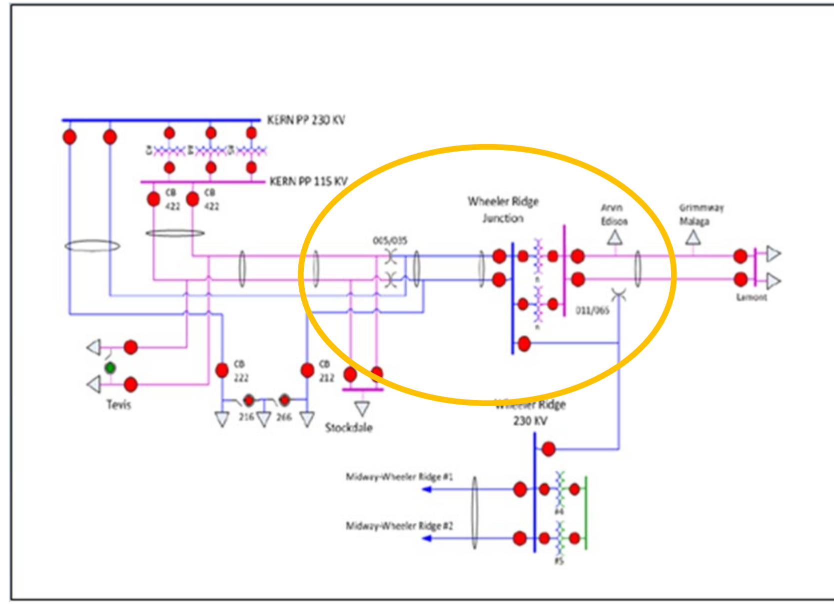
North East Kern 115 kV Line Reconductoring Project

- Reliability Assessment Need
  - The near and long term issues driven by P1 through P7 category contingencies.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductoring several of the lines in the North Eastern Kern 115 kV pocket surrounding Midway 115 kV.
- Estimated Project Cost
  - $128M - $256M (AACE Level 5)
- Estimated In-service Date
  - 2032
- Alternatives Considered
  - Alternative 1: Adding BESS in the Shafter 115 kV pocket. This alternative was not selected for recommendation because it would not address all the issues identified and there would be a significant cost with upgrading stations in the pocket for interconnection as well as concerns with deliverability of the battery.
  - Alternative 2: Connecting Rio Bravo 115 kV to 7TH Standard 115 kV substation by using a portion of an idle line (Rio Bravo to Kern Oil 115 kV) and any necessary substation upgrades required in Rio Bravo and 7TH Standard 115 kV substations; Build new switching station at Shafter 115 kV junction. This alternative was not selected for recommendation because it does not fully address all the issues identified.
- Recommendation
  - Approval



Wheeler Ridge Junction Project

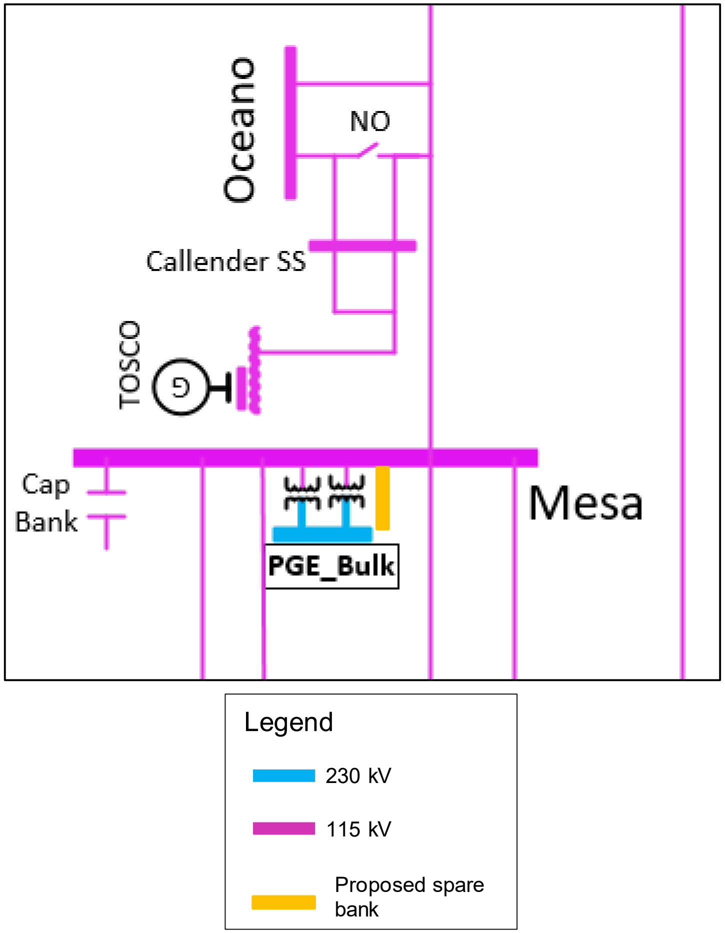
- Reliability Assessment Need
  - The near and long term issues driven by P1, P2 and P7 category contingencies.
- Project Submitter
  - CAISO
- Project Scope
  - Previously approved project to build a new 230/115 kV transmission substation at Wheeler Ridge Junction (WRJ) with out the scope to reconductor the line to Magunden Substation.
- Estimated Project Cost
  - $259M - $517M
- Estimated In-service Date
  - 2033
- Alternatives Considered
  - Several Alternatives were considered including 3 additional 230 kV options and 3 500 kV options. These options were not recommended due to feasibility concerns, cost, or concerns with both feasibility and cost.
- Recommendation
  - Release of hold



Legend
- Reconfigured area
- 230 kV
- 115 kV
- 70 kV

Mesa 230/115 kV Spare Transformer

- Reliability Assessment Need
  - Change in the Point of Interconnection (POI) of the battery storage from the 115 kV to the 230 kV at the Mesa substation.
- Project Submitter
  - CAISO
- Project Scope
  - Install a spare 230/115 kV transformer at Mesa substation.
- Estimated Project Cost
  - $12M - $24M
- Estimated In-service Date
  - 2026
- Alternatives Considered
  - Mesa 115 kV BESS POI: The original POI is not recommended due to the complications associated with the 115 kV interconnection, which will result in high interconnection cost and commercial interest.
- Recommendation
  - Approval



Reliability Assessment Recommendations – SCE Area
Draft 2022-2023 Transmission Plan

Meng Zhang and Frank Chen
Regional Transmission – South

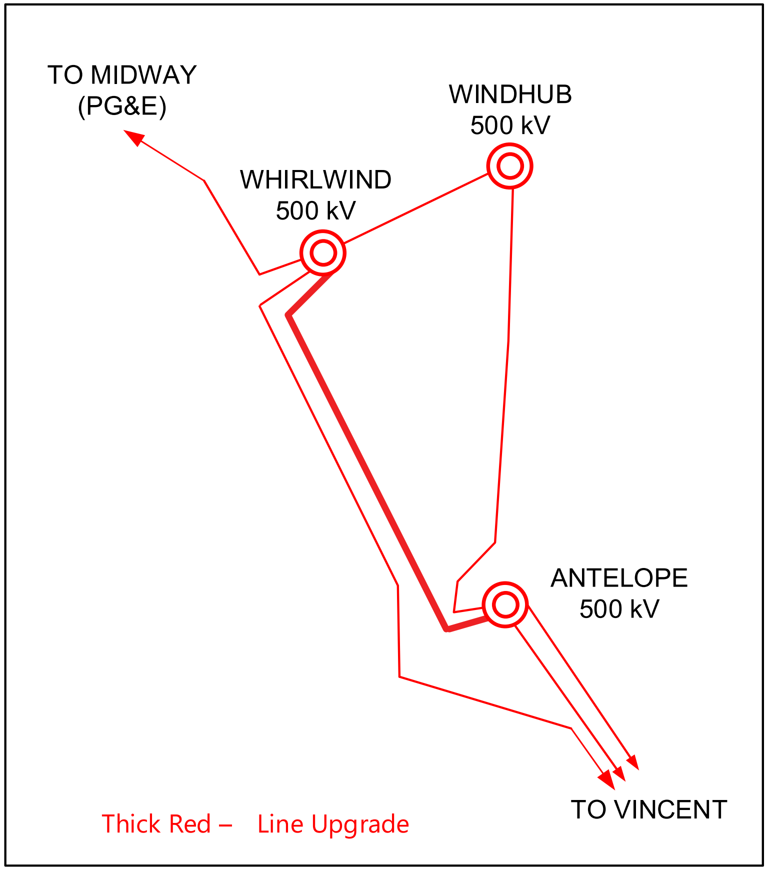
2022-2023 Transmission Planning Process Stakeholder Meeting
April 11, 2023

New Reliability Projects Recommended for Approval in 2022-2023 TPP - SCE Area

Projects	Planning Area	Status
Barre 230 kV Switchrack Conversion to BAAH Project	Main	Management Approved in December
Mira Loma 500 kV CB Upgrade Project	Main	Management Approved in December
Antelope – Whirlwind 500 kV Line Upgrade Project	Main	Recommended for Approval
Serrano 4AA 500/230 kV Transformer Bank Addition	Main	Recommended for Approval
Sylmar Transformer Replacement Project	Main	Recommended for Approval
New Coolwater 1A 230/115 kV Transformer Project	North of Lugo Area	Recommended for Approval
New Control 115 kV Shunt Reactor Project	North of Lugo Area	Recommended for Approval

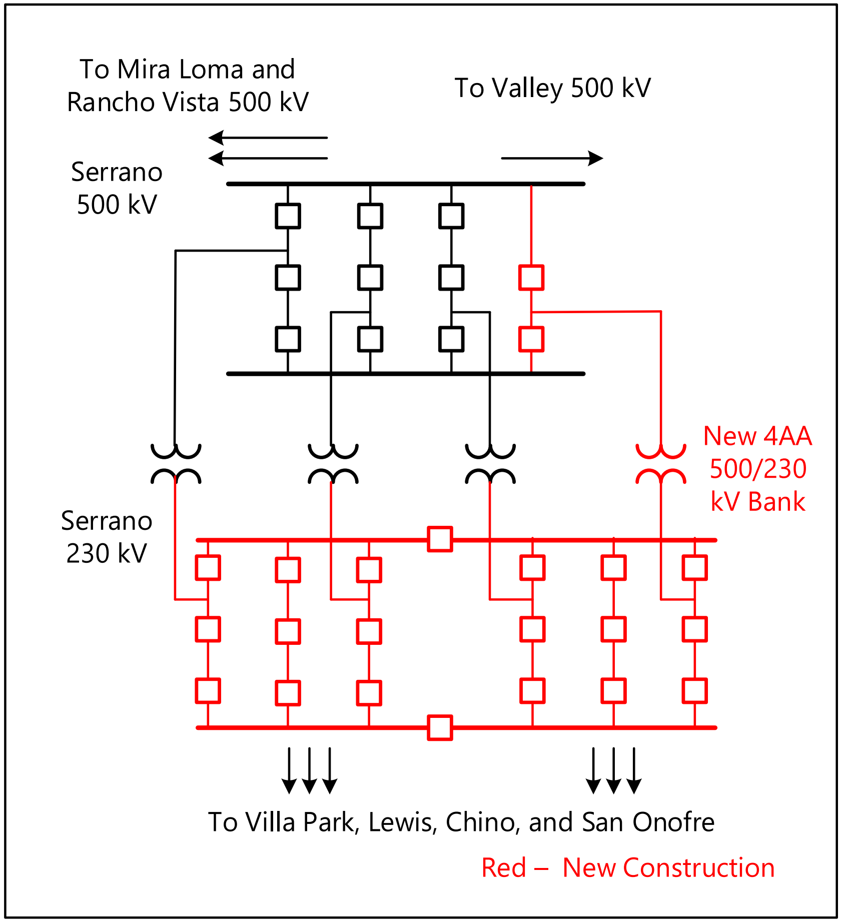
Antelope – Whirlwind 500 kV Line Upgrade

- Reliability Assessment Need
  - Antelope-Whirlwind 500 kV line overloaded for multiple Category P2, P4, and P5 contingencies
- Project Submitter
  - SCE
- Project Scope
  - Uprate Antelope – Whirlwind 500 kV line by increasing the ground clearance for nine (9) towers
- Estimated Project Cost
  - $4M ~ $6M
- Estimated In-service Date
  - 2024
- Alternatives Considered
  - None
- Recommendation
  - Approval



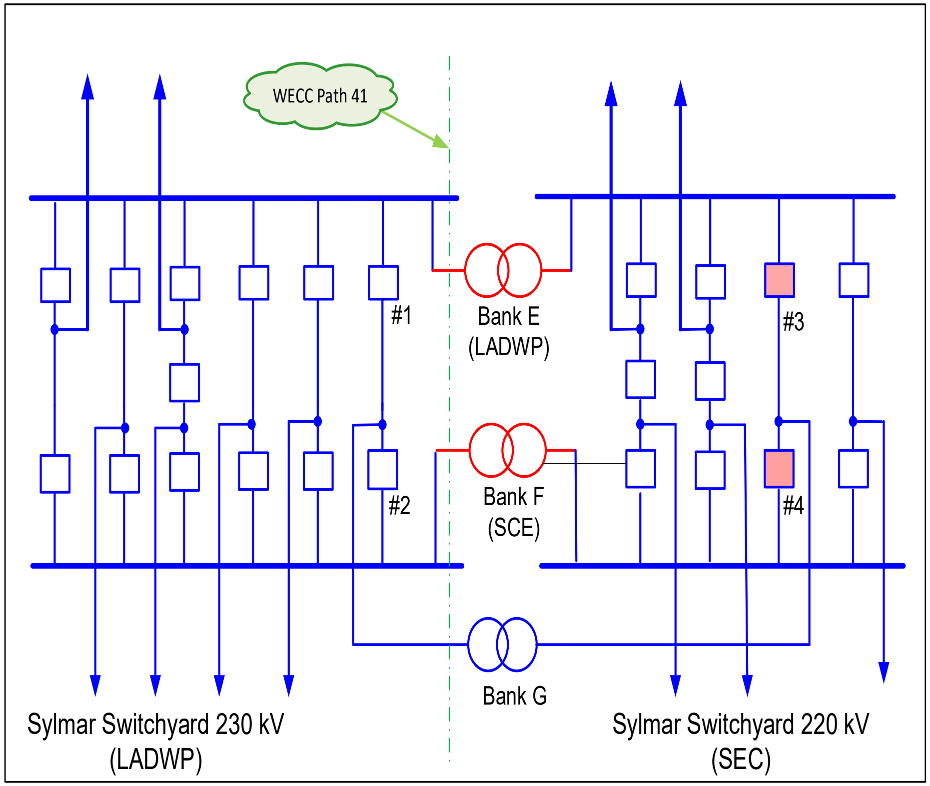
Serrano 4AA 500/230 kV Transformer Bank Addition

- Reliability Assessment Need
  - Serrano banks Category P6 overload in high density urban load area
- Project Submitter
  - SCE
- Project Scope
  - install a new 4th 500/230 kV 1120/1344 MVA transformer bank at Serrano Substation
  - rebuild Serrano 230 kV switchrack to 80 kA capability
- Estimated Project Cost
  - $120M
- Estimated In-service Date
  - December 2027
- Alternatives Considered
  - Rely on available resources including energy storage and DR along with existing OP in Western LA Basin. This alternative is not recommended as the 4-hour duration storage resources are not adequate to mitigate the overload during the peak hours
- Recommendation
  - Approval



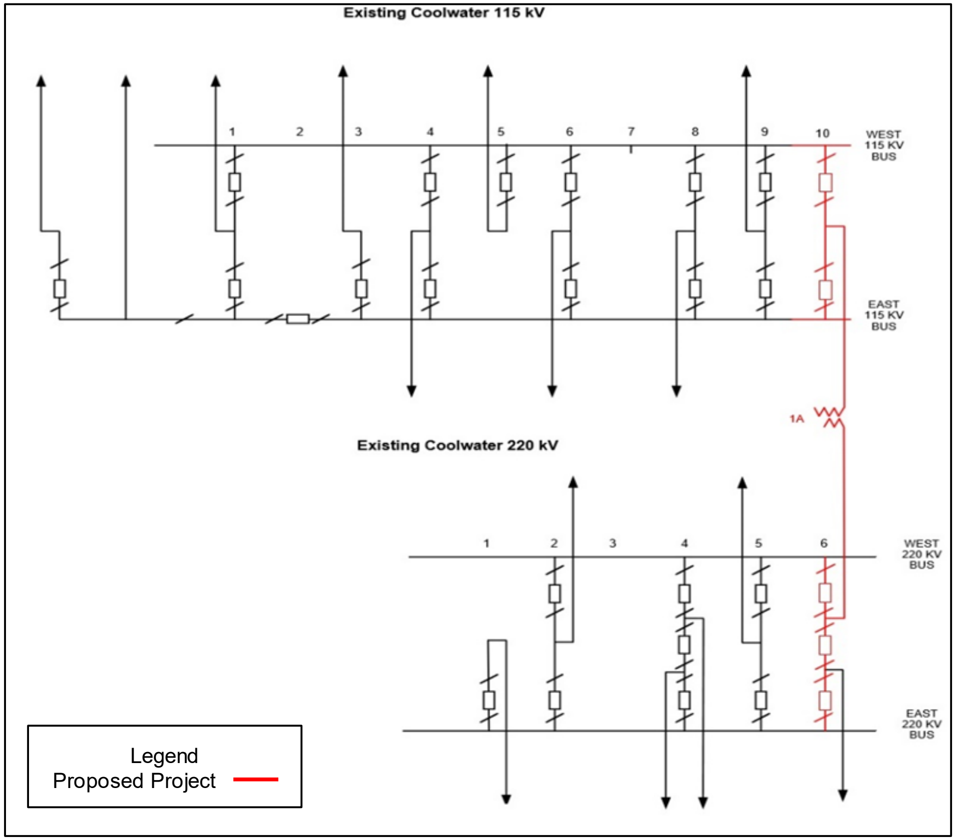
Sylmar Transformer Replacement Project

- Reliability Assessment Need
  - LAWDP and SCE jointly-owned Sylmar banks E and F overloaded for Category P2 and P4 events
- Project Submitter
  - SCE
- Project Scope
  - Replace the SCE-owned Bank F with increased capacity
  - Not include LADWP-owned Bank E replacement that will be completed by LADWP by June 2025
- Estimated Project Cost
  - $23M
- Estimated In-service Date
  - June 2026
- Alternatives Considered
  - Reconfigure the switchyard by adding one-and-half breaker scheme. This alternative was eliminated due to space limitation
- Recommendation
  - Approval



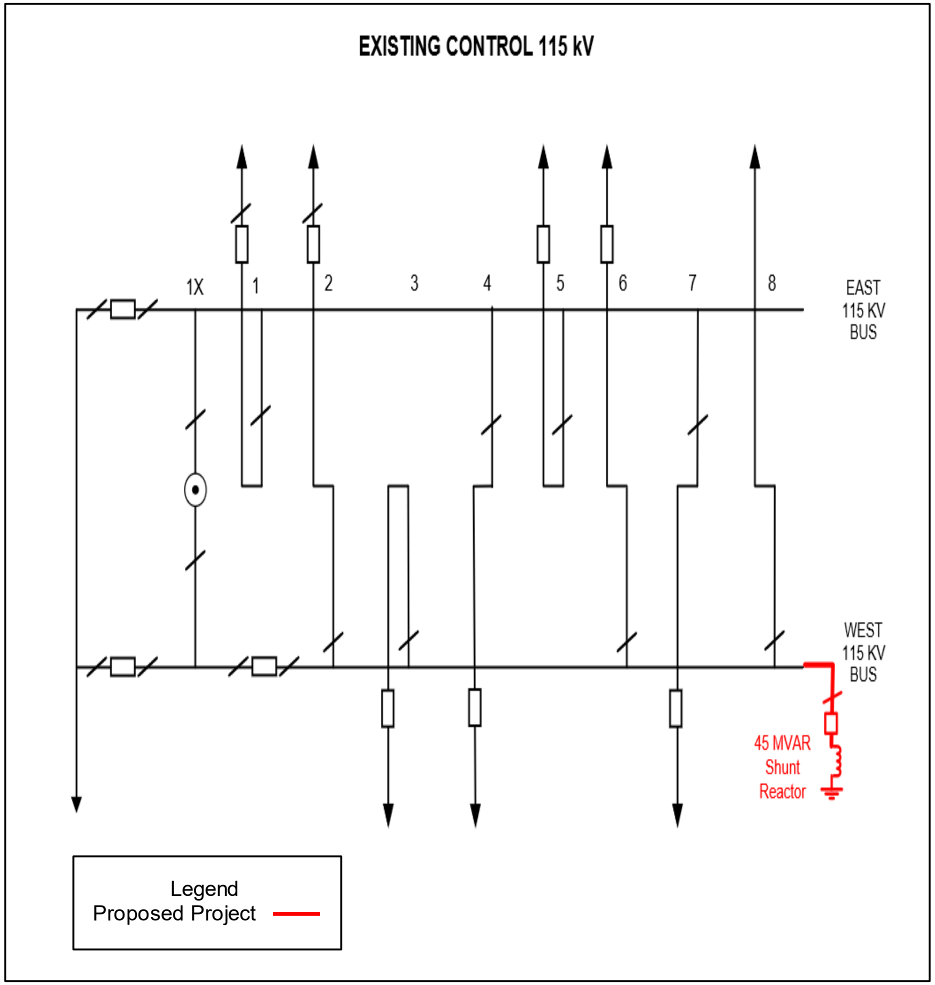
New Coolwater 1A 230/115 kV Transformer Project

- Reliability Assessment Need
  - NERC Category P6 voltage collapse starting 2024.
  - Allow retirement of the existing operating procedure which radializes the system for a forced or scheduled outage in advance as system adjustment for a P6 contingency.
  - Allow reliability interconnection of a high speed rail project
- Project Submitter
  - SCE
- Project Scope
  - Install one new 230/115kV transformer at Coolwater substation and associated bus extension, equipment and structures work
  - Electrically connects the existing Coolwater 230kV and 115kV switchracks.
- Estimated Project Cost
  - $47M
- Estimated In-service Date
  - 2026
- Alternatives Considered
  - Install a new 115kV line between Coolwater and Tortilla substations, about 11.26 miles. This option is not recommended as it cannot mitigate the reliability impact of the high speed rail interconnection project.
- Recommendation
  - Approval



New Control 115 kV Shunt Reactor Project

- Reliability Assessment Need
  - Real time high voltage issues at Inyo 230 kV bus
  - Actual bus voltages that are far beyond the voltage limits in the ISO Planning Standards.
- Project Submitter
  - SCE
- Project Scope
  - Install a new 45 MVAR shunt reactor at Control 115 kV substation
- Estimated Project Cost
  - $4M
- Estimated In-service Date
  - 2026
- Alternatives Considered
  - Continue to utilize the system operating bulletins SOB 80 and SOB 17. This alternative has been ineffective
- Recommendation
  - Approval



Reliability Assessment Recommendations – SDG&E Area Draft 2022-2023 Transmission Plan

Rene Romo de Santos
Regional Transmission - South

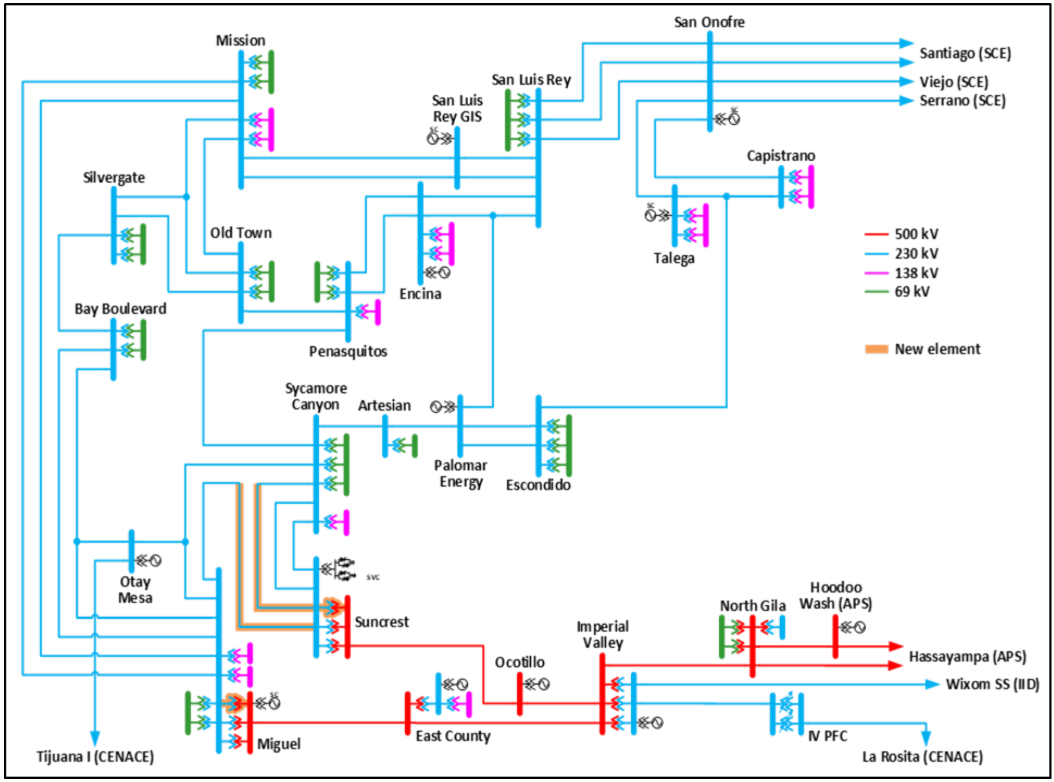
2022-2023 Transmission Planning Process Stakeholder Meeting
April 11, 2023

New Reliability Project Recommended for Approval in 2022-2023 TPP – SDG&E Area

Projects	Planning Area	Status
Miguel-Sycamore Canyon 230 kV Line Loop-in to Suncrest	SDG&E	Recommended for Approval

Miguel-Sycamore Canyon 230 kV Loop-in to Suncrest

- Reliability Assessment Need
  - P3 and P6 contingencies in the near-term and long-term planning assessments resulted in thermal overloads on the Suncrest – Sycamore Canyon 230 kV transmission lines and Suncrest and Miguel 500/230 kV banks.
- Project Submitter
  - SDG&E
- Project Scope
  - A 16-mile double circuit 230kV transmission line that will loop-in the existing TL23021 Miguel – Sycamore Canyon into Suncrest substation.
  - Install two new 500/230 kV banks at Suncrest and Miguel substations (one at each substation).
- Estimated Project Cost
  - $275M - $375M
- Estimated In-service Date
  - 2032
- Alternatives Considered
  - Status Quo: Not recommended due to the risk that the necessary operational actions could not be implemented under 30 minutes per ISO Planning Standards.
- Recommendation
  - Approval



Frequency Response Assessment and Data Requirements
Draft 2022-2023 Transmission Plan

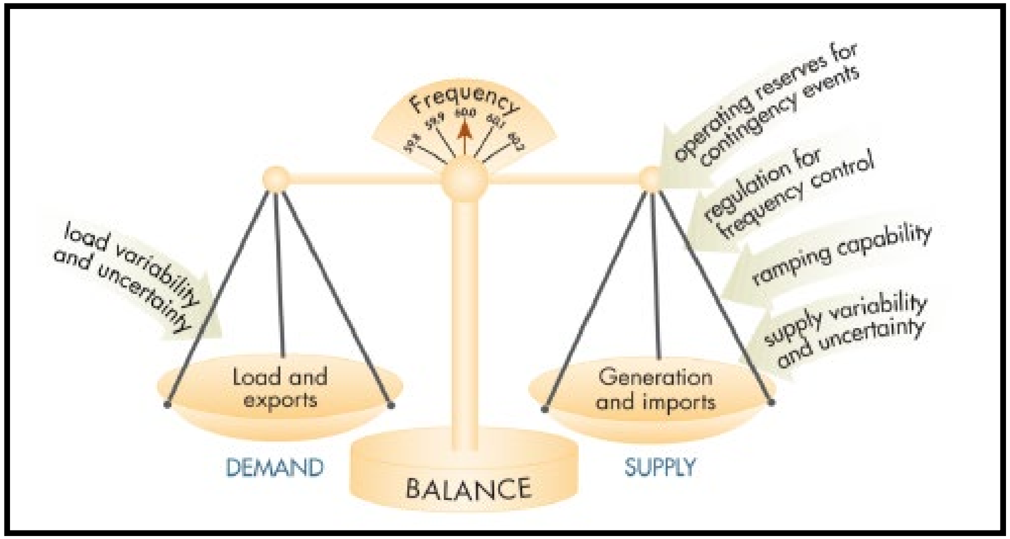
Christopher Fuchs
Regional Transmission North

2022-2023 Transmission Planning Process Stakeholder Meeting
April 11, 2023

Overview

- Basics of frequency response (will focus on under-frequency events)
- ISO frequency response study results in previous TPPs
- ISO frequency response study results 2022-2023 TPP - impact of frequency response from Inverter Based Resources (IBRs) and Battery Energy Storage Systems (BESS)
- Data collection, model improvement efforts and validation

Continuous Supply and Demand Balance



Load-Resource balance must be maintained at all time scales:

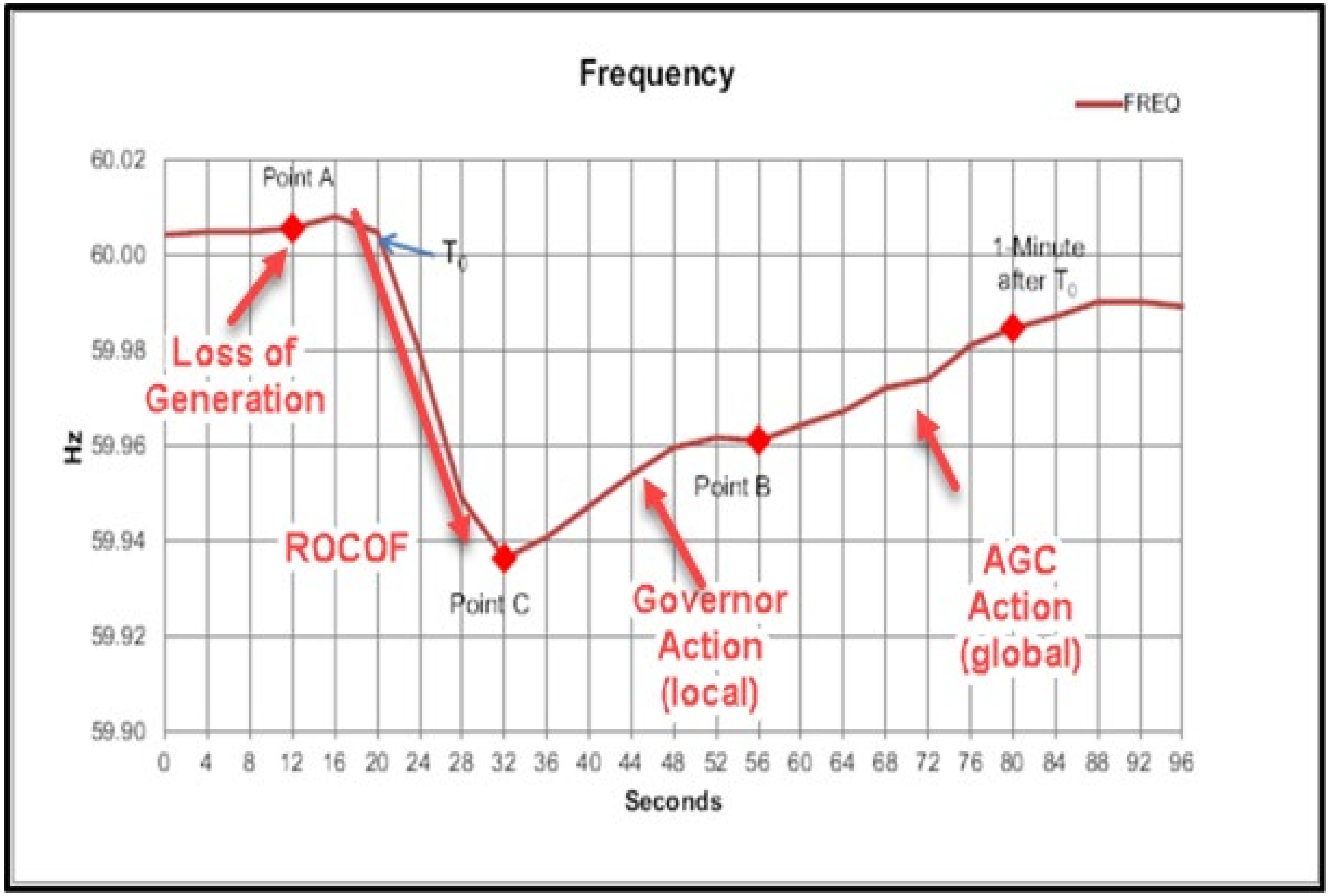
$$\sum Load = \sum Generation$$

During system disturbances/outages this balance is upset

For example on the loss of a large generator we have:

$$\sum Load > \sum Generation \Rightarrow \text{Underfrequency } (< 60 \text{ Hz})$$

