Agenda
Preliminary Policy and Economic Assessments

Isabella Nicosia
Stakeholder Engagement and Policy Specialist

2020-2021 Transmission Planning Process Stakeholder Meeting
November 17, 2020

2020-2021 Transmission Planning Process Stakeholder Call – Agenda

Topic	Presenters
Overview & Key Issues	Jeff Billinton
Policy Assessment	RT - Engineers
Reliability-Driven Project Approval and Concurrence Recommendations - SCE Area - PG&E Area	 Alison Auld-Hill (SCE) / Robert Sparks Ebrahim Rahimi / Abhishek Singh
Economic Assessment	Yi Zhang
10-year Local Capacity Technical Study	Catalin Micsa / Abhishek Singh / David Le
Projects on Hold - SDG&E Area - PG&E Area	 Charles Cheung Abhishek Singh / Lindsey Thomas
Wildfire Impact Assessment – PG&E Area	Binaya Shrestha
Next Steps	Isabella Nicosia

Introduction and Overview
Preliminary Reliability Assessment Results

Jeff Billinton
Director, Transmission Infrastructure Planning

2020-2021 Transmission Planning Process Stakeholder Meeting
September 23-24, 2020

2020-2021 Transmission Planning Process

December 2020 | April 2020 | March 2021

Phase 1 – Develop detailed study plan

State and federal policy

CEC - Demand forecasts

CPUC - Resource forecasts and common assumptions with procurement processes

Other issues or concerns

Phase 2 - Sequential technical studies

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

Publish comprehensive transmission plan with recommended projects

Phase 3 Procurement

CAISO Board for approval of transmission plan

California ISO

2020-2021 Transmission Plan Milestones

- Draft Study Plan posted on February 21
- Stakeholder meeting on Draft Study Plan on February 28
- Comments to be submitted by March 13
- Final Study Plan to be posted on March 31
- Stakeholder call – update June 3
- Comments to be submitted by June 17
- Preliminary reliability study results to be posted on August 14
- Stakeholder meeting on September 23 and 24
- Comments to be submitted by October 8
- Request window closes October 15
- Preliminary policy and economic study results on November 17
- Comments to be submitted by December 1
- Draft transmission plan to be posted on January 31, 2019
- Stakeholder meeting in 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 results
- Economic assessment preliminary results
- Local Capacity Technical Study – Preliminary alternatives for economic assessment
- Less than $50 million reliability-driven project recommendations
- Projects on hold
- Wildfire assessment update – PG&E area

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

- Load forecast based on California Energy Demand Updated Forecast 2020-2030 (CED 2019) adopted by California Energy Commission (CEC) on January 22, 2020

  https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report/2019-iepr

- RPS portfolio direction for 2020-2021 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=6442464144

2020-2021 Transmission Planning Process Reliability Assessment - Update

- 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, 2021

2020 Request Window Submissions

Project Name	Submitter	Review of Submission
Rearrange TL23013 and TL6969	SDGaE	May be considered for reliability alternative
Metro Region Reliability and Economic Project	SDGaE	May be considered for reliability alternative
Kasson-Kasson Jct1 115 kV Line Section Reconductoring Project	PG&E	May be considered for reliability alternative
Manteca #1 60 kV Line Section Reconductoring Project	PG&E	May be considered for reliability alternative
Palermo-Wyandotte 115 kV Line Section Reconductoring Project	PG&E	May be considered for reliability alternative
Metcalf 500/230 kV Transformers Dynamic Series Reactor Project	PG&E	May be considered for reliability alternative and/or economic alternative
Santa Teresa 115 kV Substation Project	PG&E	ISO concurs with PG&E submission
Brightline West High-Speed Rail Load Interconnection	SCE	ISO concurs with SCE submission
Contra Costa 230 kV	HWT	May be considered for reliability alternative
Lopez 230/115 kV	HWT	May be considered for reliability alternative
Metcalf 230 kV	HWT	May be considered for reliability alternative

2020 Request Window Submissions

Project Name	Submitter	Review of Submission
Contra Costa 230 kV	HWT	May be considered for reliability alternative
Lopez 230/115 kV	HWT	May be considered for reliability alternative
Metcalf 230 kV	HWT	May be considered for reliability alternative
LEAPS	NHC	Not considered as reliability alternative as the submission does not meet a reliability need identified in the CAISO reliability assessment results.
Pacific Transmission Expansion	WGD	Not considered as reliability alternative as the submission does not meet a reliability need identified in the CAISO reliability assessment results.
Great Basin Transmission	LSPower	Not considered as reliability alternative as the submission does not meet a reliability need identified in the CAISO reliability assessment results.
Westside Canal Reliability Center	ConEdison	Not considered as reliability alternative as the submission does not meet a reliability need identified in the CAISO reliability assessment results.

Stakeholder Comments

- Stakeholder comments to be submitted by December 1
  - 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

2020-2021 TPP Policy-driven Assessment

Regional Transmission South:

Nebiyu Yimer, Meng Zhang, Songzhe Zhu, Charles Cheung, and Lyubov Kravchuk

Regional Transmission North:

Vera Hart, Bryan Fong, Lindsey Thomas and Krithika Gurusankar

2020-2021 Transmission Planning Process Stakeholder Meeting

November 17, 2020

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- **Policy-driven assessment context and objectives**
- **Portfolio descriptions and modeling**
- **Battery storage and resource retirement mapping**
- **Deliverability assessment methodology and results**
- **Production cost simulation results**

  (To be presented separately with the Preliminary Production Cost Simulation Results)
- **Summary of results and next steps**

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February and June 2020 Presentations on the Policy Driven Assessment

- In February, we presented the study plan for the Policy-driven Assessment including objectives and methodology

- Provided modeling assumptions transmitted by the CPUC primarily for the Base Portfolio

- In June, we presented the storage mapping and resource retirement instructions provided by the CPUC

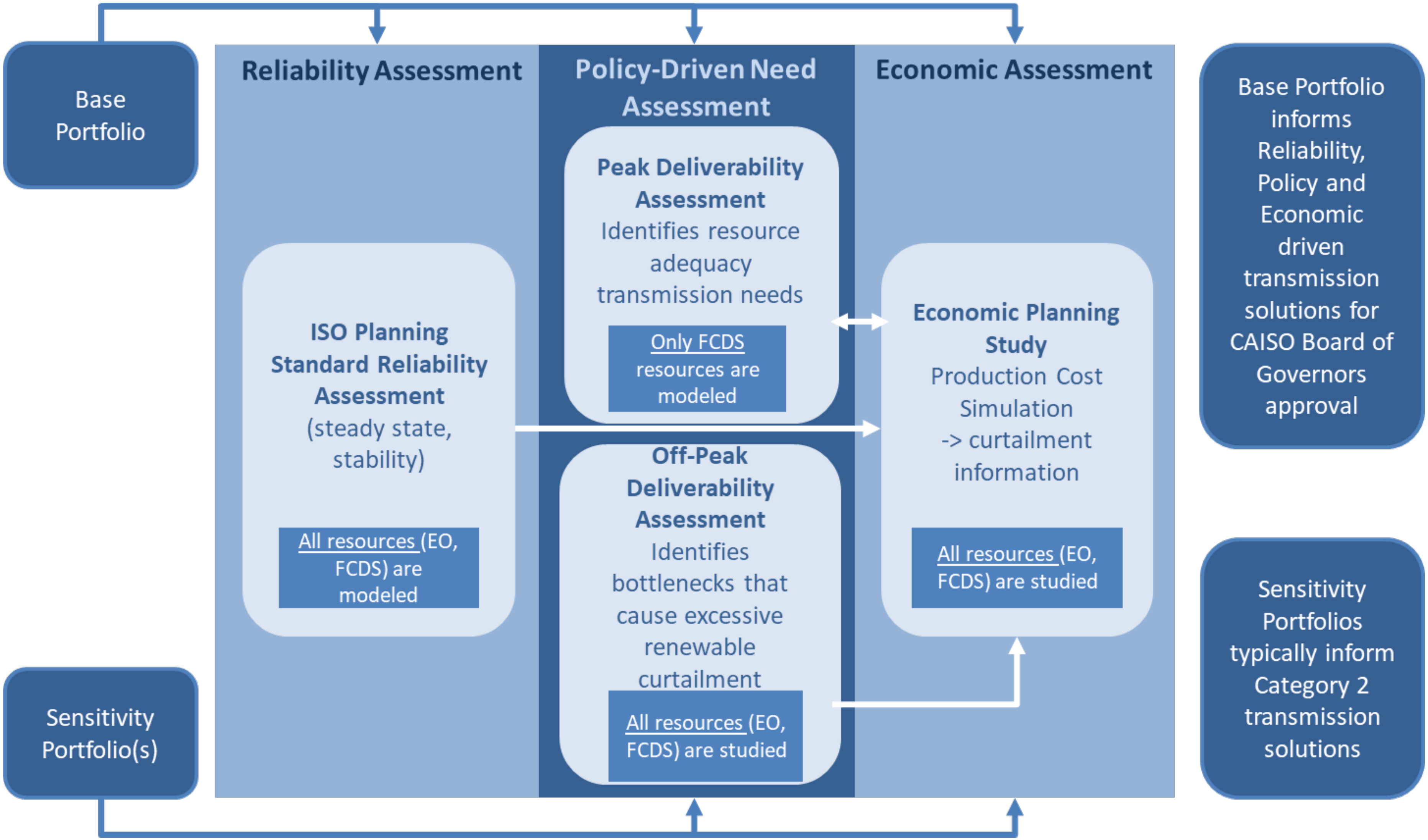
Objectives of the policy-driven assessment

- Assess the transmission impacts of portfolio resources using
  - o Reliability assessment
  - o Peak and Off-peak deliverability assessment and
  - o Production cost simulation

- Identify transmission upgrades or other solutions needed to ensure reliability, deliverability or alleviate excessive curtailment.

- Gain further insights to inform future portfolio development

Overview of the policy-driven assessment



California ISO

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The CPUC provided a base portfolio and two sensitivity portfolios

- Base Portfolio – 2018 Preferred System Portfolio with updated baseline (Updated 2018 PSP)

- Sensitivity Portfolio 1 – 2019 Reference System Portfolio (2019 RSP) with 46 MMT by 2030 GHG target

- Sensitivity Portfolio 2 – 2019 30 MMT by 2030 Energy Only Sensitivity (2019 30 MMT EO Portfolio)

Base portfolio modeling assumptions

- CPUC Staff Report: Modeling Assumptions for the 2020-2021 TPP Release 1 (TPP Base Portfolio)
  ftp://ftp.cpuc.ca.gov/energy/modeling/Modeling_Assumptions_2020_2021_TPP-Report-Release1.pdf

- CEC busbar mapping results for generation resources (TPP Base Portfolio)
  https://caenergy.databasin.org/documents/documents/1995d63284044bf3b3debf0a0ce7b2a3/

Sensitivity portfolios modeling assumptions

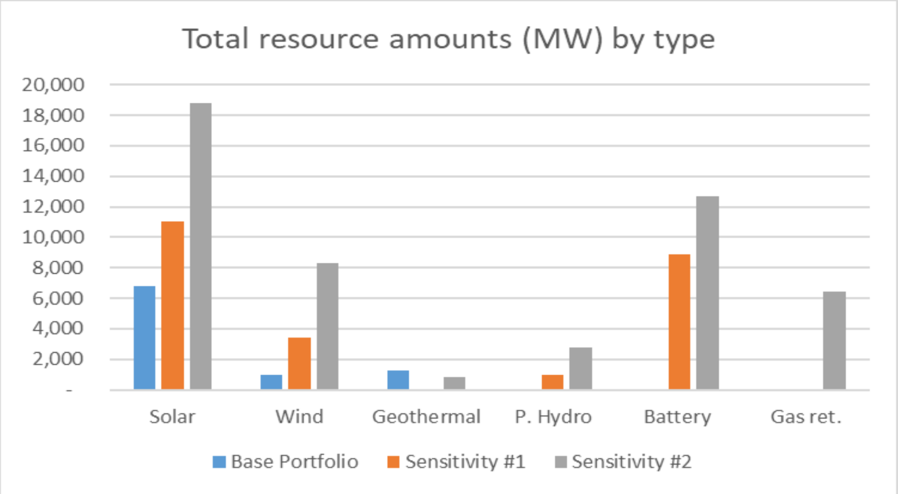
- CPUC Staff Report: Modeling Assumptions for the 2020-2021 TPP Release 2 (TPP Sensitivity Portfolios)
  ftp://ftp.cpuc.ca.gov/energy/modeling/Modeling_Assumptions_2020_2021_TPP-Report-Release2.pdf

- CEC busbar mapping results for generation resources
  https://caenergy.databasin.org/documents/documents/b90faf47be4045a398171a5cfac51b87/ (Sensitivity 1)
  https://caenergy.databasin.org/documents/documents/3124eabfe9b14c5083c99f7f080f7551/ (Sensitivity 2)

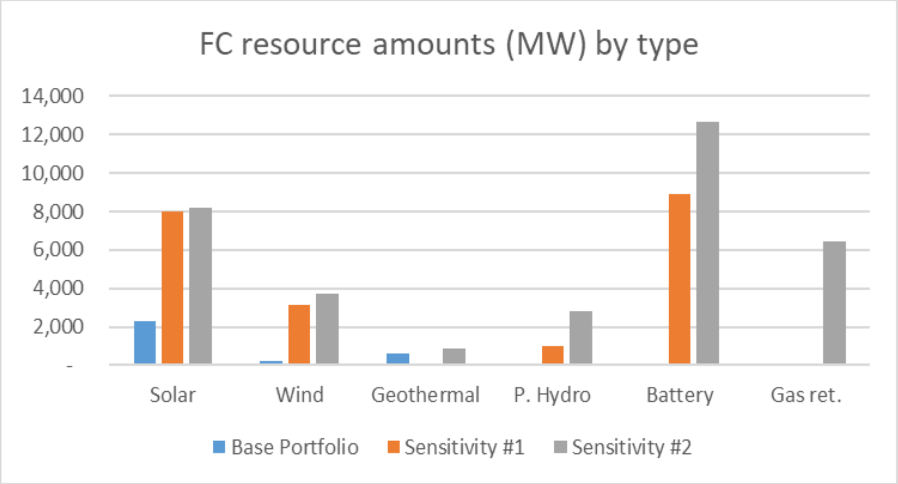
- CPUC Busbar mapping results for battery storage – sensitivity portfolios
  ftp://ftp.cpuc.ca.gov/energy/modeling/BusbarMapping-Results-Battery-2020-03-30.xlsx

Total and FC generic resource mix in the three portfolios

Total (FC + EO) generic resources (MW)			
	Base	Sensitivity #1	Sensitivity #2
Solar	6,763	11,017	18,770
Wind	992	3,443	8,279
Geothermal	1,256	-	851
P. Hydro	-	974	2,798
Battery	-	8,873	12,657
Gas ret.	-	-	(6,456)
Total	**9,011**	**24,307**	**36,899**



Full Capacity (FC) generic resources (MW)			
	Base	Sensitivity #1	Sensitivity #2
Solar	2,273	8,019	8,216
Wind	188	3,122	3,700
Geothermal	604	-	851
P. Hydro	-	974	2,798
Battery	-	8,873	12,657
Gas ret.	-	-	(6,456)
Total	**3,065**	**20,988**	**21,766**



Total generic generation resources additions (EO + FC) by location (excludes battery storage)

	Base Portfolio (MW)					Sensitivity 1 (MW)					Sensitivity 2 (MW)				
Renwable Tx Zone	**Solar**	**Wind**	**GeoT**	**P. Hydro**	**Total**	**Solar**	**Wind**	**GeoT**	**P. Hyd**	**Total**	**Solar**	**Wind**	**GeoT**	**P. Hydro**	**Total**
Arizona (CAISO)	428				428	2,352				2,352	1,350				1,350
Carrizo		160			160		287			287	600	287			887
Central_Valley_North_Los_Banos		146			146		173			173		173			173
Greater_Imperial			1,256		1,256	548				548	356		716		1,072
GreaterImpOutsideTxConstraintZones									974	974				1,216	1,216
Humboldt							34			34		34			34
Inyokern_North_Kramer	554				554	97				97	97				97
Kern_Greater_Carrizo						242	60			302	3,001	60			3,061
Mountain_Pass_El_Dorado						248				248	248				248
North_Victor						300				300	300				300
Northern_California_Ex							866			866		866			866
Riverside_Palm_Springs	1,622	42			1,664						29				29
SCADSNV						330				330	4,303				4,303
SCADSNV-Riverside_Palm_Spring														1,582	1,582
Solano		644			644		542			542		542	135		677
Southern_Nevada (CAISO)	3,006				3,006	862				862	1,727	442			2,169
Tehachapi	1,153				1,153	4,202	275			4,477	4,801	275			5,076
Westlands						1,836				1,836	1,958				1,958
Baja_California							600			600		600			600
New_Mexico												1,500			1,500
NW_Ext_Tx												1,500			1,500
SW_Ext_Tx												500			500
Wyoming							606			606		1,500			1,500
Grand Total	**6,763**	**992**	**1,256**		**9,011**	**11,017**	**3,443**		**974**	**15,434**	**18,770**	**8,279**	**851**	**2,798**	**30,698**

California ISO

FC generic generation resources by location (excludes battery storage)

	Base Portfolio (MW)					Sensitivity 1 (MW)					Sensitivity 2 (MW)				
Renwable Tx Zone	**Solar**	**Wind**	**GeoT**	**P. Hydro**	**Total**	**Solar**	**Wind**	**GeoT**	**P. Hyd**	**Total**	**Solar**	**Wind**	**GeoT**	**P. Hydro**	**Total**
Arizona (CAISO)	-				-	1,196				1,196	-				-
Carrizo	-	-			-	287	-			287	-	187			187
Central_Valley_North_Los_Banos		146			146		173			173		173			173
Greater_Imperial	-		604		604	-		-		-	-		716		716
GreaterImpOutsideTxConstraintZones				-	-				974	974				1,216	1,216
Humboldt		-			-		-			-		-			-
Inyokern_North_Kramer	554				554	97				97	97				97
Kern_Greater_Carrizo	-	-			-	97	60			157	121	60			181
Mountain_Pass_El_Dorado	-				-	-				-	248				248
North_Victor	-				-	300				300	300				300
Northern_California_Ex		-			-		866			866		866			866
Riverside_Palm_Springs	192	42			234	-	-			-	-	-			-
SCADSNV	-				-	-				-	2,333				2,333
SCADSNV-Riverside_Palm_Springs				-	-				974	974				1,582	1,582
Solano		-	-		-		542	-		542		464	135		599
Southern_Nevada (CAISO)	802	-			802	862	-			862	257	442			699
Tehachapi	725	-			725	3,402	275			3,677	3,402	275			3,677
Westlands	-				-	1,778				1,778	1,458				1,458
Baja_California		-			-		600			600		203			203
New_Mexico		-			-		606			606		-			-
NW_Ext_Tx		-			-		-			-		530			530
SW_Ext_Tx		-			-		-			-		500			500
Wyoming		-			-		-			-		-			-
Grand Total	**2,273**	**188**	**604**	**0**	**3,065**	**8,019**	**3,122**	**0**	**1,948**	**13,089**	**8,216**	**3,700**	**851**	**2,798**	**15,565**

Overview of portfolio modeling assumptions

- For all portfolios, generic generation resources were modeled per busbar mapping provided by the CEC

- For the base portfolio, the CPUC did not map generic battery storage (up to 2,157 MW/5,504 MWh) and recommended the CAISO apply the resource at locations where it can mitigate transmission issues identified

- For Sensitivity 2, the CPUC mapped the 12,657 MW of generic battery storage and provided further instructions on refining the mapping to implement the resource retirement assumptions in the portfolio

- For Sensitivity 1, the CPUC staff provided instructions to the CAISO to incorporate battery storage to meet the total 8,873 MW in the portfolio using the Portfolio 2 mapping as a starting point

