Agenda
Policy and Economic Assessment

Isabella Nicosia
Associate Stakeholder Engagement and Policy Specialist

2019-2020 Transmission Planning Process Stakeholder Meeting
November 18, 2019

2019-2020 Transmission Planning Process Stakeholder Meeting - Agenda

Topic	Presenter
Introduction	Isabella Nicosia
Overview & Key Issues	Jeff Billinton
Policy Assessment	Sushant Barave
Flexible Deliverability	Songzhe Zhu
Economic Assessment	Neil Millar Yi Zhang
LCR Economic Assessment	RT Engineers
Reliability <$50 million Project Recommendations	RT Engineers
Wrap-up & Next Steps	Isabella Nicosia

Overview
Policy and Economic Assessment Preliminary Results

Jeff Billinton

Sr Manager, Regional Transmission - North

2019-2020 Transmission Planning Process Stakeholder Meeting

November 18, 2019

2019-2020 Transmission Planning Process

January 2019 — April 2019 — March 2020

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

ISO Board for approval of transmission plan

California ISO

2019-2020 Transmission Plan Milestones

- Draft Study Plan posted on February 22
- Stakeholder meeting on Draft Study Plan on February 28
- Comments to be submitted by March 14
- Final Study Plan to be posted on March 31
- Preliminary reliability study results to be posted on August 16
- Stakeholder meeting on September 25 and 26
- Comments to be submitted by October 10
- Request window closes October 15
- Preliminary policy and economic study results on November 18
- Comments to be submitted by December 2
- Draft transmission plan to be posted on January 31, 2020
- Stakeholder meeting on February
- Comments to be submitted within two weeks after stakeholder meeting
- Revised draft for approval at March Board of Governor meeting

Scope of Presentations

- Policy assessment preliminary deliverability results
- Overview of economic modeling requirements and preliminary economic assessment results
- Alternatives for Potential LCR reduction
- Flexible Deliverability
- Less than $50 million reliability-driven project recommendations

Forecast coordination is continuing with CPUC and CEC, with focus on renewable generation:

- Load forecast based on California Energy Demand Updated Forecast 2018-2030 adopted by California Energy Commission (CEC) on January 9, 2019
  https://ww2.energy.ca.gov/2018_energypolicy/documents/

- RPS portfolio direction for 2019-2020 transmission planning process was received from the CPUC and CEC
  - The CPUC IRP Base Case portfolio – is used for the reliability, policy and economic assessment
  - Two sensitivity portfolios to be assessed in the policy assessment

  https://www.cpuc.ca.gov/General.aspx?id=6442460548

Update on reliability assessment - 2019-2020 Ten Year Reliability Assessment

- ISO recommended projects have two paths for approval:
  - For management approval, reliability projects less than $50 million can be presented at November stakeholder session
  - For Board of Governor approval of reliability projects over $50 and projects not approved by management, are included in draft plan to be issued for stakeholder comments by January 31, 2020

2019 Request Window Submissions

Project Name	Submitter	Review of Submission
Carpenter Canyon-Charleston 230 kV	Horizon West	• May be considered for reliability alternative
Gamebird 230 kV Station	Horizon West	• May be considered for reliability alternative
Lopez-Divide 230 kV	Horizon West	• May be considered for reliability alternative
Pittsburg-Birds Landing 230 kV	Horizon West	• May be considered for reliability alternative
Pittsburg-Contra Costa 230 kV	Horizon West	• May be considered for reliability alternative
Sobrante-Oakland 230 kV	Horizon West	• May be considered for reliability alternative
Weber-Manteca 230 kV	Horizon West	• May be considered for reliability alternative
New Sub-Embarcadero 230 kV	Horizon West	• Not considered as reliability alternative as the submission does not meet a reliability need identified by the CAISO.
Sobrante-Embarcadero 230 kV	Horizon West	• Not considered as reliability alternative as the submission does not meet a reliability need identified by the CAISO.
TBC Reliability Bi-Directional Flow Upgrade	TBC	• Not considered as reliability alternative as the submission does not meet a reliability need identified by the CAISO.

2019 Request Window Submissions

Project Name	Submitter	Review of Submission
Red Bluff - Mira Loma 500 kV	Horizon West	• Not considered as reliability alternative as the submission does not meet a reliability need identified by the CAISO. • May be considered for economic study.
Suncrest - Sycamore 230 kV	Horizon West	• Not considered as reliability alternative as the submission does not meet a reliability need identified by the CAISO. • May be considered for economic study.
Table Mountain 230 kV BESS	Horizon West	• Not considered as reliability alternative as the submission does not meet a reliability need identified by the CAISO. • May be considered for economic study.
Imperial Smart Wire Solution	Imperial Renewable	• Not considered as reliability alternative as the submission does not meet a reliability need identified by the CAISO. • May be considered for economic study.
LEAPS	Nevada Hydro	• Not considered as reliability alternative as the submission does not meet a reliability need identified by the CAISO. • May be considered for economic study.
COI Power Flow Control	Smart Wires	• Not considered as reliability alternative as the submission does not meet a reliability need identified by the CAISO. • May be considered for economic study.
Delta Reliability Energy Storage	Tenaska	• Not considered as reliability alternative as the submission does not meet a reliability need identified by the CAISO. • May be considered for economic study.
Sycamore Reliability Energy Storage	Tenaska	• Not considered as reliability alternative as the submission does not meet a reliability need identified by the CAISO. • May be considered for economic study.

2019 Request Window Submissions

Project Name	Submitter	Review of Submission
Chula Vista Energy Reliability Center	Wellhead	• Not considered as reliability alternative as the submission does not meet a reliability need identified by the CAISO. • May be considered for economic study.
Pacific Transmission Expansion (PTE)	Western Grid Development	• Not considered as reliability alternative as the submission does not meet a reliability need identified by the CAISO. • May be considered for economic study.
Christie-Sobrante 115 kV	Smart Wires	• Not considered as reliability solution as the submission is functionally duplicative of transmission solutions that have previously been approved by the CAISO.

Study Information

- Stakeholder comments to be submitted by December 2
  - Stakeholders requested to submit comments to: regionaltransmission@caiso.com
  - Stakeholder comments are to be submitted within two weeks after stakeholder meetings
  - ISO will post comments and responses on website

2019-2020 TPP Policy-driven Assessment

Regional Transmission North:

Vera Hart and Abhishek Singh

Regional Transmission South:

Songzhe Zhu, Lyubov Kravchuk and Sushant Barave

2019-2020 Transmission Planning Process Stakeholder Meeting

November 18, 2019

Agenda

- **Deliverability assessment results**
- **Draft production cost simulation results**
  (To be presented with the Economic Assessment results)
- **Summary and next steps**

Agenda

- **Deliverability assessment results**

- **Draft production cost simulation results**
  (To be presented as with the Economic Assessment results)

- **Summary and next steps**

Key points to remember while interpreting PCM and deliverability results

- Portfolio selected by the RESOLVE model are comprised of resources with capacity deliverability status (FCDS) and energy only deliverability status (EODS).
- Deliverability assessment modeled only the FCDS resources.
- FCDS and EODS resources are treated the same way in PCM studies because deliverability is a capacity construct; the economic dispatch is agnostic to deliverability status.
- Renewable curtailment identified in PCM studies can be caused by two main drivers – (i) over-generation or (ii) transmission congestion.
- Stand-alone “generic” energy storage selected in the portfolio is not modeled in the PCM run because locational mapping of storage resources was not provided with the portfolios.

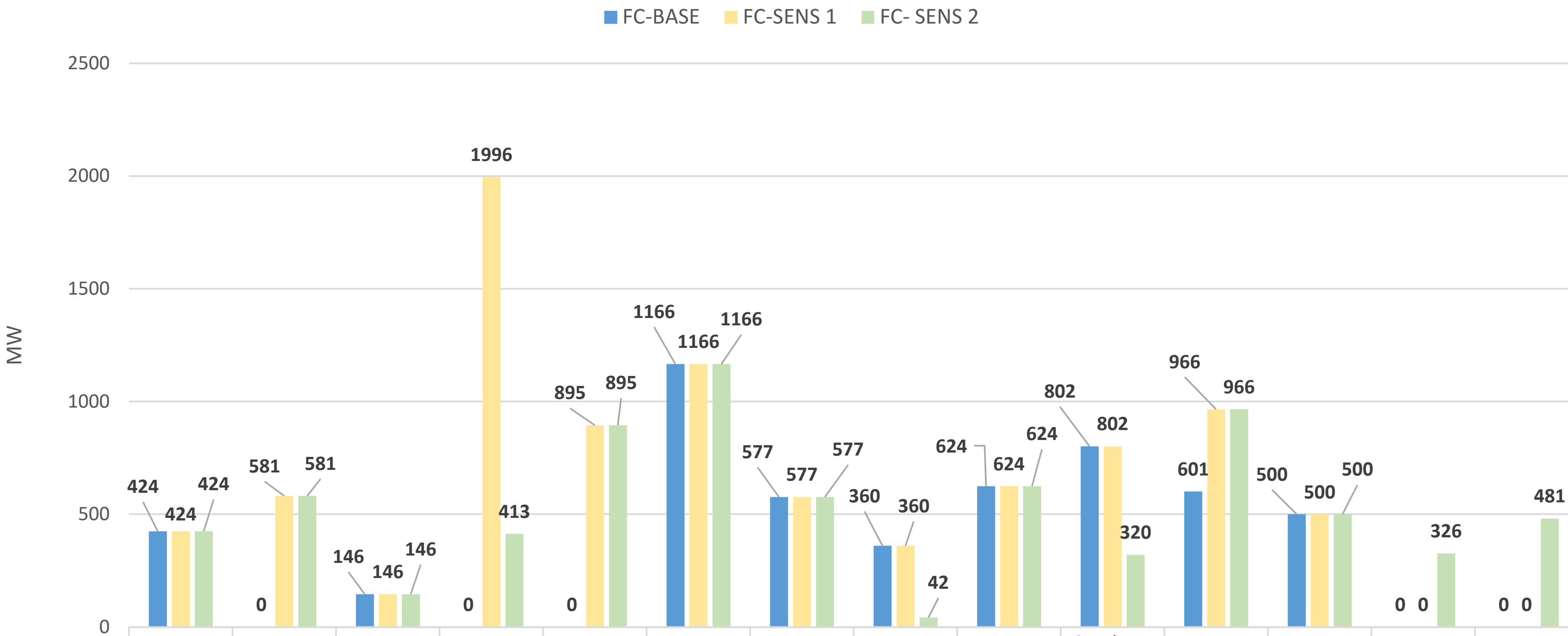
Total “generic” resource mix (EO + FC) in portfolios

Renewable zone	PCM and snapshot study capacity (MW)												Deliverability study capacity (MW)		
	BASE				SENS 1				SENS 2				BASE	SENS 1	SENS 2
	Solar	Wind	GeoT	Total	Solar	Wind	GeoT	Total	Solar	Wind	GeoT	Total			
Northern California	0		424	424	750		424	1,174	750		424	1,174	424	424	424
Solano	0	643	0	643	0	643	0	643	40	643	0	683	0	581	581
Central Valley and Los Banos	0	146	0	146	0	146	0	146	0	146	0	146	146	146	146
Westlands	0	0	0	0	2,699	0	0	2,699	1,116	0	0	1,116	0	1,996	413
Greater Carrizo	0	160	0	160	0	1095	0	1,095	0	1095	0	1,095	0	895	895
Tehachapi	1,013	153	0	1,166	1,013	153	0	1,166	1,013	153	0	1,166	1,166	1,166	1,166
Kramer and Inyokern	577	0	0	577	577	0	0	577	577	0	0	577	577	577	577
Riverside East and Palm Springs	1,320	42	0	1,362	2,842	42	0	2,884	577	42		619	360	360	42
Greater Imperial*	0	0	1276	1276	1,401	0	1276	2,677	1,401	0	1,276	2,677	624	624	624
Southern CA desert and Southern NV	3,006	0	0	3,006	2,307	442	320	3,069	745	0	320	1,065	802	802	320
None (Distributed Wind)	0	0	0	0	0	253	0	253	0	253	0	253	0	253	253
NW_Ext_Tx (Northwest wind)	0	601	0	601	0	1500	0	1,500	0	1,500	0	1,500	601	966	966
SW_Ext_Tx (Southwest wind)	0	500	0	500	0	500	0	500	0	500	0	500	500	500	500
New Mexico wind (new Tx)	0	0	0	0	0	0	0	0	0	2,250	0	2,250	0	0	326
Wyoming wind (New Tx)	0	0	0	0	0	0	0	0	0	2,000	0	2,000	0	0	481
TOTALS	**5,916**	**2,245**	**1,700**	**9,861**	**11,589**	**4,774**	**2,020**	**18,383**	**6,219**	**8,582**	**2,020**	**16,822**	**5,200**	**9,290**	**7,714**

Objectives of deliverability assessment of portfolios

- Test deliverability of portfolio resources selected as FCDS in accordance with the deliverability methodology as used in GIDAP
- Identify upgrades needed to ensure deliverability of resources selected as FCDS in the commission-developed renewable portfolios
- Gain insights about FCDS transmission capability estimates and corresponding upgrade information to feed it back into IRP

FCDS resource selection in the commission-developed portfolios – Base vs. Sensitivity 1 vs. Sensitivity 2



	Northern California	Solano	Central Valley and Los Banos	Westlands	Greater Carrizo	Tehachapi	Kramer and Inyokern	Riverside East and Palm Springs	Greater Imperial*	Southern NV, Eldorado and Mountain Pass	NW wind (Ext Tx)	SW wind (Ext Tx	New Mexico wind (New Tx)	Wyoming wind (New Tx)
FC-BASE	424	0	146	0	0	1166	577	360	624	802	601	500	0	0
FC-SENS 1	424	581	146	1996	895	1166	577	360	624	802	966	500	0	0
FC- SENS 2	424	581	146	413	895	1166	577	42	624	320	966	500	326	481

Generation assumptions

- Deliverability assessment is performed for FCDS resources selected in the base, sensitivity #1 (SENS-01) and sensitivity #2 (SENS-02) portfolios

- Generation capacity tested for deliverability
  - Existing non-intermittent resources: most recent summer peak NQC
  - New non-intermittent resources: installed capacity in the base portfolio
  - Intermittent resources: 50% (low level) exceedance during summer peak load hours
    (20% exceedance not tested because the focus is on finding area-wide issues, not local issues)

Load and transmission assumptions

- ISO 2029 1-in-5 load

- Same transmission assumptions as power flow studies
  – Existing transmission
  – Approved transmission upgrades

Import assumptions

- Maximum summer peak simultaneous historical import schedules (2020 Maximum RA Import Capability)
- Historically unused Existing Transmission Contracts were modeled by equivalent generators at the tie point
- IID import through IID-CAISO branch groups were increased from the 2020 MIC to support portfolio renewables modeled in IID

Preliminary results for SCE-VEA-GLW area

Overview of renewable zones likely to impact SCE-GLW-VEA area

	Deliverability study capacity (MW)		
Renewable zone	**BASE**	**SENS 1**	**SENS 2**
Tehachapi	1,166 Solar 1013, Wind 153	1,166 Solar 1013, Wind 153	1,166 Solar 1013, Wind 153
Kramer and Inyokern	577 Solar	577 Solar	577 Solar
Riverside East and Palm Springs	360 Solar 318, Wind 42	360 Solar 318, Wind 42	42 Wind
Greater Imperial*	624 GeoT	624 GeoT	624 GeoT
Southern CA desert and Southern NV	802 Solar	802 Solar 40, Wind 442, GeoT 320	320 GeoT
SW_Ext_Tx (Southwest wind)	500 Wind	500 Wind	500 Wind
New Mexico wind (new Tx)	0	0	326 Wind
Wyoming wind (New Tx)	0	0	481 Wind

California ISO

Deliverability Assessment Results for SCE-GLW-VEA Constraint #1: VEA-NVE 138 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Mercury Switch to Northwest 138 kV lines (NVE)	Northwest – Desert View 230 kV	159% to 172%	150% to 163%	106% to 115%
	Innovation – Desert View 230 kV	135% to 149%	142% to 155%	106% to 115%
	Pahrump – Innovation 230 kV and Vista – Johnnie 138 kV	<100%	105% to 113%	102% to 125%
	Pahrump – Innovation 230 kV and Pahrump – Vista 138 kV	<100%	101%	<100%

Affected renewable zones	Southern NV (GLW-VEA)
Renewable MW affected	802 MW
Total generation behind the constraint	802 MW
Mitigation	RAS to trip generation identified in GIDAP
Deliverable renewable MW w/o mitigation	~300 MW

Deliverability Assessment Results for SCE-GLW-VEA Constraint #2: Pahrump – Sloan Canyon 230 kV path

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Pahrump – Gamebird (proposed) 230 kV line	Base case	117%	<100%	<100%
	Trout Canyon (proposed) – Sloan Canyon	129%	<100%	<100%
Trout Canyon (proposed) – Sloan Canyon 230 kV	Pahrump – Gamebird (proposed) 230 kV	129%	<100%	<100%

Affected renewable zones	Southern NV (GLW-VEA)
Renewable MW affected	526 MW
Total generation behind the constraint	526 MW
Mitigation	For N-1: RAS to trip generation identified in GIDAP For N-0: Only seen in BASE portfolio. (~90 MW of mapped portfolio generation is not deliverable)
Deliverable renewable MW w/o mitigation	~440 MW

Preliminary results for PG&E area

Overview of renewable zones likely to impact PG&E area

Renewable zone	Deliverability study capacity (MW)		
	BASE	SENS 1	SENS 2
Northern California	424 GeoT	424 GeoT	424 GeoT
Solano	0	581 Wind	581 Wind
Central Valley and Los Banos	146 Wind	146 Wind	146 Wind
Westlands	0	1,996 Solar	413 Solar
Greater Carrizo	0	895 Wind	895 Wind
NW_Ext_Tx (Northwest wind)	601 Wind	966 Wind	966 Wind

Deliverability Assessment Results for PG&E Constraint #1

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Round Mountain-Table Mountain 500 kV Line # 1 or # 2	Round Mountain-Table Mountain Line # 1 or # 2	106	110	110

Affected renewable zones	Round Mountain
Renewable MW affected	424
Total generation behind the constraint	4145
Mitigation	RAS to drop Portfolio renewable generation
Deliverable renewable MW w/o mitigation	20 MW

Deliverability Assessment Results for PG&E Constraint #2

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Round Mountain-Cottonwood E 230 kV Line # 3	Round Mountain 500/230 kV T/F # 1	116	116	116

Affected renewable zones	Round Mountain
Renewable MW affected	424
Total generation behind the constraint	1408
Mitigation	RAS to drop Portfolio renewable generation
Deliverable renewable MW w/o mitigation	252 MW

Deliverability Assessment Results for PG&E Constraint #3

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Delevan-Cortina 230 kV Line	Round Mountain 500/230 kV T/F # 1	104		

Affected renewable zones	Round Mountain
Renewable MW affected	424
Total generation behind the constraint	3906
Mitigation	RAS to drop Portfolio renewable generation
Deliverable renewable MW w/o mitigation	186 MW

Deliverability Assessment Results for PG&E Constraint #4

<table>
<tr><th rowspan="2">Overloaded Facility</th><th rowspan="2">Contingency</th><th colspan="3">Flow</th></tr>
<tr><th>BASE</th><th>SENS-01</th><th>SENS-02</th></tr>
<tr><td rowspan="3">Moss landing-Las Aguilas 230 kV line</td><td>Base Case</td><td>106</td><td>109</td><td>111</td></tr>
<tr><td>Moss Landing-Los Banos 500 kV line</td><td>105</td><td>112</td><td>108</td></tr>
<tr><td>Tesla-Metcalf 500 kV Line</td><td>93</td><td>107</td><td>97</td></tr>
</table>

Baseline Overloads Only	
Affected renewable zones	Westland
Renewable MW affected	1070
Total generation behind the constraint	3000
Mitigation	Ensure LCR Requirement Met in Greater Bay LCR Area
Deliverable renewable MW w/o mitigation	NA

Deliverability Assessment Results for PG&E Constraint #5

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Borden-Storey # 1 230 kV line	Borden-Storey # 2 230 kV line	133	145	141
Borden-Storey # 2 230 kV line	Borden-Storey # 1 230 kV line	122	134	130

Baseline Overloads Only	
Affected renewable zones	Westland
Renewable MW affected	1581
Total generation behind the constraint	4724
Mitigation	Utilize existing series reactor at Wilson 230 kV/ Proposed GIP upgrade
Deliverable renewable MW w/o mitigation	289 (For worst overload)

Deliverability Assessment Results for PG&E Constraint #6

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Borden-Storey # 1 230 kV line	Borden-Storey # 2 230 kV line	133	145	141
Borden-Storey # 2 230 kV line	Borden-Storey # 1 230 kV line	122	134	130

Baseline Overloads Only	
Affected renewable zones	Westland
Renewable MW affected	1581
Total generation behind the constraint	4724
Mitigation	Insert Series Reactor at Wilson 230 kV/Area deliverability constraint in GIP Studies
Deliverable renewable MW w/o mitigation	289 (For worst overload)

Deliverability Assessment Results for PG&E Constraint #7

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
GWF HEP-Contadina 115 kV / Contadina-Jackson Switching station/Jackson Switching Station to Kingsburg line	Basecase	104	106	105
	Mustang-CSR09Swstation 230 kV line	106	112	107

Baseline Overloads Only	
Affected renewable zones	Westland
Renewable MW affected	752
Total generation behind the constraint	854
Mitigation	RAS proposed in in GIP Studies
Deliverable renewable MW w/o mitigation	695 (For worst overload)

Deliverability Assessment Results for PG&E Constraint #8

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Dairyland-NewHall 115 kV line	Panoche-Mendota 115 kV line	104	104	104

Baseline Overloads Only	
Affected renewable zones	Westland
Renewable MW affected	226
Total generation behind the constraint	256
Mitigation	Mitigation in GIP studies
Deliverable renewable MW w/o mitigation	209

Deliverability Assessment Results for PG&E - Incremental Sensitivity Only Overloads

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Wilson-Storey # 1 / # 2 230 kV lines	Wilson-Storey # 2/ # 1 230 kV lines	<100	104	<100
Gates-Mustang Switching Station # 1/ # 2 230 kV line	Gates-Mustang Switching Station # 2/ # 1 230 kV line	<100	101	<100
Gates- Calflat Switching Station 230 kV line	Midway-Caliente Switching Station # 1 & # 2 230 kV Lines	<100	105	113

Additionally-Portfolio generation modeled at 500 kV in Sensitivity 1 was modeled at 230 kV to analyze the additional impacts

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01 500kV	SENS-01a 230kV
Gates bank # 11/12	Gates bank # 11/12	<100	<100	127

California ISO

Preliminary results for SDG&E area

Overview of renewable zones likely to impact SDG&E area

	Deliverability study capacity (MW)		
Renewable zone	**BASE**	**SENS 1**	**SENS 2**
Riverside East and Palm Springs	360 Solar 318, Wind 42	360 Solar 318, Wind 42	42 Wind
Greater Imperial*	624 GeoT	624 GeoT	624 GeoT
SW_Ext_Tx (Southwest wind)	500 Wind	500 Wind	500 Wind
New Mexico wind (new Tx)	0	0	326 Wind

Deliverability Assessment Results for SDG&E Area Constraint #1: Friars-Doublet Tap 138 kV

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Friars-Doublet Tap 138 kV	Penasquitos-Old Town 230 kV and Sycamore-Penasquitos 230 kV	108%	109%	108%

Affected renewable zones	Imperial
Renewable MW affected	406 MW
Total generation behind the constraint	1969 MW
Mitigation	RAS to trip generation identified in GIDAP
Deliverable renewable MW w/o mitigation	239 MW

Deliverability Assessment Results for SDG&E Area Constraint #2: Silvergate-Old Town 230 kV

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Silvergate-Old Town 230 kV	Silvergate-Old Town-Mission 230 kv	110%	112%	110%
Silvergate-Old Town Tap 230 kV	Silvergate-Old Town 230 kV	112%	113%	111%

Affected renewable zones	Imperial
Renewable MW affected	2385 MW
Total generation behind the constraint	4585 MW
Mitigation	RAS to trip generation identified in GIDAP
Deliverable renewable MW w/o mitigation	1960 MW

Deliverability Assessment Results for SDG&E Area Constraint #3: San Luis Rey-San Onofre 230 kV

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
San Luis Rey-San Onofre 230 kV #1	San Luis Rey-San Onofre 230 kV #2 and #3	103%	101%	102%

Affected renewable zones	Imperial
Renewable MW affected	2983 MW
Total generation behind the constraint	6892 MW
Mitigation	RAS to trip generation identified in GIDAP
Deliverable renewable MW w/o mitigation	2941 MW

Deliverability Assessment Results for SDG&E Area Constraint #4: Silvergate-Bay Boulevard 230 kV

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Silvergate-Bay Boulevard 230 kV	Miguel-Mission 230 kV #1 and #2	116%	117%	116%
	Sycamore-Penasquitos 230 kV	109%	109%	109%

Affected renewable zones	Imperial
Renewable MW affected	2385 MW
Total generation behind the constraint	4459 MW
Mitigation	RAS to trip generation identified in GIDAP
Deliverable renewable MW w/o mitigation	1693 MW

Agenda

- Deliverability assessment results
- **Draft production cost simulation results**
  (To be presented as part of the Economic Assessment results)
- Summary and next steps

Agenda

- Deliverability assessment results
- Draft production cost simulation results
  (To be presented as part of the Economic Assessment results)
- **Summary and next steps**

Key observations: Deliverability

- **BASE portfolio**
  - ~90 MW of resources identified as FCDS are behind a deliverability constraint in Southern NV zone
  - This is likely to be driven by the intra-zonal mapping distribution
  - All the remaining FCDS resources are expected to be deliverable with RAS and local upgrades identified in GIDAP
- **Sensitivity #1**
  - All the FCDS resources are expected to be deliverable with RAS and local upgrades identified in GIDAP
  - A mapping sensitivity (SENS-01a) in Westlands identified an area-wide constraint which could limit the deliverability of generation on 230 kV system.
- **Sensitivity #2**
  - Out-of-state FCDS resources identified in the portfolio can be accommodated over the existing MIC
  - All the FCDS resources are expected to be deliverable with RAS and local upgrades identified in GIDAP

Key observations: Renewable curtailment

(To be presented as part of the Economic Assessment results)

Next steps

- Select snapshots for power flow assessment and perform assessment
- Finalize curtailment and congestion results
- Revise the EODS capability estimates and provide an update to transmission capability assumption in IRP
- Evaluate policy-driven transmission upgrade need based on deliverability, PCM and power flow snapshot studies
- Document the policy-driven assessment results and conclusions in 2020-2021 TPP

Flexible Capacity Deliverability Assessment 2019-2020

Luba Kravchuk, Sr. Regional Transmission Engineer
Abhishek Singh, Regional Transmission Engineer Lead
Sushant Barave, Regional Transmission Engineer Lead
Songzhe Zhu, Sr. Advisor Regional Transmission Engineer

2019-2020 Transmission Planning Process Stakeholder Meeting
November 18, 2019

Outline

- What is flexible capacity deliverability
- Test procedure of flexible capacity deliverability
- Test results
- Future work

Definition of Flexible Capacity Deliverability

- Deliverability of the flexible capacity shall mean that the output of a flexible resource could be ramped to Effective Flexible Capacity simultaneously with other flexible resources in the same generator pocket to match the system net load ramping without being constrained by the transmission capability.

Effective Flexible Capacity

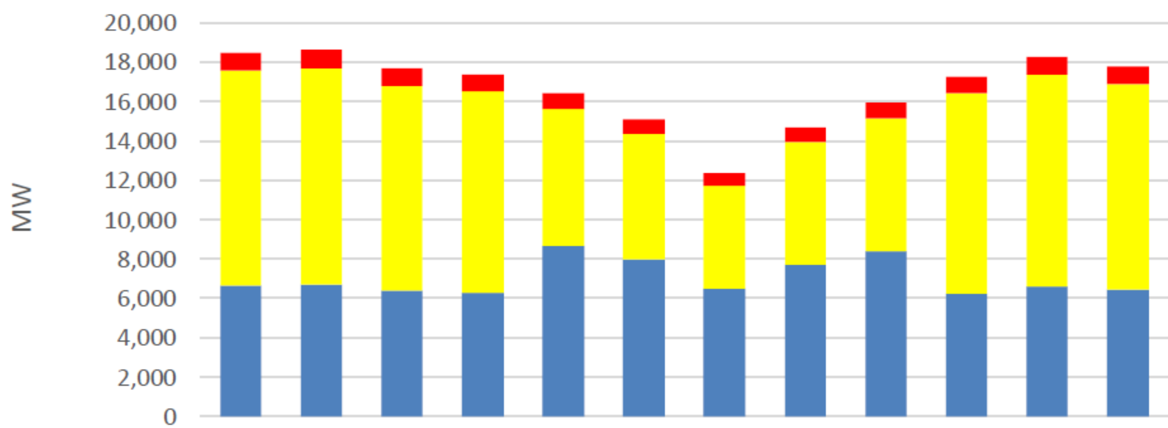
- Flexible capacity must be able to respond to five-minute dispatch instruction.
- Effective flexible capacity of a resource is NQC minus Pmin limited by 3 hour ramping capability.
  - Relies on the assumption that ramping from Pmin to NQC is not constrained by transmission capability

Flexible Capacity Need

$$Flexibility\ Need_{MTH_y} = \underbrace{Max\left[\left(3RR_{HR_x}\right)_{MTH_y}\right]}_{\text{Largest 3-hr ramping}} + Max\left(\underbrace{MSSC}_{\text{Most severe single contingency}}, 3.5\% * \underbrace{E\left(PL_{MTH_y}\right)}_{\text{Expected peak load}}\right) + \underbrace{\varepsilon}_{\text{Error adjustment}}$$

- Base Flexibility: for the largest 3-hour secondary net load ramp
  - The largest daily secondary 3-hour net load ramp is the largest net load ramp that does not correspond with the daily maximum net load ramp.
- Peak Flexibility: for the difference between 95 percent of the maximum 3-hour net load ramp and the largest 3-hour secondary net load ramp
- Super-Peak Flexibility: for the five percent of the maximum 3-hour net load ramp of the month

2020 ISO System-Wide Flexible Capacity Need



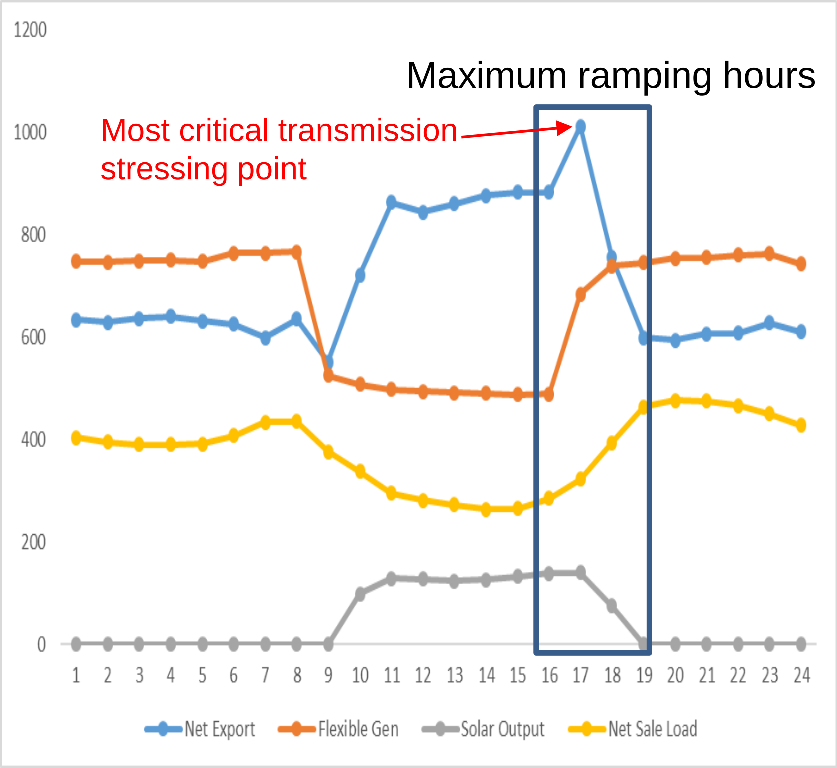
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	925	931	885	869	822	756	617	733	798	863	913	890
Peak Flexibility	10,900	10,974	10,428	10,240	6,970	6,406	5,230	6,218	6,766	10,174	10,758	10,493
Base Flexibility	6,675	6,721	6,387	6,271	8,652	7,951	6,491	7,718	8,398	6,231	6,589	6,426

http://www.caiso.com/Documents/Final2020FlexibleCapacityNeedsAssessment.pdf

The time period for peak and super-peak flexible capacity is HE16 through HE20.