Standard Frequency Event Progression



Point C – nadir
Point B – settling frequency

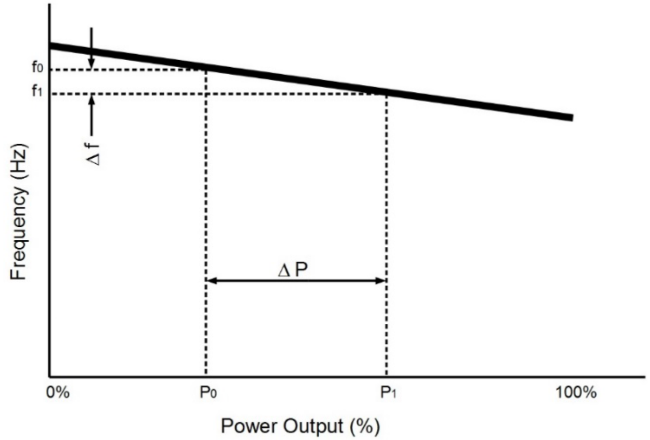
Nadir needs to be higher than the 1st set-point for Under Frequency Load Shedding (59.5 Hz)

Generator Response to Frequency Events

- Generating units play a major role in controlling system frequency through their governors
- Governors are the first 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
- The headroom of the generator and the droop and deadband of the governor determine a generator response to frequency events

Governor Droop Curve

- 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 4%-5% range



  - *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 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

Governor Frequency Deadband

- Frequency Deadband is a margin (high/low) around 60 Hz and is a means of restricting excessive and usually unrequired control action
- The minimum frequency deviation from 60 Hz before governor responds; Deadband is typically 0.036 Hz

Frequency Response Characterization

- For studies of off-nominal frequency events, it is essential to properly characterize the response of each generator
- System inertia 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)

ISO Frequency Response Study Results in Previous TPPs

- All studies assessed primary frequency response for the most severe credible contingency involving frequency disturbance: outage of two Palo Verde nuclear units
- Off-peak cases appeared to be more severe than peak cases because of lower generation dispatch and less frequency-responsive units being on-line
- Under off-peak spring conditions (weekend afternoon) there is more solar generation on-line, which historically did not participate in primary frequency response

Previous Studies – Conclusions

- The ISO system meets BAL-003-1.2 requirements under the assumptions studied
- With lower commitment of frequency-responsive units, frequency response from the ISO could go below the FRO specified by NERC
- Compared to the ISO's actual system performance during disturbances, the simulation results seemed optimistic

Frequency Response Study 2022-2023 TPP - Study Background

- NERC has number of standards related to resource and demand balancing which is becoming challenging for the ISO to meet due to the variability of wind and solar generation
- FERC Order 842 requires all new IBRs to have frequency response capability
- This study evaluated the potential impact of activating the frequency response of existing IBRs and changing droop and frequency deadband settings of new IBRs, on system frequency response

Frequency Response Study 2022-2023 TPP - Study Background (cont'd)

- With FERC Order 842, all IBRs that sign Large Generation Interconnection Agreements (LGIA) on or after 5/15/2018 will have frequency response capability
- The majority of the existing IBRs installed prior to 2018 do not provide frequency response
- With high levels of IBRs it is critical to assess the frequency response of the system in future years and identify mitigation measures if there are any issues

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 2027 & 2032 and identify any performance issues related to frequency response
- The starting base case was the Spring off-Peak case for 2027 & 2032. The cases studied had different assumptions on the generation dispatch and headroom and on frequency response provided by IBRs and battery energy storage devices
- An outage of two Palo Verde nuclear units was studied
- Dynamic stability simulations were run for up to 60 seconds

Study Scenarios

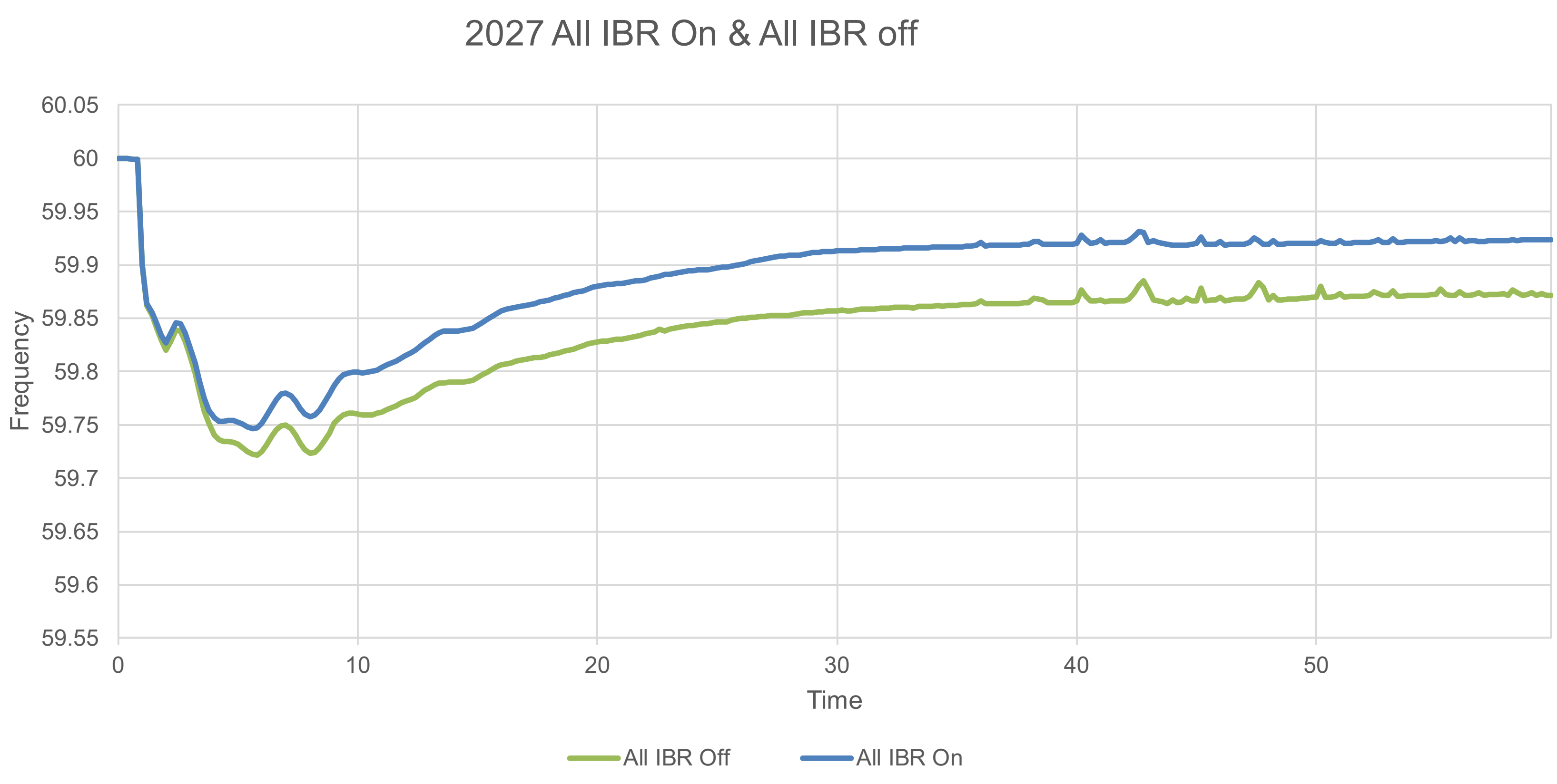
- Cases: Base case 2032 Spring off-Peak and the selected case with reduced headroom
- BESS are mostly in charging mode

Scenarios	SC1	SC2	SC3	SC4	SC5
IBR Frequency Control is switched off	✓	-	-	-	-
IBR Frequency Control is switched on	-	✓	-	✓	-
Frequency Control enabled for BESS at 10% headroom	-	-	✓	-	✓
IBR Frequency Control switched on and CAISO at spinning reserve headroom	-	-	-	✓	-
BESS at 10% headroom and CAISO at spinning reserve headroom					✓

Monitored Values

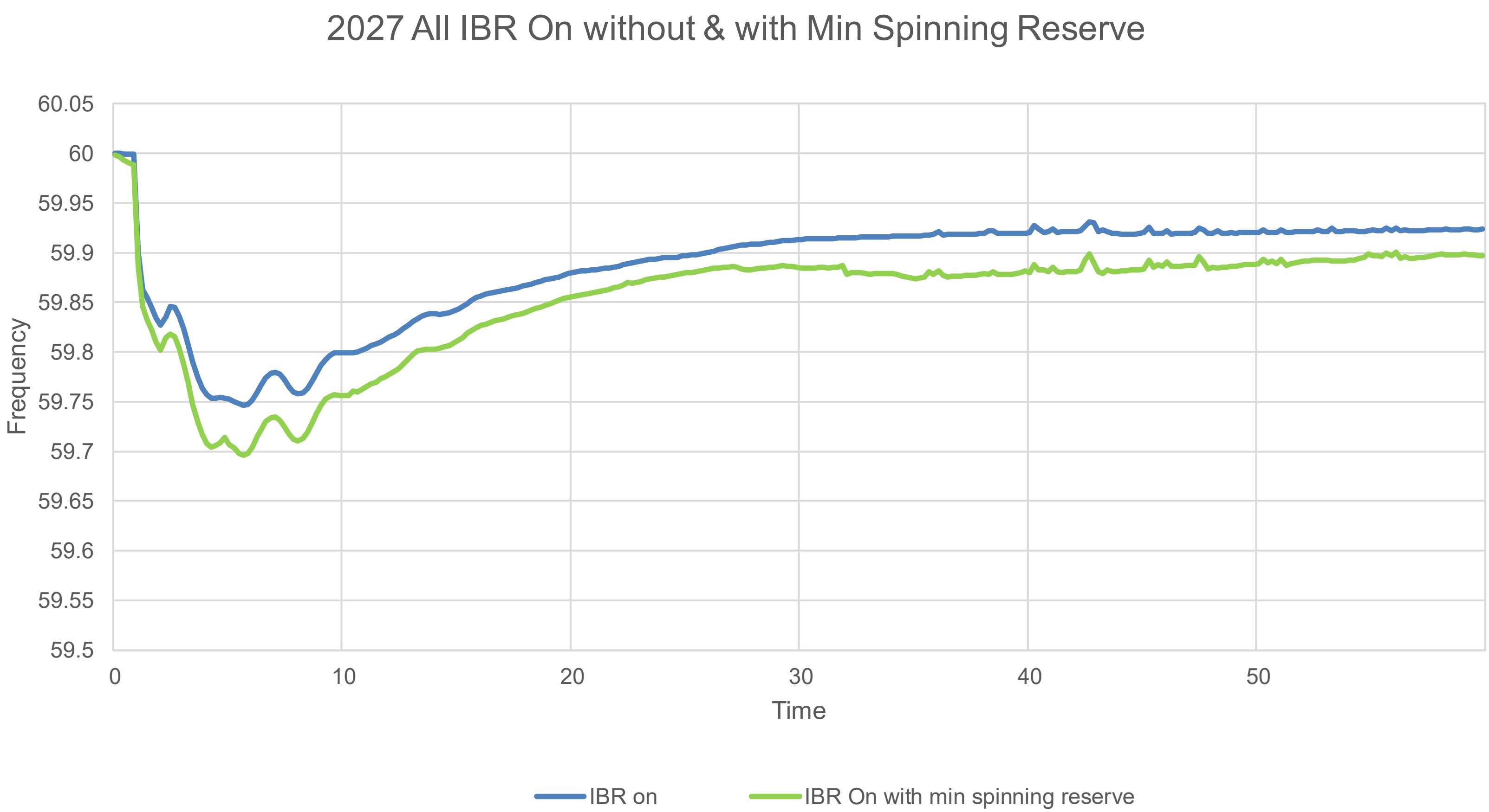
- System frequency including frequency nadir and settling frequency after primary frequency response
- The total new IBR output
- The total output of all other CAISO generators
- The major path flows
- Frequency Response Measures of the WECC and CAISO (MW/0.1 Hz)
- Frequency response from each unit in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

Scenario #1&2: 2027 All IBR On & Off



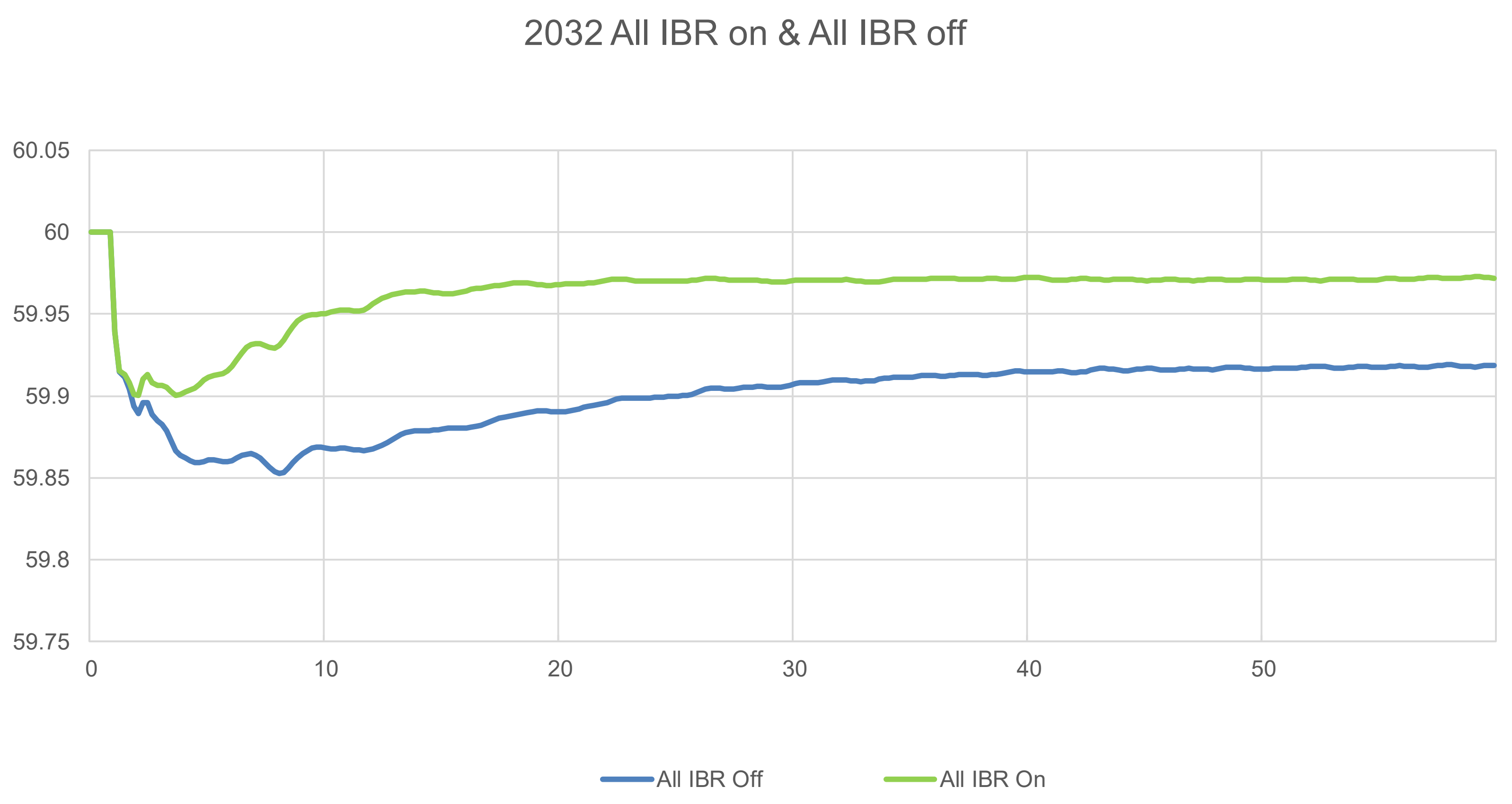
California ISO

Scenario #2&4: 2027 All IBR on without & with Min Reserve

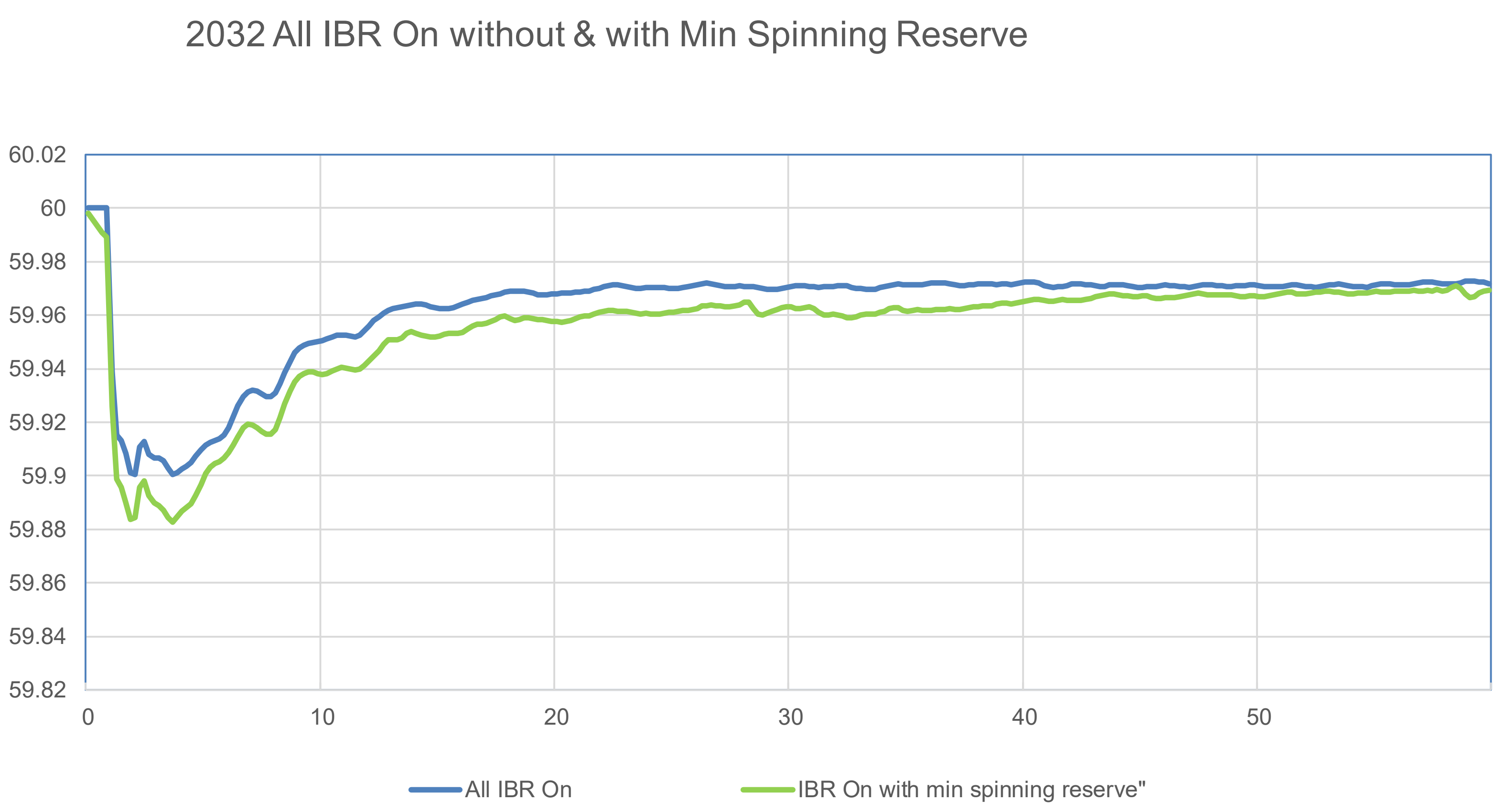


Scenario #3&5: 2027 BESS@10% w/o & with Min Reserve

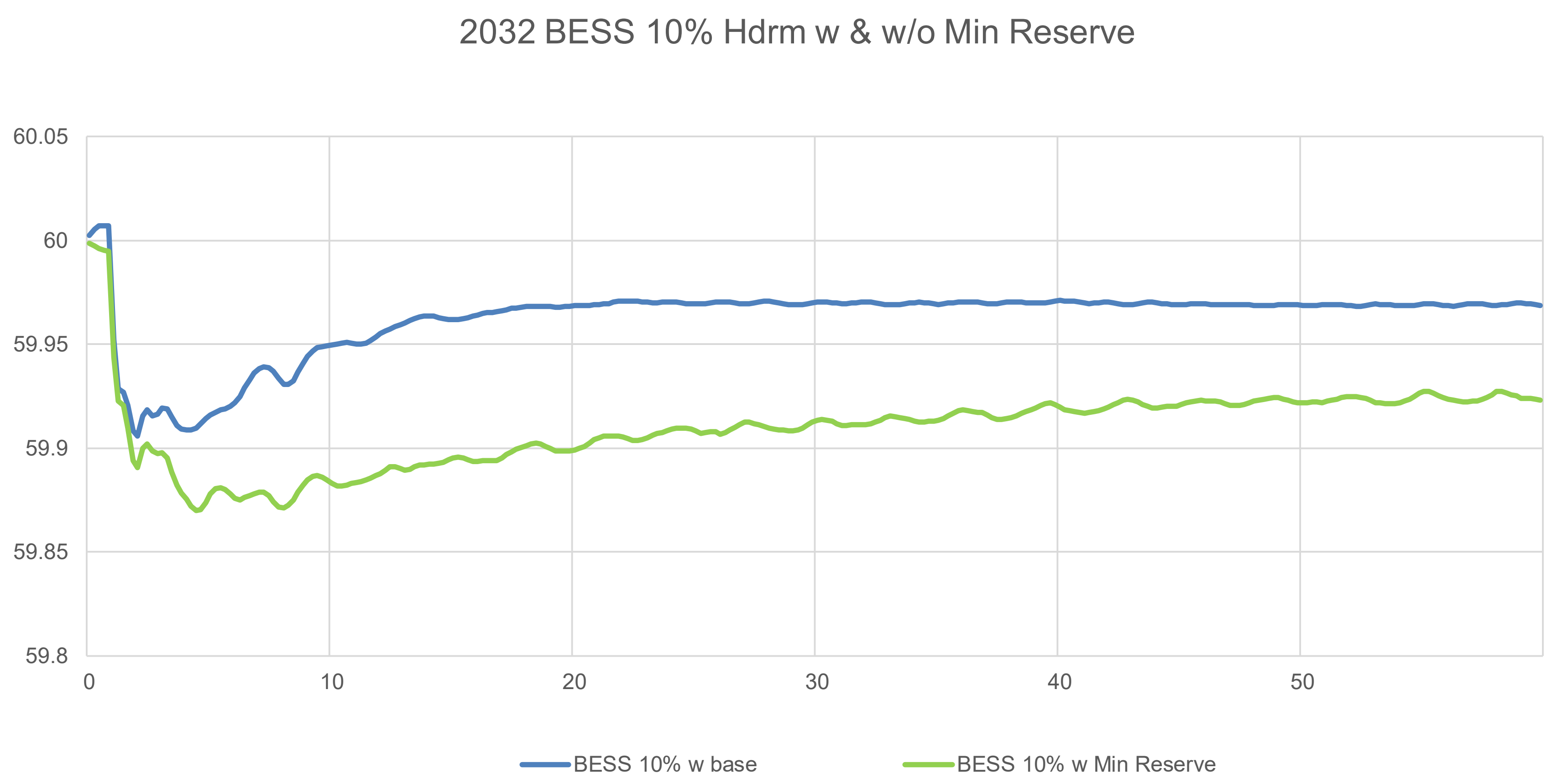
Scenario #1&2: 2032 All IBR On & Off



Scenario #2&4: 2032 All IBR on without & with Min Reserve



Scenario #3&5: 2032 BESS@10% w/o & with Min Reserve



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 2032 scenarios is greater than the 2027 scenarios
- BESS units have a much higher impact in 2032 due to the higher overall proportional of them in the system compared to 2027

2022-2023 TPP Study Conclusions

- BESS and IBR having frequency response will significantly improve the system frequency performance and will allow the ISO to fulfill its FRO, even if not all pre-2018 IBR and BESS provide frequency response
- Both BESS and IBR are effective in enhancing frequency stability and providing compliance with the BAL-003-2 Standard, if they have frequency response
- Being in compliance with the BAL-003-2 Standard while having 100% of energy provided by renewable resources in the ISO is possible if the new IBR resources have frequency response and have and adequate headroom

California ISO

2022 MIC Expansion Requests

Catalin Micsa
Senior Advisor, Transmission Infrastructure Planning

2022-2023 Transmission Planning Process Stakeholder Meeting
April 11, 2023

Valid 2022 MIC expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Resource type
1-4	San Diego Community Power	IID-SCE_ITC (MIR2)	150	Hybrid (Solar Battery)
1-4	San Diego Community Power	ELDORADO_ITC (WILLOWBEACH)	333	Wind
5-7	Valley Electric Association	MEAD_ITC (MEAD 230)	33	Hydro
8	Valley Electric Association	MEAD_ITC (MEAD 230)	90	Solar
9-10	Sonoma Clean Power	GONDIPPDC_ITC (GONIPP)	68	Geothermal
9-10	Sonoma Clean Power	MERCHANT_BG (ELDORADO230)	40	Geothermal
9-10	Sonoma Clean Power	IID-SDGE_BG (IVLY2)	50	Geothermal
9-10	Sonoma Clean Power	SILVERPK_BG (SILVERPEAK55)	13	Geothermal
11	East Bay Community Energy	SUMMIT_ITC (SUMMIT120) SILVERPK_BG (SILVERPEAK55)	40	Geothermal
12	Peninsula Clean Energy	IID-SCE_ITC (MIR2)	26	Geothermal
13	Southwestern Power Group II, LLC	PALOVRDE_ITC (PVWEST)	1257	Wind

Not all 2022 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 2022 MIC expansion requests

No.	Requestor Name	Intertie Name (Scheduling Point)	MW quantity	Triggers expansion	Comments:
1-4	San Diego Community Power	IID-SCE_ITC (MIR2)	150	No	CPUC portfolio triggers MIC expansion.
		ELDORADO_ITC (WILLOWBEACH)	333	In CPUC portfolio	CPUC portfolio triggers MIC expansion.
5-7	Valley Electric Association	MEAD_ITC (MEAD 230)	33	Potentially	Together with CPUC portfolio triggers MIC expansion
8			90		
9-10	Sonoma Clean Power	GONDIPPDC_ITC (GONIPP)	68	Yes	
		MERCHANT_BG (ELDORADO230)	40	In CPUC portfolio	CPUC portfolio triggers MIC expansion.
		IID-SDGE_BG (IVLY2)	50	No or in CPUC portfolio	CPUC portfolio triggers MIC expansion.
		SILVERPK_BG (SILVERPEAK55)	13	Yes	
11	East Bay Community Energy	SUMMIT_ITC (SUMMIT120)	40	Yes	
		SILVERPK_BG (SILVERPEAK55)		Yes	
12	Peninsula Clean Energy	IID-SCE_ITC (MIR2)	26	No	CPUC portfolio triggers MIC expansion.
13	Southwestern Power Group II, LLC	PALOVRDE_ITC (PVWEST)	1257	No	CPUC portfolio triggers MIC expansion.

NQC Deliverability Study (2023)

Intertie Name (Scheduling Point)	Status	Comments:
ELDORADO_ITC (WILLOWBEACH)	Pass	Temporary expansion included in 2023 MIC.
MEAD_ITC (MEAD 230)	Pass	Temporary expansion included in 2023 MIC.
IID-SCE_ITC (MIR2)	Failed	Due to delay in "S" line upgrade.
IID-SDGE_BG (IVLY2)	Failed	Due to delay in "S" line upgrade.

- Only applicable to MIC expansion request for RA year 2023
- Permanent expansion depends on the TPP and GIP deliverability study results

Updates regarding TPP Deliverability Study

Intertie Name (Scheduling Point)	Status	Comments	Outcome
ELDORADO_ITC (WILLOWBEACH)	Failed	Included in the CPUC portfolio.	Moving forward as part of the portfolio with mitigation for Lugo-Victorville constraint.
MERCHANT_BG (ELDORADO230)	Failed	Included in the CPUC portfolio.	Moving forward as part of the portfolio with mitigation for Lugo-Victorville constraint.
MEAD_ITC (MEAD 230)	Failed	Stand alone request.	Moving forward alongside the portfolio with mitigation for Lugo-Victorville constraint.
GONDIPPDC_ITC (GONIPP)	Failed	Stand alone request.	Moving forward alongside the portfolio with mitigation for Lugo-Victorville constraint.
SILVERPK_BG (SILVERPEAK55)	Failed	Stand alone request.	Partially moving forward (15 MW) alongside the portfolio with mitigation for SCE North of Lugo area constraints.
SUMMIT_ITC (SUMMIT120)	Failed	Stand alone request.	Not moving forward. Multiple constraints in the Drum-Rio Oso-Atlantic-Gold Hill area without a portfolio need.
IID-SCE_ITC (MIR2)	N/A	No need for expansion.	Portfolio triggers an expansion with mitigation for SCE Eastern, San Diego as well as Lugo-Victorville constraint.
IID-SDGE_BG (IVLY2)	N/A	No need for expansion.	Portfolio triggers an expansion with mitigation for SCE Eastern, San Diego as well as Lugo-Victorville constraint.
PALOVRDE_ITC (PVWEST)	N/A	No need for expansion.	Portfolio triggers an expansion with mitigation for SCE Eastern, San Diego as well as Lugo-Victorville constraint.