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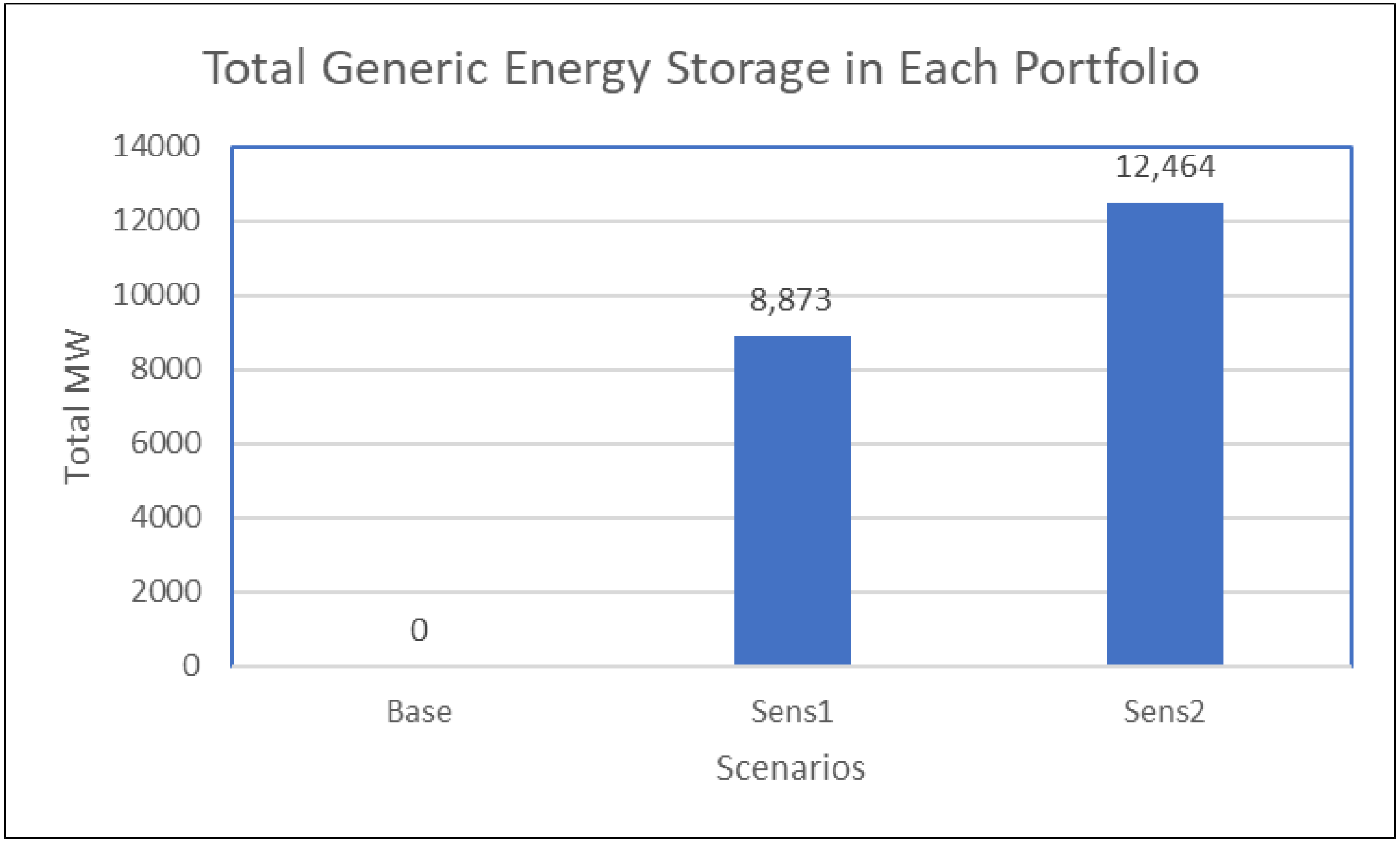
- Summary of results and next steps

Battery Storage Modeling Assumption

- The CPUC staff’s battery storage mapping described in their modeling assumptions report are summarized as follows:

Battery Storage Type	RESOLVE Portfolio
High Confidence (MMA)	1,215
High Confidence (non-MMA)	1,977
Moderate Confidence	4,564
LCR Area solutions	4,902
Total	**12,657**

Total Generic Energy Storage Modeled in Each Portfolio



STORAGE ADJUSTMENT FOR SENSITIVITY 1 PORTFOLIO

Portfolio Sensitivity 1 Battery Storage Modeling Assumptions

- For Sensitivity 1 the CPUC staff recommend the CAISO incorporate battery storage resources in the following order to meet the total 8,873 MW.
    1. Include all base portfolio storage
    2. Include all “High Confidence” battery storage
    3. Include “Moderate Confidence” and “LCR Area solutions”

Energy Storage Mapping Result

Battery Storage Type	CPUC Mapping (MW)	CAISO Sensitivity 1 (MW)
High Confidence (MMA)	1,215	1,215
High Confidence (non-MMA)	1,977	1,977
Moderate Confidence	4,564	2,739
LCR Area Solutions	4,902	2,942
Total	**12,658**	**8,873**

RESOURCE RETIREMENT MODELING AND STORAGE MAPPING FOR SENSITIVITY 2 PORTFOLIO

CPUC's recommendations for resource retirement modeling for sensitivity 2 portfolio

1. Rank all existing generation units by age in the categories of: combined cycle (CCGT), combustion turbine (Peaker), and reciprocating engine. Combined heat and power units are excluded from this list since RESOLVE assumes they remain online through 2030.
2. Model offline the oldest units up to but not exceeding the amounts in each category
3. If known local area requirements are not met then add battery storage to meet the local area requirement up to known battery storage charging limits (Note 1).
4. If known local area requirements are still not met then local gas generation will be restored in reverse order in steps 1 and 2.
5. If specific local units are turned back on in step 4 then an equal amount of additional system generation capacity will be modeled off-line following steps 1 and 2.

Resource Category	MW
CCGT	2,260
Peaker	4,125
Reciprocating Engine	71

Note 1: Based on the 2025 Local Capacity Technical Report, May 2020

LCR Area	LCR Sub-area	Total Retirement	LCR surplus before retirements	LCR Charging Capability MW	Storage needed for gas retirement	Storage needed for gas retirement (4hr)	Busbar Mapping	CPUC Busbar Allocation MW	CAISO Busbar Addition MW	ISO Busbar Reduction MW
Bay Area	Pittsburg	880	705	Flow through	175	438	Pittsburg	168	270	
	Llagas, South Bay-Moss Landing	141.4	213	110	0	0				
	Contra Costa	799.79	623	Flow through	176.79	443	Cayetano	85		
							Contra Costa	79		
							Mariposa		200	
							MARSHLD		625	
Total Bay Area		**1821.19**	**1234**	**1850**	**587.19**	**1468**				
Fresno	Herndon	194.57	683	390	0	0				
		319.62	1220	1300	0	0				
Total Fresno		**514.19**	**1220**	**1300**	**0**	**0**				
Kern	South Kern PP	157.06	149	150	8.06	19	Kern PWR		19	
Sierra	Pease, Drum-Rio Oso	47.6	Need eliminated	N/A	0	0				
	Bogue, Drum-Rio Oso	47.6	Need eliminated	N/A	0	0				

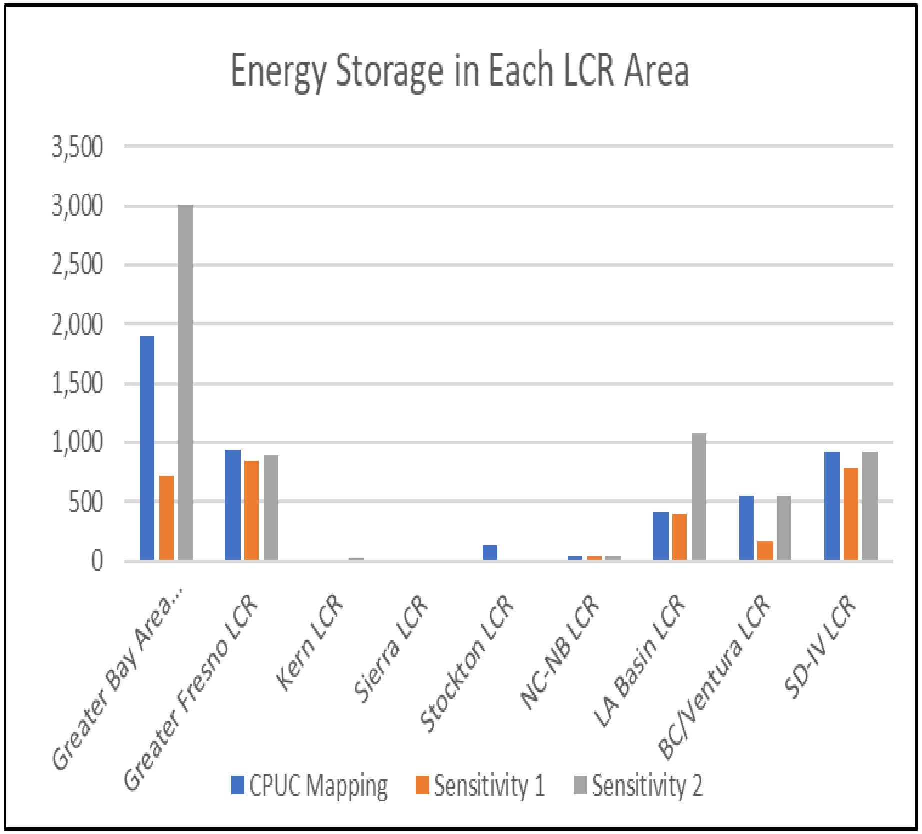
LCR Area	LCR Sub-area	Total Retirement	LCR surplus before retirements	LCR Charging Capability MW	Storage needed for gas retirement	Storage needed for gas retirement (4hr)	Busbar Mapping	CPUC Busbar Allocation MW	CAISO Busbar Addition MW	ISO Busbar Reduction MW
LA Basin	Eastern	209.79	1308	1800	0	0				
	Eastern, Valley-Devers	337.02	Need eliminated	N/A	0	0				
	Western	837.24	405	2700	432.24	1081	La Cienega	67		
							Hinson		650	
							Walnut Creek		340	
							Barre		24	
							Devers	341		-341
Total LA Basin		**1384.05**	**1114**	**4500**	**270.05**	**676**				
BC/Ventura	S.Clara, Moorpark, Goleta	54	Need eliminated	N/A	0	0				
	S.Clara, Moorpark	75.7	217	0	0	0				
SD-IV	San Diego	89	205	920	0	0	Miramar		162	
							Imperial Valley	441		-223
	San Diego, Border	180.83	81	156	99.83	125	Otay	252		
	San Diego, El Cajon	45.42	2	49	43.42	103	El Cajon	42	61	
	San Diego, Esco	96.75	Need eliminated	N/A	0	0				
	San Diego, Pala Inner, Pala Outer	96	N/A	N/A	0	0				
Total SD-IV		**459.9**	**205**	**920**	**254.9**	**574**	Avocado Boulevard Escondido Kearny Miramar Miramar GT	59 42 42 8 8 25		
CAISO System		1867.98	N/A	N/A	N/A	N/A				

Energy Storage Mapping Result

Battery Storage Type	CPUC Mapping (MW)	CAISO Sensitivity 2 (MW)
High Confidence (MMA)	1,215	1,215
High Confidence (non-MMA)	1,977	1,977
Moderate Confidence	4,564	2,756
LCR Area Solutions	4,902	6,516
Total	**12,658**	**12,464**

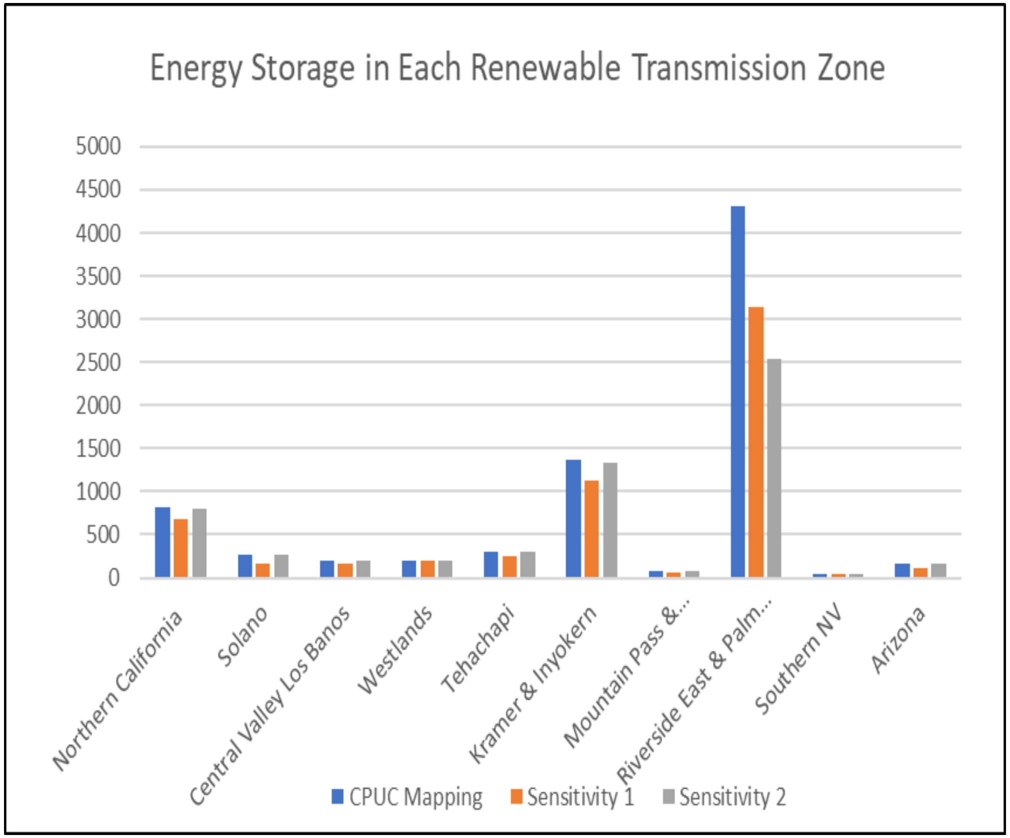
Summary of Energy Storage by LCR Areas

LCR Area	CPUC Mapping (MW)	Sensitivity 1 (MW)	Sensitivity 2 (MW)
Greater Bay Area	1,898	716	3,013
Greater Fresno	943	843	887
Kern	0	0	19
Sierra	10	10	10
Stockton	134	0	0
North Coast North Bay	33	32	33
LA Basin	408	388	1,081
Big Creek Ventura	553	170	553
San Diego Imperial Valley	920	783	920



Summary of Energy Storage by Renewable Transmission Zones

Renewable Transmission Zone	CPUC Mapping MW)	Sensitivity 1 (MW)	Sensitivity 2 (MW)
Northern California	825	674	806
Solano	263	158	263
Central Valley Los Banos	192	157	192
Westlands	197	190	197
Tehachapi	295	257	295
Kramer & Inyokern	1,365	1,127	1,341
Mountain Pass & Eldorado	81	66	81
Riverside East & Palm Spring	4,303	3,137	2,538
Southern NV	40	40	40
Arizona	171	111	171



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On-peak deliverability assessment of portfolios

- Test deliverability of portfolio resources selected as FCDS in accordance with the on-peak 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

Study scenarios in on-peak deliverability assessment

- Highest system need (HSN) scenario
  - when the capacity shortage is most likely to occur
  - Transmission upgrades identified for the base portfolio are recommended as policy driven upgrades
- Second system need (SSN) scenario
  - when the capacity shortage risk will increase if the intermittent generation while producing at a significant output level is not deliverable
  - Transmission upgrades identified for the base portfolio will go through a comprehensive economic, policy, and reliability benefit analysis to be considered for approval as a policy driven or economic upgrade.

Modeling assumptions for Highest System Need scenario

Selected Hours	HE18 ~ 22 in summer month and (loss of load event in ELCC simulation by CPUC or UCM < 6% in CAISO summer assessment)
Load	1-in-5 peak sale forecast by CEC
Non-Intermittent Generators	Study amount set to highest summer month Qualifying Capacity in last three years
Intermittent Generators	Study amount set to 20% exceedance level during the selected hours
Import	MIC data with expansion approved in TPP

California ISO

Modeling assumptions for Secondary System Need scenario

Select Hours	HE15 ~ 17 in summer month and (loss of load event in ELCC simulation by CPUC or UCM < 6% in CAISO summer assessment)
Load	1-in-5 peak sale forecast by CEC adjusted to peak consumption hour
Non-Intermittent Generators	Study amount set to highest summer month Qualifying Capacity in last three years
Intermittent Generators	Study amount set to 50% exceedance level during the selected hours, but no lower than the average QC ELCC factor during the summer months
Import	Highest import schedules for the selected hours

Off-peak deliverability assessment of portfolios

- Identify transmission constraints that might result in excessive renewable curtailment in accordance with the off-peak deliverability methodology as used in GIDAP

- Identify potential upgrades needed to relieve excessive renewable curtailment

- Provide inputs to Production Cost Model for a more thorough evaluation of renewable curtailment

Modeling assumptions in off-peak deliverability assessment

Load	55% ~ 60% of summer peak load
Imports	~6000 MW total
System-Wide Generator Dispatch Level	
Wind	44%
Solar	68%
Energy Storage	0
Hydro	30%
Thermal	15%

Increase Local Area Renewable Output

- After balancing load and resource under the system-wide conditions, the renewable generation in a local area is increased to identify transmission constraints.
- General local study areas include
  - PG&E : North, Fresno and Kern
  - SCE/VEA/GWL/DCRT: Northern, North of Lugo, East of Pisgah, Eastern
  - SDGE: Inland and East
- Off-peak deliverability assessment is performed for each study area separately.

Study Area Wind/Solar Dispatch Assumptions

- The study area wind/solar dispatch assumptions are based on the 90% energy production level of existing generators inside the study area.
- If more than 70% of the study area capacity is wind, then the study area is deemed a wind area; otherwise it is treated as a solar area.