Deliverability Requirement for Flexible Capacity on the Ramping Curve

- Deliverable along the entire ramping curve, not only at the starting and ending of the ramping
  - Starting point: around HE16, high solar output, net sale load is not at the daily peak, low flexible generation
  - Ending point: around HE20, no solar output, net sale load reaches the daily peak, high flexible generation



Actual Data on 2/25/2019 for a Gen-Pocket

Seasonal Deliverability Requirement for Flexible Capacity

- Flexible capacity need is higher in non-summer months
  - A new flexible capacity deliverability test is needed ensure the flexible capacity can be delivered to meet the highest flexible capacity need
- Flexible capacity need in summer is relatively lower, but still significant especially in September
  - Rely on the on-peak deliverability assessment
    - Highest system need scenario represents the ending of the flexible ramping: maximum flexible output and minimum solar output
    - Secondary system need scenario represents a mid-point of the flexible ramping: maximum flexible output and reduced solar output

Flexible Capacity Deliverability Assessment

- Test flexible capacity in the time window of HE 16 through HE 20 of non-summer month.
  - Flexible generation ramps from Pmin to Pmax
  - Transmission connected solar output ramps from Pmax to 0
  - Load ramps up to daily peak
    - Gross consumptions ramps up then slightly down
    - Behind-the-meter generation ramps down to 0
- A test procedure was developed as the first step to comprehensively assess flexible capacity deliverability.
  - Verify if the flexible capacity deliverability is a pressing concern
  - Identify all factors impacting flexible capacity deliverability
  - Explore mathematical models/tools to assess deliverability along a ramping curve

Flexible Deliverability Test Procedure

- Step 1: Identify potential transmission constraints under potential light load & high generation conditions from planning studies and operation data.
- Step 2: Define a gen-pocket for each transmission constraint.
- Step 3: Formulate transmission constraints in terms of flexible generation, non-flexible generation and load.
- Step 4: Evaluate flexible deliverability along the ramping curve and calculate a flexible deliverability margin.

Essentially this is a transfer study from the gen-pocket to the rest of the system accounting for multi-variables involved in the transfer.

Identify Potential Flexible Deliverability Constraints

- Identify potential transmission constraints that could limit energy delivery of flexible resources during a ramping period
- Use transmission planning studies and operation data
  - Transmission overloads in planning studies under off-peak conditions
  - Transmission congestion in TPP economic studies
  - Real-time market congestion during the high net load ramping hours

Define Gen-Pockets

- Model the system conditions when the daily highest net load ramping is about to start.

Solar resources in the study area	Full output
Wind resources in the study area	Pgen = historical maximum output
Other non-dispatchable resources in the study area	Full output
Flexible resources in the study area	Pgen = Minimum output (Pmin)
Load in the study area	Historical minimum
CAISO BAA imports that impact the study area	Historical maximum

Historical data: 16HE to 20HE in the spring

- Calculate shift factors of gen and load on the potential constraint
- Gen-pocket: gen with shift factor >=5% load with shift factor <=-5%

Formulate the Transmission Constraints

$$\sum_{\substack{w \in wind \\ resources}} d_w \Delta P_{gw} + \sum_{\substack{s \in solar \\ resources}} d_s \Delta P_{gs} + \sum_{\substack{f \in flexible \\ resources}} d_f \Delta P_{gf} + \sum_{\substack{i \in import \\ generators}} d_i \Delta P_{gi} + \sum_{l \in loads} d_l \Delta P_l$$

$$\leq Flow\ Limit - Flow\ in\ the\ Base\ Case$$

$$d_w, d_s, d_f, d_i, d_l\ are\ distribution\ factors\ of\ P_g\ and\ P_l$$

$$\Delta P_{gw} \leq Pmax_w - Pgen_w$$

$$-Pgen_s \leq \Delta P_{gs} \leq 0$$

$$\Delta P_{gf} \leq Pmax_f - Pgen_f$$

$$\Delta P_{gi} \leq Pmax_i - Pgen_i$$

$$\Delta P_l \leq Off\ peak\ season\ highest\ load - P_l$$

$$\sum \Delta P_{gf} \leq k\left(\sum \Delta P_l - \sum \Delta P_{gs}\right), 1 < k$$

Understanding the Constraint Expression

- Multi-dimension of variables: load, wind, solar, flexible gen & import
- Each variable varies in the range of historical minimum to historical maximum
- All variables and the constraint are expressed as incremental to the starting point established in the base case
- Incremental changes of flexible gen, solar, load and pocket net generation changes are directionally co-related
  - Flexible gen increases, solar reduces, load increases and net generation increases

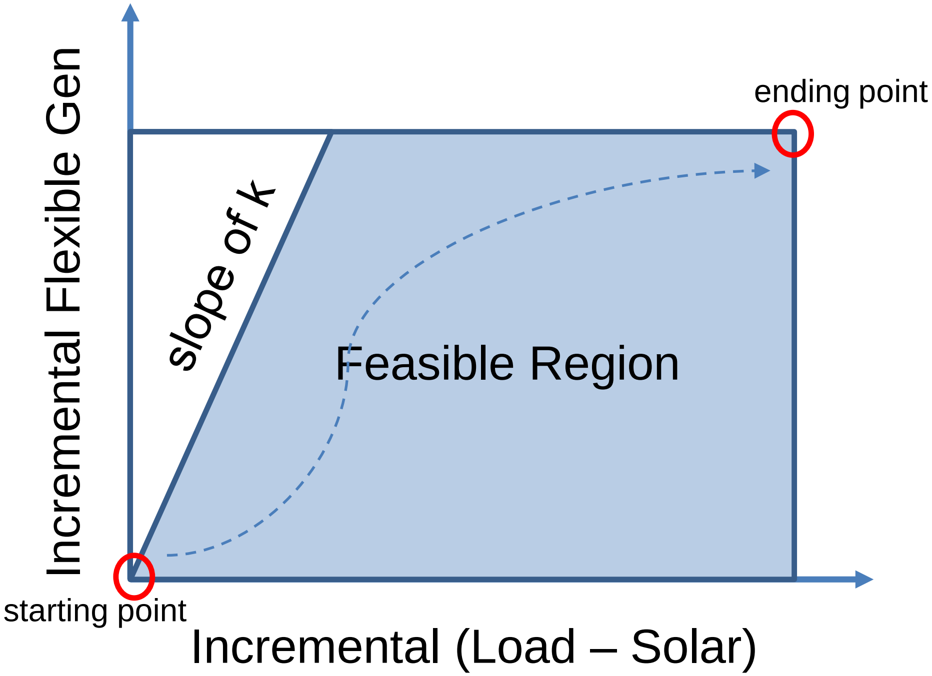
Set an Upper-Limit on Flexible Gen Change

- If all variables are free to move in the defined range, the constraint is most stressed with
  - Flexible gen at maximum
  - Solar gen at maximum
  - Load at minimum
  - Import at maximum
  - Wind at maximum

Variable	Incremental Change Direction	Impact on the Constraint
Flexible Gen	+	+
Solar	-	-
Load	+	-
Import	+	+
Wind	+	+

- This is a false operating condition to determine flexible deliverability
  - Flexible gen does not reach maximum when solar gen is at maximum and the load is at the minimum
  - Need a upper limit for flexible gen change relative to the load and solar gen change and this is the k-factor in the formulation

Meaning of k-factor



The dispatch condition moves from the starting point to the ending point during the ramping period. The formulation does not rely on a particular ramping path. It covers all the points in the shaded area.

Evaluate Flexible Deliverability

$$\max \sum_{\substack{w \in wind \\ resources}} d_w \Delta P_{gw} + \sum_{\substack{s \in solar \\ resources}} d_s \Delta P_{gs} + \sum_{\substack{f \in flexible \\ resources}} d_f \Delta P_{gf} + \sum_{\substack{i \in import \\ generators}} d_i \Delta P_{gi} + \sum_{l \in loads} d_l \Delta P_l$$

$$s.t.$$

$$\Delta P_{gw} \le Pmax_w - Pgen_w$$

$$-Pgen_s \le \Delta P_{gs} \le 0$$

$$\Delta P_{gf} \le Pmax_f - Pgen_f$$

$$\Delta P_{gi} \le Pmax_i - Pgen_i$$

$$\Delta P_l \le Off\ peak\ season\ highest\ load - P_l$$

$$\sum \Delta P_{gf} \le k\left(\sum \Delta P_l - \sum \Delta P_{gs}\right), 1 < k$$

- Solve the optimization problem
- Use the solution to modify the power flow dispatch and get the stressed flow
- Calculate deliverability margin as (Flow Limit – Stressed Flow)

2019-2020 Flexible Capacity Deliverability Test

- The 2019-2020 TPP 2029 spring off-peak base scenario is used as the starting base case.

Scenario	Day/Time (PST)	BTM-PV			Transmission Connected PV			Transmission Connected Wind			% of managed peak load		
	2029	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE
Spring Off Peak	4/7 HE 13	80%	81%	79%	100%	98%	98%	55%	54%	22%	21%	26%	17%

- Potential flexible deliverability gen-pockets were identified.
- Dispatch in the starting base case was adjusted for each gen-pocket according to the test procedure.

SCE Area – Potential Flexible Deliverability Constraints

Constraint Name	Monitored	Contingency	Source
North of Lugo	Lugo AA bank	base case	Cluster 11 Phase I RTM
North of Magunden	Vestal - Magunden No. 1	Vestal - Magunden No. 2	Cluster 11 Phase I RTM
Blythe	Julian Hinds - Mirage 230kV	base case	RTM

California ISO

North of Lugo Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=2)	Max Flow Point (k=3)	Max Flow Point (k=10)
Flexible Gen	52.82	0	1153	1153	1153	1153
Solar Gen	1427	0	1427	981	1130	1337
Load	227	227	604	332	297	248
Monitored Flow	583			840	918	1026
Flow Margin				25%	18%	8%

- Normal flow on Lugo 500/230kV Bank No. 1 or No. 2
- The deliverability margin is reduced as k increases.
- Based on historical data, k is about 2. There is sufficient margin (25%) under this condition. Flexible capacity is unlikely being constrained by the transmission.
- About 280 MW energy storage could be added without hitting the transmission limit.

North of Magunden Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=2)	Max Flow Point (k=3)	Max Flow Point (k=10)
Flexible Gen	0	0	1069	1069	1069	1069
Solar Gen	157	0	157	15	62	129
Load	244	244	678	637	506	323
Monitored Flow	-21			210	299	424
Flow Margin				65%	51%	30%

- Vestal – Magunden 230kV No. 1 flow under outage of Vestal – Magunden 230kV No. 2
- The deliverability margin is reduced as k increases.
- Based on historical data, k is about 3. There is sufficient margin (51%) under this condition. Flexible capacity is unlikely being constrained by the transmission.
- About 500 MW energy storage could be added without hitting the transmission limit.

California ISO

Blythe Constraint

- Julian Hinds – Mirage 230kV normal flow
- The load in the gen-pocket are pumps, which does not have the same ramping pattern
- The line is stressed most under low pumping and high import condition

Variable	Min	Max	Max Flow Point
Flexible Gen	0	493	493
Pump	0	317	0
Import	0	17	17
Monitored Flow			315
Flow Margin			12%

- Historical lowest pumping during the interested hours is 0.
- The corresponding highest import is 17 MW.
- With the flexible resource ramping to maximum, the flow margin is 12%. Flexible capacity is unlikely being constrained by the transmission.
- About 70 MW energy storage could be added without hitting transmission limit.

SDG&E Area – Potential Flexible Deliverability Constraints

Constraint Name	Monitored	Contingency	Source
Doublet Tap-Friars	Doublet Tap-Friars 138 kV	San Luis Rey-Encina 230 kV and San Luis Rey-Encina-Palomar 230 kV	RTM
San Luis Rey-San Onofre	San Luis Rey-San Onofre 230 kV #1	San Luis Rey-San Onofre 230 kV #2 and #3	PCM
Silvergate-Bay Boulevard	Silvergate-Bay Boulevard 230 kV	Miguel-Mission 230 kV #1 and #2	PCM

Doublet Tap-Friars Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=0.8)
Flexible Gen	100	0	1914	129
Solar Gen	1450	0	1479	1312
Load	438	438	1322	522
Monitored Flow	18			126
Flow Margin				84%

- Based on historical data, k is 0.8. There is sufficient margin (84%) under this condition. Flexible capacity is unlikely being constrained by the transmission.
- More than 500 MW energy storage could be added without hitting the transmission limit.

Silvergate-Bay Boulevard Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=1.2)	Max Flow Point (k=3)	Max Flow Point (k=10)
Flexible Gen	0	0	2068	2068	2068	2068
Solar Gen	1395	0	1423	11	842	1229
Load	152	152	494	491	287	193
Monitored Flow	460			663	767	816
Flow Margin				44%	35%	31%

- The deliverability margin is reduced as k increases.
- Based on historical data, k is 1.2. There is sufficient margin (44%) under this condition. Flexible capacity is unlikely being constrained by the transmission.
- More than 500 MW energy storage could be added without hitting the transmission limit.

San Luis Rey-San Onofre Constraint

Variable	Starting Point	Min	Max	Max Flow Point (k=1.2)	Max Flow Point (k=2)	Max Flow Point (k=3)
Flexible Gen	0	0	3698	1353	2300	2300
Solar Gen	1450	0	1479	894	894	1079
Load	941	941	2577	1568	1568	1359
Monitored Flow (with RAS)	541			694	941	1077
Flow Margin (with RAS)				40%	18%	6%

- The deliverability margin is reduced as k increases.
- Based on historical data, k is 1.2. There is sufficient margin (40%) under this condition with the proposed RAS. Flexible capacity is unlikely being constrained by the transmission.

PG&E Area – Potential Flexible Deliverability Constraints

Constraint Name	Monitored	Contingency	Source
North of Fresno # 1	Mosslanding-LosAguilas 230 kV	Mosslanding-LosBanos 500 kV	Cluster 11 Phase I/ RTM
North of Fresno # 2	Los Banos-Quinto 230 kV Line	Tesla-LosBanos 500 kV line	RTM

California ISO

North of Fresno Constraint # 1

Variable	Starting Point	Min	Max	Max Flow Point (k=1)	Max Flow Point (k=3)	Max Flow Point (k=5)
Flexible Gen	35	204	760	600	760	760
Solar Gen	1192	0	1349	842	1108	1186
Load	174	148	566	255	174	150
Monitored Flow	266			272	314	323
Flow Margin				32%	21%	19%

- Contingency Flow on Moss Landing-Lasa Aguilas 230 kV line
- The deliverability margin is reduced as k increases.
- Based on historical data, **k is about 1**. There is sufficient margin (19%) under this condition. Flexible capacity is unlikely being constrained by the transmission.
- ~ 700 MW of energy storage can be added based on assumed location and associated distribution factors.

North of Fresno Constraint # 2

Variable	Starting Point	Min	Max	Max Flow Point (k=1)	Max Flow Point (k=1.5)	Max Flow Point (k=2)
Flexible Gen	128	211	1921	1100	1545	1921
Solar Gen	3051	0	3051	3051	3004	3030
Load	995	844	2530	844	870	857
Monitored Flow	265			307	329	353
Flow Margin				74%	72%	70%
Energy Storage						

- Contingency flow on LosBanos-Quinto 230 kV line
- The deliverability margin is reduced as k increases.
- Based on historical data, **k is about 1**. There is sufficient margin (70%) under this condition. Flexible capacity is unlikely being constrained by the transmission.
- No Energy storage estimates are provided due to very high flow margins in this case. The margin is primarily due to a new upgrade not present in historical congestion data.

Observations and Future Work

- The study hasn't identified any flexible deliverability concerns
- Better representation of the system outside the gen-pocket
  - Refine starting base case for the entire CAISO planning area
  - Reflect system changes during the ramping period and capture the impacts on the gen-pocket transmission constraints
- Consider planned outages – use the N-1-1 results from TPP
- Need to capture the non-linear correlation among flexible gen, solar output and load
- Consider assessment of energy storage charging to allow ramping of energy storage to meet flexible capacity need

California ISO

The Deliverability Assessment Suite

		RA		Non-RA
Purpose		Ensure system reliability, i.e. generation capacity is not constrained by the transmission capability when needed for reliability		Address renewable curtailment due to local transmission constraints
Deliverability Assessment		On-Peak	Flexible Capacity	Off-Peak
Resources under Test		FCDS/PCDS	Flexible	Wind and Solar
Load Condition		Summer peak sale and peak consumption	Winter/spring daily ramping from peak consumption to peak peak sale	55% ~ 60% of summer peak sale; corresponding to load levels in many hours in all seasons
Non-intermittent Resources	Flexible	NQC	Ramping from Pmin to NQC	Historical minimum
	Non-Flexible	NQC	NQC	Historical minimum
Intermittent Resources		Low to medium output per methodology	Solar ramps from Pmax to 0	Medium to high output per methodology

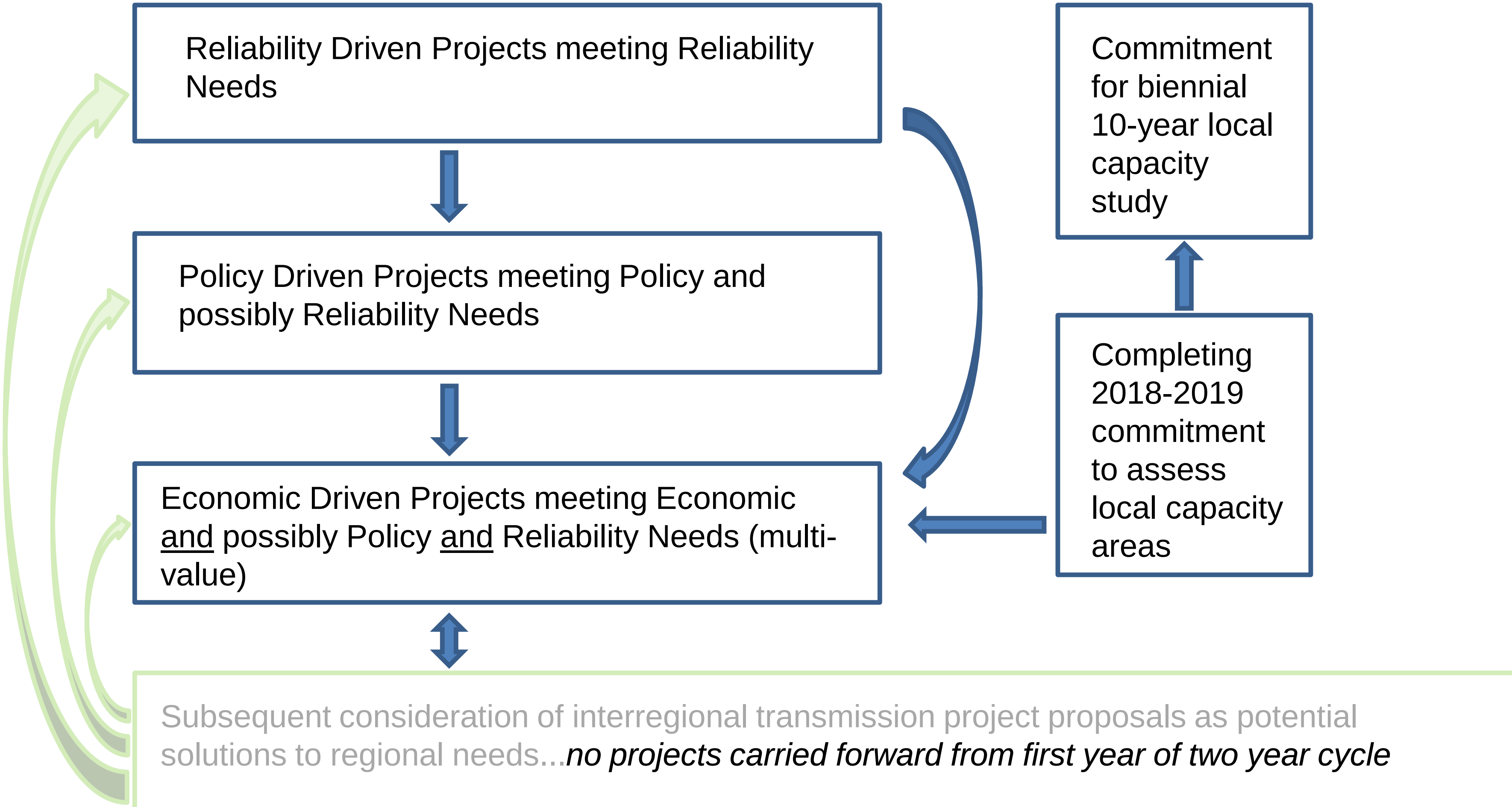
California ISO

Emerging Economic Study Considerations
Transmission Planning Process

Neil Millar
Executive Director, Infrastructure Development

2018-2019 Transmission Planning Process Stakeholder Meeting
November 16, 2018

The 2019-2020 economic analysis is becoming clearer as the planning cycle has progressed



Key focus of economic studies

- Economic assessment of reduction or elimination of gas-fired generation in local capacity areas not studied last year are being done this year as an extension to the 2018-2019 Transmission Plan:
  - Potential mitigations for the LCR areas and sub-areas that were not assessed in the 2018-2019 planning cycle will be assessed using the assumptions and models consistent with the 2018-2019 planning cycle
  - Recommended LCR criteria changes will be taken into consideration when considering potential alternatives
- High Priority study areas not yet finalized…but are being narrowed down
- Interregional transmission planning process is again being documented in a separate chapter
  - Interregional projects submitted into the two year process last year were addressed as per tariff-defined processes
  - No interregional projects were carried forward into the 2019-2020 transmission plan - the second year of the interregional study cycle.

Storage considerations will be largely consistent with the 2018-2019 cycle

- Will continue evaluating preferred resources including storage as possible solutions and considering “ISO ratepayer benefits” on a case-by-case basis – including production cost and potential market revenues
- Will continue to rely CPUC-led processes for resource procurement input, and will consider the status of system resource procurement activities when exploring mitigations for transmission needs
- Will assess preferred resources and storage – whether storage is considered an RA resource or transmission asset – on an equal basis, in selecting preferred solutions in Phase 2
  - The SATA initiative remains on hold pending resolution of merchant storage dispatch issues – upon which SATA will be based
  - Potential market revenue benefits to ratepayers of storage as a transmission asset may be taken into account and only if similar benefits to ratepayers can be attributed to preferred resources including storage procured as a market resource and performance requirements don’t conflict

In considering economic benefits to reduce local capacity reductions in this cycle:

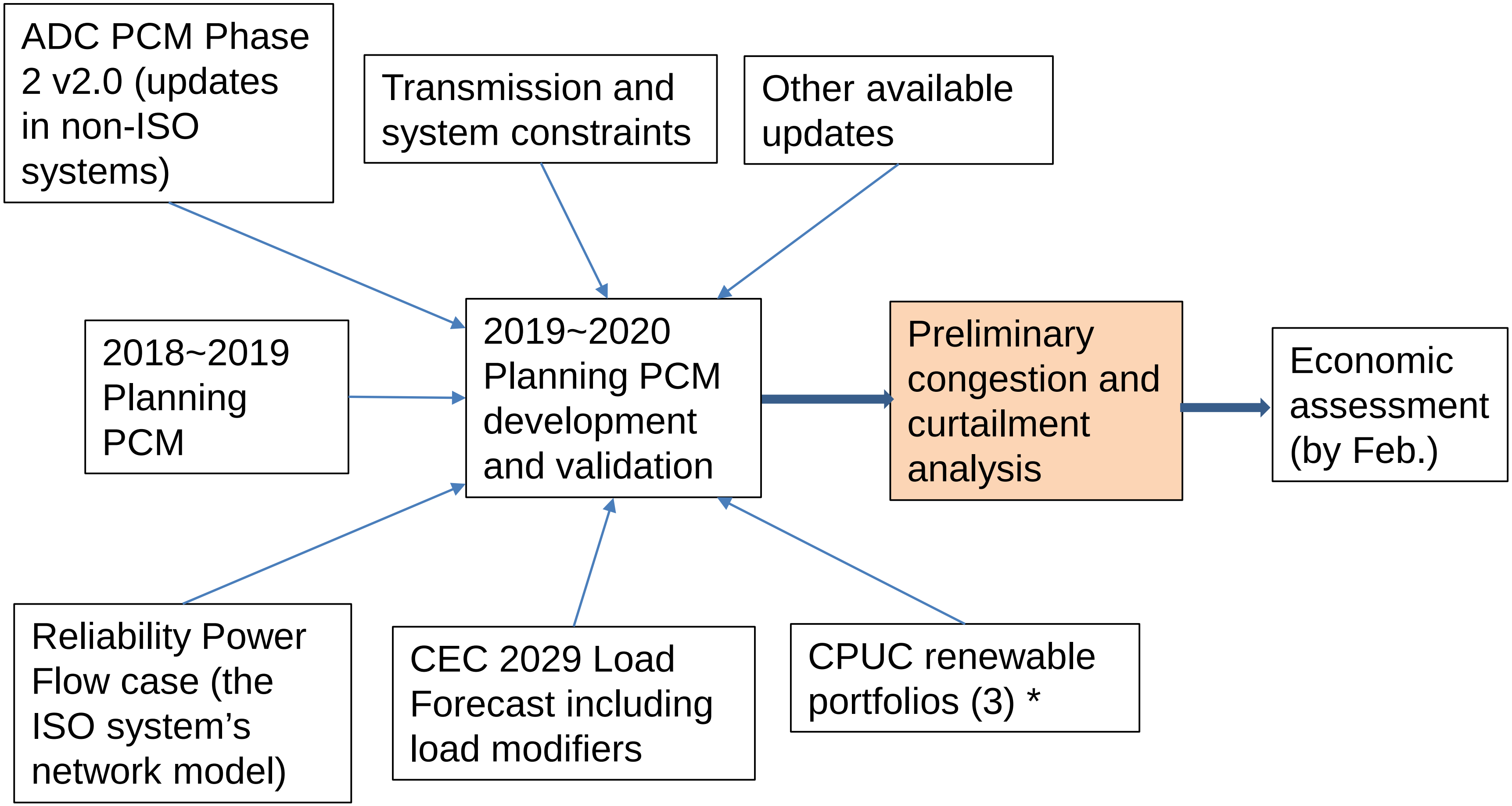
- Conservative assumptions will again be employed – consistent with the 2018-2019 transmission planning cycle - for potential transmission project approvals, while awaiting clearer direction in future CPUC IRP cycles on SB 100-related gas-fired generation reduction plans
- These alternatives can include conventional transmission, multi-faceted solutions, and preferred resources including storage
  - Multi-faceted solutions require careful coordination with entities procuring resources and the CPUC
  - Resource substitution decisions fall exclusively to the CPUC
- System capacity benefits – a consideration for preferred resources including storage, or storage as transmission assets – will be identified, but valuing system capacity benefits will likely be deferred pending increased coordination with the CPUC IRP process

Preliminary Economic Assessments Results

Yi Zhang
Regional Transmission Engineering Lead

2019-2020 Transmission Planning Process Stakeholder Meeting
November 18, 2018

Planning PCM development and simulations



* The base portfolio is for economic planning study; the sensitivity portfolios are for policy-driven study

Key modeling assumptions

- Wind and Solar multi-blocks model as proposed in the September stakeholder meeting
  - Applied to all ISO's wind or solar generators
  - Each generator is modeled as five separate generators (blocks) with identical hourly profile, each block's Pmax is 20% of the Pmax of the actual generator
  - Each block has different curtailment price around $-25 with $1 step size (-$23, -$24, -$25, -$26, -$27)
- Battery operation cost and depth of discharge (DoD) model as proposed in the September stakeholder meeting
  - 80% DoD
  - Flat average cost at $33.75/MWh

Round Mountain – Table Mountain line rating and Future generators in portfolios in IID area

- Round Mountain – Table Mountain congestion was observed under N-1 contingency in this planning cycle due to the line rating change
  - SPS of bypassing series caps can mitigate the congestions
- Future generators in the CPUC portfolios in the IID area need to be mapped appropriately to balance flows between interfaces of IID-SCE and IID-SDGE

Portfolios

- Three portfolios were studied
- Base portfolio is used for both economic assessment and policy-driven study
- Sensitivity 1 and Sensitivity 2 portfolios are for policy-driven study

Congestion analyses – Base Portfolio, Sensitivity 1, and Sensitivity 2

Base portfolio - Summary of Congestion, with Round Mtn. – Table Mtn. line rating enforced under N-1

Area and Branch Group	Sum of Cost T (M$)	Congestion Duration (Hr)
COI Corridor	71.91	1,937
Path 26	18.84	736
SCE NOL-Kramer-Inyokern-Control	8.30	945
VEA	7.85	832
PG&E/TID Exchequer	5.84	2,170
PDCI	5.20	641
SCE Sylmar - Pardee 230 kV	5.11	325
PG&E Fresno	3.55	2,946
SCE RedBluff-Devers	1.76	27
Path 45	1.62	893
SDGE-CFE OTAYMESA-TJI 230 kV line	1.39	490
SDGE Silvergate-Bay Blvd 230 kV line	1.21	78
SCE LagunaBell-Mesa Cal	0.89	23
Path 42 IID-SCE	0.59	29
SDGE Sanlusry-S.Onofre 230 kV	0.45	110
IID-SDGE (S line)	0.43	36
Path 15/CC	0.43	20
SDGE IV-SD Import	0.40	12
San Diego	0.36	120
PG&E POE-RIO OSO	0.32	298
PG&E DRUM-BRNSWCKP 115 kV line	0.24	172
SCE J.HINDS-MIRAGE 230 kV line	0.21	56
Path 46 WOR	0.11	11

COI corridor congestion includes Round Mtn – Table Mtn congestion, about $61M.