Policy-driven Assessment Recommendations
Draft 2022-2023 Transmission Plan

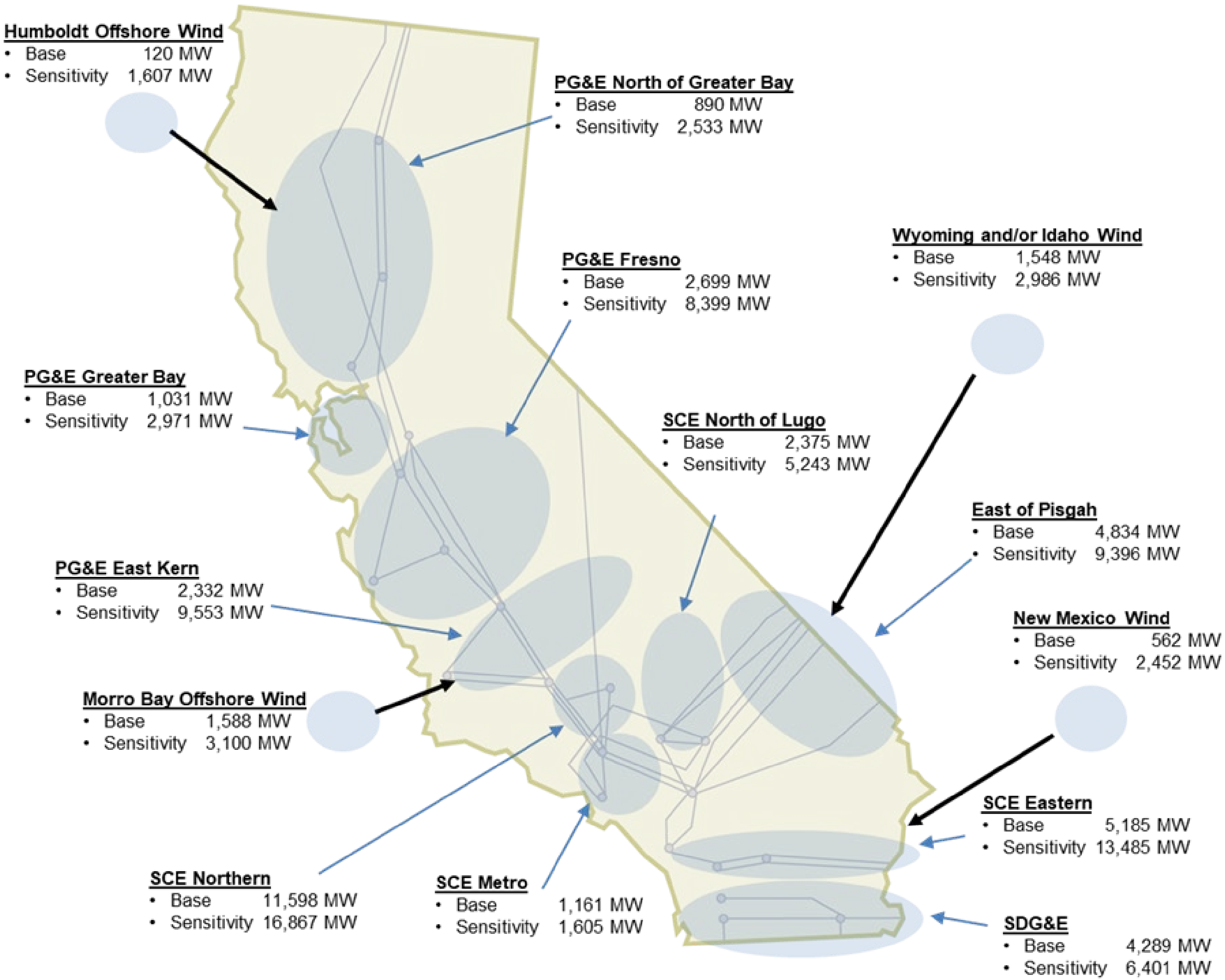
Transmission Infrastructure Planning

2022-2023 Transmission Planning Process Stakeholder Meeting
April 11, 2023

Background

- The 2022-2023 TPP policy-driven deliverability assessment is based on the base and sensitivity portfolios transmitted by CPUC
  - The base portfolio is based on the 38 MMT by 2030 GHG target and the 2020 IEPR demand forecast utilizing the high electric vehicle assumptions
  - The sensitivity portfolio is a 2035 resource portfolio based on 30 MMT by 2030 GHG target and the CEC's high electrification load forecast
- The latest 2035 base portfolio adopted by the CPUC in Decision 23-02-040 is based on the same GHG and load forecast assumptions as the 2022-23 TPP sensitivity portfolio although some mapping details vary

Transmission Planning Zones and Portfolio Capacities



Base and Sensitivity Portfolios by Resource Types (FCDS, EO and Total)

Resource Type	Base Portfolio			Sensitivity Portfolio		
	FCDS (MW)	EO (MW)	Total (MW)	FCDS (MW)	EO (MW)	Total (MW)
Solar	5,490	11,889	**17,379**	11,806	28,948	**40,754**
Wind – In State	2,533	499	**3,032**	2,697	546	**3,244**
Wind – Out-of-State (Existing TX)	610	-	**610**	610	-	**610**
Wind – Out-of-State (New TX)	1,500	-	**1,500**	4,828	-	**4,828**
Wind - Offshore	1,588	120	**1,708**	4,587	120	**4,707**
Li Battery	13,564	-	**13,564**	28,402	-	**28,402**
Geothermal	1,159	-	**1,159**	1,794	-	**1,794**
Long Duration Energy Storage (LDES)	1,000	-	**1,000**	2,000	-	**2,000**
Biomass/Biogass	134	-	**134**	134	-	**134**
Distributed Solar	125	-	**125**	125	-	**125**
Total	**27,703**	**12,508**	**40,211**	**56,983**	**29,614**	**86,598**

The mapped base portfolio in each interconnection area also includes the adjustments to the base portfolio made by CPUC staff to account for allocated TPD and additional in-development resources.
https://files.cpuc.ca.gov/energy/modeling/BaseCase_Updated_inDevTPD_wTxCalc_v01-23-23.xlsx

Utilization of transmission capability by portfolios - North

Transmission Constraint	Existing System FCDS Capability (MW)**	FCDS Capability Exceedance (MW)		
		Current TPP 2032 Base	Current TPP 2035 Sensitivity	2023-24 TPP 2035 Base
PG&E Greater Bay and North of Greater Bay Area				
Humboldt–Trinity 115 kV	21	--	32	145
Cortina–Vaca Dixon 230 kV	454	446	1774	2213
Rio Oso-SPI-Lincoln 115 kV	96*	--	42	--
Woodland-Davis 115 kV Line	64	--	71	--
Contra Costa-Delta 230kV Line	1523	--	279	641
Humboldt Offshore Wind constraint	0*	--	1487	1446
PG&E Greater Fresno Area				
Gates 500/230kV Bank #13 Constraint	3151	--	1112	598
Los Banos 500/230kV ***	1573*	--	930	1155
Wilson-Storey-Borden 230 kV	113	72	869	1109
Tesla-Westley 230 kV Constraint	1098	--	361	339
Las Aguillas-Panoche 230 kV	334*	20	1149	783
Los Banos—Gates #1 500 kV Line Constraint	1265*	--	3175	2683
Moss Landing–Los Banos 230 kV Constraint	1611*	--	3290	2885
Warnerville-Wilson 230 kV	272*	76	1182	909
Moss Landing—Las Aguillas 230 kV	316*	38	1257	1009
PG&E Kern Area				
Midway – Gates 230 kV Line	1431	--	1793	1507
Kern-Lamont-Stockdale 115 kV	100*	--	198	--
Morro Bay-Templeton 230kV	1708	--	2383	2118

* Default constraints; ** Include values updated by CPUC based on information in 2021-22 TPP;
*** capability includes projects approved in 2021-22 TPP

Utilization of transmission capability by portfolios - South

Transmission Constraint	Existing System FCDS Capability (MW)**	FCDS Capability Exceedance (MW)		
		Current TPP 2032 Base	Current TPP 2035 Sensitivity	2023-24 TPP 2035 Base
East of Pisgah Area				
Eldorado 500/230 kV #5 Constraint	3360	--	144	--
GLW-VEA Area Constraint***	1300*	240	1676	1058
Mohave/Eldorado 500 kV Default Constraint	1560*	166	745	1326
SCE Northern Area				
Antelope – Vincent 500 kV Constraint	4040	--	831	822
SCE North of Lugo				
Kramer to Victor Area 230 kV Constraint	826	441	536	355
Victor to Lugo 230 kV Constraint	1156	180	440	86
Lugo 500/230 kV Transformer Constraint	1576	20	530	23
SCE Eastern Area				
Colorado River 500/230 kV Constraint	1490	--	--	175
Devers – Red Bluff 500 kV Constraint	5400	--	1821	2163
Serrano–Alberhill–Valley 500 kV Constraint	5700	1671	4119	4932
SDG&E Area				
East of Miguel Area Constraint	731	388	459	397
Encina-San Luis Rey Constraint	1000	1343	1771	1888
Internal San Diego Constraint	968	1021	1326	1217
San Luis Rey-San Onofre Constraint	1500	843	1271	1388

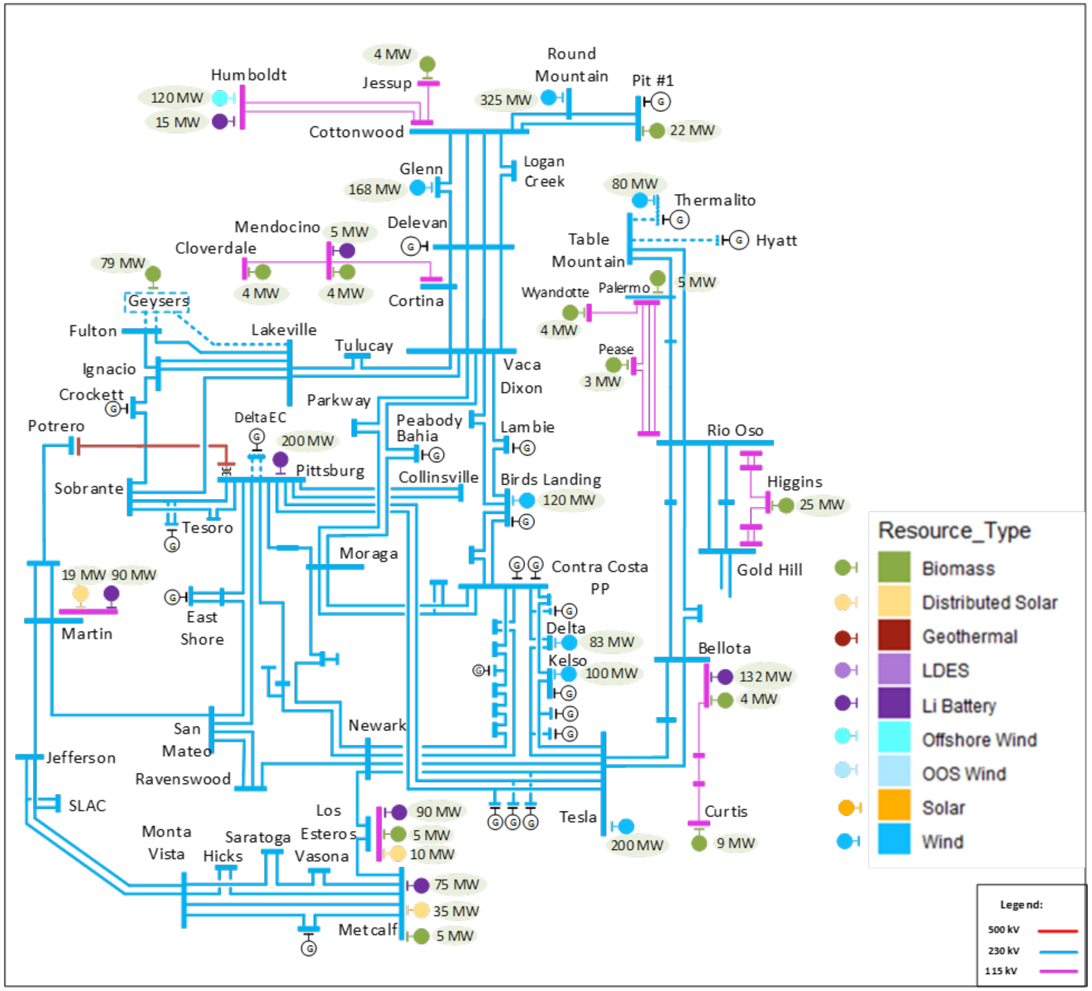
* Default constraints; ** Include values updated by CPUC based on inforamation from 2021-22 TPP;
*** capability includes projects approved in 2021-22 TPP

Policy-driven Projects Recommended for Approval

Project	Interconnection Area	Proposed Recommendation
Borden-Storey 230 kV 1 and 2 Line Reconductoring	PG&E Greater Fresno	Approval
Henrietta 230/115 kV Bank 3 Replacement	PG&E Greater Fresno	Approval
Beatty 230 kV Project	VEA	Approval
Trout Canyon – Lugo 500 kV Line	GLW and SCE	Approval
Lugo – Victor – Kramer 230 kV Upgrade	SCE North of Lugo	Approval
Colorado River-Red Bluff 500 kV 1 Line Upgrade	SCE Eastern	Approval
Devers-Red Bluff 500 kV 1 and 2 Line Upgrade	SCE Eastern	Approval
Devers-Valley 500 kV 1 Line Upgrade	SCE Eastern	Approval
Serrano-Alberhill-Valley 500 kV 1 Line Upgrade	SCE Eastern	Approval
San Bernardino-Etiwanda 230 kV 1 Line Upgrade	SCE Eastern	Approval
San Bernardino-Vista 230 kV 1 Line Upgrade	SCE Eastern	Approval
Vista-Etiwanda 230 kV 1 Line Upgrade	SCE Eastern	Approval
Mira Loma-Mesa 500 kV Underground Third Cable	SCE Metro/Eastern	Approval
Imperial Valley–North of SONGS 500 kV Line and Substation	SDG&E	Approval
North of SONGS–Serrano 500 kV line	SDG&E and SCE Eastern	Approval
Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement	SCE Metro	Approval
North Gila–Imperial Valley 500 kV line	SDG&E	Approval
Upgrade series capacitors on HW-NG and HA-NG to 2739 MVA	APS	Approval
Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento	SDG&E	Approval
Reconductor TL680C San Marcos-Melrose Tap	SDG&E	Approval
3 ohm series reactor on Sycamore-Penasquitos 230 kV line	SDG&E	Approval
Upgrade TL13820 Sycamore-Chicarita 138 kV	SDG&E	Approval

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

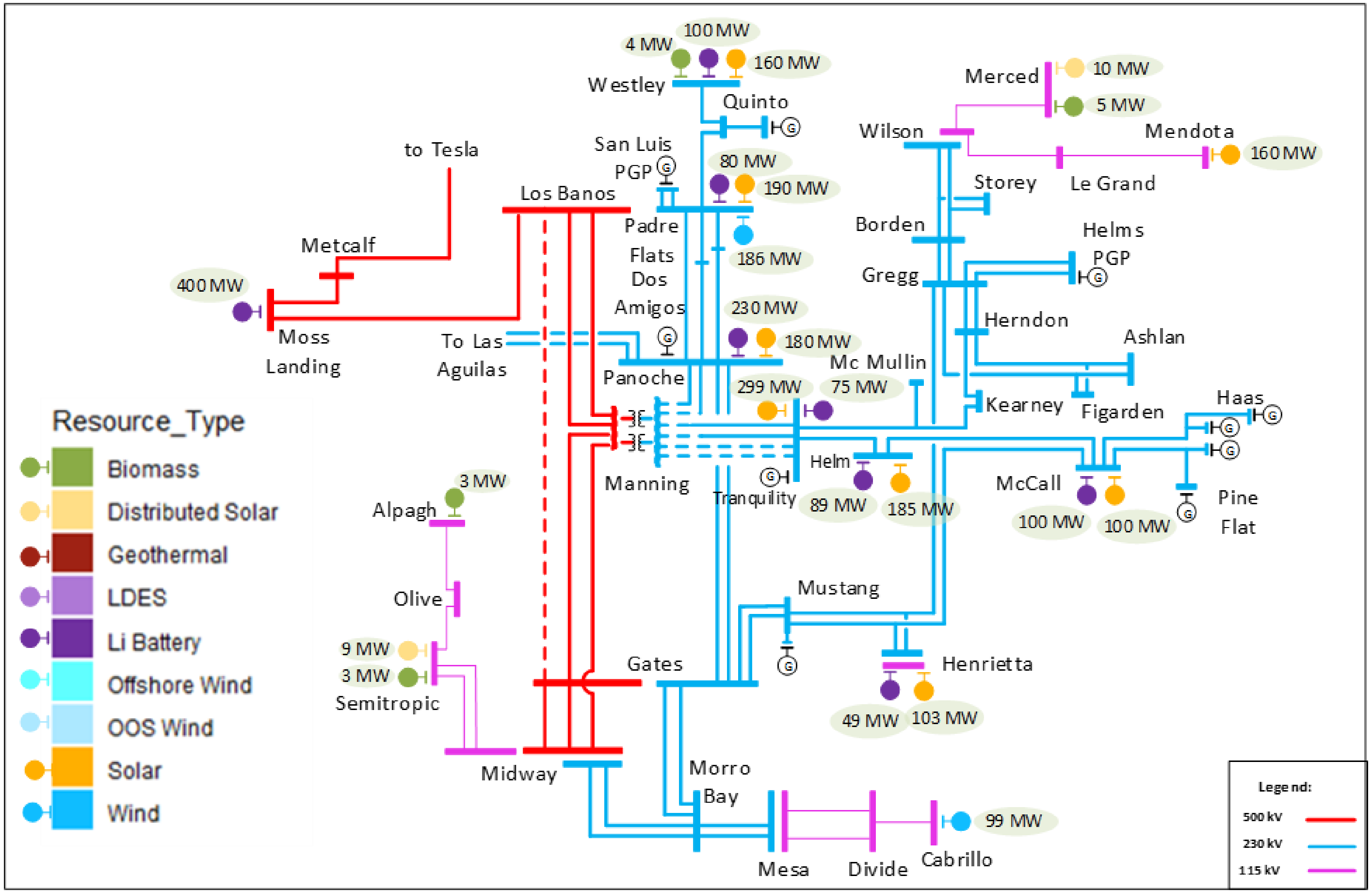
Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Collinsville – Pittsburg E 230 kV Lines	Base	40	0	0	1,342	Reduce the overall series compensation on the Table Mountain-Vaca-Collinsville-Tesla 500 kV path.
	Sensitivity	1,527	0	0	2,629	
Cloverdale – Eagle Rock 115 kV Line	Base	79	0	41	38	Portfolio resource to be moved to higher kV level
	Sensitivity	0	0	0	264	
Eagle Rock- Fulton-Silverado 115 kV Line	Base	133	5	114	24	Continue to monitor
	Sensitivity	-	-	-	-	None required
Humboldt Bay Area 60 kV	Base	0	15	0	71	Garberville Area Reinforcement reliability project recommended for approval in this cycle
	Sensitivity	0	15	0	240	
Cortina No. 4 60 kV Line	Base	50	0	42	8	Portfolio resource to be moved to higher kV level
	Sensitivity	-	-	-	-	None required

PG&E Greater Bay and North of Greater Bay Mitigation Plan

- There are no policy-driven upgrades identified in the Greater Bay and the North of Greater Bay interconnection planning areas.
- For the Humboldt Bay Area 60 kV constraint, the Garberville Area Reinforcement reliability-driven project will mitigate the identified constraint.
- The constraints only observed in the sensitivity portfolio and not in the base portfolio will be further assessment in the next planning cycle.

PG&E Greater Fresno Interconnection Area

PG&E Greater Fresno Interconnection Area Mapped Base Portfolio



PG&E Greater Fresno Interconnection Area On-Peak Constraints

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Borden - Storey #1 and #2 230 kV lines	Base	18	139	0	581	Borden-Storey 230 kV lines reconductoring project
	Sensitivity	79	2,168	0	2,689	
Henrietta 230/115 kV Bank 3	Base	0	0	0	191	Henrietta 230/115 kV Bank 3 replacement project
	Sensitivity	0	0	0	300	

California ISO

Borden-Storey 230 kV 1 and 2 Line Reconductoring

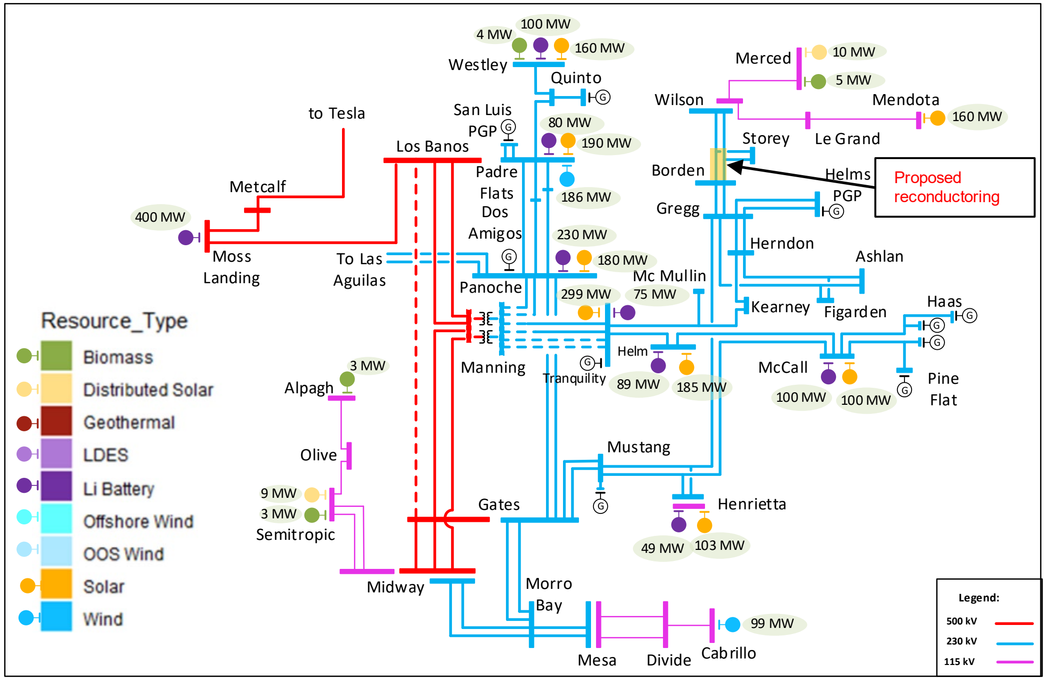
Overloaded Facility	Contingency	Scenario	Loading	
			BASE	SENS-01
Borden - Storey #1 or #2 230 kV line	Borden - Storey #2 or #1 230 kV line	HSN	112	150

Affected transmission zones			
		Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)		18	79
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		139	2168
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		581	2689
Mitigation Options	RAS	Not feasible	Not feasible
	Re-locate generic portfolio battery storage (MW)	NA	NA
	Transmission upgrade including cost	Reconductor ($25.24-$50.48M)	Reconductor ($25.24-$50.48M)
Recommended Mitigation		Borden-Storey 230 kV lines reconductoring project	

Borden-Storey 230 kV 1 and 2 Line Reconductoring

- Policy Assessment Need
  - Base and sensitivity HSN scenario
- Project Scope
  - Reconductoring the Borden – Storey section(s) of the Wilson – Storey #1 and #2 230 kV lines
- Estimated Project Cost
  - $25M - $50M
- Estimated In-service Date
  - 2032
- Alternatives Considered
  - RAS was considered as an alternative but was not selected due to not meeting the RAS guidelines
  - Series compensation was also considered as an alternative but was not selected due to the size that would be needed to mitigate the overload
- Recommendation
  - Approval

PG&E Greater Fresno Interconnection Area – Mapped Base Portfolio



Henrietta 230/115 kV Bank 3 Replacement

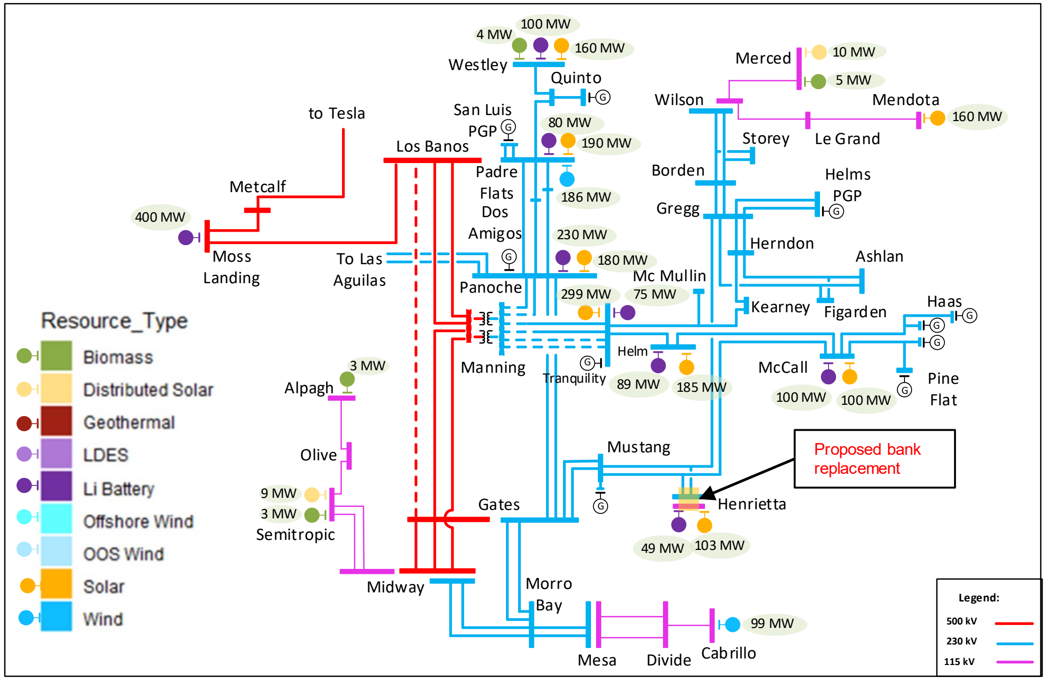
Overloaded Facility	Contingency	Scenario	Loading	
			BASE	SENS-01
Henrietta 230/115 kV bank	Helm-McCall 230 kV & Hentap2-MustangSS #1 230 kV lines	HSN	103	111

Affected transmission zones			
		Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)		0	0
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		0	0
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		191	300
Mitigation Options	RAS	Not feasible	Not feasible
	Re-locate generic portfolio battery storage (MW)	NA	NA
	Transmission upgrade including cost	Bank replacement ($12M-$20M)	Bank replacement ($12M-$20M)
Recommended Mitigation		Henrietta 230/115 kV Bank 3 replacement project	

Henrietta 230/115 kV Bank 3 Replacement

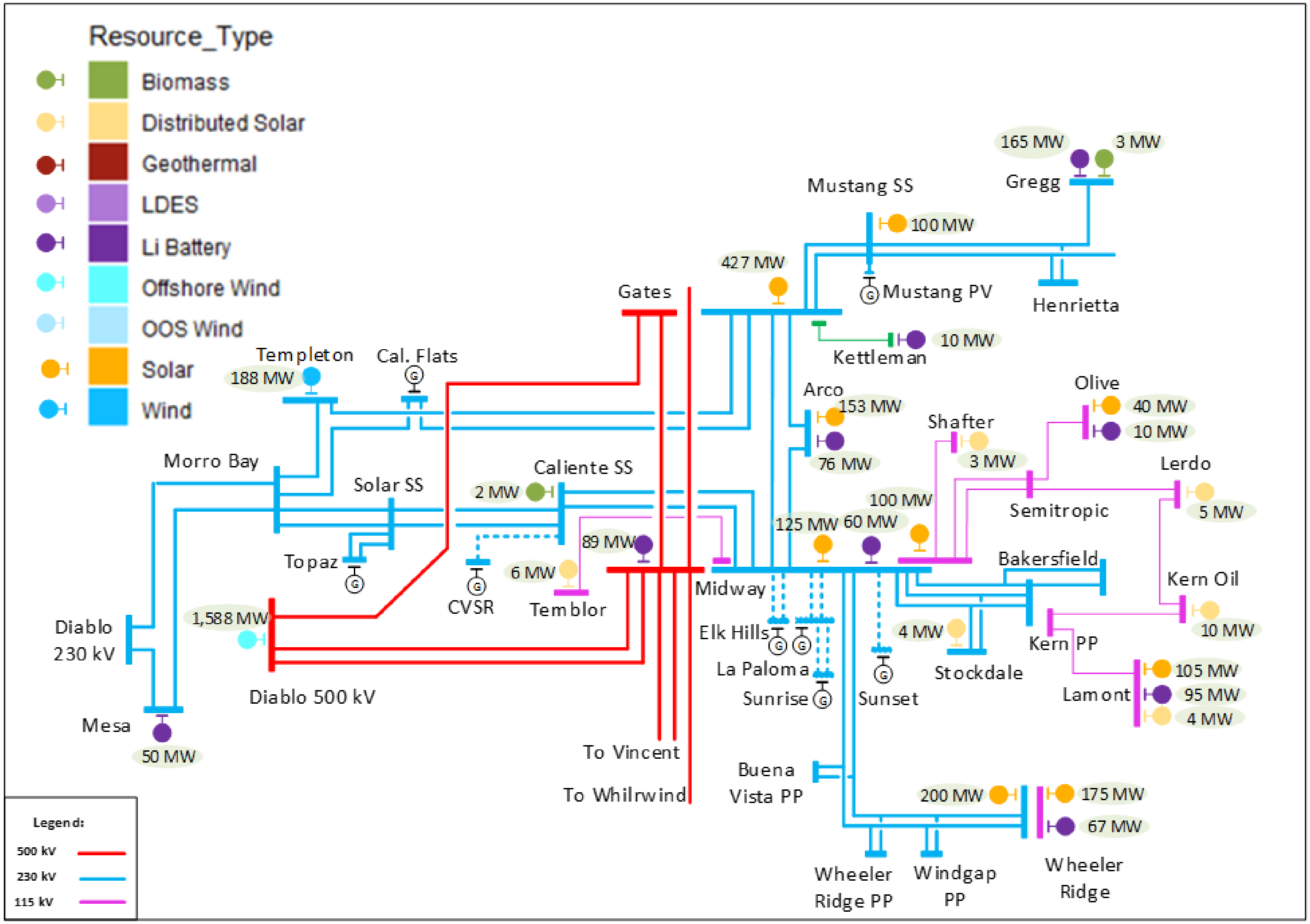
- Policy Assessment Need
  - Base and sensitivity HSN scenario
- Project Scope
  - Replace Henrietta 230/115 kV Bank 3
- Estimated Project Cost
  - $12M - $20M
- Estimated In-service Date
  - 2032
- Alternatives Considered
  - RAS was considered as an alternative but was not selected due to not meeting the RAS guidelines.
- Recommendation
  - Approval

PG&E Greater Fresno Interconnection Area – Mapped Base Portfolio



PG&E East Kern Interconnection Area

PG&E East Kern Interconnection Area Mapped Base Portfolio



PG&E East Kern Interconnection Area On-Peak Constraints

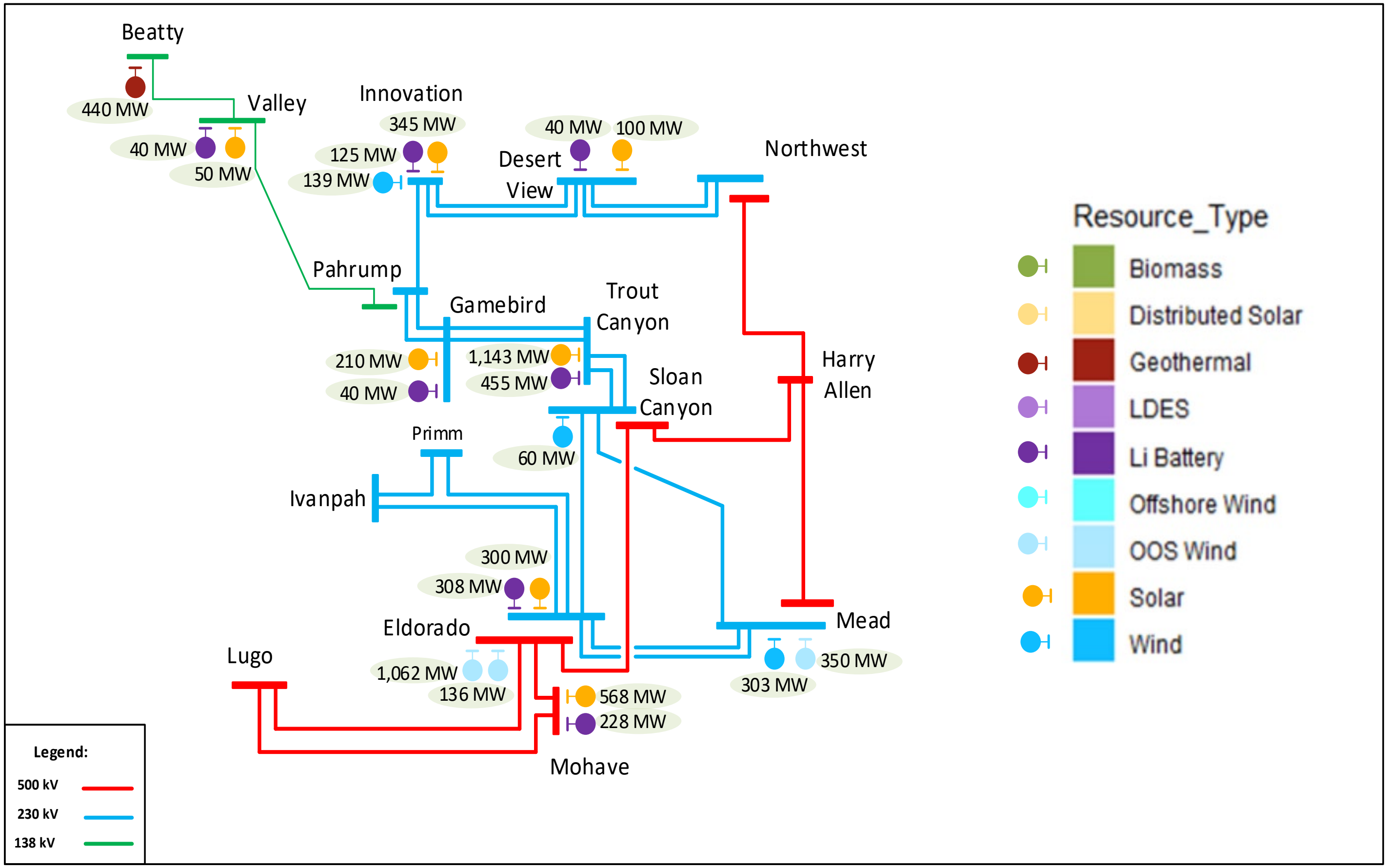
Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Wheeler 115/70 kV Bank 2	Base	0	67	53	14	Wheeler Ridge Junction previously approved reliability project currently on hold recommended to proceed in Chapter 2
	Sensitivity	70	117	103	84	
Arco-Cholame 70 kV Line	Base	60	0	31	14	Portfolio resource to be moved to higher kV level
	Sensitivity	-	-	-	-	

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 previously approved Wheeler Ridge Junction reliability-driven project that is currently on hold and recommended to proceed with a scope change will mitigate the identified constraint.
- The constraints only observed in the sensitivity portfolio and not in the base portfolio will be further assessment in the next planning cycle.