Wind/Solar Dispatch Assumptions in Wind Area

	Wind	Solar
SDG&E	69%	
SCE	64%	68%
PG&E	63%	

Wind/Solar Dispatch Assumptions in Solar Area

	Solar	Wind
SDG&E	79%	
SCE	77%	44%
PG&E	79%	

Preliminary results for SCE area

Overview of transmission zones likely to impact SCE area (FC+EO)

Transmission Zone	Total (FC + EO) (MW)		
	Base	SENS-01	SENS-02
Inyokern_North_Kramer	554	1,224 (97 solar, 1,127 BESS)	1,438 (97 solar, 1,341 BESS)
Mountain_Pass_El_Dorado	-	314 (248 solar, 66 BESS)	329 (248 solar, 81 BESS)
North_Victor	-	300	300
Riverside_Palm_Springs	1,664 (1,622 solar 42 wind)	3,137 BESS	2567 (29 solar, 2,538 BESS)
SCADSNV	-	330	4,303
SCADSNV-Riverside_Palm_Springs	-	-	1,582 (P. Hydro)
Southern_Nevada (CAISO)	3,006	902 (862 solar, 40 BESS)	2,209 (1,727 solar 442 wind, 40 BESS)
Tehachapi	1,153	4,734 (4,202 solar 275 wind, 257 BESS)	5,371 (4,801 solar 275 wind, 295 BESS)
Arizona	428	2,469 (2,352 solar, 117 BESS)	1,521 (1,350 solar, 171 BESS)

*Unless otherwise noted, the resource type is solar

Overview of transmission zones likely to impact SCE area (FC Only)

Transmission Zone	Full Capacity Only (MW)		
	Base	SENS-01	SENS-02
Inyokern_North_Kramer	554	1,224 (97 solar, 1,127 BESS)	1,438 (97 solar, 1,341 BESS)
Mountain_Pass_El_Dorado	-	66 BESS	329 (248 solar, 81 BESS)
North_Victor	-	300	300
Riverside_Palm_Springs	234 (192 solar, 42 wind)	3,137 BESS	2,538 BESS
SCADSNV	-	-	2,333
SCADSNV-Riverside_Palm_Springs	-	974	1,582 (P.Hydro)
Southern_Nevada (CAISO)	802	902 (862 solar, 40 BESS)	739 (257 solar, 442 wind, 40 BESS)
Tehachapi	725	3,934 (3,402 solar 275 wind, 257 BESS)	3,972 (3,402 solar 275 wind, 295 BESS)
Arizona	-	1,313 (1,196 solar, 117 BESS)	171 BESS

*Unless otherwise noted, the resource type is solar

On-Peak Deliverability Assessment Results: South of Kramer – Kramer to Victor Constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Roadway – Victor 115kV	Base Case	HSN	<100%	<100%	<100%
		SSN	<100%	103.06%	120.83%
Kramer – Victor 230kV No. 1 & 2	Base Case	HSN	<100%	<100%	<100%
		SSN	<100%	101.82%	114.93%

Affected renewable transmission zones	Inyokern_North_Kramer		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	100	97	97
Energy storage portfolio MW behind the constraint	0	917.6	1104.5
Mitigation	Not needed	Reconductor Kramer – Victor 230kV lines (~$100M) Loop Kramer – Victor 115kV line into Roadway (~$8M)	
Deliverable MW w/o mitigation	480 MW w/o mitigation 620 MW with Kramer – Victor 115kV loop-in upgrade		

On-Peak Deliverability Assessment Results: South of Kramer – Victor to Lugo Constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Victor – Lugo 230kV No. 1, 2, 3 & 4	Base case	HSN	<100%	<100%	<100%
		SSN	<100%	103.79%	113.88%

Affected renewable transmission zones	Inyokern_North_Kramer		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	363	397	397
Energy storage portfolio MW behind the constraint	0	1025.9	1237
Mitigation	Not needed	Reconductor Victor – Lugo 230kV lines (~$250M)	
Deliverable MW w/o mitigation	1100 MW		

On-Peak Deliverability Assessment Results: Lugo Bank Constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Lugo 500/230kV No. 1 & 2	Base Case	HSN	<100%	<100%	<100%
		SSN	<100%	<100%	103.81%

Affected renewable transmission zones	Inyokern_North_Kramer		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	554	397	397
Energy storage portfolio MW behind the constraint	0	1126	1340.8
Mitigation	Not needed		Lugo 500/230kV No. 3 (~$150M)
Deliverable MW w/o mitigation	1200 MW		

On-Peak Deliverability Assessment Results: Colorado River Bank Constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Colorado River 500/230kV No. 1 & 2	Base Case	HSN	<100%	100.79%	<100%
		SSN	<100%	122.83%	<100%

Affected renewable transmission zones	Riverside_Palm_Springs		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	65	0	0
Energy storage portfolio MW behind the constraint	0	2091	1322
Mitigation	Not needed	Colorado River 500/230kV No. 3 (~$150M)	Not needed
Deliverable MW w/o mitigation	1631 MW		

Off-Peak Deliverability Assessment Results: Whirlwind Bank Constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Whirlwind 500/230kV No. 1, 2 & 3	Base Case	<100%	103.3%	106.86%

Affected renewable transmission zones	Tehachapi (Whirlwind)		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	307	1119	1278
Energy storage portfolio MW behind the constraint	0	267	305
Mitigation Options:			
Renewable curtailment (MW)	0	120	240
Energy storage re-dispatched in charging mode (MW)	0	120	240
Transmission upgrades	Not needed	Whirlwind 500/230kV No. 4 (~$100M)	

California ISO

Preliminary results for VEA/GLW area

Overview of transmission zones likely to impact VEA/GLW area

TX Zone / Location	Total (FC + EO) (MW)			Full Capacity Only (MW)		
	Base	SENS-01	SENS-02	Base	SENS-01	SENS-02
Southern_Nevada (CAISO)	700	700	2,170 (1,728 solar 442 wind)	700	700	700 (258 solar 442 wind)
SCADSNV			290			-

TX Zone / Location	Base	SENS-01	SENS-02
Southern_Nevada (CAISO)	-	40	40

*Unless otherwise noted, the resource type is solar

California ISO

Off-Peak Deliverability Assessment Results: VEA/GLW Area Constraints

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Trout Canyon-Sloan Canyon 230kV line	Base Case	<100%	<100%	214.32%
Mercury SW-Northwest 138kV line	Base Case	<100%	<100%	165.23%-180.38%
Amargosa 230/138kV transformer	Base Case	<100%	<100%	176.13%
Innovation-Desert View 230kV line	Base Case	<100%	<100%	173.05%
Gamebird-Trout Canyon 230kV line	Base Case	<100%	<100%	143.27%
Northwest-Desert View 230kV line	Base Case	<100%	<100%	130.68%
Pahrump-Gamebird 230kV line	Base Case	<100%	<100%	117.15%
Amargosa-Sandy 138kV line	Base Case	<100%	<100%	111.47%
Jackass Flat-Mercury SW 138kV line	Base Case	<100%	<100%	108.53%

Mitigation Options

Options	Pahrump-Sloan Canyon rebuild	Innovation-Desert View reconductor	Desert View-Northwest reconductor	Innovation-Northwest 138kV rebuild	Pahrump-Sloan Canyon #2	Innovation-Desert View #2	Desert View-Northwest #2	138kV Phase Shifter	Gamebird-Arden 230kV	Cost Estimate ($M)*	Gen Curtailment (MW)	Inc MW/$M
Status Quo										0	830	
Option 1	✓	✓	✓	✓						192	450	1.98
Option 2A					✓	✓	✓			112	120	6.34
Option 2B				✓	✓	✓	✓			162	110	4.44
Option 2C					✓	✓	✓	✓		121	130	5.79
Option 3						✓	✓		✓	90	0	9.22
Option 4			✓	✓	✓	✓				162	80	4.63
Option 5	✓					✓	✓	✓		121	350	3.97
Option 6			✓	✓	✓			✓		151	300	3.51

* Cost estimate as provided by GLW

Summary of VEA/GLW Constraint and Mitigation Options

Affected renewable transmission zones	Southern NV (CAISO)		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	700	700	2,460
Energy storage portfolio MW behind the constraint	0	40	40
Mitigation Options:			
Renewable curtailment (MW)	0	0	830
Energy storage re-dispatched in charging mode (MW)	0	0	N/A
Transmission upgrades	Not needed	Not needed	Multiple options involving new transmission lines and existing lines reconductoring/rebuild ($90M~$192M)

California ISO

Preliminary results for SDG&E area

Overview of transmission zones likely to impact SDG&E area

TX Zone / Location	Total (FC + EO) (MW)			Full Capacity Only (MW)		
	Base	SENS-01	SENS-02	Base	SENS-01	SENS-02
Greater Imperial (geothermal)	1,256	-	716	604	-	716
Greater Imperial (solar)	-	548	356	-	-	-
Arizona (solar)	428	2,352	1,350	-	1,196	-
Arizona (BESS)	-	111	171	-	111	171
Baja California (wind)	-	600	600	-	600	203
San Diego Sycamore (pumped hydro)	-	487	608	-	487	608
San Diego Imperial Valley LCR Area (BESS)	-	783	920	-	783	920

On-Peak Deliverability Assessment Results: Avocado 69 kV Constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Avocado-Monserate Tap 69 kV	TL691 Avocado-Monserate-Pendleton 69 kV	HSN	<100%	147%	151%
		SSN	<100%	155%	159%
Avocado-Avocado Tap 69 kV		HSN	<100%	100%	<100%
		SSN	<100%	115%	<100%
Monserate-Monserate Tap 69 kV		HSN	<100%	<100%	<100%
		SSN	<100%	102%	<100%
Avocado-Avocado Tap 69 kV	TL698 Avocado-Monserate-Pala 69 kV	HSN	133%	214%	198%
		SSN	148%	231%	208%
Avocado-Avocado Tap 69 kV	TL6932 Lilac-Pala 69 kV	HSN	<100%	<100%	<100%
		SSN	<100%	100%	<100%

On-Peak Deliverability Assessment Results: Avocado 69 kV Constraint

Affected renewable transmission zones	None		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	56	59
Mitigation	RAS to trip generation		
Deliverable MW w/o mitigation	20 MW		

On-Peak Deliverability Assessment Results: Doublet Tap-Friars Constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Doublet Tap-Friars 138 kV	Old Town-Penasquitos and Sycamore Penasquitos 230 kV	HSN	<100%	121%	116%
		SSN	<100%	117%	113%

Affected renewable transmission zones	None		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	1095	1209
Mitigation		RAS to trip generation	
Deliverable MW w/o mitigation		400 MW	

On-Peak Deliverability Assessment Results: Encina-San Luis Rey Constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Encina Tap-San Luis Rey 230 kV	Encina-San Luis Rey 230 kV	HSN	<100%	115%	115%
		SSN	<100%	133%	133%
Encina-Encina Tap 230 kV		HSN	<100%	<100%	<100%
		SSN	<100%	<100%	103%
Encina-San Luis Rey 230 kV	San Luis Rey-Encina-Palomar 230 kV	HSN	<100%	<100%	102%
		SSN	<100%	116%	118%
	San Luis Rey-Encina-Palomar 230 kV and - Palomar-Batiquitos 138 kV or - Encina-Palomar 138 kV or - Batiquitos-Shadowridge 138 kV	HSN	<100%	<100%	102%
		SSN	<100%	116%	118%
	San Luis Rey-Encina-Palomar and Palomar-Sycamore 203 kV	HSN	<100%	101%	105%
		SSN	<100%	117%	120%

On-Peak Deliverability Assessment Results: Encina-San Luis Rey Constraint

Affected renewable transmission zones	Imperial, Baja, Arizona		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	1222	203
Energy storage portfolio MW behind the constraint	0	1265	1580
Mitigation		RAS to trip existing and new generation	
Deliverable MW w/o mitigation		750 MW	

On-Peak Deliverability Assessment Results: San Marcos-Melrose Tap Constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
San Marcos-Melrose Tap 69 kV	Encina-San Luis Rey 230 kV and Encina-San Luis Rey-Palomar 230 kV	HSN	<100%	116%	108%
		SSN	<100%	141%	132%

Affected renewable transmission zones	None		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	947	868
Mitigation		RAS to trip existing and new generation	
Deliverable MW w/o mitigation		260 MW	

On-Peak Deliverability Assessment Results: National City Constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
National City-Silvergate 69 kV	Sweetwater-Naval Station Metering 69 kV	HSN	<100%	106%	106%
		SSN	<100%	103%	103%
Sweetwater-National City 69 kV		HSN	<100%	105%	104%
		SSN	<100%	101%	102%

Affected renewable transmission zones	None		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	148	280
Mitigation		RAS to trip generation	
		100 MW	

On-Peak Deliverability Assessment Results: Montgomery Constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Bay Boulevard-Montgomery 69 kV	Bay Boulevard-Montgomery Tap 69 kV	HSN	<100%	110%	116%
		SSN	<100%	<100%	104%

Affected renewable transmission zones	None		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	148	280
Mitigation		RAS to trip generation	
Deliverable MW w/o mitigation		90 MW	

On-Peak Deliverability Assessment Results: Otay Constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Otay-Otay Lakes Tap 69 kV	Base Case	HSN	<100%	<100%	101%
		SSN	<100%	<100%	<100%
Otay-Bay Boulevard 69 kV #2	TL623 Otay-Imperial Beach-San Ysidro 69 kV	HSN	<100%	<100%	109%
		SSN	<100%	<100%	116%
Otay-Otay Lakes Tap 69 kV		HSN	<100%	<100%	128%
		SSN	<100%	<100%	111%
Otay-Bay Boulevard 69 kV #2	TL649 Otay-Otay Lakes-San Ysidro-Border 69 kV	HSN	<100%	<100%	<100%
		SSN	<100%	<100%	113%
Otay-Bay Boulevard 69 kV #2	TL645 Otay-Bay Boulevard 69 kV #1	HSN	<100%	116%	143%
		SSN	<100%	133%	158%
Otay-Bay Boulevard 69 kV #1	TL646 Otay-Bay Boulevard 69 kV #2	HSN	<100%	109%	133%
		SSN	<100%	126%	150%

On-Peak Deliverability Assessment Results: Otay Constraint

Affected renewable transmission zones	None		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	148	280
Mitigation		RAS to trip generation	Reconductor Otay-Otay Lakes Tap 69 kV (~$2.3M); RAS to trip generation
Deliverable MW w/o mitigation		100 MW	

On-Peak Deliverability Assessment Results: San Luis Rey-San Onofre Constraint

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	HSN	<100%	101%	<100%
		SSN	<100%	126%	123%

Affected renewable transmission zones	Imperial, Baja, Arizona		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	1222	203
Energy storage portfolio MW behind the constraint	0	1321	1639
Mitigation		RAS to trip generation	
Deliverable MW w/o mitigation		900 MW	

On-Peak Deliverability Assessment Results: Miramar Constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Miramar-Miramar GT 69 kV	TL664 Miramar GT-Rose Canyon-Penasquitos 69 kV	HSN	<100%	108%	<100%
		SSN	<100%	108%	<100%
Miramar GT-Miramar Tap 69 kV	TL668 Mirmar-Miramar GT 69 kV	HSN	<100%	103%	<100%
		SSN	<100%	103%	<100%

Affected renewable transmission zones	None		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	24	25
Mitigation		RAS to trip generation	
Deliverable MW w/o mitigation		0 MW	

California ISO

On-Peak Deliverability Assessment Results: Border Constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Otay-Bay Boulevard 69 kV #2	Border-Salt Creek 69 kV	HSN	<100%	101%	<100%
		SSN	<100%	114%	<100%
Otay-Otay Lake Tap 69 kV		HSN	<100%	<100%	<100%
		SSN	<100%	109%	<100%
Otay Lake Tap-San Ysidro 69 kV		HSN	100%	<100%	<100%
		SSN	<100%	101%	<100%
Otay Lake Tap-Otay 69 kV		HSN	<100%	<100%	<100%
		SSN	112%	<100%	<100%
Otay-Bay Boulevard 69 kV #2	Miguel-Salt Creek 69 kV	HSN	<100%	<100%	<100%
		SSN	<100%	101%	<100%

On-Peak Deliverability Assessment Results: Border Constraint

Affected renewable transmission zones	None		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	148	280
Mitigation	Add storage to existing generation tripping RAS		
Deliverable MW w/o mitigation	0 MW		

Off-Peak Deliverability Assessment Results SDG&E area

- There are no off-peak deliverability constraints identified in the SDG&E area under Base, Sensitivity 1 or Sensitivity 2 scenarios

Preliminary results for PG&E South area

Overview of transmission zones likely to impact PG&E area FC only.

	Deliverability study capacity (MW)		
Renewable zone	BASE	SENS 1	SENS 2
Central Valley_North_los_Banos	Wind 146	330 Wind 173, BESS 157	365 Wind 173,BESS 192
Kern_Greater_Carizzo	0	157 Solar 97, Wind 60	181 Solar 121, Wind 60,
Humbodlt	0	0	0
Northern_California_Ex	0	2311 Wind 866, BESS 1445	4480 Wind 866, BESS 3614
Solano	0	700 Wind 542, BESS 158	862 Wind 464, GeoT 135, BESS 263
Westlands	0	2816 Solar 1778, BESS 1038	2560 Solar 1458, BESS 1102

On-Peak Deliverability Assessment Results: Gates-Midway 500 kV line constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Gates-Midway 500 kV line	Base case	HSN	<100%	<100%	124%
		SSN	<100%	102%	124%

Affected transmission zones	Westlands, Central Valley, Los Banos, Northern California and Solano		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	3726	4043
Energy storage portfolio MW behind the constraint	0	2793	5592
Mitigation	N/A	New Gates-Midway 500 kV line	
Deliverable MW w/o mitigation	N/A	6155 MW	7524 MW

On-Peak Deliverability Assessment Results: Gates 500/230 kV TB #11 constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Gates 500/230 kV TB #11	Gates 500/230 kV TB #12	HSN	<100%	<100%	<100%
		SSN	<100%	100%	<100%

Affected transmission zones	Westlands and Greater Carrizo		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	836	632
Energy storage portfolio MW behind the constraint	0	1032	1083
Mitigation	N/A	RAS to trip generation	
Deliverable MW w/o mitigation	N/A	1853 MW	Fully deliverable

On-Peak Deliverability Assessment Results: Panoche-Gates #1 and #2 230 kV constraint

Overloaded Facility	Contingency		Flow		
			BASE	**SENS-01**	**SENS-02**
Panoche-Gates #1 and #2 230 kV lines	Gates-Mustang #1 and #2 230 kV lines	HSN	<100%	<100%	<100%
		SSN	<100%	110%	115%

Affected transmission zones	Westlands, Central Valley, Los Banos and Northern CA		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	573	626
Energy storage portfolio MW behind the constraint	0	834	878
Mitigation	N/A	RAS to trip generation	
Deliverable MW w/o mitigation	N/A	1046 MW	

On-Peak Deliverability Assessment Results: Melones-Cottle 230kV line constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Melones-Cottle 230 kV line	Base Case	HSN	<100%	<100%	<100%
		SSN	<100%	101%	<100%
	Gates-Mustang #1 and # 2 230 kV lines	HSN	<100%	<100%	<100%
		SSN	<100%	111%	111%

Affected transmission zones	Westlands		
	BASE	**Base Case overload SENS-01**	**Contingency Overload SENS-01 and SENS-02**
Renewable portfolio MW behind the constraint	0	136	252
Energy storage portfolio MW behind the constraint	0	0	433
Mitigation	N/A	Operational solution	RAS to trip generation
Deliverable MW w/o mitigation	N/A	0 MW	318 MW

On-Peak Deliverability Assessment Results: Borden-Wilson 230 kV constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Borden-Storey #1 and Wilson-Storey 230 kV lines	Gates-Mustang #1 and # 2 230 kV	HSN	<100%	<100%	<100%
		SSN	<100%	113%*	<100%
Borden-Storey #2 230 kV line	Borden-Storey #1 230 kV	HSN	<100%	<100%	<100%
		SSN	<100%	103%	<100%

Affected transmission zones	Westlands		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	328	252
Energy storage portfolio MW behind the constraint	0	747	786
Mitigation	N/A	RAS to trip generation	
Deliverable MW w/o mitigation	N/A	809 MW	

* Represents worst loading

On-Peak Deliverability Assessment Results: Gates-Mustang #1 and # 2 230 kV lines constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Gates-Mustang #1 and # 2 230 kV lines	Gates-Mustang #1 or # 2 230kV lines	HSN	<100%	<100%	<100%
		SSN	<100%	131%	126%

Affected transmission zones	Westlands		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	328	252
Energy storage portfolio MW behind the constraint	0	748	778
Mitigation	N/A	RAS to trip generation	
Deliverable MW w/o mitigation	N/A	723 MW	

On-Peak Deliverability Assessment Results: Gates-Arco and Arco-Midway 230 kV lines constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Gates-Arco and Arco-Midway 230 kV lines	Los Banos-Midway#2 and Gates-Midway 500 kV lines	HSN	<100%	<100%	162%*
		SSN	<100%	109%	162%*

Affected transmission zones	Westlands, Central Valley, Los Banos and Northern CA		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	2664	1776
Energy storage portfolio MW behind the constraint	0	2780	3681
Mitigation	N/A	Existing RAS under review	
Deliverable MW w/o mitigation	N/A	4027 MW	1491 MW

* Represents worst loading

On-Peak Deliverability Assessment Results: GWF-Contandina-Jacksson 115 kV line constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
GWF-Contandina-Jacksson 115 kV line	Gates-Mustang #1 and # 2 230 kV lines	HSN	<100%	<100%	<100%
		SSN	<100%	105%	103%

Affected transmission zones	Westlands		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	72	55
Energy storage portfolio MW behind the constraint	0	404	425
Mitigation	N/A	RAS to trip generation	
Deliverable MW w/o mitigation	N/A	370 MW	

On-Peak Deliverability Assessment Results:
Arco-Cholame (Chlomale-cholame Jct) 70 kV line constraint

Overloaded Facility	Contingency		Flow		
			BASE	**SENS-01**	**SENS-02**
Arco-Cholame (Chlomale-cholame Jct) 70 kV line	Base Case	HSN	<100%	119%	119%
		SSN	<100%	<100%	<100%

Affected transmission zones	Greater Carrizo		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0	60	60
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation	N/A	Reconductor Arco-Cholame 70 kV line	
Deliverable MW w/o mitigation	N/A	51 MW	

Overview of transmission zones likely to impact PG&E area FC+EO (excluding storage)

	Deliverability study capacity (MW)		
Renewable zone	BASE	SENS 1	SENS 2
Central Valley_North_los_Banos	Wind 146	330 Wind 173, 157 BESS	365 Wind 173,BESS 192
Kern_Greater_Carizzo	0	302 Solar 242, Wind 60	3061 Solar 3001, Wind 60
Humbodlt	0	Wind 34	Wind 34
Northern_California_Ex	0	2311 Wind 866, BESS 1445	4480 Wind 866, BESS 3614
Solano	644 Wind	700 Wind 542, BESS 158	940 Wind 542,135 GeoT, BESS 263
Westlands	0	2874 Solar 1836, BESS 1038	3060 Solar 1958, BESS 1102