Base portfolio-Summary of Congestion, without enforcing the Round Mtn. – Table Mtn. line rating under N-1

Assuming the SPS of bypassing series caps in place, only COI corridor congestion reduced. The impacts on other congestions were limited

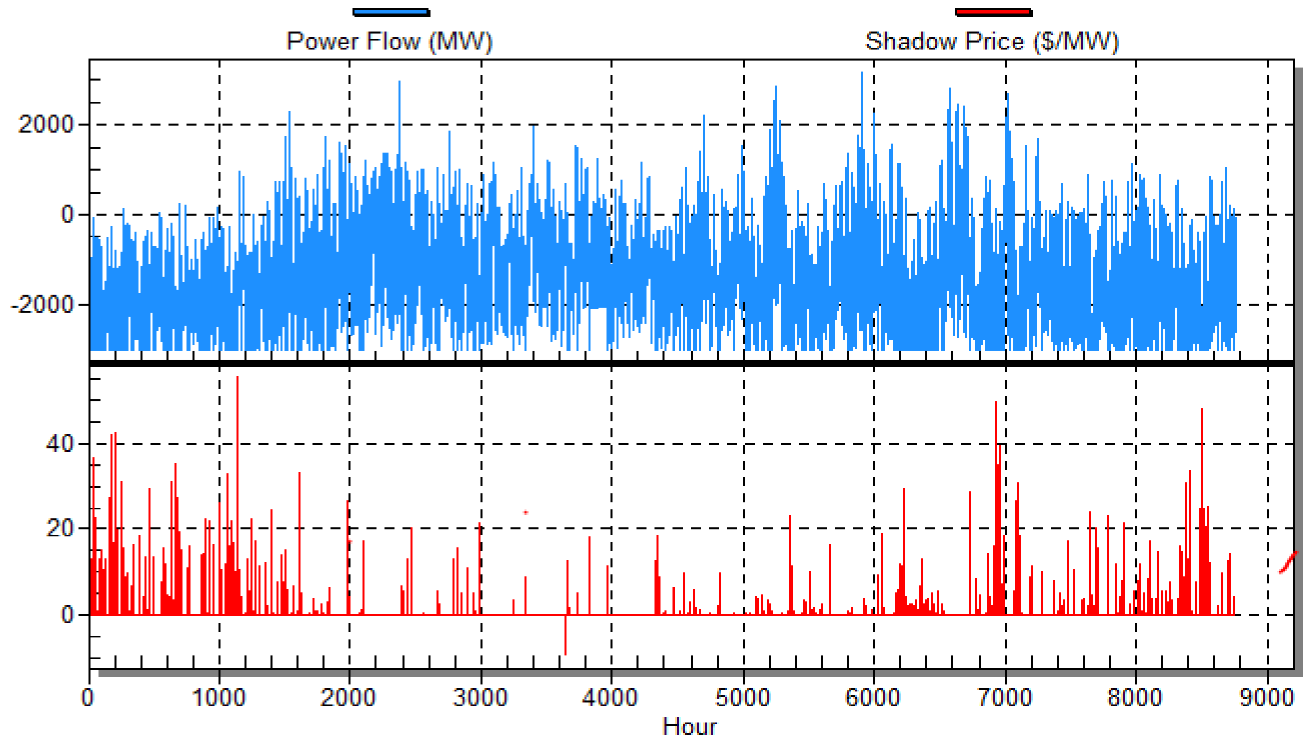
In following slides, only show results without enforcing the Round Mtn. – Table Mtn. line rating under N-1

Area or Branch Group	Congestion Cost T ($M)	Congestion Duration (Hr)
Path 26	19.13	720
COI Corridor	11.80	453
SCE NOL-Kramer-Inyokern-Control	8.24	1,130
VEA	7.75	839
PG&E/TID Exchequer	5.81	2,159
PDCI	5.19	637
SCE Sylmar - Pardee 230 kV	4.19	294
PG&E Fresno	3.50	2,927
SDGE-CFE OTAYMESA-TJI 230 kV line	2.14	790
SCE RedBluff-Devers	1.69	27
SDGE Silvergate-Bay Blvd 230 kV line	1.38	84
SCE LagunaBell-Mesa Cal	1.18	21
Path 45	1.04	627
Path 42 IID-SCE	0.58	33
SDGE Sanlusry-S.Onofre 230 kV	0.52	102
IID-SDGE (S line)	0.50	44
SDGE IV-SD Import	0.48	13
Path 15/CC	0.43	22
San Diego	0.34	109
PG&E POE-RIO OSO	0.27	297
PG&E DRUM-BRNSWCKP 115 kV line	0.24	159
SCE J.HINDS-MIRAGE 230 kV line	0.22	57
Path 46 WOR	0.14	13
SCE LCIENEGA-LA FRESA 230 kV line	0.11	7

Base portfolio – Path 26 congestions

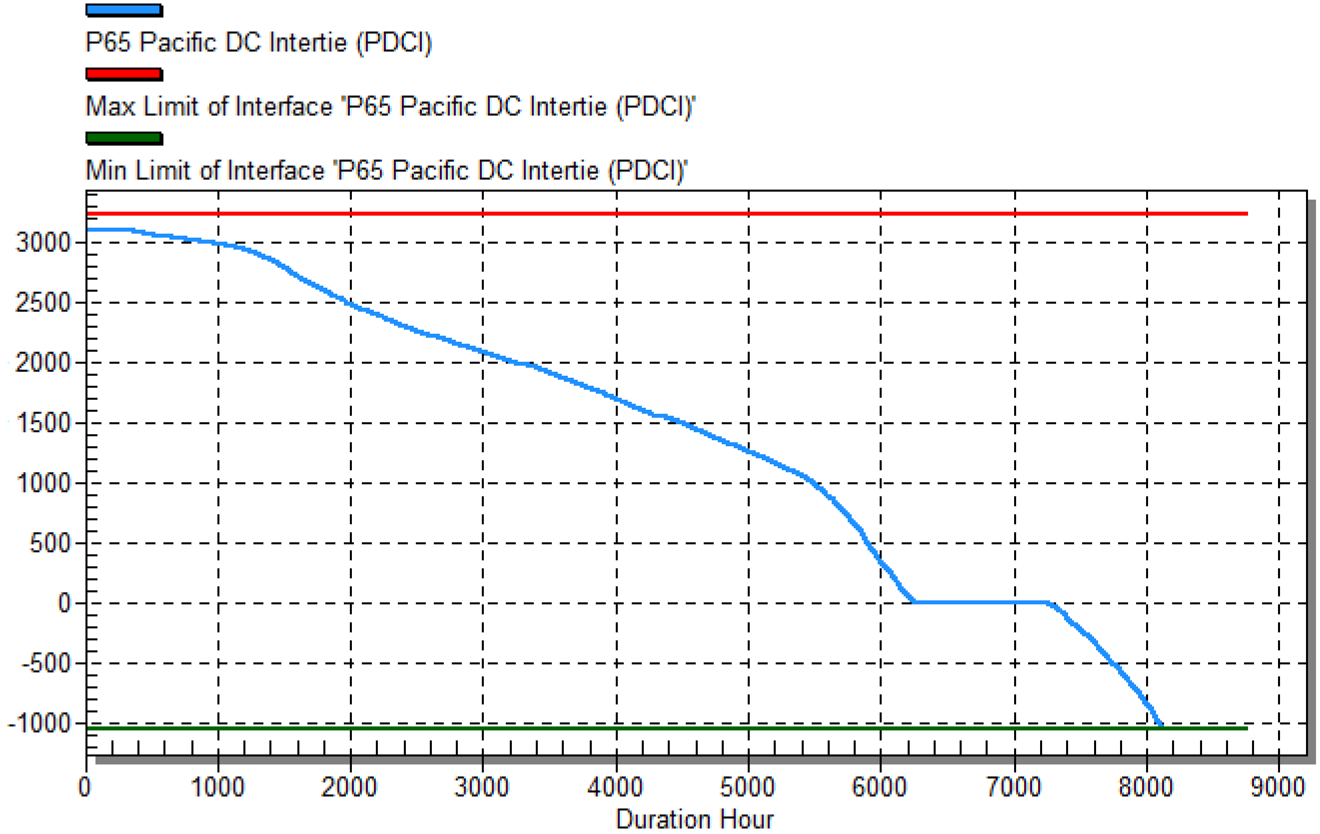
Constraints Name	Costs_F (M$)	Duration_F (Hrs)	Costs_B (M$)	Duration_B (Hrs)	Costs T (M$)	Duration_T (Hrs)
P26 Northern-Southern California	6	1	14.58	604	14.58	605
MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	3.74	79	3.74	79
MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	0	0	0.80	35	0.80	35

Path 26 path rating were binding in south to north direction mainly



Base portfolio - PDCI

Constraints Name	Costs_F (M$)	Duration_F (Hrs)	Costs_B (M$)	Duration_B (Hrs)	Costs T (M$)	Duration_T (Hrs)
P65 Pacific DC Intertie (PDCI)	0.00	0	5.19	637	5.19	637



Base portfolio – Northern California

COI corridor

Constraints Name	Costs_F (M$)	Duration_F (Hrs)	Costs_B (M$)	Duration_B (Hrs)	Costs T (M$)	Duration_T (Hrs)
P66 COI	7.72	339	0	0	7.72	339
TM_VD_11-TM_VD_12 500 kV line #1	1.40	42	0	0	1.40	42
TABLE MT-TM_TS_11 500 kV line #1	0.66	15	0	0	0.66	15
RM_TM_21-RM_TM_22 500 kV line #2	0.48	19	0	0	0.48	19
RM_TM_11-RM_TM_12 500 kV line #1	0.47	14	0	0	0.47	14
TM_TS_12-TESLA 500 kV line #1	0.44	7	0	0	0.44	7
TM_TS_11-TM_TS_12 500 kV line #1	0.27	5	0	0	0.27	5
TM_VD_12-VACA-DIX 500 kV line #1	0.14	5	0	0	0.14	5
TABLE MT-TM_VD_11 500 kV line #1	0.10	2	0	0	0.10	2
RM_TM_12-TABLE MT 500 kV line #1	0.07	2	0	0	0.07	2
ROUND MT-RM_TM_21 500 kV line #2	0.03	2	0	0	0.03	2
RM_TM_22-TABLE MT 500 kV line #2	0.02	1	0	0	0.02	1

PG&E Fresno

Constraints Name	Costs_F (M$)	Duration_F (Hrs)	Costs_B (M$)	Duration_B (Hrs)	Costs T (M$)	Duration_T (Hrs)
HURONJ-CALFLAX 70 kV line, subject to PG&E N-2 Panoche-Excelsior 115 kV with SPS-Huron	0.09	2	1.17	1,221	1.26	1,223
ORO LOMA-EL NIDO 115 kV line #1	1.16	180	0.00	0	1.16	180
KETLMN T-GATES 70.0 kV line #1	0.74	1,472	0.00	0	0.74	1,472
RPNJ2-MANTECA 115 kV line #1	0.00	0	0.28	8	0.28	8
LE GRAND-CHWCHLASLRJT 115 kV line #1	0.00	0	0.03	22	0.03	22
HENTAP1-MUSTANGSS 230 kV line #1	0.00	0	0.03	3	0.03	3
JACKSONSWSTA-WAUKENA_SS 115 kV line #1	0.00	0	0.00	19	0.00	19

Base portfolio – Southern California and VEA

SCE North of Lugo

Constraints Name	Costs_F (M$)	Duration_F (Hrs)	Costs_B (M$)	Duration_B (Hrs)	Costs T (M$)	Duration_T (Hrs)
VICTOR-LUGO 230 kV line	7.70	255	0	0	7.70	255
P60 Inyo-Control 115 kV Tie	0.00	2	0.44	857	0.44	859
KRAMER-VICTOR 230 kV line #1	0.09	3	0	0	0.09	3
CONTROL-INYOKERN 115 kV line #1	0.01	13	0	0	0.01	13

VEA

Constraints Name	Costs_F (M$)	Duration_F (Hrs)	Costs_B (M$)	Duration_B (Hrs)	Costs T (M$)	Duration_T (Hrs)
PAHRUMP-CARPENTERCYN 230 kV line #	0.00	0	7.24	679	7.24	679
JACKASSF-MERCRYSW 138 kV line #1	0.51	160	0.00	0	0.51	160

SCE Sylmar - Pardee

Constraints Name	Costs_F (M$)	Duration_F (Hrs)	Costs_B (M$)	Duration_B (Hrs)	Costs T (M$)	Duration_T (Hrs)
PARDEE-SYLMAR S 230 kV line, subject to SCE N-1 Sylmar-Pardee 230kV	0.00	0	4.19	294	4.19	294

Sensitivity 1 portfolio

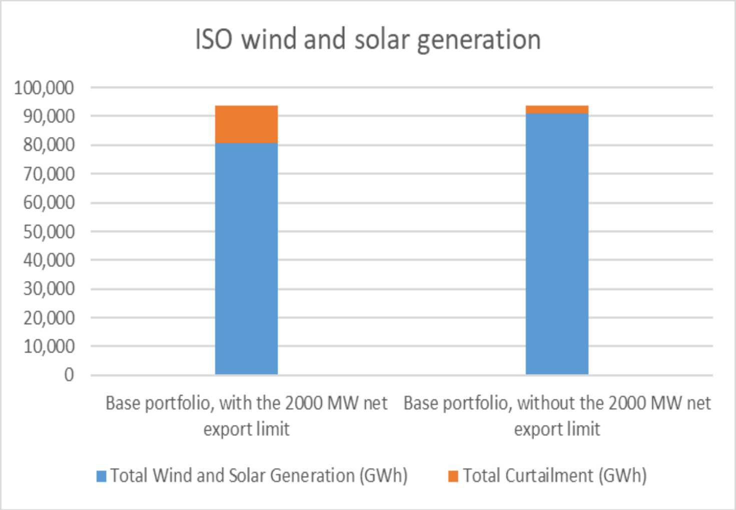
Area or Branch Group	Congestion Cost T ($M)	Congestion Duration (Hr)
Path 42 IID-SCE	50.62	1,672
COI Corridor	20.39	722
VEA	8.29	1,097
Path 26	5.66	293
PG&E/TID Exchequer	5.01	1,855
PDCI	3.97	535
SCE Sylmar - Pardee 230 kV	3.08	270
SCE RedBluff-Devers	2.87	36
SDGE-CFE OTAYMESA-TJI 230 kV line	2.18	794
PG&E Fresno	1.20	1,443
IID-SDGE (S line)	1.13	80
SCE NOL-Kramer-Inyokern-Control	1.12	555
SCE Serrano-Villa PK 230 kV	1.10	11
Path 45	0.94	576
SCE LagunaBell-Mesa Cal	0.93	26
SDGE Sanlusry-S.Onofre 230 kV	0.72	86
SDGE Silvergate-Bay Blvd 230 kV line	0.61	50
Path 46 WOR	0.48	30
SCE Alberhill-Valley 500 kV line	0.35	23
SDGE IV-SD Import	0.30	11
SCE J.HINDS-MIRAGE 230 kV line	0.24	62
PG&E POE-RIO OSO	0.23	264
San Diego	0.20	86
PG&E DRUM-BRNSWCKP 115 kV line	0.11	91

Sensitivity 2 portfolio

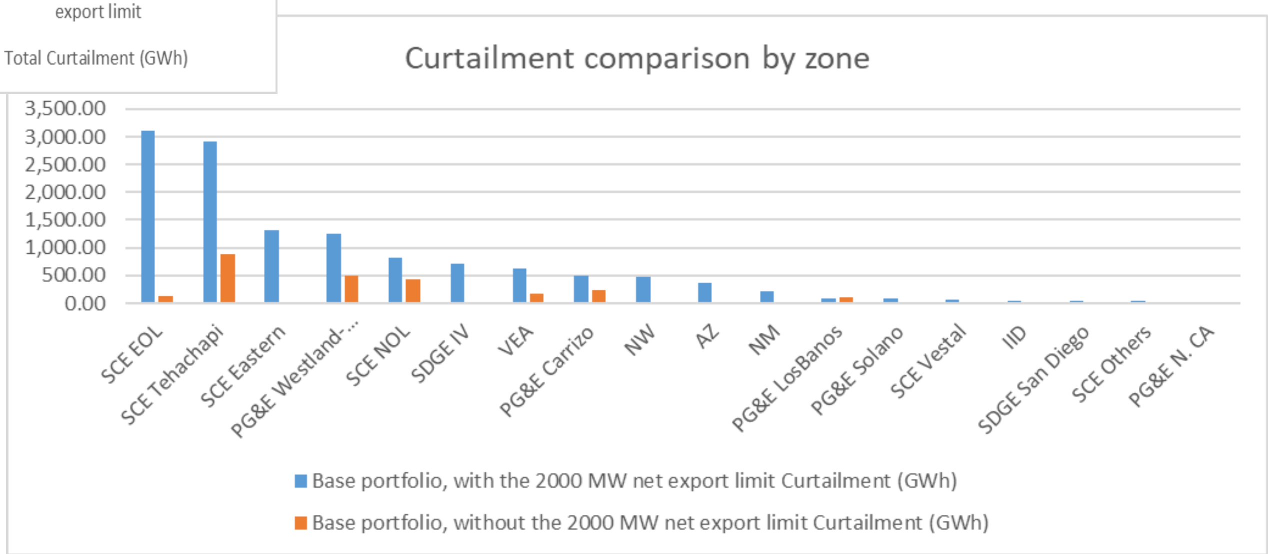
Area or Branch Group	Sum of Cost T (M$)	Congestion Duration (Hr)
Path 42 IID-SCE	47.81	1,642
COI Corridor	19.24	676
Path 26	16.96	732
PG&E/TID Exchequer	4.83	1,870
SCE RedBluff-Devers	4.66	48
PDCI	3.48	493
SCE Sylmar - Pardee 230 kV	2.98	305
Path 46 WOR	2.74	90
VEA	2.70	536
SCE Serrano-Villa PK 230 kV	2.51	16
SDGE-CFE OTAYMESA-TJI 230 kV line	1.87	698
IID-SDGE (S line)	1.86	140
SCE NOL-Kramer-Inyokern-Control	1.47	488
PG&E Fresno	1.44	1,738
SCE Alberhill-Valley 500 kV line	1.20	39
SDGE Silvergate-Bay Blvd 230 kV line	1.09	93
SDGE Sanlusry-S.Onofre 230 kV	0.83	92
SCE LagunaBell-Mesa Cal	0.74	23
Path 45	0.60	413
SDGE IV-SD Import	0.45	17
Path 15/CC	0.35	28
PG&E POE-RIO OSO	0.23	267
San Diego	0.21	88
SCE J.HINDS-MIRAGE 230 kV line	0.19	54
SCE LCIENEGA-LA FRESA 230 kV line	0.16	9
PG&E DRUM-BRNSWCKP 115 kV line	0.13	105

Renewable curtailment – Base portfolio, Sensitivity 1, and Sensitivity 2

Base portfolio - comparison of renewable generation and curtailment

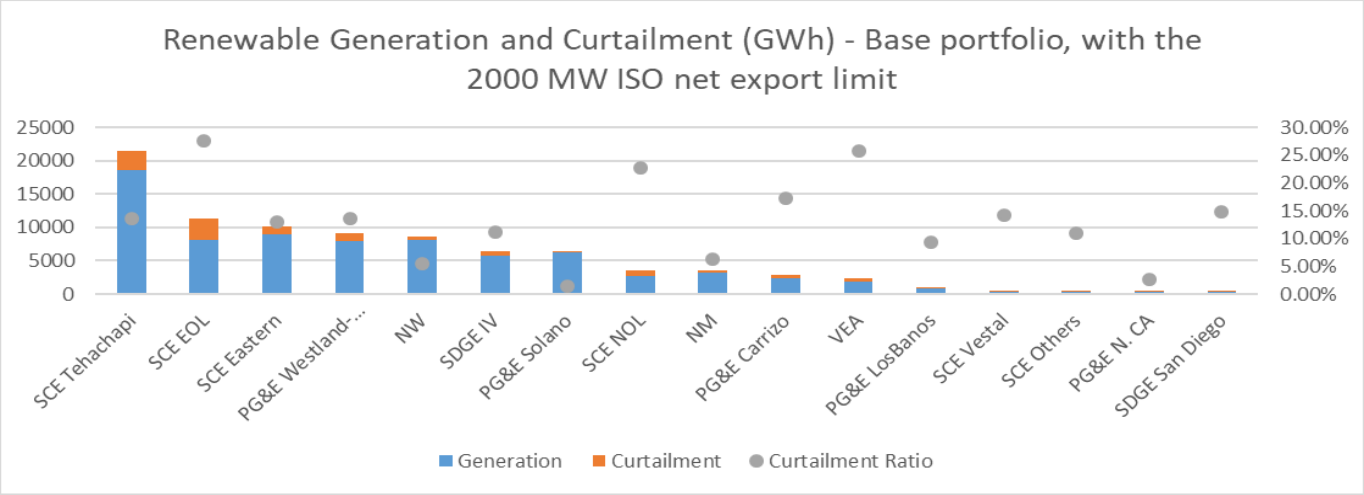


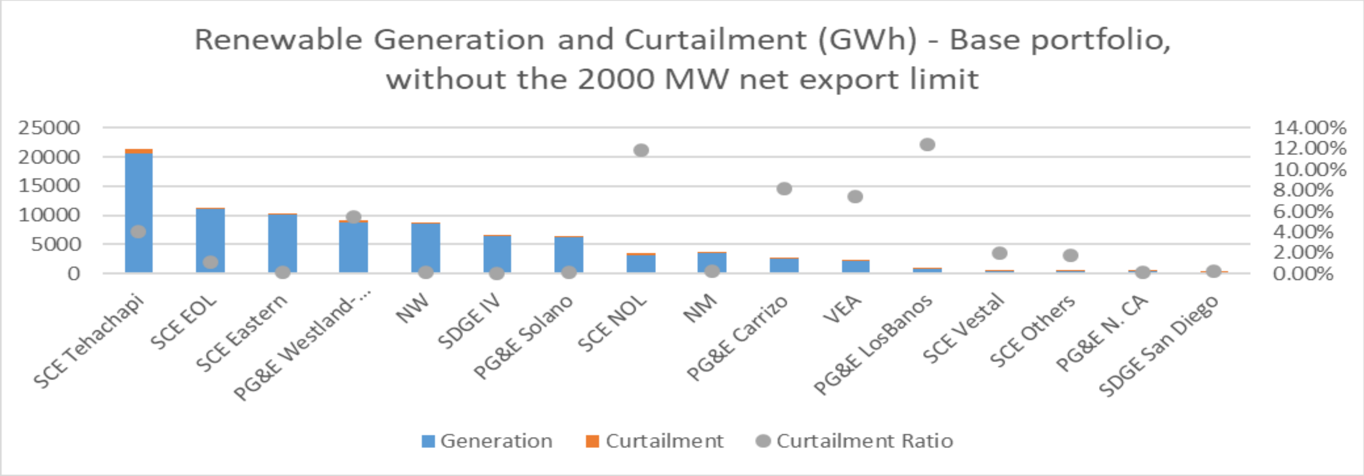
Case	Base portfolio, with the 2000 MW net export limit	Base portfolio, without the 2000 MW net export limit
Total Wind and Solar Generation (GWh)	80,731	90,994
Total Curtailment (GWh)	12,812	2,551



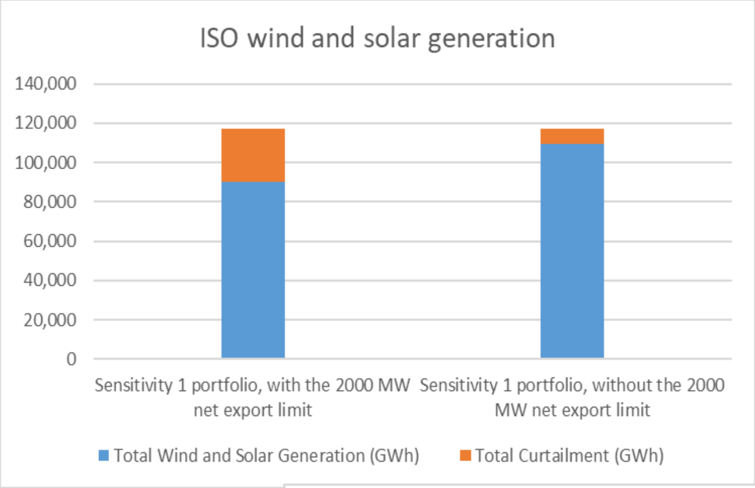
California ISO

Base portfolio - renewable curtailment analysis by zone

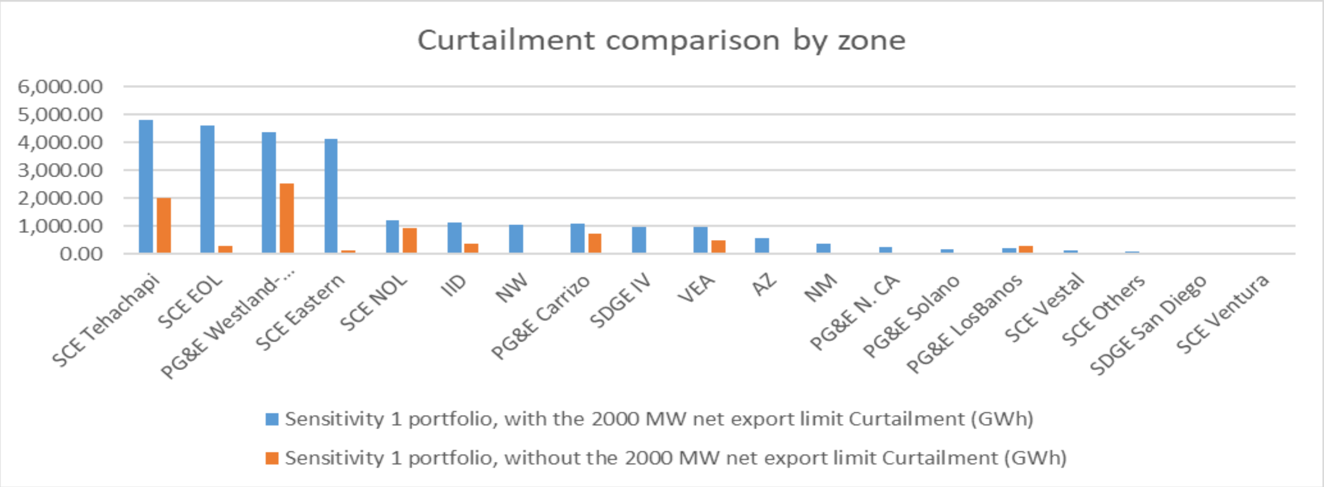




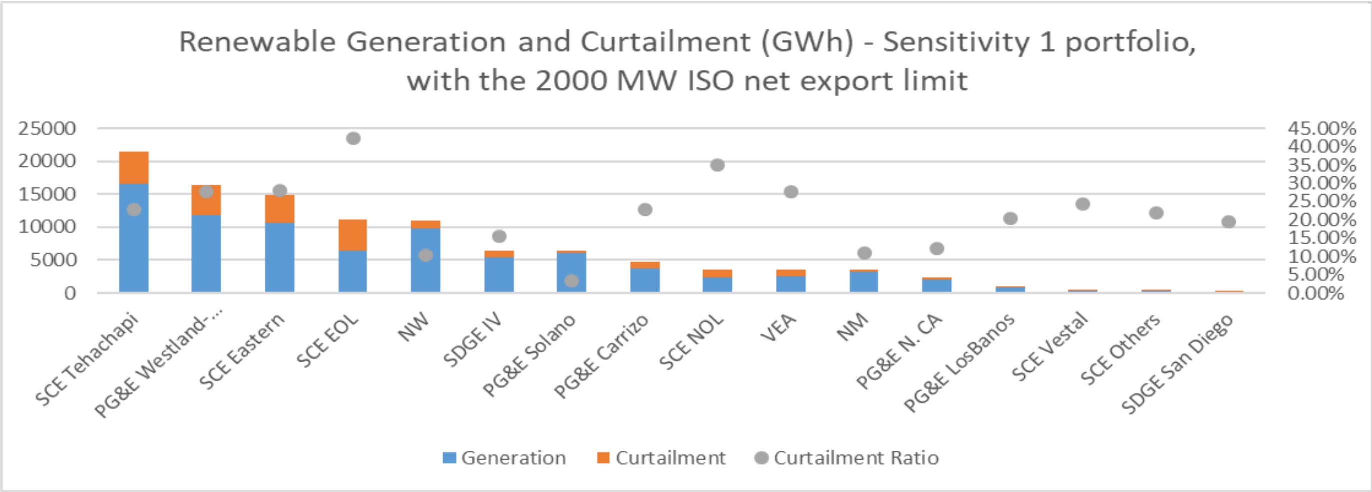
Sensitivity 1 portfolio - comparison of renewable generation and curtailment

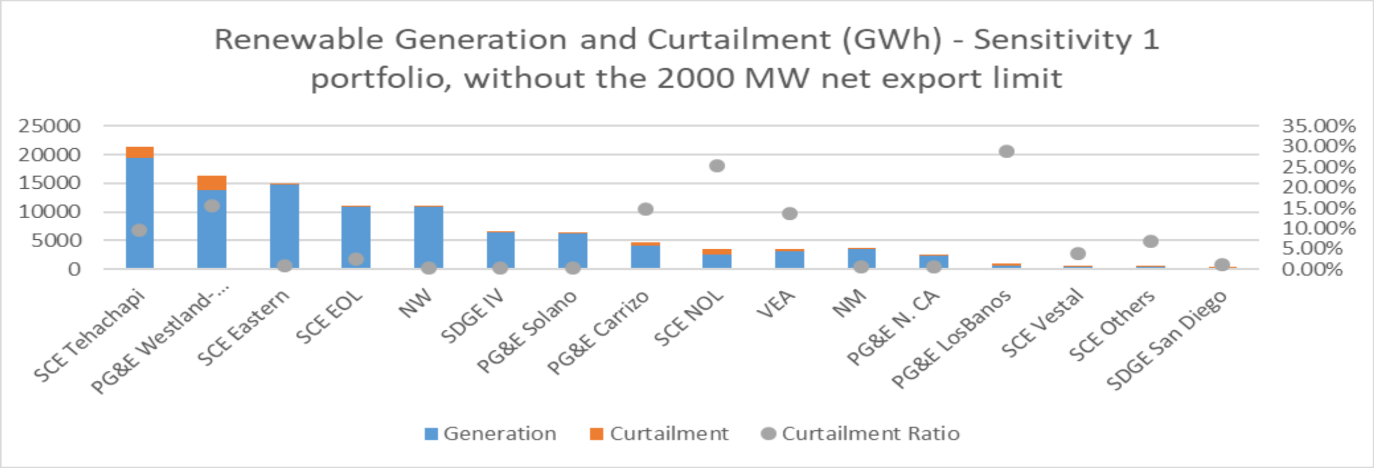


Case	Sensitivity 1 portfolio, with the 2000 MW net export limit	Sensitivity 1 portfolio, without the 2000 MW net export limit
Total Wind and Solar Generation (GWh)	90,843	109,308
Total Curtailment (GWh)	26,317	7,855

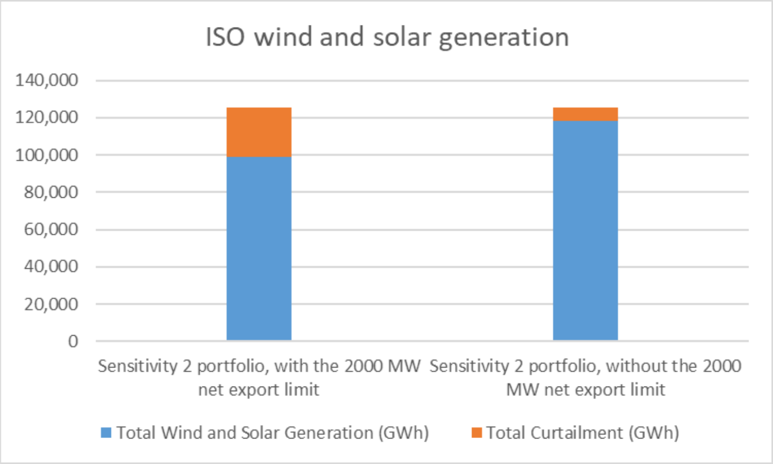


Sensitivity 1 portfolio - renewable curtailment analysis by zone

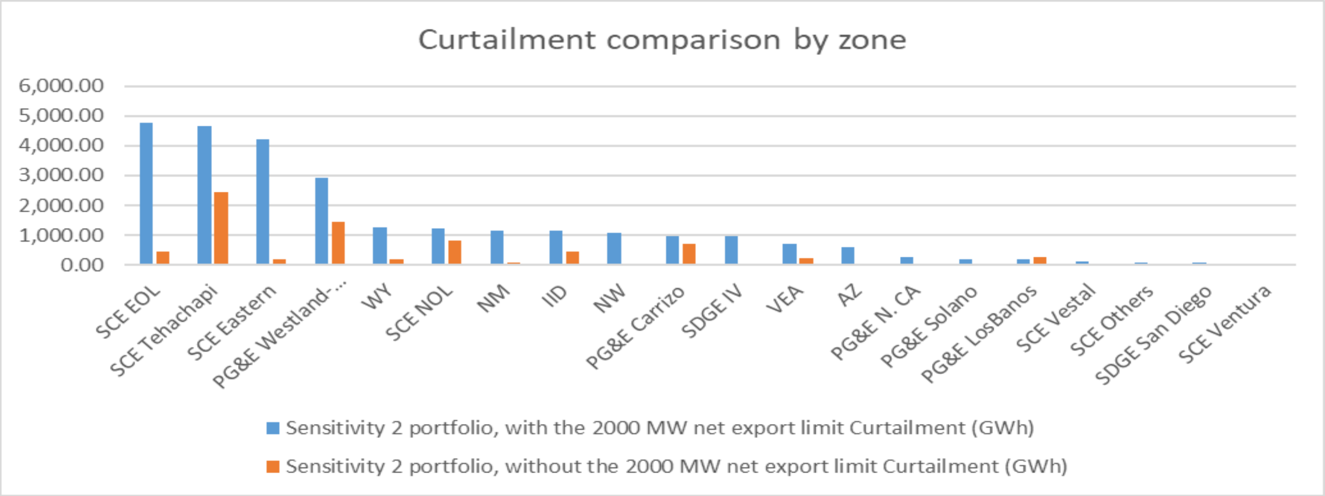




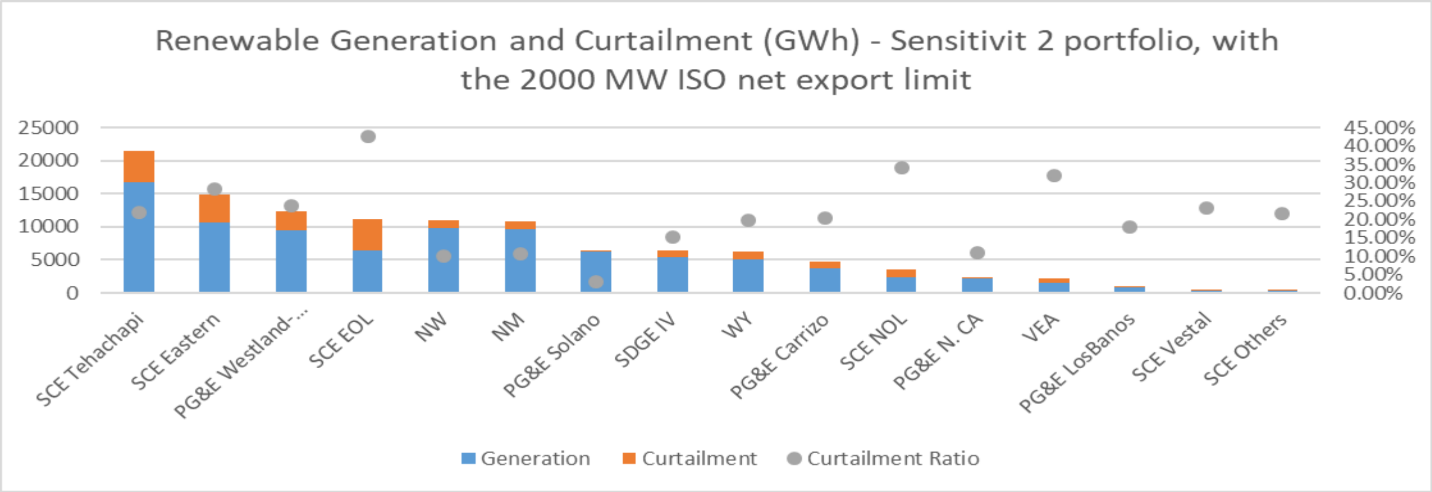
Sensitivity 2 portfolio - comparison of renewable generation and curtailment

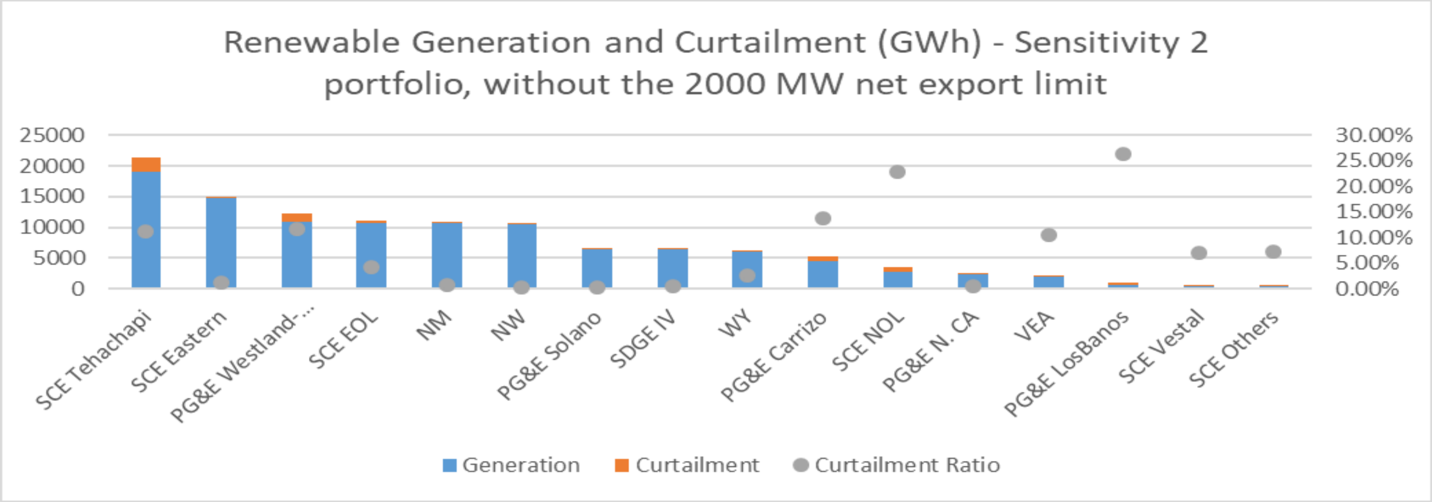


Case	Sensitivity 2 portfolio, with the 2000 MW net export limit	Sensitivity 2 portfolio, without the 2000 MW net export limit
Total Wind and Solar Generation (GWh)	98,760	118,147
Total Curtailment (GWh)	26,810	7,425



Sensitivity 2 portfolio - renewable curtailment analysis by zone





Next Steps

Economic planning study requests received:

No.	Study Request	Submitted By	Location
1	Lake Elsinore Advanced Pumped Storage Project ("LEAPS")	Nevada Hydro Company	Southern California
2	California Transmission Project (CTP) updated with Pacific Transmission Expansion (PTE)	Cal Energy Development Company, LLC updated with Western Grid Development	Northern/Souther n California
3	GLW/VEA service area transmission upgrade (includes Pahrump-Sloan Canyon Line Rebuild)	Gridliance West	Southern Nevada
4	Boardman to Hemingway 500 kV transmission project (B2H)	Idaho Power	Northwest (Oregon/Idaho)
5	SWIP-North	LS Power	Idaho/Nevada
6	Red Bluff to Mira Loma 500 kV line	NextEra Energy Resources (NEER)	Southern California
7	North Gila Imperial Valley #2 (NGIV2)	NGIV2, LLC	Arizona/California
8	Fresno Avenal area upgrade (Gates-Tulare Lake 70 kV line)	PG&E	Northern California

Additional request window submissions received that cited economic benefits:

No.	Study Request	Submitted By	Location
1	Chula Vista Energy Reliability Center	Wellhead	Southern California
2	Suncrest - Sycamore 230 kV	Horizon West	Southern California
3	Red Bluff - Mira Loma 500 kV	Horizon West	Southern California
4	Sycamore Reliability Energy Storage	Tenaska	Southern California
5	Imperial Smart Wire Solution	Imperial Renewable	Southern California

Listing excludes request window submissions that are also economic study requests.