East of Pisgah Interconnection Area

East of Pisgah Interconnection Area – Mapped Base Portfolio



East of Pisgah Interconnection Area On-peak Deliverability Constraints

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
VEA 138 kV System	Base	480	40	120	360	Beatty 230 kV Project
	Sensitivity	1,330	590	430	900	
GLW 230 kV System	Base	2,253	635	2,034	219	Innovation RAS
	Sensitivity	4,102	2,022	2,456	1,646	Re-scoping of GLW Area Upgrade
Lugo-Victorville 500 kV	Base	6,895	2,246	6,500	395	Expand the Lugo – Victorville RAS
	Sensitivity	16,374	6,789	11,380	4,994	Trout Canyon – Lugo 500 kV line

GLW 230 kV Area On-peak Deliverability Constraints

Overloaded Facilities	Contingency	Loading (%)	
		Base Portfolio	Sensitivity Portfolio
IS Tap – Radar – Northwest 138kV line	Desert View-Northwest 230kV Nos 1 & 2	120.23	224.71
	Innovation-Desert View 230kV Nos 1 & 2	111.18	189.71
Amargosa 230/138kV Transformer, Sandy-Amargosa and Gamebird-Sandy 138kV lines	Trout Canyon-Sloan Canyon 230kV No.2	<100	108.62
	Desert View-Northwest 230kV Nos 1 & 2	<100	150.81
	Innovation-Desert View 230kV Nos 1 & 2	<100	140.07
	Trout Canyon-Sloan Canyon 230kV Nos 1 & 2	<100	198.54
Innovation PST	Desert View-Northwest 230kV Nos 1 & 2	<100	124.86
	Innovation-Desert View 230kV Nos 1 & 2	<100	106.13
Innovation – Desert View 230kV No.1 line	Basecase	<100	118.57
	Trout Canyon-Sloan Canyon 230kV Nos 1 & 2	<100	172.4
	Innovation-Desert View 230kV No.2	<100	149.27
	Trout Canyon-Sloan Canyon 230kV No.1 or No.2	<100	105.64
Innovation – Desert View 230kV No.2 line	Trout Canyon-Sloan Canyon 230kV Nos 1 & 2	<100	120.91
Pahrump - Gamebird 138kV	Desert View-Northwest 230kV Nos 1 & 2	<100	164.77
	Innovation-Desert View 230kV Nos 1 & 2	<100	157.86

GLW 230 kV System Constraints Summary

Affected transmission zones/substations		VEA 138 kV and GLW 230 kV substations	
		Base Portfolio	Sensitivity Portfolio
Generic portfolio MW behind the constraint (installed FCDS capacity)		2,253	4,102
Generic battery storage portfolio MW behind the constraint (installed FCDS capacity)		635	2,022
Deliverable generic portfolio MW w/o mitigation (Installed FCDS capacity)		2,034	2,456
Total undeliverable baseline and portfolio (Installed FCDS capacity)		219	1,646
Mitigation Options	RAS	Innovation RAS	Not applicable
	Re-locate portfolio battery storage (MW)	Reduce 165 MW battery storage portfolio at Innovation and Desert View	Not sufficient
	Potential transmission upgrade	Not required	Trout Canyon – Sloan Canyon 500 kV upgrade
Recommended Mitigation		Innovation RAS	Trout Canyon – Sloan Canyon 500 kV upgrade

California ISO

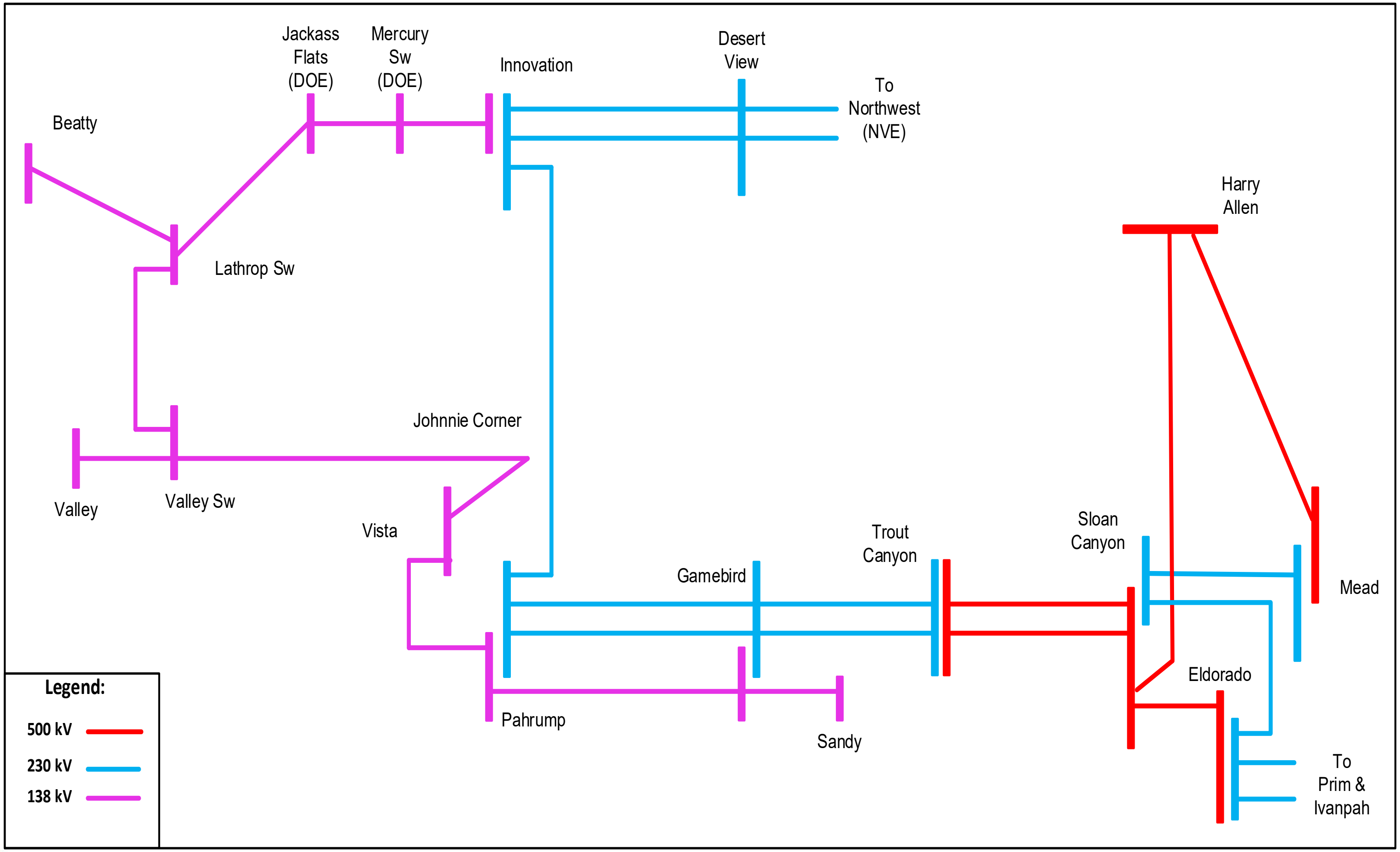
Re-scoping of GLW/VEA Area Upgrade Project

- **Policy Assessment Need:**
  - Various base case, Category P1 and P7 contingency overloads in sensitivity portfolio on-peak and off-peak deliverability analysis
  - Insufficient capacity on the Trout Canyon – Sloan Canyon 230 kV path to deliver the GLW and VEA generation to the ISO load without relying on the neighboring system
- **Revised GLW/VEA Area Upgrades Project Scope (change to the 2021-2022 Transmission Plan approved scope in red):**
  - Install a new Trout Canyon 500 kV bus and three 500/230 kV transformers
  - Rebuild Trout Canyon – Sloan Canyon 230 kV DCTL lines to 500 kV DCTL lines
  - Rebuild Desert View – Northwest 230 kV, Pahrump – Gamebird 230 kV, Gamebird – Trout Canyon 230kV and Trout Canyon – Sloan Canyon 230 kV to double circuit lines;
  - Rebuild Innovation – Desert View 230 kV No.1 line with a normal rating of 1,154 MVA and an emergency rating of 1,578 MVA
  - Add a second Innovation – Desert View 230 kV line;
  - Rebuild Innovation – Pahrump 230 kV line;
  - Add a 500/230 kV transformer at Sloan Canyon and loop in the Harry Allen – Eldorado 500 kV line;
  - Install a 138kV phase shifter at Innovation on the planned tie-line to NV Energy
  - Upgrade VEA's Amargosa 230/138 kV transformer

Re-scoping of GLW/VEA Area Upgrade Project (continued)

- **Project Objectives:**
  - Mitigate the identified GLW area constraints
  - Provide sufficient transmission capability on the ISO system to deliver the GLW and VEA area portfolio resources without needing to rely on the neighboring system facilities
- **Estimated Project Cost:**
  - The estimated cost of the GLW/VEA Area Upgrades project as approved in 2021-2022 TPP was $278 million
  - The estimated cost of the increased scope is $228 million
  - The total estimated cost of the re-scoped project is 506 million
- **Estimated In-service Date:**
  - 2027
- **Alternatives Considered:**
  - Relocate battery storage: not considered a potential mitigation as it was not sufficient to mitigate all the issue and this area also relies on battery charging to mitigate off-peak deliverability constraints
- **Recommendation:**
  - Approval

Re-scoping of GLW/VEA Area Upgrade Project (continued)



VEA 138 kV Area On-peak Deliverability Constraints

Overloaded Facilities	Contingency	Loading (%)	
		Base Portfolio	Sensitivity Portfolio
Beatty – Lathrop SS 138kV Line	Base Case	342.93	513.95
Lathrop SS – Jackass Flats 138kV Line	Base Case	212.68	412.66
Lathrop SS – Valley SS 138kV Line	Base Case	209.71	367.37
Valley SS – Vista 138kV Line	Base Case	204.8	360.52
Jackass Flats – Mercury SS 138kV Line	Base Case	202.11	394.86
Vista – Pahrump 138kV Line	Base Case	192.31	404.07
Innovation 230/138kV Transformer	Base Case	176.75	280.78
Mercury SS –Innovation 138kV Line	Base Case	149.06	257.02
Pahrump – Gamebird 138kV Line	Base Case	<100	164.1
Jackass Flats – Mercury SS 138kV Line	Multiple P1 contingencies	374.59	745.68
Lathrop SS – Jackass Flats 138kV Line	Multiple P1 contingencies	284.34	561.82
	Trout Canyon-Sloan Canyon 230kV Nos 1 & 2	177.86	356.16
Mercury SS –Innovation 138kV Line	Multiple P1 contingencies	270.59	523.19
	Trout Canyon-Sloan Canyon 230kV Nos 1 & 2	171.95	313.8
Innovation 230/138kV Transformer	Multiple P1 contingencies	223.86	487.34
IS Tap – Radar – Northwest 138kV Line	Multiple P1 contingencies	<100	165.87
Pahrump 230/138kV Transformer	Multiple P1 contingencies	<100	161.17
Pahrump – Gamebird 138kV Line	Multiple P1 contingencies	123.09	257.83
Valley SS – Vista - Pahrump 138kV Line	Multiple P1 contingencies	284.34	561.82
	Desert View-Northwest 230kV Nos 1 & 2	160.78	286.35
	Innovation-Desert View 230kV Nos 1 & 2	159.93	282.99

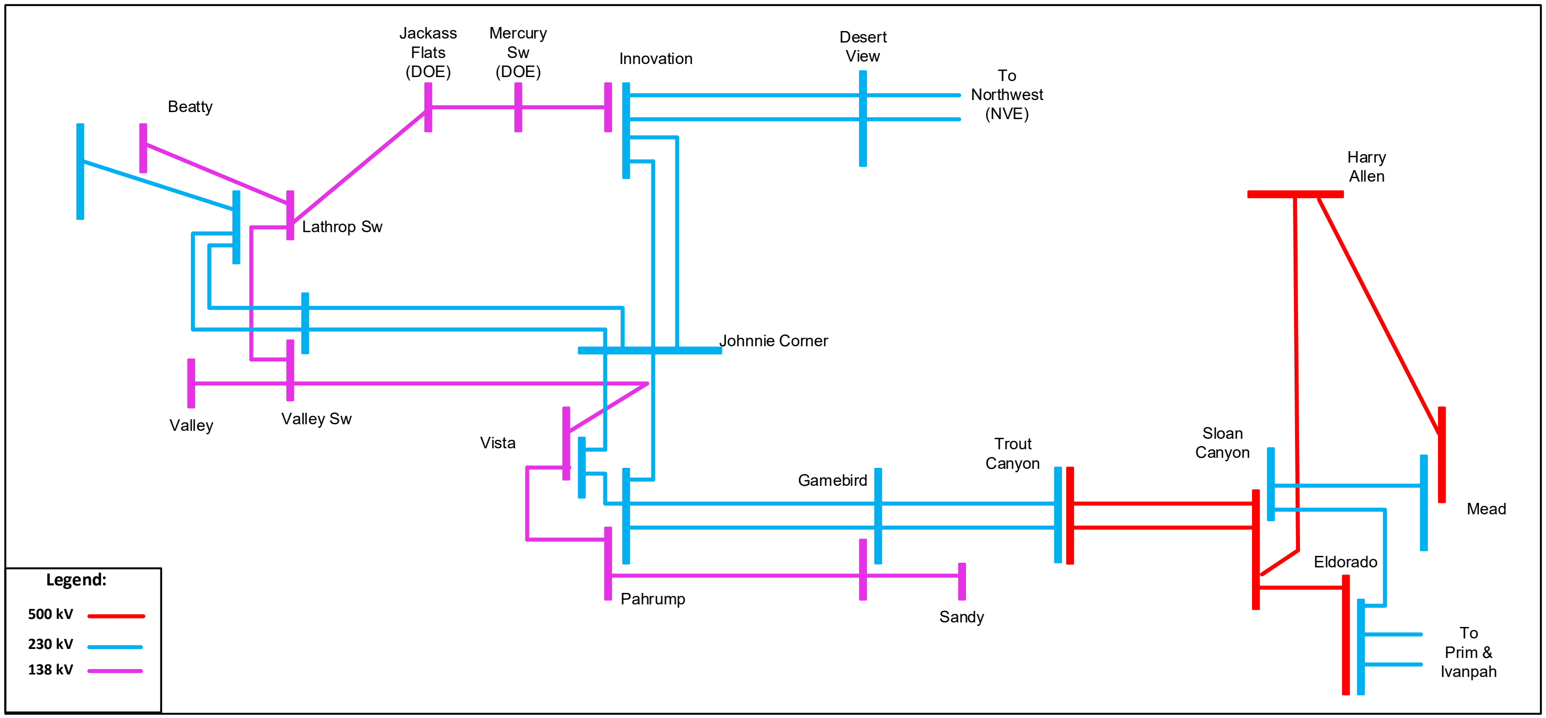
VEA 138 kV System Constraints Summary

Affected transmission zones/substations		VEA 138 kV substations	
		Base Portfolio	Sensitivity Portfolio
Generic portfolio MW behind the constraint (installed FCDS capacity)		480	1,330
Generic battery storage portfolio MW behind the constraint (installed FCDS capacity)		40	590
Deliverable generic portfolio MW w/o mitigation (Installed FCDS capacity)		120	430
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		360	900
Mitigation Options	RAS	Not applicable	
	Re-locate generic portfolio battery storage (MW)	Not applicable	
	Potential transmission upgrade	Beatty 230 kV Project	
Recommended Mitigation		Beatty 230 kV Project	

Beatty 230 kV Project

- **Policy Assessment Need**
  - Multiple base case, Category P1 and P7 contingency overloads were identified in both base and sensitivity portfolio on-peak and off-peak deliverability analysis
- **Project Scope:**
  - Build a new Johnnie Corner 230 kV station and loop into the Pahrump – Innovation 230 kV line.
  - Expand existing Beatty, Lathrop, Valley Switch and Vista 138 kV substations to 230 kV substations.
  - Build 32 miles Beatty – Lathrop 230 kV line next to the existing 138 kV line in an adjacent ROW.
  - Build 30 miles Johnnie Corner – Valley Switch – Lathrop 230 kV DCTL lines next to the existing 138kV line in an adjacent ROW.
  - Install a second Johnnie Corner – Innovation and Johnnie Corner – Vista – Pahrump 230 kV line on the Innovation – Pahrump double circuit tower approved in 2021/22 TPP
- **Project Objectives:**
  - Mitigate all identified VEA 138 kV area constraints in both base and sensitivity portfolio
  - Provide sufficient transmission deliverability to accommodate geothermal and other renewable resources in VEA area
- **Estimated Project Cost:**
  - $155 million
- **Estimated In-service Date:**
  - 2027
- **Alternatives Considered:**
  - Not applicable
- **Recommendation:**
  - Approval

GLW/VEA Transmission System with the recommended re-scoping of GLW Area Upgrades Project and Beatty 230 kV Project



Lugo – Victorville 500 kV On-peak Deliverability Constraints

Overloaded Facilities	Contingency	Loading (%)	
		Base Portfolio	Sensitivity Portfolio
Victorville – McCullough 500kV Line	Base Case	<100	112.11
Victorville – McCullough 500kV Line	Eldorado-Lugo 500kV Line	<100	112.81
Lugo – Victorville 500kV Line	Base Case	<100	106.4
Lugo-Victorville 500kV Line	Eldorado-Lugo 500kV Line	103.5	125.6
Lugo-Victorville 500kV Line	Lugo-Mohave 500kV Line	<100	107.39
Lugo-Victorville 500kV Line	Eldorado-Mohave 500kV Line	<100	104.94
Eldorado – McCullough 500kV Line	Eldorado-Lugo 500kV Line	<100	118.57
Eldorado – Lugo 500kV Line	Lugo-Victorville 500kV Line	<100	113.03

Lugo – Victorville 500 kV Constraints Summary

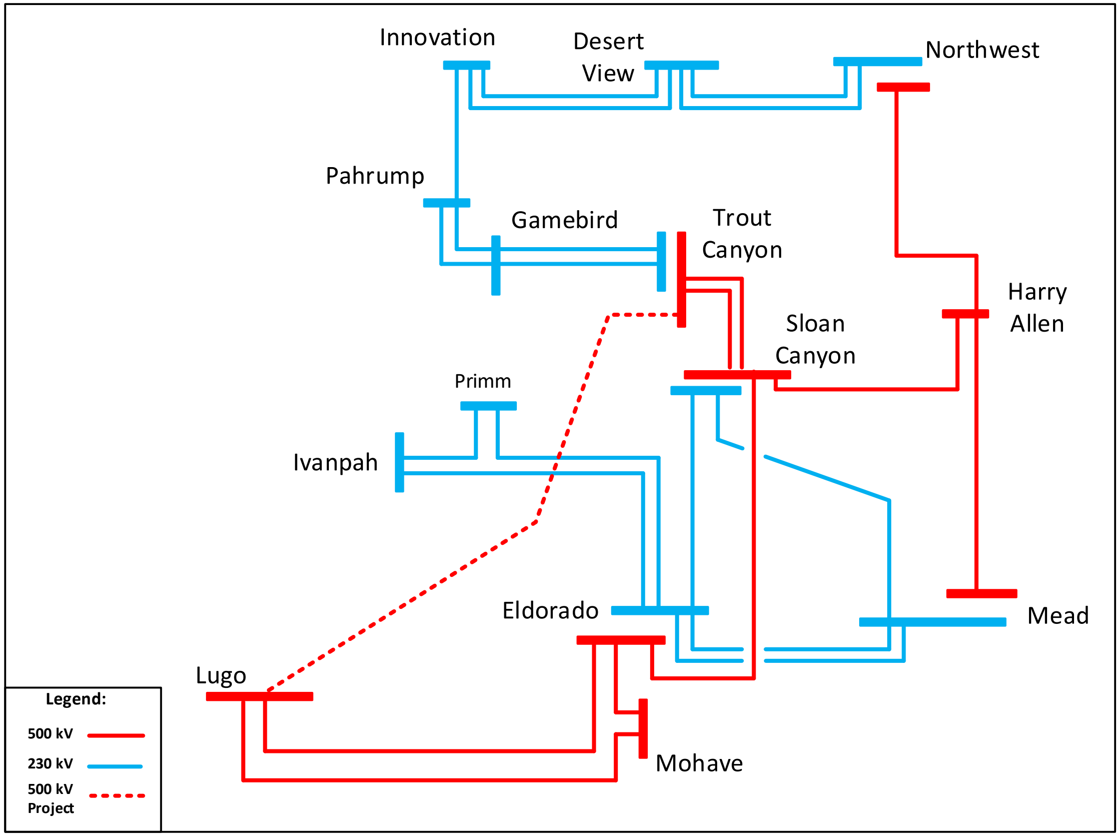
Affected transmission zones/substations		East of Pisgah, SCE Eastern, SCE Northern and SDG&E	
		Base Portfolio	Sensitivity Portfolio
Generic portfolio MW behind the constraint (installed FCDS capacity)		6,895	16,374
Generic battery storage portfolio MW behind the constraint (installed FCDS capacity)		2,467	6,789
Deliverable generic portfolio MW w/o mitigation (Installed FCDS capacity)		6,500	11,380
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		395	4,994
Mitigation Options	RAS	Expanding the Lugo – Victorville RAS	Not applicable
	Re-locate portfolio battery storage (MW)	Not required	Not applicable
	Potential transmission upgrade	Not required	1. Trout Canyon – Lugo 500 kV line 2. Eldorado – Lugo 500 kV No.2 line
Recommended Mitigation		Expanding the Lugo – Victorville RAS	Trout Canyon – Lugo 500 KV line project

California ISO

Trout Canyon – Lugo 500 kV Line

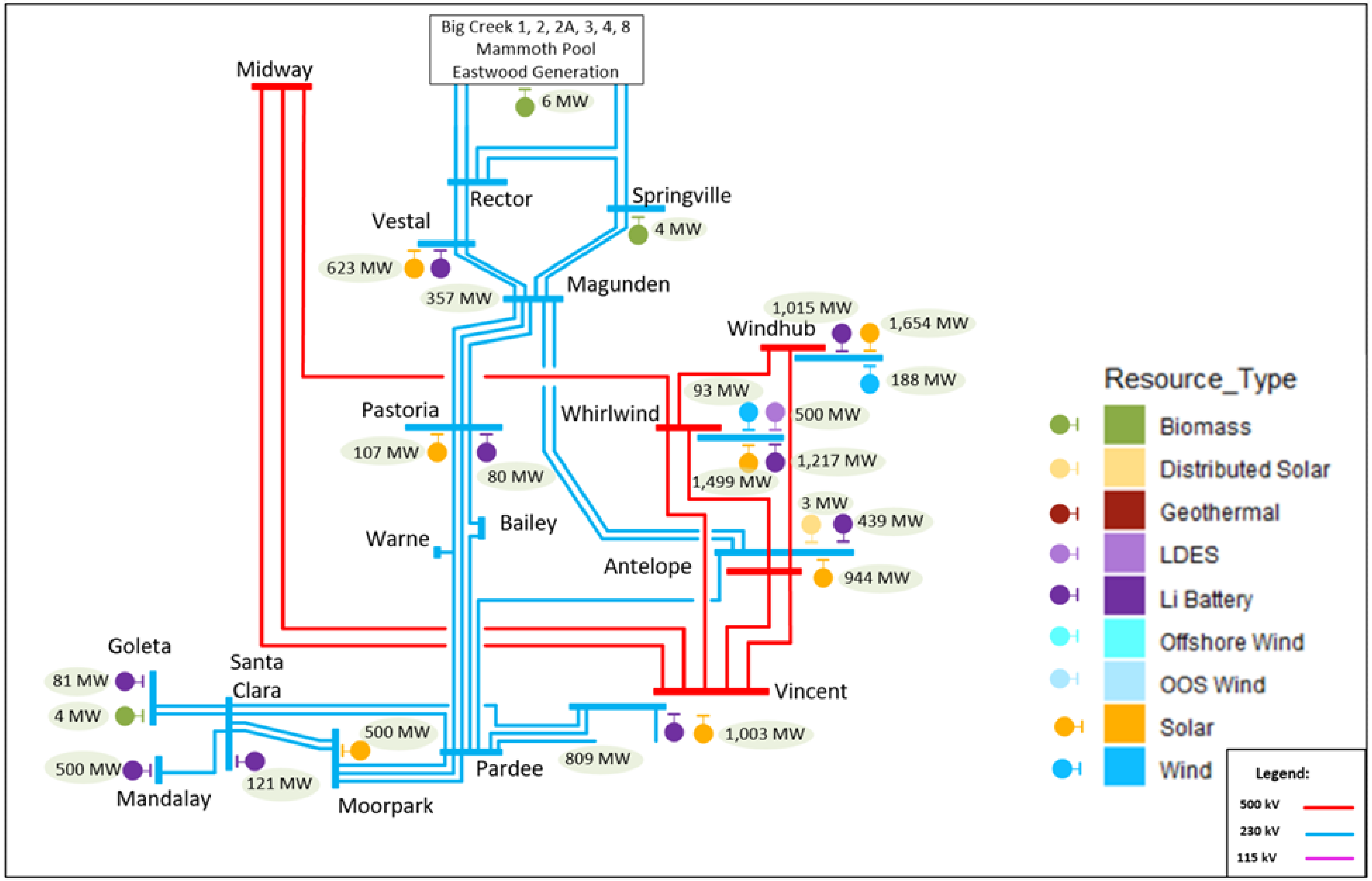
- **Policy Assessment Need**
  - Category P1 contingency overload in base portfolio on-peak deliverability analysis
  - Multiple base case and Category P1 contingency overloads in sensitivity portfolio on-peak and off-peak deliverability analysis
  - East of Pisgah interconnection area in-state and out-of-state resources as well as some of SCE Eastern interconnection area and SDG&E interconnection area resources are behind the constraints and subject to curtailment
- **Project Scope:**
  - Build a new 500 kV line from the new Trout Canyon 500 kV substation to Lugo 500 kV substation, approximately 180 miles, with 70% series compensation
- **Project Objectives:**
  - Mitigate the identified Lugo – Victorville 500 kV area constraints in both base and sensitivity portfolios.
  - Improve deliverability of GLW and VEA area portfolio resources and mitigate GLW area constraints
  - Provide opportunity for future transmission expansion in the area that would build transmission access to the geothermal resources in Nevada
- **Estimated Project Cost:**
  - $1,500~2,000 million
- **Estimated In-service Date:**
  - 2033
- **Alternatives Considered:**
  - Eldorado – Lugo 500 kV No.2 Line: This alternative provides similar results in mitigating the Lugo – Victorville 500 kV area constraints. However, it was not considered a potential mitigation because this option would require additional transmission upgrade to address GLW area constraints, and it would include an excessive number of line crossings in a very congested area
- **Recommendation:**
  - Approval

Trout Canyon – Lugo 500 kV Line Project One-line Diagram



SCE Northern Interconnection Area

SCE Northern Interconnection Area Mapped Base Portfolio



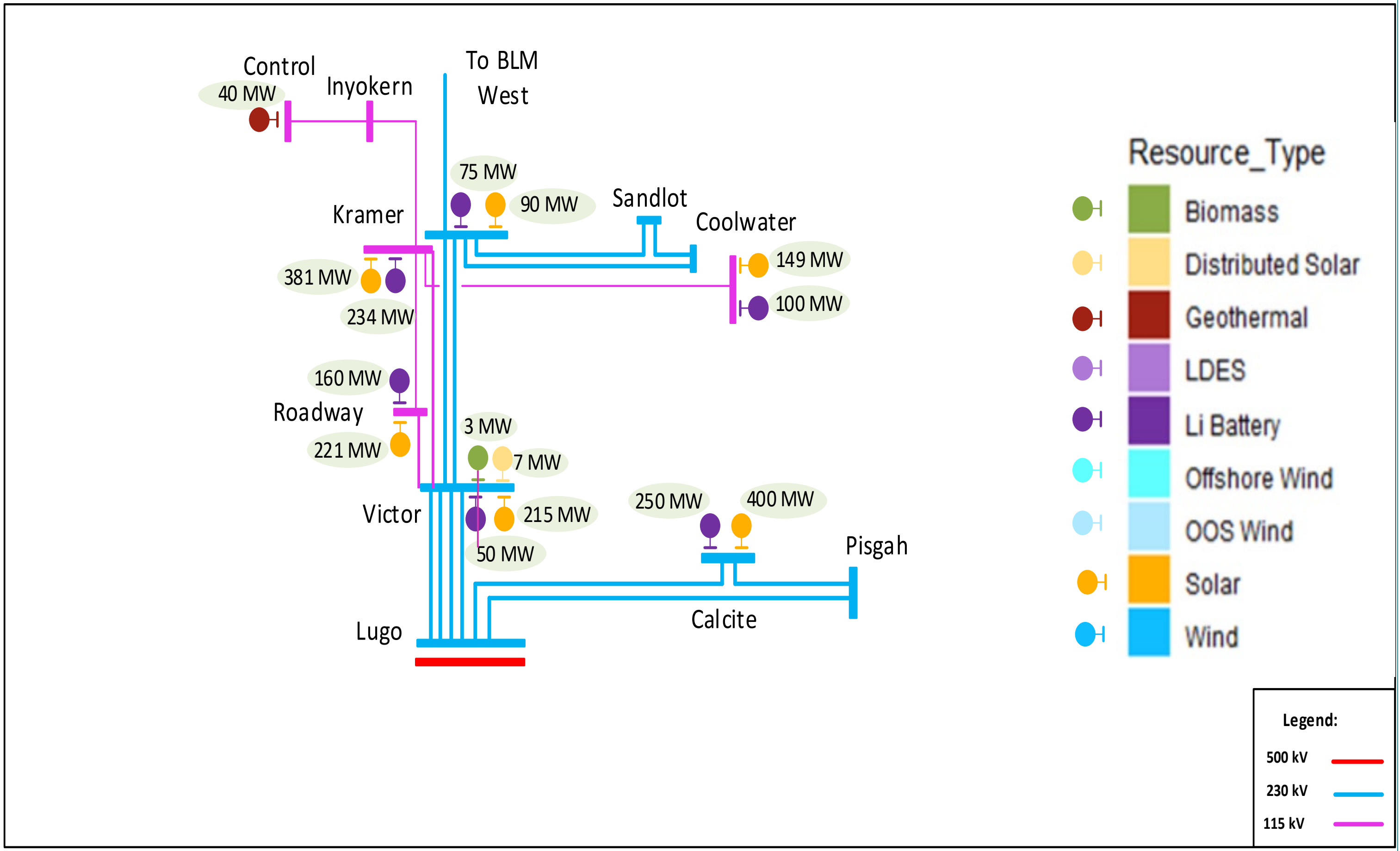
SCE Northern Interconnection Area On-Peak Constraints

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Windhub 500/230 kV	Base	0	0	-	108	Planned Windhub CRAS
	Sensitivity	35	0	0	149	

- There are no policy-driven upgrades identified in the SCE Northern interconnection planning area.