Off-Peak Deliverability Assessment Results: Dairyland-Le Grand & Le Grand-Chowchilla 115 kV lines constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Dairyland-Le Grand and Le Grand-Chowchilla 115 kV lines	Panoche-Mendota 115kV line	123%	123%	123%

Affected transmission zones	Westlands		
	BASE	**SENS-01**	**SENS-02**
Renewable MW behind the constraint	248	248	248
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	22	22	22
Energy storage re-dispatched in charging mode (MW)	0	0	0
Transmission upgrades	RAS to trip generation		

Off-Peak Deliverability Assessment Results: Kettleman- Gates 70 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Kettleman-Gates 70 kV line	Base Case	127%	127%	127%

Affected transmission zones	Westlands		
	BASE	SENS-01	SENS-02
Renewable MW behind the constraint	60	60	60
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	10	10	10
Energy storage re-dispatched in charging mode (MW)	0	0	0
Transmission upgrades	Reconductor Kettleman-Gates 70 kV line		

Off-Peak Deliverability Assessment Results: Five points-Huron-Gates 70 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Five Points-Huron-Gates 70 kV line	Panoche-Excelciours #1 and #2 115 kV lines	110%	119%	121%

Affected transmission zones	Westlands		
	BASE	SENS-01	SENS-02
Renewable MW behind the constraint	154	154	154
Energy storage portfolio MW behind the constraint	0	8	8
Mitigation Options:			
Renewable curtailment (MW)	8	16	18
Renewable Curtailment with Energy storage re-dispatched in charging mode (MW)	0	8 MW storage + 8 MW renewables	8 MW storage + 10 MW renewables
Transmission upgrades	RAS to trip generation		

Off-Peak Deliverability Assessment Results: Gates–Arco–Midway 230 kV lines constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Gates–Arco–Midway 230 kV lines	Arco – Midway 230 kV line*	<100%	<100%	166%

Affected transmission zones	Greater Carrizo		
	BASE	SENS-01	SENS-02
Renewable Portfolio MW behind the constraint	0	0	679
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	0	0	229
Energy storage re-dispatched in charging mode (MW)	0	0	0
Transmission upgrades	RAS to trip generation		

* Represents worst loading

Off-Peak Deliverability Assessment Results: Stockdale – Kern PP 230 kV line constraint

Overloaded Facility	Contingency	Flow		
		BASE	**SENS-01**	**SENS-02**
Stockdale – Kern PP 230 kV line	Stockdale B – Kern PP #1 230 kV line*	<100%	<100%	138%

Affected transmission zones	Greater Carrizo		
	BASE	**SENS-01**	**SENS-02**
Renewable Portfolio MW behind the constraint	0	0	617
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	0	0	129
Energy storage re-dispatched in charging mode (MW)	0	0	0
Transmission upgrades	RAS to trip generation		

* Represents worst loading

Off-Peak Deliverability Assessment Results: Midway–Renfro–Tupman 115 kV line constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Midway–Renfro–Tupman 115 kV line	Base case*	<100%	<100%	268%

Affected transmission zones	Greater Carrizo		
	BASE	SENS-01	SENS-02
Renewable Portfolio MW behind the constraint	0	0	615
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	0	0	378
Energy storage re-dispatched in charging mode (MW)	0	0	0
Transmission upgrades	RAS to trip generation		

California ISO

* Represents worst loading

Off-Peak Deliverability Assessment Results:
San Miguel–Coalinga & San Miguel–Union 70 kV line constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
San Miguel–Coalinga & San Miguel–Union 70 kV lines	Templeton-Gates & Gates-Calflatss #1 230 kV lines	<100%	<100%	134%

Affected transmission zones	Greater Carrizo		
	BASE	SENS-01	SENS-02
Renewable Portfolio MW behind the constraint	0	0	688
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	0	0	244
Energy storage re-dispatched in charging mode (MW)	0	0	0
Transmission upgrades	RAS to trip generation		

Off-Peak Deliverability Assessment Results: Wind Gap Jct 1 and 2–Wheeler Ridge 230 kV constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Wind Gap Jct 1 and 2–Wheeler Ridge 230 kV line	Midway-Wheeler Ridge #1 230 kV or Midway-Wheeler Ridge #2 230 kV lines	<100%	<100%	109%

Affected transmission zones	Greater Carrizo		
	BASE	SENS-01	SENS-02
Renewable Portfolio MW behind the constraint	0	0	552
Energy storage portfolio MW behind the constraint	0	0	0
Mitigation Options:			
Renewable curtailment (MW)	0	0	37
Energy storage re-dispatched in charging mode (MW)	0	0	0
Transmission upgrades	TPP Wheeler Ridge Jct project		

Preliminary results for PG&E North area

On-Peak Deliverability Assessment Results: Round Mountain 500/230 kV Bank #1 constraint

Overloaded Facility	Contingency		Flow		
			BASE	**SENS-01**	**SENS-02**
Round Mountain 500/230 kV Bank #1	Malin-Round Mountain #1 and #2 500 kV DLO	HSN	<100%	106%	132%
		SSN	<100%	<100%	100%

Affected transmission zones	Northern California		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0 MW	494 MW	1024 MW
Energy storage portfolio MW behind the constraint	0 MW	0 MW	0 MW
Mitigation	N/A	RAS under review	
Deliverable MW w/o mitigation	N/A	TBD	

On-Peak Deliverability Assessment Results: Round Mountain–Cottonwood 230 kV Constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Round Mountain–Cottonwood 230 kV lines	Table Mountain-Tesla and Table Mountain-Vaca Dixon 500 kV DLO	HSN	<100%	107%	139%*
		SSN	<100%	<100%	<100%

Affected transmission zones	Northern California		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0 MW	201 MW	731 MW
Energy storage portfolio MW behind the constraint	0 MW	14 MW	23 MW
Mitigation	N/A	RAS under review	
Deliverable MW w/o mitigation	N/A	TBD	

* Represents worst loading

On-Peak Deliverability Assessment Results: Cayetano–North Dublin 230 kV constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Cayetano-North Dublin 230 kV line	Contra Costa-Moraga Nos. 1 & 2 - 230 kV lines	HSN	<100%	116%	120%*
		SSN	<100%	<100%	<100%

Affected transmission zones	Solano and Northern California		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0 MW	121 MW	104 MW
Energy storage portfolio MW behind the constraint	0 MW	316 MW	810 MW
Mitigation	N/A	Reconductor North Dublin-Cayetano 230 kV Line (2.63 miles OH Line & 2.82 UG cable with new UG cable 797 MVA/2000 A ~ $42.4 M)	
Deliverable MW w/o mitigation	N/A	379 MW	

* Represents worst loading

On-Peak Deliverability Assessment Results : Las Positas – Newark 230 kV constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Las Positas-Newark 230 kV line	Contra Costa - Moraga Nos. 1 & 2 - 230 kV lines	HSN	<100%	110%	116%*
		SSN	<100%	<100%	<100%

Affected transmission zones	Solano and Northern California		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0 MW	121 MW	104 MW
Energy storage portfolio MW behind the constraint	0 MW	316 MW	810 MW
Mitigation	N/A	Reconductor Las Positas-Newark 230 kV line (~ $12.5 M)	
Deliverable MW w/o mitigation	N/A	482 MW	

* Represents worst loading

On-Peak Deliverability Assessment Results : Contra Costa Bus E–F 230 kV constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Contra Costa Bus E-F 230 kV	Contra Costa - Las Positas and North Dublin -Vineyard 230 kV lines	HSN	<100%	101%	102%*
		SSN	<100%	<100%	<100%

Affected transmission zones	Solano and Northern California		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0 MW	542 MW	270 MW
Energy storage portfolio MW behind the constraint	0 MW	506 MW	1073 MW
Mitigation	N/A	RAS to trip generation	
Deliverable MW w/o mitigation	N/A	996 MW	1269 MW

* Represents worst loading

On-Peak Deliverability Assessment Results: Delevan–Cortina 230 kV constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Delevan–Cortina 230 kV line	Table Mountain-Tesla and Table Mountain-Vaca Dixon 500 kV DLO	HSN	<100%	122%	133%*
		SSN	<100%	<100%	101%

Affected transmission zones	Northern California		
	BASE	**SENS-01**	**SENS-02**
Renewable portfolio MW behind the constraint	0 MW	494 MW	494 MW
Energy storage portfolio MW behind the constraint	0 MW	0 MW	0 MW
Mitigation	N/A	RAS under review	
Deliverable MW w/o mitigation	N/A	TBD	

* Represents worst loading

On-Peak Deliverability Assessment Results: Fulton 60 kV lines constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Fulton area 60 kV lines	Geysers #9-Lakeville 230 kV & Eagle Rock-Fulton-Silverado 115kV Lines	HSN	104%	109%	109%
		SSN	<100%	104%	112%*

Affected transmission zones	Northern California and N. Coast		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	11	11
Mitigation	RAS to trip generation		
Deliverable MW w/o mitigation	0	0	

* Represents worst loading

On-Peak Deliverability Assessment Results: Caribou #2 60kV line constraint

Overloaded Facility	Contingency		Flow		
			BASE	SENS-01	SENS-02
Caribou #2 60 kV line	Caribou 230/115/60 kV TB 11	HSN	<100%	<100%	112%
		SSN	<100%	106%	Diverge

Affected transmission zones	Northern California		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0	0	0
Energy storage portfolio MW behind the constraint	0	14	23
Mitigation	Existing RAS under review		
Deliverable MW w/o mitigation	0	0	

Off-Peak Deliverability Assessment Result : Cottonwood – Round Mountain 230 kV Constraint

Overloaded Facility	Contingency	Flow		
		BASE	SENS-01	SENS-02
Cottonwood-Round Mountain 230 kV lines	Round Mountain #1 500/230 kV Transformer	<100 %	<100%	118%*

Affected transmission zones	Northern California		
	BASE	SENS-01	SENS-02
Renewable portfolio MW behind the constraint	0 MW	0 MW	1603 MW
Energy storage portfolio MW behind the constraint	0 MW	0 MW	0 MW
Mitigation Options:			
Renewable curtailment (MW)	0 MW	0 MW	20 MW
Energy storage re-dispatched in charging mode (MW)	0 MW	0 MW	0 MW
Transmission upgrades	N/A	RAS under review	

* Represents worst loading

Agenda

- Policy-driven assessment context and objectives
- Portfolio descriptions and modeling
- Battery storage and resource retirement mapping
- Deliverability assessment methodology and results
- **Production cost simulation results**

  (To be presented separately with the Preliminary Production Cost Simulation Results)
- Summary of results and next steps

Agenda

- Policy-driven assessment context and objectives
- Portfolio descriptions and modeling
- Battery storage and resource retirement mapping
- Deliverability assessment methodology and results
- Production cost simulation results

  (To be presented separately with the Preliminary Production Cost Simulation Results)
- **Summary of results and next steps**

Summary of on-peak deliverability assessment results

- **Base Portfolio -** All the FCDS resources are expected to be deliverable with RAS. No policy-driven transmission upgrades are identified
- **Sensitivity Portfolios**
  - FCDS resources in several renewable transmission zones are not deliverable without upgrades or a reduction in battery storage as summarized below:

		Battery Storage Behind the Constraint (Base/Sens-1/Sens-2) (MW)	Potential Mitigation		Portfolio for which Mitigation is Identified		
Renewable Transmission Zone	Constraint		Transmission	Mapped Battery Reduction	Base	Sens-01	Sens-02
Inyokern_North_Kramer	Kramer to Victor	0/918/1105	Reconductor Kramer – Victor 230kV lines (~$100M) Loop Kramer – Victor 115kV line into Roadway (~$8M)	Yes	-	√☐	√☐
Inyokern_North_Kramer	Victor to Lugo	0/1026/1237	Reconductor Victor – Lugo 230kV lines (~$250M)	Yes	-	√☐	√☐
Inyokern_North_Kramer	Lugo 500/230 kV Bank	0/1126/1341	Lugo 500/230kV No. 3 (~$150M)	Yes	-	-	√☐
Riverside_Palm_Springs	Colorado River 500/230 kV Bank	0/2091/1322	Colorado River 500/230kV No. 3 (~$150M)	Yes	-	√☐	-
None (San Diego Area)	Otay Constraint	0/148/280	Reconductor Otay-Otay Lakes Tap 69 kV (~$2.3M)	Yes	-	-	√☐
Westlands, Central Valley, Los Banos, Northern California and Solano	Gates-Midway 500kV Line	0/2793/5592	New Gates-Midway 500 kV line	Yes	-	√☐	√☐
Greater Carrizo	Arco-Cholame 70kV Line	0	Reconductor Arco-Cholame 70 kV line	No	-	√☐	√☐
Solano and Northern Calif	Cayetano – North Dublin 230 kV	0/316/810	Reconductor North Dublin-Cayetano 230 kV Line (~ $42.4 M)	Yes	-	√☐	√☐
Solano and Northern Calif	Las Positas – Newark 230 kV	0/316/810	Reconductor Las Positas-Newark 230 kV line (~ $12.5 M)	Yes	-	√☐	√☐

  - FCDS resources including energy storage in other renewable transmission zones are expected to be deliverable with RAS.

Summary of off-peak deliverability assessment results

- Pre-contingency renewable curtailment was identified to varying extent in the base and sensitivity portfolios
- In addition to RAS, transmission upgrades, dispatching storage behind the constraint in charging mode and adding storage (subject to on-peak deliverability) are considered to mitigate renewable curtailment

Renewable Transmission Zone	Constraint	Battery Storage Behind Constraint (Base/Sens-1/Sens-	Renweable Curtailment (Base/Sens-1/Sens-2)(MW)	Potential Mitigation		
				Transmission	Dispatch Storage (Base/Sens-1/Sens-2) (MW)	Add Storage (Base/Sens-1/Sens-2) (MW)
Tehachapi (Whirlwind)	Whirlwind 500/230 Banks	0/267/305	0/120/240	Whirlwind 500/230kV No. 4 (~$100M) **- Sens-1, Sens-2**	0/120/240	N/A
Southern NV (CAISO)	VEA/GLW Area Constraints	0/40/40	0/0/830	Multiple options (~$90M-$192M each) **- Sens-2**	0/0/NA	0/0/790
Westlands	Kettleman- Gates 70 kV constraint	0	10/10/10	Reconductor Kettleman-Gates 70 kV line **- Base, Sens-1, Sens-2**	N/A	10/10/10

- RAS is expected to address pre-contingency curtailment in other areas

Summary of production simulation results

(To be presented with the Preliminary Production Cost Simulation Results)

Next steps

- Study selected renewable zones to evaluate the effectiveness of transmission solutions and any re-mapping of storage.
- Identify policy-driven transmission upgrade need based on deliverability and PCM studies
- Update transmission capability estimates for use in future CPUC IRP portfolio development cycles
- Document the policy-driven assessment results and conclusions in the draft 2020-2021 Transmission Plan

2020-2021 Transmission Planning Process
SCE Area
Project for Concurrence

Robert Sparks
Sr. Manager, Regional Transmission - South

2020-2021 Transmission Planning Process Stakeholder Meeting
November 17, 2020

Point of Service Network Upgrades

- SCE submitted a load interconnection request to the CAISO for review and concurrence
- The Brightline West High-Speed Rail load interconnection request
- 56 MW connected to the Ivanpah 115 kV bus
  – The scope of the network upgrades requires an expansion of the bus with an estimated cost of $4 M
- 56 MW connected to the Kramer-Tortilla 115 kV line
  – The scope of the network upgrades requires looping the Kramer-Tortilla line into a new switching station with an estimated cost of $10 M

Analysis of CAISO System Impacts from the Ivanpah load interconnection

- The CAISO reviewed SCE’s system impact analysis
- No impacts were identified

Analysis of CAISO System Impacts from the Kramer-Tortilla line load interconnection

- The CAISO reviewed SCE’s system impact analysis
- Post transient voltage deviation exceeding 8% and low voltages below 90% were identified at several 115 kV buses for the worst P1 contingency
- During single line outage conditions as the load fluctuates due to the nature of the train’s electrical load voltage deviations and low voltages were also observed

Mitigation Alternatives to Address Impacts from the Kramer-Tortilla line load interconnection

The CAISO reviewed SCE's analysis of four mitigation alternatives:

1. Install a new 220/115 kV transformer bank at Coolwater substation at an estimated cost of $47 M
2. Loop existing Kramer-Cool Water 220 kV line into the new load substation
   - Development timeline would not meet customers needs
3. New 115 kV line from Kramer to the new load substation
   - Development timeline would not meet customers needs
4. SVC/STATCOM added to the new load substation
   - Would not provide the benefit of an additional source to the Kramer 115 kV system and would have a higher anticipated O&M cost than the transformer

Comparison of Alternatives

- Two of the alternatives have a much higher cost and do not meet the customers timeline
- The transformer alternative is recommended by SCE and would provide an additional source into the Kramer 115 kV system and could potentially accommodate additional renewable generation interconnection projects
  - Results in the Sandlot switchyard and the Kramer-Sandlot-Coolwater 230 kV lines becoming network facilities recovered through the CAISO TAC
- The SVC/Statcom would not increase the thermal capability of the Kramer 115 kV system and would not create additional opportunities for renewable generation to interconnect.