Preliminary list of high priority study areas to receive detailed consideration:

- Fresno Avenal area upgrade (Gates-Tulare Lake 70 kV line) – economic study request
- Fresno area congestion mitigation – mitigating congestions that the ISO has identified for potential economic driven upgrades
- Pahrump - Sloan Canyon Line Rebuild (subset of GLW/VEA service area economic study request)
- Advancement of Pardee - Sylmar 230 kV upgrade – reliability need that the ISO has identified for potential economic driven advancement
- Western LA Basin local capacity area study, including consideration of the Pacific Transmission Expansion (PTE) economic study request
- Santa Clara sub-area local capacity study, including consideration of the Pacific Transmission Expansion (PTE) economic study request

Next steps of simulation and economic assessment

- Continue to develop and enhance ISO Planning PCM
- Conduct production cost simulations using updated PCM for
  - Economic planning
  - Policy study
- Conduct economic assessment for identified high priority upgrades or studies
- Provide update in the next TPP Stakeholder Meeting

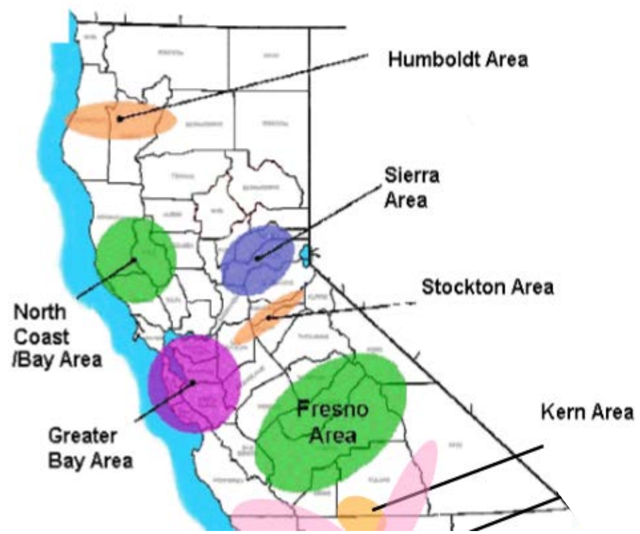
Local Capacity Requirements Potential Reduction Study

PG&E Area

2019-2020 Transmission Planning Process Stakeholder Meeting
November 18, 2019

LCR areas and subareas in PG&E service area

LCR Area	Subarea	Studied in 2018-2019 TPP cycle	Without need for studies	Studied in this cycle
Humboldt	-			√
North Coast-North Bay	Eagle Rock		√	
	Fulton		√	
	Overall		√	
Sierra	Placerville		√	
	Placer		√	
	Bogue		√	
	Pease	√		
	Drum-Rio Oso		√	
	South of Rio Oso	√		
	South of Palermo		√	
	Overall	√		
Stockton	Weber			√
	Lockeford		√	
	Stanislaus			√
	Tesla-Bellota			√
Greater Bay Area	Llagas	√		
	San Jose	√		
	South Bay-Moss Landing	√		
	Oakland			√
	Ames-Pittsburg-Oakland	√		
	Contra Costa			√
	Overall	√		√
Greater Fresno Area	Hanford	√		
	Coalinga			√
	Borden		√	
	Reedley	√		
	Herndon	√		
	Wilson (Overall)			√
Kern	Kern PP 70 kV	√		
	Westpark	√		
	Kern Oil	√		
	South Kern PP			√
	Overall	√		If needed



Presentation Format

- Load & resource information
  - Includes load and resource information for the LCR area or subarea for year 2028.
- Area / subarea one-line diagram.
- Requirements
  - Starts with current constraint and requirement based on ten-year (2028) LCR study.
  - Identification of subsequent constraints and requirements (layers)
    - until the requirement is completely eliminated. This information at this point is mostly based on thermal assessment only.
    - if multiple limitations are found after few iterations, it will be identified as such.
  - Alternatives and corresponding worst constraint and requirement.
- Summary of total requirement and corresponding reliance on gas-fired generation capacity for each alternative considered.
- LCR reduction benefit evaluation performed for selected area/subarea.

Local Capacity Requirements Potential Reduction Study

Greater Bay Area

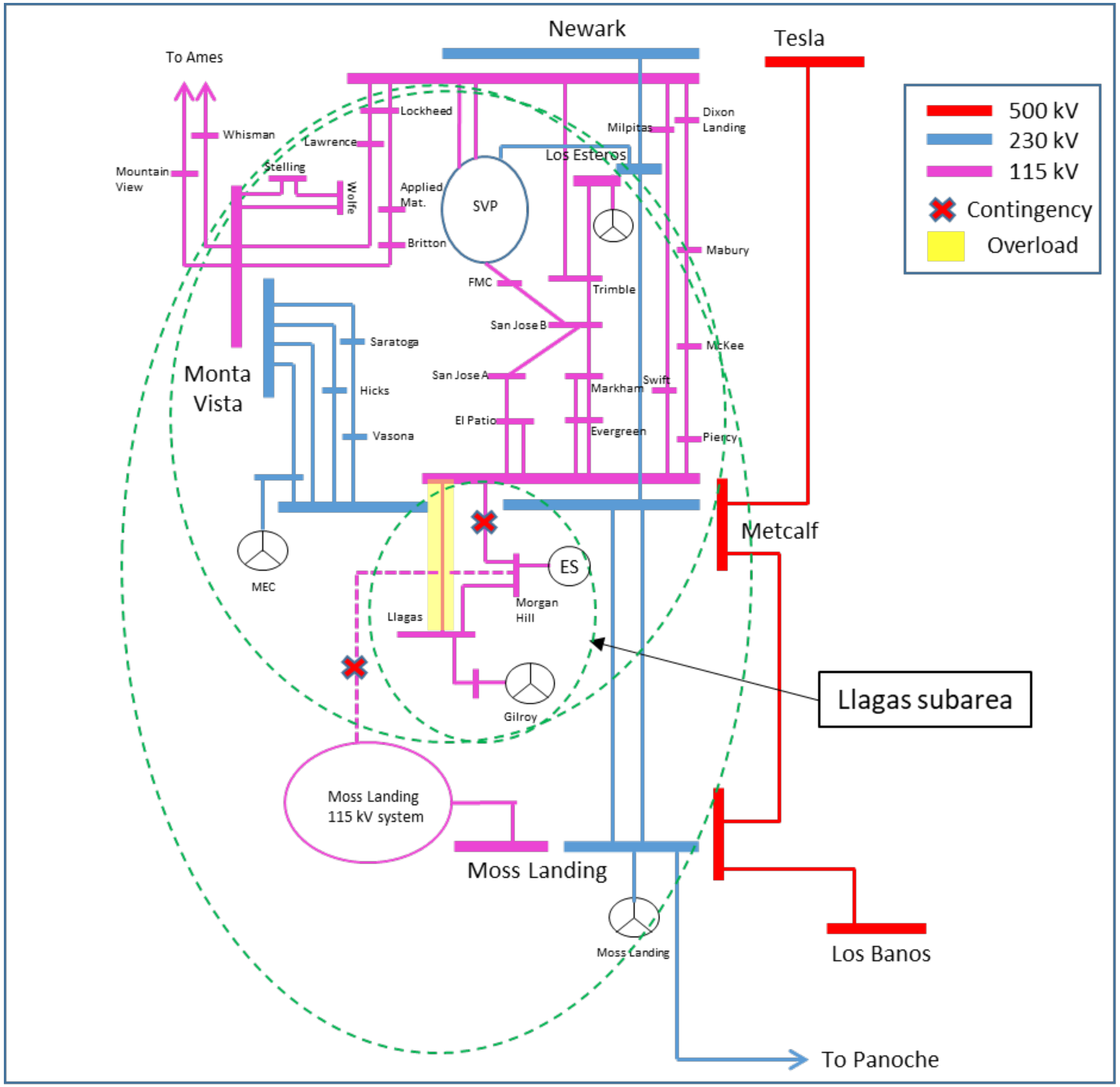
Binaya Shrestha

Regional Transmission Engineer Lead

Llagas Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	212	Market Gas	247
AAEE	-12	Other Gas	0
Behind the meter DG	-9	Non-Gas	0
Net Load	**191**		
Transmission Losses	0	Future preferred resource and energy storage	20
Pumps	0	**Total Qualifying Capacity**	**267**
Load + Losses + Pumps	**191**		

Llagas Subarea : One-line diagram



California ISO

Llagas Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First limit	B	None	None	No requirement
2028	First limit	C	Metcalf-Morgan Hill 115 kV line	Moss Landing-Green Valley #1 and #2 115 kV lines	92
Subsequent requirements (layers)					
2028	Second limit	C	Moss Landing-Green Valley #1 or #2 115 kV lines	Metcalf-Morgan Hill and Moss Landing-Green Valley #2 or #1 115 kV lines	40
2028	Third limit	C	Metcalf-Llagas 115 kV line	Metcalf-Morgan Hill and Morgan Hill-Green Valley 115 kV lines	24
2028	Fourth limit	C	Metcalf-Morgan Hill 115 kV line	Metcalf-Llagas and Morgan Hill-Green Valley 115 kV lines	17
with Metcalf-Llagas loop-in					
2028	First limit	C	Metcalf-Morgan Hill #1 or #2 115 kV line	Morgan Hill-Green Valley and Metcalf-Morgan Hill #2 or #1 115 kV lines	17

Llagas Subarea : Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
Status Quo	NA	NA	92	72	0	20
Metcalf-Llagas 115 kV line loop into Morgan Hill	PG&E	6-7	17	0	0	17

Llagas Subarea : LCR Reduction Benefits[1]

Loop in Metcalf-Llagas 115 kV line to Morgan Hill 115 kV station as an scope addition to previously approved Morgan Hill Area Reinforcement project		
	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (Llagas Sub-area) (MW)	75	
Capacity value (per MW-year)	$1,560	$840
LCR Reduction Benefit ($million)	$0.12	$0.06
Local Capacity Benefits		
	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.12	$0.06
PV of LCR Savings ($million)	$1.61	$0.87
Capital Cost		
Capital Cost Estimate ($ million)	$7	
Estimated “Total” Cost (screening) ($million)	$9.1	
Benefit to Cost		
PV of Savings ($million)	$1.61	$0.87
Estimated “Total” Cost (screening) ($million)	$9.1	
Benefit to Cost	0.18	0.10

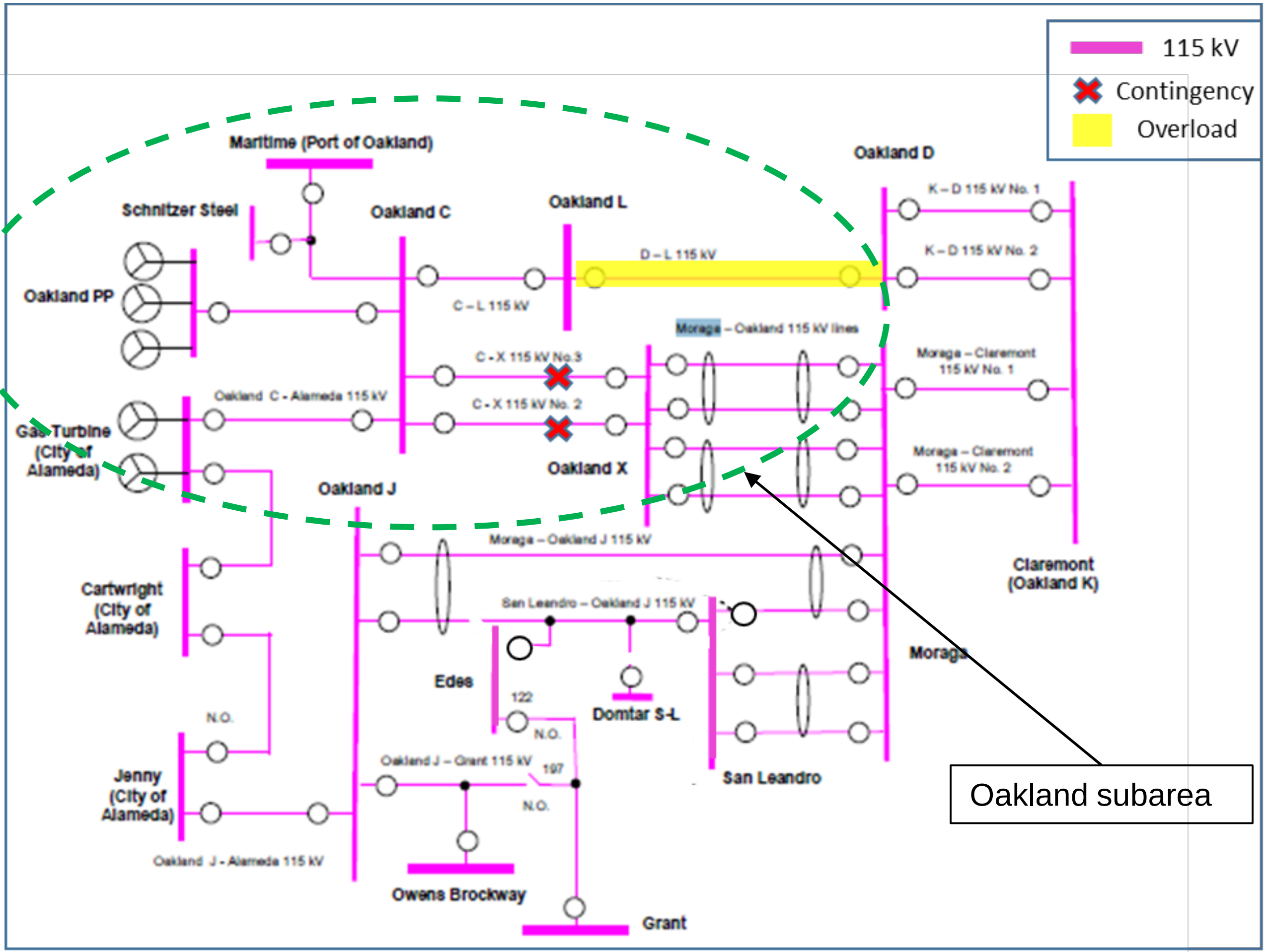
Note[1]: LCR reduction benefits are calculated using financial parameters and benefit of local capacity requirement reductions values provided in Section 4.3 of the 2018-2019 ISO Transmission Plan.

Oakland Subarea: Load and Resources (2028)

Load (MW)	2028	Generation (MW)	2028
Gross Load	208[1]	Market	165
AAEE	-14.7	Wind	0
Behind the meter DG	-6.1	Muni	48
Net Load	**187**	QF	0
Transmission Losses	0	Future preferred resource and energy storage	15
Pumps	0	**Total Qualifying Capacity**	**228**
Load + Losses + Pumps	**187**		

Note[1]: Recent forecast shows significant increase in load in this pocket. As such, results presented here may not be consistent with the most recent forecast. The load forecast is under review.

Oakland Subarea: One-line diagram



Oakland Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First limit	B	None	None	No requirement
2028	First limit	C	Oakland D-L 115 kV cable	Oakland C-X #2 & #3 115 kV cables	29
Subsequent requirements (layers)					
2028	Second limit	C	Oakland C-X #2 115 kV cable	Oakland D-L & C-X #3 115 kV cables	28
With Operating solution - Load transfer following first contingency					
2028	First limit	C	Oakland D-L 115 kV cable	Oakland C-X #2 & #3 115 kV cables	7

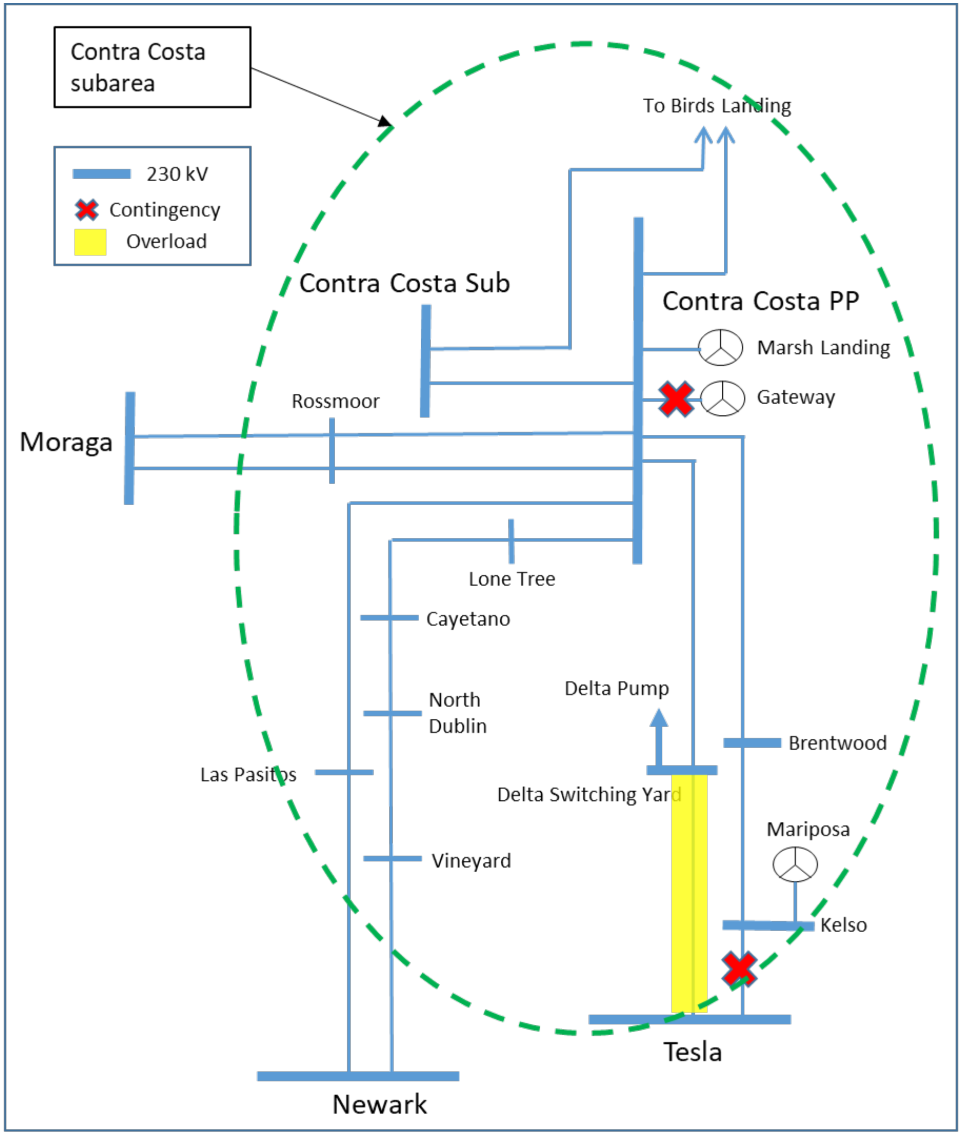
Oakland Subarea : Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
Status Quo	NA	NA	29	0	14	15
Operating solution - Load transfer following first contingency	NA	0	7	0	0	7

Contra Costa Subarea: Load and Resources

Load (MW)	2028	Generation (MW)	2028
Gross Load	**NA – Flow through area.**	Market	1748
AAEE		Wind	307
Behind the meter DG		Muni	127
Net Load		QF	0
Transmission Losses		Future preferred resource and energy storage	0
Pumps		**Total Qualifying Capacity**	**2,182**
Load + Losses + Pumps			

Contra Costa Subarea: One-line diagram



Contra Costa sub-area stand alone analysis

Contra Costa Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First limit	B	Delta Switching Yard-Tesla 230 kV Line	Kelso-Tesla 230 kV with the Gateway off line	1274
2028	First limit	Same as category B			
Subsequent requirements (layers)					
2028	Second limit	C	Kelso-Brentwood 230 kV Line	Delta Switching Yard-Tesla 230 kV Line with the Gateway off line	606
with Tesla-Delta Switch Yard 230 kV line reconductor					
2028	First limit	C	Kelso-Brentwood 230 kV Line	Delta Switching Yard-Tesla 230 kV Line with the Gateway off line	606
with Delta Reliability Energy Storage (75MW 4HR)					
2028	First limit	B	Delta Switching Yard-Tesla 230 kV Line	Kelso-Tesla 230 kV with the DRES off line	602

Contra Costa Subarea: Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
Status Quo	NA	NA	1274	1207	0	67
Tesla-Delta Switch Yard 230 kV line reconductor	ISO	30	606	299	0	307
Delta Reliability Energy Storage (75MW 4HR)	Tenaska	128-149	602	203	0	399

Contra Costa Subarea : LCR Reduction Benefits[1]

Tesla-Delta Switch Yard 230 kV line reconductor		
	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (Llagas Sub-area) (MW)	668	
Capacity value (per MW-year)	$1,560	$840
LCR Reduction Benefit ($million)	$1.04	$0.56
Local Capacity Benefits		
	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$1.04	$0.56
PV of LCR Savings ($million)	$14.38	$7.74
Capital Cost		
Capital Cost Estimate ($ million)	$30	
Estimated “Total” Cost (screening) ($million)	$39	
Benefit to Cost		
PV of Savings ($million)	$14.38	$7.74
Estimated “Total” Cost (screening) ($million)	$39	
Benefit to Cost	0.37	0.20

Note[1]: LCR reduction benefits are calculated using financial parameters and benefit of local capacity requirement reductions values provided in Section 4.3 of the 2018-2019 ISO Transmission Plan.

Contra Costa Subarea : LCR Reduction Benefits[1]

Delta Reliability Energy Storage (75MW 4HR)		
	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (Llagas Sub-area) (MW)	672	
Capacity value (per MW-year)	$1,560	$840
LCR Reduction Benefit ($million)	$1.05	$0.56
Local Capacity Benefits		
	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$1.05	$0.56
PV of LCR Savings ($million)	$14.47	$7.79
Capital Cost		
Capital Cost Estimate ($ million)	$149	
Estimated “Total” Cost (screening) ($million)	$193.7	
Benefit to Cost		
PV of Savings ($million)	$14.47	$7.79
Estimated “Total” Cost (screening) ($million)	$193.7	
Benefit to Cost	0.07	0.04

Note[1]: LCR reduction benefits are calculated using financial parameters and benefit of local capacity requirement reductions values provided in Section 4.3 of the 2018-2019 ISO Transmission Plan.

Contra Costa sub-area with gas-gen reduction in Llagas/San Jose/South Bay-Moss Landing and Pittsburg-Ames

Contra Costa Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First limit	B	Delta Switching Yard-Tesla 230 kV Line	Kelso-Tesla 230 kV with the Gateway off line	1274
2028	First limit	Same as category B			
with 4-terminal DC (2000-350-300-1350), 500 MVAR Reactive Support at Metcalf, E-4949 (ES forced), Collinsville 500 kV substation, Moraga-Claremont and Moraga-Sobrante 115 kV lines upgrade and 600 MW storage in Peninsula (or 600 MW HVDC from Pittsburg to Peninsula)					
2028	First limit	B	Delta Switching Yard-Tesla 230 kV Line	Kelso-Tesla 230 kV with the Highwinds off line	383
South Bay/Pittsburg upgrades + Tesla-Delta Switch Yard 230 kV line reconductor					
2028	First limit	C	Kelso-Brentwood 230 kV Line	Delta Switching Yard-Tesla 230 kV Line with the Gateway off line	210
South Bay/Pittsburg upgrades + Delta Reliability Energy Storage (75MW 4HR)					
2028	First limit	B	Delta Switching Yard-Tesla 230 kV Line	Kelso-Tesla 230 kV with the DRES off line	437

Contra Costa Subarea : Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
With 4-terminal DC (2000-350-300-1350), 500 MVAR Reactive Support at Metcalf, E-4949 (ES forced), Collinsville 500 kV substation, Moraga-Claremont and Moraga-Sobrante 115 kV lines upgrade and 600 MW storage in Peninsula (or 600 MW HVDC from Pittsburg to Peninsula)	ISO	>2,000	383	59	0	324
South Bay/Pittsburg upgrades + Tesla-Delta Switch Yard 230 kV line reconductor	ISO	>2,000	210	0	0	210
South Bay/Pittsburg upgrades + Delta Reliability Energy Storage (75MW 4HR)	Tenaska	>2,000	437	38	0	399

LCR reduction benefit evaluation not performed due to very high cost of mitigation.

Greater Bay Area Overall: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	11,576	Market Gas	5,940
AAEE	-653	Other Gas	482
Behind the meter DG	-309	Non-Gas	519
Net Load	**10,614**		
Transmission Losses	268	Future preferred resource and energy storage (Resolution E-4949)	567
Pumps	264	**Total Qualifying Capacity**	**7,508**
Load + Losses + Pumps	**11,146**		

Greater Bay Area Overall : Requirements

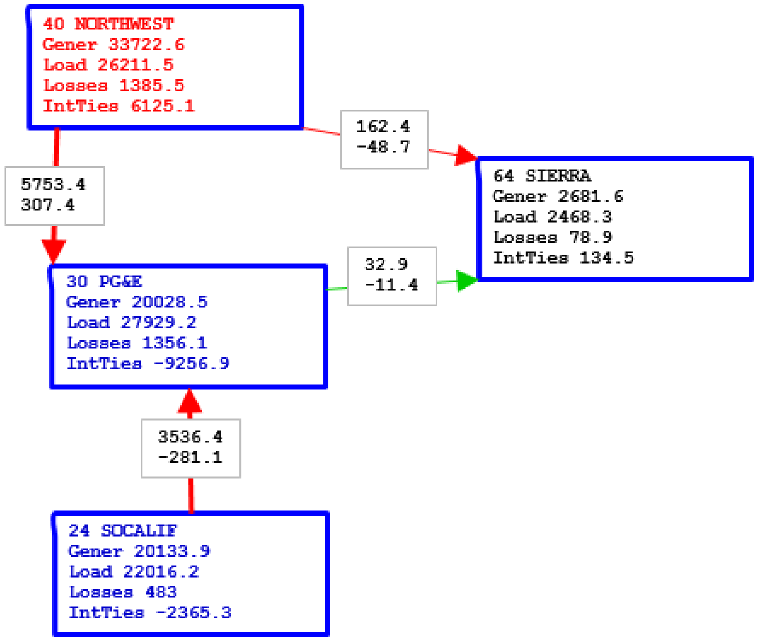
Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First limit	B	Reactive margin	Tesla-Metcalf 500 kV line & DEC unit	4795
2028	First limit	C	Aggregate of subareas		5600 (204)
With 4-terminal DC (2000-350-300-1350), 500 MVAR Reactive Support at Metcalf, E-4949 (ES forced), Collinsville 500 kV substation, Moraga-Claremont and Moraga-Sobrante 115 kV lines upgrade, 600 MW storage in Peninsula (or 600 MW HVDC from Pittsburg to Peninsula) and Delta Switching Yard-Tesla 230 kV line upgrade.					
2028	First limit	A	Reactive margin		TBD (depends on reactive capabilities of storage and HVDC solutions)
2028	First limit	C	Thermal overload of Moss Landing-Las Aguilas 230 kV	Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV	1985

Greater Bay Area Overall : Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
Status Quo	NA	NA	5600	5033	488	79
With 4-terminal DC (2000-350-300-1350), 500 MVAR Reactive Support at Metcalf, E-4949 (ES forced), Collinsville 500 kV substation, Moraga-Claremont and Moraga-Sobrante 115 kV lines upgrade, 600 MW storage in Peninsula (or 600 MW HVDC from Pittsburg to Peninsula) and Delta Switching Yard-Tesla 230 kV line upgrade.	PGE, ISO	>2,000	1985	0	630	1230

LCR reduction benefit evaluation not performed due to very high cost of mitigation.

