Agenda – Day 2

Tom Cuccia
Lead Stakeholder Engagement and Policy Specialist

2015-2016 Transmission Planning Process Stakeholder Meeting
September 21-22, 2015

2014-2015 Transmission Planning Process Stakeholder Meeting - Today’s Agenda

Topic	Presenter
Introduction	Tom Cuccia - ISO
Gas-Electric Coordination in Transmission Planning Reliability Results	David Le - ISO
Buck Blvd Gen-Tie Loop-in Project (a continuation from the 2014-2015 TPP)	Nebiyu Yimer
SDG&E Proposed Reliability Solutions	Enrique Romero – SDG&E
SCE Proposed Reliability Solutions	Rabi Kiran Jonathan Yuen - SCE
PG&E Proposed Reliability Solutions	Isaac Read – PG&E
Next Steps	Tom Cuccia - ISO

California ISO
Shaping a Renewed Future

Gas – Electric Coordination In Transmission Planning Reliability Studies

David Le
Senior Advisor Regional Transmission Engineer

2015-2016 Transmission Planning Process Stakeholder Meeting
September 21-22, 2015

Gas – Electric Coordination in Transmission Planning Reliability Studies was included in the Study Plan

- Section 6.3 of the ISO 2015-2016 Transmission Planning Process Study Plan included the following:
  - Potential impacts of the changing role of gas-fired generation in providing local capacity support and flexible generation needs has been raised as a concern regarding physical capacity and gas contracting requirements
  - Reliability of gas supply concern and its potential impact to the gas-fired electric generating facilities will be explored, and to the extent that it's viable, studied in this planning cycle.
  - Further transmission planning studies, if not completed, or identified to be investigated further, may be carried over several planning cycles

Focus of the Gas-Electric Coordination in Transmission Planning Studies

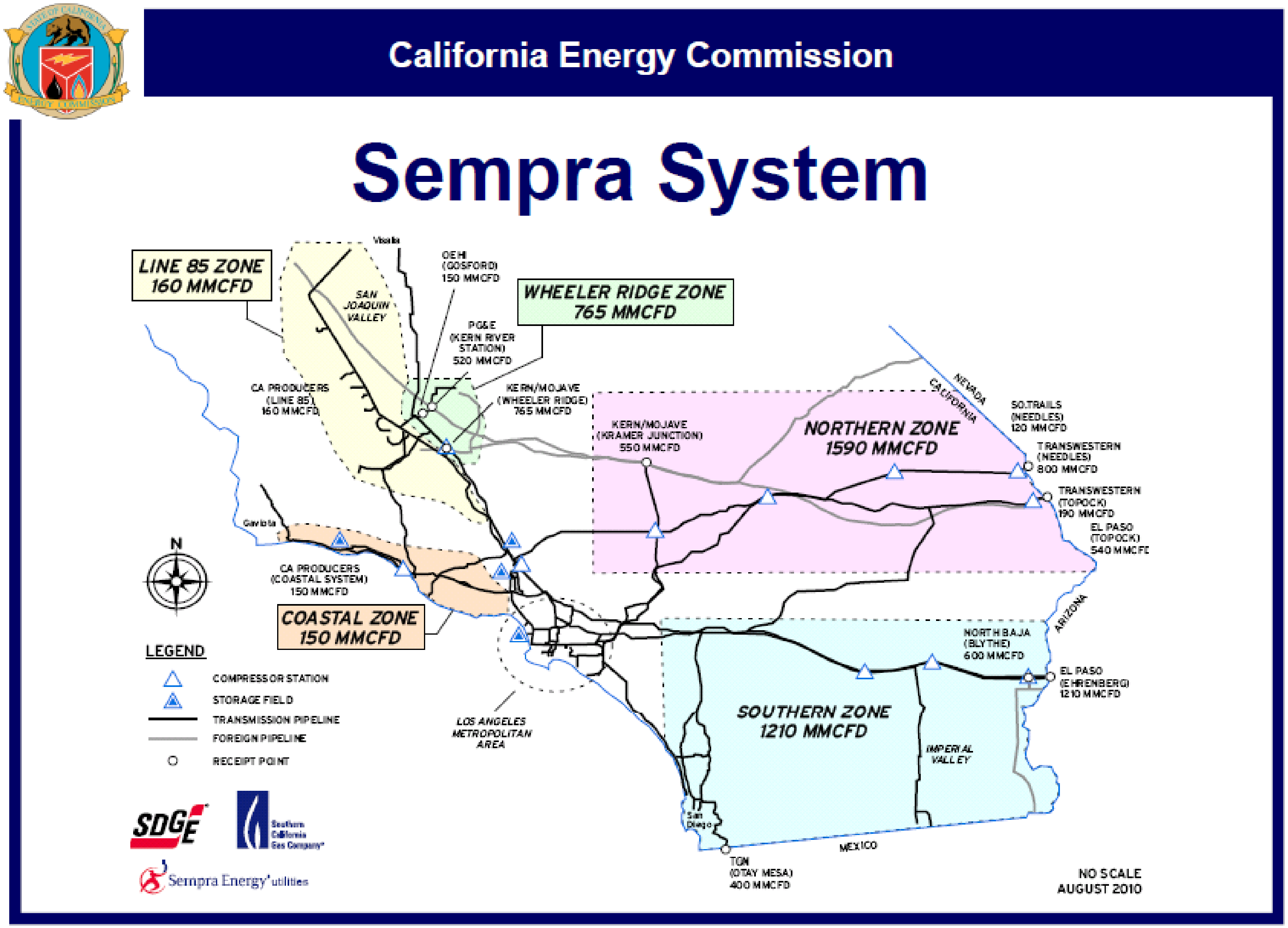
- Recent known gas supply issue events, and gas transmission outage that affected gas-fired electric generating facilities all occurred in Southern California
- Therefore, the transmission planning studies will focus on the gas supply impact concerns to the reliability of the transmission system in the LA Basin and San Diego areas in this planning cycle.

Los Angeles Basin and San Diego Metropolitan Areas

Overview of Southern California Gas System

- Most of natural gas used in California comes from out-of-state basins:
  - 35% from the Southwest
  - 16% from Canada
  - 40% from Rocky Mountains
  - 9% from basins within California
- Major inter-state pipelines that deliver natural gas to Southern California:
  - El Paso Natural Gas Company
  - North Baja – Baja Norte Pipeline (takes gas from El Paso Pipeline at the CA/AZ border and re-deliver through Southern California and into Northern Mexico)
  - Kern River Transmission Company
  - Mojave Pipeline Company
  - Questar's Southern Trails Pipeline Company;
  - Transwestern Pipeline Company

SoCalGas and SDG&E's Gas Systems



Major Events of Gas Curtailments on Gas-Fired Electric Generating Facilities

- Winter Gas Curtailments
  - February 3, 2011 Event
    - Cold weather in Texas affected gas supplies to California
    - SoCalGas and SDG&E curtailed non-core and electric generation customers
    - About 200 million cubic feet per day (MMcfd) of gas curtailment was implemented
    - Approximately 59 – 476 MW of electric generation was curtailed in SCE service area
    - About 117 – 440 MW of electric generation was curtailed for 13 hours in San Diego; an additional 57 – 379 MW was curtailed for 14 hours
  - February 6, 2014 Event
    - Other states outside California experienced severe cold weather conditions
    - SoCalGas declared emergency to its Southern system
    - SDG&E curtailed gas to Encina Units 1, 2, 4 and 5 service area, with a total of 700 MW to be off-line
    - About 1,000 MW of generation was reduced in SCE service area
    - Demand response was requested, with 548 MW of firm load was curtailed in SCE service area, and 2 MW in SDG&E service area

Gas Supply Impact Concerns on Gas-Fired Electric Generating Facilities (cont'd)

- Summer Gas Curtailment
  - June 30, 2015 Event
    - SoCalGas had an outage on gas transmission line No. 4000, impacting delivery of gas to the LA Basin
    - Extended outage for maintenance need lasted from June 30, 2015 to August 28, 2015
    - The ISO was requested to reduce 1,700 MW from electric generating facilities located in the North and South LA Basin of SoCalGas Transmission Zone
    - Approximately 400 MW of demand response was requested in SCE service area

Summary of Total Electric Generation Output and Total Gas Volume Usage in Each Gas Transmission Zone In the LA Basin and San Diego Areas

	Gas Transmission Zone	Aggregated Generation Output (MW)	Total Gas Volume Usage (MMCFH)
1	South of Moreno/SDG&E	2,997	27.35
2	South of Moreno / SCE	742	6.75
3	West of Moreno	748	6.8
4	East of Moreno	1,425	12.95
5	North of LA Basin	384	3.49
6	South of LA Basin	5,798	52.71
7	Northern Gas Transmission Zone	1,937	17.61

Gas – Electric Coordination Transmission Planning Studies

- Summer Reliability Assessment
  - To assess the impacts of a major gas transmission pipeline extended outage due to maintenance on electric transmission reliability impact in the LA Basin and San Diego areas
  - Perform reliability assessment, using applicable NERC/WECC/ISO transmission planning performance requirements, for the long-term 2025 summer peak study case.
    - Generation curtailment located in the LA Basin (i.e., SoCalGas' North and South LA Basin Gas Transmission Zones based on outage of gas transmission line), OR
    - Other generation curtailment amount based on the most critical gas transmission outage located in the SoCalGas or SDG&E system

Gas – Electric Coordination Transmission Planning Studies (cont'd)

- Winter Reliability Assessment
  - To assess whether a future external gas supply shortage, due to high demand in the winter time, would cause gas curtailments to generating facilities in the LA Basin and/or San Diego areas
  - Perform long-term Winter reliability assessment (2025) for the LA Basin and San Diego areas using the 2025 Winter study case for SDG&E as the starting case. Since the SoCalGas' Southern and SDG&E systems are most susceptible to potential winter gas curtailment due to its delivery constraints in previous winter gas curtailment incidents, these two systems will be the primary focus of the winter assessment studies.

Gas – Electric Coordination Transmission Planning Studies (cont'd)

- Generation Ramping Impact Assessment
  - Ramping Impact Due to Generation Redispatch After the First N-1 Contingency
    - The ISO will determine an estimated amount of generation capacity needed to be brought on-line after the first N-1 contingency to prepare for the next N-1 contingency
    - Critical N-1-1 contingencies will be considered
  - Ramping Impact Due to Flexible Capacity Need
    - The ISO, in a number of studies, has identified future flexible capacity needs to integrate and meet the state's 33% Renewable Portfolio Standards (RPS) target.
    - The ISO took initial steps toward addressing flexible capacity needs in 2013 -14 in the ISO's Flexible Resource Adequacy Criteria and Must Offer Obligation (FRACMOO) stakeholder initiative and in the CPUC's RA proceeding. In 2015, the ISO continues with Phase 2 of the FRACMOO stakeholder initiative.
    - The ISO recognizes that there is a need to evaluate potential impact to the existing gas system due to ramping need from flexible capacity resources, such gas-fired peaking facility and other resources, ***upon*** having further clarity and development of specific amount of flexible capacity available from applicable technologies needed for meeting flexible capacity need.

Tentative Study Schedule

	Major Milestone	Tentative Schedule
1	Internal Discussion and Concurrence on Study Scopes / White Paper Discussion	July 20 – September 11, 2015
2	Present Issues and Study Scopes at the Second 2015-2016 TPP Stakeholder Meeting	September 21 – 22, 2015
3	Perform Gas-Electric Reliability Assessment	September 28 – November 30, 2015
4	Incorporate Study Results in the Draft 2015-2016 Transmission Plan	December 2015 – January 2016
5	Provide further edits as necessary for the Final Draft 2015-2016 Transmission Plan	February 2016
6	Present at the Fourth 2015-2016 TPP Stakeholder Meeting	February 2016

2014-2015 Transmission Planning Process Continued Study

Buck Blvd Generation Tie Loop-In Project

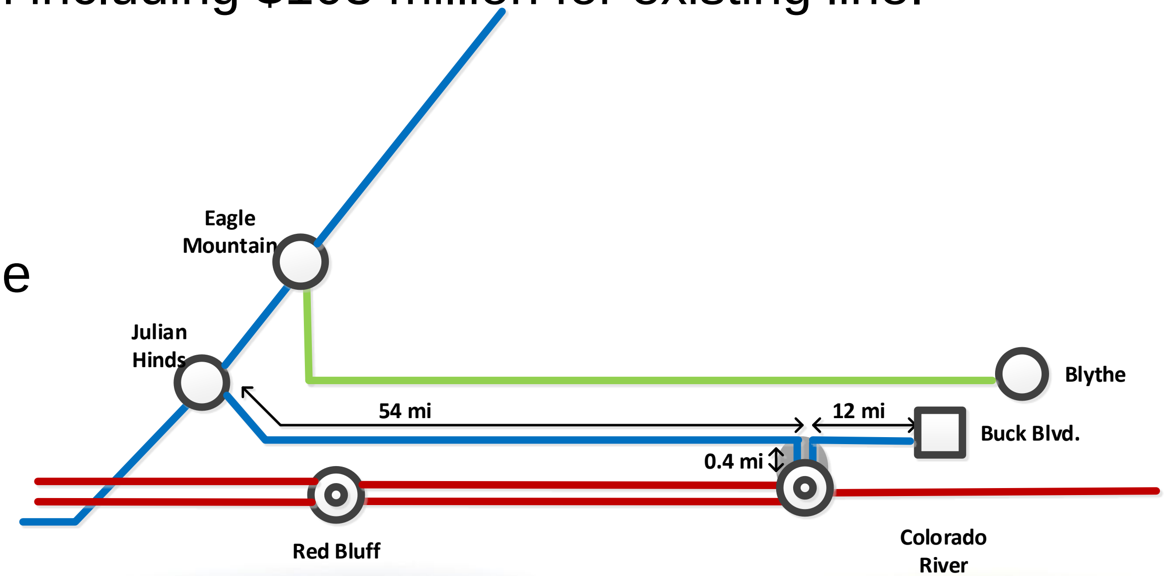
Nebiyu Yimer / Robert Sparks
Regional Transmission - South

2015-2016 Transmission Planning Process Stakeholder Meeting
September 21-22, 2015

Alternatives Considered

1. <u>Loop Buck Blvd–Julian Hinds into Colorado River</u>

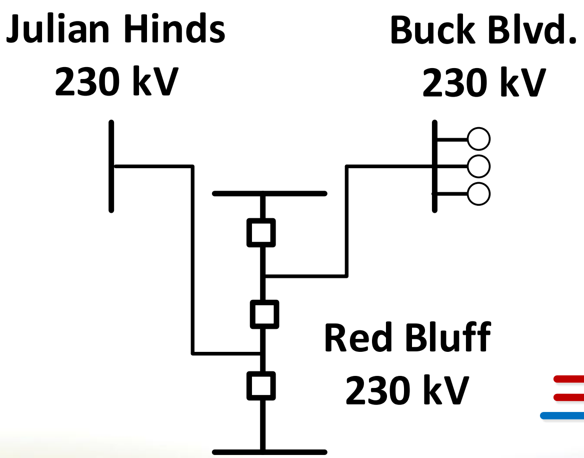
- This project (alternative) was submitted by AltaGas through the 2014-15 TPP request window as a project with net reliability and economic benefits.
- The Project results in conversion of ~54 miles of the gen-tie with a normal/emergency rating of 1482/2002 MVA into a network facility.
- Total cost $128 million including $103 million for existing line.
- Requested in-service date Dec 2016. SCE estimates it will take 27 months to equip the position at the substation.

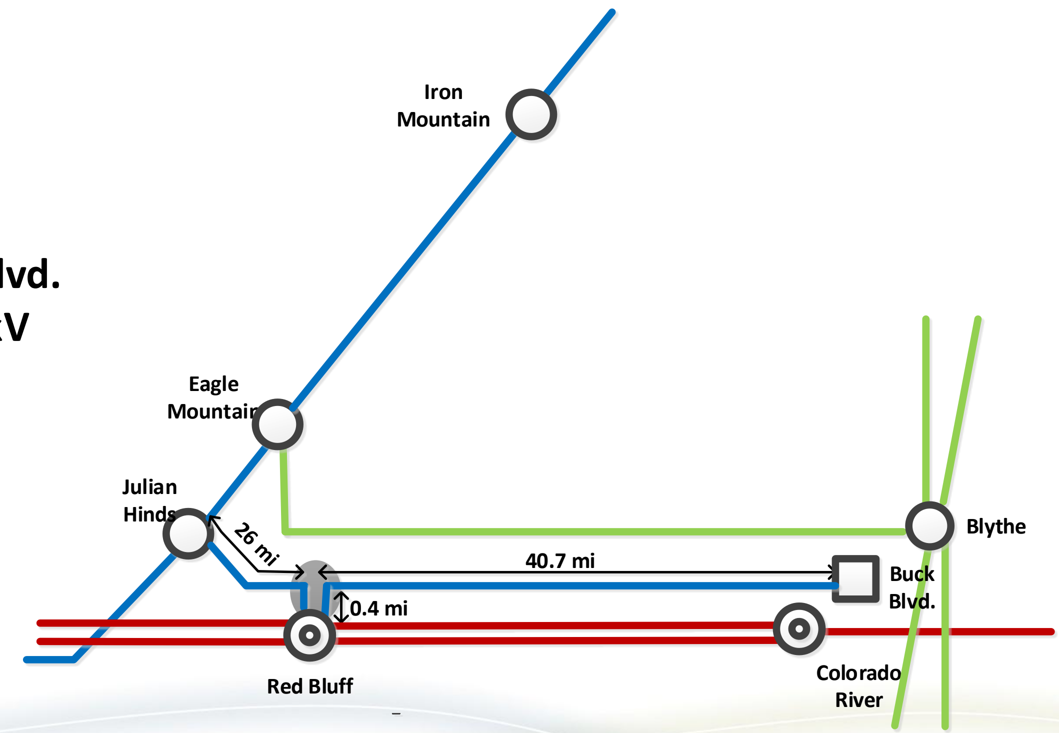


Alternatives considered – cont'd

2. <u>Loop Buck Blvd–Julian Hinds into Red Bluff</u>

- This alternative was identified by the ISO as a variation of the AltaGas proposal.
- Results in the conversion of ~26 miles of the gen-tie with a normal/emergency rating of 1482/2002 MVA into a network facility.
- Total cost - $74 million including $49 million for existing line.