Conclusions

- The CAISO concurs with the network upgrades proposed at the new load substations
- The CAISO concurs with SCE's system impact analysis and the recommended network upgrades proposed to mitigate the identified reliability concerns

2020-2021 Transmission Planning Process
PG&E Area
Less than $50 Million Project Approvals and Project for Concurrence

2020-2021 Transmission Planning Process Stakeholder Meeting

November 17, 2020

Palermo – Wyandotte 115 kV Line Section Reconductoring (North Valley Area)

- Reliability Assessment Need
  - NERC Category P0 starting 2022.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductor the Wyandotte – Pole 003/025 115 kV line section (~0.05 miles) with larger conductor and remove any limiting element.
- Project Cost
  - $0.125M - $0.250M
- Alternatives Considered
  - Status quo which is not acceptable due to P0 issue.
  - Re-rate is not feasible as the overload occurs after 7pm which is not allowed by re-rate methodology.
- Recommendation
  - Approval

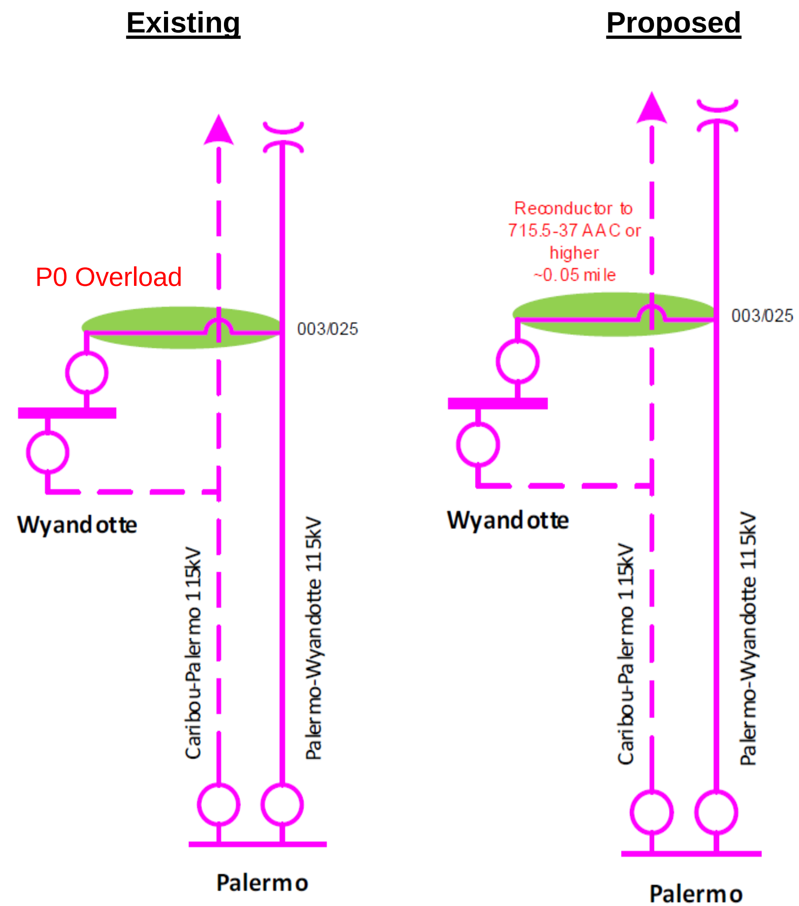
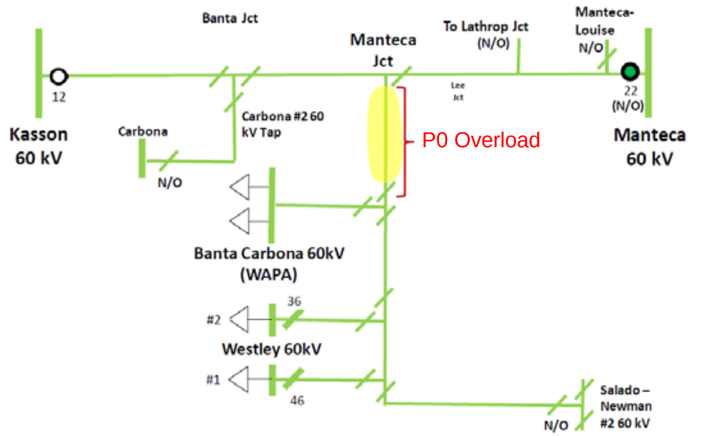


Diagram source: PG&E 2020-2021 TPP RW submission

Manteca #1 60 kV Line Section Reconductoring (Central Valley Area)

- Reliability Assessment Need
  - NERC Category P0 starting 2022.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductor ~1.13 miles of the Manteca #1 60 kV Line with larger conductor and remove any limiting component as necessary.
- Project Cost
  - $1.4M - $2.8M
- Alternatives Considered
  - Re-rate is not feasible as the overload occurs after 7pm which is not allowed by re-rate methodology.
  - 10 Mvar Cap Bank at Westley does not address the issue due to magnitude of overload.
  - Energy storage. There is not enough room in the existing substation. The interconnection cost from a new storage substation will be higher than re-conductoring a short section of the line.
- Recommendation
  - Approval

Existing



Proposed

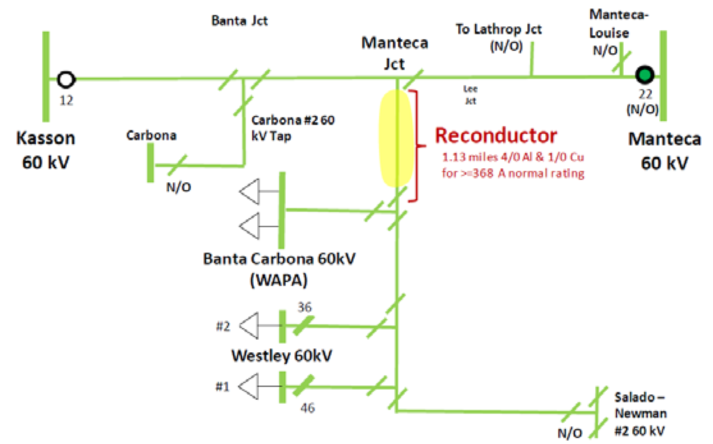


Diagram source: PG&E 2020-2021 TPP RW submission

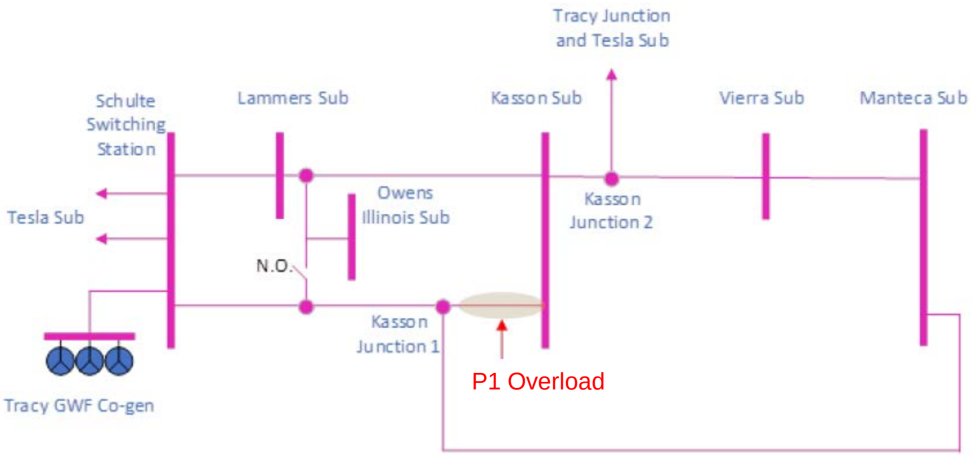
Kasson – Kasson Junction 1 115 kV Line Section Reconductoring (Central Valley Area)

- Reliability Assessment Need
  - NERC Category P1 starting 2022.
- Project Submitter
  - PG&E
- Project Scope
  - Reconductor the Kasson – Kasson Junction 1 (~0.08 miles) 115 kV line section with larger conductor and replace structure, if necessary.
- Project Cost
  - $0.25M - $0.5M

- Alternatives Considered
  - Status quo which is not acceptable due to P1 issue.
  - Re-rate is not feasible as the overload occurs after 7pm which is not allowed by re-rate methodology.

- Recommendation
  - Approval

Existing



Proposed

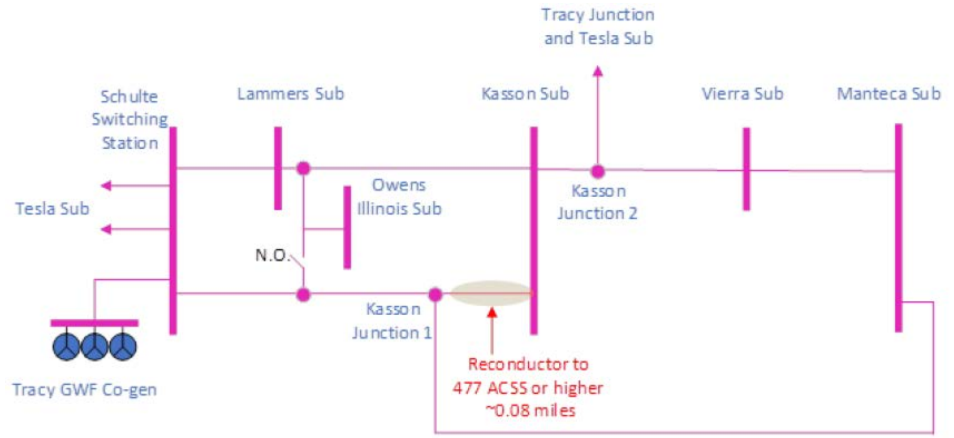
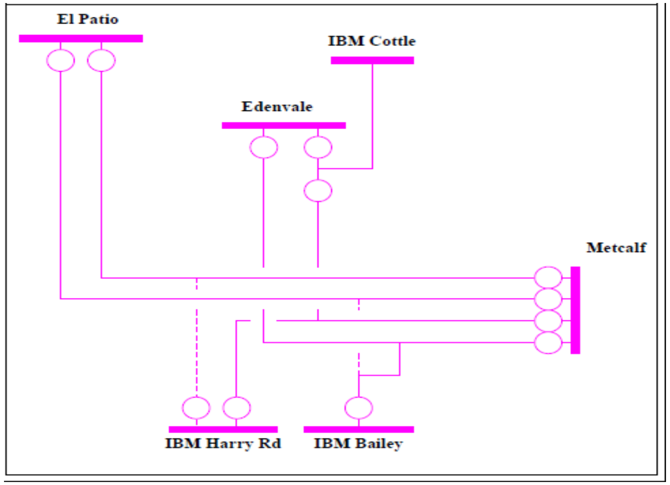


Diagram source: PG&E 2020-2021 TPP RW submission

Santa Teresa 115/21 kV Substation Load Interconnection Project

- Reliability Assessment Need
  - Load growth in the area
- Project Submitter
  - PG&E
- Project Scope
  - New four-element 115 kV ring bus
  - One 45MVA 115/21kVdistributionbank,
  - Loopin Metcalf-EdenvaleNo.1 115kV line into the Santa Teresa substation.
- Project Cost
  - $6M-$9M (transmission cost)
- Alternatives Considered
  - Status Quo
  - Replace banks at Edenvale
- Recommendation
  - ISO concurs

Existing



Proposed

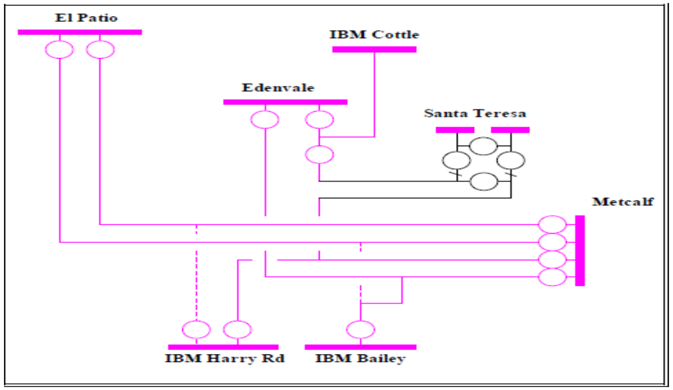


Diagram source: PG&E 2020-2021 TPP RW submission

Preliminary Economic Assessment Results

Yi Zhang
Senior Advisor, Transmission Infrastructure Planning

2020-2021 Transmission Planning Process Stakeholder Meeting
November 16, 2020

ISO Planning PCM Development

- Used the ADS PCM 2030 v1.0 as a starting point
- Rebuilt the ISO system model in PCM with updated network topology, load forecast, and resource assumption
  – Consistent with the ISO's reliability assessment power flow basecase and the policy power flow basecases, which modeled the CPUC's renewable portfolios
- Continue to incorporate validated changes in the ADS PCM into the ISO's planning PCM

Portfolios and Key assumptions

- 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 only
- Continue to use some key assumptions same as in the last cycle
  - 2000 MW CAISO Net Export Limit
  - $33.75/MWh operation cost for batteries
  - Multi-blocks model for wind and solar generators

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

Base portfolio PCM congestion – summary

Area or Branch Group	Congestion Cost T ($M	Congestion Duration (H
SDGE DOUBLTTP-FRIARS 138 kV	76.95	3,753
SCE Wirlwind Transformer	22.99	300
COI Corridor	14.43	352
PDCI	9.12	558
PG&E Fresno	8.79	4,534
Path 26 Corridor	6.79	247
SDGE Silvergate-Bay Blvd 230 kV line	6.15	154
PG&E Sierra	6.11	414
Path 45	4.98	1,041
SDGE-CFE OTAYMESA-TJI 230 kV line	4.31	861
SCE RedBluff-Devers 500 kV	3.77	32
Path 60 Inyo-Control 115 kV	3.35	1,678
SCE NOL-Kramer-Inyokern-Control	3.33	271
SCE LCIENEGA-LA FRESA 230 kV line	3.22	85
SCE Antelope 66 kV system	2.78	1,005
Path 25 PACW-PG&E 115 kV	2.63	550
Path 42 IID-SCE	1.85	63
SDGE IV-San Diego Corridor	1.00	50
SCE LagunaBell-Mesa Cal	0.81	23
SCE J.HINDS-MIRAGE 230 kV line	0.66	77
Path 61/Lugo - Victorville	0.53	46
San Diego	0.31	131
SDGE-CFE IV-ROA 230 kV line and IV PFC	0.28	56
SCE Devers 500/230 kV transformer	0.14	2
Path 15 Corridor	0.13	6
SCE Lugo 500 kV Transformer	0.12	5
PG&E Mosslanding -Lasguilass 230 kV	0.10	8
PG&E USWP JRW-Cayetano 230 kV	0.05	4
SDGE N.Gila-Imperial Valley 500 kV	0.05	1
PG&E POE-RIO OSO	0.05	20
PG&E North Valley	0.04	1
PG&E/Sierra MARBLE transformer	0.03	5
VEA	0.03	66

Base portfolio PCM congestion – SDGE area

Constraints Name	Costs_F (K$)	Duration_F (Hrs)	Costs_B (K$)	Duration_B (Hrs)	Costs T (K$)	Duration_T (Hrs)
DOUBLTTP-FRIARS 138 kV line, subject to SDGE N-2 SX-PQ + PQ-OT 230 kV with RAS	0	0	76,953	3,753	76,953	3,753
SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2 with RAS	0	0	6,151	154	6,151	154
P45 WECC SDG&E-CFE	509	133	4,475	908	4,983	1,041
OTAYMESA-TJI-230 230 kV line #1	0	0	4,314	861	4,314	861
SUNCREST-SUNCREST TP1 230 kV line, subject to SDGE N-1 Eco-Miguel 500 kV with RAS	541	29	0	0	541	29
SUNCREST-SUNCREST TP2 230 kV line, subject to SDGE N-1 Sycamore-Suncrest 230 kV #1 with RAS	424	18	0	0	424	18
IV Phase Shifter	276	56	0	0	276	56
N.GILA-IMPRLVLY 500 kV line #1	49	1	0	0	49	1
MIGUEL-MIGUEL 230 kV line, subject to SDGE T-1 Miguel 500-230 kV #1 with RAS	0	0	37	3	37	3

- Doublet Tap to Friars 138 kV line congestion under N-2 contingency can be greater without modeling the RAS to trip OtayMesa and PioPico
- Importing flow from SWPL 500 kV line contributes to the congestion on Doublet Tap to Friars 138 kV line and Sivergate to Bay Boulevard 230 kV line

Base portfolio PCM congestion – SCE Path 26 corridor and Tehachapi area, and PDCI

Constraints Name	Costs_F (K$)	Duration _F (Hrs)	Costs_B (K$)	Duration _B (Hrs)	Costs T (K$)	Duration _T (Hrs)
WIRLWIND 500/13.8 kV transformer #1	0	0	22,985	300	22,985	300
MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	0	0	3,855	77	3,855	77
P26 WECC Northern-Southern California	3	2	2,844	159	2,847	161
NEENACH-TAP 85 66.0 kV line #1	2,437	886	0	0	2,437	886
ANTELOPE-NEENACH 66 kV line, subject to SCE N-1 Neenach-Bailey-WestPack 66kV N-1	0	0	345	119	345	119
MW_VINCNT_11-MW_VINCNT_12 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	88	9	0	0	88	9
P65 WECC Pacific DC Intertie (PDCI)	0	0	9,117	558	9,117	558

- Path 26 congestion was observed mainly in south to north direction
- Whirlwind 500 kV transformer and Antelope 66 kV congestion were driven by the local generators
- PDCI congestion is in south to north direction. The rating in this direction in the PCM is 1050 MW, which is the LADWP's operation limit

Base portfolio PCM congestion – SCE North of Lugo Kramer area

Constraints Name	Costs_F (K$)	Duration _F (Hrs)	Costs_B (K$)	Duration _B (Hrs)	Costs T (K$)	Duration _T (Hrs)
VICTOR-LUGO 230 kV line #1	1,550	52	0	0	1,550	52
VICTOR-LUGO 230 kV line #4	641	14	0	0	641	14
VICTOR-LUGO 230 kV line #2	634	17	0	0	634	17
VICTOR-LUGO 230 kV line #3	407	12	0	0	407	12
LUGO 500/13.8 kV transformer #2	0	0	121	5	121	5
VICTOR 230/115 kV transformer #2	0	0	81	165	81	165
INYOKERN-KRAMER 115 kV line #1	22	11	0	0	22	11

- Congestion in the SCE North of Lugo area were mainly driven by local generators in the portfolio
- Congestion may happen in the hours when solar output is high. Total congestion hour is not significant

Base portfolio PCM congestion – PG&E Fresno area

Constraints Name	Costs_F (K$)	Duration _F (Hrs)	Costs_B (K$)	Duration _B (Hrs)	Costs T (K$)	Duration _T (Hrs)
LE GRAND-CHWCHLASLRJT 115 kV line, subject to PG&E N-1 Panoche-Mendota 115 kV	0	0	4,877	1,375	4,877	1,375
Q526TP-PLSNTVLY 70 kV line, subject to PG&E N-2 Panoche-Schindler and Panoche-Excelsesiorss 115 kV	1,485	633	0	0	1,485	633
KETLMN T-GATES 70.0 kV line #1	1,058	1,344	0	0	1,058	1,344
FIVEPOINTSSS-CALFLAX 70 kV line, subject to PG&E N-2 Panoche-Schindler and Panoche-Excelsesiorss 115 kV	844	866	50	1	895	867
HELM 70.0/230 kV transformer #1	342	296	0	0	342	296
MOSSLNSW-LASAGUILASS 230 kV line, subject to PG&E N-1 Mosslanding-LosBanos 500 kV	0	0	101	8	101	8
ORO LOMA-EL NIDO 115 kV line #1	65	11	0	0	65	11
GATES D-CALFLATSSS 230 kV line #1	0	0	43	2	43	2
COTTLE-MELONES 230 kV line #1	0	0	29	6	29	6

- Solar generators in Fresno area are the main driver for the congestion in this area
- Lines coming out of Fresno area may be congested during high solar generation hours

Base portfolio PCM congestion – PG&E COI corridor and Path 25

Constraints Name	Costs_F (K$)	Duration _F (Hrs)	Costs_B (K$)	Duration _B (Hrs)	Costs T (K$)	Duration _T (Hrs)
P66 WECC COI	10,227	282	0	0	10,227	282
P25 WECC PacifiCorp/PG&E 115 kV Interconnection	0	0	2,627	550	2,627	550
TABLE MT-TM_TS_11 500 kV line #1	1,922	21	0	0	1,922	21
TM_VD_11-TM_VD_12 500 kV line #1	642	7	0	0	642	7
TM_TS_12-TESLA 500 kV line #1	618	6	0	0	618	6
RM_TM_11-RM_DRS 500 kV line #1	534	17	0	0	534	17
RM_TM_21-RM_DRS 500 kV line #2	492	19	0	0	492	19

- Majority of COI corridor congestion cost is attributed to Path 66 path rating binding in north to south direction
- Downstream 500 kV lines may also be binding occasionally
- Path 25, which is the 115 kV inter-tie between PacifiCorp and the CAISO and is a parallel path to COI, was also congested in north to south direction

Sensitivity 1 Portfolio congestion – summary

(only shows the congestion with cost greater than $0.05M)

Area or branch group	Congestion Cost T ($M	Congestion Duration (H
SDGE DOUBLTTP-FRIARS 138 kV	77.79	3,558
SCE Wirlwind Transformer	76.26	891
SCE Vincent-PearBlossom 230 kV	28.49	2,903
COI Corridor	27.11	511
Path 45	12.15	1,572
PG&E Fresno	11.66	5,546
SCE LagunaBell-Mesa Cal	11.49	123
SCE LCIENEGA-LA FRESA 230 kV line	5.98	303
PDCI	5.87	506
SCE Antelope 66 kV system	5.15	1,737
Path 26 Corridor	4.57	164
Path 60 Inyo-Control 115 kV	4.28	2,089
SCE J.HINDS-MIRAGE 230 kV line	3.29	316
PG&E Sierra	3.17	263
Path 25 PACW-PG&E 115 kV	2.69	542
SCE NOL-Kramer-Inyokern-Control	2.67	1,633
SDGE Silvergate-Bay Blvd 230 kV line	1.96	53
SDGE IV-San Diego Corridor	1.88	90
SCE RedBluff-Devers 500 kV	1.57	35
SCE Devers 500/230 kV transformer	1.41	122
Path 61/Lugo - Victorville	1.31	94
SDGE-CFE OTAYMESA-TJI 230 kV line	0.85	150
PG&E Mosslanding -Lasguilass 230 kV	0.82	135
SDGE N.Gila-Imperial Valley 500 kV	0.78	16
SCE Windhub 500 kV transformer	0.53	28
San Diego	0.34	560
SCE Vincent 500 kV Transfomer	0.15	3
PG&E Tesla 500 kV Transformer	0.13	15
PG&E POE-RIO OSO	0.12	14
SDGE-CFE IV-ROA 230 kV line and IV PFC	0.10	23
Path 41 Sylmar transformer	0.09	8
Path 15 Corridor	0.08	15
VEA	0.07	96

California ISO

Sensitivity 2 Portfolio congestion – summary (only shows the congestion with cost greater than $0.05M)