2028 Basecase w\o GBA market gas generation: Area 30 imports, bulk system overloads and area voltages.



Basecase overloads

Facility	%Loading
Table Mt.-Vaca Dixon 500 kV line	132
Round Mt.-Table Mt. 500 kV line	104
Malin-Round Mt. 500 kV line	103
Quinto_SS – Los Banos 230 kV line	118

Local Capacity Requirements Potential Reduction Study

Fresno Area

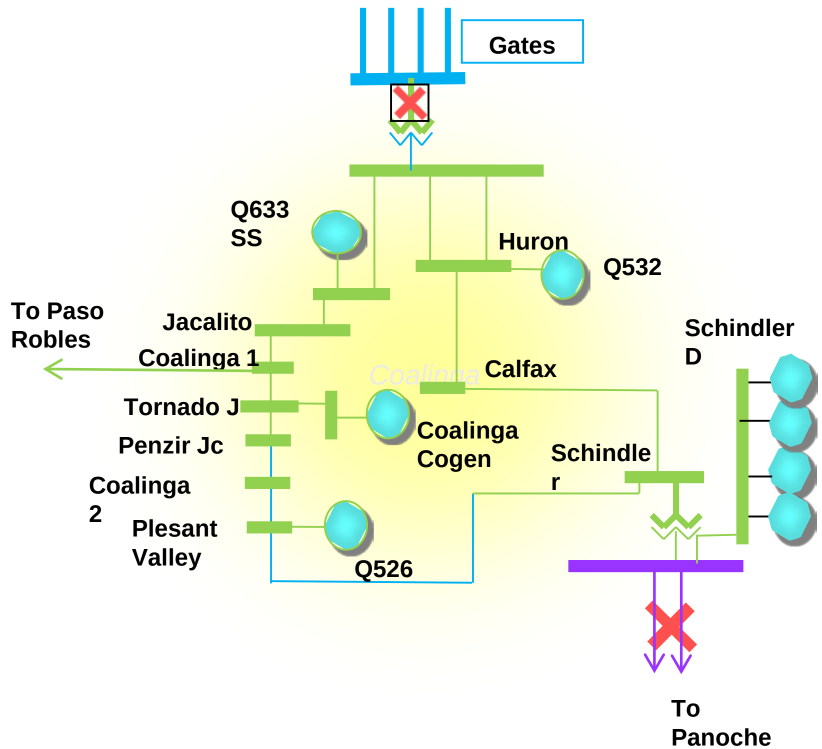
Vera Hart

Sr. Regional Transmission Engineer

Coalinga Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	90.8	Market Gas	37.3
AAEE	-7.1	Other Gas	0
Behind the meter DG		Non-Gas	8.2
Net Load	**83.7**		
Transmission Losses	1.6		
Pumps	0	**Total Qualifying Capacity**	**45.5**
Load + Losses + Pumps	**85.3**		

Coalinga Sub-Area



California ISO

Coalinga Sub-Area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2028	First Limit	P1-P7	Voltage Instability	T-1/L-2: Gates 230/70kV TB #5 and Panoche-Schindler #1 & #2 115kV common tower lines	17
2028	Second Limit	P1-P7	Coalinga-San Miguel 70kV Line	T-1/L-2: Gates 230/70kV TB #5 and Panoche-Schindler #1 & #2 115kV common tower lines	13
2028	Third Limit	P1-P7	Coalinga1-Coalinga 2 70kV line	T-1/L-2: Gates 230/70kV TB #5 and Panoche-Schindler #1 & #2 115kV common tower lines	13
Add a 25MVAR Capacitor at Coalinga 70kV Sub					
2028	Second Limit	P1-P7	Coalinga-San Miguel 70kV Line	T-1/L-2: Gates 230/70kV TB #5 and Panoche-Schindler #1 & #2 115kV common tower lines	13
2028	Third Limit	P1-P7	Coalinga1-Coalinga 2 70kV line	T-1/L-2: Gates 230/70kV TB #5 and Panoche-Schindler #1 & #2 115kV common tower lines	13
Add a Second Transformer Bank at Gates 230/70kV TB #6					
2028	Worst limit	C	None	None	0

Coalinga Subarea : Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Solar
Status Quo	NA	NA	17	9	0	8
25 MVAR Capacitor at Coalinga 70kV	CAISO	~$7-$10	13	5	0	8
New Gates 230/70kV TB #6	CAISO	$44	0	0	0	0

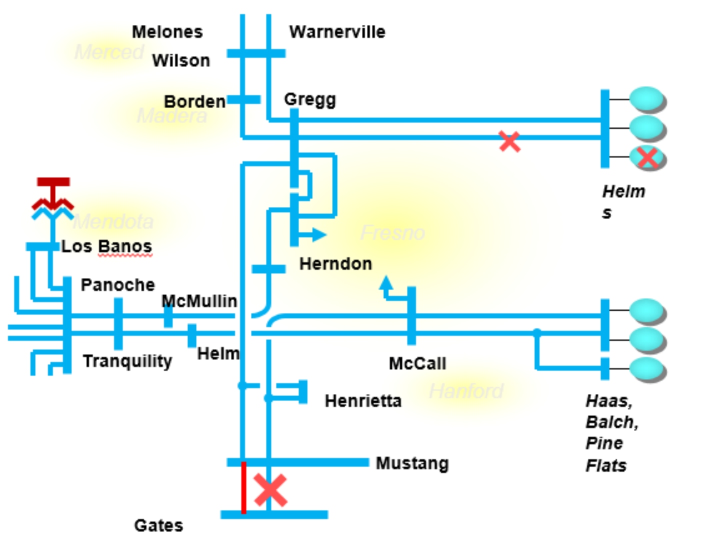
Coalinga Subarea : LCR Reduction Benefits[1]

Add new Gates 230/70kV TB #6		
	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (Coalinga Sub-area) (MW)	17	
Capacity value (per MW-year)	$2,160	$1,440
LCR Reduction Benefit ($million)	$0.04	$0.02
Local Capacity Benefits		
	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.04	$0.02
PV of LCR Savings ($million)	$0.51	$0.34
Capital Cost		
Capital Cost Estimate ($ million)	$44.0	
Estimated “Total” Cost (screening) ($million)	$57.2	
Benefit to Cost		
PV of Savings ($million)	$0.51	$0.34
Estimated “Total” Cost (screening) ($million)	$57.20	
Benefit to Cost	0.01	0.01

Note[1]: LCR reduction benefits are calculated using financial parameters and benefit of local capacity requirement reductions values provided in Section 4.3 of the 2018-2019 ISO Transmission Plan.

Overall Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	3617	Market Gas	810
AAEE	-227	Other Gas	0
Behind the meter DG	-3	Non-Gas	2426
Net Load	**3387**		
Transmission Losses	109	Solar	1465
Pumps	0	**Total Qualifying Capacity**	**4701**
Load + Losses + Pumps	**3496**		



California ISO

Overall Fresno Sub Area : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2028	First limit	P3	Remaining Gates-Mustang 230kV line	Gates-Mustang 230kV #1 or #2 line and one Helms unit out	1628
2028	First limit	P6	Remaining Gates-Mustang 230kV line	Gates-Mustang 230kV #1 or #2 line and Helms-Gregg 230kV line	1728

Overall Subarea : Potential LCR Reduction Alternatives

Alternatives	**Submitted By**	**Estimated Cost ($M)**	**Requirement (MW)**				
			Total	Market Gas	Other Gas	Solar	Other non Gas non Solar
Status Quo	NA	NA	1728	0	0	0	1728

No LCR Reduction proposed as there is enough non-gas (mainly hydro) generation to meet the requirement.

Local Capacity Requirements Potential Reduction Study

Humboldt Area

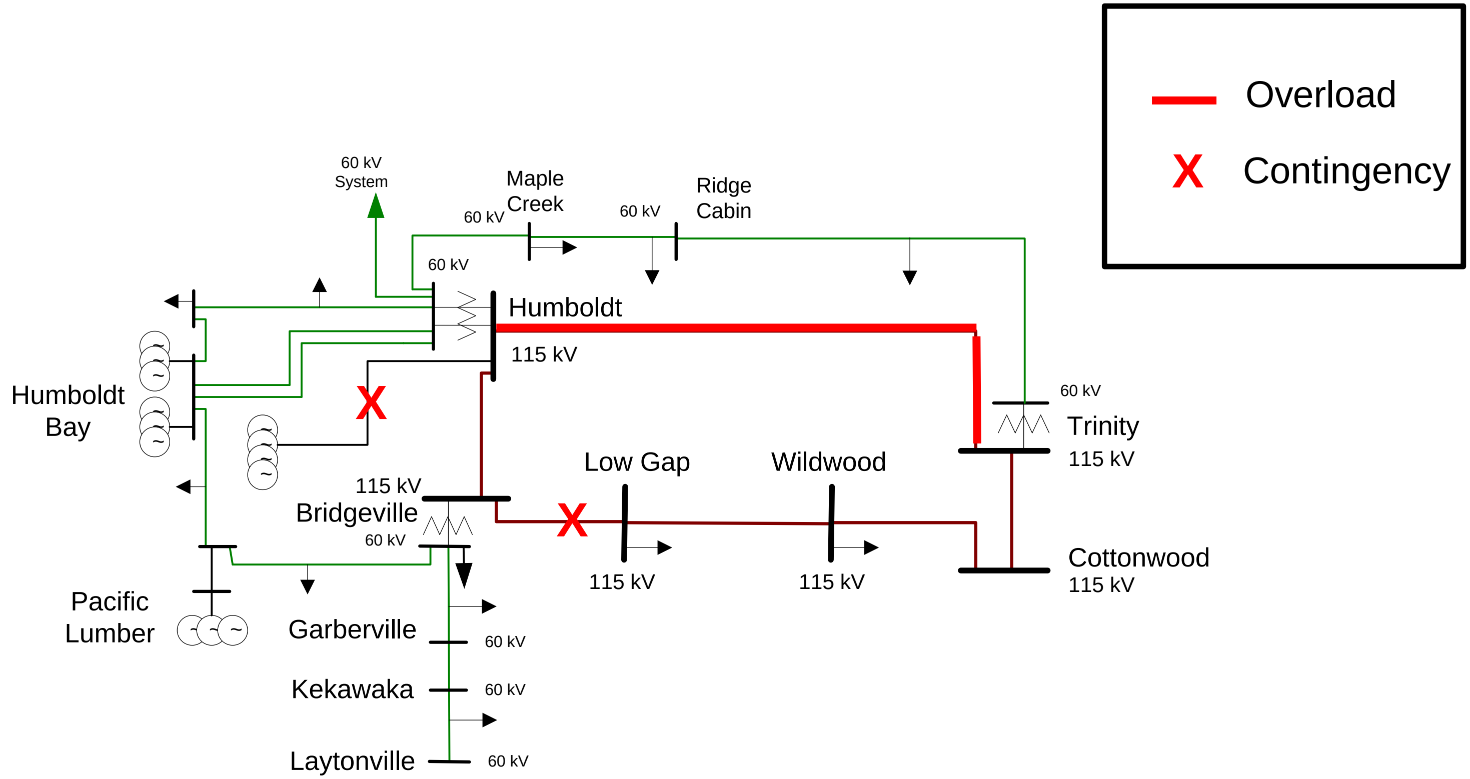
Lindsey Thomas

Regional Transmission Engineer

Overall Humboldt: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	183	Market	201
AAEE	-9	Wind	0
Behind the meter DG	0	Muni	0
Net Load	**174**	QF	0
Transmission Losses	11	**Total Qualifying Capacity**	**201**
Pumps	0		
Load + Losses + Pumps	**185**		

Overall Sub-Area Requirements



Overall Humboldt Sub Area : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2028	First Limit	B	Thermal overload of Humboldt-Trinity 115 kV	Cottonwood-Bridgeville 115kV line with one of the Humboldt Bay units already out of service.	117
2028	First Limit	C	Thermal overload of Humboldt-Trinity 115 kV	Cottonwood-Bridgeville and Humboldt - Humboldt Bay 115kV line.	170

Humboldt Subarea: Requirements & Proposed Mitigations

Build New Humboldt-Trinity 115kV line		
	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (Humboldt Sub-area) (MW)	170	
Capacity value (per MW-year)	$2,160	$1,440
LCR Reduction Benefit ($million)	$0.37	$0.24
Local Capacity Benefits		
	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.37	$0.24
PV of LCR Savings ($million)	$5.07	$3.38
Capital Cost		
Capital Cost Estimate ($ million)	$318.0	
Estimated “Total” Cost (screening) ($million)	$413.4	
Benefit to Cost		
PV of Savings ($million)	$5.07	$3.38
Estimated “Total” Cost (screening) ($million)	$413.40	
Benefit to Cost	0.01	0.01

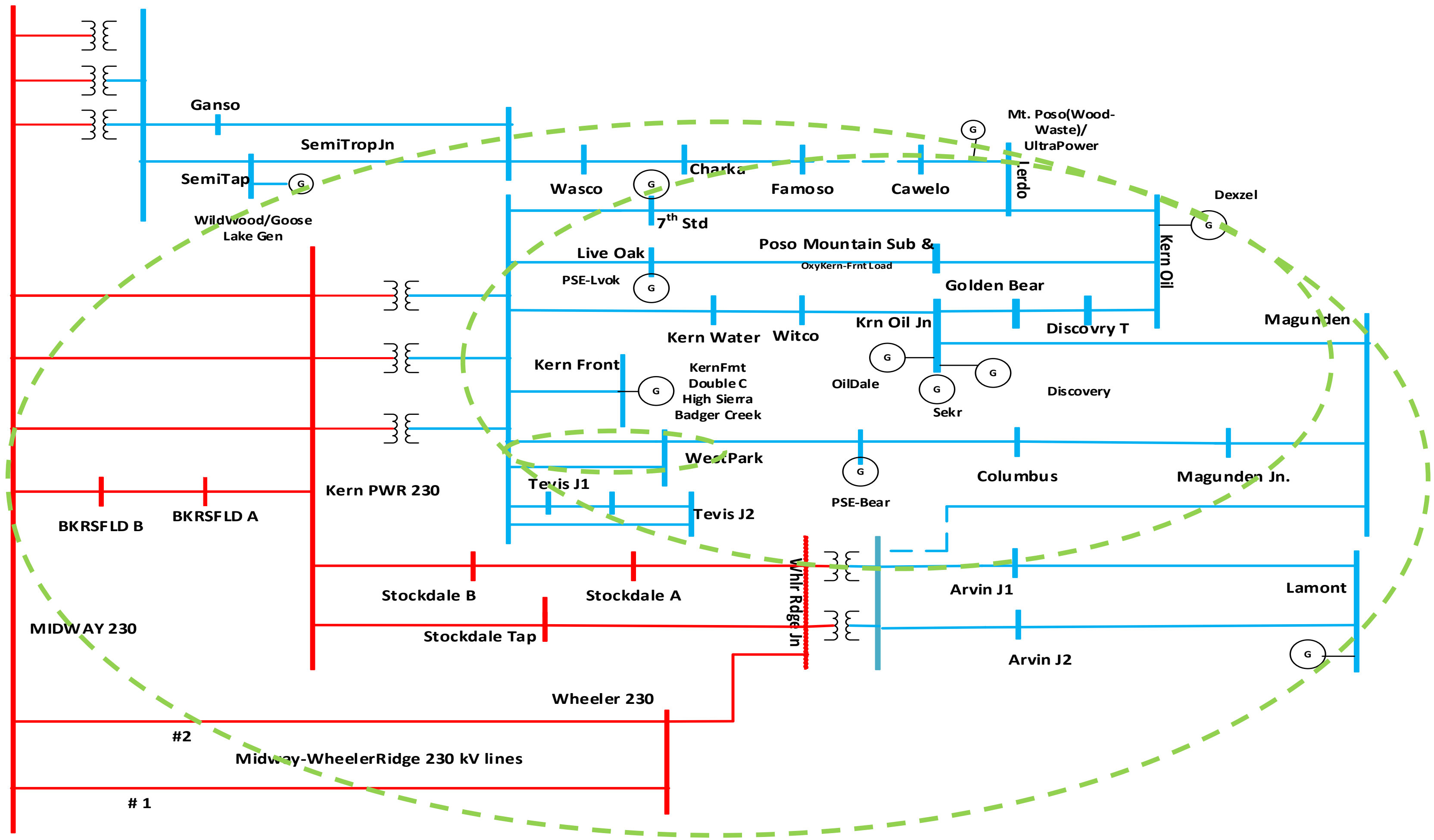
Local Capacity Requirements Potential Reduction Study

Kern Area

Abhishek Singh

Regional Transmission Engineer Lead

Kern-2028 LCR Area



South Kern Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	1468	Market Gas	301
AAEE	-88	Non Gas	161
Behind the meter DG	0	Other Gas	13
Net Load	**1380**	**Total Qualifying Capacity**	**475**
Transmission Losses	13		
Pumps	0		
Load + Losses + Pumps	**1393**		

South Kern Subarea: Requirements & Proposed Mitigations

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2028	First Limit	C	Midway-Kern PP # 4 230 kV line	Midway-Kern PP # 1 & Midway-Kern PP # 3 230 kV	80

South Kern Sub Area : Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
SPS to Drop 75 MW of Load at Stockdale A substation for the loss of any combination of Midway –Kern PP 230 kV lines (1,3&4)	ISO	5-10	0	0	0	0

South Kern Subarea: LCR Reduction BCR calculation

SPS to Drop 75 MW of Load at Stockdale A substation for the loss of any combination of Midway –Kern PP 230 kV lines		
	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (South Kern Sub-area) (MW)	80	
Capacity value (per MW-year)	$2,160	$1,440
LCR Reduction Benefit ($million)	$0.17	$0.12
Local Capacity Benefits		
	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.17	$0.12
PV of LCR Savings ($million)	$2.38	$1.59
Capital Cost		
Capital Cost Estimate ($ million)	$10.0	
Estimated “Total” Cost (screening) ($million)	$13.0	
Benefit to Cost		
PV of Savings ($million)	$2.38	$1.59
Estimated “Total” Cost (screening) ($million)	$13.00	
Benefit to Cost	0.18	0.12

Note[1]: LCR reduction benefits are calculated using financial parameters and benefits of local capacity requirement reductions values provided in Section 4.3 of the 2018-2019 ISO Transmission Plan.

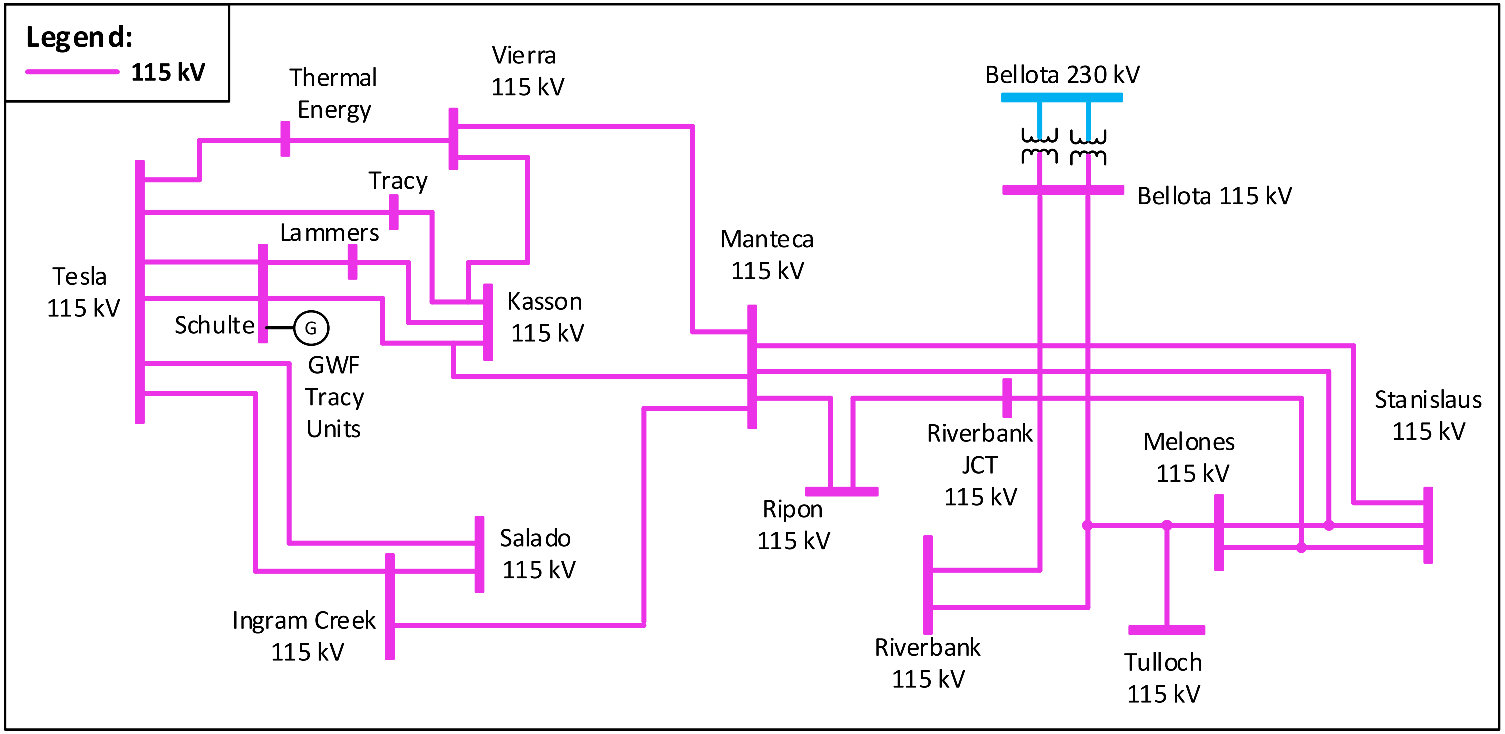
Local Capacity Requirements Potential Reduction Study

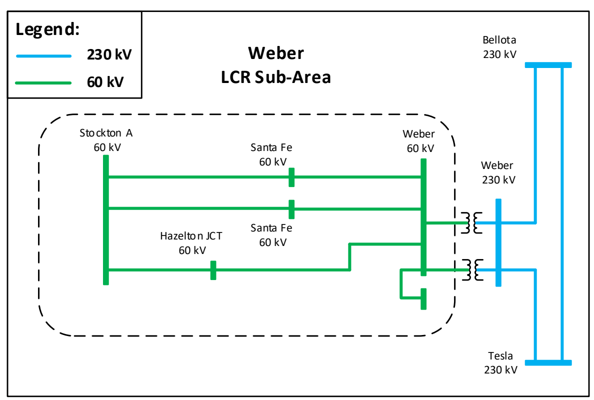
Stockton Area

Ebrahim Rahimi

Lead Regional Transmission Engineer

Stockton Area Transmission System & LCR Subareas

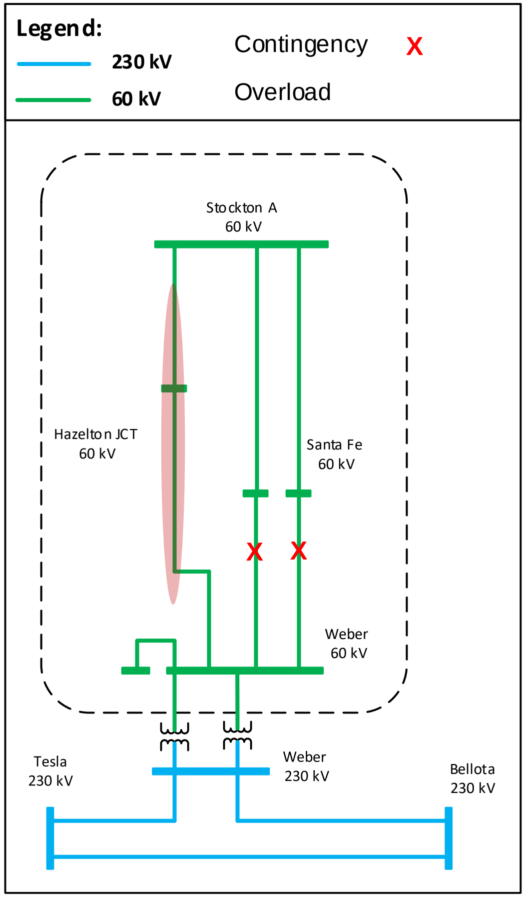




California ISO

Weber Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	270	Market Gas	0
AAEE	-16	Other Gas	0
Behind the meter DG	0	Non-Gas	44
Net Load	**253**		
Transmission Losses	2		
Pumps	0	**Total Qualifying Capacity**	**44**
Load + Losses + Pumps	**256**		



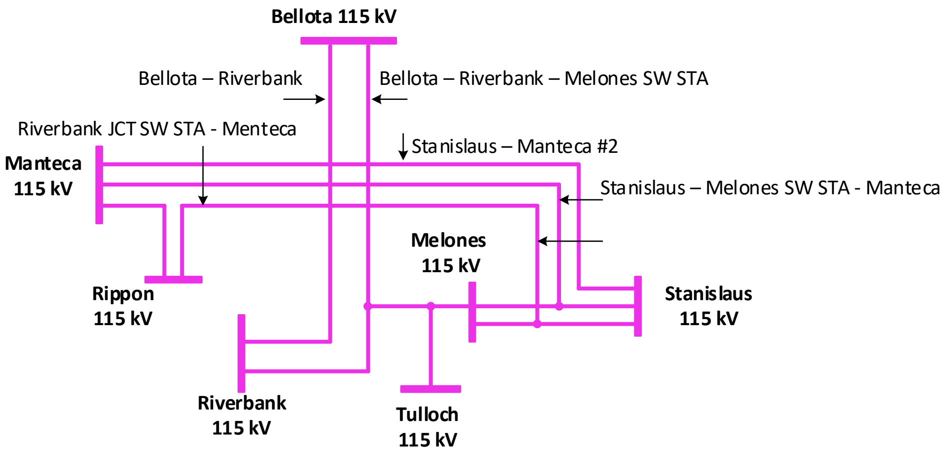
Weber Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First limit	B	None	None	No requirement
2028	First limit	C	Stockton A-Weber #3 60 kV	Stockton A-Weber #1 60 kV and Stockton A-Weber #2 60 kV	30
Subsequent requirements (layers)					
2028	Second limit	C	None	None	No requirement

- Due to the following factors no transmission alternatives were developed to reduce LCR requirements in the Weber subarea:
  - The 30 MW requirement for the area is supplied by biomass generation and there is no need for gas generation.
  - The limiting conditions is P6 contingency of non-bulk 60 kV elements overloading non-bulk 60 kV element which is beyond the scope of the new CAISO planning standards.

Stanislaus Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	247	Market Gas	0
AAEE	-17	Other Gas	0
Behind the meter DG	0	Non-Gas	218
Net Load	**230**		
Transmission Losses	8		
Pumps	0	**Total Qualifying Capacity**	**218**
Load + Losses + Pumps	**238**		



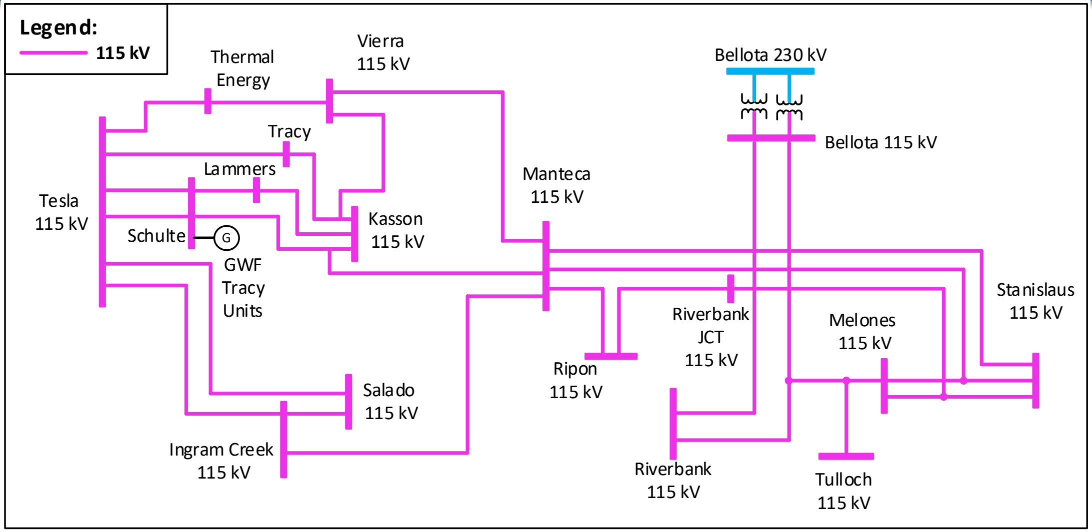
Stanislaus Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First limit	B	Rippon Jct. – Manteca 115 kV Line	Bellota-Riverbank-Melones 115 kV line and Stanislaus PH	174
2028	First limit	C	Same as B	Same as B	Same as B

- Since the 174 MW LCR requirement for the area could be supplied by hydro generation, no transmission alternatives were developed to reduce LCR requirements in the Stanislaus subarea.

Tesla – Bellota Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	933	Market Gas	365
AAEE	-55	Other Gas	0
Behind the meter DG	0	Non-Gas	248
Net Load	**878**		
Transmission Losses	19		
Pumps	0	**Total Qualifying Capacity**	**614**
Load + Losses + Pumps	**897**		



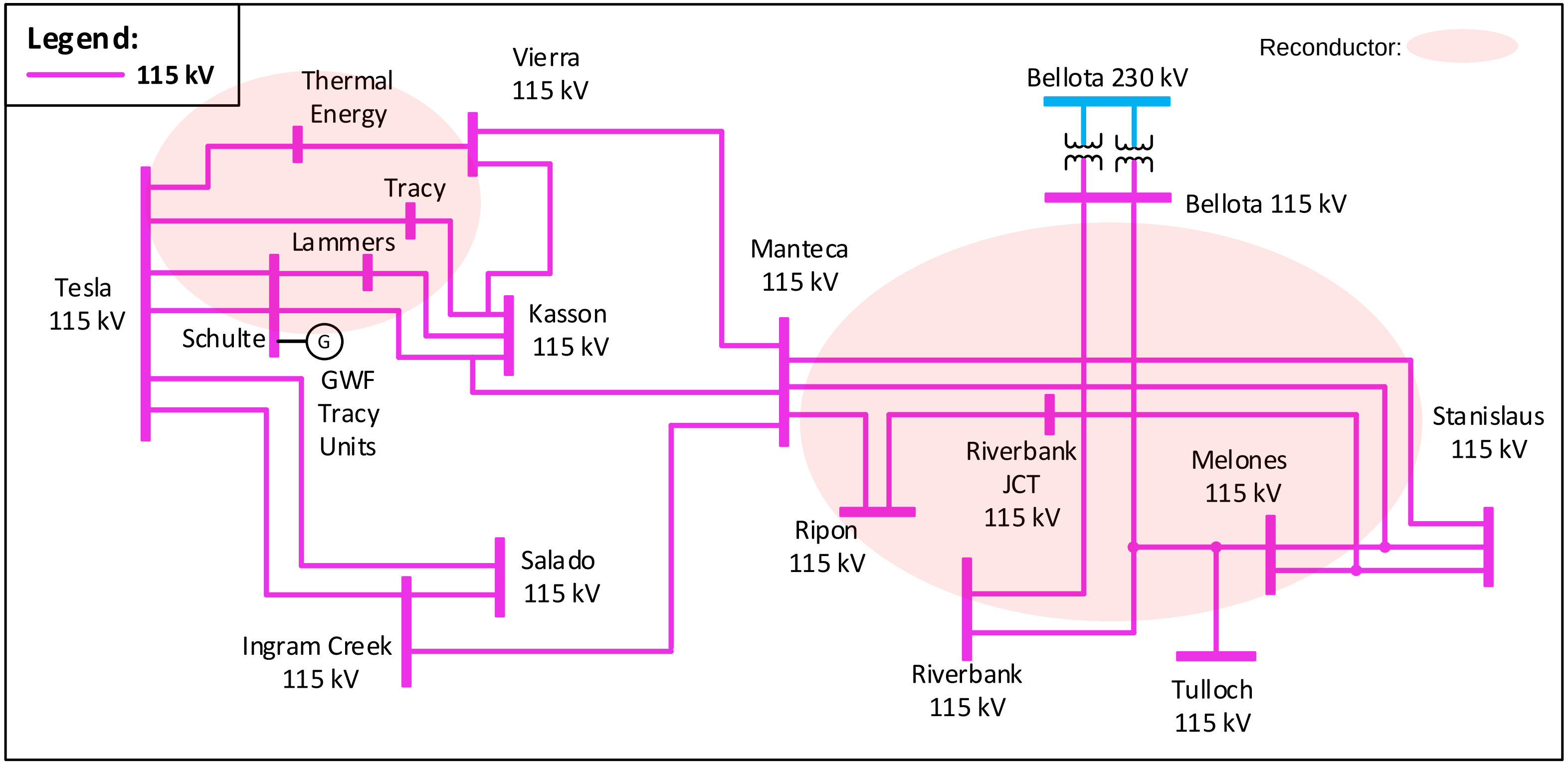
Tesla - Bellota Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First limit	B	Tesla – Tracy 115 kV	Tesla – Vierra 115 kV and GWF Tracy #3 unit	303
2028	First limit	C	Tesla – Tracy 115 kV	Schulte - Lammers115 kV and Schulte-Kasson-Manteca 115 kV	507 (213)
Subsequent requirements (layers)					
2028	Second limit	B	Tesla – Vierra 115 kV	Tesla – Tracy 115 kV and GWF Tracy #3 unit	291
2028	Second limit	C	Tesla – Vierra 115 kV	Schulte - Lammers115 kV and Schulte-Kasson-Manteca 115 kV	460 (167)
2028	Third limit	C	Tesla – Schulte #2 115 kV	Tesla – Vierra 115 kV and Tesla – Schulte #1 115 kV	247
Alternative 1: Reconductor 115 kV lines in the Tesla – Bellota Subarea					
2028	First limit	C	Melones – Melones JB 115 kV	Schulte – Kasson - Manteca and Stanislaus – Riverbank – Manteca 115 kV lines	143
Alternative 2: Weber – Manteca 230 kV Project + Reconductoring					
2028	First limit	C	Tesla – Tracy 115 kV	Schulte – Kasson - Manteca and Schulte – Lammers 115 kV lines	146
Alternative 3: Westside – Kasson 230 kV Project + Reconductoring					
2028	First limit	C	Manteca – Ripon 115 kV	Schulte – Kasson - Manteca and Stanislaus – Melones - Riverbank 115 kV lines	222

Tesla - Bellota Subarea : Potential LCR Reduction Alternatives (1/2)

Alternative 1: Reconductor overloaded lines

- Number of lines in the Tesla to Manteca area (~50mi) and Stanislaus to Manteca area (~150mi) should be reconductored

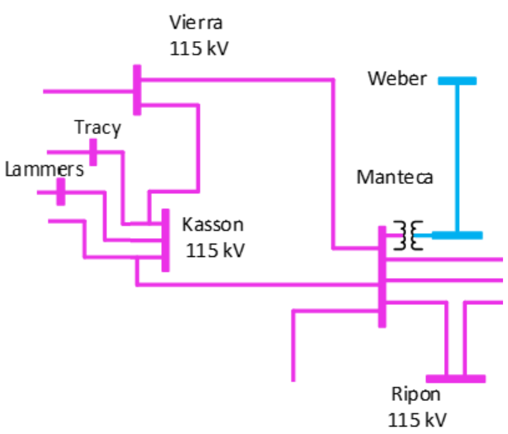


Tesla - Bellota Subarea :
Potential LCR Reduction Alternatives

Alternative 2: Weber – Manteca 230 kV Project + Reconductoring

- In addition to the Weber – Manteca 230 kV project, number of lines in the Tesla to Manteca area (~25mi) and Stanislaus to Manteca area (~100mi) should be reconductored

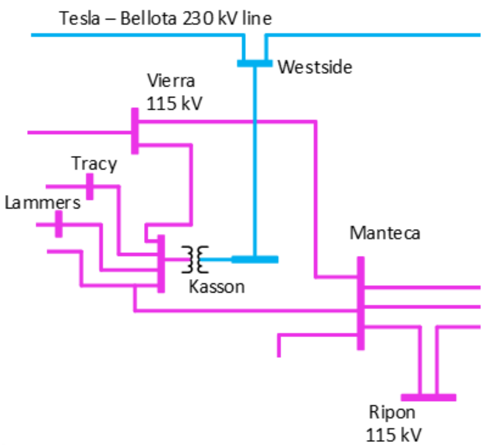
Weber – Manteca 230 kV



Alternative 3: Westside – Kasson 230 kV Project + Reconductoring

- In addition to the Westside – Kasson 230 kV project number of lines in the Stanislaus to Manteca area (~75mi) should be reconductored

Westside - Kasson 230 kV



Tesla - Bellota Subarea : Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
Status Quo	NA	NA	613	365	0	248
Reconductor the overloaded 115 kV Lines (around 200 mi)	ISO	$143M	143	0	0	143
Weber – Manteca 230 kV Project + Reconductor around 125 mi lines	Horizon West	$35M + $117M = $152M	146	0	0	146
Westside – Kasson 230 kV Project + Reconductor around 75 mi lines	ISO	$117M	222	0	0	222

Tesla - Bellota Subarea : LCR Reduction Benefits[1]

	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (Tesla-Bellota Sub-area) (MW)	365	
Capacity value (per MW-year)	$2,160	$1,440
LCR Reduction Benefit ($million)	$0.79	$0.53
Local Capacity Benefits		
	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.79	$0.53
PV of LCR Savings ($million)	$10.88	$7.25
Capital Cost		
Capital Cost Estimate ($ million)	$117 (minimum of the cost estimates)	
Estimated “Total” Cost (screening) ($million)	$152	
Benefit to Cost		
PV of Savings ($million)	$10.88	$7.25
Estimated “Total” Cost (screening) ($million)	$152	
Benefit to Cost	0.07	0.05

Note[1]: LCR reduction benefits are calculated using financial parameters and benefits of local capacity requirement reductions values provided in Section 4.3 of the 2018-2019 ISO Transmission Plan.