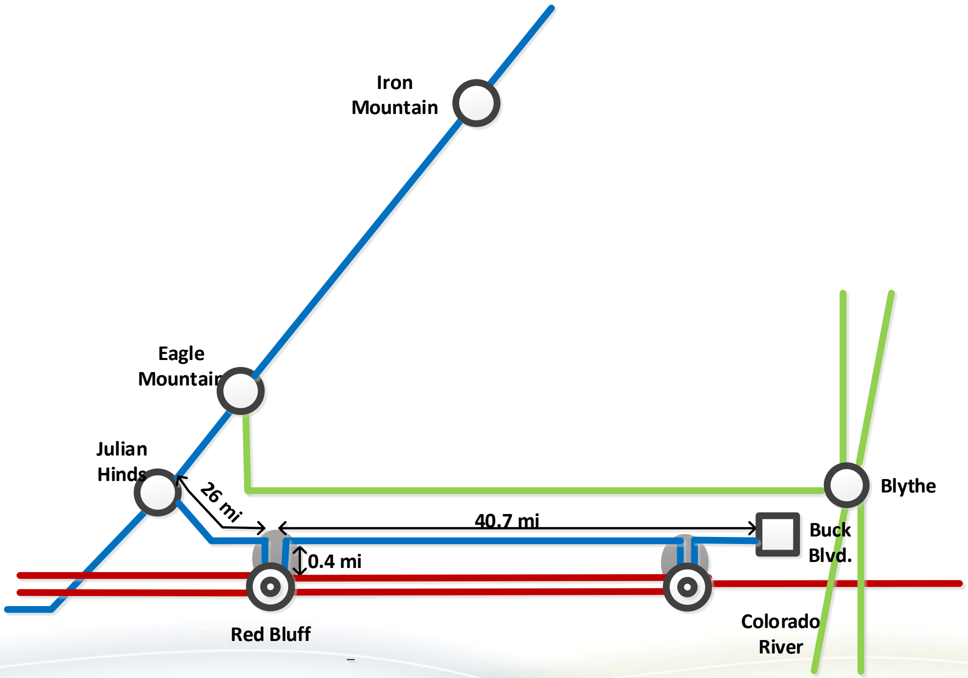




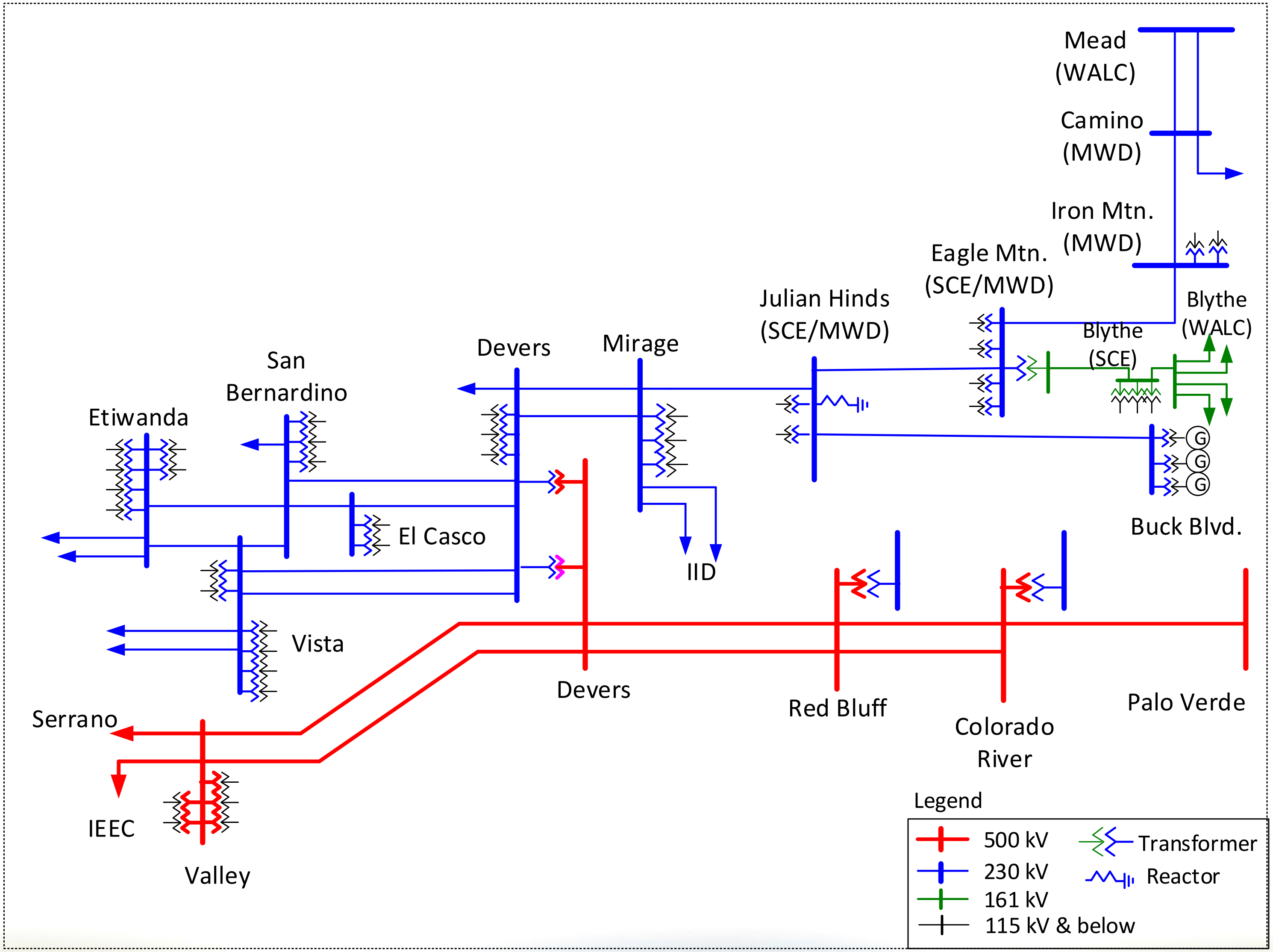
Alternatives considered – cont'd

3. <u>Loop Buck Blvd–Julian Hinds into both Red Bluff and Colorado River</u>

- This alternative was proposed by AltaGas as another variation of the two alternatives.
- Results in the conversion of ~ 54 miles of the gen-tie with a normal/emergency rating of 1482/2002 MVA into a network facility.
- Total cost - $153 million including $103 million for existing line.



Project Area Transmission System



Existing Eastern Area Reliability Issues and Mitigations

Issue	Condition	Mitigation
Julian Hinds–Mirage overload	N-0 (high Blythe output)	Congestion management/ Blythe RAS
Julian Hinds–Mirage or JH-Eagle Mountain overload	N-1 (high Blythe output)	Blythe RAS
Voltage stability/161 kV overload	N-1-1 (heavy pump load, Blythe OOS)	SCE OP 128 - Open 161 kV line after N-1
Transient stability/161 kV overload	N-1-1 (light pump load, high Blythe output)	ISO OP 7720F – reduce Blythe output after N-1
Colorado River Corridor overloads & contingencies	N-1, N-2 (heavy CR Corridor generation)	Planned Colorado River Corridor (CRC) SPS
WOD 230 kV overloads	N-1, N-2 (heavy EOD gen., Path 46 transfers)	WOD RAS and congestion management scheme
High voltages, circuit breaker voltage ratings	N-1, N-1/N-1 (light load, Blythe OOS)	SCE OP 128 – Open Blythe gen-tie, new shunt reactor (proposed)
MWD 6.9 kV CBs SCD	N/A	Series reactors (90w, 75w)

Study cases

- The following 2014-15 TPP reliability assessment, Path 46 study and policy-driven study base cases were used for the study
  1. 2016 Peak, low renewable output, MWD pumps and Blythe 1 online

  1a. 2016 Peak, heavy renewable output, MWD pumps and Blythe 1 online (only run for certain contingencies for sensitivity studies)

  2. 2019 Peak, low renewable output, MWD pumps online, Blythe 1 offline
  3. 2024 Peak, low renewables output, MWD pumps and Blythe 1 online
  4. 2016 Off Peak, heavy renewable output, MWD pumps offline, Blythe 1 online
  5. 2019 Light Load, low solar output, MWD pumps and Blythe 1 offline
  6. 2016 Off Peak, Path 46 stressed
  7. Policy-driven 2024 Peak CI Portfolio, heavy renewable output.
- The study cases are used to identify the reliability benefits and impacts of the project under a wide range of system conditions.

Study cases – cont'd

- The following projects were included in the base cases as follows:
  - Colorado River - Delaney 500kV [ISD-2020]
  - Eldorado – Harry Allen 500kV [ISD-2020]
  - West of Devers (WOD) 230 kV upgrades [ISD-2020]
  - Colorado River 500/230 kV #2 Transformer [modeled in 2024 base cases only]. Project timing is dependent on generation interconnection triggers.
  - Red Bluff 500/230 kV #2 Transformer [modeled in 2024 base cases only]. Project is dependent on generation interconnection triggers.

Positive Impacts of the Project

- The Project reduces N-0 loading on the Julian Hinds–Mirage line in most cases where BEP1 is online. Currently N-0 overload on the line is mitigated using congestion management.
- The Project alleviates N-1 overloading on MWD area 230 kV lines for local 230 kV contingencies in most cases. Currently, these overloads are mitigated by the Blythe Energy RAS.
- The Project addresses existing MWD area N-1/N-1 voltage and transient stability issues involving JH–Mirage outage. Currently, these issues are mitigated using established operating procedures.
- The Project alleviates some of the high voltage issues at Julian Hinds and Eagle Mountain. SCE has proposed adding shunt reactors to address the high voltages.

Negative Impacts of the Project

1. Colorado River or Red Bluff (Alt. 2) AA bank N-0 loading

The Project increases loading on the AA banks at Colorado River (Alt 1), Red Bluff (Alt 2) or both (Alt 3). Generators connecting at the substations including Blythe may be curtailed under N-0 conditions until a second AA bank is installed at the respective substation.

2. Colorado River/Red Bluff AA bank contingency

Outages of Colorado River (Alt 1) or Red Bluff (Alt 2, Alt 3) caused divergence or overload on the Julian Hinds–Mirage line. SPS is needed to either trip up to 1150 MW of generation or reconfigure the system in response to the contingency.

Negative Impacts of the Project – Cont'd

<u>3. Devers–Red Bluff #2 Contingency</u>

- In both pre-project and post project policy cases, the Devers–Red Bluff #1 line overloaded to 116-119%. In addition, JH–Mirage is overloaded in the post project cases.
- Blythe RAS, if triggered due to the JH–Mirage overload, could aggravate the overload on Devers–Red Bluff #1
- The CRS SPS (1150 MW gen drop) and bypassing the series caps after the contingency, if needed, would mitigate the overload on Devers–Red Bluff #1.
- Bypassing series caps to reduce Devers–Red Bluff #1 loading could lead to overload on JH-Mirage and trigger Blythe RAS.
- To avoid this conflict between Devers–Red Bluff #1 and JH–Mirage overload mitigation, SPS to trip the new bus breakers at Red Bluff and/or Colorado River and return the system to the existing configuration may be needed for this contingency.

Negative Impacts of the Project – Cont'd

4. Devers–Red Bluff N-2 Contingency

- In the pre-project policy case, the contingency triggered the existing Blythe RAS which trips Blythe (500 MW) and the CRC SPS which trips an additional 1400 MW. The Julian Hinds–Mirage constraint will need to be addressed in order to meet the SPS guideline limit.
- In the post-project policy cases, the contingency caused severe overloading on the Julian Hinds–Mirage line (up to 250%) and voltage deviation of up to 13% with 1400 MW of generation tripped by the CRC SPS.
- An SPS to trip the new CR and/or RB bus breakers and return the system to the existing configuration is considered to address the overloading and voltage deviation concerns.
- This SPS action will be needed for the N-2 contingency in addition to generation tripping by CRS SPS and the Blythe RAS.

Negative Impacts of the Project - Cont'd

5. Devers–Valley N-2 Contingency

- In the 2016 heavy generation and Path 46 transfer cases, WOD 230 kV lines were overloaded after tripping up to 1400 MW of generation in both pre-project and post-project cases. In both cases the overload would need to be mitigated through congestion management until WOD project is in service.
- However, applying the Devers RAS back-up scheme which trips the Devers AA Banks led to divergence and/or severe overloads in the post-project cases and may need to be mitigated by an SPS if the project is to be connected before the WOD upgrades are in place.

6. Short Circuit Impacts

- The Project increases short circuit levels in the area. However, circuit breaker evaluations indicated that the Project doesn't trigger circuit breaker upgrades.
- MWD prefers the Colorado River Alternative because of its smaller impact on their system.

Economic Analysis

- The model used for the study was developed from the database used it the 2014-2015 ISO Transmission Planning Process using ABB's GridView software program.
- Details regarding the 2014-2015 economic database development are available in the Board-Approved 2014-2015 Transmission Plan at http://www.caiso.com/Documents/Board-Approved2014-2015TransmissionPlan.pdf.

The following cases were created for the study:

Alternative 1

- 2024 base portfolio database with Buck Boulevard-Julian Hinds 230 kV line looped in to Colorado River 230 kV

Alternative 2

- 2024 base portfolio database with Buck Boulevard-Julian Hinds 230 kV line looped in to Red Bluff 230 kV
- 2019 base portfolio database with Buck Boulevard-Julian Hinds 230 kV line looped in to Red Bluff 230 kV (assumed West of Devers project in-service for interpolation purposes)

Yearly production benefits computed by production simulation Analysis

Alternative 1

Year	Production benefit calculated by production simulation	Consumer benefit	Producer benefit	Transmission benefit
2024	$13.4 M	$19.6 M	($3.3 M)	($2.9 M)

Alternative 2

Year	Production benefit calculated by production simulation	Consumer benefit	Producer benefit	Transmission benefit
2019	$5.9 M	$6.8 M	($0.1 M)	($0.8 M)
2024	$8.2 M	$11.1 M	($1.8 M)	($1.2 M)

Capacity Loss Benefits

- 9.1 MW increase in NQC of the Blythe Energy generation due to shorter gen-tie losses to Colorado River
- 4.5 MW increase in NQC of the Blythe Energy generation due to shorter gen-tie losses to Red Bluff
- Increase in NQC assumed to be valued at cost of capacity difference between Arizona and California
- $0.4 M annual benefit at Colorado River
- $0.2 M annual benefit at Red Bluff

Summary of Benefits

- Alternative 1 and Alternative 2 benefits are comparable to the project costs shown in slides 2 and 3
- Based on comparing powerflows between Alternative 1 and Alternative 3, Alternative 3 benefits are expected to be in the range of Alternative 1 and less than or comparable to the project costs in slide 4

Conclusion

- The Project's reliability benefits include alleviating some of the loading, voltage and stability issues in the local 230 kV system by providing a third 230 kV source for the area and offloading the Blythe 1 generating plant from the weak 230 kV system. However, these issues are currently mitigated without the Project using RAS and established operating procedures or could be addressed by the proposed addition of shunt reactors.
- On the other hand, by creating a parallel path between the 500 kV system and the weak 230 kV system the Project introduces new loading and voltage issues and adds to the complexity of area SPSs.
- The study identified a potential SPS guideline violation associated with the Devers-Red Bluff N-2 contingency in both the pre-project and post-project policy cases. The Project adds to the complexity of the SPS actions involved.
- As a result, proceeding with the Blythe Gen-tie Loop-in Project at this time without upgrading the 357 MVA-rated Julian Hinds–Mirage line appears problematic.
- Among the three alternatives, Alternative 2 appears more attractive because it provides a source closer to load while at the same time having the least cost. Alternative 3 appears to be the least attractive option as it increases the cost of the project without providing material reliability benefits.
- The ISO is considering deferring and revisiting the Project in the future when the need to upgrade or reconfigure the Julian Hinds–Mirage line is identified.