Area or branch group	Congestion Cost T ($M	Congestion Duration (H
SDGE DOUBLTTP-FRIARS 138 kV	57.03	2,566
COI Corridor	42.44	767
SCE Wirlwind Transformer	27.33	701
SCE Vincent 500 kV Transfomer	23.57	216
SCE LagunaBell-Mesa Cal	19.46	353
SCE Vincent-PearBlossom 230 kV	17.33	2,937
Path 26 Corridor	16.05	643
VEA	13.15	2,475
SCE LCIENEGA-LA FRESA 230 kV line	11.77	273
PG&E Fresno	9.88	5,564
Path 45	9.56	1,295
SCE Antelope 230 kV GSU transformer	8.89	1,657
PDCI	8.53	736
Path 25 PACW-PG&E 115 kV	7.39	907
SCE Devers 500/230 kV transformer	7.25	371
SCE NOL-Kramer-Inyokern-Control	6.22	2,886
PG&E Gates - Arco 230 kV	5.67	1,017
Path 60 Inyo-Control 115 kV	4.05	2,375
SCE Antelope 66 kV system	2.74	1,465
PG&E Sierra	2.27	194
SDGE IV-San Diego Corridor	1.98	108
Path 61/Lugo - Victorville	1.90	111
PG&E Mosslanding -Lasguilass 230 kV	1.83	483
SDGE N.Gila-Imperial Valley 500 kV	1.64	34
SDGE Silvergate-Bay Blvd 230 kV line	1.64	36
SDGE-CFE OTAYMESA-TJI 230 kV line	1.37	246
SCE RedBluff-Devers 500 kV	0.81	32
PG&E Stockdale - Kern PP 230 kV	0.56	249
SCE J.HINDS-MIRAGE 230 kV line	0.51	36
SCE-LADWP Eldorado - McCullough 500 kV	0.41	13
PG&E VacaDixon - TESLA 500 kV	0.38	25
PG&E CC Sub 230 kV transformer	0.38	1,130
Path 42 IID-SCE	0.36	14
San Diego	0.27	822
SCE Windhub 500 kV transformer	0.24	12
Path 41 Sylmar transformer	0.16	10
PG&E Gates - Templeton 230 kV	0.15	35
SCE Pardee-Vincent 230 kV	0.12	2
Path 15 Corridor	0.10	21
PG&E Tesla 500 kV Transformer	0.09	48
SCE Antelope - Pardee 230 kV	0.09	7
PG&E USWP JRW-Cayetano 230 kV	0.09	6

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

Base portfolio curtailment

	2000 MW Net Export Limit		
Zone	Generation (GWh)	Curtailment (GWh	Ratio
SCE Tehachapi	20,416	4,413	18%
SCE Eastern	10,434	2,232	18%
PG&E Fresno-Kern	7,409	1,576	18%
SCE EOL	7,366	1,174	14%
NW	5,909	464	7%
SDGE IV	5,053	595	11%
PG&E Solano	5,014	96	2%
AZ	2,230	1,166	34%
SCE NOL	2,795	509	15%
PG&E Carrizo	1,863	653	26%
VEA	1,778	107	6%
PG&E N. CA	1,032	26	2%
NM	829	168	17%
SCE Vestal	671	155	19%
IID	713	69	9%
AB	473	11	2%
ID	346	52	13%
SCE Others	271	48	15%
SDGE San Diego	247	33	12%
CO	186	32	15%
SCE Ventura	27	6	17%
Total	75,061	13,585	15%

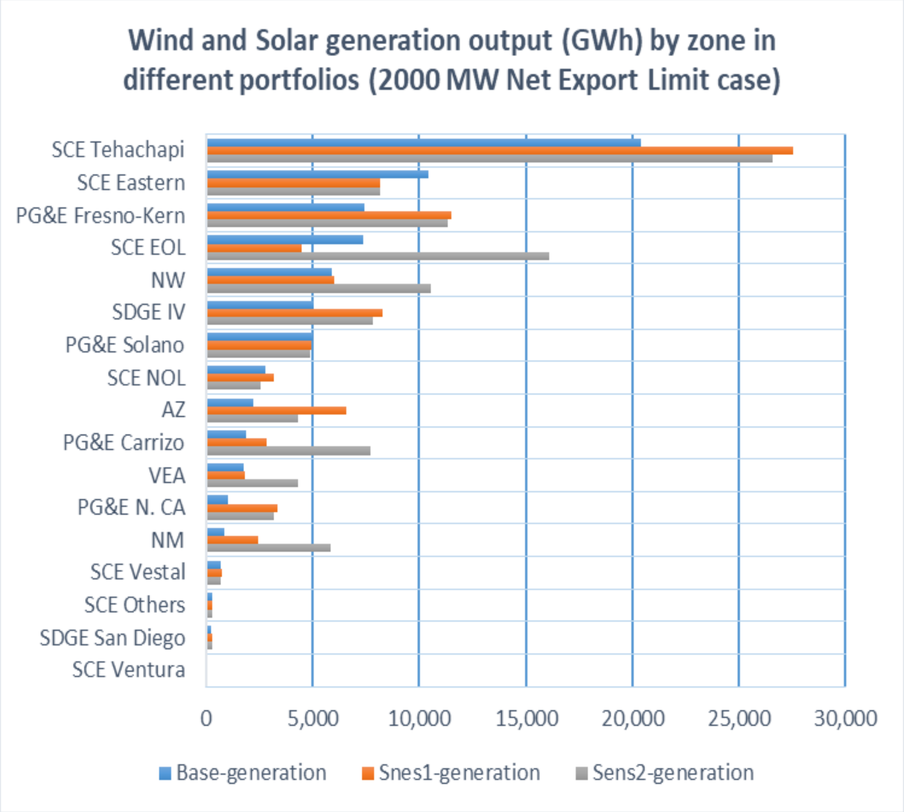
Sensitivity 1 portfolio curtailment

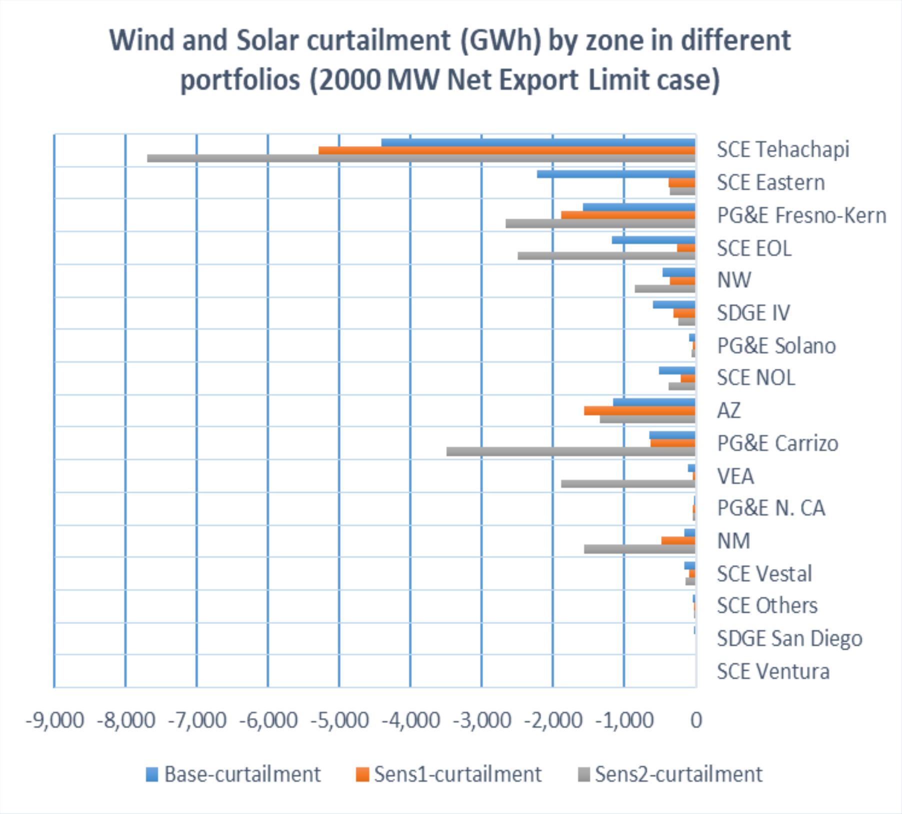
	2000 MW Net Export Limit		
Zone	Generation (GWh)	Curtailment (GWh	Ratio
SCE Tehachapi	27,536	5,297	16%
PG&E Fresno-Kern	11,504	1,896	14%
SDGE IV	8,249	315	4%
SCE Eastern	8,168	383	4%
AZ	6,551	1,564	19%
NW	6,009	364	6%
PG&E Solano	4,911	46	1%
SCE EOL	4,490	271	6%
PG&E Carrizo	2,823	628	18%
SCE NOL	3,203	207	6%
PG&E N. CA	3,362	47	1%
NM	2,455	491	17%
VEA	1,837	49	3%
SCE Vestal	735	91	11%
IID	766	16	2%
AB	478	6	1%
ID	350	48	12%
SCE Others	299	20	6%
SDGE San Diego	264	15	5%
CO	189	29	13%
SCE Ventura	30	3	9%
Total	94,207	11,786	11%

Sensitivity 2 portfolio curtailment

	2000 MW Net Export Limit		
Zone	Generation (GWh)	Curtailment (GWh	Ratio
SCE Tehachapi	26,596	7,689	22%
SCE EOL	16,075	2,503	13%
PG&E Fresno-Kern	11,326	2,660	19%
NW	10,569	858	8%
PG&E Carrizo	7,681	3,496	31%
SCE Eastern	8,182	369	4%
SDGE IV	7,818	250	3%
NM	5,867	1,561	21%
VEA	4,313	1,890	30%
AZ	4,305	1,348	24%
PG&E Solano	4,903	53	1%
PG&E N. CA	3,162	44	1%
SCE NOL	2,578	384	13%
SCE Vestal	682	144	17%
IID	748	34	4%
AB	474	10	2%
ID	337	61	15%
SCE Others	289	30	9%
SDGE San Diego	263	17	6%
CO	179	39	18%
SCE Ventura	28	5	15%
Total	116,374	23,445	17%

Comparison of wind and solar generation and curtailment by zone



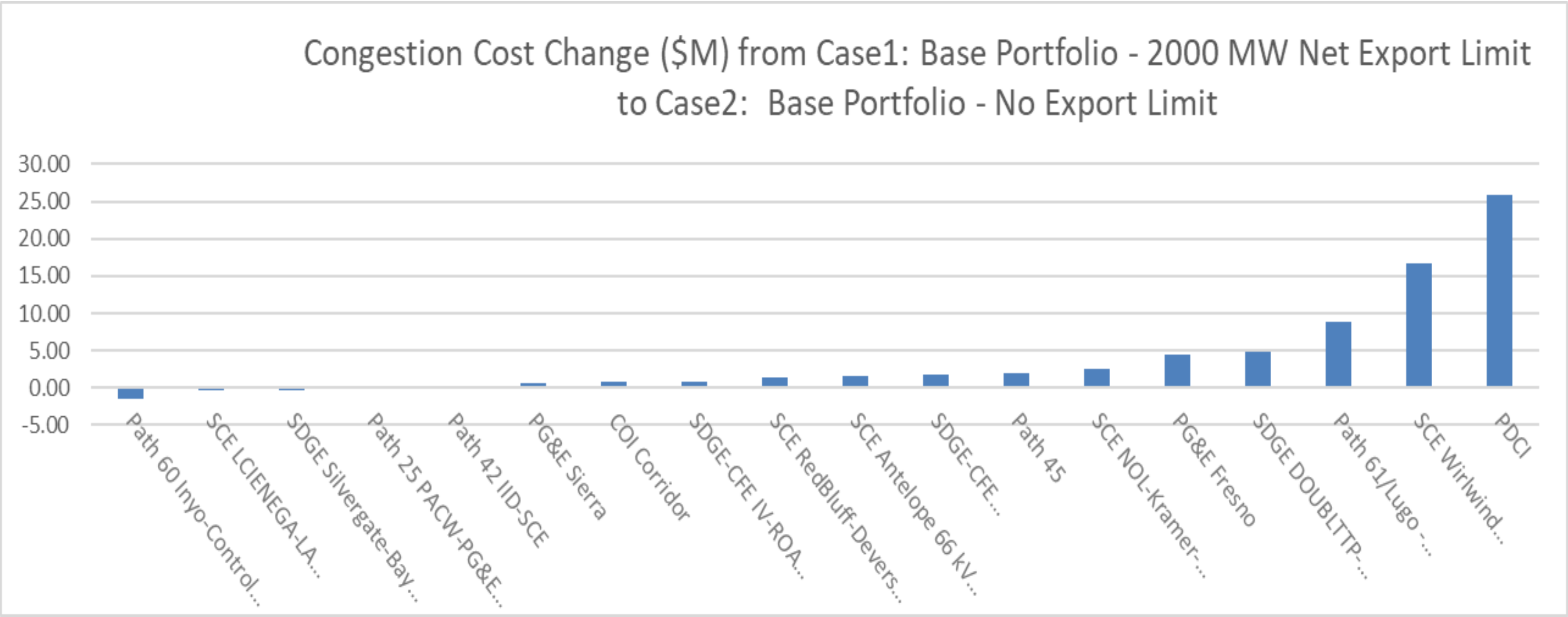


*Only shows in-state zones (including VEA) and Northwest (NW), Arizona (AZ), and New Mexico (NM)

Comparison with the “No Export Limit” case

- The “No Export Limit” case was used as reference to estimate curtailment related to system constraint
  - It works if the congestion in the “No Export Limit” case is not significant or the congestion pattern does not change much
- As more renewable resources are included in the portfolio to meet the state GHG goal,
  - Congestion in the “No Export Limit” case increases and is in different pattern from the “2000 MW Net Export Limit” case
  - The “No Export Limit” case may not be a good reference for estimating system curtailment
- The next two slides compared the results of the “2000 MW Net Export Limit” and the “No Export Limit” cases for the base portfolio
  - The results for the sensitivity portfolios have the similar pattern

Base portfolio congestion – 2000 MW Net Export Limit vs. No Export Limit



- Total congestion cost increased in the “No Export Limit” case, compared with the 2000 MW Net Export Limit case
- Increase of congestion was not only observed on the inter-ties but also in some local areas

Base portfolio curtailment – 2000 MW Net Export Limit vs. No Export Limit

	2000 MW Net Export Limit			No Export Limit		
Zone	Generation (GWh)	Curtailment (GWh	Ratio	Generation (GWh)	Curtailment (GWh	Ratio
SCE Tehachapi	20,416	4,413	18%	21,508	3,322	13%
SCE Eastern	10,434	2,232	18%	12,110	935	7%
PG&E Fresno-Kern	7,409	1,576	18%	7,824	1,161	13%
SCE EOL	7,366	1,174	14%	7,922	618	7%
NW	5,909	464	7%	6,295	78	1%
SDGE IV	5,053	595	11%	5,424	224	4%
PG&E Solano	5,014	96	2%	5,082	28	1%
AZ	2,230	1,166	34%	2,723	295	10%
SCE NOL	2,795	509	15%	2,930	374	11%
PG&E Carrizo	1,863	653	26%	1,990	525	21%
VEA	1,778	107	6%	1,790	95	5%
PG&E N. CA	1,032	26	2%	1,049	8	1%
NM	829	168	17%	899	99	10%
SCE Vestal	671	155	19%	722	104	13%
IID	713	69	9%	761	21	3%
AB	473	11	2%	484	0	0%
ID	346	52	13%	370	28	7%
SCE Others	271	48	15%	287	32	10%
SDGE San Diego	247	33	12%	268	12	4%
CO	186	32	15%	213	5	2%
SCE Ventura	27	6	17%	29	4	12%
Total	75,061	13,585	15%	80,680	7,967	9%

*The No Export Limit case has less curtailment than the 2000 MW Net Export Limit case, but we cannot simply conclude that the reduction is system constraint related curtailment

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Sensitivity 1 portfolio curtailment

	2000 MW Net Export Limit			No Export Limit		
Zone	Generation (GWh)	Curtailment (GWh	Ratio	Generation (GWh)	Curtailment (GWh	Ratio
SCE Tehachapi	27,536	5,297	16%	28,667	4,165	13%
PG&E Fresno-Kern	11,504	1,896	14%	11,990	1,410	11%
SDGE IV	8,249	315	4%	8,471	93	1%
SCE Eastern	8,168	383	4%	8,386	165	2%
AZ	6,551	1,564	19%	7,734	381	5%
NW	6,009	364	6%	6,303	70	1%
PG&E Solano	4,911	46	1%	4,941	16	0%
SCE EOL	4,490	271	6%	4,604	157	3%
PG&E Carrizo	2,823	628	18%	3,040	411	12%
SCE NOL	3,203	207	6%	3,247	162	5%
PG&E N. CA	3,362	47	1%	3,394	15	0%
NM	2,455	491	17%	2,645	301	10%
VEA	1,837	49	3%	1,840	45	2%
SCE Vestal	735	91	11%	774	52	6%
IID	766	16	2%	780	2	0%
AB	478	6	1%	484	0	0%
ID	350	48	12%	377	21	5%
SCE Others	299	20	6%	305	14	4%
SDGE San Diego	264	15	5%	276	4	1%
CO	189	29	13%	214	4	2%
SCE Ventura	30	3	9%	31	2	6%
Total	94,207	11,786	11%	98,504	7,490	7%

Sensitivity 2 portfolio curtailment

	2000 MW Net Export Limit			No Export Limit		
Zone	Generation (GWh)	Curtailment (GWh	Ratio	Generation (GWh)	Curtailment (GWh	Ratio
SCE Tehachapi	26,596	7,689	22%	28,437	5,847	17%
SCE EOL	16,075	2,503	13%	17,538	1,041	6%
PG&E Fresno-Kern	11,326	2,660	19%	11,713	2,274	16%
NW	10,569	858	8%	11,265	161	1%
PG&E Carrizo	7,681	3,496	31%	8,319	2,858	26%
SCE Eastern	8,182	369	4%	8,441	110	1%
SDGE IV	7,818	250	3%	8,012	56	1%
NM	5,867	1,561	21%	6,512	916	12%
VEA	4,313	1,890	30%	4,371	1,832	30%
AZ	4,305	1,348	24%	5,343	310	5%
PG&E Solano	4,903	53	1%	4,936	20	0%
PG&E N. CA	3,162	44	1%	3,189	16	1%
SCE NOL	2,578	384	13%	2,702	259	9%
SCE Vestal	682	144	17%	746	79	10%
IID	748	34	4%	777	5	1%
AB	474	10	2%	484	0	0%
ID	337	61	15%	375	23	6%
SCE Others	289	30	9%	302	17	5%
SDGE San Diego	263	17	6%	277	3	1%
CO	179	39	18%	214	5	2%
SCE Ventura	28	5	15%	30	3	9%
Total	116,374	23,445	17%	123,985	15,835	11%

Next Steps

Economic planning study requests received:

No.	Study Request	Submitted By	Location
1	Congestion on Doublet Tab to Friars 138 kV in SDG&E area	Calpine Corporation	Southern California SDG&E area
2	Congestion on Gates to Tulare Lake 70 kV in PG&E Fresno area	conEdison Development	Northern California PG&E area
3	GridLiance West/VEA system upgrades	GridLiance West LLC	Southern Nevada GridLiance/VEA
4	COI congestion and SWIP-North project	LS Power Development LLC	California/Oregon, Idaho/Nevada
5	Flow Control for Congestion Reduction on the California-Oregon Intertie (COI)	SmartWires	Northern California PG&E area
6	Economic Study Requests to Reduce Local Capacity Requirements (LCR) Using Power Flow Control	SmartWires	a. South Bay – Moss Landing sub-area b. Ames-Pittsburg-Oakland sub-area c. Fresno area d. Western LA Basin sub-area
7	Path 26 congestion study	SouthWestern Power Group	Northern/Southern California PG&E and SCE areas
8	Pacific Transmission Expansion Project (PTE Project)	Western Grid Development LLC	Northern/Southern California PG&E and SCE areas

Preliminary list of high priority study areas to receive detailed consideration

- Preliminary high priority study areas were proposed based on the preliminary production cost simulation results for the base portfolio and the economic study requests:
  - SDG&E area Doublet Tap – Friars 138 kV congestion
  - SDG&E Silvergate-Bay Boulevard 230 kV congestion
  - PG&E Fresno area congestion – multiple lines are congested, may consider them together or separately
  - Path 26 corridor and SCE Tehachapi area congestion
  - COI corridor congestion
- The list may change with considering stakeholder comments and detailed planning study results