LCR Reduction Assessment
Big Creek–Ventura Area and Santa Clara Sub-area

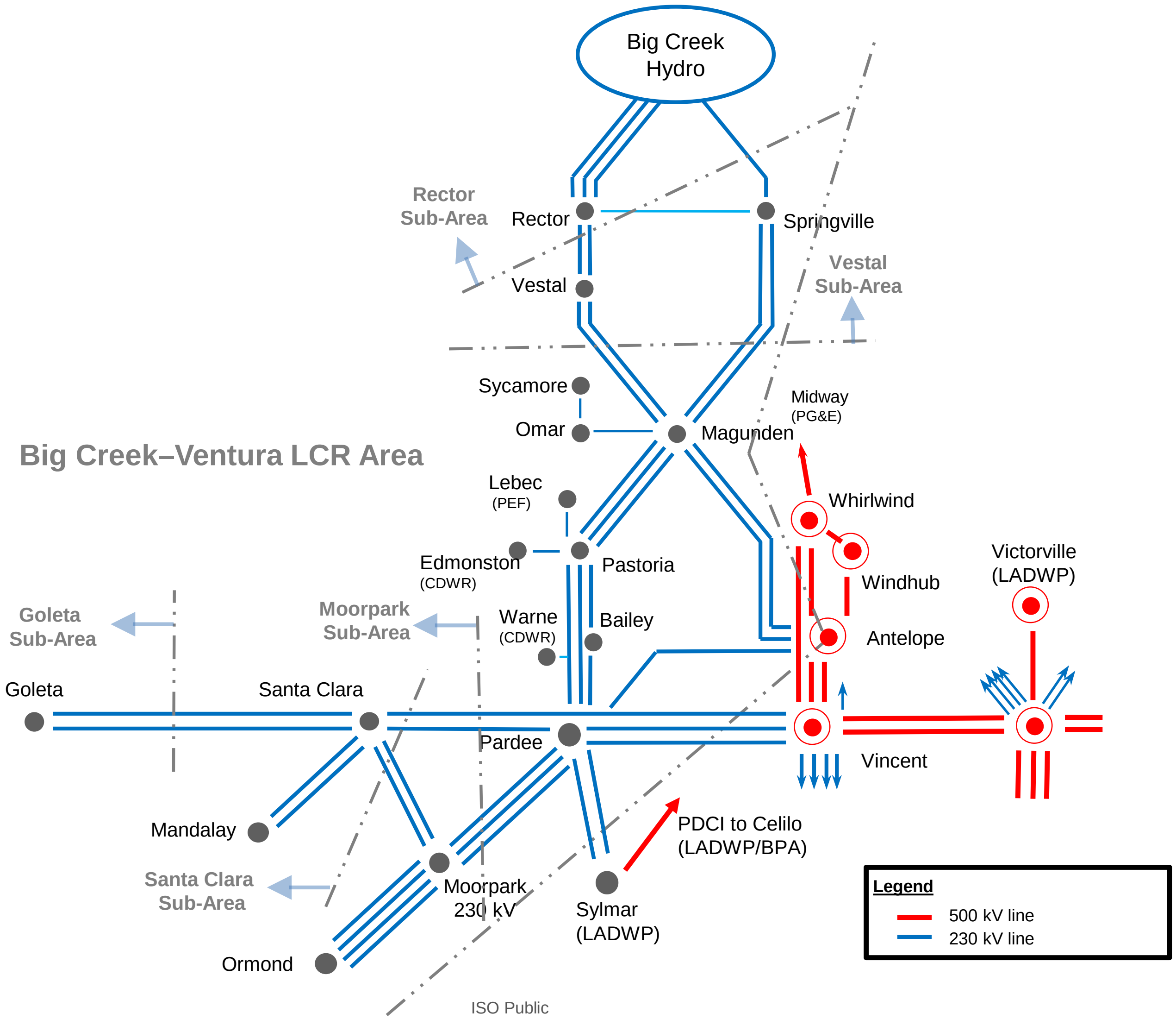
Nebiyu Yimer

Regional Transmission Engineer Lead

2019-2020 Transmission Planning Process Stakeholder Meeting

November 18, 2019

Big Creek–Ventura Area Transmission System



Big Creek–Ventura Area Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	5456	Market	2975
AAEE	-301	Pref. Res & ES	112
Behind the meter DG	-609	Muni	372
Net Load	**4547**	QF	52
Transmission Losses	105	**Total Qualifying Capacity**	**3511**
Pumps	379		
Load + Losses + Pumps	**5031**		

2028 Gas-fired Generation Local Capacity Requirements

Sub-Area	2028 LCR (MW)	2028 Resource Capacity (MW, NQC)			2028 Gas-fired Generation Local Capacity Requirement	
		Total	Non Gas-fired	Gas-fired	MW	Percent of Gas
Rector	N/A	1,028	1,028	0	0	0%
Vestal	465	1,205	1,151	54	0	0%
Goleta	42+	7	7(35)	0	0	0%
Santa Clara	318	199	15(119)	184	184	100%
Moorpark	0	223	39	184	0	0%
Overall Big Creek Ventura	2251	3511	1815	1696	436	26%

(1) Values in parenthesis indicate deficiency to be filled by ongoing SCE RFP

(2) 2028 resource capacity values exclude Ellwood (54 MW) and Ormond Beach (1491 MW)

LCR Reduction Alternatives Considered

1. Pardee-Sylmar No. 1 and No. 2 230 kV Line Rating Increase Project
   - Upgrade terminal equipment at Pardee and Sylmar to increase the rating of the lines to 1287/1737 MVA (145% increase in emergency ratings)
   - Project cost - $15.4 million, proposed ISD - May 2025
   - Submitted by SCE

2. Pacific Transmission Expansion (PTE) HVDC Project
   - The 2000 MW HVDC project will have a northern terminal at Diablo and three southern terminals including a 500 MW VSC terminal in the BCV Area (Goleta substation)
   - Project cost - $1,850 million, proposed ISD Dec. 2026
   - Submitted by Western Grid Development LLC

LCR Reduction Alternatives Considered – Cont'd

3. <u>Santa Clara Area Upgrades</u>
   - Install a 79 MVAR, 230 kV shunt capacitor at Goleta
   - Raise multiple towers and upgrade terminal equipment on Santa-Clara Vincent, Santa Clara-Pardee, and Santa Clara-Moorpark No.1 & 2 230kV lines to achieve ratings of 494 MVA (normal)/665 MVA (emergency) – up to 135% increase in emergency ratings
   - Total cost - $ 12.3 million
     - Shunt capacitor - $3.3 million
     - Line rating upgrades - $9.0 million
   - ISD – 4 years from approval (April 2024)
   - Alternative identified by CAISO

LCR Assessment Results

Area/Sub-area	Category	Limiting Facility	Contingency	LCR (MW)
Status Quo				
BCV	C	Sylmar-Pardee #1 or #2 230 kV line	Lugo–Victorville 500 kV line and one Sylmar–Pardee 230 kV line	2,251
Santa Clara	D	Voltage collapse	Pardee–Santa Clara 230 kV and Moorpark–Santa Clara 230 kV DCTL	318
1. Pardee-Sylmar Line Rating Increase Project				
BCV	C	Antelope 500/230 kV #1 or #2 transformer	PDCI Monopole and one Antelope 500/230 kV Tr.	1,414
Santa Clara	Same as Status Quo			
2. Pacific Transmission Expansion (PTE) HVDC Project				
BCV	C	Sylmar–Pardee #1 or #2 230 kV line	Lugo–Victorville 500 kV and one Sylmar–Pardee 230 kV line	1,858
Santa Clara/Goleta	C	Low Goleta 230 kV voltage	PTE and Santa Clara Goleta 230 kV	70
3. Santa Clara Area Upgrades				
BCV	Same as Status Quo			
Santa Clara	D	Voltage collapse	Pardee–Santa Clara 230 kV and Moorpark–Santa Clara 230 kV DCTL	270

Potential LCR Reduction - Pardee-Sylmar 230 kV Project

Alternatives	Capacity (MW)		
	Total	Non-Gas	Gas
Status Quo			
Overall BCV LCR Requirement	2,251	1,815	436
Santa Clara LCR Requirement	318	15 (119)[1]	184
Pardee-Sylmar 230 kV Project			
Overall BCV LCR Requirement	1,414	1,230	184[2]
Reduction	837	585	252
Santa Clara LCR Requirement	318	15 (119)[1]	184
Reduction	0	0	0

(1) Values in parenthesis indicate deficiency to be filled by ongoing SCE RFP

(2) The Pardee-Sylmar 230 kV Rating Increase Project eliminates need for gas fired-generation in the greater BCV area. However, the 184 MW of existing gas-fired resources located in the Santa Clara Sub-area will continue to be needed to meet the sub-area need.

Potential LCR Reduction – PTE Project

Alternatives	Capacity (MW)		
	Total	Non-Gas	Gas
Status Quo			
Overall BCV LCR Requirement	2,251	1815	436
Santa Clara LCR Requirement	318	15(119)[1]	184
Santa Clara Area Upgrades			
Overall BCV LCR Requirement	1,858	1,815	43
Reduction	393	0	393
Santa Clara LCR Requirement	70	15 (55) [1]	0
Reduction	248	64	184

(1) Values in parenthesis indicate deficiency to be filled by ongoing SCE RFP

Potential LCR Reduction – Santa Clara Area Upgrades

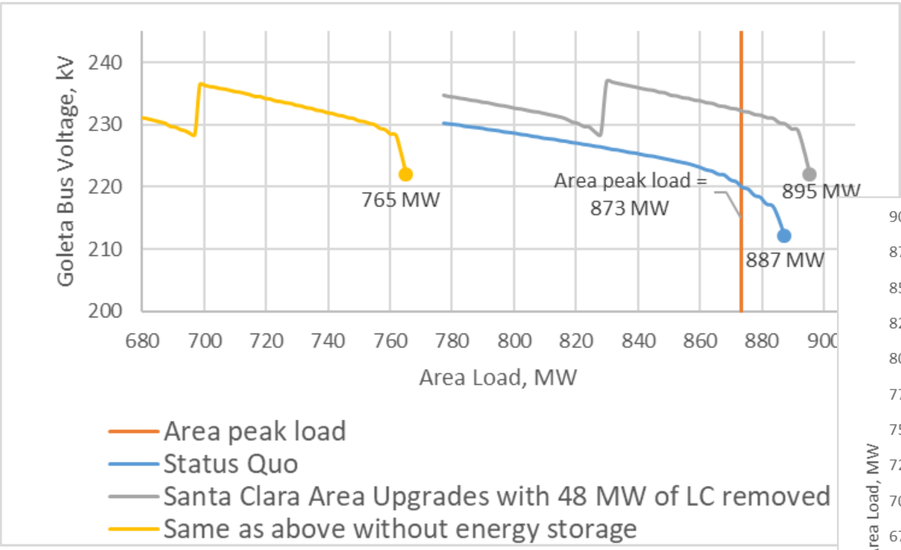
Alternatives	Capacity (MW)		
	Total	Non-Gas	Gas
Status Quo			
Overall BCV LCR Requirement	2,251	1815	436
Santa Clara LCR Requirement	318	15(119)[1]	184
Pacific Transmission Expansion (PTE)			
Overall BCV LCR Requirement	2,251	1815	436
Reduction	0	0	0
Santa Clara LCR Requirement	270	15 (119) [1]	136
Reduction	48	0	48

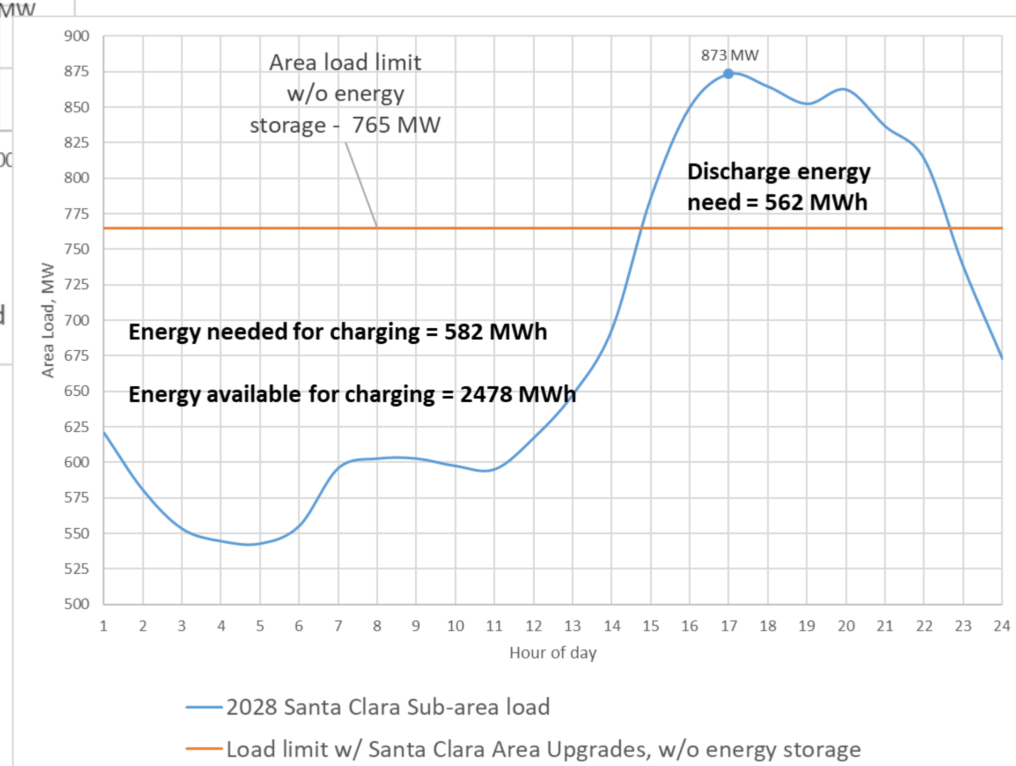
(1) Values in parenthesis indicate deficiency to be filled by ongoing SCE RFP

SCE Santa Clara RFP Results (CPUC approval pending)

Project	Technology	Capacity (MW)	Duration (Hour)	Connection	Online Date
Swell SC	Lithium Ion Batteries	14.0	4.0	Santa Clara 66 kV	1/1/2021
Strata Saticoy	Lithium Ion Batteries	100.0	4.0	Santa Clara 66 kV	12/1/2020
Ormat Vallecito	Lithium Ion Batteries	10.0	4.0	Goleta 66 kV	12/1/2020
AltaGas Goleta	Lithium Ion Batteries	40.0	4.0	Goleta 66 kV	12/1/2020
EGP Hollister	Lithium Ion Batteries	10.0	4.0	Goleta 66 kV	3/1/2021
Painter	Lithium Ion Batteries	10.0	4.0	Goleta 66 kV	3/1/2021
Silverstrand	Lithium Ion Batteries	11.0	4.0	Santa Clara 66 kV	3/1/2021

Analysis to assess whether the Santa Clara Area Upgrade alternative allows procured energy storage resources to discharge and charge





LCR Reduction Benefits – Pardee–Sylmar Project[1]

	Local versus System Capacity	Local versus SP26 Capacity
LCR capacity reduction (MW)	837	
Capacity value (per MW-year)	$16,320	$22,320
Local Capacity Benefits		
LCR Savings ($million/year)	$13.7	$18.7
PV of LCR Savings ($million)	$182	$249
Capital Cost		
Capital Cost ($ million)	$15.4	
PV Revenue Req. ($ million)	$20.0	
Benefit to Cost Ratio		
Benefit to Cost Ratio	**9.1**	**12.4**
Benefit of Advancing ISD		
NPV of Advancing ISD by 2 Years	$20.5 ($ million)	$29.0 ($ million)

Note[1]: LCR reduction benefits are calculated using the methodology and financial parameters provided in Section 4.3 of the 2018-2019 ISO Transmission Plan.

LCR Reduction Benefits of Pacific Transmission Expansion (PTE) in the Big Creek Ventura Area[1]

	Local versus System Capacity	Local versus SP26 Capacity
LCR capacity reduction (MW)	393	
Capacity value (per MW-year)	16,320	$22,320
Local Capacity Benefits		
LCR Savings ($million/year)	$6.4	$8.8
PV of LCR Savings ($million)	$88.5	$121.0
Capital Cost		
Capital Cost ($ million)	$1,850	
PV Revenue Req. ($ million)	$2,405	
Benefit to Cost Ratio		
Benefit to Cost Ratio	BCR values for PTE are calculated taking into account its LCR reduction benefits in the LA Basin Area. See presentation for El Nido and Western LA Basin sub-areas	

Note[1]: LCR reduction benefits are calculated using the methodology and financial parameters provided in Section 4.3 of the 2018-2019 ISO Transmission Plan.

LCR Reduction Benefits – Santa Clara Area Upgrades[1]

	Local versus System Capacity	Local versus SP26 Capacity
LCR capacity reduction (MW)	0	
Capacity value (per MW-year)	$16,320	$22,320
Local Capacity Benefits		
LCR Savings ($million/year)	$0	$0
PV of LCR Savings ($million)	$0	$0
Capital Cost		
Capital Cost ($ million)	$12.3	
PV Revenue Req. ($ million)	$16.0	
Benefit to Cost Ratio		
Benefit to Cost Ratio	**0**	**0**

Note[1]: LCR reduction benefits are calculated using the methodology and financial parameters provided in Section 4.3 of the 2018-2019 ISO Transmission Plan.

- LCR reduction benefit is zero because the LCR for the greater BCV area remains unchanged. Sub-area versus area local capacity cost differential data is not available

Conclusion

- Three alternatives were evaluated to reduce local capacity in the Big Creek-Ventura and/or Santa Clara Sub-area
- The Pardee–Sylmar 230 kV reliability project results in approximately 837 MW of LCR reduction and a BCR of 9.1–12.4
- The Pacific Transmission Expansion (PTE) project reduces BCV area LCR by approximately 393 MW. BCR for the project is calculated in the presentation for El Nido and Western LA Basin sub-areas taking into account its LCR reduction benefits in those areas
- The Santa Clara Area Upgrades alternative reduces Santa Clara area LCR by approximately 48 MW but does not reduce that of the greater BCV area. Sub-area versus area local capacity cost differential data is not available

Local Capacity Requirements Potential Reduction Study for the El Nido and Western LA Basin Subareas

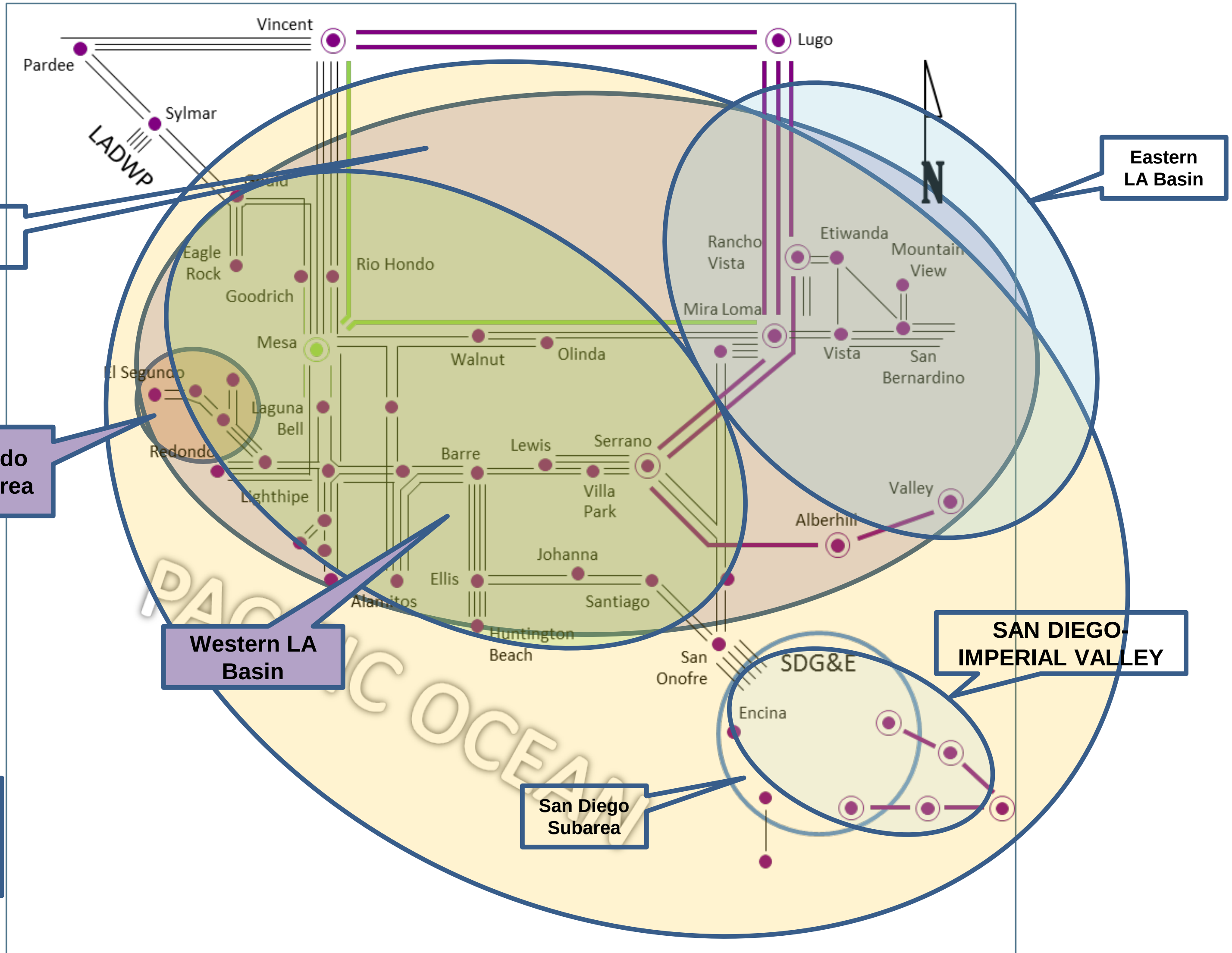
David Le
Senior Advisor, Regional Transmission Engineer

2019-2020 Transmission Planning Process Stakeholder Meeting #3
November 18, 2019

Agenda

- Recap of 2028 LCR needs for the subject study areas
- CAISO-considered potential solutions
- Request Window project proposal
- LCR reduction benefit calculations
- Benefit-to-Cost calculations

LA Basin and San Diego-Imperial Valley LCR Areas



LCR Area/Subareas considered for evaluation in the 2019/2020 TPP cycle

El Nido Subarea: Load and Resources (2028)

Loads (MW)		Resources (MW)	
Gross Load	1,998	Market	536
AAEE	-139	Wind	0
Behind the meter DG (production)	-145	Muni	0
Net Load	**1,714**	QF	0
Transmission Losses	31	LTPP Preferred Resources	31
Pumps	0	Existing 20-minute Demand Response	10
Loads + Losses + Pumps	**1,745**	Mothballed	0
		Total Qualifying Capacity	**577**

Western LA Basin Subarea: Load and Resources (2028)

Loads (MW)		Resources (MW)	
Gross Load	13,100	Market	2,957
AAEE	-897	Solar	4
Behind the meter DG (production)	-1,092	Muni	582
Net Load	**11,111**	QF	53
Transmission Losses	203	LTPP Preferred Resources	432
Pumps	0	Existing 20-minute Demand Response	154
Loads + Losses + Pumps	**11,314**	Mothballed	0
		Total Qualifying Capacity	**4,182**

Recap of El Nido Subarea Local Capacity Requirements

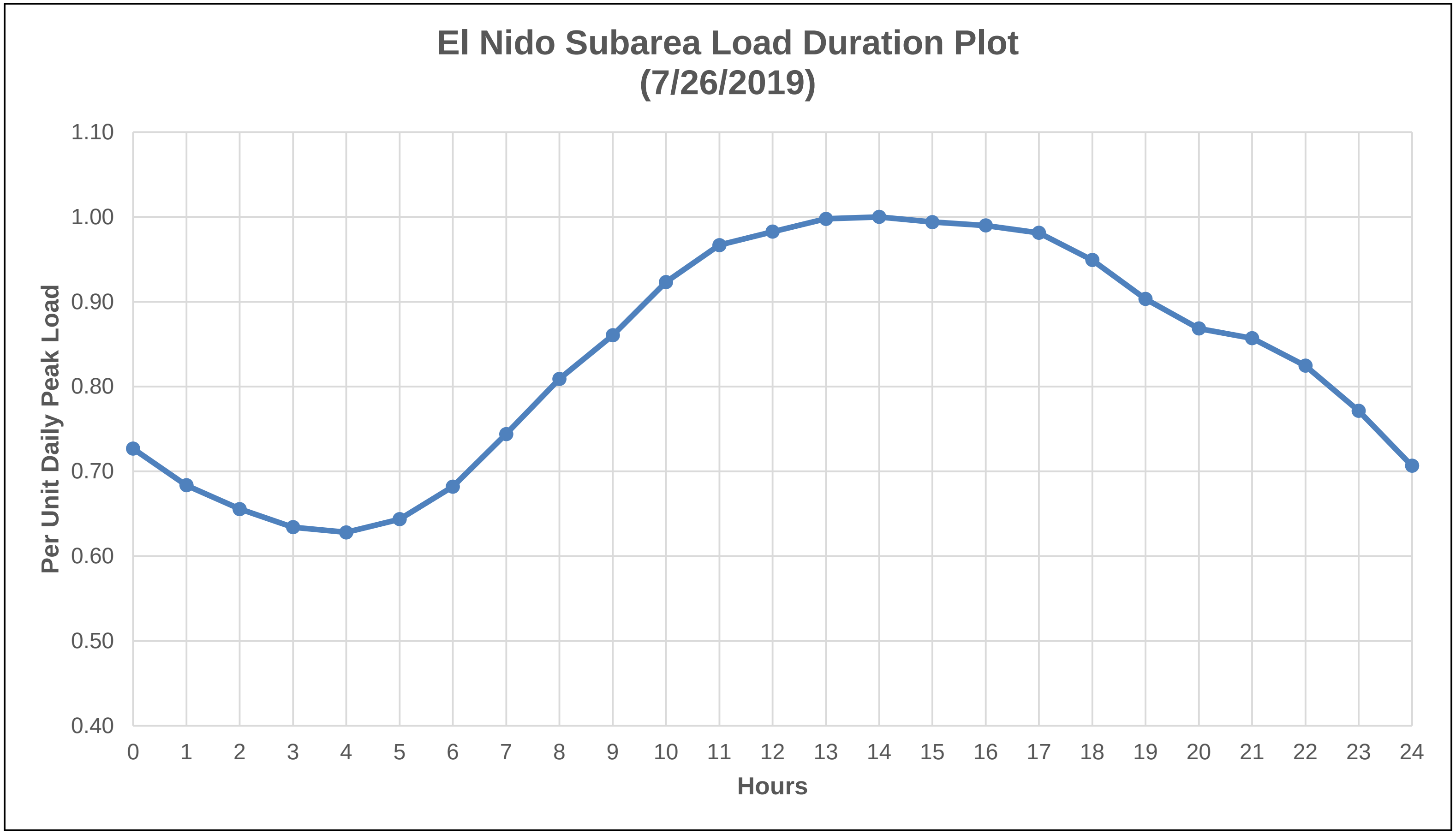
Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
Requirements Based on 2028 LCR Study					
2028	First Limit	C	Thermal loading on La Fresa-La Cienega 230kV line	La Fresa – El Nido #3 & 4 230kV lines	400 MW*^
2028	N/A	B	None	Various contingencies	No requirements

Notes:

*This includes LTPP-procured preferred resources (21.6 MW of behind-the-meter storage, 18.4 MW EE, 1 MW DR) and 10.4 MW of existing 20-minute DR.

^All procured resources in the El Nido subarea are also used toward meeting the western LA Basin LCR need.