SCE North of Lugo (NOL) Interconnection Area

SCE North of Lugo Interconnection Area – Mapped Base Portfolio



SCE North of Lugo On-Peak Constraints

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Lugo 500/230 kV Transformer	Base	466	400	0	944	Lugo–Victor–Kramer 230 kV Upgrade
	Sensitivity	1,860	1,132	821	1,092	
Lugo–Victor 230 kV 1, 2, 3 & 4	Base	164	150	0	354	Lugo–Victor–Kramer 230 kV Upgrade
	Sensitivity	1,191	692	843	401	
Kramer-Victor 1 & 2 – 230 kV (Voltage stability and overload)	Base	150	150	0	1,194	Lugo–Victor–Kramer 230 kV Upgrade
	Sensitivity	954	533	26	1,251	
Control-Silver Peak 55 kV	Base	0	0	-	38	Reduce MIC Expansion Request to 15 MW
	Sensitivity	0	0	-	38	
Lugo-Calcite-Pisgah 230 kV Corridor	Base	302	250	237	65	Planned Calcite area RAS
	Sensitivity	669	440	374	295	Further evaluation in 2023-2024 planning cycle

Lugo–Victor–Kramer On-peak Deliverability Constraints

Overloaded Facility	Contingency	Loading (%) (HSN/SSN)	
		Base	Sensitivity
Lugo 500/230 Tr. 1 & 2	Lugo 500/230 Tr. No. 1 or 2 (P1)	125%/126%	143%/130%
Lugo–Victor 230 kV 1, 2, 3 & 4	Two Lugo–Victor 230 kV lines (P7)	106%/113%	117%/113%
Roadway–Victor 115 kV	Kramer–Victor 230 kV #1 &2 (P7)	Diverged (150/156%)	Diverged (154%/151%)
Kramer–Victor 115 kV		Diverged (147%/167%)	Diverged (153%/165%)
Kramer–Roadway 115 kV		Diverged (143%/165%)	Diverged (150%/164%)
Kramer 230/115 Tr. 1 & 2		188%/Diverged (188%)	195%/Diverged (193%)
Kramer–Victor 230 kV #1 & 2	Kramer–Victor 230 kV #1 or 2 (P1)	95%/110%	99%/108%

Lugo–Victor–Kramer Off-peak Deliverability Constraints

Overloaded Facility	Contingency	Loading (%)	
		Base	Sensitivity
Lugo 500/230 Tr. 1 & 2	Base Case	<100%	108%
Lugo 500/230 Tr. 1 & 2	Lugo 500/230 Tr. No. 1 or 2 (P1)	115%	173%
Victor–Lugo 230 kV 1, 2, 3 & 4	Base Case	<100%	103%
	Victor–Lugo 230 kV 1&2 or 3 & 4	<100%	152%
Kramer–Victor 230 kV #1 & 2	Base Case	<100%	143%
Kramer–Victor 230 kV #1 & 2	Kramer–Victor 230 kV 1 or 2 (P1)	119%	185%
Roadway–Victor 115 kV	Kramer–Victor 230 kV #1 &2 (P7)	Diverged (191%)	Diverged (261%)
Kramer–Victor 115 kV		Diverged (176%)	Diverged (260%)
Kramer–Roadway 115 kV		Diverged (168%)	Diverged (251%)
Kramer 230/115 Tr. 1 & 2		Diverged (175%)	Diverged (256%)
Coolwater–Dunn Siding 115 kV		Diverged (105%)	Diverged (181%)
Dunn Siding–Baker 115 kV		Diverged (105%)	Diverged (181%)
Baker–Mountain Pass 115 kV		<100%	Diverged (164%)
Victor 230/115 kV Tr. 2, 3 &4		<100%	Diverged (126%)
Mountain Pass–Ivanpah 115 kV		<100%	Diverged (126%)
Roadway–Victor 115 kV	Base Case	<100%	113%
	Kramer–Victor 230 kV #1 or 2 (P1)	<100%	117%

On-peak Lugo 500/230 kV constraint summary summary

<table>
<tr><th colspan="2">Affected transmission zones</th><th colspan="2">North of Lugo Area</th></tr>
<tr><td colspan="2"></td><td>Base (SSN)</td><td>Sensitivity (SSN)</td></tr>
<tr><td colspan="2">Generic portfolio MW behind the constraint (installed FCDS capacity)</td><td>466 MW</td><td>1,860 MW</td></tr>
<tr><td colspan="2">Generic battery storage portfolio MW behind the constraint (installed FCDS capacity)</td><td>400 MW</td><td>1,132 MW</td></tr>
<tr><td colspan="2">Deliverable generic portfolio MW w/o mitigation (Installed FCDS capacity)</td><td>0 MW</td><td>821 MW</td></tr>
<tr><td colspan="2">Total undeliverable baseline and portfolio MW (Installed FCDS capacity)</td><td>944 MW</td><td>1,092 MW</td></tr>
<tr><td rowspan="3">Mitigation Options</td><td>RAS</td><td colspan="2">Not sufficient</td></tr>
<tr><td>Re-locate portfolio battery storage (MW)</td><td colspan="2">Not applicable</td></tr>
<tr><td>Transmission upgrade including cost</td><td colspan="2">1. Add 3rd Lugo 500/230 kV Transformer ($70M)
2. Lugo–Kramer 500 kV development ($700M)</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td colspan="2">Add 3rd Lugo 500/230 kV Transformer ($70M)</td></tr>
</table>

On-peak Lugo–Victor 230 kV constraint summary

Affected transmission zones		North of Victor Area including Victor	
		Base (SSN)	Sensitivity (SSN)
Generic portfolio MW behind the constraint (installed FCDS capacity)		164 MW	1,191 MW
Generic battery storage portfolio MW behind the constraint (installed FCDS capacity)		150 MW	692 MW
Deliverable generic portfolio MW w/o mitigation (Installed FCDS capacity)		0	843 MW
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		354 MW	401 MW
Mitigation Options	RAS	Not sufficient	
	Re-locate portfolio battery storage (MW)	Not applicable	
	Transmission upgrade including cost	1. Reconductor Lugo–Victor 230 kV No. 1, 2, 3 & 4 lines ($112M) 2. Lugo–Kramer 500 kV development ($700M)	
Recommended Mitigation		Reconductor Lugo–Victor 230 kV No. 1, 2, 3 & 4 lines ($112M)	

On-peak Kramer–Victor #1 & 2 230 kV contingency voltage stability and overload constraint summary

Affected transmission zones		North of Victor, Kramer–Coolwater Area	
		Base (SSN)	Sensitivity (SSN)
Generic portfolio MW behind the constraint (installed FCDS capacity)		150 MW	954 MW
Generic battery storage portfolio MW behind the constraint (installed FCDS capacity)		150 MW	533 MW
Deliverable generic portfolio MW w/o mitigation (Installed FCDS capacity)		0 MW	26 MW
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		1,194 MW	1,251 MW
Mitigation Options	RAS	Not sufficient	
	Re-locate portfolio battery storage (MW)	Not sufficient or applicable	
	Transmission upgrade including cost	1. Rebuild/build Kramer–Victor 115 kV lines to 230 kV ($300 M) 2. Lugo–Kramer 500 kV development ($700M)	
Recommended Mitigation		Rebuild/build Kramer–Victor 115 kV lines to 230 kV($300 M)	

Need for transmission upgrades to address constraints

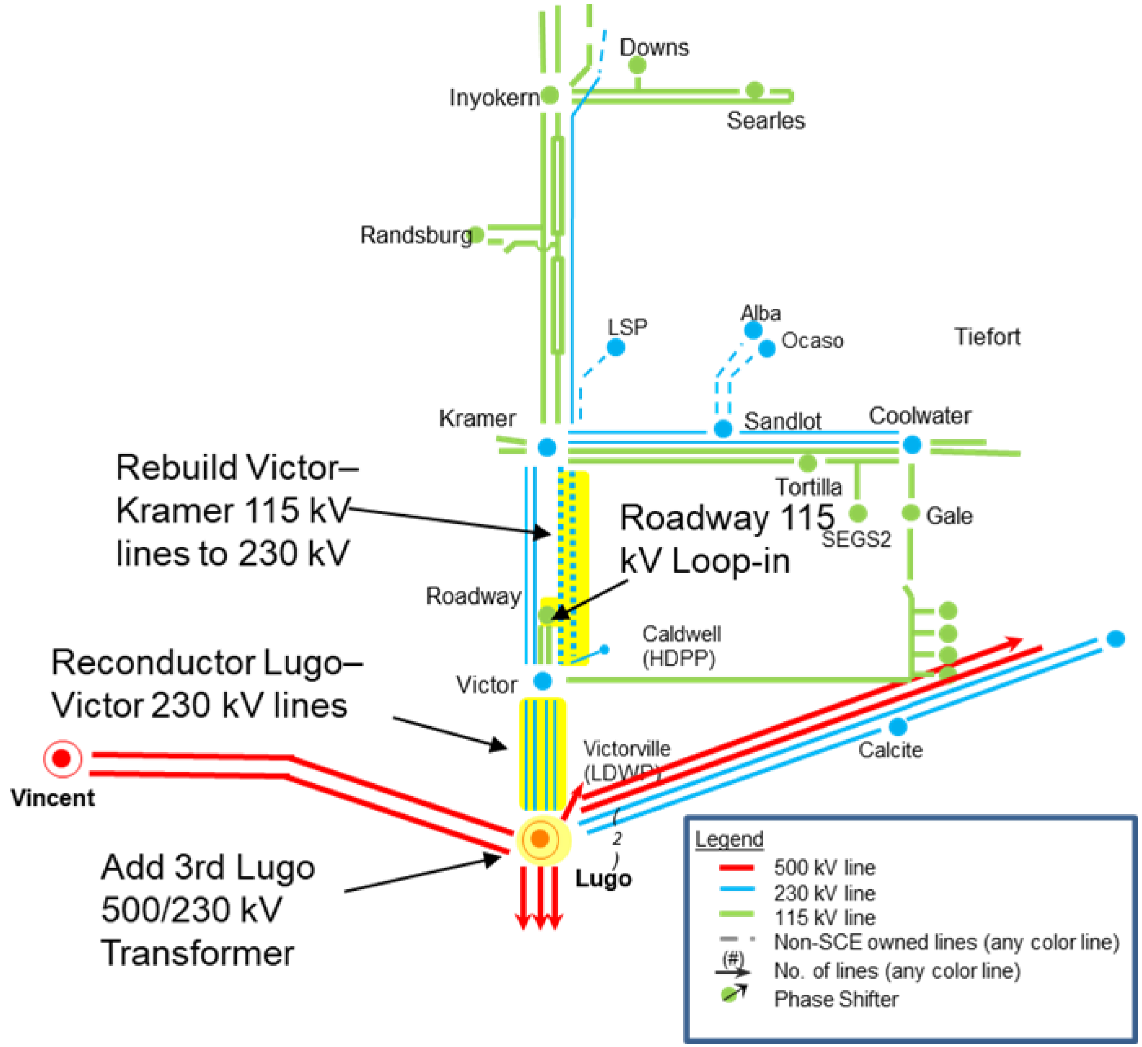
- Due to the planned addition of significant amount of resources without the necessary transmission upgrades, the currently planned system is already going beyond several ISO Planning Standards RAS design guidelines.
- Further expanding area RAS for portfolio resources is not considered a valid alternative to reliably integrate the resources or maximize their deliverable capacity. As such, transmission upgrades are needed.
- PCM results for the base portfolio further indicate the NOL area has the highest aggregate congestion costs in the ISO system (out of 34 aggregation zones) at $80 million and 6,214 hours. High congestion is due mainly to:
  - Victor–Kramer #1 and #2 lines under N-0 conditions and
  - Lugo 500/230 kV transformers under N-1 conditions with RAS
- Base portfolio PCM wind and solar curtailment results indicate NOL is fifth (out of 23 transmission zones) in renewable generation and has the second highest curtailment ratio at 5.16%

Proposed Lugo–Victor–Kramer corridor upgrades

- **Description:**
  - Add Lugo 500/230 kV transformer #3;
  - Reconductor ~10.8 miles (each) of Lugo–Victor 230 kV No. 1, 2, 3 & 4 lines; and
  - Rebuild/build Kramer–Victor 115 kV lines for 230 kV operation; loop the south segment of the existing Kramer–Victor 115 kV line into Roadway.
- **Objectives**
  - Primarily needed to mitigate the Lugo–Victor–Kramer base and sensitivity deliverability constraints. Estimated incremental deliverable MW (study output amount) is ~1,004 MW to 1,337 MW
  - Effectively mitigates the very high congestion in the area; reduces the NOL area and overall system curtailment (See economic study presentation)
  - Improves reliability, reduces operational complexity and simplifies area RAS

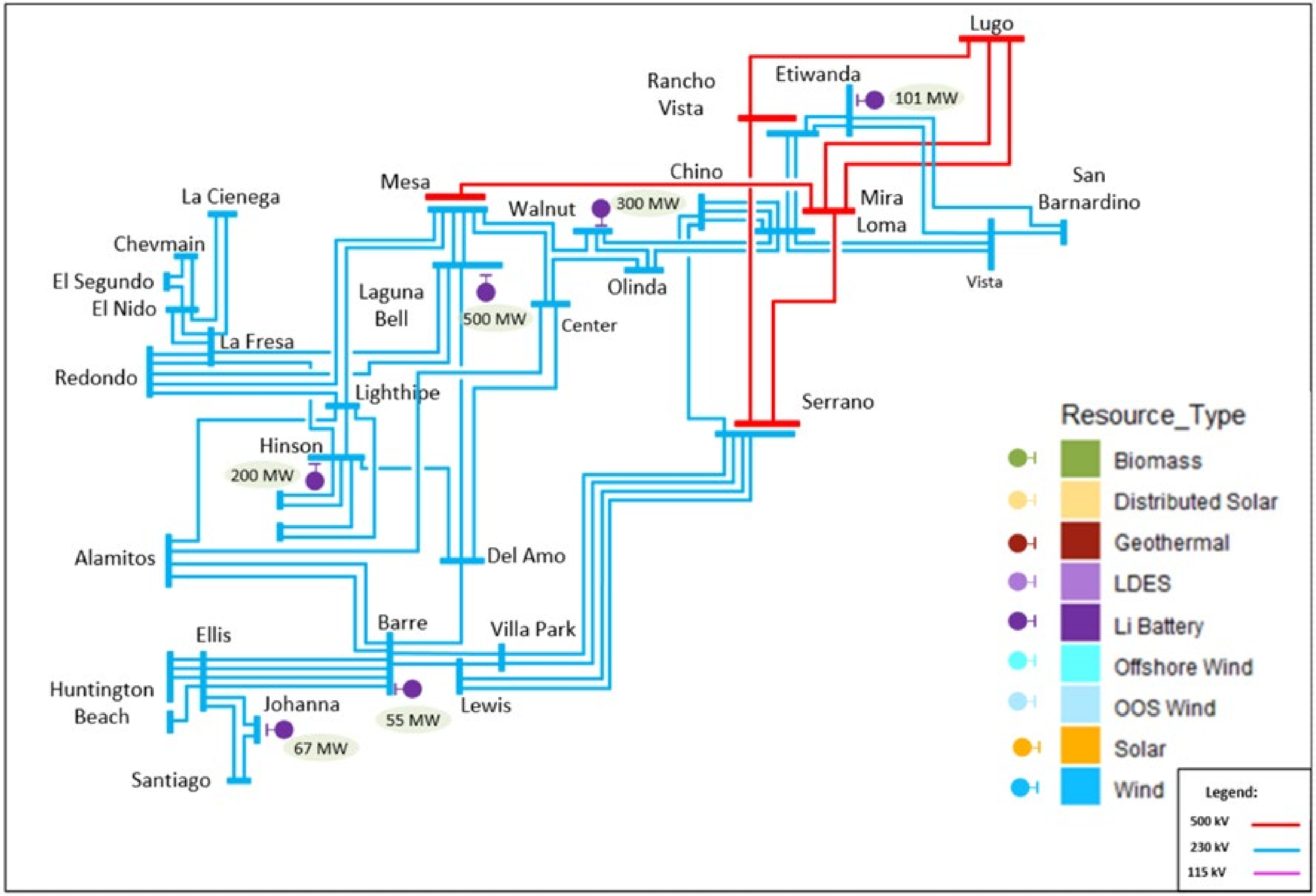
- **Estimated Project Cost:**
  - ~ $482 million
- **Estimated In-service Date:**
  - Lugo transformer addition and reconductor Lugo–Victor 230 kV - December 2027
  - Kramer–Victor 115 kV conversion to 230 kV - December 2032
- **Recommendation:** Approval

Recommended Lugo–Victor–Kramer corridor upgrades



SCE Metro Interconnection Area

SCE Metro Interconnection Area – Base Portfolio



California ISO

SCE Metro Area On-Peak Constraints

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
South of Mesa Constraint	Base	-	-	-	0	Not required
	Sensitivity	1,934	1,807	0	2,991	South Area Reinforcement
Serrano-Barre Corridor	Base	-	-	-	0	Not required
	Sensitivity	6,350	3,109	4,712	1,638	South Area Reinforcement
Mesa-Mira Loma 500 kV Line UG Segment	Base	8,917	3,932	8,851	388	Mesa-Mira Loma Underground Third Cable included in the South Area Reinforcement
	Sensitivity	21,160	9,192	18,031	3,451	

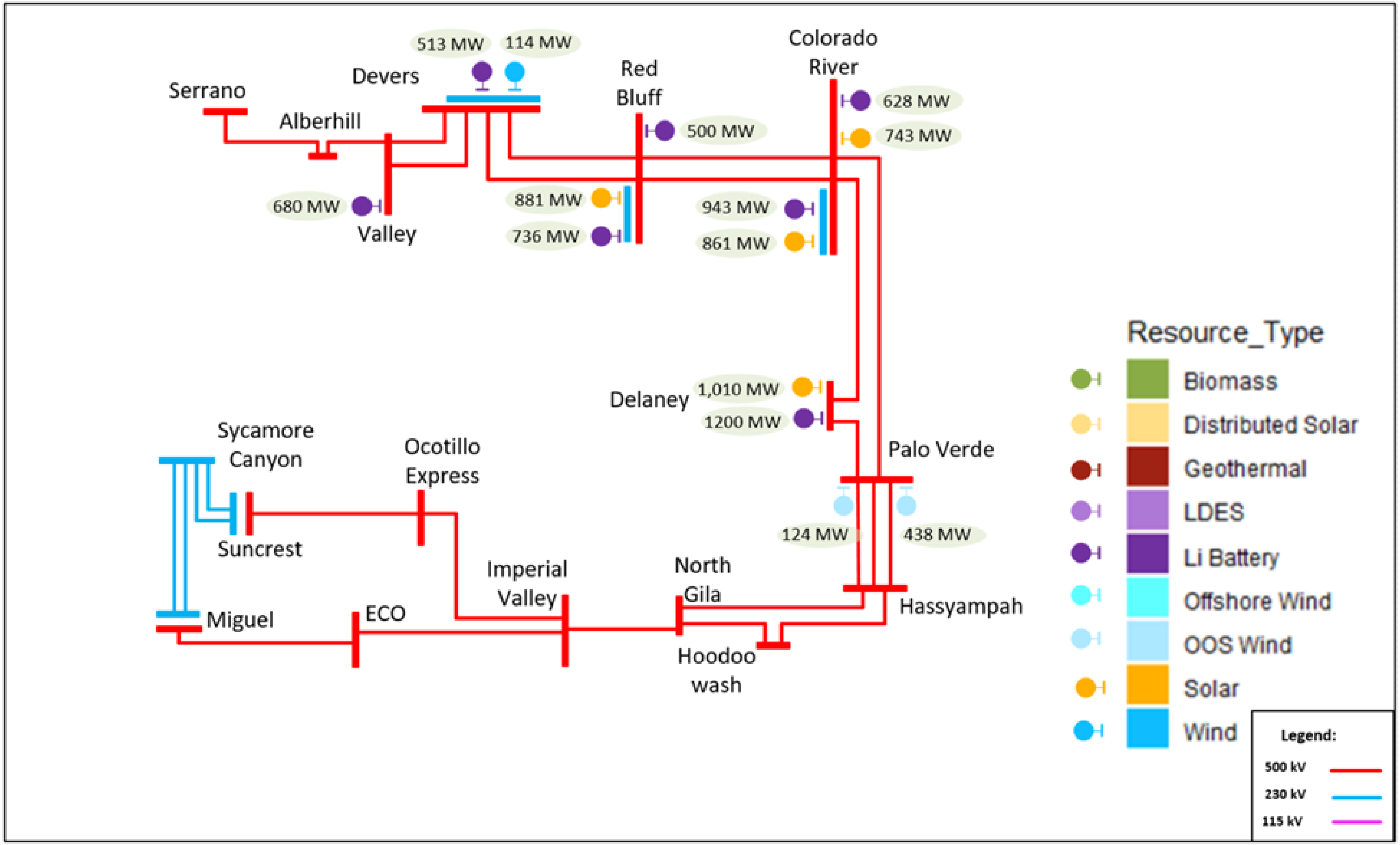
Mesa–Mira Loma 500 kV deliverability constraint

Overloaded Facility	Contingency	Loading (%) HSN	
		Base	Sensitivity
Mesa–Mira Loma 500 kV line (UG segment)	Base Case	101%	111%

Affected transmission zones		Eastern, NOL, EOP, SDG&E and IID areas	
		Base	Sensitivity
Generic portfolio MW behind the constraint (installed FCDS capacity)		8,917 MW	21,160 MW
Generic battery storage portfolio MW behind the constraint (installed FCDS capacity)		3,932 MW	9,192 MW
Deliverable generic portfolio MW w/o mitigation (Installed FCDS capacity)		8,851 MW	18,031 MW
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		388 MW	3,451 MW
Mitigation Options	RAS	Not applicable	Not applicable
	Re-locate portfolio battery storage (MW)	Not applicable	Not applicable
	Transmission upgrade including cost	Add a third set of cables to the UG segment of Mesa–Mira Loma 500 kV line ($35 Million).	
Recommended Mitigation		Add a third set of cables to the UG segment of Mesa–Mira Loma 500 kV line (ISD - Q4 2026)	

SCE Eastern Interconnection Area

SCE Eastern Interconnection Area – Mapped Base Portfolio



SCE Eastern Area On-Peak Constraints

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
Devers-Red Bluff 500 kV	Base	5,821	1,404	0	7,956	Devers-Red Bluff 1 and 2 Upgrade
	Sensitivity	14,739	5002	0	15,033	Base upgrade plus South Area Reinforcement
Serano-Alberhill-Valley 500 kV	Base	2,514	769	0	2,732	Upgrade of 2 – 500 kV lines, 3 – 230 kV lines and adding third underground cable to the existing Mira Loma 500 kV circuit.
	Sensitivity	8,233	2,961	2,952	5,281	Base upgrade
Colorado River-Red Bluff 500 kV	Base	5,821	1,404	4,847	1,150	Colorado River-Red Bluff 1 Upgrade
	Sensitivity	13,221	4,523	11,450	1,972	Colorado River-Red Bluff 1 Upgrade
Colorado River 500/230 kV	Base	0	0	-	323	West of Colorado River CRAS
	Sensistivity	371	207	0	465	

On-peak Devers-Red Bluff 500 kV Deliverability Constraint

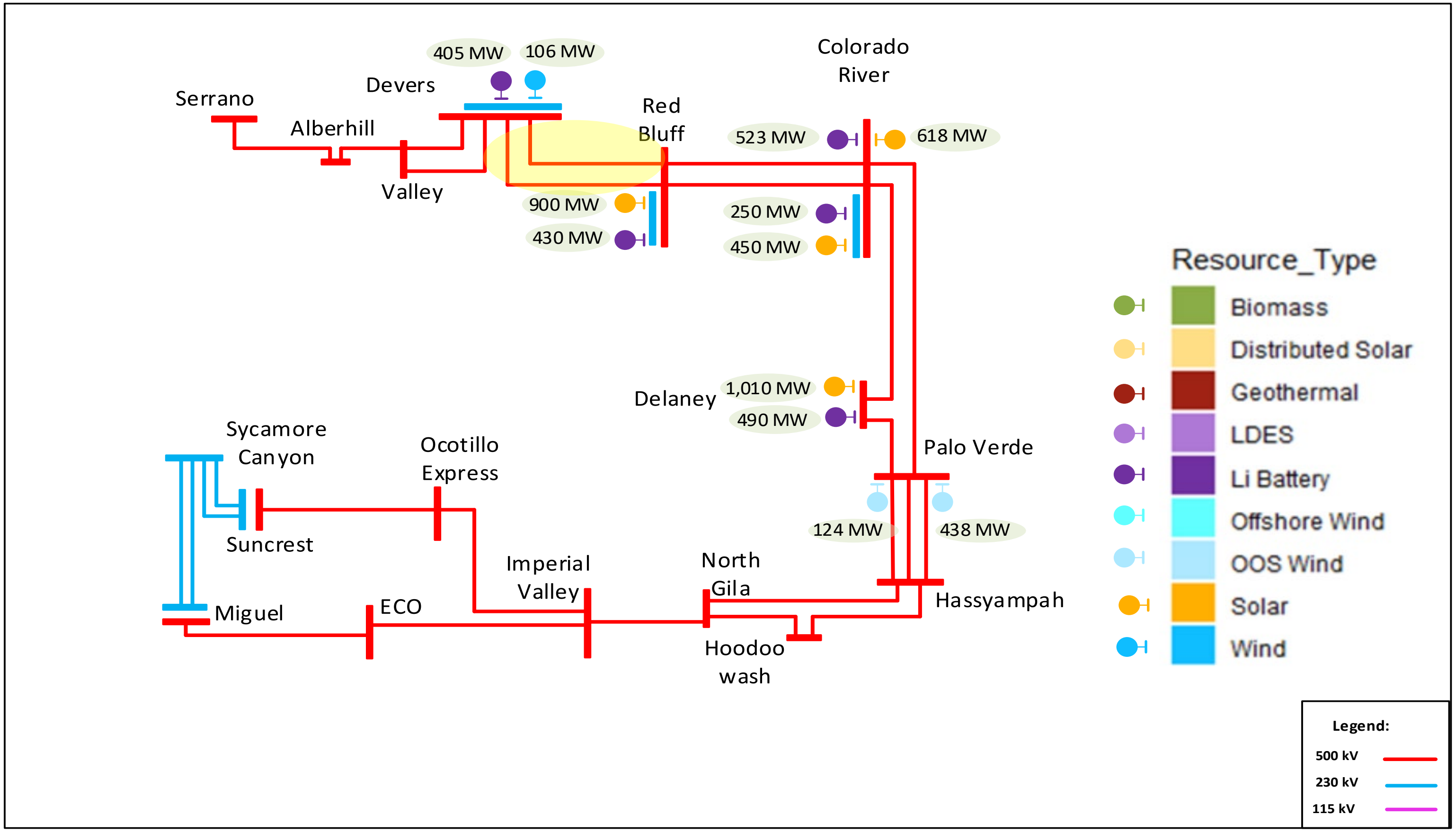
Overloaded Facility	Contingency	Highest Loading (%) (HSN)	
		Base	Sensitivity
Devers – Red Bluff 500 kV No.1	Devers – Red Bluff 500 kV No. 2	145	172
	N.Gila – Imperial Valley 500 kV No.1	<100	105
	Base Case	<100	104
	Devers – Mirage 230 kV No.1 AND Devers – Mirage 230 kV No.2	<100	101
	Eldorado – Lugo 500 kV No.1	<100	101
Devers – Red Bluff 500 kV No. 2	Devers – Red Bluff 500 kV No.1	142	169
	Base Case	<100	104

Affected transmission zones	SCE Eastern (east of Red Bluff), East of Pisgah, and SDG&E areas	
	Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)	5821	14739
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)	1404	5002
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)	0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)	7956	15033