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 study
  - Policy study
- Conduct economic assessment for identified high priority upgrades or studies
- Provide update in the next TPP Stakeholder Meeting

2030 Final LCR Study Results – Overall Summary

Catalin Micsa
Senior Advisor Regional Transmission Engineer

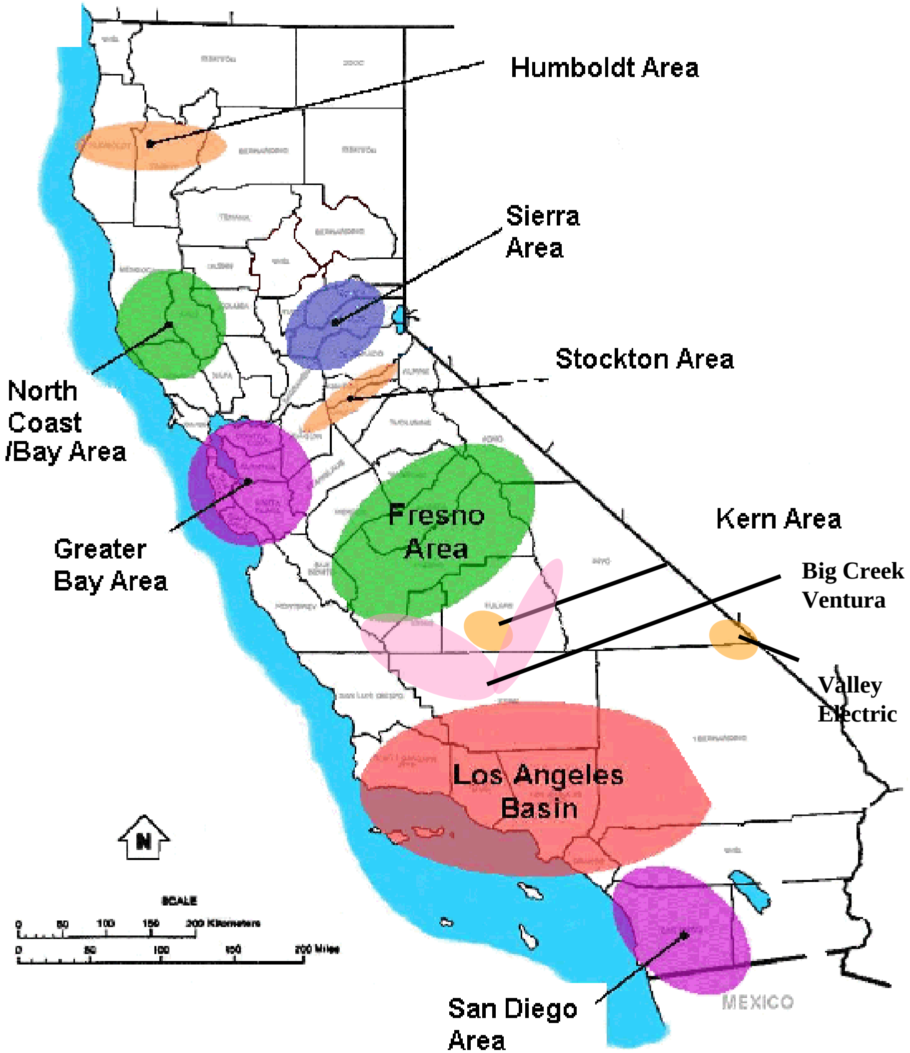
2020-2021 Transmission Planning Process Stakeholder Meeting
November 17, 2020

Long-Term Local Capacity Technical Study

Based on the alignment of the CAISO Transmission Planning Process (TPP) with the CEC Integrated Energy Policy Report (IEPR) demand forecast and the CPUC Integrated Resource Plan (IRP), the Long-Term LCR assessment is to be evaluated ***every two years.***

In the 2020-2021 transmission planning process all LCR areas within the CAISO BAA will be evaluated for long-term assessment.

LCR Areas within CAISO



2030 Final LCR Needs

	Qualifying Capacity				Capacity Available At Peak	2030 LCR Need
Local Area Name	**QF/MUNI (MW)**	**Non-Solar (MW)**	**Solar (MW)**	**Total (MW)**	**Total (MW)**	**Capacity Needed**
Humboldt	0	191	0	**191**	**191**	**135**
North Coast / North Bay	119	723	0	**842**	**842**	**636**
Sierra	1183	938	5	**2126**	**2121**	**1518**
Stockton	115	487	11	**613**	**602**	**613**
Greater Bay	604	6732	8	**7344**	**7344**	**7344**
Greater Fresno	216	2815	361	**3392**	**3191**	**2296**
Kern	5	330	78	**413**	**335**	**413**
Big Creek/Ventura	424	3524	250	**4198**	**4198**	**1151**
LA Basin	1197	6204	11	**7412**	**7412**	**6194**
San Diego/ Imperial Valley	2	4017	394	**4413**	**4019**	**3718**
Total	3865	25961	1118	**30944**	**30255**	**24018**

Battery Storage

- Currently there is high regulatory and commercial interest in this technology
- Highest interest is in building 4-hour resources, mostly due to RA counting rules.
- Mixed expectations
  - maximize the local and system RA value
  - minimize the CAISO back-stop costs
- For all “4 hour” batteries installed in local areas, once the local need passes the 4-hour mark, they do not eliminate the local need for other local resources on a 1 for 1 MW bases.

Battery Storage Characteristics - Assumptions

- Storage replacing existing resources are assumed to have the same effectiveness factors
- Charging/discharging efficiency is 85%
- Energy required for charging, beyond the transmission capability is produced by other LCR required resources
- Daily charging required is distributed to all non-discharging hours proportionally using delta between net load and the total load serving capability (transmission + remaining resources)
- Hydro resources are considered to be available for production during off-peak hours
- The study assumes the ability to provide perfect dispatch; CAISO software improvements and/or augmentations are required in order to achieve this goal
- Deliverability for incremental capacity is not evaluated

Battery Storage Calculation Improvements

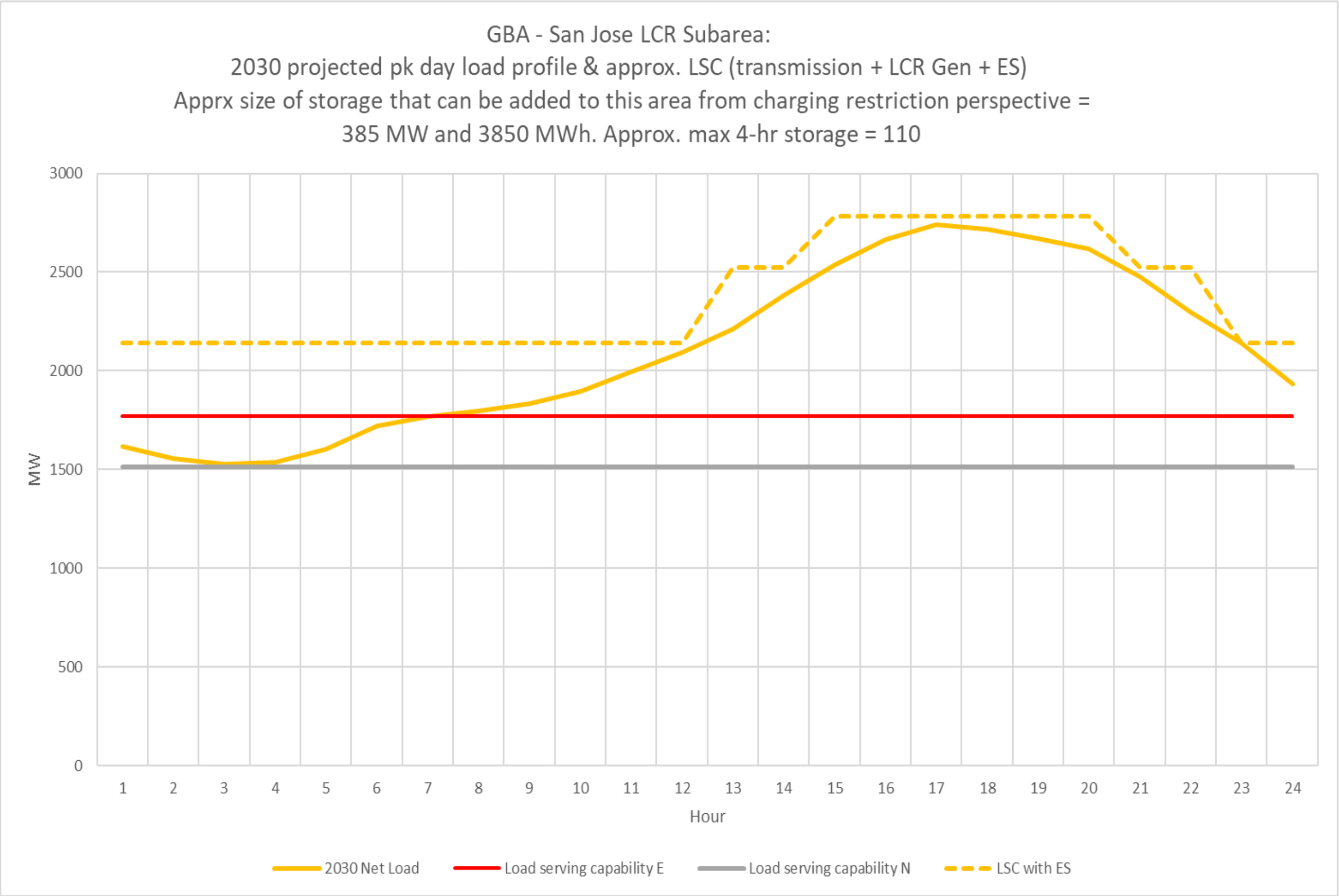
Since our last stakeholder meeting in September, ISO has made a few improvements to the battery storage calculation and graphs:

- Improved “energy calculation” to more closely follow the load shape
- Capped maximum charging at the capacity of storage added
- Limit the amount of storage added to not exceed the LCR
- Added the greater of 5% or 10 MW margin for both charging and discharging

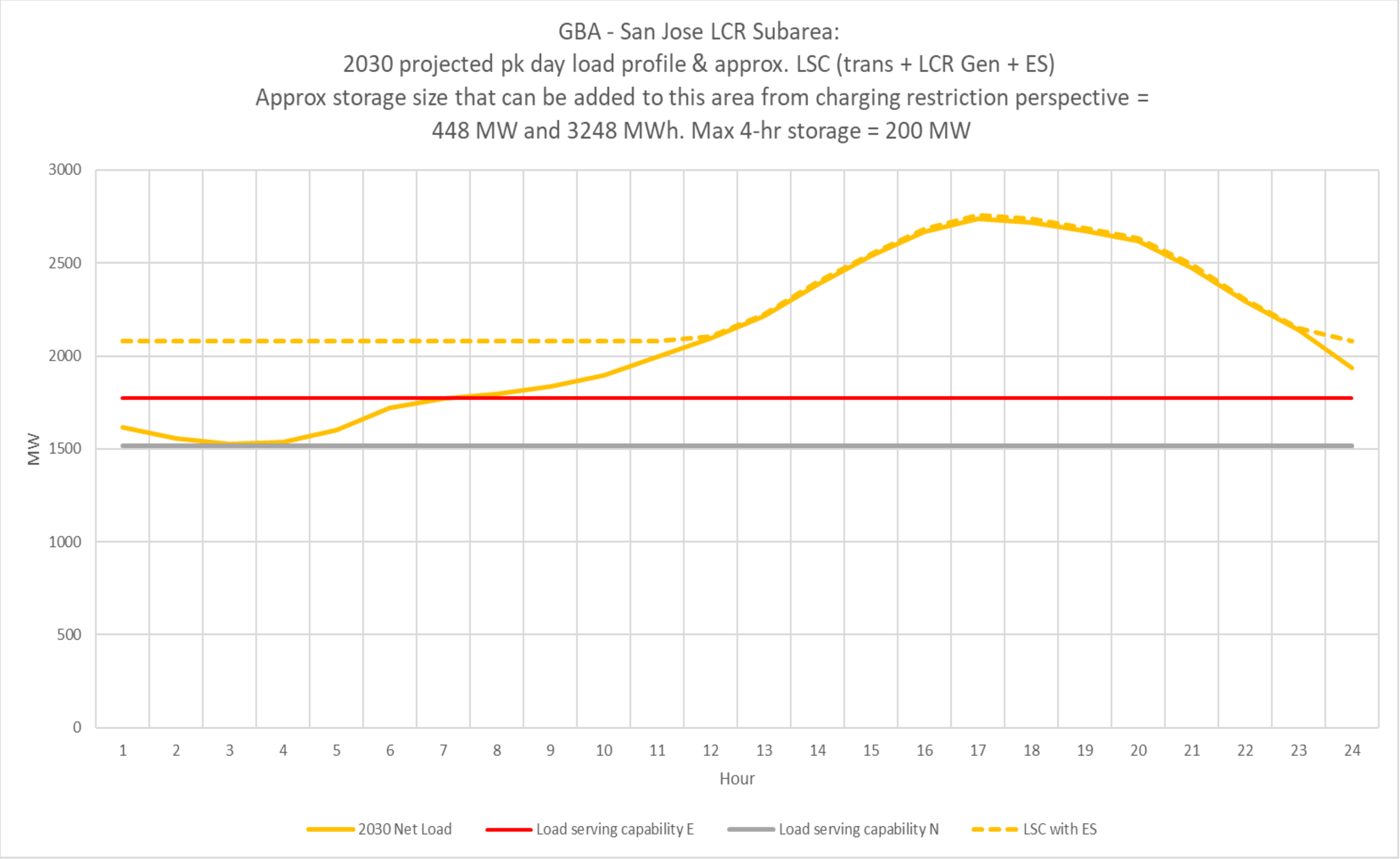
This has resulted in changes to some of the previous results:

- Mixed result regarding Maximum MW
- General decrease in Maximum MWh
- General increase in Max 1-for-1 replacement with 4-hour battery

Example: Graph before change (non-flow through area)



Example: Graph after change (non-flow through area)



Updated Battery Storage Calculation

Area/Sub-area	Pmax (MW)	Energy MWh	Max. # of discharge hours	Average discharge hours	Max. MW for 4-hour BESS as 1-for-1 Replacement	Replacing mostly	Comment
Humboldt	43	131	5	3	32	gas	
North Coast/North Bay Overall	290	2089	11	7.2	55	geothermal	
Eagle Rock	29	200	9	6.9	15	geothermal	
Fulton							Need eliminated
Sierra							Flow through
Placer	72	398	9	5.5	34	hydro	
Pease							Need eliminated
Drum-Rio Oso							Need eliminated
Gold Hill-Drum							Need eliminated
South of Rio Oso							Flow through
South of Palermo							Need eliminated
Stockton	444	2349	9	5.3	282	gas	Tesla-Bellota
Lockeford							Need eliminated
Stanislaus							Flow through
Tesla-Bellota	444	2349	9	5.3	282	gas	

Updated Battery Storage Calculation

Area/Sub-area	Pmax (MW)	Energy MWh	Max. # of discharge hours	Average discharge hours	Max. MW for 4-hour BESS as 1-for-1 Replacement	Replacing mostly	Comment
Greater Bay Overall	2630	15804	10	6	1500	gas	
Llagas	31	167	7	5.4	13	gas	
San Jose	448	3249	11	7.3	200	gas	
South Bay-Moss Landing	477	2721	17	5.7	375	gas	
Oakland	36	271	15			gas	
Ames-Pittsburg-Oakland							Flow through
Contra Costa	135	1267	20	9.4	24	gas	Flow through
Greater Fresno Overall	2296	8826	6	3.8	2206	hydro	
Panoche	35	240	14	6.8	19	gas	
Wilson							Need eliminated
Herndon	476	1815	9	3.8	453	hydro	
Borden							Need eliminated
Hanford	65	230	6	3.5	57	gas	
Coalinga	75	274	8	3.7	68	gas	
Reedley	71	429	9	6	33	hydro	

Updated Battery Storage Calculation

Area/Sub-area	Pmax (MW)	Energy MWh	Max. # of discharge hours	Average discharge hours	Max. MW for 4-hour BESS as 1-for-1 Replacement	Replacing mostly	Comment
Kern Overall	430	2599	12	6	275	gas	South Kern PP
Westpark	44	224	8	5.1	41	gas	
Kern 70 kV							Need eliminated
Kern PWR-Tevis	44	198	7	4.5	35	solar	
Kern Oil	115	623	10	5.4	76	gas	
South Kern PP	430	2599	12	6	275	gas	
Big Creek/Ventura Overall	363	2752	15	7.6	128	gas	
Vestal	115	1003	13	8.7	15	hydro	
Santa Clara	148	1159	11	7.8	18	gas	
LA Basin Overall	3550	27244	11	7.7	1070	gas	
Eastern	1610	12142	11	7.5	475	gas	
Western	1510	12348	11	8.2	420	gas	
El Nido	231	1587	11	6.9	91	gas	
San Diego/Imperial Valley Overall	1187	6994	10	5.9	680	gas	
San Diego	1187	6973	10	5.9	680	gas	
El Cajon							Need eliminated
Border	31	185	8	6	16	gas	

Battery Storage - Graph

- Maximum storage (MW and MWh) that can charge under contingency conditions in order to be available the next day to meet local needs
- Maximum 4-hour storage, added per stakeholder request – it is the maximum MW value where the technical local need = RA counting on a 1 for 1 MW basis
- The results represent <u>an estimate of future buildout</u> – actuals could differ mainly due to effectiveness factors
- The new estimates for flow-through areas have a much higher degree of uncertainty because the need to mitigate the main constraint may not follow the "estimated" load curve and could impact the charging/discharging cycle.

CAISO will perform an economic study as part of this transmission planning cycles

- Identify potential transmission upgrades that would economically lower gas-fired generation capacity requirements in local capacity areas or sub-areas
  - Retirement of gas-fired generation in the IRP has not identified significant retirement, as such methodology for economic assessment will be the same as in the 2018-2019 and 2019-2020 transmission planning process
- Explore and assess alternatives – conventional transmission and preferred resources - to reduce or eliminate need for gas-fired generation in all existing areas and sub-areas.

Availability of public RA costs

- CAISO is using public cost information, from the latest RA reports provided by CPUC.

Weighted average price ($kW/month)	LA Basin	Big Creek/ Ventura	Bay Area	Other PG&E area	San Diego/ Imperial Valley	CAISO System	NP 26	SP 26
2017	3.48	3.45	2.22	2.27	3.18	2.09	2.15	1.59
2018	3.66	3.19	2.77	3.11	3.07	2.76	2.87	2.38

Economic analyses of alternatives

- The differential in cost between all local areas and CAISO system (including NP26 and SP26) has reduced, therefore there is no need to reassess projects assessed in past planning cycles that were not found to be economic.
- The current studies have concentrated only on new projects received from stakeholders or close to being economically feasible in the last 2 years located in these areas:
  - Bay Area
  - LA Basin
  - San Diego/Imperial Valley

Schedule

- ✓ September 23-24 TPP stakeholder Meeting
  - – 10-year LCR assessment results
    - Include update on storage capability
  - – Stakeholder comments and alternatives
- November 17 TPP stakeholder meeting
  - – Update on storage capability calculation
  - – Preliminary alternative assessment
  - – Stakeholder comments
- January 31, 2021 Draft Transmission Plan
  - – Final analysis and recommendations (if any)

Local Capacity Requirements Potential Reduction Study

PG&E Area

Abhishek Singh

Regional Transmission Engineer Lead

Projects Evaluated

- With the differential in cost between all local areas and CAISO system (including NP26 and SP26) reducing, there is no need to reassess the projects assessed in past planning cycles that were not found to be economic.

- The following new project alternatives were submitted into 2020-2021 transmission planning process for assessment, all in the Greater Bay area.