Attachment
Summary of Study Results

Thermal Loading Results

Cont.[Worst Cases]	Overload	Existing	Alt.1	Alt. 2	Alt. 3	Mitigation
N-0 [7,1]	JH - Mirage	85-97%	57-80%	57-89%	51-86%	Congestion Mgmt.(Pre)
N-0 [4]	Col. River Tr.	<100%	102%	<100%	<100%	Congestion Mgmt. (Post)
Col. River Tr. [1,4]	JH - Mirage	<100%	165%/NC	<100%	<100%	Modify CRC SPS (Post)
Red Bluff Tr. [1,1a,4,7]	JH - Mirage	<100%	<100%	148%/NC	109%	Modify CRC SPS (Post)
JH - Eagle Mtn. [3,7]	JH - Mirage	150%	<100%	104%	102%	Blythe RAS (Pre) Blythe RAS (Post)
JH - Mirage [3,4,7]	JH SCE-MWD	153%	<100%	<100%	<100%	Blythe RAS (Pre)
Devers–Red Bluff #2 [7]	JH–Mirage	<100%	101%	118%	115%	CRC SPS, Blythe RAS (Post)
	Devers–Red Bluff #1	119%	118%	116%	116%	CRC SPS (Pre, Post), Blythe RAS can aggravate overload (Post)
Above with CRC SPS 1150 MW gen trip [7]	JH–Mirage	94%	88%	96%	94%	Bypass series caps after contingency. (This triggers Blythe RAS and increase loading on Devers-Red Bluff)
	Devers–Red Bluff #1	100%	101%	100%	100%	

Thermal Loading Results – Cont'd

Cont.[Worst Cases]	Overload	Existing	Alt.1	Alt. 2	Alt. 3	Mitigation
Devers-Red Bluff N-2 with CRC SPS tripping up to 1400 MW [7,1a,1,3]	JH - Mirage	140%	205%	250%	248%	- Existing Blythe RAS (Pre). - SPS to trip CR and/or RB bus breakers and Blythe RAS (Post)
Devers-Valley N-2 [1a,4,6]	4 WOD lines	120-143%	120-143%	120-143%	120-143%	WOD RAS & Congestion Mgmt. (Pre, Post)
Above with up to 1400 MW Devers RAS gen trip [4,6,1a]	2 WOD lines	100-105%	101-108%	100-107%	101-108%	
Above w/ Devers AA bank tripped by Devers RAS back-up scheme [1a,6,4]	JH – Mirage	132%	Diverged (182%)*	Diverged (212%)*	Diverged (211%)*	Trip JH–RB/CR (Blythe RAS) or new CR/RB bus breakers from RB/CR for Devers-Valley N-2 * Solved by relaxing reactive power limits
	Lugo-Victorville	102%	Diverged	Diverged	Diverged	

Thermal Loading Results – Cont'd

Cont.[Worst Cases]	Overload	Existin g	Alt.1	Alt. 2	Alt. 3	Mitigation
JH-CR/RB & Devers–Red Bluff #2, 1400 MW tripped[7]	Devers–Red Bluff #1	N/A	105%	105%	106%	System adjustment/30 minute rating (Post)
Devers–Mirage N-2 [4]	JH – Eagle Mtn.	120%	<100%	<100%	<100%	Blythe RAS (Pre)
Path 42 N-2 [7,1,3,]	JH – Mirage	117%	106%	115%	113%	Blythe RAS trips CT (Pre) Blythe RAS trips JH–RB/CR (Post)
Devers #1 & #2 AA banks [7]	JH – Mirage	109%	127%	144%	142%	Blythe RAS trips CT (Pre) Blythe RAS trips JH–RB/CR (Post)

High/Low Voltage Results

Cont.[Case 5]	Facility	Existing	Alt.1	Alt. 2	Alt. 2	Mitigation
Julian Hinds–Mirage (N-1)	Julian H. 230 kV	243.7	<242	<242	<242	Add up to two shunt reactors to bring voltages below the maximum ratings of circuit breakers at Julian Hinds and Eagle Mtn. (JH=242 kV, EM=245 kV, EM 161 kV = 169 kV) .
Julian H.–Mirage & Julian H. shunt reactor (N-1/N-1)	Julian H. 230 kV	251.8	<242	<242	<242	
	Eagle Mt. 230 kV	250.1	<245	<245	<245	
Julian H.–Eagle M. & Iron M.–Camino (N-1/N-1)	Eagle Mt. 161 kV	170.3	170.2	170.2	170.2	
Julian H.–Mirage & Iron M.–Camino (N-1/N-1)	Julian H. 230 kV	251.4	<242	<242	<242	
	Eagle Mt. 230 kV	251.0	<245	<245	<245	
Julian H.– Mirage & Eagle M. A Bank (N-1/N-1)	Julian H. 230 kV	245.8	<242	<242	<242	
	Eagle Mt. 230 kV	245.5	<245	<245	<245	
Julian H.–Eagle M. & Parker–Gene	Eagle Mt. 161 kV	170.0	170.0	170.0	170.0	

Voltage and Transient Stability Results

Cont.[Worst Case]	Facility	Existing	Alt.1	Alt. 2	Alt. 3	Mitigation
Julian H.–Mirage & Iron M.–Camino (N-1/N-1) without system adjustment [1,2,3,4]	N/A	Diverged/ Unstable	Converged/Stable	Converged/Stable	Converged/Stable	System adjustments after initial contingency per SCE OP 128 and ISO OP 7720F (Pre-project)
Julian H.–Mirage & Eagle M.–Iron M (N-1/N-1) without system adjustment [2,3,4,1]	N/A	Diverged/ Unstable	Converged/Stable	Converged/Stable	Converged/Stable	
Devers-Red Bluff N-2 with CRC tripping 1400 MW [7]	Multiple	≤9.5%	Up to 13.3%(DV) (48 IID buses, 12 MWD/SCE buses)	Up to 12.9%(DV) (50 IID buses, 2 MWD buses)	Up to 12.6%(DV) (50 IID buses)	SPS to trip CR and/or RB bus breakers and Blythe RAS (Post)
Same as above with Blythe gen-tie (Pre) or JH–RB/CR line (Post) tripped [7]	IID (Ave. 58)	9.8% (DV)	10.3%(DV)	10.2%(DV)	10.2%(DV)	

2015 Grid Assessment Results

CAISO Stakeholder Meeting

September 21-22, 2015

Introduction

Objectives

- <u>SDG&E Project Proposals</u>
  - Mitigate overloaded facilities
    - Category P1 contingencies
  - Mitigate voltage deviations
    - Category P1 contingencies
  - Operating procedures, SPS
    - Category P2-P7 contingencies

SDG&E Grid Assessment Study

Study Assumptions

Study years

- Five-Year Studies (2016-2020)
- Ten-Year Study (2025)

Major assumptions

- CEC Load Forecast for San Diego
- Cabrillo II peakers retired in 2015, Naval QF’s retirements in 2020 & 2025
- Pio Pico peakers online starting in year 2016
- Encina retired end of year 2017
- SX-PQ 230 kV line in study years 2017 and later
- MS-PQ 230 kV line in study years 2019 and later
- CAISO-approved reactive power projects
  - 2x225MVAr Synchronous Condensors at Talega 230kV – energized 8/2015
  - 2x225MVAr Synchronous Condensors at San Luis Rey 230kV in year 2016
  - 1x225MVAr Synchronous Condensors at San Onofre 230kV in year 2017
  - 2x225MVAr Synchronous Condensors at Miguel 500kV in year 2017
  - 300MVAr Static VAr Compensator at Suncrest 230kV in year 2017
  - Imperial Valley Phase Shifter in year 2017

Expansion Plan Summary

Project #	Project Title	ISO Status	ISD
Proposed Projects Requiring CAISO Approval			
2015-00036	Reinforcement of Southern 230 kV System	Pending	2019
2015-00020	New Miramar 230 kV Tap (MS-MRGT-PQ)	Pending	2020
2015-00036	SCR Reinforcement	Pending	2020
2015-00039	Install 3rd Miguel Class 80 Bank	Pending	2017
2015-00024	TL600: Mesa Heights Loop-In + Reconductor	Pending	2018
2015-00031	Install a new 3rd SA-ME 69kV Line	Pending	2017
2018-00013	Reconductor TL605 Silvergate– Urban	Pending	2018
2018-00034	New Capacitor at Pendleton Substation	Pending	2017
2015-00035	New Capacitor at Basilone Substation	Pending	2016
P15XYZ	Valley Inland Powerlink - Resubmittal	Pending	2025
New Distribution Substations			
Info Only	Ocean Ranch Substation - Resubmittal	-	2019

SDGE
A Sempra Energy utility

Project Title:
Reinforcement of Southern 230 kV System

In-Service Date:
June 2019

Project:
2015-00036

Driving Factor:

- NERC Cat C5 (common tower outage (P7), MS- ML) overloads TL23042 (ML-BB) by:

  108.1% in 2019 , 112.8% in 2020

- Post Project Results:
  - Mitigate Cat B (P1) overloads in the Sycamore Area, TL6916.
  - Mitigate Cat C (P4), Stuck Breakers at Bay Blvd
  - Mitigate Cat C (P7), Common Tower in the area

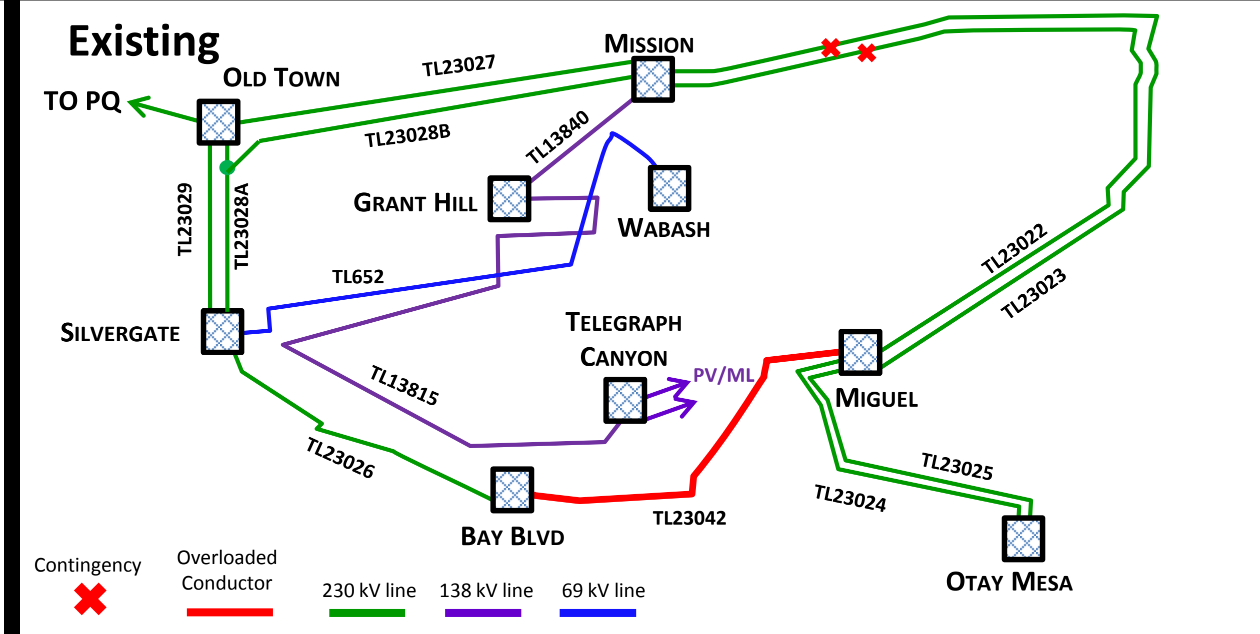
Scope:

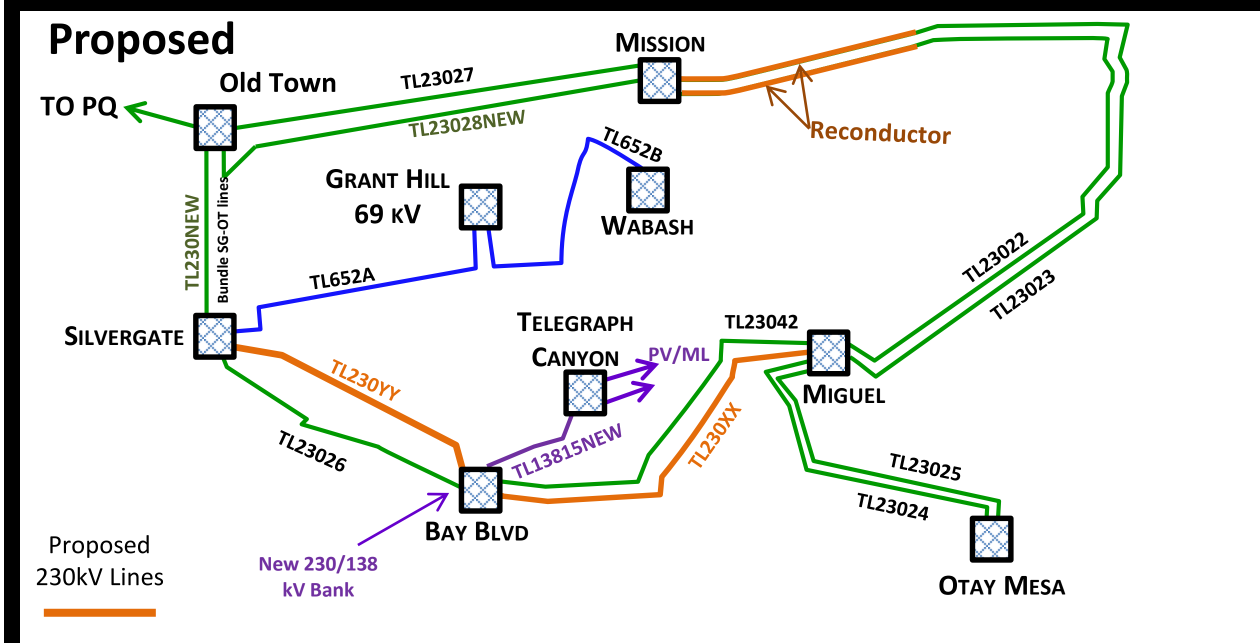
- Add a second 230kV line from Miguel to Bay Blvd. with a minimum rating of 1175 MVA
- Add a second 230 kV line from Bay Blvd to Silvergate with a minimum rating of 912/1176 MVA to mitigate new NERC thermal violation
- Convert Grant Hill to 69 kV and loop-in TL652
- Reconductor approx. 8 miles from Mission to Fanita Junction (TL23022 and TL23023)
- Add 230/138 bank at Bay Blvd to maintain reliability at Telegraph Canyon (TC)
- Bundle TL23029 and TL23028A, results in a strong SG-OT 230kV line.

Cost: Pending

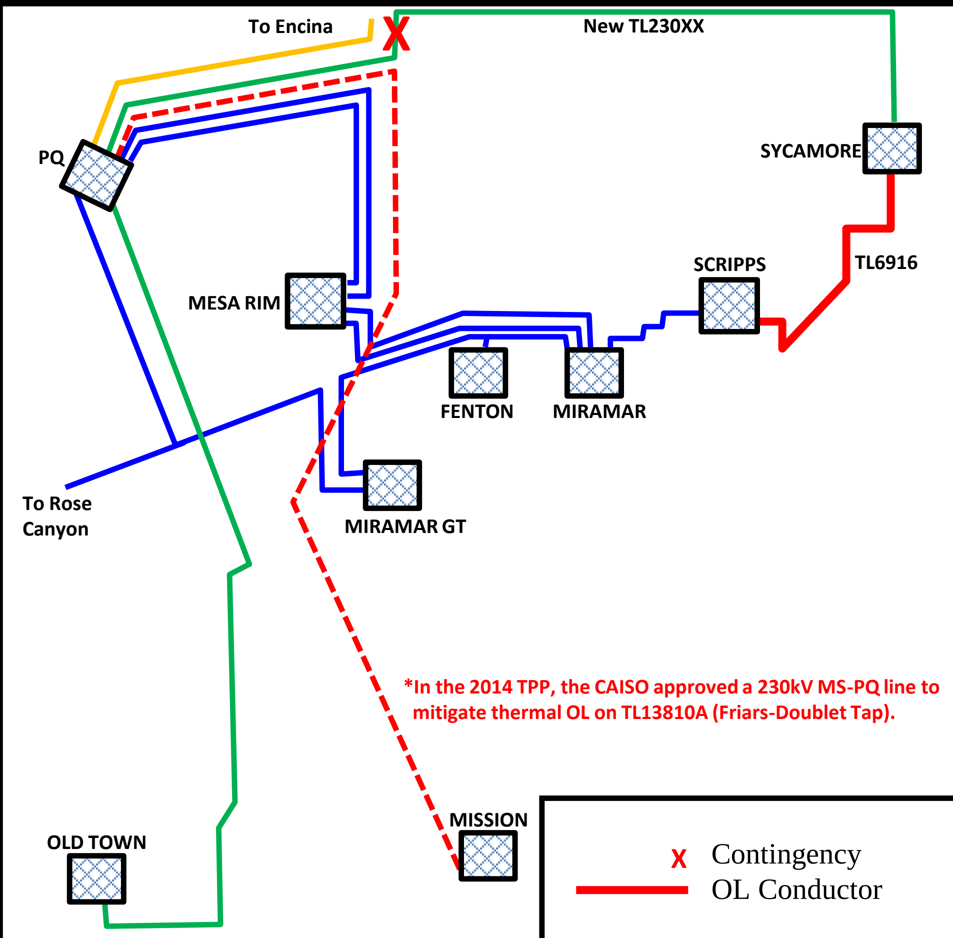
Benefits:

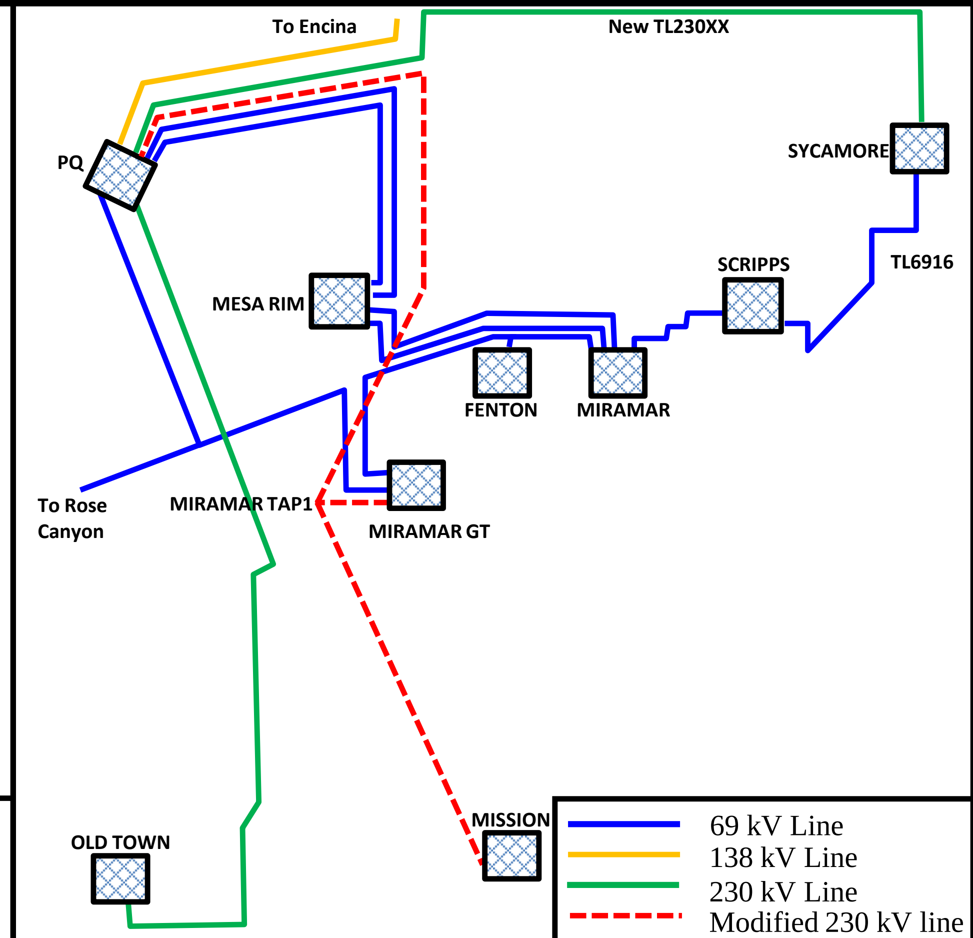
- Reinforce Southern 230kV loop
- Increase operational flexibility





Project Title:	District:	Need-Date:	Project:
New Miramar 230 kV Tap (MS-MRGT-PQ)	BC	June 2020	2015-00020





Issues:

- NERC Cat P1 (N-1) of the new PQ-SX TL loads TL6916 to 101% of it's emergency rating.
- The CAISO identified an LCR need of 68MW in the Miramar Sub area for this contingency violation.