On-peak Devers-Red Bluff 500 kV Deliverability Constraint

Affected transmission zones		**SCE Eastern (east of Red Bluff), East of Pisgah, and SDG&E areas**	
		Base	Sensitivity
Mitigation Options	RAS	West of Colorado River CRAS RAS alone not sufficient RAS is marginally sufficient with SCE Eastern area line upgrades	West of Colorado River CRAS with Eastern area line upgrades is not sufficient
	Re-locate generic portfolio battery storage (MW)	Not sufficient	
	Transmission upgrade	Upgrade Devers-Red Bluff No.1 Upgrade Devers-Red Bluff No.2 Transmission development alternatives: • New Imperial Valley-Inland-Serrano 500 kV transmission line • New Imperial Valley-N.SONGS-Serrano 500 kV transmission line • Multi-terminal HVDC VSC Imperial Valley – Inland – Del Amo • New Devers-Red Bluff and Devers-Mira Loma 500 kV transmission lines	
Recommended Mitigation		Upgrade Devers-Red Bluff No. 1 and Devers-Red Bluff No. 2 as a first step to increase deliverability in the SCE Eastern area Plus South Area Reinforcement – *The recommended transmission development alternative will be discussed in the SDG&E area presentation*	

Recommended Line Upgrades for Devers-Red Bluff 500 kV Constraint



Devers-Red Bluff 500 kV 1 and 2 Line Upgrade

- Description:
  - Increase the rating of the Devers-Red Bluff 500 kV 1 Line from 2598 / 2858 MVA (normal/emergency) to 3291 / 3880 MVA (normal/emergency)
  - Increase the rating of the Devers-Red Bluff 500 kV 2 Line from 2598 / 2910 MVA (normal/emergency) to 3291 / 3880 MVA (normal/emergency)
- Objectives:
  - To mitigate the Devers-Red Bluff 500 kV deliverability constraint. First step of transmission upgrades considered to address this constraint, and to maximize the use of existing transmission infrastructure as much as possible.
- Expected in-service date: 2028
- Project cost: $140M

On-peak Serrano-Alberhill-Valley 500 kV Deliverability Constraint

Overloaded Facility	Contingency	Highest Loading (%) (HSN)	
		Base	Sensitivity
Devers – Valley 500 kV No.1	Devers – Valley 500 kV No.2	114	136
Serrano–Alberhill–Valley 500 kV No.1	Base Case	110	127
San Bernardino – Vista 230 kV No.1	Devers – Vista 230 kV No.1 AND Devers – Vista 230 kV No.2	111	127
	San Bernardino – Etiwanda 230 kV No.1	101	110
	San Bernardino – Etiwanda 230 kV No.1 AND Vista – Etiwanda 230 kV No.1	<100	104
	Serrano–Alberhill–Valley 500 kV No.1	<100	106
Vista – Etiwanda 230 kV No.1	Wildlife – Vista 230 kV No.1 AND Mira Loma – Vista 230 kV No.2	110	118
	Mira Loma – Wildlife 230 kV No.1 AND Mira Loma – Vista 230 kV No.2	102	108
	Serrano–Alberhill–Valley 500 kV No.1	103	106

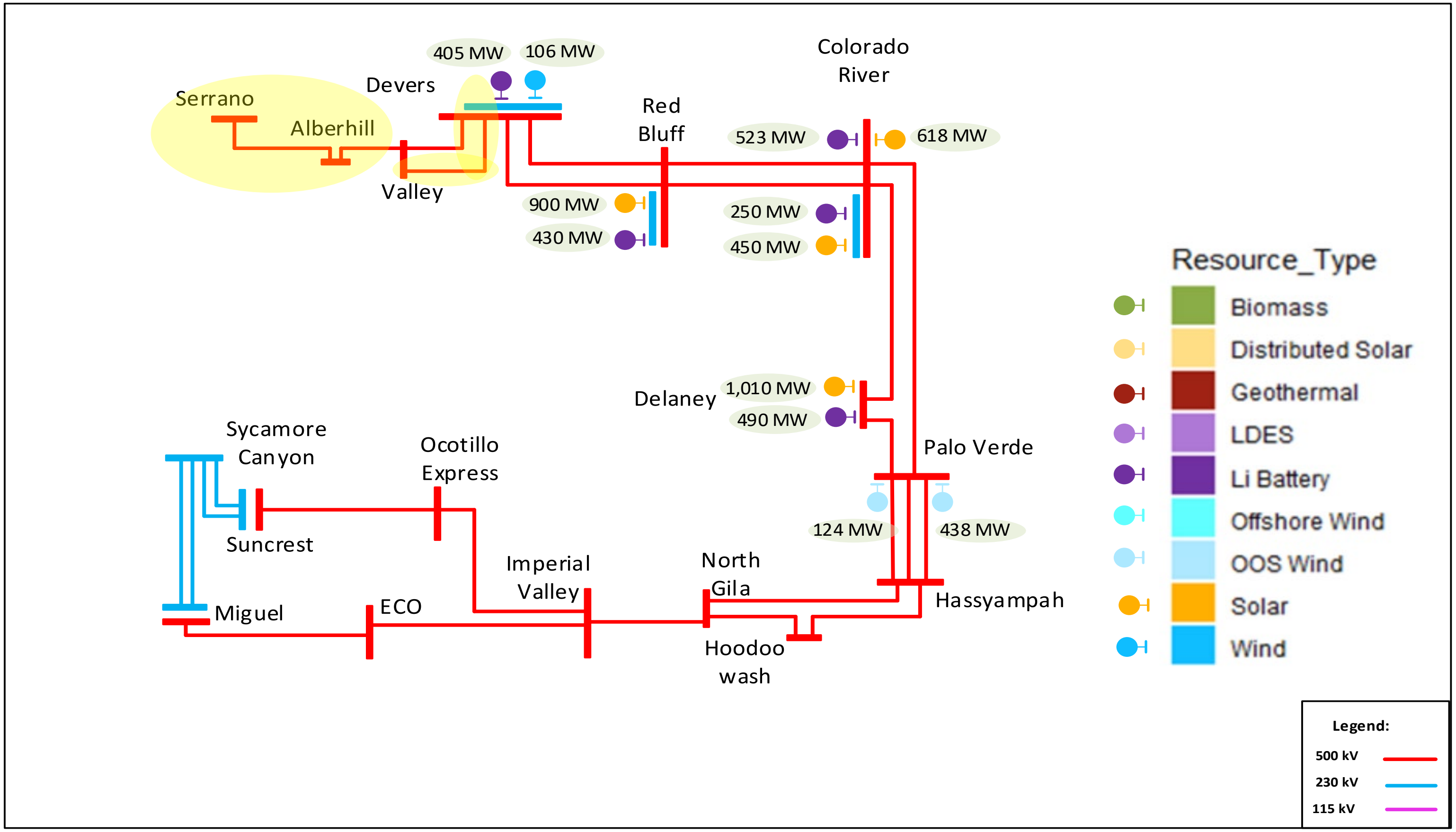
On-peak Serrano-Alberhill-Valley 500 kV Deliverability Constraint

Overloaded Facility	Contingency	Highest Loading (%) (HSN)	
		Base	Sensitivity
San Bernardino – Etiwanda 230 kV No.1	San Bernardino – Vista 230 kV No.1	104	113
	Serrano–Alberhill–Valley 500 kV No.1	<100	103
Mira Loma – Mesa 500 kV No.1	Base Case	102	111
Devers 500/230 kV Transformer No.1	Serrano–Alberhill–Valley 500 kV No.1	102	117
Devers 500/230 kV Transformer No.2	Serrano–Alberhill–Valley 500 kV No.1	<100	109

On-peak Serrano-Alberhill-Valley 500 kV Deliverability Constraint

Affected transmission zones		SCE Eastern and SDG&E	
		Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)		2514	8233
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		769	2961
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		0	2952
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		2732	5281
Mitigation Options	RAS	West of Colorado River CRAS No RAS available to address Base Case and 230 kV line overloads	
	Re-locate generic portfolio battery storage (MW)	Not sufficient	
	Transmission upgrade	Upgrade Devers-Valley No.1 Upgrade Serrano-Alberhill No.1 and Alberhill-Valley No.1 Upgrade San Bernardino-Etiwanda No.1 Upgrade San Bernardino-Vista No.1 Upgrade Vista-Etiwanda No.1 Mira Loma-Mesa 500kV Underground Cable Addition	
Recommended Mitigation		Upgrade the lines identified in the “Transmission upgrade” section above	

Recommended Line Upgrades for Serrano-Alberhill-Valley 500 kV Constraint



Devers-Valley 500 kV 1 Line Upgrade

- Description:
  - Increase the line rating from 2598 / 2858 MVA (normal/emergency) to 3421 / 3880 MVA (normal/emergency)
- Objectives:
  - To mitigate the Serrano-Alberhill-Valley 500 kV deliverability constraint
- Expected in-service date: 2028
- Project cost: $45M

Serrano-Alberhill-Valley 500 kV 1 Line Upgrade

- Description:
  - Increase the line rating of the Serrano-Alberhill 500 kV 1 Line from 2598 / 4157 MVA (normal/emergency) to 3421 / 4157 MVA (normal/emergency)
  - Increase the line rating of the Alberhill-Valley 500 kV 1 Line from 2598 / 4157 MVA (normal/emergency) to 3421 / 4616 MVA (normal/emergency)

- Objectives:
  - To mitigate the Serrano-Alberhill-Valley 500 kV deliverability constraint

- Expected in-service date: 2028

- Project cost: $60M

San Bernardino-Etiwanda 230 kV 1 Line Upgrade

- Description:
  - Increase the line rating of the San Bernardino-Etiwanda 230 kV 1 Line from 988 / 1040 MVA (normal/emergency) to 1287 / 1737 MVA (normal/emergency)
- Objectives:
  - To mitigate the Serrano-Alberhill-Valley 500 kV deliverability constraint
- Expected in-service date: 2031
- Project cost: $65M

San Bernardino-Vista 230 kV 1 Line Upgrade

- Description:
  - Increase the line rating of the San Bernardino-Vista 230 kV 1 line from 988 / 1331 MVA (normal/emergency) to 1287 / 1737 MVA (normal/emergency)

- Objectives:
  - To mitigate the Serrano-Alberhill-Valley 500 kV deliverability constraint

- Expected in-service date: 2026

- Project cost: $18M

Vista-Etiwanda 230 kV 1 Line Upgrade

- Description:
  - Increase the line rating of the Vista-Etiwanda 230 kV 1 Line from 797 / 876 MVA (normal/emergency) to 988 / 1331 MVA (normal/emergency)
- Objectives:
  - To mitigate the Serrano-Alberhill-Valley 500 kV deliverability constraint
- Expected in-service date: 2031
- Project cost: $13M

Mira Loma-Mesa 500 kV Underground Third Cable

- Description:
  - Add 3rd set of 5000 kcmil to underground section to increase the rating of the most limiting section of the existing Mira Loma-Mesa 500 kV circuit, the rating will be upgraded from 1992 / 3204 MVA (normal/emergency) to 3421 / 4616 MVA (normal/emergency)

- Objectives:
  - To mitigate the Serrano-Alberhill-Valley 500 kV and Mesa-Mira Loma 500 kV Line UG Segment deliverability constraints

- Expected in-service date: 2026

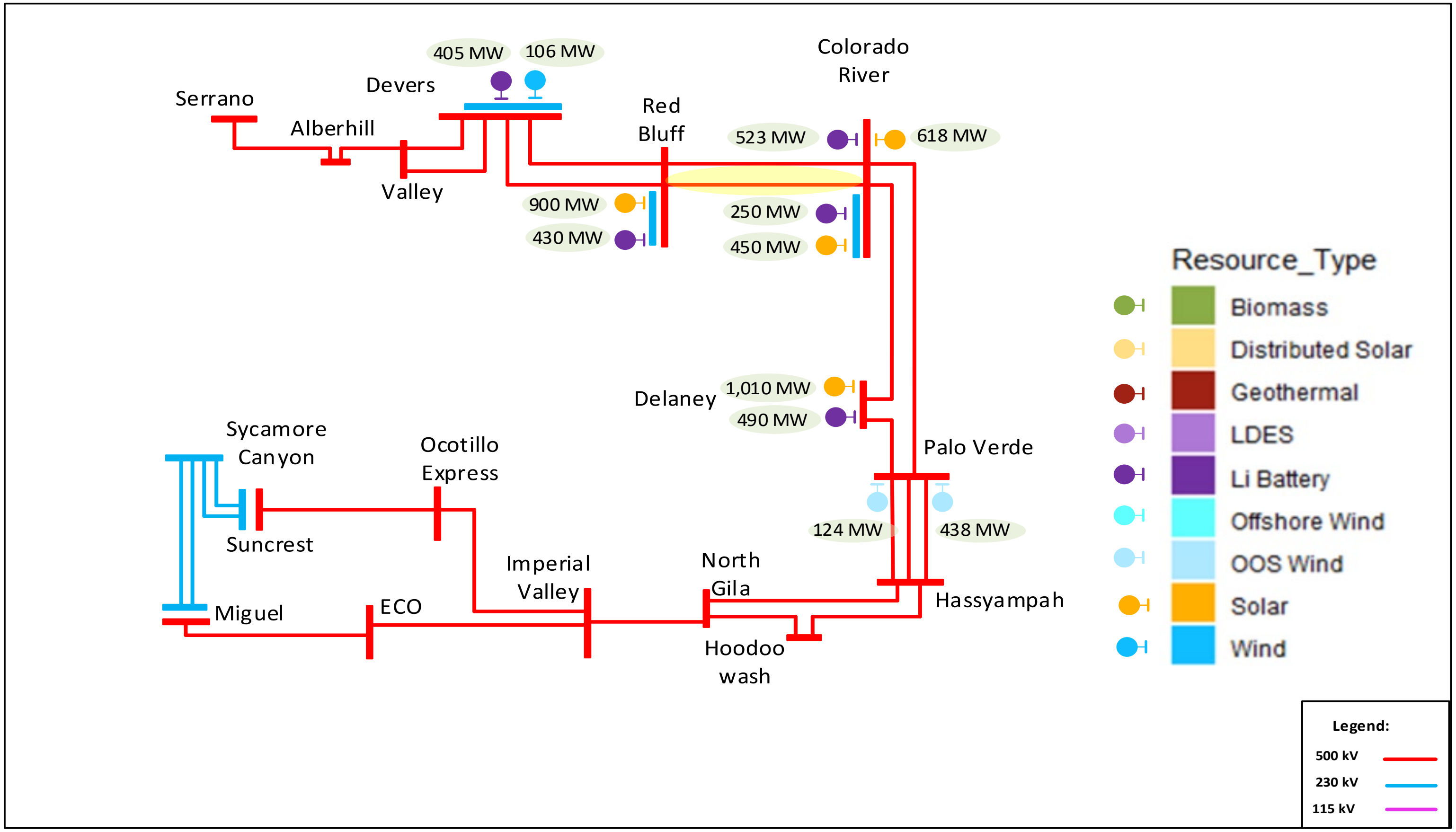
- Project cost: $35M

On-peak Colorado River-Red Bluff 500 kV Deliverability Constraint

Overloaded Facility	Contingency	Highest Loading (%) (HSN)	
		Base	Sensitivity
Colorado River – Red Bluff 500 kV No.1	Colorado River – Red Bluff 500 kV No.2	108	109

Affected transmission zones		SCE Eastern (east of Colorado River), East of Pisgah, and SDG&E areas	
		Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)		5821	13221
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		1404	4523
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		4847	11450
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		1150	1972
Mitigation Options	RAS	West of Colorado River CRAS RAS is marginally sufficient	West of Colorado River CRAS is not sufficient
	Re-locate generic portfolio battery storage (MW)	Not sufficient	
	Transmission upgrade	Upgrade Colorado River-Red Bluff No.1	
Recommended Mitigation		Upgrade Colorado River-Red Bluff No.1	

Recommended Line Upgrades for Colorado River-Red Bluff 500 kV Constraint

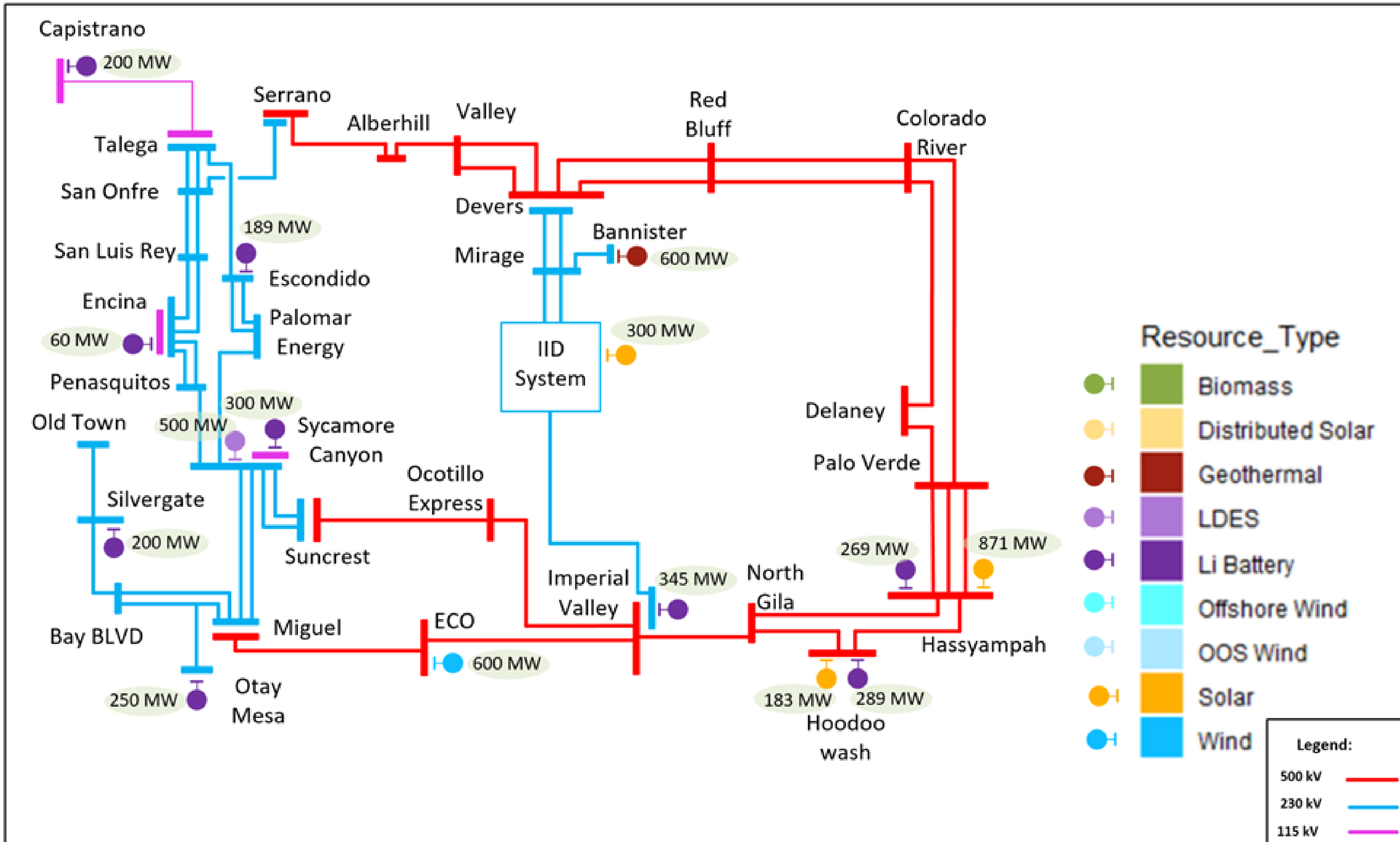


Colorado River-Red Bluff 500 kV 1 Line Upgrade

- Description:
  - Increase the line rating from 2338 / 2858 MVA (normal/emergency) to 3421 / 3880 MVA (normal/emergency)
- Objectives:
  - To mitigate the Colorado River-Red Bluff 500 kV deliverability constraint
- Expected in-service date: 2028
- Project cost: $50M

SDG&E Interconnection Area

SDG&E Interconnection Area – Mapped Base Portfolio



SDG&E Interconnection Area On-Peak Constraints

Constraint	Portfolio	Portfolio MW behind the constraint	Energy storage portfolio MW behind the constraint	Deliverable Portfolio MW w/o mitigation	Total undeliverable baseline and portfolio MW	Mitigation
East of Miguel	Base	1,178	279	0	3,080	Southern area reinforcement
	Sensitivity	5,834	2,173	0	10,398	
Bay Boulevard-Silvergate	Base	1,209	10	0	2,373	2 hour emergency rating on Silvergate-Bay Boulevard 230 kV line and south area reinforcement
	Sensitivity	1,676	475	0	3,408	
Encina-San Luis Rey	Base	1,958	510	0	2,776	30 minute emergency rating on Encina Tap-San Luis Rey 230 kV Line and south area reinforcement
	Sensitivity	3,260	1,808	2,765	1,422	
Sycamore Area	Base	1,509	310	1,030	680	30 min emergency rating for Sycamore-Scripps 69 kV line upgrade Sycamore-Chicarita 138 kV, new 3 ohm reactor on Sycamore-Penasquitos 230 kV and South area reinforcement
	Sensistivity	2,716	1,264	1,314	2,329	
San Luis Rey-San Onofre	Base	2,427	1,028	0	3,454	South area reinforcement
	Sensistivity	3,625	2,037	3,801	1,120	
Silvergate-Old Town	Base	909	210	0	1,944	Use 30 min emergency rating for Silvergate-Old Town and Silvergate-Old Town Tap 230 kV lines and South area reinforcement
	Sensitivity	1,376	675	0	2,466	
Friars-Doublet Tap	Base	500	500	0	1,339	SDGE Project Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento
	Sensitivity	2,155	1,055	0	2,604	
San Marcos-Melrose Tap	Base	1,189	689	0	1,784	Reconductor TLC680C San Marcos-Melrose Tap
	Sensitivity	2,279	1,179	797	1,482	

On-peak San Diego study area deliverability constraints – SX

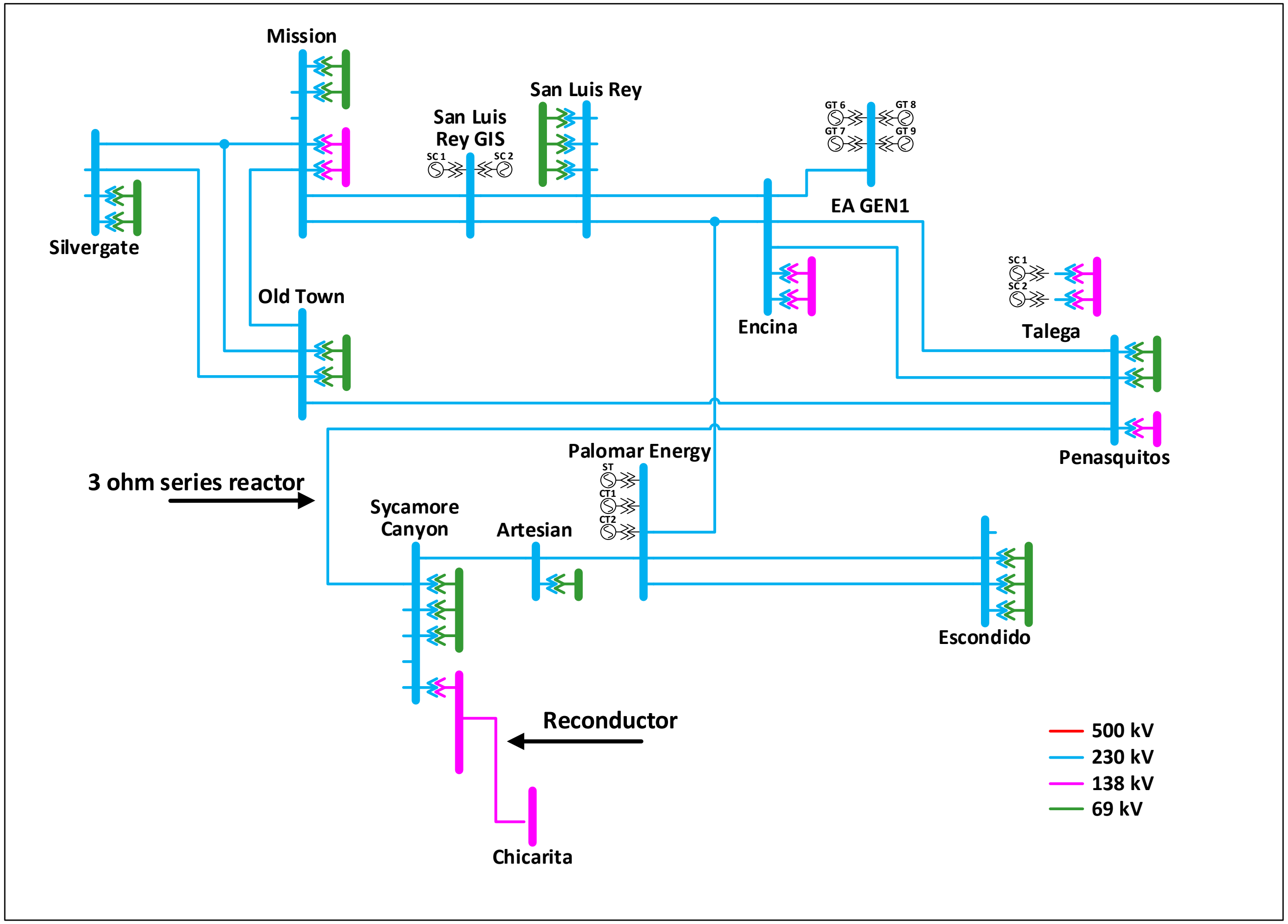
Constraint Grouping	Overloaded Facility	Contingency	Highest Loading (%) (HSN)	
			Base	Sensitivity
Sycamore	Sycamore-Chicarita 138 kV	Multiple P1 and P7 contingencies	132.93	153.88
	Sycamore-Scripps 69 kV	P1 contingency	< 100	116.47
	Sycamore-Artesian 230 kV	P1 contingency	< 100	101.42
	Sycamore-Penasquitos 230 kV	Base Case	< 100	102.89
		Multiple P1 and P7 contingencies	114.64	127.95

Affected transmission zones	Arizona, Baja, Imperial, San Diego	
	Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)	1509	2716
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)	310	1264
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)	1030	1314
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)	680	2329

On-peak San Diego study area deliverability constraints – SX

Affected transmission zones	Arizona, Baja, Imperial, San Diego	
Mitigation Options	RAS	None
	Re-locate generic portfolio battery storage (MW)	Not adequate
	Transmission upgrade	Option 1: • SDGE BES Project Part 2 - Old Town/Silvergate area - rebuild TL13822 Mission-Carlton Hills for a double 230 kV for looping TL23041 OM-ML-SX into Mission (Sycamore-San Luis Rey and Miguel-Mission #3). Reconductor TL23022 (ML-MS) and TL23023 (ML-MS) and TL23001 (SLR-MS) and TL23004 (SLR-MS). Install 2 phase shifter transformers at Mission (MS-ML and SX-SLR) • upgrade TL13820 Sycamore-Chicarita 138 kV • use 30 min emergency rating for Sycamore-Scripps 69 kV line
		Option 2: • South Area Reinforcement Alternatives • upgrade Sycamore-Chicarita 138 kV • use 30 min emergency rating for Sycamore-Scripps 69 kV line • new 3 ohm reactor on Sycamore-Penasquitos 230 kV
Recommended Mitigation		• North Gila-Imperial Valley–North of SONGS-Serrano-Del Amo–Mesa 500 kV upgrade • upgrade Sycamore-Chicarita 138 kV • use 30 min emergency rating for Sycamore-Scripps 69 kV line • new 3 ohm reactor on Sycamore-Penasquitos 230 kV

Upgrade TL13820 Sycamore-Chicarita 138 kV; 3 ohm series reactor on Sycamore-Penasquitos 230 kV Line



Upgrade TL13820 Sycamore-Chicarita 138 kV

- Objective:
  - To address the Sycamore Area constraint identified in the base and sensitivity portfolios
- Project scope:
  - Reconductor Sycamore-Chicarita 138 kV line to 250 MVA
- Project cost:
  - $60M
- Expected in-service date:
  - 2032

3 ohm series reactor on Sycamore-Penasquitos 230 kV Line

- Objective:
  - To address the Sycamore Area constraint identified in the base and sensitivity portfolios
- Project scope:
  - Install 3 ohm series reactor on Sycamore-Penasquitos 230 kV Line
- Project cost:
  - $8M
- Expected in-service date:
  - 2032

On-peak San Diego study area deliverability constraints – SLR-SO

Overloaded Facility		Contingency	Highest Loading (%) (HSN)	
			Base	Sensitivity
San Luis Rey-San Onofre	San Luis Rey-San Onofre 230 kV #1	San Luis Rey-San Onofre 230 kV #2 and #3	160.55	148.02
		Multiple P1 contingencies	103.97	< 100

Affected transmission zones	Arizona, Baja, Imperial, San Diego	
	Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)	2427	3625
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)	1028	2037
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)	0	3801
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)	3454	1120

On-peak San Diego study area deliverability constraints – SLR-SO

<table>
<tr><th>Affected transmission zones</th><th colspan="3">Arizona, Baja, Imperial, San Diego</th></tr>
<tr><td colspan="2"></td><td>Base</td><td>Sensitivity</td></tr>
<tr><td colspan="2">Generic Portfolio MW behind the constraint (installed FCDS capacity)</td><td>2427</td><td>3625</td></tr>
<tr><td colspan="2">Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)</td><td>1028</td><td>2037</td></tr>
<tr><td colspan="2">Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)</td><td>0</td><td>3801</td></tr>
<tr><td colspan="2">Total undeliverable baseline and portfolio MW (Installed FCDS capacity)</td><td>3454</td><td>1120</td></tr>
<tr><td rowspan="4">Mitigation Options</td><td>RAS</td><td colspan="2">CEC RAS (under construction), not sufficient</td></tr>
<tr><td>Re-locate generic portfolio battery storage (MW)</td><td colspan="2">Not adequate</td></tr>
<tr><td rowspan="2">Transmission upgrade</td><td colspan="2">Option 1: SDGE BES Project Part 3 - Proposed projects in the San Luis Rey/San Onofre area - upgrade TL23006 SLR-SO to form new SLR-SO 230 kV #4 line</td></tr>
<tr><td colspan="2">Option 2: South Area Reinforcement Alternatives</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td colspan="2">North Gila-Imperial Valley–North of SONGS-Serrano-Del Amo–Mesa 500 kV upgrade</td></tr>
</table>

On-peak San Diego study area deliverability constraints – SG-OT

Overloaded Facility		Contingency	Highest Loading (%) (HSN)	
			Base	Sensitivity
Silvergate-Old Town	Silvergate-Old Town 230 kV	Multiple P1 and P7 contingencies	152.22	161.22
	Silvergate-Old Town Tap 230 kV		149.83	159.1

Affected transmission zones	Baja, Imperial, San Diego	
	Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)	909	1376
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)	210	675
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)	0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)	1944	2466

On-peak San Diego study area deliverability constraints – SG-OT

<table>
<tr><th>Affected transmission zones</th><th colspan="2">Baja, Imperial, San Diego</th></tr>
<tr><td rowspan="4">Mitigation Options</td><td>RAS</td><td>Proposed RAS to trip generation at Silvergate, not sufficient</td></tr>
<tr><td>Re-locate generic portfolio battery storage (MW)</td><td>Not adequate</td></tr>
<tr><td rowspan="2">Transmission upgrade</td><td>Option 1:
• Use 30 min emergency rating for Silvergate-Old Town and Silvergate-Old Town Tap 230 kV lines
• SDGE BES Project Part 4 - Old Town 230 kV rearrangement - loop TL23028 SG-OT into Mission, tap TL23029 SG-OT on TL23013 OT-PQ
• Mitigate overload on Old Town Tap-Penasquitos 230 kV</td></tr>
<tr><td>Option 2:
• Use 30 min emergency rating for Silvergate-Old Town and Silvergate-Old Town Tap 230 kV lines
• South Area Reinforcement Alternatives</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td>• Use 30 min emergency rating for Silvergate-Old Town and Silvergate-Old Town Tap 230 kV lines
• North Gila-Imperial Valley–North of SONGS-Serrano-Del Amo–Mesa 500 kV upgrade</td></tr>
</table>