The following El Nido Subarea load duration plot shows primarily commercial and industrial loads in the area



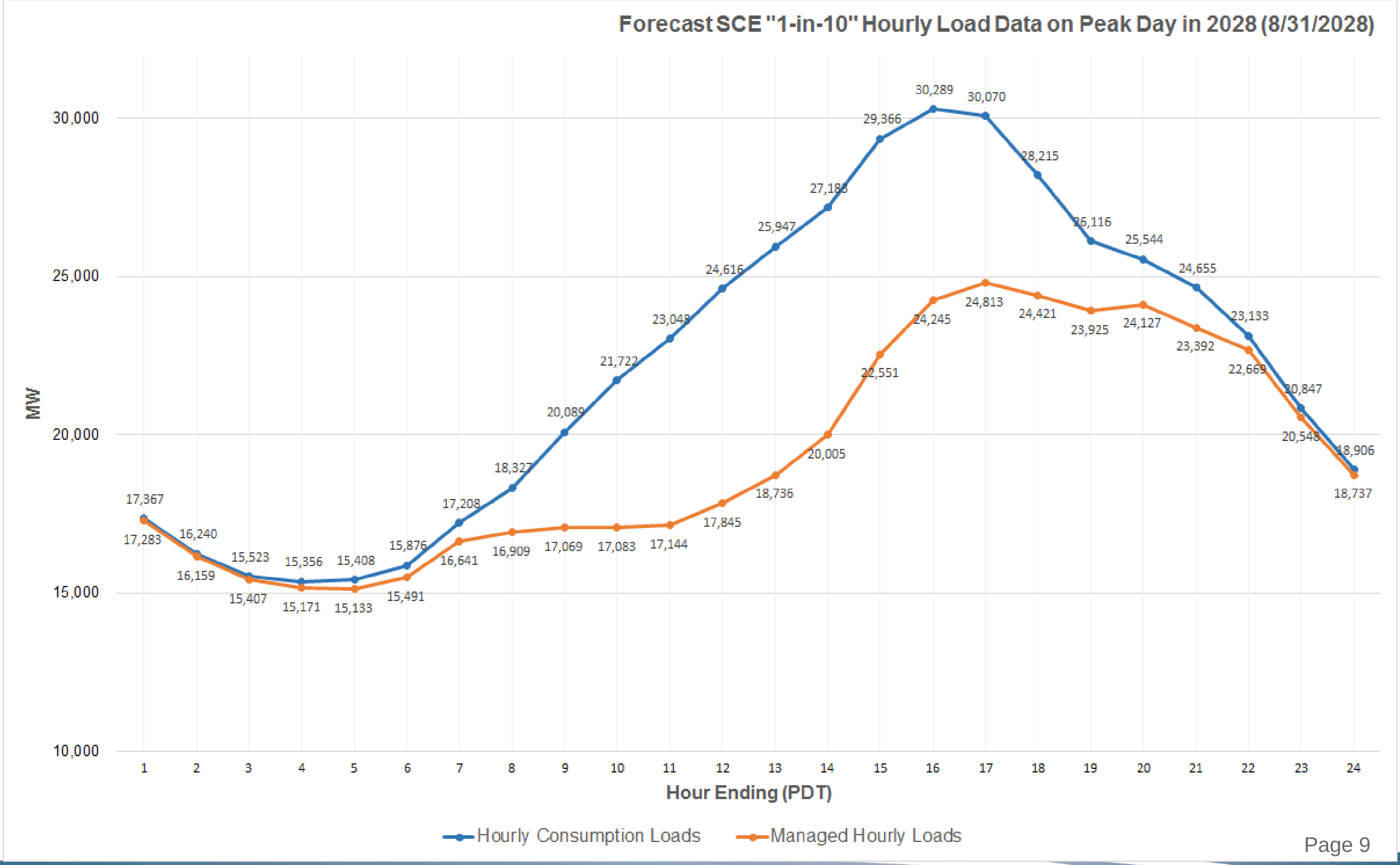
Recap of Western LA Basin Local Capacity Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
Requirements Based on 2028 LCR Study					
2028	First Limit	C	Thermal loading on the Mesa-Laguna Bell #1 230kV line	Mesa – Redondo #1 230 kV line, followed by Mesa - Lighthipe 230 kV line, or vice versa	3,912*
2028	N/A	B	None-binding	Multiple combinations possible	N/A

<u>Notes:</u>

*This includes 153.8 of existing 20-minute DR, 431.7 MW of CPUC-approved LTPP Track 4 preferred resources (i.e., DR, EE, BESS), 105 MW of PRP (DR and BESS) and 12 MW of existing BESS)

The load profile for the aggregated SCE area reflects a pattern of peak shift toward late afternoon and early evening



Recap of Eastern LA Basin Subarea 2028 LCR (this area is evaluated for potential impact due to LCR reduction in the Western LA Basin)

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
Requirements Based on 2028 LCR Study					
2028	First Limit	C	Post-transient voltage stability	Serrano-Valley 500kV line, followed by Devers – Red Bluff 500kV #1 and 2 lines	2,678*
2028	N/A	B	None-binding	Multiple combinations possible	N/A

<u>Notes:</u>

*This includes 140.6 MW of existing 20-minute demand response and 50 MW of existing BESS.

Recap of Overall San Diego-Imperial Valley 2028 LCR (this area is evaluated for potential impact due to LCR reduction in the Western LA Basin)

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
Requirements Based on 2028 LCR Study					
2028	First Limit (No Solar Generation Due to Load Peaking at 8 p.m.)	B/C	El Centro 230/92 kV transformer thermal loading	G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500kV line (N-1)	3,977 MW*

Notes:

**This includes 79.5 MW of procured BESS, 16 MW of existing DR, 4.6 MW future DR, 19 MW future EE (beyond AAEE), 77.5 MW of existing BESS and 133 MW of deficient resources at effective location in San Diego – Imperial Valley area

- ❖ Additional resources (1,177 MW) of preferred resources (893 MW) and others (284 MW) in the LA Basin were also utilized for mitigating this thermal loading concern

CAISO-Considered LCR Reduction Solutions and Request Window Project Submittal

	Name of Solutions	Submitter	Submission date	Target LCR reduction areas	500kV Voltage	230kV Voltage	DC Voltage (425kV)	Estimated costs ($ million)
1	Install 350 MW BESS in El Nido subarea	CAISO	2019-20 TPP	El Nido		√		$ 581
2	Upgrade La Fresa – La Cienega 230kV line (12 mi.)	CAISO	2019-20 TPP	El Nido		√		$ 104
3	Install 350 MW BESS in Nido and 350 MW in Western LA Basin subareas	CAISO	2019-20 TPP	El Nido, Western LA Basin		√		$ 1,162
4	Install BESS in Nido and Upgrade Mesa – Laguna Bell 230kV line	CAISO	2019-20 TPP	El Nido, Western LA Basin		√		$ 631
5	Install 350 MW BESS in Nido subarea and Install 3 Ω Line Series Reactor on the Mesa-Laguna Bell 230kVline	CAISO	2019-20 TPP	El Nido, Western LA Basin		√		$ 596
6	Upgrade La Fresa – La Cienega 230kV line and Install 3 Ω Line Series Reactor on the Mesa – Laguna Bell 230kV line	CAISO	2019-20 TPP	El Nido, Western LA Basin		√		$119
7	Pacific Transmission Expansion HVDC Project	Western Grid Development, LLC	10/15/2019	Big Creek/Ventura LCR area and Western LA Basin	√	√		$ 1,850

Interaction between subareas within LA Basin and between LA Basin and San Diego-Imperial Valley area

- The LCR subareas within the LA Basin, and the areas between the LA Basin and San Diego-Imperial Valley are connected by high voltage transmission lines. These high voltage transmission lines facilitate delivery of energy from one area to the other, similar to the major freeways between regions. When local resources in a subarea or area are reduced, energy will flow from the adjacent area that have available resources. When that occurs, the adjacent areas either experience increased line loading and may cause contingency line overloading concerns or potential voltage instability due to increased line loadings in its area.
- To determine potential impact to adjacent LCR subarea or LCR area, when gas-fired resources area reduced in an area, the adjacent areas are checked for potential adverse impact by performing contingency analysis with the most critical contingency. If the previously determined LCR need for an impacted area turned out to be insufficient, additional local resources will be increased within that area until identified reliability concern is mitigated.
  – The increase in local capacity resource in the adjacent impacted area will be noted as adverse impact due to reduction of local resources in its adjacent area.

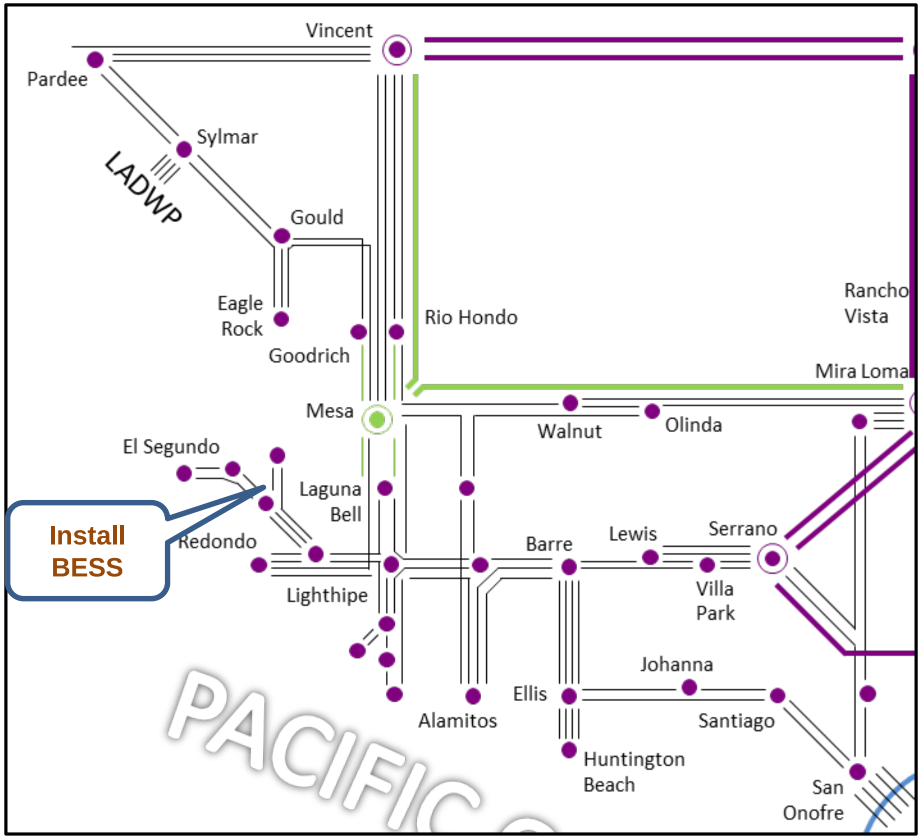
Interaction between subareas within LA Basin and between LA Basin and San Diego-Imperial Valley area

- The adverse impact to local capacity need will be subtracted from the estimated local capacity reduction benefit to provide for the total capacity reduction benefit (or impact).
- The following is an example:
  - The El Nido subarea's local gas-fired generation capacity need is reduced by an X MW amount via transmission upgrades.
  - Since El Nido is a subarea within the Western LA Basin, the Western LA Basin LCR need is checked for adequacy by running critical contingency.
  - If additional local resources are required to mitigate reliability concern, then the amount of dispatch of additional local capacity in the Western LA Basin is noted as local resource impact to the Western LA Basin.
  - This process is repeated for the Eastern LA Basin and then the San Diego-Imperial Valley area for arriving at the total capacity reduction benefit (or impact) to the overall LA Basin and San Diego-Imperial Valley area.

Alternative 1: Install 350 MW of BESS in the El Nido Subarea

<u>Alternative:</u>

- Install BESS at the following locations: 200 MW at La Cienega and 150 MW at El Nido substations or vicinity
- Estimated Total Cost: <u>$581 million</u> (using Lazard unit cost)
- Amount of gas-fired generation capacity reduction in El Nido subarea: <u>337 MW</u>
- Net amount of gas-fired generation reduction in the Western LA Basin:
  - Additional gas-fired generation reduction in El Nido subarea: 190 MW
  - Adverse impact to the Western LA Basin: -140 MW
  - Net capacity reduction: <u>50 MW</u>
- Adverse impact to Eastern LA Basin LCR: <u>0 MW</u> (assume system readjustment to Devers voltage schedule to provide more VAR output from Devers SVC)
- Adverse impact to the San Diego – Imperial Valley LCR: -<u>10 MW</u>



Alternative 1: Local Capacity Reduction Benefit Assessment

	Alternative 1: Install 350 MW BESS in El Nido subarea	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (El Nido) (MW)	337	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.6	$7.6
Net LCR reduction benefit (Western LA Basin) (MW)	50	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.8	$1.1
LCR increase (Eastern LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
LCR increase (San Diego-Imperial Valley) (MW)	-10	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	-$0.1	-$0.2
Net LCR Saving ($million/year)	$6.3	$8.6

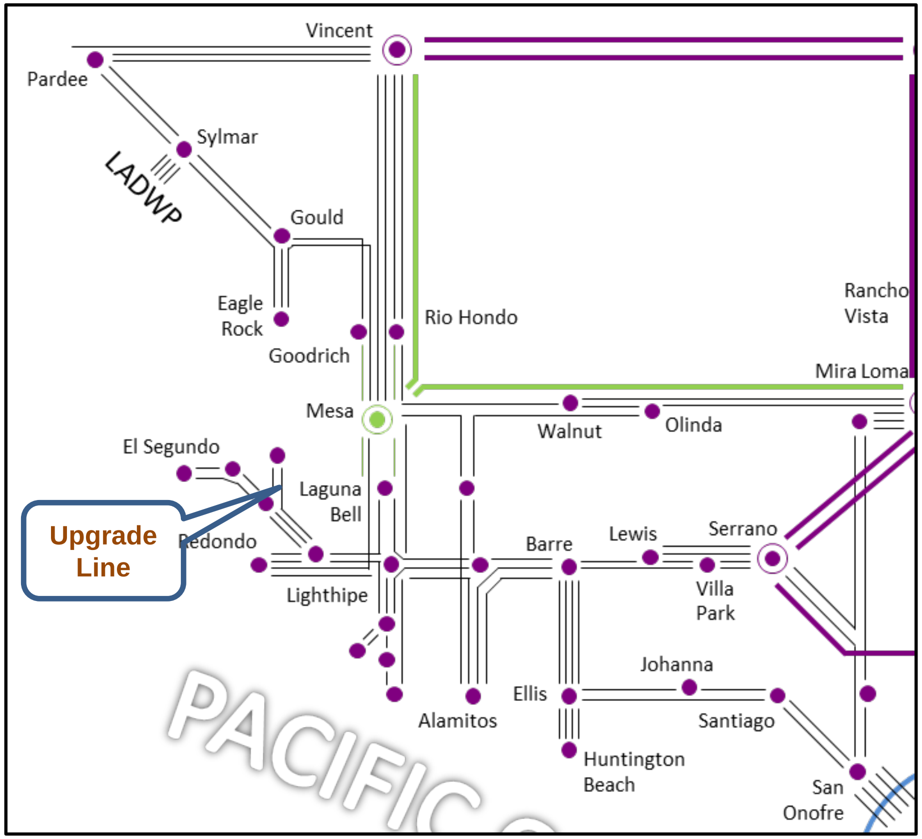
- The benefit to cost ratio of this project is less than 1, indicating that this option is not economic based on local capacity benefits.

Alternative 1: Install 350 MW in the El Nido Subarea		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$6.3	$8.6
Capital Cost		
Capacity (MW)	350	
Capital Cost Source	Lazard	Lazard
Capital Cost ($ million)		
Capital Cost $/kW	$1,660	$1,660
Levelized Fixed Cost ($/kW-year)	$394	$394
Estimated Levelized Fixed Cost (screening) ($million/year)	$138	$138
Benefit to Cost		
Savings ($million/year)	$6	$9
Estimated Levelized Fixed Cost (screening) ($million/year)	$138	$138
Benefit to Cost	0.05	0.06

Alternative 2: Upgrade La Fresa – La Cienega 230kV Line

<u>Alternative:</u>

- Upgrade La Fresa – La Cienega 230kV line (12 mi.) to higher capacity (i.e., 787 MVA normal, 1062 MVA emergency)
  - Line clearance for existing line was evaluated but is still insufficient
- Estimated Total Cost: <u>$104 million</u> (using SCE transmission unit cost; no other costs (i.e., unforeseen environmental mitigation, no contingency cost) are added at this time)
- Amount of gas-fired generation capacity reduction in El Nido subarea: <u>337 MW</u>
- Net amount of adverse impact to the Western LA Basin LCR need:
  - Additional gas-fired generation reduction in El Nido subarea: 190 MW
  - Adverse impact to the Western LA Basin: -721 MW
  - Net adverse impact: -<u>531 MW</u>
- Adverse impact to Eastern LA Basin LCR: -<u>84 MW</u>
- Adverse impact to the San Diego – Imperial Valley LCR: <u>0 MW</u> (after factoring impacts to Western and Eastern LA Basin above)



Alternative 2: Local Capacity Reduction Benefit Assessment

	Alternative 2: Upgrade La Fresa - La Cienega 230kV Line	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (El Nido) (MW)	337	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.6	$7.6
LCR increase (Western LA Basin) (MW)	-531	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	-$8.9	-$12.0
LCR increase (Eastern LA Basin) (MW)	-84	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	-$1.4	-$1.9
LCR increase (San Diego-Imperial Valley) (MW)	0	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	$0.0	$0.0
Net LCR Saving ($million/year)	**-$4.6**	**-$6.3**

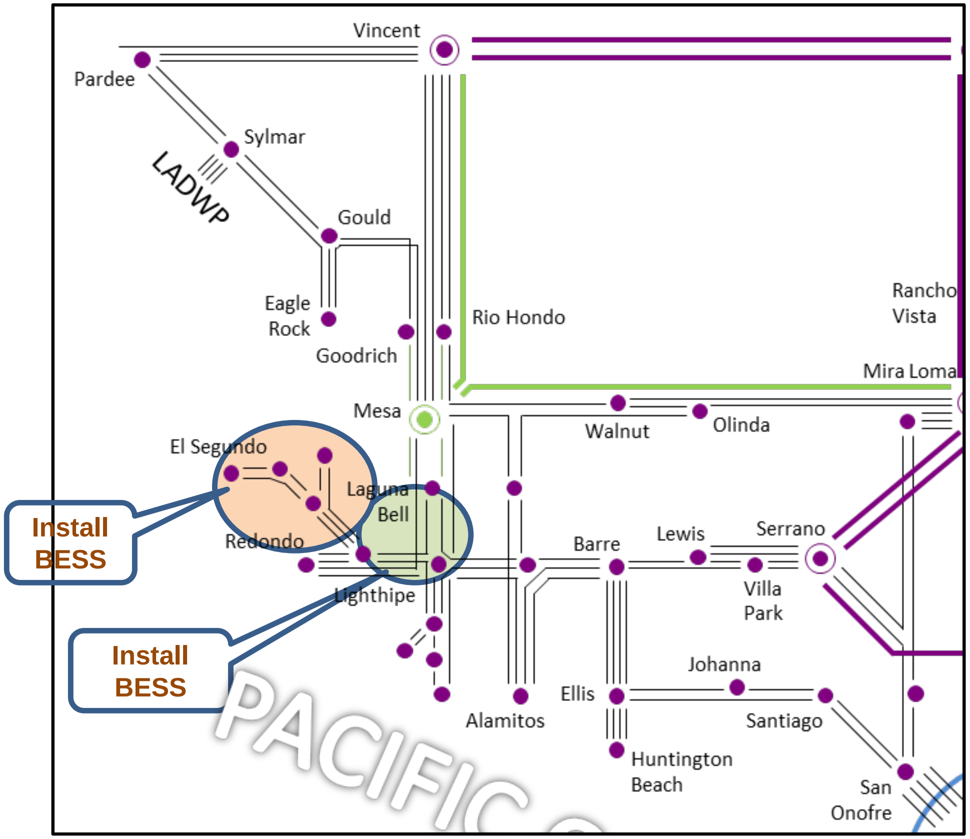
- The benefit to cost ratio of this project is less than 1, indicating that this option is not economic based on local capacity benefits.

Alternative 2: Upgrade La Fresa - La Cienega 230kV Line		
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	-$4.6	-$6.3
PV of LCR Savings ($million)	($63.99)	($87.01)
Capital Cost		
Capital Cost Estimate ($ million)	$104	
Estimated “Total” Cost (screening) ($million)	$135	
Benefit to Cost		
PV of Savings ($million)	($63.99)	($87.01)
Estimated “Total” Cost (screening) ($million)	$135.20	
Benefit to Cost	**-0.47**	**-0.64**

Alternative 3: Install BESS in the El Nido and Western LA Basin Subareas

<u>Alternative:</u>

- Install a total of 700 MW BESS at the following locations:
  - 200 MW at La Cienega and 150 MW at El Nido substations or vicinity (load side)
  - 200 MW at Laguna Bell, 100 MW at La Fresa and 50 MW at Del Amo
- Estimated Total Cost: <u>$1,162 million</u> (using Lazard unit cost)
- Amount of gas-fired generation capacity reduction in El Nido subarea: <u>337 MW</u>
- Net amount of gas-fired generation reduction in the in the Western LA Basin:
  - Additional gas-fired generation reduction in El Nido subarea: 190 MW
  - Additional gas-fired generation reduction in the Western LA Basin: 480 MW
  - Net benefit: <u>670 MW</u>
- Adverse impact to Eastern LA Basin LCR: - <u>42 MW</u> (assume system readjustment to Devers voltage schedule to provide more VAR output from Devers SVC)
- Adverse impact to the San Diego – Imperial Valley LCR: - <u>35 MW</u>



Alternative 3: Local Capacity Reduction Benefit Assessment

	Alternative 3: Install BESS in El Nido and Western LA Basin Subareas	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (El Nido) (MW)	337	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.6	$7.6
LCR reduction benefit (Western LA Basin) (MW)	670	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$11.2	$15.2
LCR increase (Eastern LA Basin) (MW)	-42	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	-$0.7	-$1.0
LCR increase (San Diego-Imperial Valley) (MW)	-35	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	-$0.5	-$0.7
Net LCR Saving ($million/year)	**$15.6**	**$21.2**

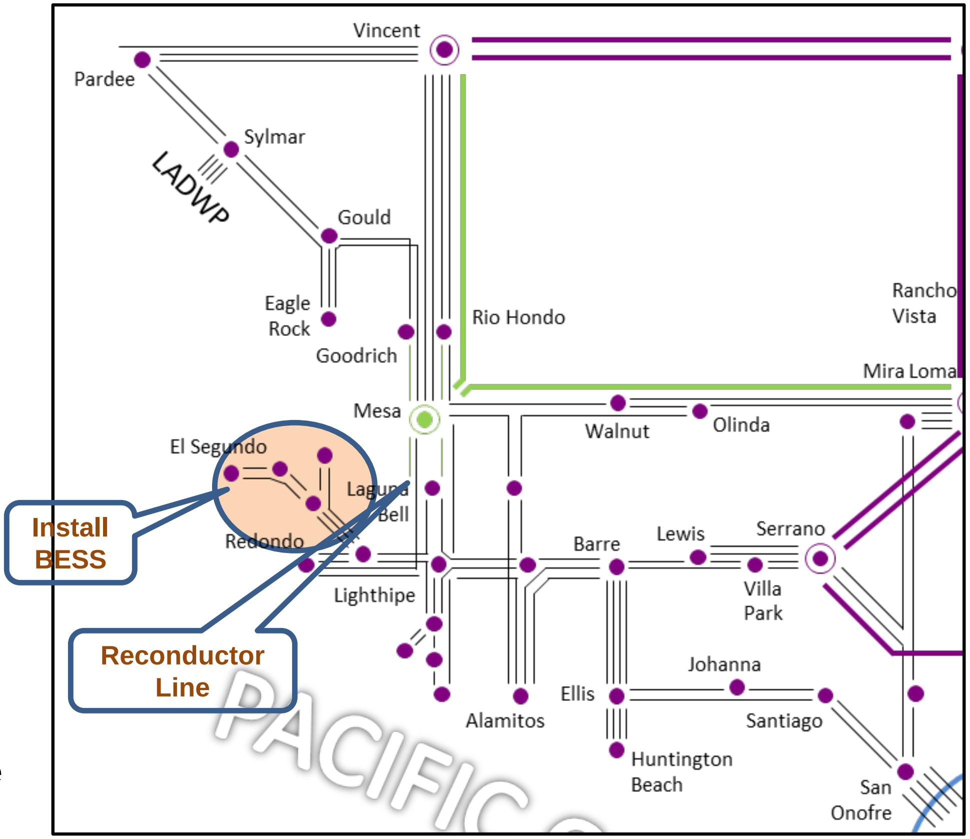
- The benefit to cost ratio of this project is less than 1, indicating that this option is not economic based on local capacity benefits.

Alternative 3: Install BESS in the El Nido and Western LA Basin Subareas		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$15.6	$21.2
Capital Cost		
Capacity (MW)	700	
Capital Cost Source	Lazard	Lazard
Capital Cost $/kW	$1,660	$1,660
Levelized Fixed Cost ($/kW-year)	$394	$394
Estimated Levelized Fixed Cost (screening) ($million/year)	$276	$276
Benefit to Cost		
Savings ($million/year)	$15.6	$21.2
Estimated Levelized Fixed Cost (screening) ($million/year)	$276	$276
Benefit to Cost	**0.06**	**0.08**

Alternative 4: Install BESS in the El Nido Subarea and Upgrade Mesa – Laguna Bell 230kV Line

<u>Alternative:</u>

- Install 350 MW BESS at the following locations:
  - 200 MW at La Cienega and 150 MW at El Nido substations or vicinity (downstream)
- Upgrade 5.6-mi of Mesa-Laguna Bell 230kV line to 1574 MVA normal, 2123 MVA emergency
- Estimated Total Cost:
  - BESS: $581 million (using Lazard unit cost)
  - Reconductor line: $50 million (using SCE unit cost)
  - Total Cost: <u>$631 million</u>
- Amount of gas-fired generation capacity reduction in El Nido subarea: <u>337 MW</u>
- Net amount of gas-fired generation reduction in the in the Western LA Basin :
  - Additional gas-fired generation reduction in El Nido subarea: 190 MW
  - Additional gas-fired generation reduction in the Western LA Basin: 480 MW
  - Net benefit: <u>670 MW</u>
- Adverse impact to Eastern LA Basin LCR: - <u>126 MW</u>
- Adverse impact to the San Diego – Imperial Valley LCR: - <u>70 MW</u>



Alternative 4: Local Capacity Reduction Benefit Assessment

	Alternative 4: Install BESS in El Nido Subarea and Reconductor Line in Western LA Basin	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (El Nido) (MW)	337	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.6	$7.6
LCR reduction benefit (Western LA Basin) (MW)	670	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$11.2	$15.2
LCR increase (Eastern LA Basin) (MW)	-126	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	-$2.1	-$2.9
LCR increase (San Diego-Imperial Valley) (MW)	-70	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	-$0.9	-$1.3
Net LCR Saving ($million/year)	$13.8	$18.6

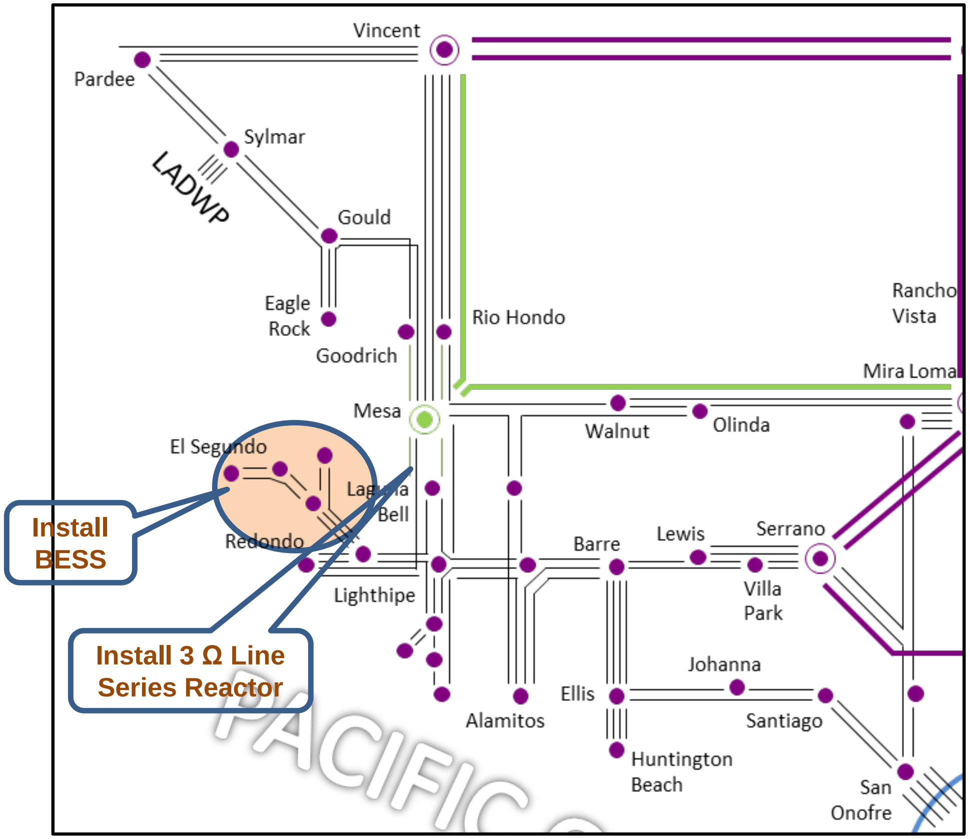
- The benefit to cost ratio of this project is less than 1, indicating that this option is not economic based on local capacity benefits.

Alternative 4: Install 350 MW in the El Nido Subarea and Reconductor in the Western LA Basin Subarea		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$13.8	$18.6
PV of LCR Savings ($million)	$190.2	$257.3
Capital Cost (BESS)		
Capacity (MW)	350	
Capital Cost Source	Lazard	Lazard
Capital Cost ($ million)	$581	$581
Capital Cost $/kW	$1,660	$1,660
Levelized Fixed Cost ($/kW-year)	$394	$394
Estimated Levelized Fixed Cost (screening) ($million/year)	$138	$138
Capital Cost (Reconductor Line)		
Capital Cost Estimate ($million)	$50	
Estimated "Total" Cost (screening) ($million)	$65	
Estimated Annual Cost (screening) ($million/year)	$5	
Benefit to Cost		
Savings ($million/year)	$14	$19
Estimated Annual Cost ($million/year)	$143	$143
Benefit to Cost	**0.10**	**0.13**

Alternative 5: Install BESS in the El Nido Subarea and Line Series Reactor on the Mesa – Laguna Bell 230kV Line

<u>Alternative:</u>

- Install 350 MW BESS at the following locations:
  - 200 MW at La Cienega and 150 MW at El Nido substations or vicinity (load side)
- Install 3 Ω line series reactor on the Mesa-Laguna Bell 230kV line
- Estimated Total Cost:
  - BESS: $581 million (using Lazard unit cost)
  - Install 3 Ω line series reactor: $15 million (using previous similar project cost)
  - Total Cost: <u>$596 million</u>
- Amount of gas-fired generation capacity reduction in El Nido subarea: <u>337 MW</u>
- Net amount of gas-fired generation reduction in the in the Western LA Basin :
  - Additional gas-fired generation reduction in El Nido subarea: 190 MW
  - Additional gas-fired generation reduction in the Western LA Basin : 480 MW
  - Net benefit: <u>670 MW</u>
- Adverse impact to Eastern LA Basin LCR: <u>0 MW</u>
- Adverse impact to the San Diego – Imperial Valley LCR: - <u>70 MW</u>



Alternative 5: Local Capacity Reduction Benefit Assessment

	Alternative 5: Install BESS in El Nido Subarea and Line Series Reactor in Western LA Basin	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (El Nido) (MW)	337	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.6	$7.6
LCR reduction benefit (Western LA Basin) (MW)	670	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$11.2	$15.2
LCR increase (Eastern LA Basin) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	$0.0	$0.0
LCR increase (San Diego-Imperial Valley) (MW)	-70	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	-$0.9	-$1.3
Net LCR Saving ($million/year)	$15.9	$21.5

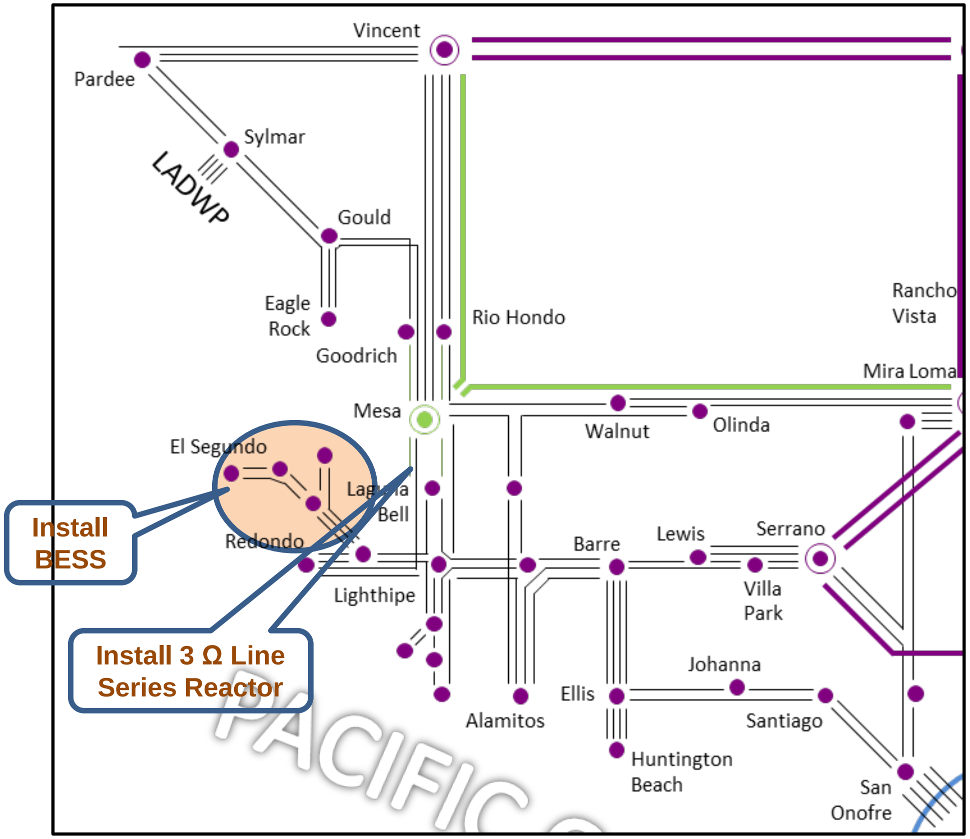
- The benefit to cost ratio of this project is less than 1, indicating that this option is not economic based on local capacity benefits.