Cost:

- **23.6M – 28.3M**

Scope:

- Modify the new Mission to Penasquitos 230kV line (ISD 2019) by adding a new Miramar tap which feeds into Miramar GT. New line into Miramar GT would be approximately 1000 Ft.
- Convert the existing Miramar GT to a 230/69kV substation.
- RFS the existing Cabrillo II CT units at Miramar GT sub and install a 230/69kV bank.

Benefit

- Mitigate the ongoing thermal overload on TL6916.
- Mitigate the LCR need identified by CAISO.
- Eliminate maintenance in CT units (2 units) ~ $1M/year/unit
- This option will still mitigate the 138kV OL originally identified by CAISO.
- Allow black start capability directly to the 230kV system.

Alternatives:

- Loop-in MS-PQ 230kV line into Miramar GT – study ongoing
- Reconductor TL6916 or a second SX-Scripps line.

Project Title:
SCR Reinforcement

District: **Bulk Power**

Need-Date: **June 2020**

Project: **2015-00036**

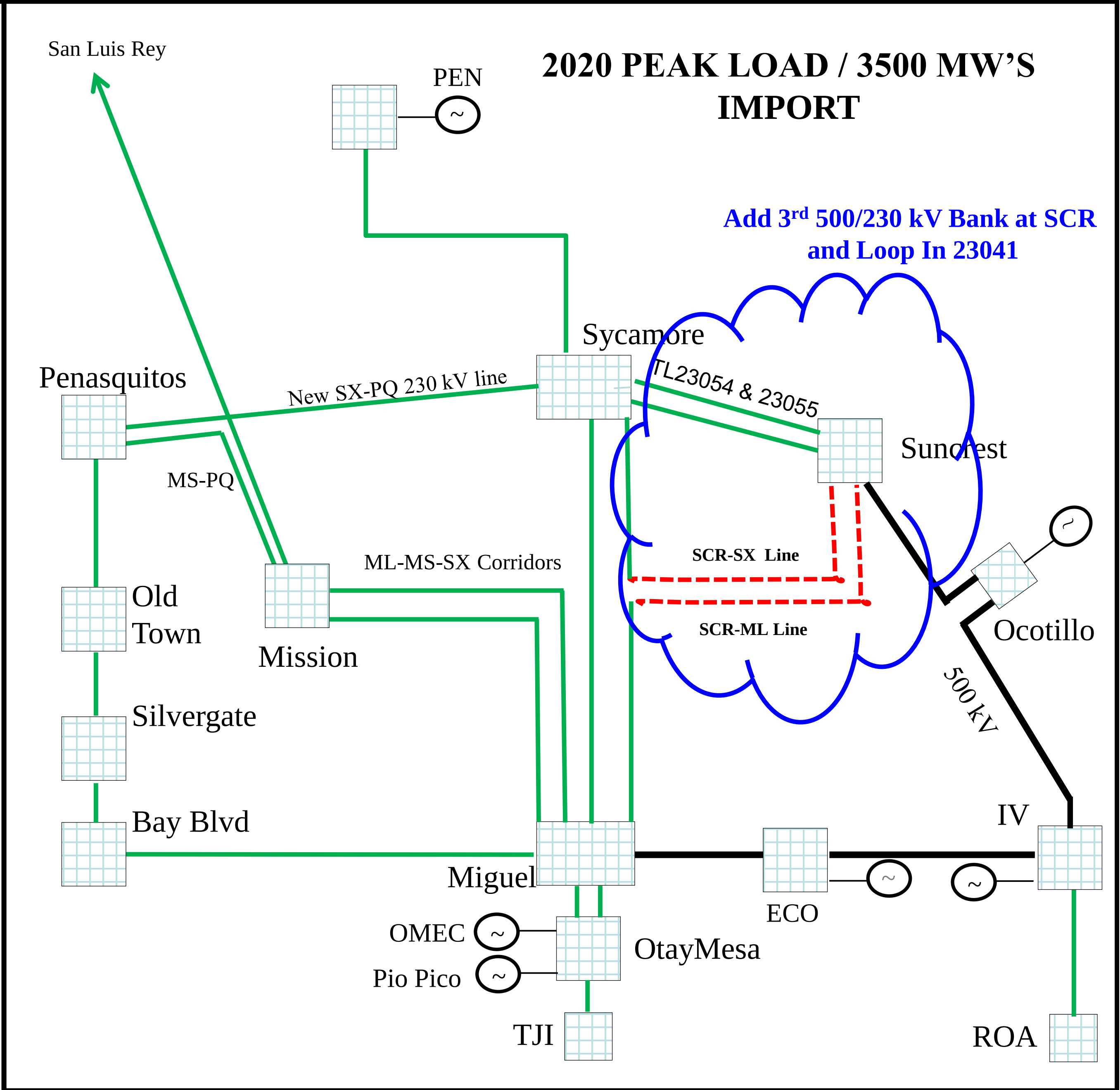
Driving Factor:
- Mitigates overloads on SCR-SX TL23054 and TL23055 for the loss of TL50001.

Scope:
- Add a 3rd 500/230kV bank at SCR.
- SCR 230 kV-add three bay positions 1 1/2 breaker design.
- Sectionalize TL23041 and convert to two 230kV lines: SCR-ML & SCR-SX.
- Upgrade 500kV Series Cap at SCR to match the SRPL conductor rating.

Cost: **Pending**

Advantages:
- Mitigates overloads on SCR-SX TL23054 and TL23055 for the loss of TL50001.
- Improves SRPL flow ability and balances the flow on SRPL and SWPL.
- Mitigates the overload of one SCR bank 80 for the other.
- Improves ML banks 80 & 81 overload of one for the other.
- Improves Miguel 500 kV voltage profile.
- Maximizes usage of SRPL under the N-1 of SWPL.

Issues:
- Routing / Environmental
- Licensing



Project Title: **Install 3rd Miguel Class 80 Bank** | *District:* **Eastern** | *Need-Date:* **June 2017** | *Project:* **2015-00039**

Driving Factor:
Cat P1 (P1.3) criteria violation

Scope:
Expand the GIS at Miguel in order to add a third class 80 transformer.

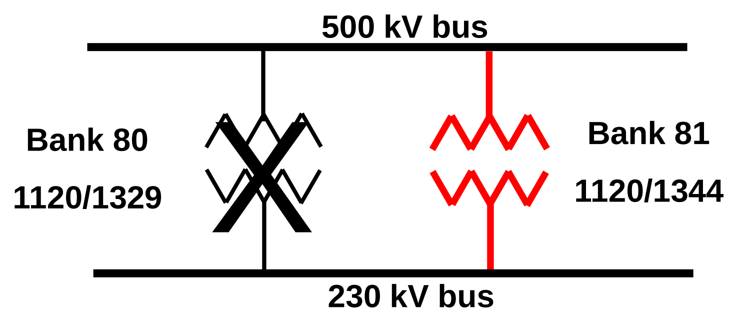
Cost: pending

Issues:
The T-1 of one class 80 bank at the Miguel substation overloads the other.

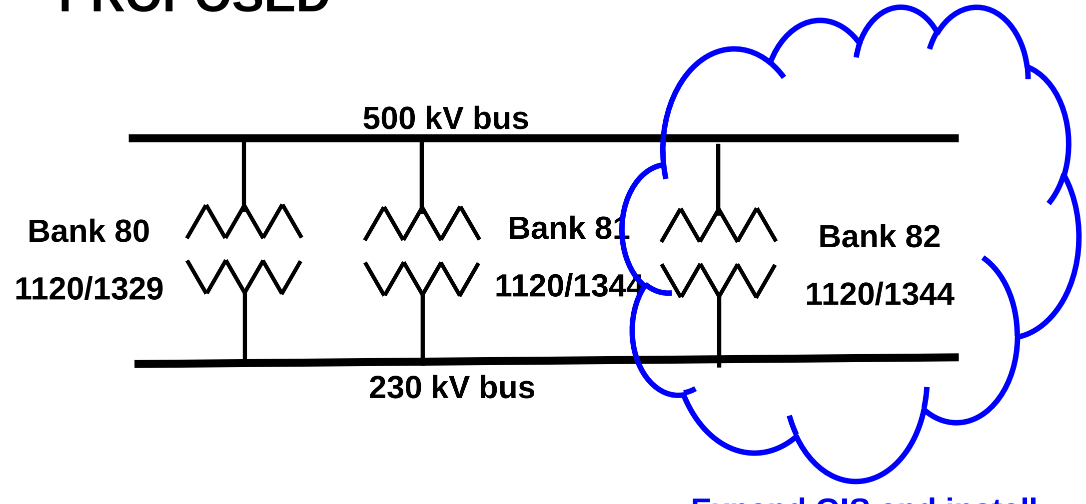
Alternative:
Continue to rely on the existing Miguel SPS intended to protect a ML bank from loading above its ER rating for a Miguel T-1.

Benefits:
Allow to install the Miguel SynCons on their own breaker positions and mitigate the greater than 5% voltage deviation violation at Miguel for the N-I of TL50001 (Miguel to Eco).

EXISTING



PROPOSED



Project Title:
TL600: "Mesa Heights Loop-In + Reconductor"

District:
Beach Cities

Need-Date:
June 2018

Project:
2015-00024

Driving Factor:
- Mitigate the LCR need identified by the CAISO in the Mission Sub area.
- NERC Thermal Overloads (P6) on TL600 due to the N-1-1 of TL663 & TL676.

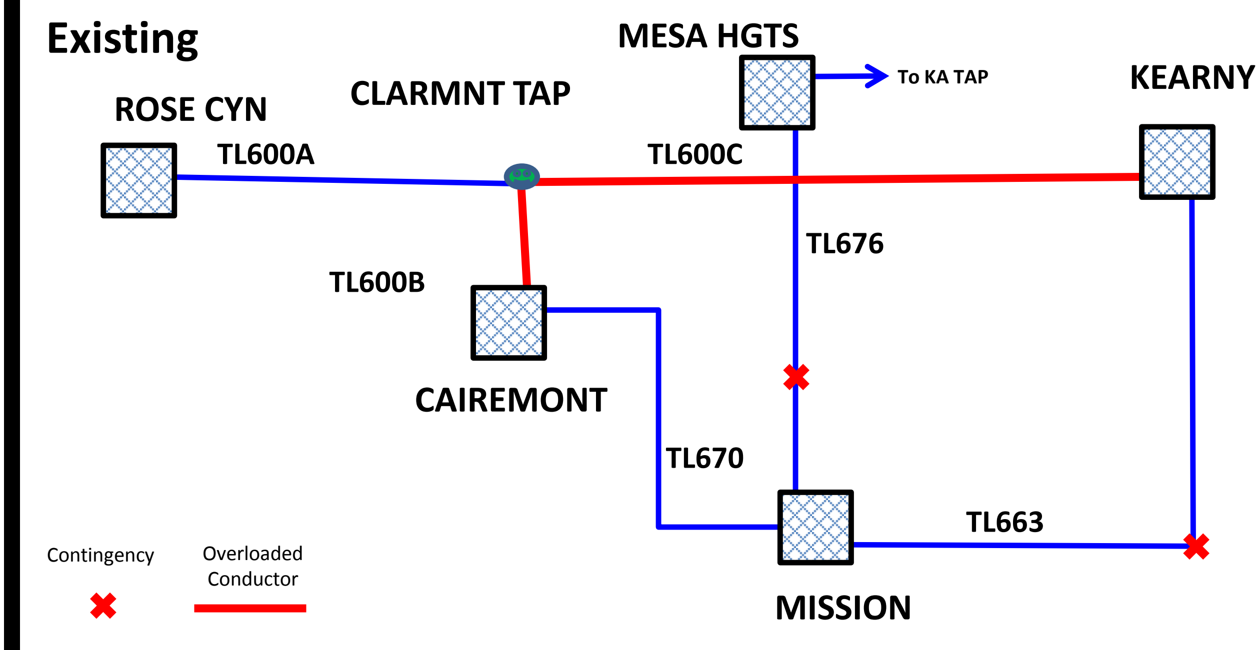
Scope:
- Loop-in TL600C into Mesa Heights
- Reconductor ~2.2 miles Clairemont-Mesa Heights to a minimum of 150 MVA
- Reconductor ~.7 miles Clairemont Tap – Clairemont to a minimum of 102 MVA

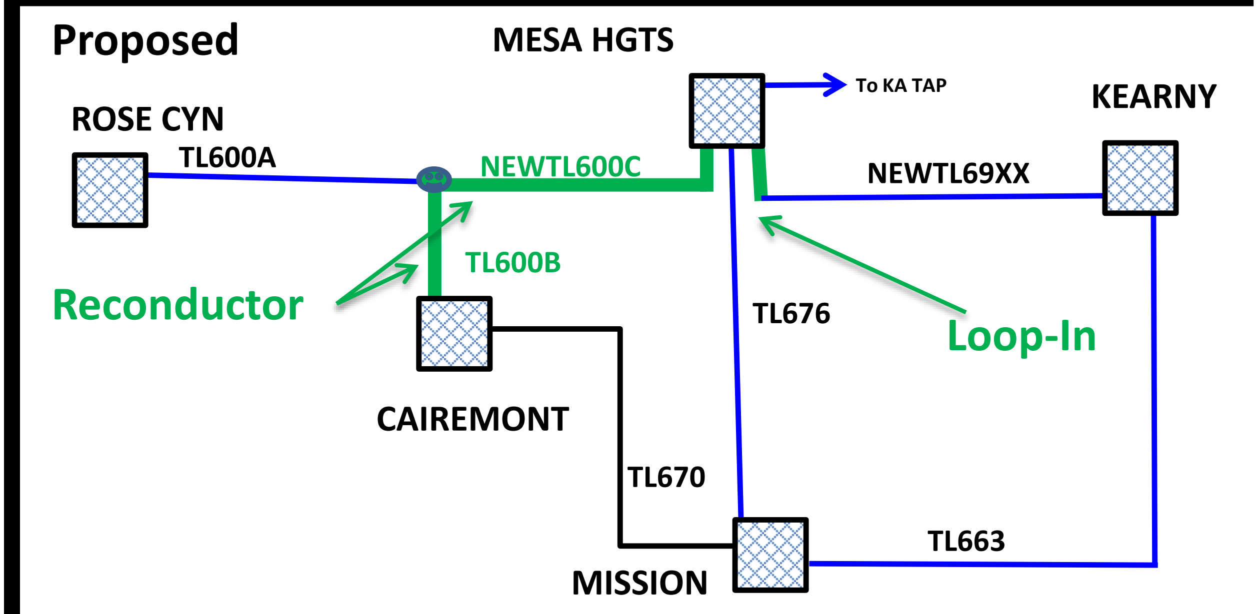
Cost: Pending

Issues:
- Kearny Gens maintenance ~ $1M a year/unit, 8 units at Kearny.
- Delay Kearny Rebuild

Benefits:
- Operational flexibility
- Increase reliability at MH (5,300 customers, 61MW)
- Eliminate LCR need identified by CAISO
- Savings of approximately $8M a year on KY maintenance

Alternatives:
- Keep Kearny Gens for congestion management





Project Title:
Install a new 3rd SA-ME 69kV Line

District: North Coast

Need-Date: June 2017

Project: 2015-00031

Driving Factor:
Cat P7 criteria violations, N-2 outage of TL693 and TL6966 San Luis Rey – Melrose overloads TL680B.

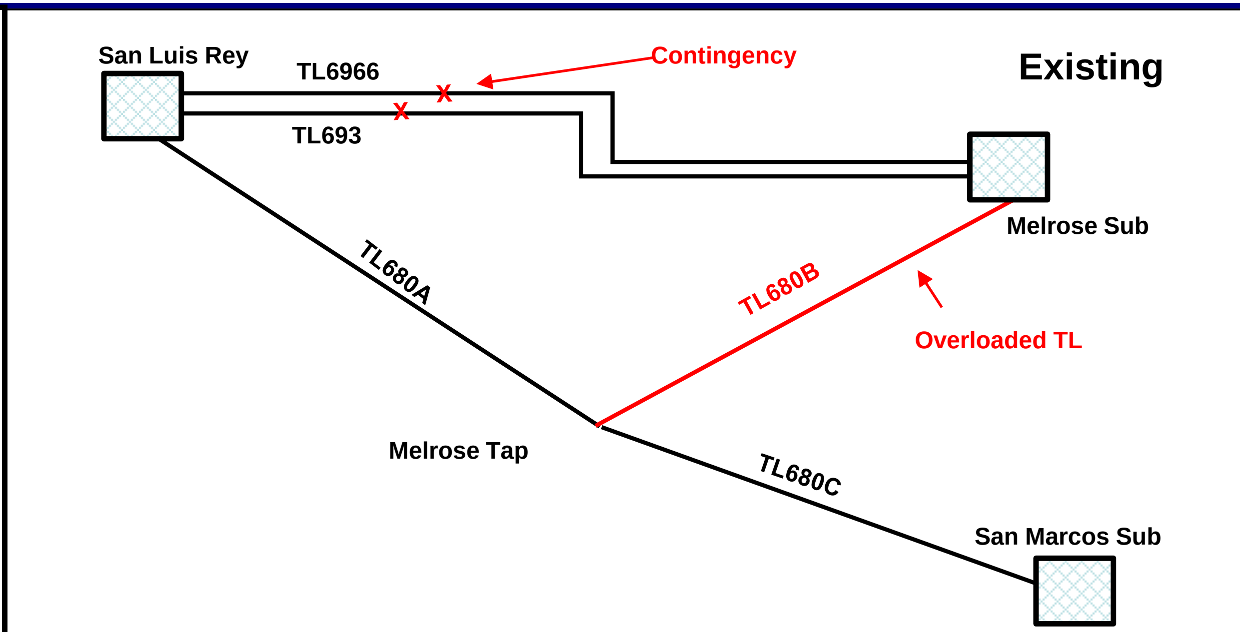
Scope:
- Construct a new 69kV, TL69XY ~ 5.7 miles, from San Luis Rey – Melrose with a minimum 102 MVA rating.