On-peak San Diego study area deliverability constraints – FR-DT

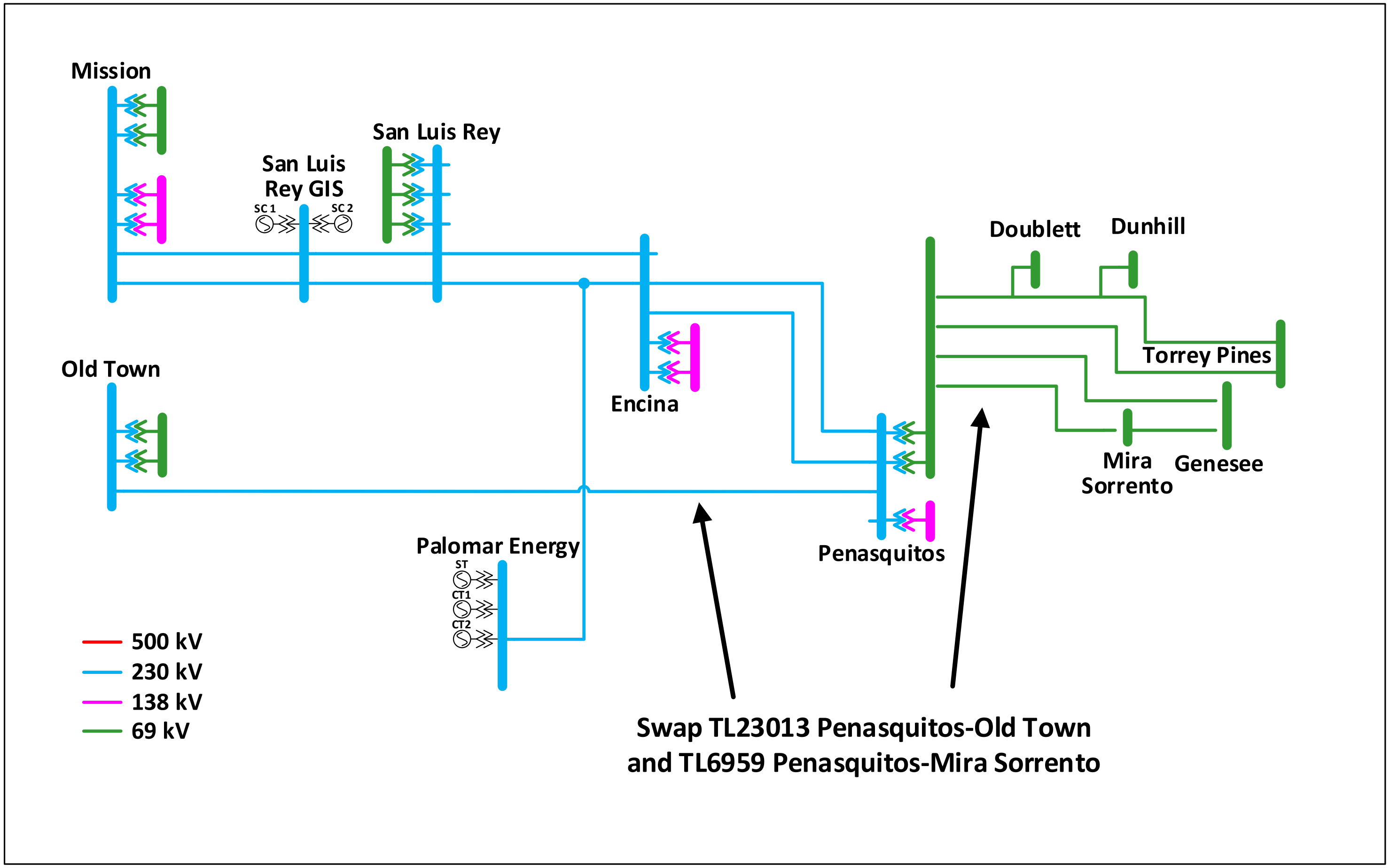
Overloaded Facility		Contingency	Highest Loading (%) (HSN)	
			Base	Sensitivity
Friars-Doublet Tap	Friars-Doublet Tap 138 kV	P7: Penasquitos-Old Town 230 kV and Sycamore-Penasquitos 230 kV	156.44	174.69
	Multiple other 138 kV and 69 kV lines		114.83	126.49

Affected transmission zones	Baja, Imperial, San Diego	
	Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)	500	2155
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)	500	1055
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)	0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)	1339	2604

On-peak San Diego study area deliverability constraints – FR-DT

Affected transmission zones	Baja, Imperial, San Diego	
Mitigation Options	RAS	RAS to trip Otay Mesa generation, not sufficient
	Re-locate generic portfolio battery storage (MW)	Not adequate
	Transmission upgrade	Option 1: SDGE Project Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento
		Option 2: Reconductor TL13810 DT-FR and TL13827 FR-MS
Recommended Mitigation		SDGE Project Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento

Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento



California ISO

Rearrange TL23013 PQ-OT and TL6959 PQ-Mira Sorrento

- Objective:
  - To address the Friars-Doublet Tap constraint identified in the base and sensitivity portfolios
- Project scope:
  - Swap TL23013 Penasquitos-Old Town with TL6959 Penasquitos-Mira Sorrento so that TL23013 & TL23071 will not share same Structures (TL23071 sharing structures withTL6959 and TL23013 sharing structures with TL13810). This proposal will require to upgrade 2 miles of 138kV structures for 230kV operation
- Project cost:
  - $21M
- Expected in-service date:
  - 2032

On-peak San Diego study area deliverability constraints – SM-MT

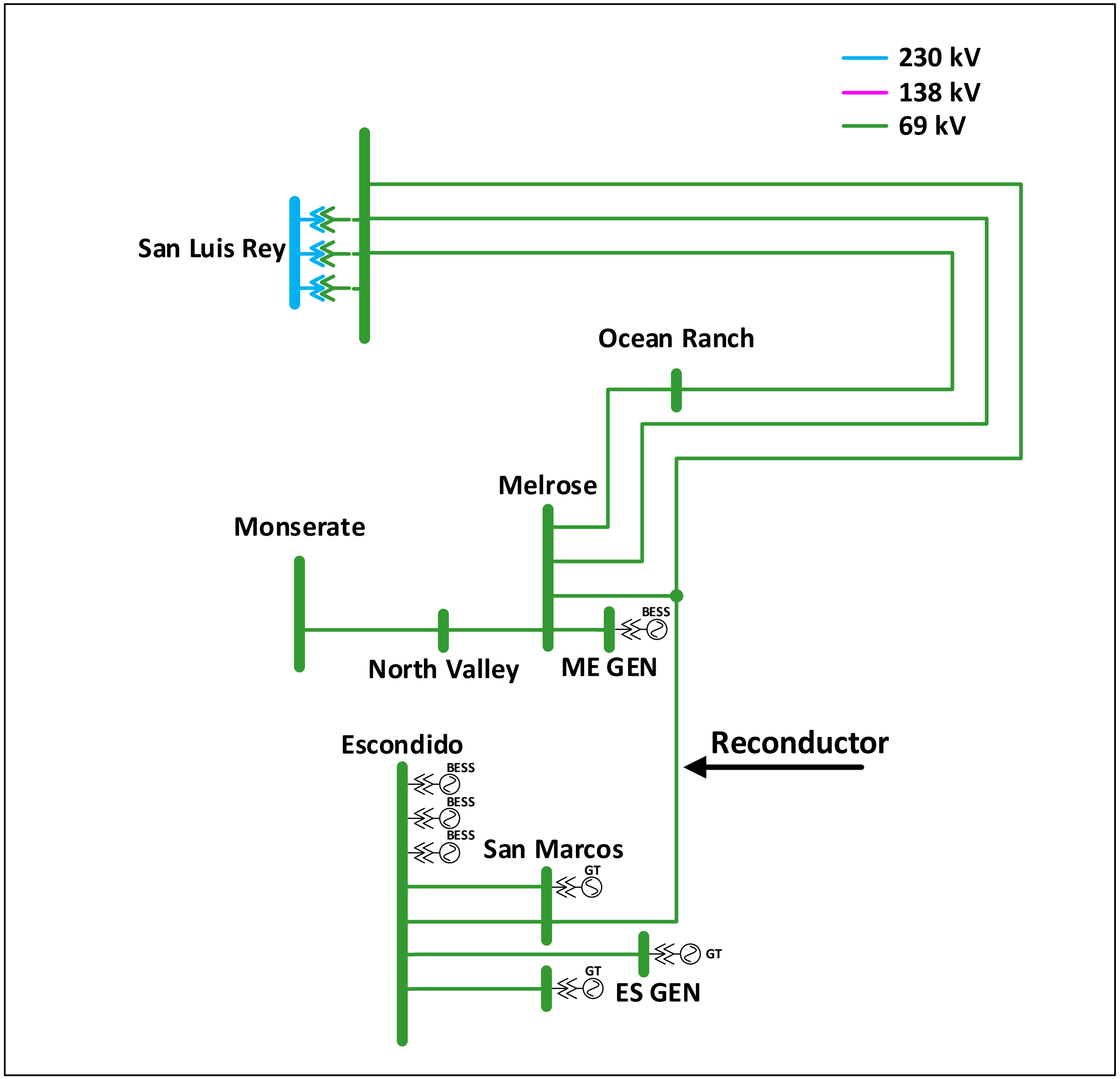
Overloaded Facility		Contingency	Highest Loading (%) (HSN)	
			Base	Sensitivity
San Marcos-Melrose Tap	San Marcos-Melrose Tap 69 kV	Multiple P1 and P7 contingencies	194.76	173.19

Affected transmission zones	Baja, Imperial, San Diego	
	Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)	1189	2279
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)	689	1179
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)	0	797
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)	1784	1482

On-peak San Diego study area deliverability constraints – SM-MT

Affected transmission zones	Baja, Imperial, San Diego	
Mitigation Options	RAS	TL680 OLS - tripping scheme to open San Marcos- Melrose Tap 69 kV line, interim solution
	Re-locate generic portfolio battery storage (MW)	Not adequate
	Transmission upgrade	Reconductor TL680C San Marcos-Melrose Tap
Recommended Mitigation		Reconductor TL680C San Marcos-Melrose Tap

Reconductor TL680C San Marcos-Melrose Tap



Reconductor TL680C San Marcos-Melrose Tap

- Objective:
  - To address the San Marcos-Melrose Tap constraint identified in the base and sensitivity portfolios
- Project scope:
  - Reconductor San Marcos-Melrose Tap 69 kV line to 250 MVA
- Project cost:
  - $28M
- Expected in-service date:
  - 2032

Interaction among SDG&E, SCE Eastern and SCE Metro Interconnection Areas

- The policy-driven assessment results indicated significant inter-dependence in the transmission needs among SDG&E, SCE Eastern and SCE Metro Interconnection Areas.
- The ISO developed and evaluated sets of southern area reinforcement alternatives for the broader area based to identify the most cost effective solution for the broader area.
- In assessing alternatives to address the needs in the areas, the ISO took into consideration the needs of the sensitivity portfolio.

South of Mesa & Serrano–Barre Corridor Constraints

Overloaded Facility	Contingency	Loading (%) (HSN/SSN)	
		Base	Sensitivity
Mesa–Lighthipe 230 kV	Mesa–Redondo & Mesa–Laguna Bell #1 (P7)	<100%	111%/109%
	Mesa–Redondo & La Fresa–Laguna Bell 230 kV (P7)	<100%	106%/107%
Mesa–Laguna Bell #2	Mesa–Redondo & Mesa–Laguna Bell #1 (P7)	<100%	99%/108%
Mesa 500/230 kV transformers 3 & 4	Mesa 500/230 kV transformers 3 or 4 (P1)	<100%	96%/103%

Overloaded Facility	Contingency	Loading (%) HSN/SSN	
		Base	Sensitivity
Barre–Lewis 230 kV	Barre–Villa Park 230 kV (P1)	<100%	109%/101%
	S. Onofre–Santiago 230 kV 1 & 2 (P7)	<100%	107%/93%
Barre–Villa Park 230 kV	Barre–Lewis 230 kV (P1)	<100%	107%/99%
Serrano–Villa Park 230 kV No. 1	Serrano–Villa Park 230 kV No. 2 (P1)	<100%	102%/100%
Serrano 500/230 kV banks	Serrano 500/230 kV transformer (P1)	<100%	104%/99%

South of Mesa corridor constraint summary

Affected transmission zones		Parts of Metro, Tehachapi and Big Creek-Ventura	
		Base	Sensitivity (SSN)
Generic portfolio MW behind the constraint (installed FCDS capacity)		N/A	1,934 MW
Generic battery storage MW behind the constraint (installed FCDS capacity)		N/A	1,807 MW
Deliverable generic portfolio MW w/o mitigation (Installed FCDS capacity)		N/A	0 MW
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		0 MW	2,991 MW
Mitigation Options	RAS	Not needed	Not applicable
	Re-locate portfolio battery storage (MW)	Not needed	Not applicable
	Transmission upgrade including cost	Not needed	See alternatives for the Serrano–Barre corridor constraint
Recommended Mitigation		Not needed	See the recommended alternatives for the Serrano–Barre corridor constraint

California ISO

Serrano–Barre corridor constraint summary

Affected transmission zones		SCE Eastern, SDG&E and IID areas	
		Base	Sensitivity (SSN)
Generic portfolio MW behind the constraint (installed FCDS capacity)		N/A	6,350 MW
Generic battery storage MW behind the constraint (installed FCDS capacity)		N/A	3,109 MW
Deliverable generic portfolio MW w/o mitigation (Installed FCDS capacity)		N/A	4,712 MW
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		0 MW	1,638 MW
Mitigation Options	RAS	Not applicable	
	Re-locate portfolio battery storage (MW)	Not applicable	
	Transmission upgrade including cost	1. Serrano-Mesa–Del Amo 500 kV Development ($1,200 million) 2. Mesa–Del Amo–Serano 500 kV Development ($1,125 million) 3. HVDC alternatives involving a 2500 MW converter station at Del Amo identified to address constraints in the SDG&E and Eastern area ($7.0B-7.6B)	
Recommended Mitigation		North Gila-Imperial Valley–North of SONGS-Serrano-Del Amo–Mesa 500 kV upgrade	

On-peak San Diego study area deliverability constraints – East of Miguel

Constraint Grouping	Overloaded Facility	Contingency	Highest Loading (%) (HSN)	
			Base	Sensitivity
Sycamore-Suncrest	Sycamore-Suncrest 230 kV #1	Multiple P1 and P7 contingencies	108.87	133.37
	Sycamore-Suncrest 230 kV #2		108.85	133.35
Miguel banks	Miguel 500/230 kV #1	Multiple P1 and P7 contingencies	115.67	143.54
	Miguel 500/230 kV #2		113.5	140.87
ECO-Miguel	ECO-Miguel 500 kV	Multiple P1 and P7 contingencies	< 100	114.28

Affected transmission zones	Arizona, Baja, Imperial, Riverside East	
	Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)	1178	5834
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)	279	2173
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)	0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)	3080	10398

On-peak San Diego study area deliverability constraints – East of Miguel

Affected transmission zones		Arizona, Baja, Imperial, Riverside East
Mitigation Options	RAS	• Existing TL23054/TL23055 RAS, not sufficient • Existing Miguel Bank 80 and 81 RAS, not sufficient
	Re-locate generic portfolio battery storage (MW)	Not adequate
	Transmission upgrade*	• Alternative A1: North Gila–Imperial Valley–Inland–Serrano–Del Amo–Mesa 500kV AC Development • Alternative A2: North Gila–Imperial Valley–N.SONGS–Serrano–Del Amo–Mesa 500kV AC Development • Alternative B1: North Gila–Imperial Valley 500 kV AC & Imperial Valley–Inland–Del Amo HVDC 500 kV Development • Alternative B2: North Gila–Imperial Valley–N.SONGS AC & N.SONGS–Del Amo HVDC 500 kV Development • Alternative B3: North Gila–Imperial Valley–Inland AC & Inland–Del Amo HVDC 500 kV Development • Alternative C: North Gila–Imperial Valley–Suncrest, Red Bluff–Devers–Mira Loma & Serrano–Del Amo–Mesa 500 kV Development
Recommended Mitigation**		North Gila-Imperial Valley–North of SONGS-Serrano-Del Amo–Mesa 500 kV upgrade

* These transmission alternatives are designed to address deliverability constraints identified in the SCE Eastern and Metro areas in addition to the SDG&E area, as is discussed in the presentations for those areas

** Upgrade details for Serrano-Del Amo-Mesa 500 kV in SCE Metro Area presentation

On-peak San Diego study area deliverability constraints – BB-SG

Constraint Grouping	Overloaded Facility	Contingency	Highest Loading (%) (HSN)	
			Base	Sensitivity
Bay Boulevard-Silvergate	Bay Boulevard-Silvergate 230 kV	Base Case	< 100	107.4
		Multiple P1 and P7 contingencies	130.45	146.11

Affected transmission zones	Baja, Imperial, San Diego	
	Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)	1209	1676
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)	10	475
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)	0	0
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)	2373	3408

On-peak San Diego study area deliverability constraints – BB-SG

Affected transmission zones		Baja, Imperial, San Diego
Mitigation Options	RAS	None
	Re-locate generic portfolio battery storage (MW)	Not adequate
	Transmission upgrade	Option 1: • 2 hour emergency rating on Silvergate-Bay Boulevard 230 kV line • SDGE BES Project Part 2 - Old Town/Silvergate area - rebuild TL13822 Mission-Carlton Hills for a double 230 kV for looping TL23041 OM-ML-SX into Mission (Sycamore-San Luis Rey and Miguel-Mission #3). Reconductor TL23022 (ML-MS) and TL23023 (ML-MS) and TL23001 (SLR-MS) and TL23004 (SLR-MS). Install 2 phase shifter transformers at Mission (MS-ML and SX-SLR)
		Option 2: • 2 hour emergency rating on Silvergate-Bay Boulevard 230 kV line • Silvergate-Bay Boulevard 230 kV 3ohm series reactor • Sycamore-Penasquitos 3ohm series reactor
		Option 3: • 2 hour emergency rating on Silvergate-Bay Boulevard 230 kV line, new Imperial Valley-Serrano 500 kV line • South Area Reinforcement Alternatives
Recommended Mitigation		• 2 hour emergency rating on Silvergate-Bay Boulevard 230 kV line, new Imperial Valley-Serrano 500 kV line • North Gila-Imperial Valley–North of SONGS-Serrano-Del Amo–Mesa 500 kV upgrade

On-peak San Diego study area deliverability constraints – EA-SLR

Constraint Grouping	Overloaded Facility	Contingency	Highest Loading (%) (HSN)	
			Base	Sensitivity
Encina-San Luis Rey	Encina Tap-San Luis Rey 230 kV	Multiple P1 and P7 contingencies	163.02	151.14
	Encina-San Luis Rey 230 kV		141.86	129.73
	Mission-San Luis Rey 230 kV #1		128.73	118.95
	Mission-San Luis Rey 230 kV #2		128.7	117.72
	Escondido-Talega Tap 230 kV		105.02	100.74
	Escondido-San Marcos 69 kV		104.72	104.66

Affected transmission zones	Baja, Imperial, San Diego	
	Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)	1958	3260
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)	510	1808
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)	0	2765
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)	2776	1422

On-peak San Diego study area deliverability constraints – EA-SLR

<table>
<tr><th>Affected transmission zones</th><th colspan="2">Baja, Imperial, San Diego</th></tr>
<tr><td rowspan="5">Mitigation Options</td><td>RAS</td><td>CEC RAS (under construction), not sufficient</td></tr>
<tr><td>Re-locate generic portfolio battery storage (MW)</td><td>Not adequate</td></tr>
<tr><td rowspan="3">Transmission upgrade</td><td>Option 1:
• 30 minute emergency rating on Encina Tap-San Luis Rey 230 kV line
• SDGE BES Project Part 2 - Old Town/Silvergate area - rebuild TL13822 Mission-Carlton Hills for a double 230 kV for looping TL23041 OM-ML-SX into Mission (Sycamore-San Luis Rey and Miguel-Mission #3). Reconductor TL23022 (ML-MS) and TL23023 (ML-MS) and TL23001 (SLR-MS) and TL23004 (SLR-MS). Install 2 phase shifter transformers at Mission (MS-ML and SX-SLR)</td></tr>
<tr><td>Option 2:
• 30 minute emergency rating on Encina Tap-San Luis Rey 230 kV line
• new Encina-San Luis Rey 230 kV line</td></tr>
<tr><td>Option 3:
• 30 minute emergency rating on Encina Tap-San Luis Rey 230 kV line
• South Area Reinforcement Alternatives</td></tr>
<tr><td colspan="2">Recommended Mitigation</td><td>• 30 minute emergency rating on Encina Tap-San Luis Rey 230 kV line
• North Gila-Imperial Valley–North of SONGS-Serrano-Del Amo–Mesa 500 kV upgrade</td></tr>
</table>

On-peak San Diego study area deliverability constraints – SLR-SO

Overloaded Facility		Contingency	Highest Loading (%) (HSN)	
			Base	Sensitivity
San Luis Rey-San Onofre	San Luis Rey-San Onofre 230 kV #1	San Luis Rey-San Onofre 230 kV #2 and #3	160.55	148.02
		Multiple P1 contingencies	103.97	< 100

Affected transmission zones	Arizona, Baja, Imperial, San Diego	
	Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)	2427	3625
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)	1028	2037
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)	0	3801
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)	3454	1120

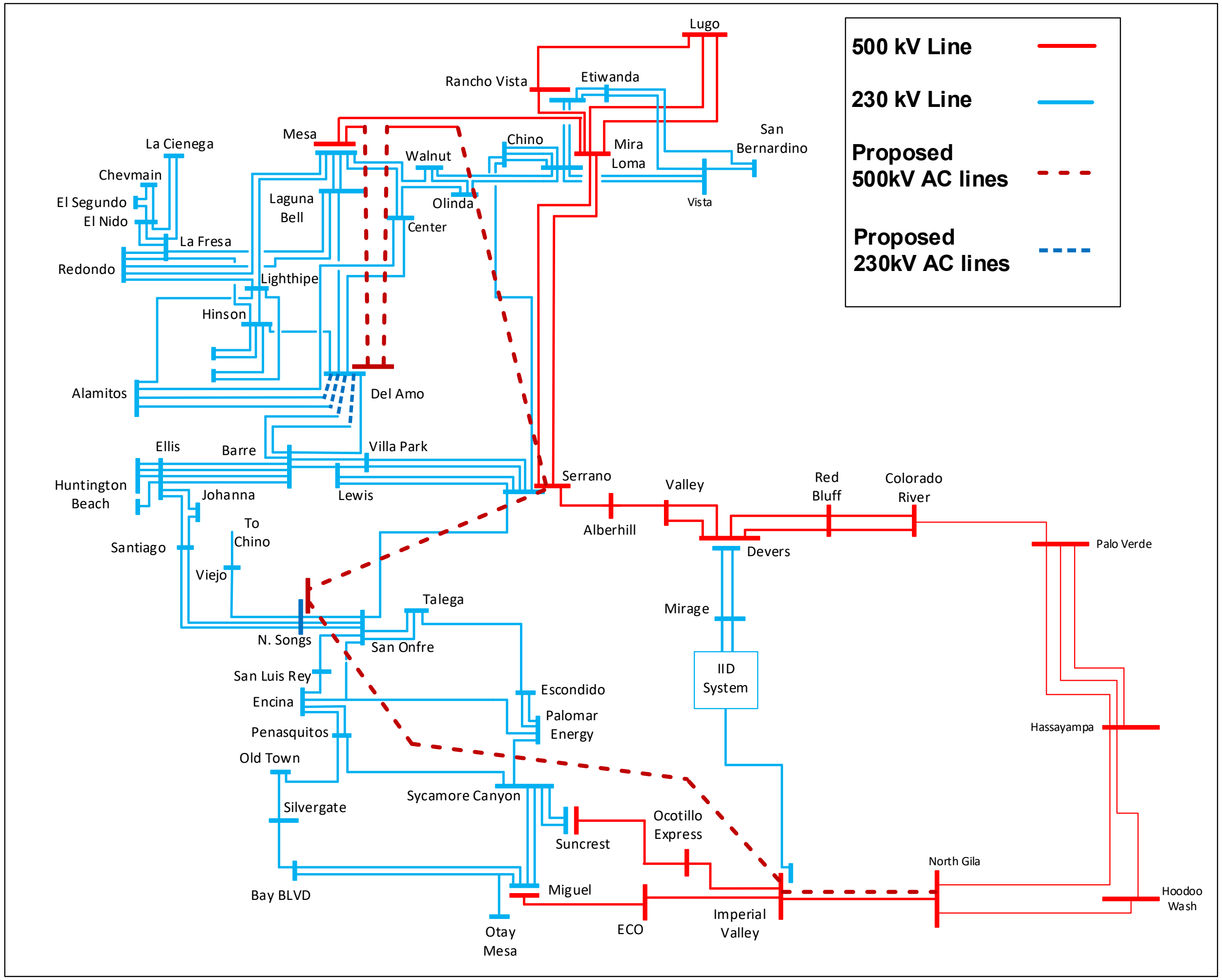
On-peak San Diego study area deliverability constraints – SLR-SO

Affected transmission zones	Arizona, Baja, Imperial, San Diego		
		Base	Sensitivity
Generic Portfolio MW behind the constraint (installed FCDS capacity)		2427	3625
Generic Battery storage portfolio MW behind the constraint (installed FCDS capacity)		1028	2037
Deliverable Generic Portfolio MW w/o mitigation (Installed FCDS capacity)		0	3801
Total undeliverable baseline and portfolio MW (Installed FCDS capacity)		3454	1120
Mitigation Options	RAS	CEC RAS (under construction), not sufficient	
	Re-locate generic portfolio battery storage (MW)	Not adequate	
	Transmission upgrade	Option 1: SDGE BES Project Part 3 - Proposed projects in the San Luis Rey/San Onofre area - upgrade TL23006 SLR-SO to form new SLR-SO 230 kV #4 line	
		Option 2: South Area Reinforcement Alternatives	
Recommended Mitigation		North Gila-Imperial Valley–North of SONGS-Serrano-Del Amo–Mesa 500 kV upgrade	

Southern Area Reinforcement Alternatives

- North Gila-Imperial Valley–North of SONGS-Serrano-Del Amo–Mesa 500 kV upgrade. Project cost: $4,710M
- North Gila–Imperial Valley–Inland–Serrano–Del Amo–Mesa 500 kV AC Development. Project cost: $5,462M
- North Gila–Imperial Valley AC & Imperial Valley–Inland–Del Amo 500 kV HVDC Development. Project cost: $7,506M
- North Gila–Imperial Valley–North of SONGS AC and North of SONGS–Del Amo HVDC 500 kV Development. Project cost: $7,017M
- North Gila–Imperial Valley–Inland AC and Inland–Del Amo HVDC 500 kV Development. Project cost: $7,614M
- North Gila–Imperial Valley–Suncrest and Red Bluff–Devers–Mira Loma 500 kV Development. Project cost: $7,290M

North Gila-Imperial Valley–North of SONGS-Serrano-Del Amo–Mesa 500 kV upgrade



Recommended Southern Area Reinforcement

- To address the constraints that have significant inter-dependence in the transmission needs among SDG&E, SCE Eastern and SCE Metro Interconnection Areas the ISO is recommending the following Southern Area Reinforcement Alternative:
  - Imperial Valley–North of SONGS 500 kV Line and Substation
  - North of SONGS–Serrano 500 kV line
  - Mesa–Del Amo–Serrano 500 kV line reconfiguration
  - North Gila–Imperial Valley 500 kV line
  - Upgrade on Hoodoo Wash-North Gila and Hassayampa-North Gila Transmission lines

Imperial Valley–North of SONGS 500 kV Line and Substation

- Objective:
  - SDG&E area: To mitigate the East of Miguel deliverability constraint
  - SCE Eastern area: To mitigate the Devers-Red Bluff 500 kV deliverability constraint
- Project scope:
  - New 500/230 kV Substation north of SONGS c/w three (3) 500/230 kV transformers; loop San Onofre–Santiago No. 1 & No. 2 and San Onofre–Viejo 230 kV lines into the new substation
  - New Imperial Valley–N.SONGS 500 kV line (~145 miles) with 50% series compensation on the first segment
- Project cost:
  - $2,288 million
- Expected in-service date:
  - 2034

North of SONGS–Serrano 500 kV line

- Objective:
  - SCE Metro area: To mitigate the Devers-Red Bluff 500 kV deliverability constraint and provide a new source line to the LA Basin/Orange County area
- Project scope:
  - New N. SONGS–Serrano 500 kV AC line (30 miles)
- Project cost:
  - $503 million
- Expected in-service date:
  - 2034

Mesa–Del Amo–Serrano 500 kV Reconfiguration

- Objective:
  - SCE Eastern area: South of Mesa and Serrano–Barre corridor deliverability constraints that are found to limit delivery of portfolio resources from much of southern California to serve the increasing load in the LA Basin local capacity area
- Project scope:
  - New 500 kV switchyard at Del Amo complete with three (3) 500/230 kV transformers;
  - Utilize the existing conductor on Mesa-Mira Loma 500 kV line and build approximately a 2 mile new section into Mesa and an approximately 13 mile new 500 kV line to Serrano; and
  - Interconnect the new Mesa-Serrano 500 kV line with 2 new 500 kV lines from Del Amo (approximately 13 miles) to form the Del Amo-Mesa and Del Amo-Serrano 500 kV lines;
  - Loop Alamitos–Barre No. 1 and No. 2 230 kV lines into Del Amo Substation.
- Project cost:
  - $1,125 million
- Expected in-service date:
  - 2033

North Gila–Imperial Valley 500 kV line

- Objective:
  - To mitigate the East of Miguel deliverability constraint
- Project scope:
  - New North Gila–Imperial Valley 500 kV AC line (97 miles)
- Project cost:
  - $340M
- Expected in-service date:
  - 2028

Upgrade on Hoodoo Wash-North Gila and Hassyampa-North Gila Transmission Lines

- Objective:
  - To mitigate P1 overloads on Hoodoo Wash-North Gila and Hassayampa-North Gila 500 kV lines
- Project scope:
  - Upgrade the Hoodoo Wash-North Gila and Hassayampa-North Gila 500 kV lines and series capacitors to 3250 Amps emergency rating
- Project cost:
  - $27M
- Expected in-service date:
  - 2032

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

Yi Zhang
Senior Advisor, Transmission Infrastructure Planning

2022-2023 Transmission Planning Process Stakeholder Meeting
April, 2023

Summary of key steps in database development since November stakeholder session

- Updated other transmission constraints based on the reliability and policy assessment results
- Modeled transmission upgrades that received early approval
- Other recommended policy or reliability upgrades, which can help resolve solution issues in production cost simulation and do not require further economic assessments
  - SDGE Sycamore - Penasquitos and Sycamore - Old Town 230 kV lines reconfiguration
  - SCE Eldorado 500 kV reconfiguration