Alternative 5: Install 350 MW in the El Nido Subarea and Line Series Reactor on 230kV Line in Western LA Basin		
Local Capacity Benefits		
Basis for capacity benefit calculation	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$15.9	$21.5
PV of LCR Savings ($million)	$219.2	$296.8
Capital Cost (BESS)		
Capacity (MW)	350	
Capital Cost Source	Lazard	Lazard
Capital Cost ($ million)	$581	$581
Capital Cost $/kW	$1,660	$1,660
Levelized Fixed Cost ($/kW-year)	$394	$394
Estimated Levelized Fixed Cost (screening) ($million/year)	$138	$138
Capital Cost (Install 3 Ω Line Series Reactor)		
Capital Cost Estimate ($million)	$15	
Estimated "Total" Cost (screening) ($million)	$20	
Estimated Annual Cost (screening) ($million/year)	$1	
Benefit to Cost		
Savings ($million/year)	$16	$22
Estimated Annual Cost ($million/year)	$139	$139
Benefit to Cost	0.11	0.15

Alternative 6: Upgrade La Fresa-La Cienega 230kV Line and Install Line Series Reactor on the Mesa – Laguna Bell 230kV Line

Alternative:

- Reconductor 12-mile La Fresa – La Cienega 230kV line
- Install 3 Ω line series reactor on the Mesa-Laguna Bell 230kV line
- Estimated Total Cost:
  - Reconductoring: $104 million (using SCE unit cost)
  - Installing 3 Ω line series reactor: $15 million (using previous similar project cost)
  - Total Cost: $119 million
- Amount of gas-fired generation capacity reduction in El Nido subarea : 337 MW
- Net amount of gas-fired generation reduction in the in the Western LA Basin:
  - Additional gas-fired generation reduction in El Nido subarea: 190 MW
  - Additional gas-fired generation reduction in the Western LA Basin : 480 MW
  - Net benefit: 670 MW
- Adverse impact to Eastern LA Basin LCR: - 206 MW
- Adverse impact to the San Diego – Imperial Valley LCR: - 120 MW



Alternative 6: Local Capacity Reduction Benefit Assessment

	Alternative 6: Reconductor 230kV Line in El Nido Subarea and Install Line Series Reactor on 230kV Line in Western LA Basin	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (El Nido) (MW)	337	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$5.6	$7.6
LCR reduction benefit (Western LA Basin) (MW)	670	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$11.2	$15.2
LCR increase (Eastern LA Basin) (MW)	-206	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	-$3.4	-$4.7
LCR increase (San Diego-Imperial Valley) (MW)	-120	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	-$1.6	-$2.3
Net LCR Saving ($million/year)	$11.8	$15.9

- The benefit to cost ratio of this project is more than 1, indicating that this option is promising in terms of economic benefits based on local capacity requirement reduction.

Alternative 6: Reconductor 230kV Line in El Nido Subarea and Install Line Series Reactor on 230kV Line in Western LA Basin		
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$11.8	$15.9
PV of LCR Savings ($million)	$162.73	$219.12
Capital Cost		
Capital Cost Estimate ($ million)	$119	
Estimated “Total” Cost (screening) ($million)	$155	
Benefit to Cost		
PV of Savings ($million)	$162.73	$219.12
Estimated “Total” Cost (screening) ($million)	$154.70	
Benefit to Cost	1.05	1.42

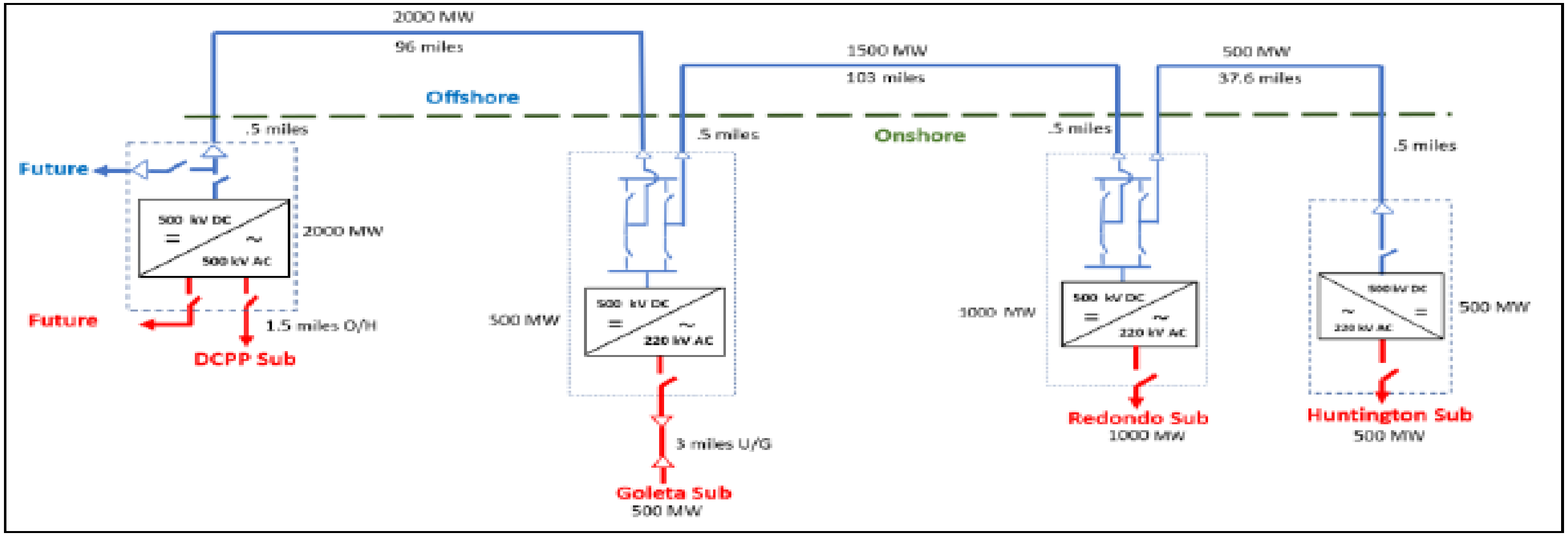
Alternative 7: Pacific Transmission Expansion Project

Alternative:

- This option is proposed by the Western Grid Development, LLC
- Scope of proposed project:
  - Install four Voltage Source Converter stations, rated 2000 MW (500kV DC/AC), 1000 MW (500kV DC / 230kV AC), two 500 MW (500kV DC / 230kV AC)
  - Install 500kV DC submarine cables connecting Diablo Canyon switchyard to Goleta, Redondo Beach and Huntington Beach substations
- Estimated Total Cost: $1.85 billion

LCR Reduction Benefits and Impacts:

- Amount of gas-fired generation reduction in the Big Creek-Ventura area: 393 MW
- Amount of gas-fired generation capacity reduction in El Nido subarea: 0 MW
- Amount of gas-fired generation in the Western LA Basin subarea: 1,889 MW
- Adverse impact to Eastern LA Basin LCR: - 149 MW
- Adverse impact to the San Diego – Imperial Valley LCR: - 140 MW



Alternative 7: Local Capacity Reduction Benefit Assessment

	Alternative 7: Pacific Transmission Expansion HVDC Project	
	Local/CPM versus System Capacity	Local/CPM versus SP 26
LCR Reduction Benefit (Big Creek/Ventura) (MW)	393	
Capacity value (per MW-year)	$16,320	$22,320
LCR Reduction Benefit ($million)	$6.4	$8.8
	Local versus System Capacity	Local versus SP 26
LCR Reduction Benefit (El Nido) (MW)	0	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$0.0	$0.0
LCR reduction benefit (Western LA Basin) (MW)	1889	
Capacity value (per MW-year)	$16,680	$22,680
LCR Reduction Benefit ($million)	$31.5	$42.8
LCR increase (Eastern LA Basin) (MW)	-149	
Capacity value (per MW-year)	$16,680	$22,680
LCR increase cost ($million)	-$2.5	-$3.4
LCR increase (San Diego-Imperial Valley) (MW)	-140	
Capacity value (per MW-year)	$13,080	$19,080
LCR increase cost ($million)	-$1.8	-$2.7
Net LCR Saving ($million/year)	$33.6	$45.6

Alternative 7: Pacific Transmission Expansion HVDC Project		
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$33.6	$45.6
PV of LCR Savings ($million)	$463.8	$628.8
Capital Cost		
Capital Cost Estimate ($ million)	$1,850	
Estimated “Total” Cost (screening) ($million)	$2,405	
Benefit to Cost		
PV of Savings ($million)	$464	$629
Estimated “Total” Cost (screening) ($million)	$2,405	
Benefit to Cost	0.19	0.26

- The benefit to cost ratio will be updated once the production cost simulation results are available.

Conclusions

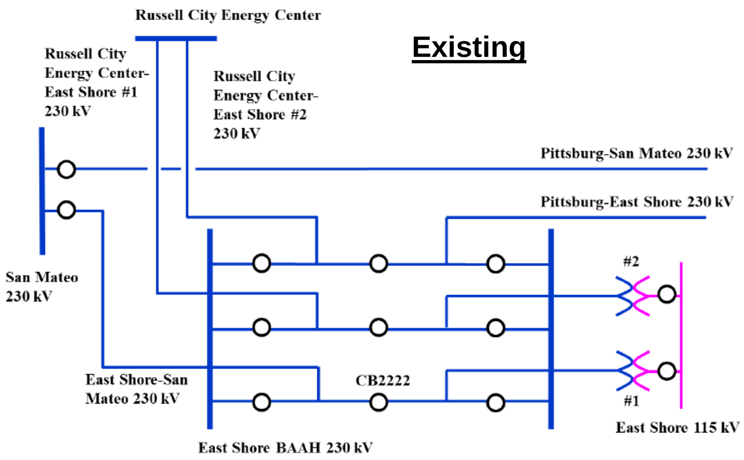
- Seven alternatives were evaluated for determining potential local capacity benefits for the El Nido and Western LA Basin LCR reductions.
- For the LCR reductions in the El Nido and Western LA Basin subareas, the adjacent Eastern LA Basin and the overall San Diego – Imperial Valley LCR areas were evaluated for potential impacts to their respective LCR need.
- Of seven alternatives, only one alternative (Alternative # 6) of line upgrade in the El Nido subarea and installation of line series reactor on a 230kV line in the Western LA Basin shows potential economic benefits based on LCR reduction with the Benefit-to-Cost Ratio (BCR) of 1.05 to 1.42.
- Further evaluation for reliability impact to system capacity need would be needed to ensure that system capacity requirement is not adversely impacted.

2019-2020 Transmission Planning Process Less than $50 Million Project Recommendations
- PG&E Area

2019-2020 Transmission Planning Process Stakeholder Meeting
November 18, 2019

East Shore 230 kV Bus Terminals Reconfiguration (Greater Bay Area)

- Reliability Assessment Need
  - NERC Category P2 starting 2021.
  - Overloads worsen in high CEC forecast sensitivity.
- Project Submitter
  - PG&E
- Project Scope
  - Reconfigure East Shore 230 kV bus
- Project Cost
  - $2M-$4M
- Alternatives Considered
  - Status quo
- Recommendation
  - Approval



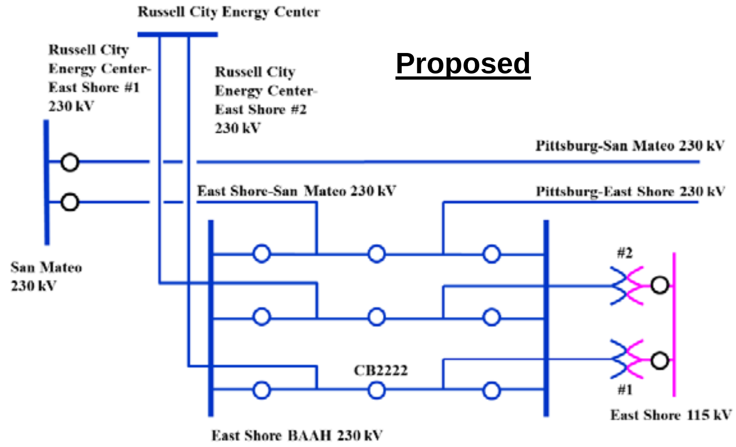


Diagram source: PG&E 2019-2020 TPP RW submission

Newark 230/115 kV Transformer Bank #7 Circuit (Greater Bay Area)

- Reliability Assessment Need
  - NERC Category P2 starting 2021.
  - Overloads worsen in high CEC forecast sensitivity.
- Project Submitter
  - PG&E
- Project Scope
  - add second high-side circuit breaker to Newark 230/115 kV transformer bank #7
- Project Cost
  - $3M-$6M
- Alternatives Considered
  - Status quo
  - Install a 230/115 kV transformer bank connecting to Newark 230 kV bus section E. Not recommended due to space issue and higher cost.
- Recommendation
  - Approval

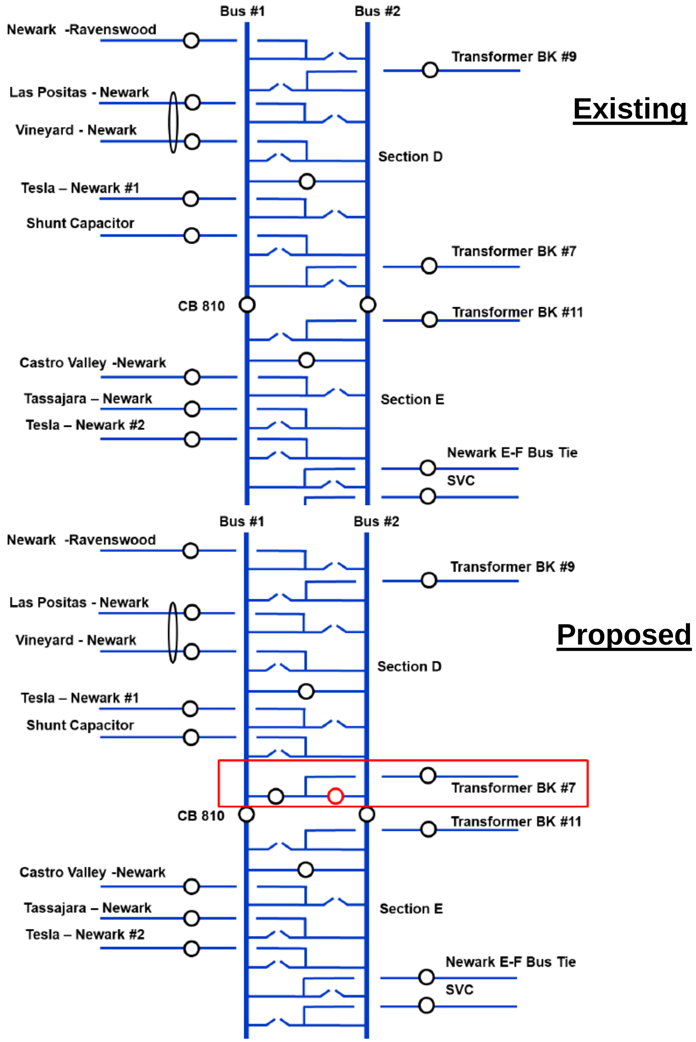


Diagram source: PG&E 2019-2020 TPP RW submission

Moraga 230 kV Bus Upgrade (Greater Bay Area)

- Reliability Assessment Need
  - NERC Category P2 starting 2021.
  - Overloads worsen in high CEC forecast sensitivity.
- Project Submitter
  - PG&E
- Project Scope
  - Add sectionalizing breakers and a bus tie breaker to Moraga 230 kV bus
- Project Cost
  - $17M
- Alternatives Considered
  - Status quo
- Recommendation
  - Approval

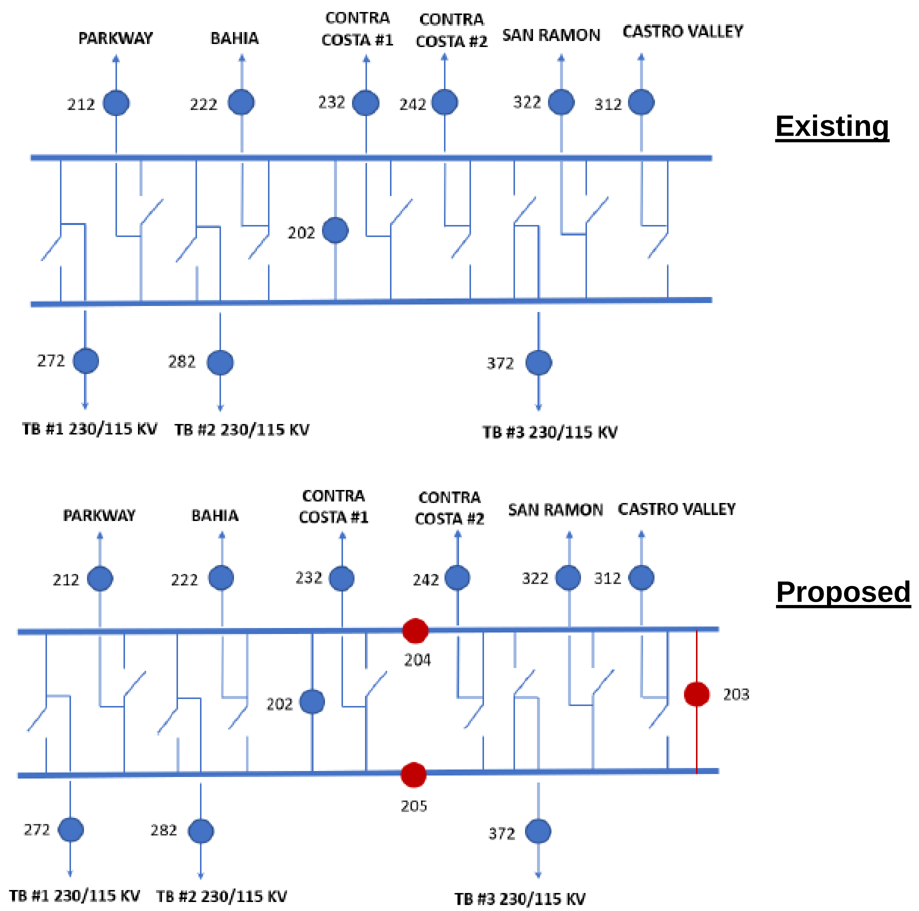
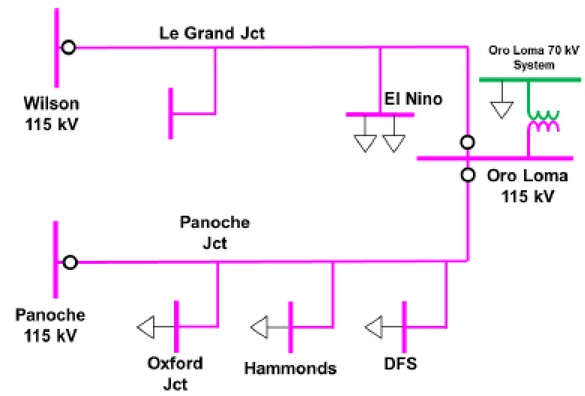


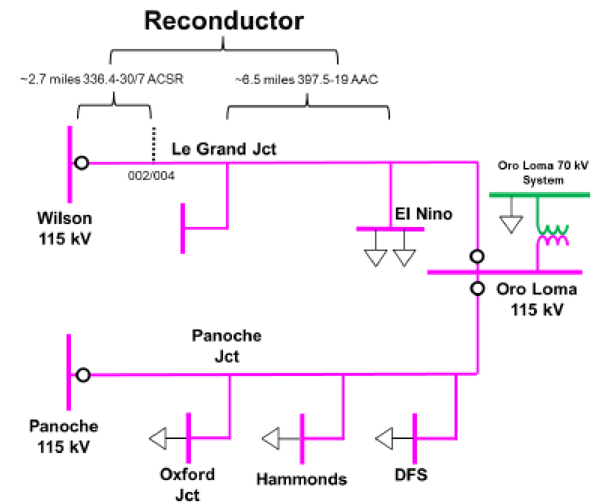
Diagram source: PG&E 2019-2020 TPP RW submission

Wilson Oro Loma 115kV Line Reconductoring (Greater Fresno Area)

- Reliability Assessment Need
  - NERC Category P2-1, P2-2,P2-4 starting 2021.
  - Overloads worsen in high CEC forecast sensitivity.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductor ~9 circuit miles between Wilson and El Nido Substations (Wilson-002/004 section and 008/002- El Nido section)
- Project Cost
  - $11.3M-22.7M
- Alternatives Considered
  - Status quo
  - Re-rate
  - Energy Storage (20MW*4h)
- Recommendation
  - Approval



Existing



Proposed

Diagram source: PG&E 2019-2020 TPP RW submission

Borden 230/70kV TB #1 Capacity Increase (Greater Fresno Area)

- Reliability Assessment Need
  - NERC Category P1,P3,P6 starting 2021.
  - Overloads worsen in high CEC forecast sensitivity.
- Project Submitter
  - PG&E
- Project Scope
  - Upgrade Bank Breaker CB 52 and associated switches to match the Transformer Bank # 1’s full capacity (200 N/220 E MVA)
  - • Upgrade Borden 70 kV Bus Section “D” to match the Transformer Bank # 1’s full capacity
- Project Cost
  - $11.5M-23M
- Alternatives Considered
  - Status quo
  - Energy Storage (15MW*4h)
- Recommendation
  - Approval

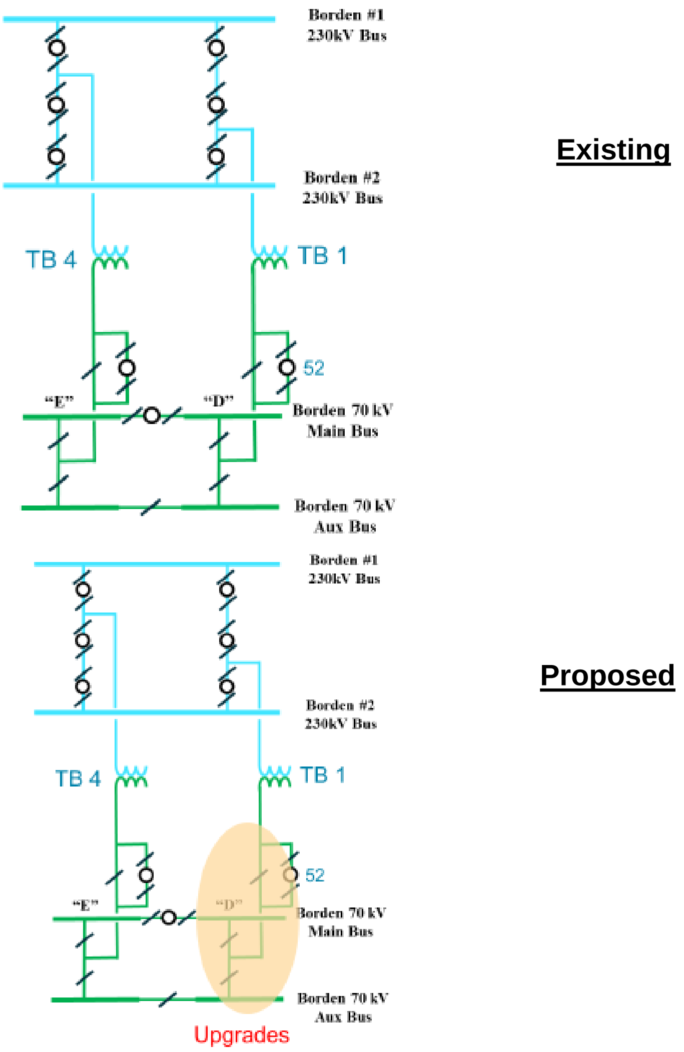


Diagram source: PG&E 2019-2020 TPP RW submission

Tulucay-Napa #2 60kV : Remove Limiting Element Project (North Coast & North Bay Area)

- Reliability Assessment Need
  - NERC Category P0 starting 2024.
  - Overloads worsen in high CEC forecast sensitivity.
- Project Submitter
  - PG&E
- Project Scope
  - Remove limiting elements on Tulucay-Napa #2 60 kV line to match the conductor rating of 1126 AMPS
- Project Cost
  - $5M-$10M
- Alternatives Considered
  - None due to P0
- Recommendation
  - Approval

Proposed

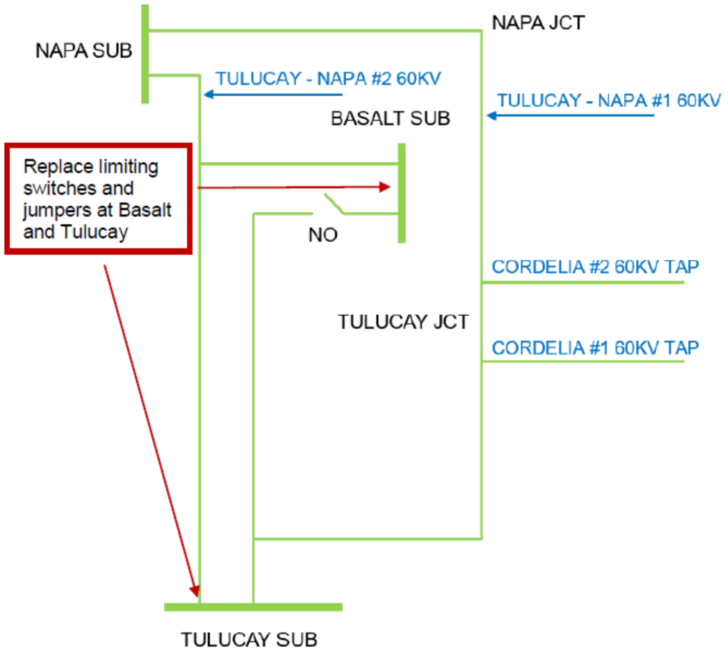


Diagram source: PG&E 2019-2020 TPP RW submission

2019-2020 TPP Projects Recommendations – VEA-GLW Area

2019-2020 Transmission Planning Process Stakeholder Meeting
November 18, 2019

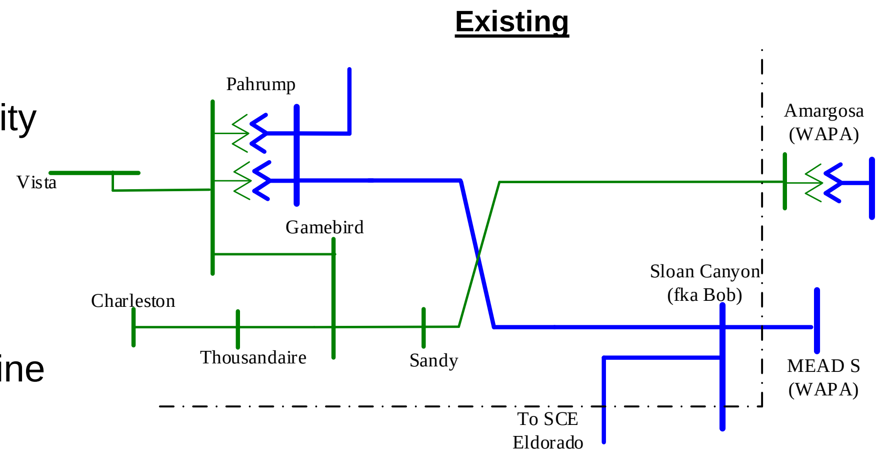
Presentation Outline

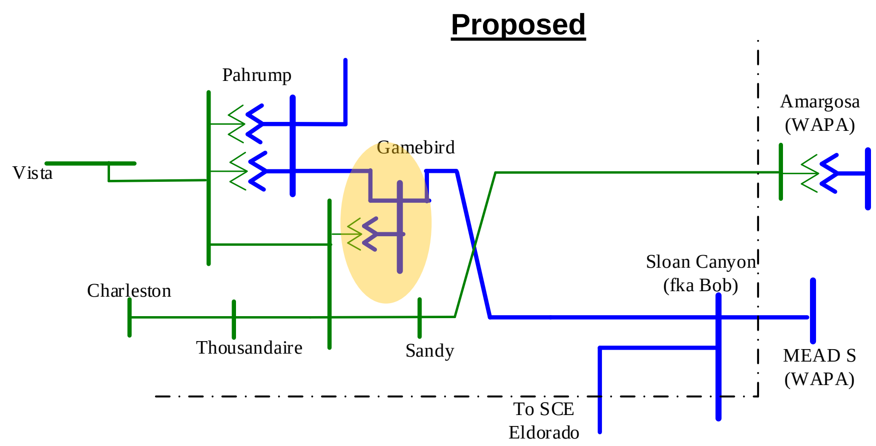
- New < $50 million projects concluded at this time for approval recommendation
- Review of on hold projects (none for VEA-GLW)

New Projects Recommended for Approval (Less than $50M projects)

Gamebird 230/138 kV Transformer Upgrade

- Reliability Assessment Need
  - NERC Category P1 and P4 starting 2021
  - Overloads worsen in high CEC forecast sensitivity
- Project Scope
  - Upgrade VEA's existing 138 kV Gamebird substation by adding a new 230/138 kV transformer
  - Loop GLW's Pahrump – Sloan Canyon 230 kV line into the upgraded Gamebird substation
- Project Cost
  - $4.9 M
- Alternatives Considered
  - Charleston – Vista 138 kV line
  - Amargosa 230/138 kV transformer upgrade
  - Carpenter Canyon – Charleston 230 kV project
  - Energy storage at Sandy 138 kV
- Recommendation
  - Approval





Summary of alternatives

Alternative	Cost Estimate	Determination
Charleston – Vista 138 kV line	~$23 M	o Mitigates the Amargosa bank overload and low voltage issues o Cannot eliminate Pahrump bank overloads
Amargosa 230/138 kV transformer upgrade	~$5 M	o Not an ISO-controlled facility o Mitigates the Amargosa bank overload and Pahrump bank overloads o Cannot eliminate Pahrump bank overloads
Carpenter Canyon – Charleston 230 kV Project	$35 M	o Will not be able to address the need starting in 2021 due to dependence of the Carpenter Canyon 230 kV substation proposed in GIDAP o In 2029 case, it mitigates the Amargosa bank overload and low voltage issues, but cannot eliminate Pahrump bank overloads
Energy storage at Sandy 138 kV (10 MW 2-Hr duration)	~$10 M	o 10 MW storage with 0.95 PF cannot mitigate voltage issues o Thermal relief provided by the 10 MW storage is unlikely to be adequate beyond 2030 timeframe (VEA is the area with the highest rate of load growth in CAISO) o Storage designed to achieve similar peak load serving capability as Gamebird transformer bank will be much higher

Wrap-up
Policy and Economic Assessment Preliminary Results

Isabella Nicosia
Associate Stakeholder Affairs and Policy Specialist

2019-2020 Transmission Planning Process Stakeholder Meeting
November 18, 2019

2019-2020 Transmission Plan Milestones

- Draft Study Plan posted on February 22
- Stakeholder meeting on Draft Study Plan on February 28
- Comments to be submitted by March 14
- Final Study Plan to be posted on March 31
- Preliminary reliability study results to be posted on August 16
- Stakeholder meeting on September 25 and 26
- Comments to be submitted by October 10
- Request window closes October 15
- Preliminary policy and economic study results on November 18
- Comments to be submitted by December 2
- Draft transmission plan to be posted on January 31, 2020
- Stakeholder meeting on February
- Comments to be submitted within two weeks after stakeholder meeting
- Revised draft for approval at March Board of Governor meeting

Stakeholder Comments

- Stakeholder comments to be submitted by December 2
  - Stakeholders requested to submit comments to: regionaltransmission@caiso.com
  - Stakeholder comments are to be submitted within two weeks after stakeholder meetings
  - ISO will post comments and responses on website