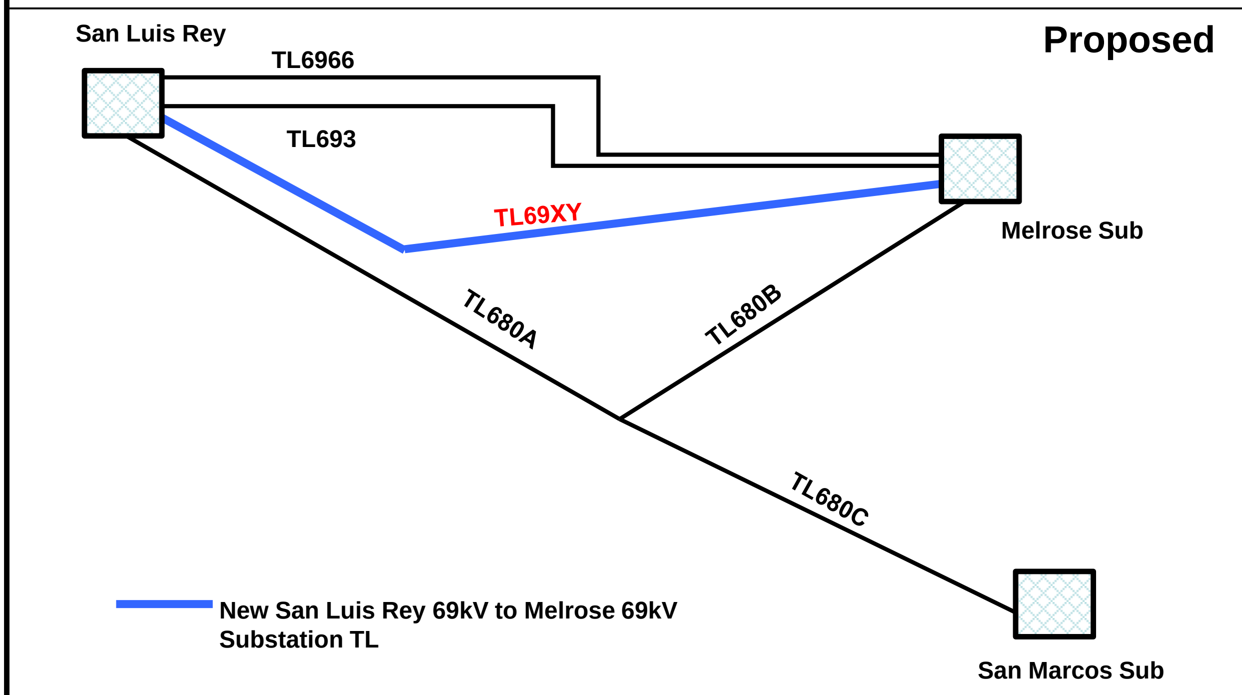
Route:
- Using the existing energized portion of TL13802 from San Luis Rey Substation to Oceanside Blvd.
- New line along Oceanside Blvd to Melrose Sub.
- Expand Melrose bus to accommodate the new TL69XY (5th circuit).

Cost: PENDING

Issues:
- N-2 outage of TL693 and TL6966 (SA-ME) causes a 110% overload on TL680B in 2016
- This NERC thermal violation existing pre and post Ocean Ranch Substation.

Alternative:
- Reconductor TL680B – rendered not feasible
- Drop Load





Project Title:
Reconductor TL605 Silvergate– Urban

District: **Metro**

Need-Date: **June 2018**

Project: **2015-00013**

Driving Factor:

- Mitigate thermal overload on TL605 for the N-1-1 of TL602 and TL699 (SG-B ckt 1 & 2), starting in 2018.

Scope:

- Reconductor TL605 to a minimum continuous rating of 137 MVA.

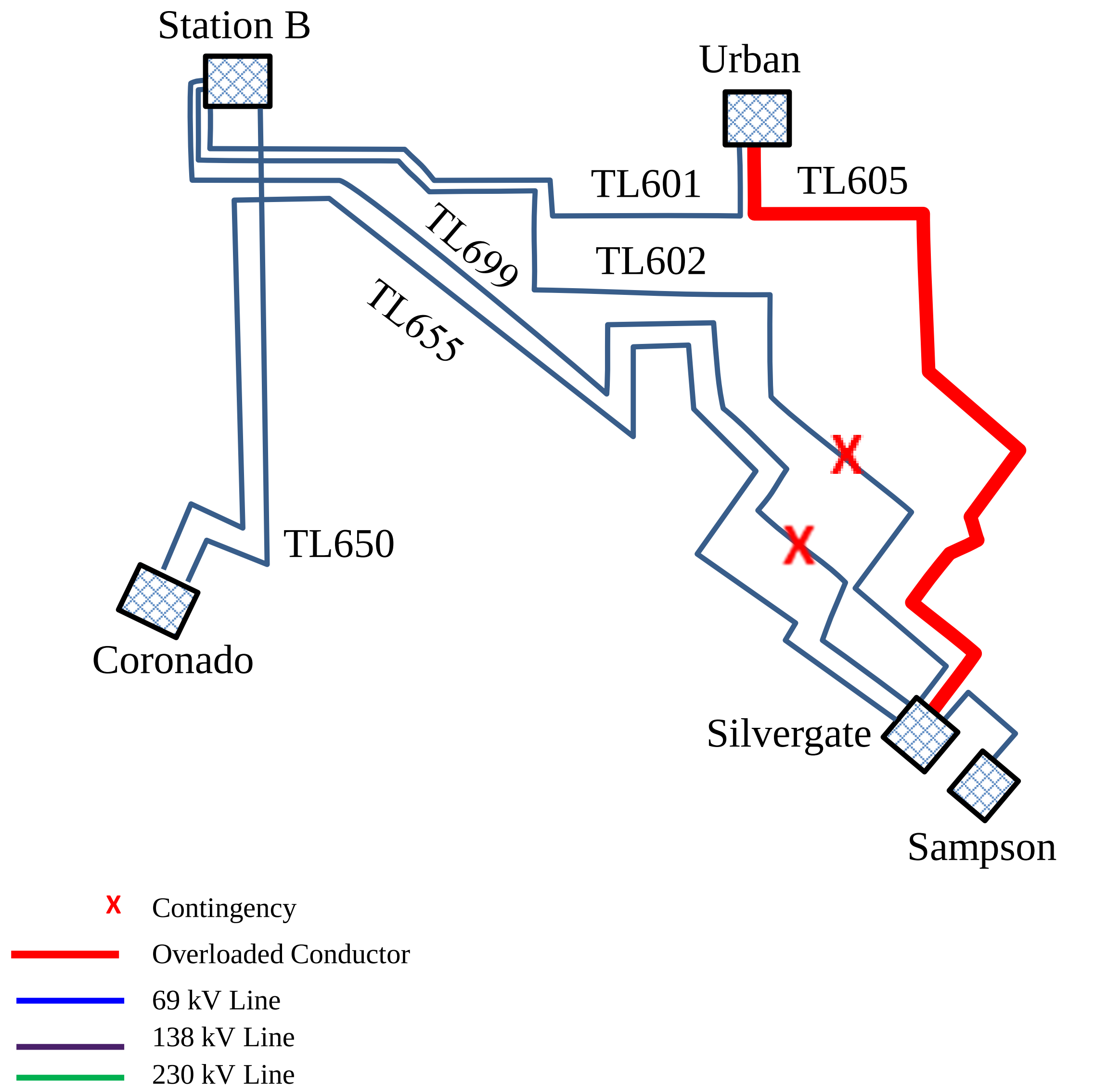
Costs: Pending

Issues:

- In 2018, an N-1-1 contingency loss of TL602 & TL699 (Silvergate – Urban ckt 1&2) overloads TL605 by 7.9% in 2018.
- No generation available to re-dispatch

Alternatives:

- 2nd Urban – Silvergate 69kV line
- Drop Load ~ 20MW



Project Title:	District:	Need-Date:	Project:
New Capacitor at Pendleton Substation	**NC/NE**	**June 2017**	**2015-00034**

Driving Factor:

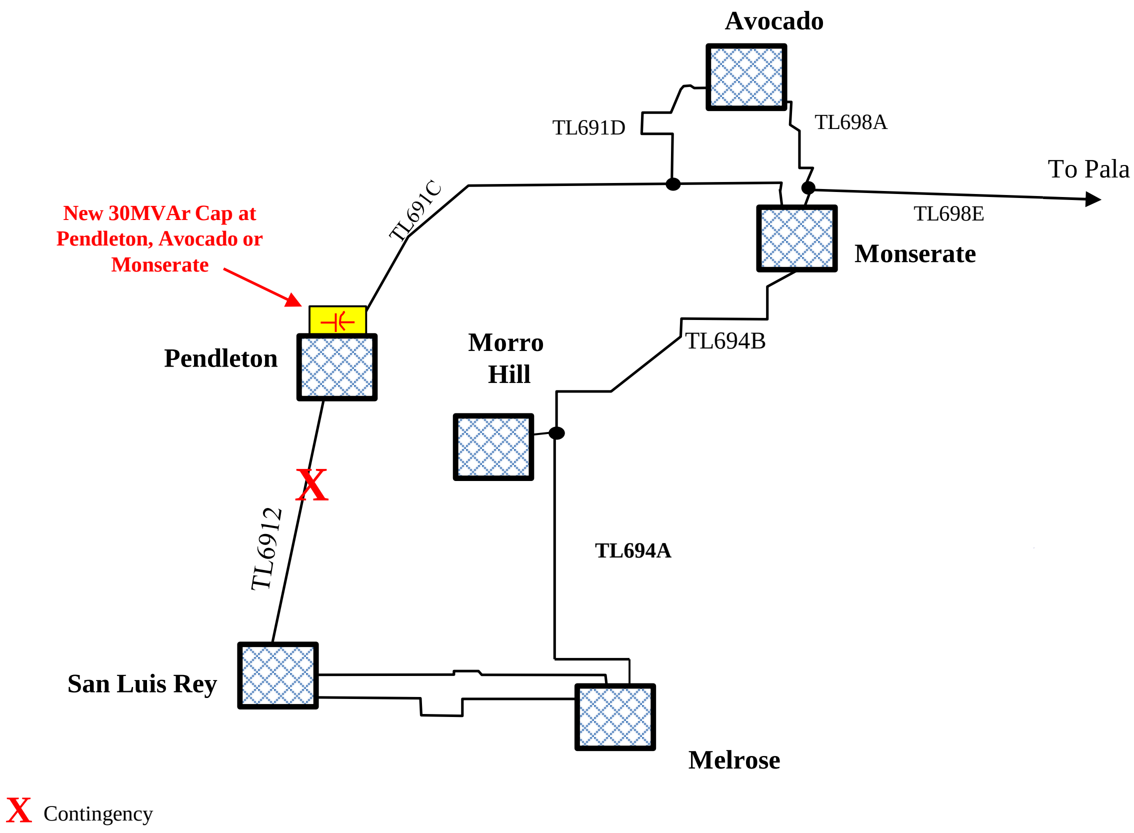
- Greater than 5% voltage deviation for N-1 of TL6912 - Base Case
- No Reactive support in the Fallbrook* Load Pocket
    - Load Pocket is ~ 110MW
    - Load Pocket loop is ~ 40 circuit miles, SA to ME.

Scope:

- Install 30MVAR Capacitor at either Avocado, Pendleton or Monserate

Benefits:

- Improve voltage in the Fallbrook Load Pocket



* Fallbrook Load Pocket includes Pendleton, Avocado, Monserate and Morro Hill

Project Title:	***District:***	***Need-Date:***	***Project:***
New 15MVAR Capacitor at Basilone Substation	**North Coast/Orange County**	**June 2016**	**2015-00035**

Driving Factor:

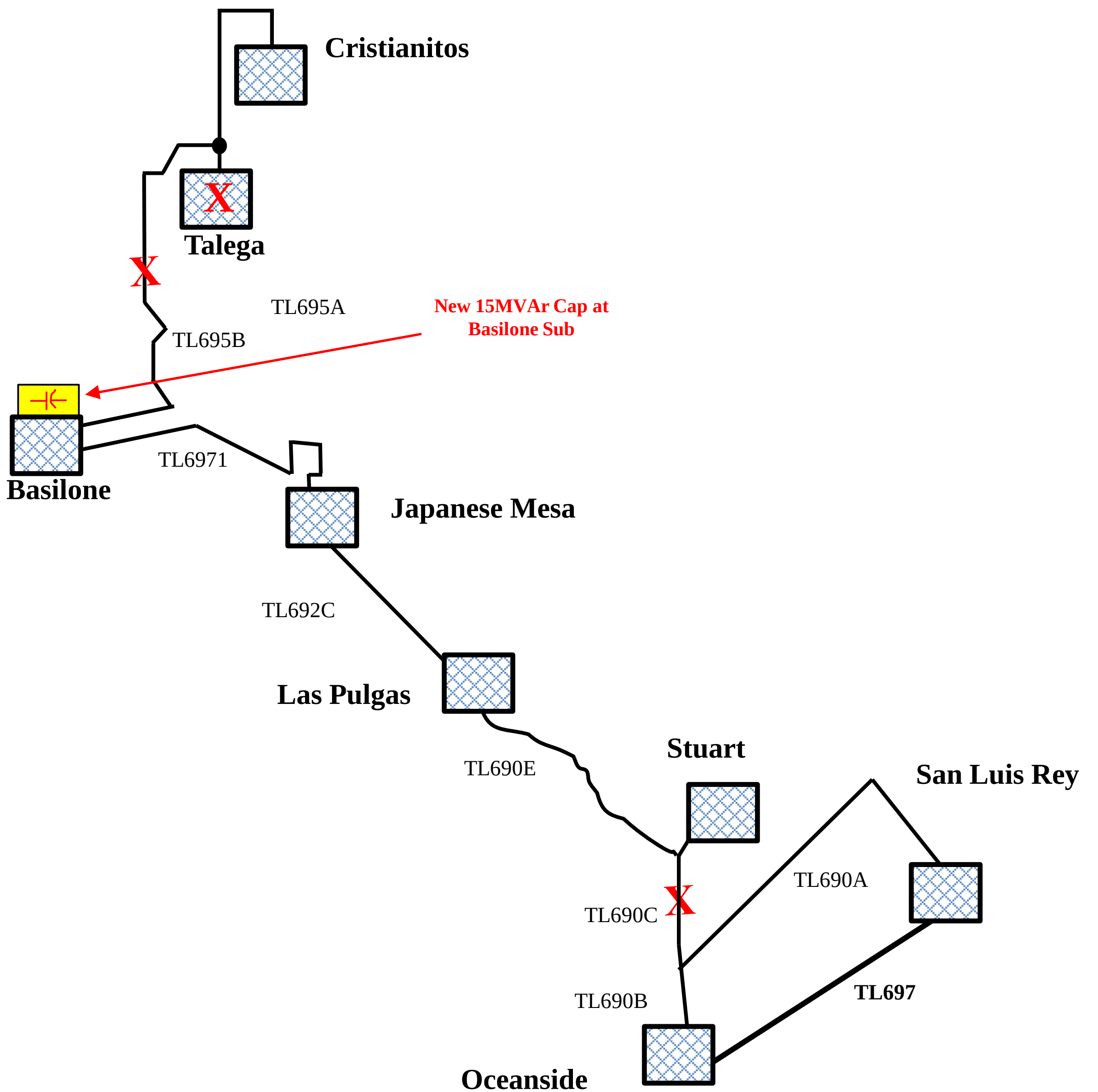
- Greater than 5% voltage deviation for N-1 of either:
  - TA Bank 50
  - TL695
  - TL690
- No Reactive support
  - Talega to OC Tap ~ 22 miles

Scope:

- Install 15MVAR Capacitor at Basilone Sub

Benefits:

- Improve voltage in the Camp Pendleton Area



Project Title:
HV Transmission Lines - Valley Inland Powerlink - Resubmittal

In-Service Date:
June 2025

Project:
P15XYZ

Needs:

- Meet G-1/N-1 Planning Criteria
- Early retirement of San Onofre Nuclear Generation (SONGS)
- Loss of Once-Through Cooling (OTC) units in SoCal

Scope:

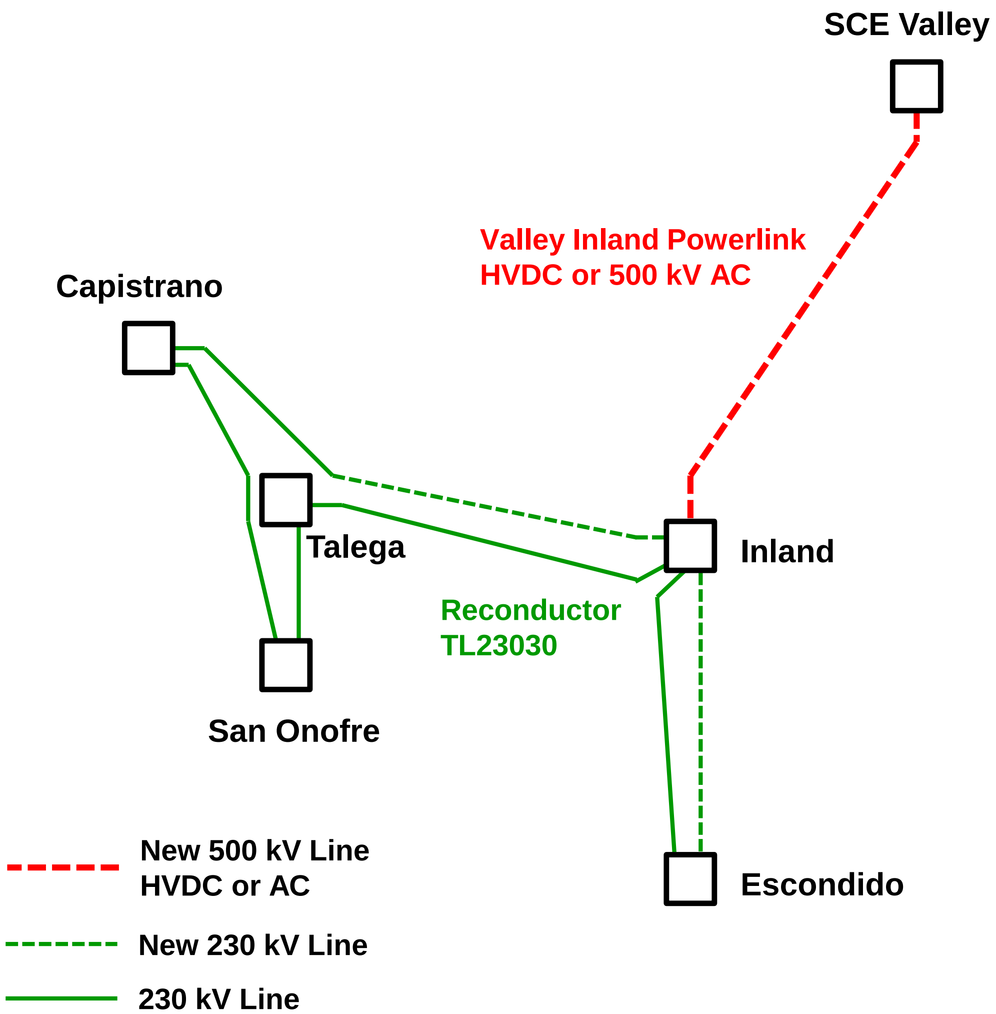
- Valley Inland Powerlink
  - New HVDC Transmission Line
- Talega-Escondido 230 kV lines
  - Reconductor and loop-in existing TL23030
  - Construct new lines between Talega and Escondido

Alternative:

- Valley Inland Powerlink – Alternative 2A
  - New 500 kV AC Line
- Talega-Escondido 230 kV lines: same scope as above

Advantages:

- Reduction of the need for in-basin generation within Southern California



Valley Inland Power Link
Summary of Justification

- Necessary to meet WECC 2.5% and 5% reactive margin requirements
- Reduces reliance on retiring OTC generation
    - South Bay (2010 retirement)
    - SONGS (2013 retirement)
    - Encina (2017 OTC compliance date)
- Renewable Integration
    - Provides dynamic reactive capabilities that typical wind and photovoltaic/solar cannot provide
- Import Capability
    - Reduces the risk of voltage collapse during high import scenarios\
    - Reduces reliance on safety net for N-1-1 of Sunrise/SWPL
- Operational Flexibility
    - Improves 230 kV voltage profile
    - Increases secure operating range
- Potential Technologies
  - AC – 500 kV and/or 230 kV
  - HVDC – Voltage TBD (±320-500 kV)

Expansion Plan Summary- New Substations

- Ocean Ranch Substation

Project Title:	***District:***	***Need-Date:***	***Project:***
New 69kV Ocean Ranch Substation Resubmittal – Info Only	**North Coast**	**June 2019**	**2014-00047**

Distribution Driving Factors

- Support the growing demand in the Vista Load Pocket.
- Offload existing highly loaded substations.