Base Portfolio - summary of congestions

Constrained area or branch group	Cost (M$)	Duration (Hours)
SCE NOL	80.06	6,214
COI Corridor	52.83	1,151
Path 26 Corridor	47.32	1,896
GridLiance/VEA	40.37	3,547
PG&E Panoche/Oro Loma area	32.24	2,213
SDGE San Diego Southern	13.91	1,018
PG&E Fresno	13.81	1,012
SCE W.LA	12.92	197
Path 46 WOR	7.86	210
PG&E Mosslanding-Las Aguilas 230 kV	7.64	334
Path 15 Corridor	7.49	253
SDGE/CFE	6.25	1,528
SCE EOL	5.56	197
SCE Antelope 66kV	5.43	1,265
PG&E Collinsville-Pittsburg 230 kV	4.29	532
PG&E North Valley	3.86	198
PDCI	1.50	157

- 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 SDG&E Doublet Tap – Friars 138 kV congestion and SCE East of Lugo congestion

Constrained areas selected for detailed investigation and economic assessment

Detailed investigation	Alternative	Proposed by	Reason
Path 26 corridor congestion	Midway-Windhub 500 kV line	ISO	Recurring congestion with large congestion cost
	PTE project	Western Grid	
GLW/VEA area congestion	GLW 500 kV Upgrade	GridLiance West	Congestion with large congestion cost, although the GLW 230 kV upgrades were modeled
PG&E Panoche/Oro Loma area congestion	Multiple alternatives	ISO	Significant congestion on the 70 kV and 115 kV in this area. Some are consistent with existing congestion in operation
PG&E Fresno Henrietta 115 kV congestion	Multiple alternatives	ISO	High congestion cost
Idaho wind scenario with SWIP North	SWIP North	LS Power	SWIP North was studied as a transmission alternative for Idaho wind, also it can help to mitigate COI congestion
SCE North of Lugo congestion	230 kV upgrades	ISO	Significant congestion was observed in the SCE North of Lugo area. Policy need was identified
	500 kV upgrade		

Path 26 corridor congestion

- Congestion on Path 26 corridor was observed mainly when the flow was from south to north
- Resources in Southern California identified in the CPUC renewable portfolio were the main driver of the Path 26 corridor congestion
- The low normal rating of the Midway – Whirlwind 500 kV line contributed to its congestion

Constraint Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
P26 Northern-Southern California	21	13	33,792	1,254	33,813	1,267
MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	13,213	610	13,213	610
MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	136	3	149	15	285	18
MW_VINCNT_12-VINCENT 500 kV line #1	7	1	0	0	7	1

Path 26 corridor congestion – Mitigation alternatives

- New 500 kV line between Midway and Windhub
  - With this new 500 kV line modeled, Path 26 path rating was assumed to be retired
- The Pacific Transmission Expansion (PTE) project
  - Economic study request with multi-terminals offshore HVDC lines between the northern and southern California systems

Path 26 corridor mitigation alternative – new Midway – Windhub 500 kV line

- With the new Midway – Windhub 500 kV line, Path 26 corridor congestion can be reduced significantly, but Midway-Whirlwind congestion still exists
- Path 15 corridor congestion increased

Scope	Path 26 corridor constraints and other constraints impacted most by the mitigation	Congestion cost ($k)	Congestion Hours
Midway – Windhub 500 kV line	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-2 Midway-Vincent 500 kV	14,121	504
	MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-WindHub 500 kV	334	15
	P15 Midway-LosBanos	9,651	218
	GT_MW_11-MIDWAY 500 kV line #1	4,208	222
	GATES-GT_MW_11 500 kV line #1	2,316	86

California ISO

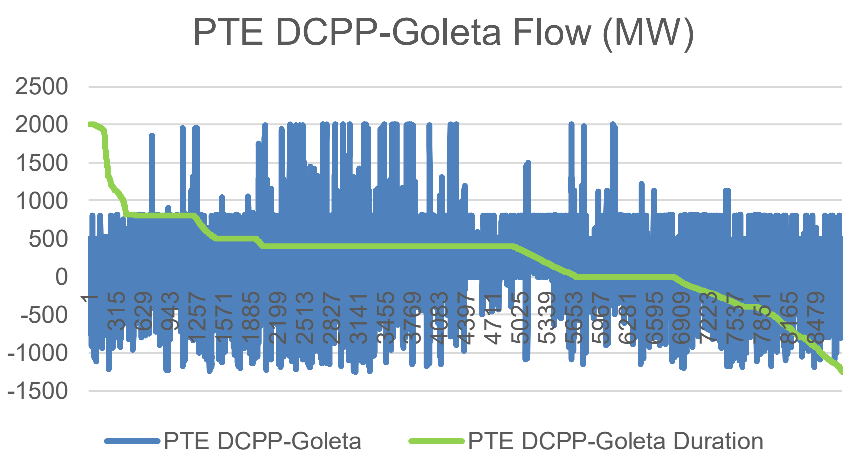
Path 26 corridor mitigation alternative – PTE project

- A 2,000 MW controllable HVDC subsea transmission cable that connects northern and southern California
- Path 26 corridor congestion reduced, but congestion cost is still large
- Path 15 corridor congestion increased
- La Cienega – La Fresa 230 kV congestion reduced

Scope	Path 26 corridor constraints and other constraints impacted most by the mitigation	Congestion cost ($k)	Congestion Hours
PTE	P26 Northern-Southern California	20,606	2029
	MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	9,775	960
	P15 Midway-LosBanos	6,743	166
	GT_MW_11-MIDWAY 500 kV line #1	2,089	107
	LB_GT_11-GATES 500 kV line #1	1,081	35
	LCIENEGA-LA FRESA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	2,084	2,238
	ISO PTE Goleta-500MW	752	2,008
	EL NIDO-LCIENEGA 230 kV line, subject to SCE N-2 La Fresa-El Nido #3 and #4 230 kV	288	348
	LITEHIPE-MESA CAL 230 kV line, subject to SCE N-2 Mesa-Laguna Bell 230 kV #1 and #2	205	37

Path 26 corridor mitigation alternative – PTE project (cont.)

- Loop flow between the PTE HVDC lines and the Path 26 corridor was still observed
- There were about 5,700 hours when the flow on the HVDC line was from DCPP to Goleta
- Total congestion hours of the Path 26 corridor congestion increased to about 3,000 hours
- There were about 1,000 hours when the Path 26 was congested in the south to north direction and the PTE flow was from DCPP to Goleta



Path 26 corridor mitigation –production cost benefit

	Base case	Path 26 A1 - Midway-Windhub 500 kV line		Path 26 A2 - PTE	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	9,840	9,822	18	9,827	12
ISO generator net revenue benefiting ratepayers	5,760	5,764	4	5,777	17
ISO transmission revenue benefiting ratepayers	457	437	-20	432	-25
ISO Net payment	3,623	3,621	2	3,618	5
WECC Production cost	13,937	13,921	16	13,914	23

- Did not show sufficient benefit to justify as an economic driven upgrade in this planning cycle
  - LCR reduction benefit of the PTE project identified in the previous planning cycles was considered as well in the BCR calculation

GridLiance West/VEA area congestion

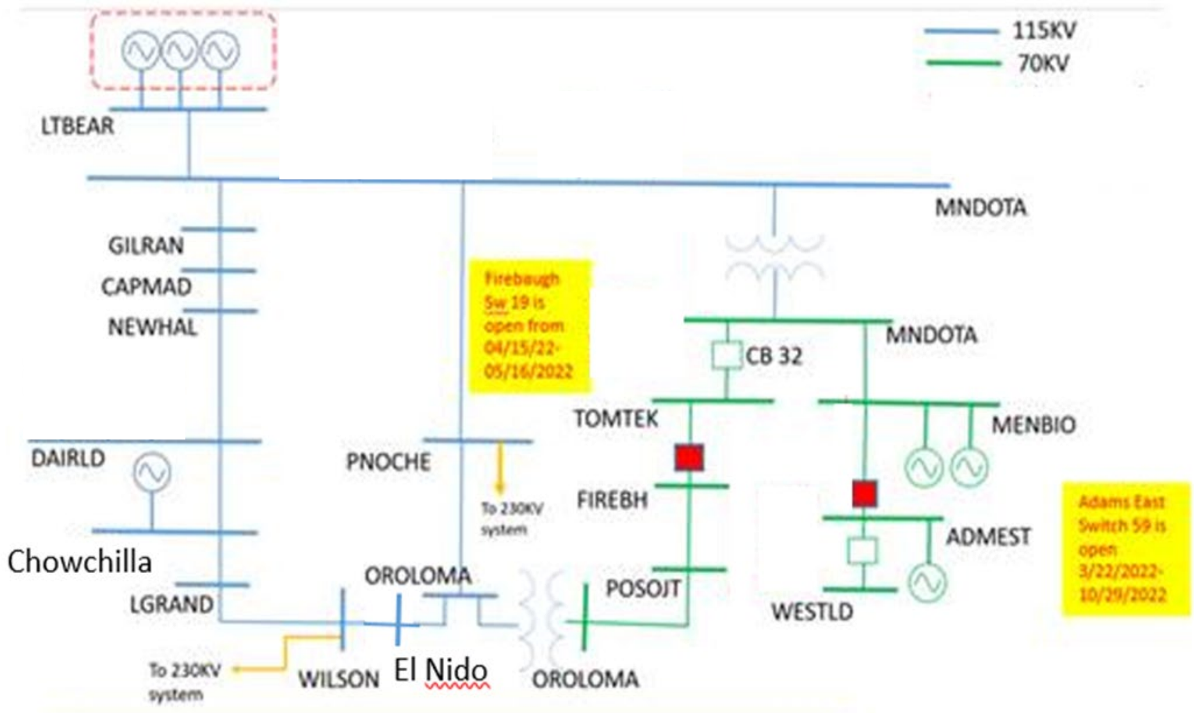
Constraint Name	Costs_F (K$)	Duration _F (Hrs)	Costs_B (K$)	Duration_ B (Hrs)	Costs T (K$)	Duration _T (Hrs)
INNOVATION-DESERT VIEW 230 kV line, subject to VEA N-2 TroutCanyon-SloanCanyon 230 kV with RAS	13,482	1,190	0	0	13,482	1,190
MEAD S-SLOAN CANYON 230 kV line #1	0	0	13,268	920	13,268	920
INNOVATION-DESERT VIEW 230 kV line #1	11,331	813	0	0	11,331	813
INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 NWest-DesertView 230 kV with RAS	1,751	523	0	0	1,751	523
INNOVATION 138/138 kV transformer #1	420	30	0	0	420	30
GAMEBIRD-GAMEBIRD 230 kV line, subject to VEA N-2 Pahrump-Gamebird 230 kV no RAS	113	65	0	0	113	65
INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 Innovation-DeservtView 230 kV with RAS	8	6	0	0	8	6

GLW 500 kV Upgrade

- Identified as a policy upgrade in this planning cycle
- Simulation results showed that the GLW 500 kV Upgrade project was effective to mitigate most of the GridLiance West/VEA area congestion
  - Except for the Innovation – Desert View congestion under N-2 contingency of the proposed Trout Canyon - Sloan Canyon 500 kV lines

Constraint Name	Costs_F (K$)	Duration F (Hrs)	Costs_B (K$)	Duration B (Hrs)	Costs T (K$)	Duration T (Hrs)
INNOVATION-DESERT VIEW 230 kV line, subject to VEA N-2 TroutCanyon-SloanCanyon 230 kV with RAS	21,688	1,615	0	0	21,688	1,615
INNOVATION 138/138 kV transformer #1	688	64	0	0	688	64
MEAD S-SLOAN CANYON 230 kV line #1	0	0	23	6	23	6
INNOVATION-INNOVATION 230 kV line, subject to VEA N-2 NWest-DesertView 230 kV with RAS	10	7	0	0	10	7

PG&E Panoche/Oro Loma area – One line diagram



PG&E Panoche/Oro Loma area congestion

Constraint Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
ORO LOMA-POSO J1 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	18,026	909	1,830	510	19,856	1,419
ORO LOMA-EL NIDO 115 kV line #1	10,077	571	0	0	10,077	571
POSO J1-FIREBAGH 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	2,004	58	0	0	2,004	58
LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	0	0	268	118	268	118
NEWHALL-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	33	44	0	0	33	44
ORO LOMA-EL NIDO 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	4	3	0	0	4	3

PG&E Panoche/Oro Loma area – Oro Loma – Poso 70 kV line and Oro Loma – El Nido 115 kV line congestion

Occurrences of Oro Loma – Poso 70 kV Congestion under Panoche – Mendota 115 kV N-1 Contingency

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	1	7	7	5	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	1	2	2	2	2	2	3	2	1	0	0	0	0	0	0	0	0
May	1	0	0	0	0	0	0	0	0	7	10	13	12	11	11	5	1	0	0	4	5	5	4	1
Jun	13	3	0	0	0	0	0	0	4	16	20	25	28	27	19	10	3	0	1	17	18	19	17	10
Jul	18	1	0	0	0	0	0	0	1	16	29	29	28	18	5	1	0	0	22	28	27	25	22	19
Aug	22	13	5	2	1	0	0	1	0	0	15	25	25	15	2	1	1	0	23	27	28	25	20	19
Sep	29	28	9	3	1	0	1	1	0	2	8	19	18	10	3	0	0	15	21	23	25	24	23	21
Oct	26	16	8	4	3	0	6	0	0	0	1	4	3	1	0	0	0	7	21	24	23	22	19	13
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

The congestion can occur when the flow was in either direction. Specifically, in daytime, the congestion mainly occurred when the flow was from Poso to Oro Loma; in nighttime, the congestion mainly occurred when the flow was from Oro Loma to Poso

Occurrences of Oro Loma – El Nido 115 kV congestion under normal condition

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	6	7	5	6	3	2	2	3	1	1	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	5	3	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	4	5	5	6	6	6	7	9	14	15	14	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	1	4	8	4	3	7	13	16	16	14	5	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	13	15	13	13	9	10	10	11	8	7	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	15	17	20	18	14	14	12	12	6	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	14	23	23	13	10	5	3	0	0	0	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

This was mainly because the summer rating of the Oro Loma – El Nido 115 kV line is lower than the winter rating. Solar generation in the 115 kV system was also contributed to the congestion as the congestion mainly occurred in daytime.

Panoche/Oro Loma area congestion mitigation

Alternative	Scope	Panoche/Oro Loma area constraints	Congestion cost ($k)	Congestion Hours
A1	Modify the 70 kV summer setup to have both 70 kV corridor open from March to October	ORO LOMA-EL NIDO 115 kV line #1	5,754	385
		LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1	3,895	656
		NEWHALL-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	586	290
		CHWCHLASLRJT-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	524	4
		ORO LOMA-EL NIDO 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	60	15
A2	RAS tripping solar generation	ORO LOMA-POSO J1 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	38,201	1,702
		ORO LOMA-EL NIDO 115 kV line #1	5,290	345
		POSO J1-FIREBAGH 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	2,215	73

- Modify the 70 kV summer setup to open both 70 kV corridors, from March to October, which can mitigate 70 kV congestion. However, the 115 kV congestion still occurred, especially Le Grand – Chowchilla 115 kV congestion increased.
- SPS tripping solar generation in the local area under contingency aggravated the 70 kV congestion when the flow was from the Oro Loma 70 kV bus to the Mendota 70 kV bus.

Panoche/Oro Loma area congestion mitigation

Alternative	Scope	Panoche/Oro Loma area constraints	Congestion cost ($k)	Congestion Hours
		BIOMSJCT-MENDOTA 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	115	24
		ORO LOMA-EL NIDO 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	76	5
A3	Reconductoring the 115 kV lines between the Oro Loma and WilsonPG&E 115 kV buses and between the Le Grand and Newhall 115 kV buses	ORO LOMA-POSO J1 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	19,015	1,350
		POSO J1-FIREBAGH 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	1,735	51
A4	A1 plus A3	MENDOTA-GILLTAP 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	577	150
A5	A1 plus A2 plus A3	LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	421	3
		CHWCHLASLRJT-DAIRYLND 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	376	3
		BIOMSJCT-MENDOTA 70 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	126	25

- Alternative 3, reconductoring the 115 kV lines, can mitigate the 115 kV normal condition congestion, but the 70 kV congestion under the N-1 contingency of the Panoche-Mendota 115 kV line increased.
- Alternative 4, reconductoring the 115 kV lines combined with modifying the 70 kV summer setup, can effectively mitigate most of the congestion in this area
- Alternative 5, SPS plus Alternative 4, congestions showed up on multiple 115 kV lines

Panoche/Oro Loma area – Economic benefit assessment

	Base case	Panoche/OroLoma A1-Summer Setup		Panoche/OroLoma A3-reconductoring the 115 kV system		Panoche/OroLoma A4-A1 plus A3		Panoche/OroLoma A5 – A1 plus A2 plus A3	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	9,840	9,823	16	9,837	3	9,807	32	9,812	28
ISO generator net revenue benefiting ratepayers	5,760	5,755	-5	5,765	5	5,754	-6	5,757	-3
ISO transmission revenue benefiting ratepayers	457	438	-19	445	-12	425	-32	426	-31
ISO Net payment	3,623	3,630	-8	3,627	-4	3,628	-6	3,629	-6
WECC Production cost	13,937	13,938	-1	13,936	1	13,935	2	13,937	0

- None of these alternatives were recommended for approval as economic driven upgrade in this planning cycle
- The CAISO will continue to coordinate with PG&E to investigate feasible and cost effective solutions

Fresno Henrietta 115 kV congestion

Constraint Name	Costs_ F (K$)	Duration_ F (Hrs)	Costs_B (K$)	Duration_ B (Hrs)	Costs T (K$)	Duration_ T (Hrs)
GWF_HEP-CONTADNA 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	11,614	498	0	0	11,614	498
JACKSONSWSTA-CONTADNA 115 kV line, subject to PG&E N-2 HELM-MCCALL and HENTAP2-MUSTANGSS #1 230kV with RAS	0	0	1,761	13	1,761	13

Occurrences of GWF_HEP to Contadina 115 kV congestion

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	9	6	10	7	5	0	2	1	0	0	1	3	1	0	0	0
Feb	0	0	0	0	0	0	0	1	9	6	3	2	2	2	2	1	3	0	2	2	0	0	0	0
Mar	0	0	0	0	0	0	0	6	4	5	5	5	4	3	3	4	1	0	1	0	0	0	0	0
Apr	0	0	0	0	0	0	5	10	10	6	4	2	2	2	2	2	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	2	1	1	1	1	1	1	1	0	0	2	1	0	0	0	0	0	0
Jun	0	0	0	0	0	1	0	0	0	1	0	0	0	0	2	4	5	4	3	5	5	5	4	2
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	8	14	9	9	9	7	3	0
Aug	0	0	0	0	0	0	2	1	0	0	0	0	1	0	0	0	2	7	8	7	5	5	4	0
Sep	0	0	0	0	0	0	3	8	8	5	5	2	1	0	2	3	1	4	10	10	8	6	4	1
Oct	0	0	0	0	0	0	1	5	15	12	8	4	2	2	1	0	0	0	0	1	0	0	0	0
Nov	0	0	0	0	0	0	0	0	3	4	1	1	0	2	1	0	0	0	1	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	5	8	5	3	2	2	0	0	0	0	1	0	0	0	0	0

Main contributors to the congestion:

- Solar generation in the Mustang and Henrietta 230 kV system
- Loop flow between the 230 kV and 115 kV systems

Fresno Henrietta 115 kV congestion mitigation

- Two alternatives were identified based on the above analysis and received detailed analysis:
  - Alternative 1 (A1) – Expanding the GWF_HEP – Contadina and Contadina – Jackson 115 kV lines to double circuit 115 kV lines
  - Alternative 2 (A2) – SPS to open the GWF_HEP – Contadina 115 kV line following the N-2 contingency of the Helm – McCall and Henrietta Tap2–Mustang 230 kV lines
- Both alternatives can effectively mitigate the Henrietta 115 kV congestion identified in this planning cycle

Henrietta 115 kV congestion – cost benefit assessment

	Base case	Henrietta 115 kV A1 - double circuit 115 kV		Henrietta 115 kV A2 - SPS to open 115 kV	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	9,840	9,776	64	9,740	99
ISO generator net revenue benefiting ratepayers	5,760	5,730	-30	5,705	-55
ISO transmission revenue benefiting ratepayers	457	435	-22	427	-30
ISO Net payment	3,623	3,611	12	3,609	14

- The SPS alternative (A2) produced higher benefit to ISO ratepayers than the double circuit alternative (A1). The ISO recommended PG&E to investigate the feasibility of the SPS and any potential reliability impact of the SPS
- However, the benefit-to-cost ratio of the double circuit alternative (A2) was calculated for information
  - Capital cost is about $160 million based on per unit cost, total cost is $208 million
  - PV of benefit is $177 million, and the BCR is 0.852

SWIP North

- "Pre" case
  - Modeled a 1062 MW Idaho wind generator at the Midpoint 500 kV bus
  - Turned off the 1062 MW Wyoming wind generator
  - Turned off the TransWest Express project
- "Post" case
  - The "pre" case with the SWIP North project
  - The phase shifter angles were set to maximize the flow on the 500 kV system at Robinson Summit substation, based on LS Power suggestion in its study request

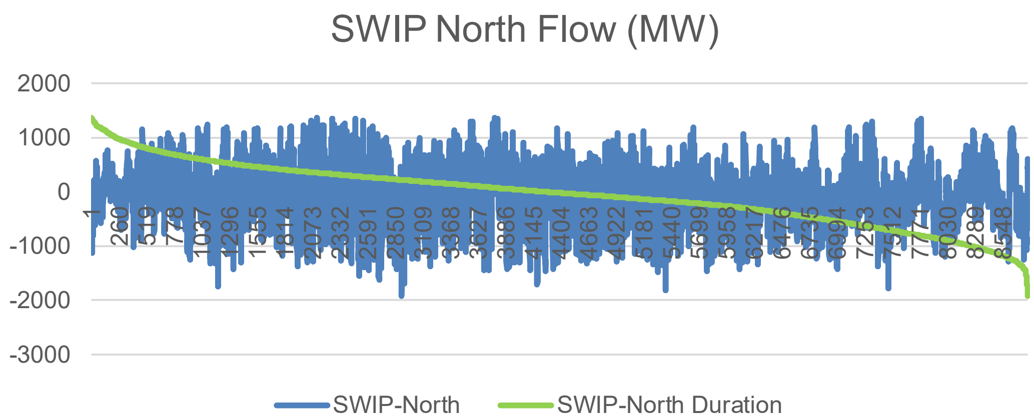
SWIP North's impact on congestion

Area or Branch Group	Congestion Cost ($M) without SWIP North	Congestion Cost ($M) with SWIP North	Change in Congestion Cost ($M)
COI Corridor	69.59	45.79	-23.80
SWIP South	0.00	1.93	1.93
Path 15 Corridor	6.55	8.57	2.01
Path 26 Corridor	36.63	46.05	9.42

- The SWIP North project can help to reduce COI congestion, which mainly happened when the flow is from North to South
- The SWIP North project aggravates Path 26 and Path 15 congestion, which mainly happened when the flow is from South to North

SWIP North flow pattern

- In 4252 hours, flow on the SWIP North line (Midpoint-Robinson Summit 500 kV) is from North to South, i.e. in 4532 hours flow is from south to north



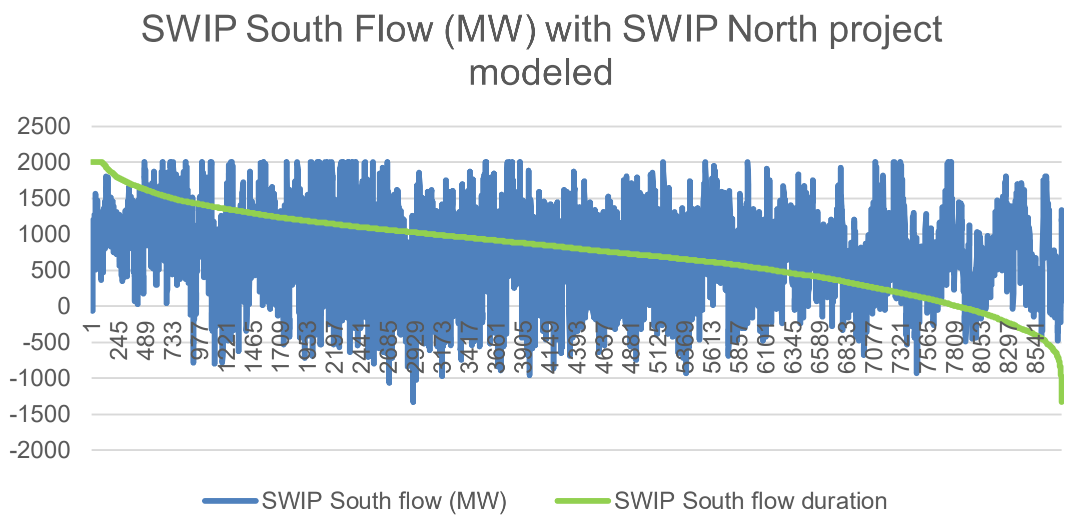
The setup of the Robinson Summit phase shifters angle has impact on the flow pattern on SWIP North and SWIP South

Occurrence of SWIP North flow from north to south

	1	2	3	4	5	6	7	8	9	#	11	#	#	#	15	16	17	18	19	20	21	22	23	24	Total
Jan	25	22	23	21	25	22	24	#	9	6	9	9	11	#	11	16	26	26	23	22	23	27	23	25	454
Feb	23	23	25	26	25	23	26	17	7	3	3	4	3	3	3	4	17	22	21	22	21	19	21	23	354
Mar	28	28	30	30	28	27	26	9	7	6	4	4	3	4	5	6	14	29	24	29	27	28	25	24	445
Apr	24	26	28	27	22	25	6	3	2	1	1	0	0	0	0	2	5	21	24	24	22	23	25	24	338
May	21	27	31	31	31	28	1	1	1	1	1	1	0	1	4	5	5	19	30	28	28	24	28	28	371
Jun	26	26	27	28	30	25	3	1	1	3	3	4	5	9	#	11	13	23	28	26	28	26	25	25	408
Jul	31	31	31	31	30	24	3	2	1	1	0	0	1	1	2	11	18	24	30	27	28	29	27	24	407
Aug	26	18	18	16	14	12	6	1	1	1	2	2	2	4	7	8	12	25	27	23	22	19	17	14	327
Sep	16	15	15	10	10	8	2	2	1	1	0	2	4	5	9	11	22	28	23	20	18	15	14	12	353
Oct	25	24	23	19	15	14	9	6	3	3	4	5	5	5	8	12	15	17	14	12	13	15	15	15	328
Nov	17	19	18	15	15	16	15	5	4	2	1	3	2	2	2	10	16	12	13	12	12	14	13	13	281
Dec	21	20	20	18	18	17	18	#	11	#	8	7	8	8	9	12	16	16	15	12	12	16	19	20	343
Total	283	279	289	272	282	241	128	73	45	38	38	41	44	52	73	108	178	283	272	257	254	255	253	245	4252

SWIP South flow pattern

- In 7858 hours, flow on SWIP South (Robinson Summit to Harry Allen 500 kV) is from North to South, or in 926 hours flow is from South to North



SWIP North economic assessment

	Base case with Idaho wind modeled	SWIP North	
	($M)	Post project ($M)	Savings ($M)
ISO load payment	9,826	9,849	-24
ISO generator net revenue benefiting ratepayers	5,660	5,694	34
ISO transmission revenue benefiting ratepayers	466	468	2
ISO Net payment	3,700	3,687	13

SWIP North Project	
Production cost savings ($million/year)	13
Capacity saving ($million/year)	0
Capital cost ($million)	636
Discount Rate	7%
PV of Production cost savings ($million)	187
PV of Capacity saving ($million)	0
Total benefit ($million)	187
Total cost (Revenue requirement) ($million)	870
Benefit-to-cost ratio (BCR)	0.22

SCE North of Lugo congestion

Constraints Name	Costs_F (K$)	Duration _F (Hrs)	Costs_ B (K$)	Duration _B (Hrs)	Costs T (K$)	Duration _T (Hrs)
KRAMER-VICTOR 230 kV line #1	34,882	1,476	0	0	34,882	1,476
LUGO-lugo 2i 500 kV line, subject to SCE N-1 Lugo Transformer #1 500-230 kV with RAS	0	0	30,264	1,941	30,264	1,941
KRAMER-VICTOR 230 kV line #2	12,287	544	0	0	12,287	544
P60 Inyo-Control 115 kV Tie	0	0	1,039	572	1,039	572
CALCITE-LUGO 230 kV line #1	597	601	0	0	597	601
VICTOR-KRAMER 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	0	418	204	418	204
VICTOR-ROADWAY 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	1	230	822	230	823
VICTOR-LUGO 230 kV line #1	161	15	0	0	161	15
ROADWAY-KRAMER 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	0	0	95	32	95	32
VICTOR-LUGO 230 kV line #3	66	4	0	0	66	4
VICTOR-LUGO 230 kV line #4	26	2	0	0	26	2

SCE North of Lugo congestion mitigation

- Policy need for upgrading the Kramer – Lugo corridor was identified in this planning cycle.
  - Alternative 1 – Kramer-Lugo 230 kV upgrade
  - Alternative 2 – Kramer-Lugo 500 kV upgrade
- Both alternatives can effectively mitigate congestions on Kramer – Victor, Victor – Lugo, and Lugo transformer

Alternative	Scope	SCE North of Lugo area constraints	Congestion cost ($k)	Congestion Hours
A1	Kramer – Lugo 230 kV upgrades	CALCITE-LUGO 230 kV line #1	1,464	1,167
		P60 Inyo-Control 115 kV Tie	756	424
A2	Kramer – Lugo 500 kV upgrades	CALCITE-LUGO 230 kV line #1	1,529	1,310
		P60 Inyo-Control 115 kV Tie	190	132

SCE North of Lugo economic assessment

	Base case	A1: Kramer-Lugo 230 kV		A2: Kramer-Lugo 500 kV	
	($M)	Post project ($M)	Savings ($M)	Post project ($M)	Savings ($M)
ISO load payment	9,840	9,761	79	9,752	87
ISO generator net revenue benefiting ratepayers	5,760	5,788	28	5,782	22
ISO transmission revenue benefiting ratepayers	457	365	-92	365	-92
ISO Net payment	3,623	3,608	15	3,605	18
WECC Production cost	13,937	13,926	11	13,954	-17

	A1	A2
Production cost savings ($million/year)	15	18
Capacity saving ($million/year)	0	0
Capital cost ($million)	482	700
Discount Rate	7%	7%
PV of Production cost savings ($million)	214	260
PV of Capacity saving ($million)	0	0
Total benefit ($million)	214	260
Total cost ($million)	627	910
Benefit-to-cost ratio (BCR)	0.340	0.286

Summary of economic studies

- No transmission solutions were found to have sufficient economic benefits to proceed solely on the merits of the economic study results
- Transmission alternatives assessed can help to address transmission congestion or renewable curtailment issues in respective study areas
- Two policy transmission upgrades identified in Chapter 3 were assessed in this chapter to compare economic benefits of different transmission alternatives
  - GLW 500 kV Upgrade
  - SCE North of Lugo area Kramer to Lugo Upgrade

Wrap-up
Draft 2022-2023 Transmission Plan

Kaitlin McGee
Sr. Stakeholder Engagement and Policy Specialist

2022-2023 Transmission Planning Process Stakeholder Meeting
April 11, 2023

Comments

- Comments due by end of day April 25, 2023
- Submit comments through the ISO's commenting tool, using the template provided on the process webpage:
- https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2022-2023-Transmission-planning-process