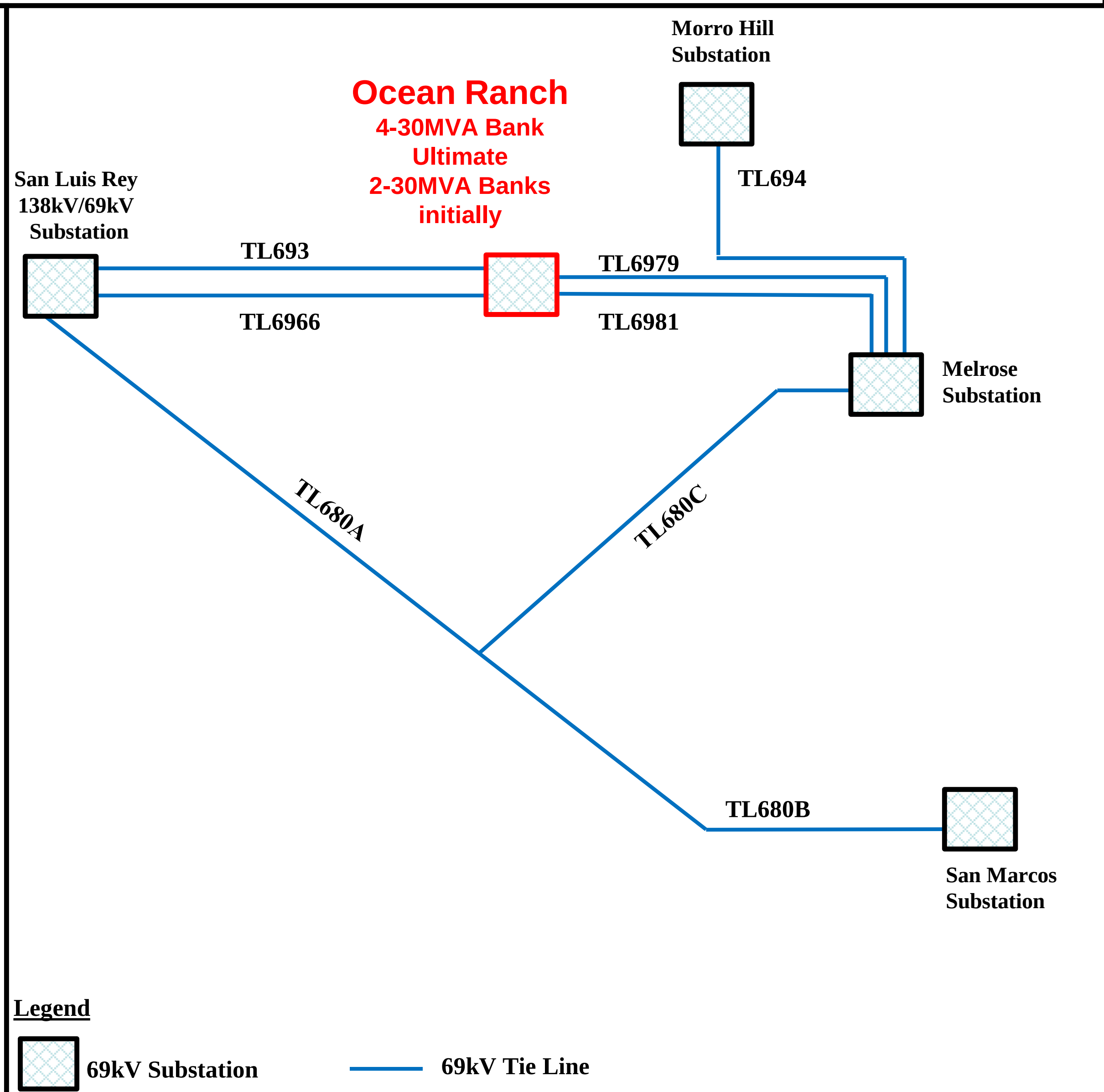
Scope

- Construct a low-profile 120 MVA ultimate Substation with 69/12 kV Transformer banks
  - Install 60MVA initially
- Reconductor the existing two tie lines from San Luis Rey to Melrose (TL693 and TL6966) and loop them into Ocean Ranch, with a max rating of 172MVA
- The lines to Melrose, TL6979 and TL6981 no reconductor required, existing rating of 102 MVA

Cost: Pending

Benefits

- Serve the ultimate growing demand in the Vista Load Pocket.
- Maintain/Improve reliability in the area.



Questions?

Send comments to:

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8316 Century Park Court, CP-52K
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Big Creek Corridor TCSC

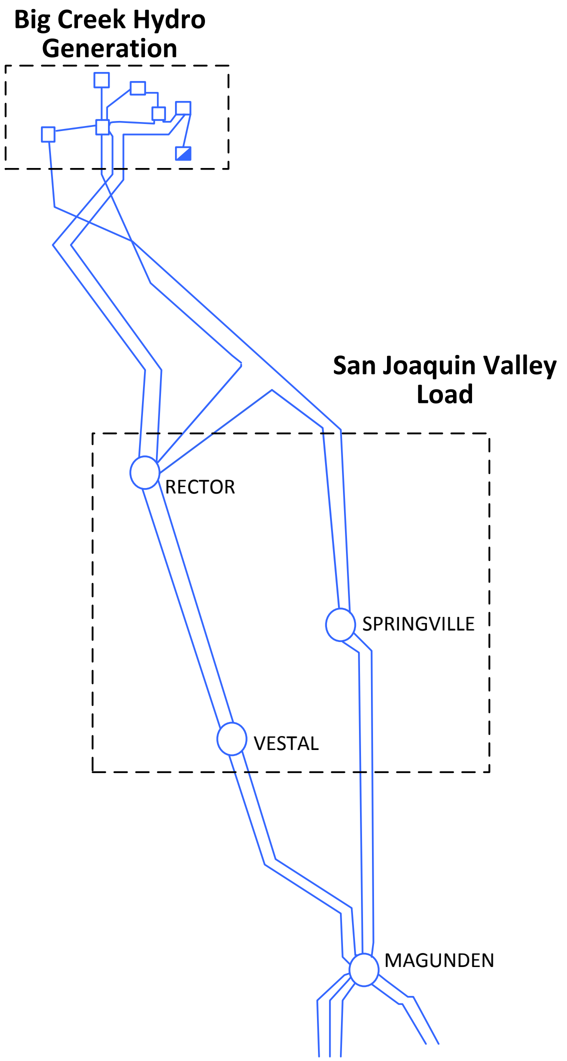
2015-2016 CAISO TPP Stakeholder Mtg

September 22, 2015

Folsom, CA

Big Creek Corridor

- Composed of 230 kV transmission lines north of Magunden Substation
- Local generation capacity:
  - Big Creek Hydro – 1,029 MW
  - Small gen at Rector & Vestal – 226 MW
- Adequate service during peak load requires both transmission and local generation
- 2014 recorded coincident peak load for San Joaquin Valley (served via Rector, Vestal and Springville Substations) was 1,146 MW
- Fourth year of drought increases risk of inability to serve load under peak conditions
- If trend continues and Big Creek generation output is low, transmission system will be unable to support high loads



Historical Load & Generation

- Average data from June through September 3-8 pm
- Over past decade, 2014 was lowest hydro capacity with highest load

Year	San Joaquin Valley Average Load	Big Creek Hydro Average Gen.
2005	613	777
2006	653	778
2007	730	535
2008	752	455
2009	736	655
2010	700	625
2011	685	734
2012	828	533
2013	836	552
2014	898	343

- Current Non-Hydro Net Qualifying Capacity (NQC)

GENERATOR NAME	2015 NQC (MW)
PANDOL (Market)	46.6
ULTRAGEN	32.5
WELLGEN	49.0
TOTAL	**128.1**

NERC Reliability Performance Requirement

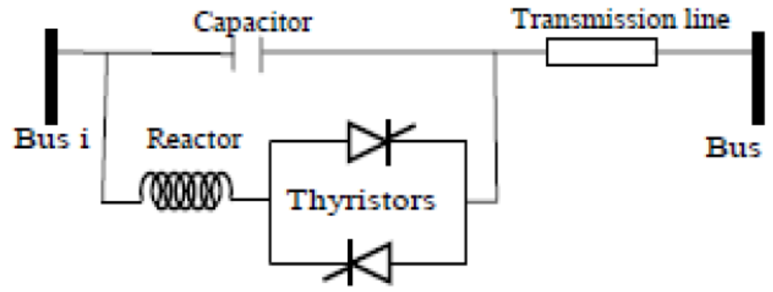
- Current BC/SJV Remedial Action Scheme (RAS) in-place to mitigate thermal overloads and generator instability
- For an N-1 of Magunden-Vestal #1 or #2 lines, up to 300 MW of load at Rector Substation is armed by RAS
- Studies performed indicate that at lower levels of generation, more than 300 MW of load will need to be shed to mitigate N-1 thermal overloads
- NERC TPL-001-4 planning standard effective 01/01/16 only allows up to 75 MW of load shed for a N-1 contingency
- In order to be compliant with TPL-001-4 in 2016, 476 MW of local generation will be required. Due to potential drought conditions, ensuring 476 MW will be challenging.

Mitigation Alternatives Explored

- For a long-term mitigation plan for the Big Creek Corridor, the following options were explored:
  - **Build two new 220 kV transmission lines from Magunden to Rector**
  - **Smart Wires Tower Routers (injects magnetizing inductance or capacitance into a transmission line)**
  - **Four (4) Phase Shifting Transformers**
  - **Four (4) Thyristor Controlled Series Capacitors (TCSC)**
- Studies concluded best transmission option to be TCSC, reducing local generation need to 250 MW (in 2025) at lowest cost (~135 million)
- Distributed Energy Resources (DER) reduces local gen required on nearly one to one basis
  - By itself requires 324 MW to achieve same impact as TCSC
  - Can play a role by eliminating load growth of ~ 12 MW/Year to extend effectiveness of TCSC beyond 2025

Thyristor Controlled Series Capacitors (TCSC)

- TCSC's fall into the family of Flexible AC Transmission System (FACTS) – fast acting semiconducting devices
- TCSC is a series-controlled capacitive reactance that can rapidly provide continuous control of active power flow on a transmission line
- Ability to quickly adjust impedance on transmission lines makes it useful for mitigating post contingency behavior in networks
- Basic structure of a TCSC is a thyristor controlled reactor connected in parallel with a capacitor as shown below:



TCSC Study Assumptions

- 250 MW of Big Creek hydro generation modeled on-line, required to mitigate base case thermal overload conditions
- 2025 peak load forecast of 1,357 MW total:
  Rector (850 MW), Springville (309 MW) and Vestal (198 MW)
- TCSC's were modeled on the following four 230 kV lines
  1. Magunden-Vestal No. 2
  2. Magunden-Springville No. 1
  3. Magunden-Springville No. 2
  4. Rector-Springville
- TCSCs can compensate each transmission line by adjusting the impedance to control the power flow to optimally utilize the existing capacity of each line

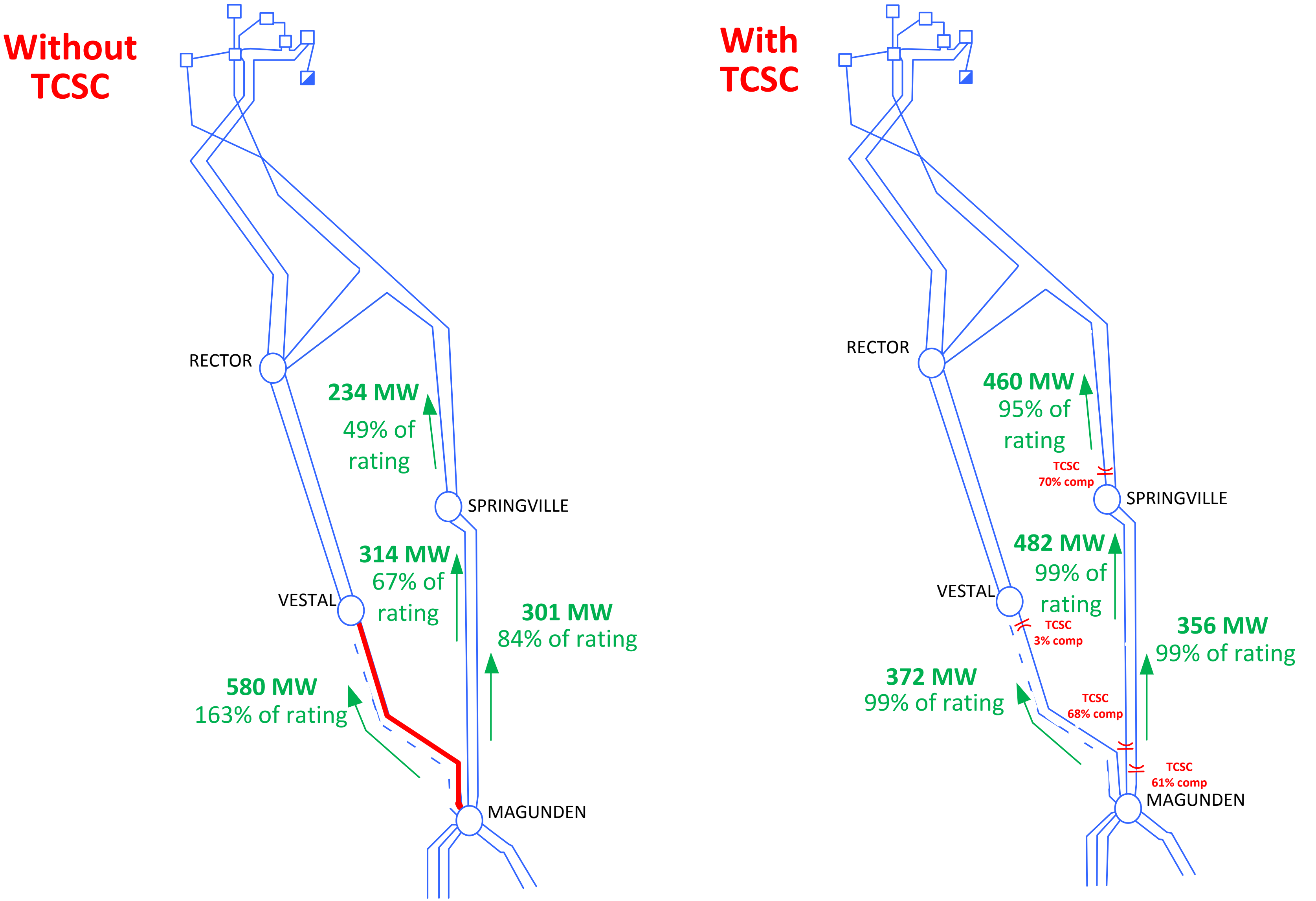
Study Results w/ 250 MW Generation and 4-TCSCs

- Power flow study results identified the following thermal overloads under N-1 contingency conditions, worst case is loss of either Magunden-Vestal #1 or #2
- 574 MW of Big Creek generation is required to mitigate N-1 overloads with 75 MW of load shed “Without TCSC”

<table>
<tr><th rowspan="3">Line Overload</th><th rowspan="3">P (MW)</th><th rowspan="3">Amps</th><th colspan="2">Rated Amps</th><th rowspan="3">% Loading Normal</th><th rowspan="3">% Loading Long Term</th><th rowspan="3">Contingency Description</th><th colspan="2">BC Gen Required with 75 MW Load Trip at Rector Substation</th></tr>
<tr><th rowspan="2">Normal</th><th rowspan="2">Long Term Emergency</th><th>WITHOUT TCSC</th><th>WITH TCSC</th></tr>
<tr></tr>
<tr><td rowspan="4">Magunden - Vestal 230 kV No.1 & 2</td><td>580</td><td>1528</td><td rowspan="5">886</td><td rowspan="5">936</td><td>172</td><td>163</td><td>Magunden - Vestal 230 kV No.1 or 2</td><td>574</td><td>159</td></tr>
<tr><td>409</td><td>1087</td><td>123</td><td>116</td><td>Magunden-Springville 230 kV No. 1</td><td>277</td><td>250</td></tr>
<tr><td>402</td><td>1060</td><td>120</td><td>113</td><td>Magunden-Springville 230 kV No. 2</td><td>261</td><td>140</td></tr>
<tr><td>397</td><td>1031</td><td>116</td><td>110</td><td>Rector – Springville 230 kV</td><td>240</td><td>242</td></tr>
<tr><td>Rector - Vestal 230 kV No.1 or 2</td><td>393</td><td>1068</td><td>121</td><td>114</td><td>Rector – Vestal 230 kV No.1 or 2</td><td>254</td><td>0</td></tr>
</table>

- Study results identified a minimum of 250 MW of Big Creek gen. required to be on-line with four TCSCs modeled (324 MW less than without TCSC) to mitigate thermal overloads under N-1 contingency conditions

TCSC Study Results (cont.)



Conclusion

- To be compliant in 2016, 476 MW of local generation will be required to mitigate worst N-1 contingency. The generation requirement grows to 574 MW by 2025.
- TCSC is SCE's preferred project alternative based on cost and performance
- Utilizes existing transmission capacity and in conjunction with DER can defer large scale transmission/generation projects beyond 2025
- TCSC minimum lead time is ~ 2.5 years from purchase order to project in service – attractive implementation period compared to new transmission line

Questions

??????????

SCE Eagle Mountain Shunt Reactors

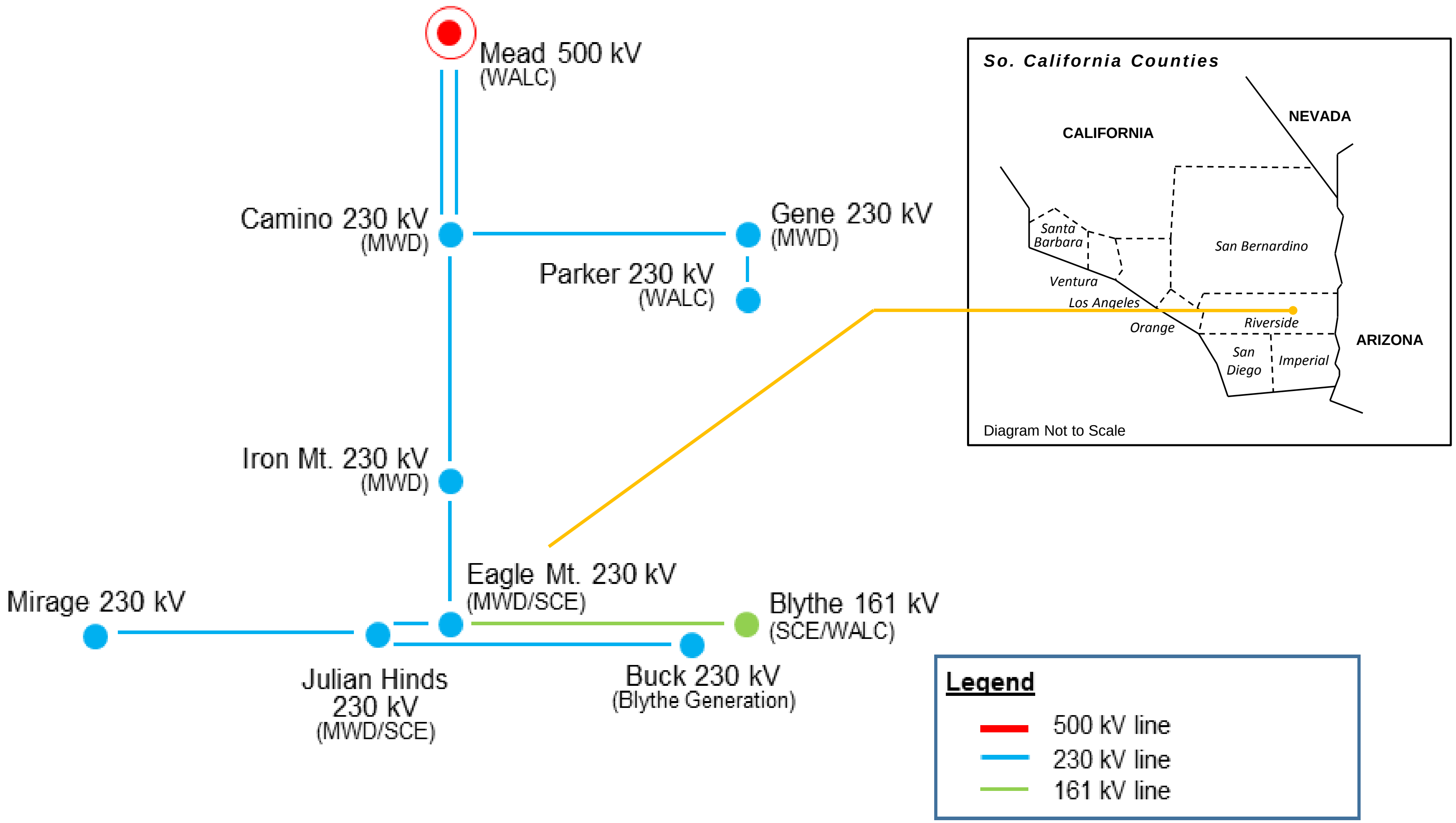
Jonathan Yuen
Power Systems Planner

2015-2016 CAISO TPP Stakeholder Mtg
September 22, 2015
Folsom, CA

Background

- SCE circuit breakers have a maximum voltage limit of 242 kV at Julian Hinds and 245 kV at Eagle Mountain & Iron Mountain
- Voltage exceeds limits at Julian Hinds, Eagle Mountain and Iron Mountain for P1 and P6 contingencies
- Proposed project - install shunt reactors to address voltage concerns
- In the interim, SCE Operating Procedure opens Buck – Julian Hinds line following a contingency and minimizes voltage exposure

System One Line



Conditions Leading to High Voltages

System Conditions:

- MWD pumps offline at all pumping stations (Julian Hinds, Eagle Mountain, Iron Mountain, Gene, and Intake)
- Blythe Generation offline (either due to maintenance or market conditions)

Contingencies:

- N-1 of Julian Hinds – Mirage 230 kV line
  - >242kV at Julian Hinds Substation
- N-1-1 of Julian Hinds – Mirage 230 kV line and Julian Hinds 25 MVAR shunt reactor
  - >245kV at Julian Hinds, Eagle Mountain, Iron Mountain Substations

Proposed: Eagle Mountain Shunt Reactors

- One (1) 34 MVAR shunt reactor installed on tertiary winding of existing 5A transformer bank
- One (1) 45 MVAR shunt reactor connected to 230 kV bus
- Requires extension of 230 kV bus to connect shunt reactor and new Mechanical Electrical Equipment Room (MEER) for associated protection equipment

- Expected Operating Date: 12/31/18
- Cost estimate: $10M

SCE/LADWP Lugo – Victorville 500 kV Upgrade

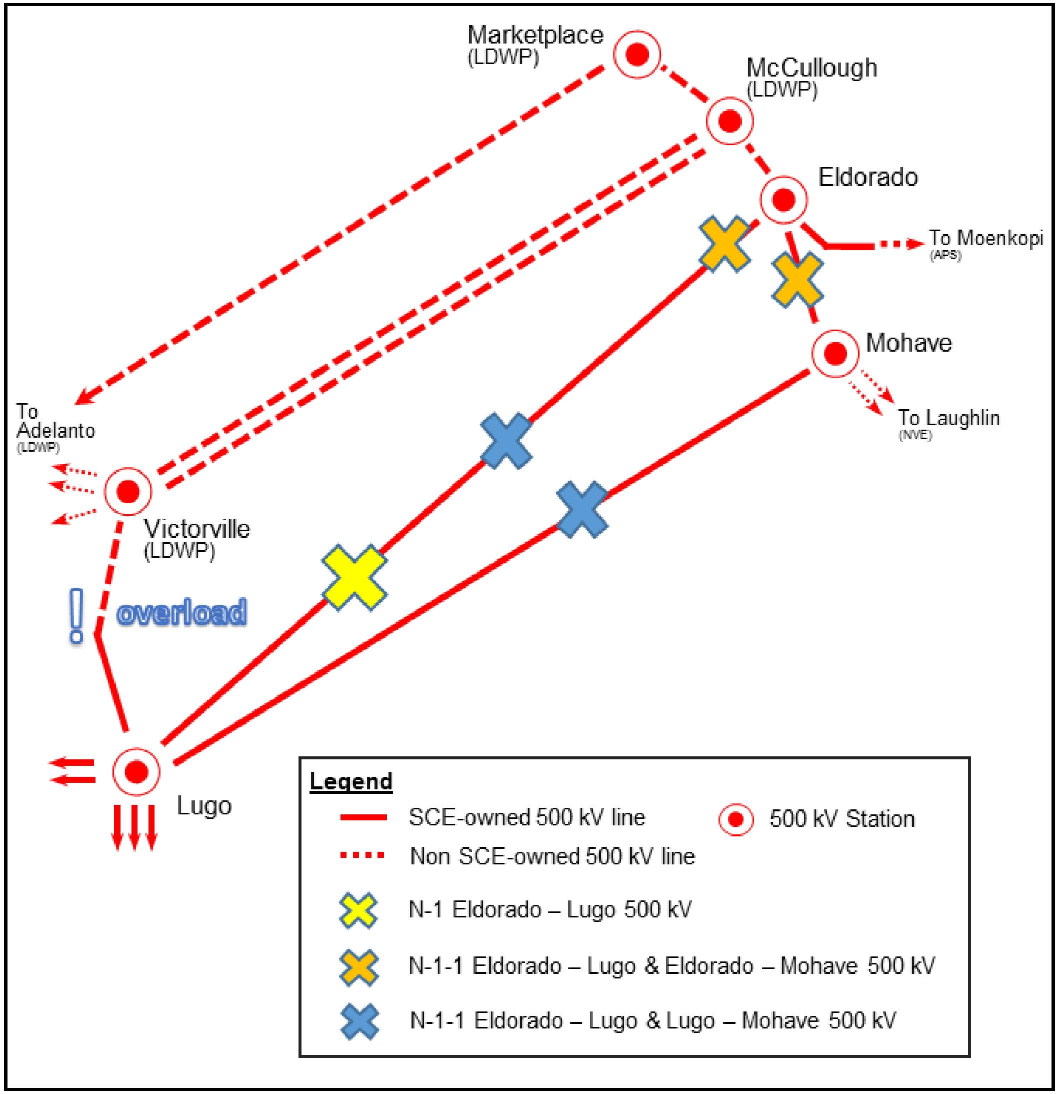
Jonathan Yuen
Power Systems Planner

2015-2016 CAISO TPP Stakeholder Mtg
September 22, 2015
Folsom, CA

Lugo – Victorville Thermal Overload

- The Lugo – Victorville 500 kV line is jointly owned by SCE and the Los Angeles Department of Water and Power (LADWP)

- Thermal overload of 500 kV line due to:
  - One (1) Category P1 (N-1) contingency
  - Two (2) Category P6 (N-1-1) contingencies



Joint SCE/LADWP Lugo-Victorville Upgrade

- Upgrade of Lugo-Victorville 500 kV line to be performed by SCE and LADWP on their respective facilities
- Increases line rating by upgrading terminal equipment at both substations and removing ground clearance limitations
- Estimated Operating Date: 12/31/18

Pre/Post Upgrade Line Ratings

PRE "Lugo - Victorville Upgrade" line ratings	Normal		4-hr	
Transmission Facility	Amps	MVA	Amps	MVA
Lugo - Victorville 500 kV	3000	2598	3000	2598

Post "Lugo-Victorville Upgrade" line ratings*	Normal		4-hr	
Transmission Facility	Amps	MVA	Amps	MVA
Lugo - Victorville 500 kV	3710	3213	4480	3880

*Increased ratings achieved once SCE & LADWP upgrades complete

	Normal		4-hr	
	Amps	MVA	Amps	MVA
Delta	710	615	1480	1282

Upgrade Scope and Cost

	SCE Portion	LADWP Portion
Scope	• Replace transmission line terminal equipment at Lugo Substation (SCE) • Replace four (4) transmission towers • SCE cost estimate: $18M	• Replace transmission line terminal equipment at Victorville Substation (LADWP) • Replace transmission towers • LADWP cost estimate: $16M

PG&E's 2015 Request Window Proposals

CAISO 2015/2016 Transmission Planning Process

September 22, 2015

Transmission Projects Overview

Projects Seeking CAISO Approval – Yosemite/Fresno

1. Panoche-Oro Loma 115 kV Re-conductoring

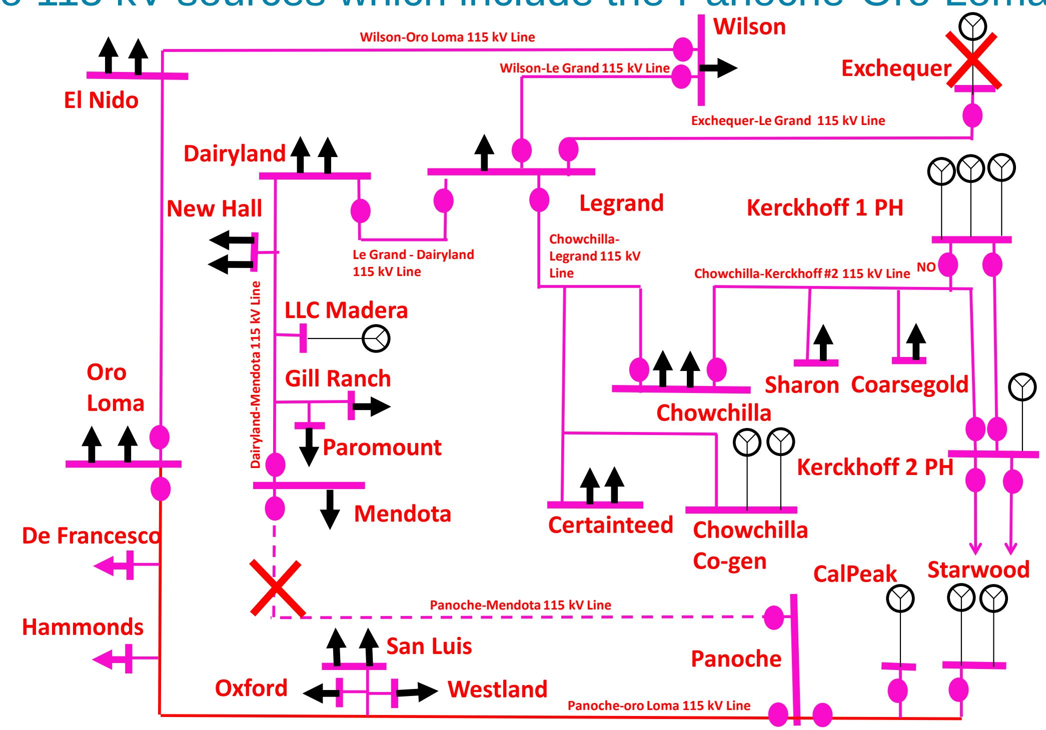
Panoche-Oro Loma 115 kV Re-conductoring

Area Background

- Panoche and Oro Loma substations are located in the western section of Fresno County and serves over 30,000 customers
- Panoche Substation currently has five (5) 115 kV sources which include the Panoche-Oro Loma, Panoche-Mendota, Panoche-Schindler #1 and #2, and Panoche-Cal Peak-Starwood 115 kV lines
- Oro Loma Substation currently has two 115 kV sources which include the Panoche-Oro Loma and Wilson-Oro Loma 115 kV lines

Assessment

- P3 Contingency: Panoche-Mendota 115 kV Line overlapped with Exchequer Generation
  - Transmission Line Facility: Panoche-Oro Loma 115 kV Line is loaded to115% of its SE ratings in 2025
- Also identified for other P2, P3, and P6 Contingencies



Panoche-Oro Loma 115 kV Reconductoring

Preferred Scope

- Reconductor 17 miles of the Panoche-Oro Loma 115 kV Line between Panoche Jct. and Oro Loma 115 kV Substation with conductors rated to handle at least 825 Amps and 975 Amps under normal and emergency conditions
- Upgrade circuit breaker and switches at Panoche Substation
- Upgrade switches and bus conductor at Hammonds Substation

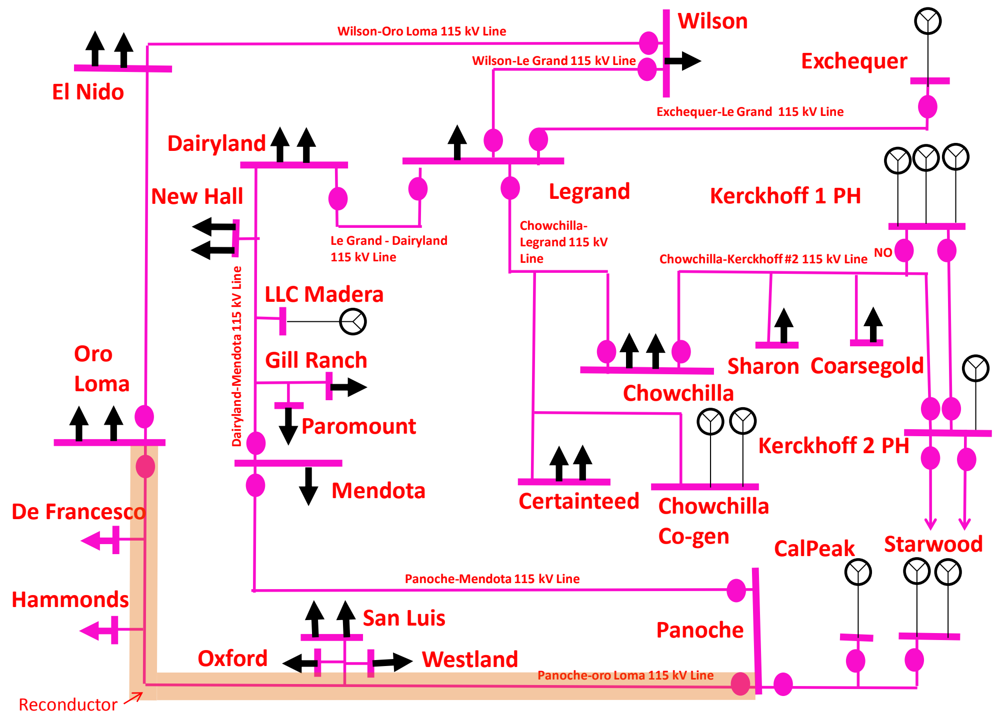
Alternative Considered

- Curtailment of roughly 500 MW of generation at Panoche and south of Panoche Substation

Proposed In Service Date

- May 2021

Estimated Cost - $20 M



Thank you

PG&E’s 2015 Request Window Proposals

CAISO 2015/2016 Transmission Planning Process

September 22, 2015

Transmission Projects Overview

Projects Seeking CAISO Approval – High Voltage Mitigation Projects

1. Round MT 500 kV Shunt Reactor
2. Metcalf 230 kV Shunt Reactor
3. Delevan 230 kV Shunt Reactor
4. Ignacio 230 kV Shunt Reactor
5. Bellota 230 kV Shunt Reactor
6. Wilson 230 kV Shunt Reactor
7. Tesla 230 kV Shunt Reactor
8. Gold Hill 230 kV Shunt Reactor
9. Cottonwood 115 kV Shunt Reactor

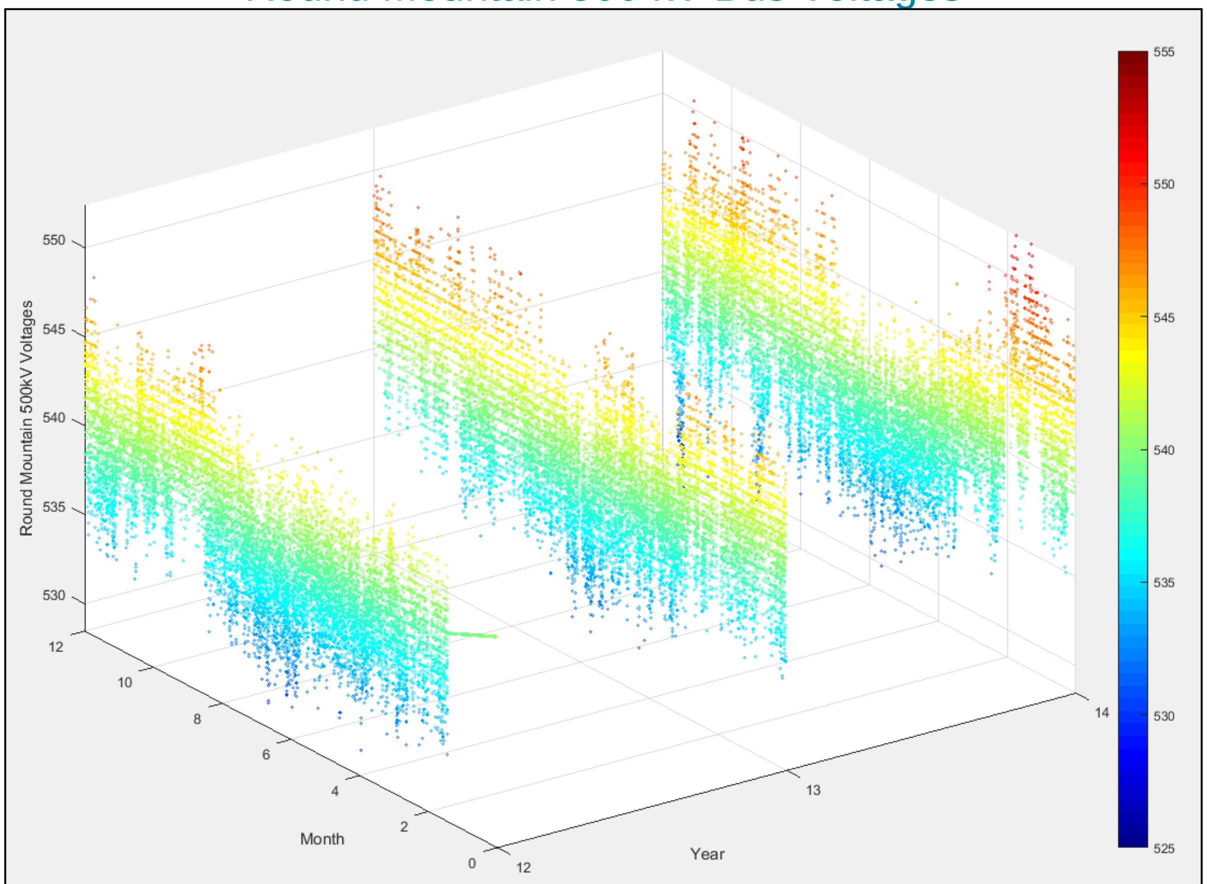
Background

- PG&E has experienced system wide high voltages on the bulk electric system during light load condition
- In addition, leading Power Factor has been observed on PG&E's electric distribution which further exacerbates the high voltage issues
- Overall it is becoming harder for system operators to maintain appropriate voltage levels during day to day operations of the grid

Real Time Operating Data

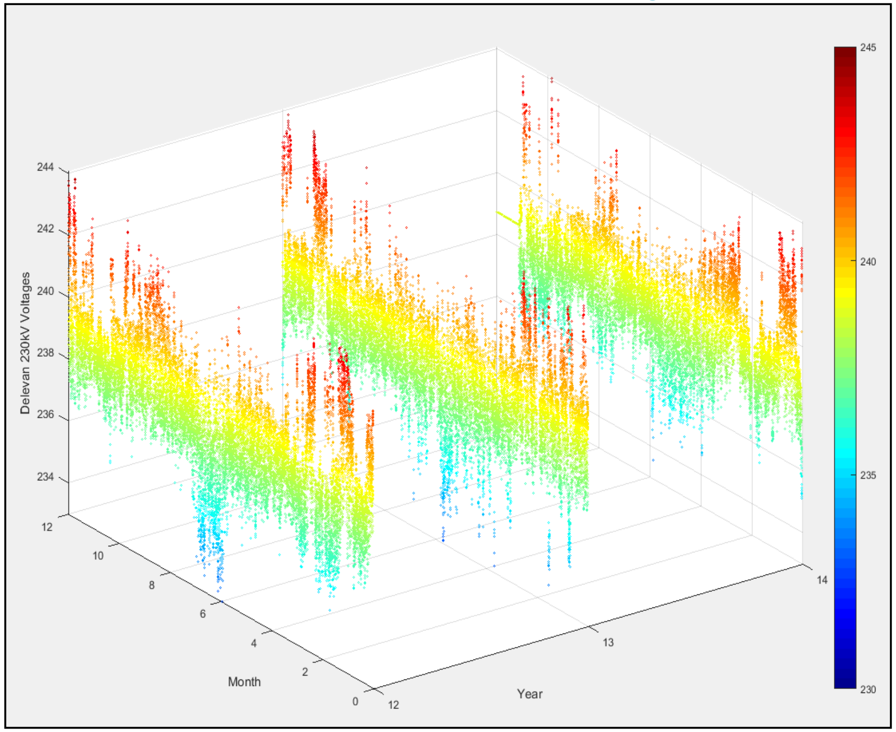
- **Recorded real time operation data from 2012 through 2014 shows voltages are higher than the PG&E's voltage operating limits during non-peak load conditions**

Round Mountain 500 kV Bus Voltages

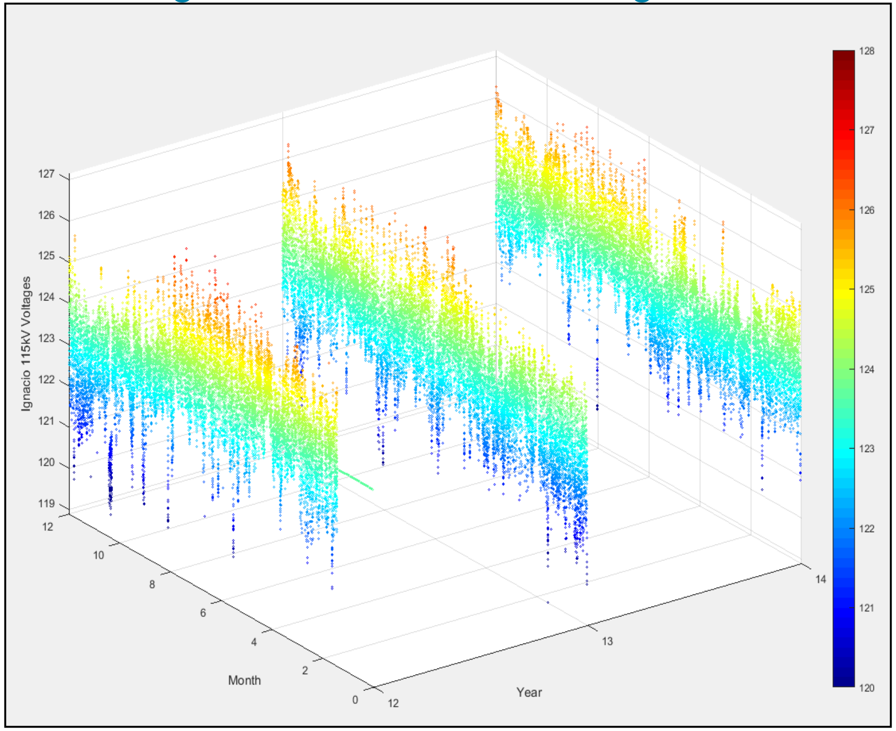


Real Time Operating Data - continued

Delevan 230 kV Bus Voltages



Ignacio 115 kV Bus Voltages



- **Real time data shows voltages regularly exceed Round Mountain 500 kV, Delevan 230 kV and Ignacio 115 buses voltage limits**

PG&E Voltage Operating Criteria

- **PG&E Grid Operations monitors and maintains the system voltages within the below voltage ranges based on existing Operating Procedures**

High Voltage Operating Limits For PG&E 115 kV and Above System

Nominal Voltage	Recommended Operating Range		High and Low Operating Limits	
	Low End	High End	Low End	High End
500 kV	525 kV	540 kV	499 kV	551 kV
230 kV	230 kV	238 kV	219 kV	242 kV
115 kV	114 kV	126 kV	110 kV	126 kV

High Voltage Statistics within the PG&E System

- **Statistical data for high voltage conditions based on PG&E Operation Procedure**

2014 Recorded Operating Voltage Data at Selected Buses

Selected Buses - 500 kV	Max (kV)	15 Mins Reading Above 540 kV Threshold
		% of Period
Los Banos	551.0	62.3%
Round Mountain	552.4	51.9%
Mid Way	544.9	11.4%
Metcalf	544.7	1.8%

Selected Buses - 115 kV	Max (kV)	15 Mins Reading Above 121 kV Threshold
		% of Period
Ignacio	126.5	99.6%
Midway	124.5	96.4%
Wilson	128.3	95.5%
Gold Hill	126.5	94.8%
Kern PP	125.2	81.7%
Metcalf	124.6	73.4%
Ravenswood	124.2	70.2%
Contra Costa	129.6	5.2%

Selected Buses - 230 kV	Max (kV)	15 Mins Reading Above 238 kV Threshold
		% of Period
Wilson	243.6	83.6%
Delevan	244.4	78.3%
Metcalf	244.8	54.3%
Gold Hill	242.7	50.8%
Ignacio	242.9	40.5%
Contra Costa	243.0	27.6%
Round Mountain	241.2	20.3%
Los Banos	242.1	2.5%
Kern PP	240.5	1.6%
Ravenswood	239.9	0.5%
Midway	239.0	0.3%

CAISO Approved Projects

The below previously CAISO approved projects are expected to help mitigate high voltage Issues:

- Rio Oso Area 230 kV Voltage Support (EDRO: Dec 2019)
- Rio Oso 230/115 kV Transformer Upgrades (EDRO: Dec 2019)
- Gates No. 2 500/230 kV Transformer (EDRO: Dec 2017)
- Northern Fresno 115 kV Area Reinforcement (EDRO: May 2019)
- Diablo Canyon Voltage Support Project (EDRO: May 2017)
- Maple Creek Reactive Support Project (EDRO: May 2017)

PG&E is also continuing to evaluate adjusting of transformers' LTC & No Load Taps as to mitigate some of the high voltages as feasible

Technical Assessment

- Optimal Power Flow was performed to determine the optimal size and the location of the voltage control devices
- High voltages of a significant number of buses would be mitigated with installation of voltage control devices across the PG&E system

Optimal Location and Size of Voltage Control Device

Bus No.	Bus Name	kV	Proposed Minimum Size (MVAR)	Division
30445	IGNACIO	230	-150	North Bay
30114	DELEVAN	230	-200	North Valley
31464	COTTONWOOD	115	-100	North Valley
30005	ROUND MT	500	-300	North Valley
30735	METCALF	230	-250	San Jose
30337	GOLDHILL	230	-50	Sierra
30500	BELLOTA	230	-100	Stockton
30625	TESLA	230	-50	Stockton
30800	WILSON	230	-75	Yosemite

Geographical View of Optimal Locations of Voltage Control Devices

High Voltage Mitigation Projects

Proposed projects to Mitigate High Voltages in PG&E Bulk Electric System

1. Round MT 500 kV Shunt Reactor

Round MT 500 kV and 230 kV buses have been identified as exceeding normal high operating limits in the 2020 minimum load base case, and further confirmed through the review of real-time data.

Scope: Install 300 MVAR Shunt Reactor at Round Mountain 500 kV Substation

Estimated Cost: $24M - $36M

Proposed In-Service Date: December 2019

Location: PG&E North Valley Division

2. Metcalf 230 kV Shunt Reactor

Metcalf 500 kV, 230 kV, and 115 kV buses have been identified as exceeding normal high operating limits in the 2020 minimum load base case, and further confirmed through the review of real-time data.

Scope: Install 250 MVAR Shunt Reactor at Metcalf 230 kV Substation

Estimated Cost: $24M - $36M

Proposed In-Service Date: December 2020

Location: PG&E San Jose Division

High Voltage Mitigation Projects, continued

3. Delevan 230 kV Shunt Reactor

Delevan 230 kV bus has been identified as exceeding normal high operating limits in the 2020 minimum load base case, and further confirmed through the review of real-time data.

Scope: Install 200 MVAR Shunt Reactor at Delevan 230 kV Switching Station

Estimated Cost: $19M - $28M

Proposed In-Service Date: December 2019

Location: PG&E North Valley Division

4. Ignacio 230 kV Shunt Reactor

Ignacio 230 kV and 115 kV buses have been identified as exceeding normal high operating limits in the 2020 minimum load base case, and further confirmed through the review of real-time data.

Scope: Install 150 MVAR Shunt Reactor at Ignacio kV Substation

Estimated Cost: $19M - $28M

Proposed In-Service Date: December 2020

Location: PG&E North Bay Division

High Voltage Mitigation Projects, continued

5. Bellota 230 kV Shunt Reactor

Bellota 230 kV and 115 kV buses have been identified as exceeding normal high operating limits in the 2020 minimum load base case, and further confirmed through the review of real-time data.

Scope: Install 100 MVAR Shunt Reactor at Bellota 230 kV Substation

Estimated Cost: $13M - $19M

Proposed In-Service Date: December 2020

Location: PG&E Stockton Division

6. Wilson 230 kV Shunt Reactor

Wilson 230 kV and 115 kV buses have been identified as exceeding normal high operating limits in the 2020 minimum load base case, and further confirmed through the review of real-time data.

Scope: Install 75 MVAR Shunt Reactor at Wilson 230 kV Substation

Estimated Cost: $13M - $19M

Proposed In-Service Date: December 2020

Location: PG&E Yosemite Division

High Voltage Mitigation Projects, continued

7. Tesla 230 kV Shunt Reactor

Tesla 230 kV and 115 kV buses have been identified as exceeding normal high operating limits in the 2020 minimum load base case, and further confirmed through the review of real-time data.

Scope: Install 50 MVAR Shunt Reactor at Tesla 230 kV Substation

Estimated Cost: $13M - $19M

Proposed In-Service Date: December 2020

Location: PG&E Stockton Division

8. Gold Hill 230 kV Shunt Reactor

Gold Hill 230 kV and 115 kV buses have been identified as exceeding normal high operating limits in the 2020 minimum load base case, and further confirmed through the review of real-time data.

Scope: Install 50 MVAR Shunt Reactor at Gold Hill kV Substation

Estimated Cost: $18M - $27M

Proposed In-Service Date: December 2019

Location: PG&E Sierra Division

High Voltage Mitigation Projects, continued

9. Cottonwood 115 kV Shunt Reactor

Cottonwood 230 kV and 115 kV buses have been identified as exceeding normal high operating limits in the 2020 minimum load base case, and further confirmed through the review of real-time data.

Scope: Install 100 MVAR Shunt Reactor at Cottonwood 230 kV Substation

Estimated Cost: $13M - $19M

Proposed In-Service Date: December 2019

Location: PG&E North Valley Division

High Voltage Mitigation Projects, continued

Load Flow Analysis Results (Based on 2020 Minimum Load Case)

Selected Buses Voltage Comparison Pre and Post - Projects

Substation	Bus No.	Division	Nominal Voltage	2020 Minimum Load	
			kV	Pre-Project (Vpu)	Post -Project (Vpu)
Ignacio	30445	North Bay	230	1.043	1.031
Ignacio	32568	North Bay	115	1.089	1.057
Round Mountain	30005	North Valley	500	1.111	1.081
Delevan	30114	North Valley	230	1.065	1.033
Round Mountain	30245	North Valley	230	1.056	1.031
Met Calf	30042	San Jose	500	1.095	1.065
Wilson	30800	San Jose	230	1.044	1.015
Metcalf	30735	San Jose	230	1.067	1.032
Metcalf	35642	San Jose	115	1.108	1.074
Gold Hill	30337	Sierra	230	1.058	1.031
Wilson	34134	Yosemite	115	1.087	1.059
Los Banos	30765	Yosemite	230	1.062	1.044

High Voltage Mitigation Projects, continued

Load Flow Analysis Results (Based on 2020 Minimum Load Case)

Voltage Statistics Pre and Post – Projects

Criteria	Without Shunt Reactors	With Shunt Reactors	Number of Buses Improved	% Reduction of High Voltages
Number of 500 kV Buses Violating 1.08 Vpu	12	3	9	75.00%
Number of 230 kV Buses Violating 1.035 Vpu	195	110	85	43.59%
Number of 115 kV Buses Violating 1.05 Vpu	501	380	121	24.15%

Thank you

Next Steps

Tom Cuccia
Lead Stakeholder Engagement and Policy Specialist

2015-2016 Transmission Planning Process Stakeholder Meeting
September 21-22, 2015

Next Steps

Date	Milestone
September 22-October 6	Stakeholder comments to be submitted to regionaltransmission@caiso.com
October 15	Request window closes. Submissions to be submitted to requestwindow@caiso.com
October 30	Post final 2015-2016 reliability study results