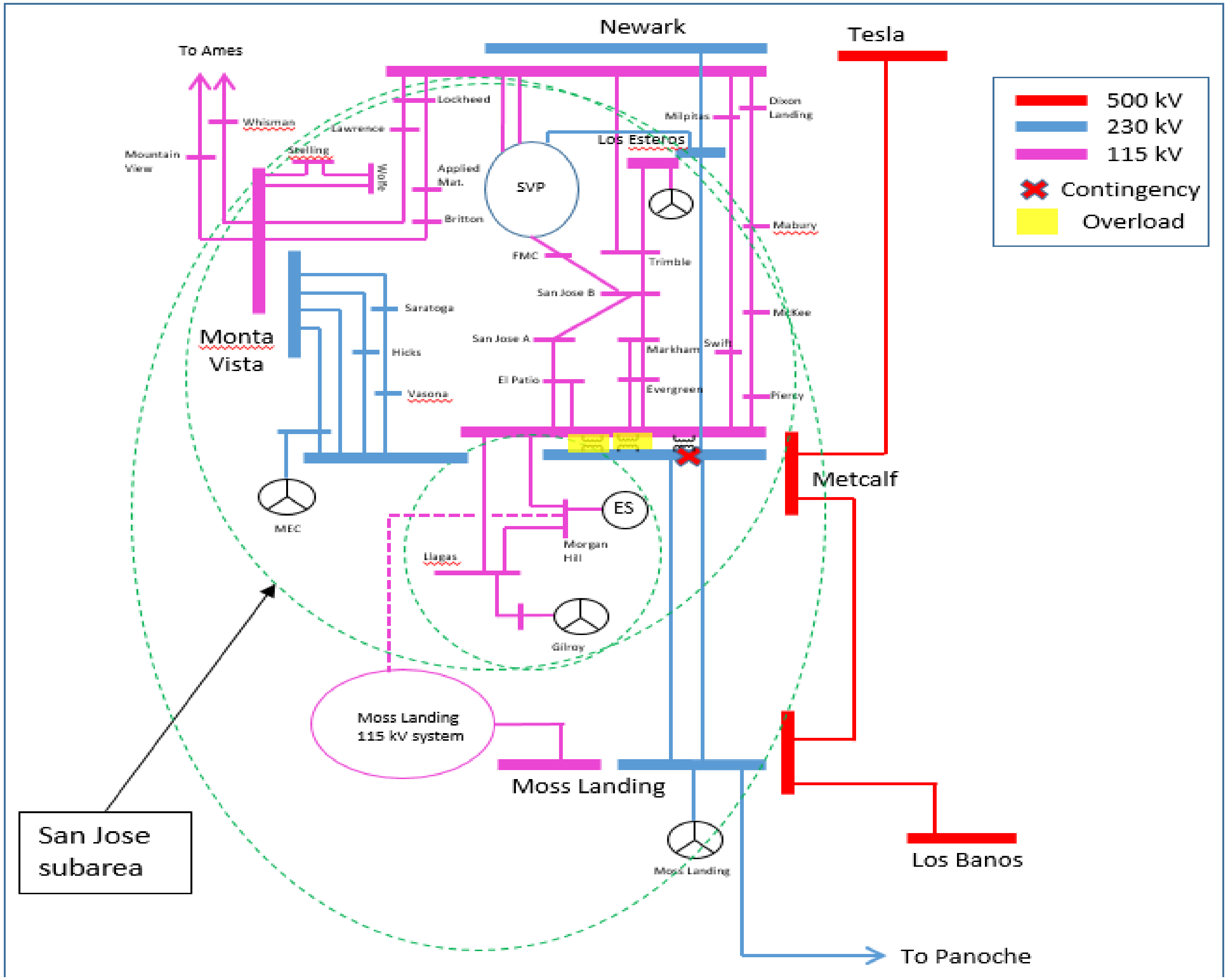
Project	Submitted By	Impacted LCR Area/Sub-Area
Contra Costa – Pittsburg 230 kV Reliability Project	Horizon West	Contra Costa sub-area
Metcalf 230 kV substation	Horizon West	San Jose sub-area
Smart valve in series with Tesla – Delta Switchyard 230 kV line	Smart Wire	Contra Costa sub-area
Metcalf 500-230 kV Transformers Dynamic Series Reactor Project	PG&E	Greater Bay Area overall

San Jose sub-area stand alone analysis

San Jose Sub-area: Load and Resources

Load (MW)	2030	Generation (MW)	2030
Gross Load	2,737	Market	575
AAEE	-61	Wind	0
Behind the meter DG	0	Muni	198
Net Load	**2,676**	QF	0
Transmission Losses	76	Future preferred resource and energy storage	75
Pumps	0	**Total Qualifying Capacity**	**848**
Load + Losses + Pumps	**2,752**		

San Jose Subarea : One-line diagram



San Jose Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2030 LCR study					
2030	First	P2-4	Metcalf 230/115 kV transformer # 1 or # 3	METCALF 230kV - Section 2D & 2E	918 (145)
Subsequent requirements (layers)					
2030	Second limit	P2	Metcalf-El Patio 2 115 kV Line	MTCALF D Section 1D & MTCALF E Section 1E 115KV	611
with HWT-Metcalf 230 kV substation					
2030	First limit	P2	Metcalf-El Patio 2 115 kV Line	MTCALF D Section 1D & MTCALF E Section 1E 115KV	611

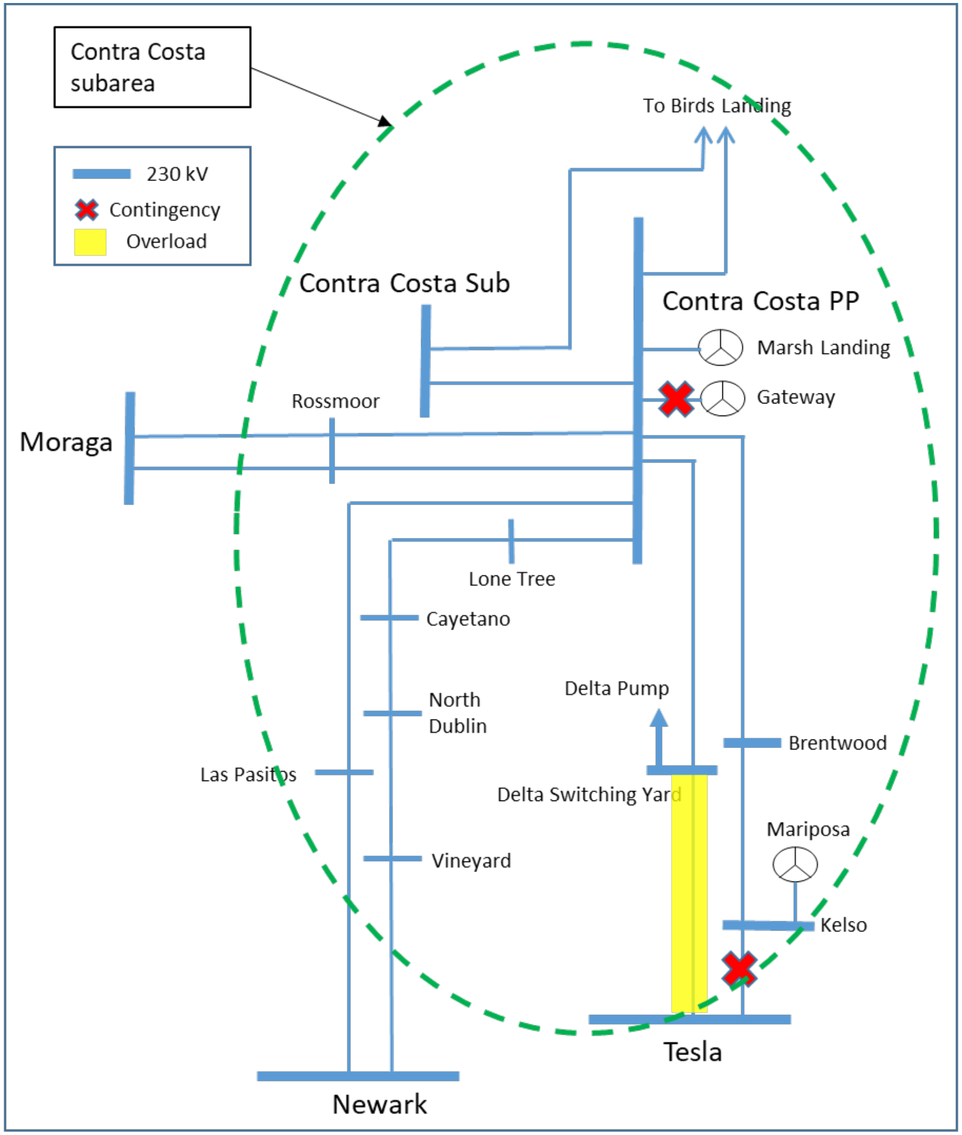
San Jose Subarea : LCR Reduction Benefits[1]

HWT-Metcalf 230 kV substation		
	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (MW)	162	
Capacity value (per MW-year)	$120	($1,200)
LCR Reduction Benefit ($million)	$0.02	-$0.19
Local Capacity Benefits		
	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.02	-$0.19
PV of LCR Savings ($million)	$0.27	($2.68)
Capital Cost		
Capital Cost Estimate ($ million)	$80.0	
Estimated "Total" Cost (screening) ($million)	$104.0	
Benefit to Cost		
PV of Savings ($million)	$0.27	($2.68)
Estimated "Total" Cost (screening) ($million)	$104.00	
Benefit to Cost	0.00	-0.03

Note[1]: LCR reduction benefits are calculated using financial parameters provided in Section 4.3 of the 2018-2019 ISO Transmission Plan. The Capacity values have been updated based on the latest available RA costs.

Contra Costa sub-area stand alone analysis

Contra Costa Subarea: One-line diagram



Contra Costa Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2030 LCR study					
2030	First limit	P3	Delta Switching Yard-Tesla 230 kV Line	Kelso-Tesla 230 kV with the Gateway off line	1334
Subsequent requirements (layers)					
None					
with Smart Wire (12.5-ohm increase in line reactance)					
None					
With HWT Contra Costa – Pittsburg 230 kV Reliability Project (Option 1 & 2)					
2030	First limit	P3	Delta Switching Yard-Tesla 230 kV Line	Kelso-Tesla 230 kV with the Gateway off line	1334[1]

Note[1]: HWT Reliability Project Increases the requirement as the overload increases by significant amount post project. The new requirements were not calculated for this project and no economic benefit calculation was done for these options

California ISO

Contra Costa Subarea : LCR Reduction Benefits[1]

Smart Wire(12.5-ohm increase in line reactance)		
	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (MW)	576	
Capacity value (per MW-year)	$120	($1,200)
LCR Reduction Benefit ($million)	$0.07	-$0.69
Local Capacity Benefits		
	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.07	-$0.69
PV of LCR Savings ($million)	$0.95	($9.54)
Capital Cost		
Capital Cost Estimate ($ million)	$5.4	
Estimated “Total” Cost (screening) ($million)	$7.0	
Benefit to Cost		
PV of Savings ($million)	$0.95	($9.54)
Estimated “Total” Cost (screening) ($million)	$7.02	
Benefit to Cost	0.14	-1.36

Note[1]: LCR reduction benefits are calculated using financial parameters provided in Section 4.3 of the 2018-2019 ISO Transmission Plan. The Capacity values have been updated based on the latest available RA costs.

Bay Area Overall analysis

Greater Bay Area Overall: Load and Resources

Load (MW)	2030	Generation (MW)	2030
Gross Load	10889	Market/ Net Seller/ Battery	5,895
AAEE	-217	Solar	8
Behind the meter DG	0	Wind	244
Net Load	**10,672**	Muni	377
Transmission Losses	259	QF	227
Pumps	264	Future preferred resource and energy storage	593
Load + Losses + Pumps	**11,195**	**Total Qualifying Capacity**	**7,344**

Greater Bay Area Overall: Requirements

Year	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2030	Multiple	Aggregate of subareas		6148 (145)
2030	P6	Metcalf 500/230 kV #13 transformer	Metcalf 500/230 kV #11 & #12 transformers	7455 (111)

Bay Area Subarea : LCR Reduction Benefits[1]

PG&E-Metcalf Smart Valve Project		
	Local versus System Capacity	Local versus NP 26
LCR reduction benefit (MW)	1342	
Capacity value (per MW-year)	$120	($1,200)
LCR Reduction Benefit ($million)	$0.16	-$1.61
Local Capacity Benefits		
	Local versus System Capacity	Local versus NP 26
Net LCR Saving ($million/year)	$0.16	-$1.61
PV of LCR Savings ($million)	$2.22	($22.22)
Capital Cost		
Capital Cost Estimate ($ million)	$32.0	
Estimated "Total" Cost (screening) ($million)	$41.6	
Benefit to Cost		
PV of Savings ($million)	$2.22	($22.22)
Estimated "Total" Cost (screening) ($million)	$41.60	
Benefit to Cost	0.05	-0.53

Note[1]: LCR reduction benefits are calculated using financial parameters provided in Section 4.3 of the 2018-2019 ISO Transmission Plan. The Capacity values have been updated based on the latest available RA costs.

Local Capacity Requirements Potential Gas-Fired Generation Reduction Study for the LA Basin and San Diego-Imperial Valley Areas

David Le

Senior Advisor, Regional Transmission Engineer

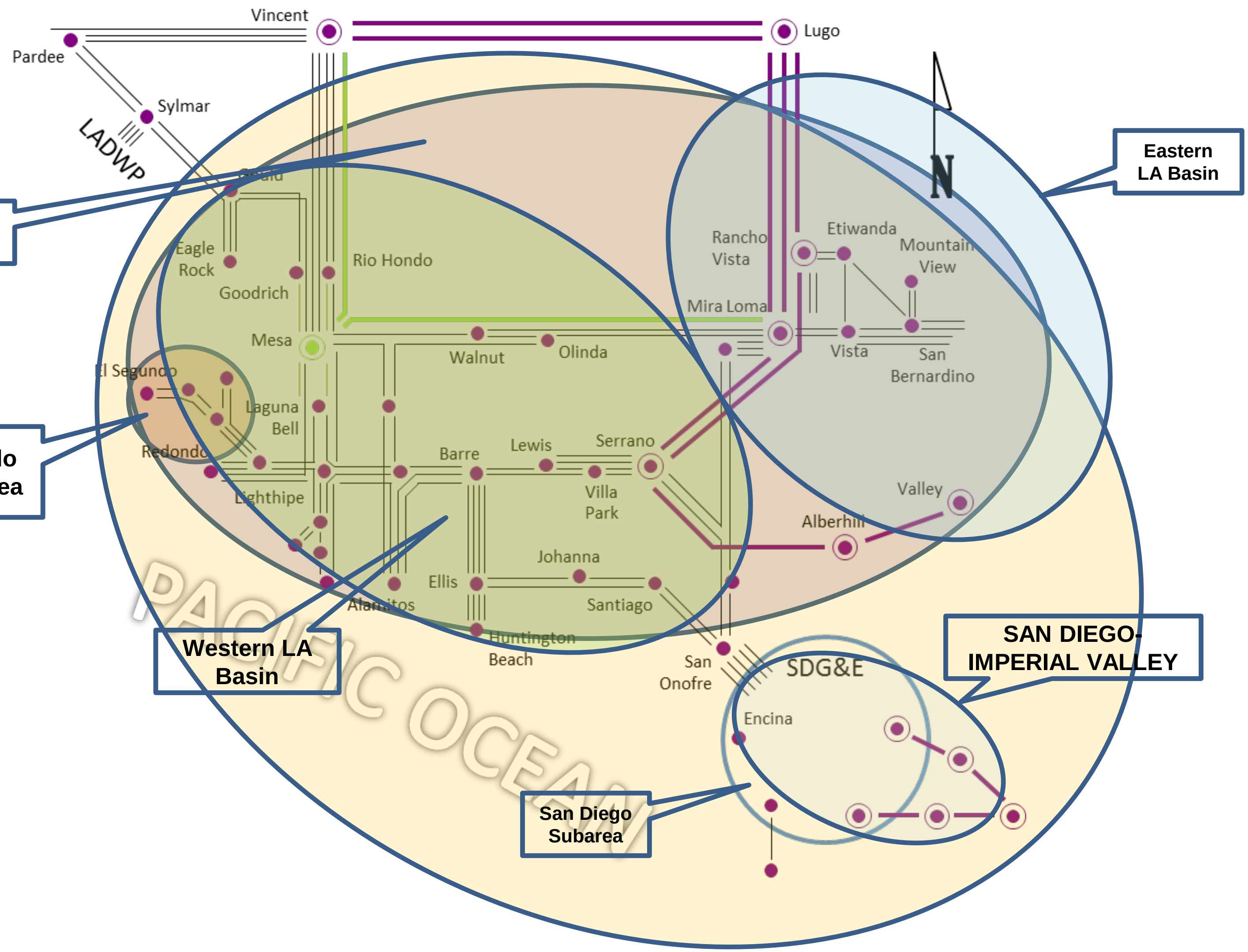
2020-2021 Transmission Planning Process Stakeholder Meeting #3

November 17, 2020

Agenda

- Evaluated alternatives
- LCR reduction benefit calculations
- Benefit-to-Cost calculations
- Estimated charging capabilities

LA Basin and San Diego-Imperial Valley LCR Areas



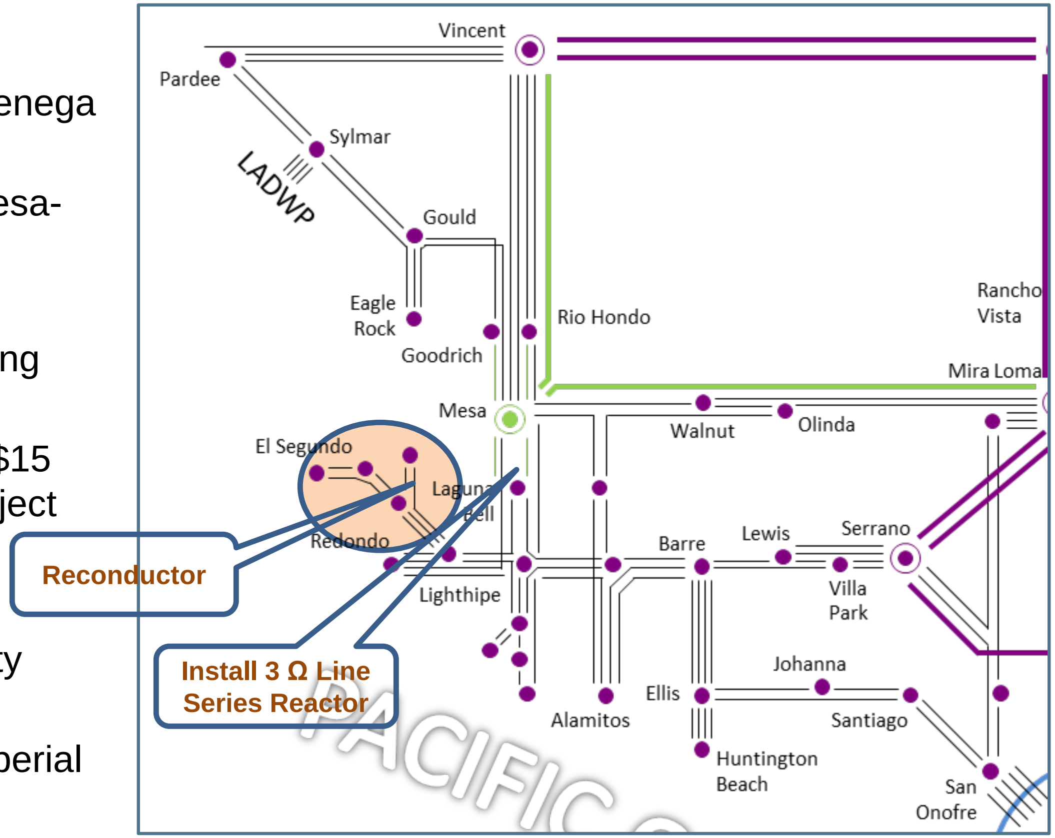
Evaluated Alternatives

	Name of Solutions	Submitter	Prior transmission planning process submittal	Target LCR reduction areas	500kV Voltage	230kV Voltage	DC Voltage	Estimated costs ($ million)
1	Upgrade La Fresa - La Cienega 230kV Line & Install Series Reactor on the Mesa - Laguna Bell and Mesa - Lighthipe 230kV Lines	CAISO	2019-2020	El Nido, Western LA Basin, overall LA Basin		√		$ 119
2a & 2b	Pacific Transmission Expansion (PTE) VSC DC Project – Options 1 & 2	Western Grid Developer	2019-2020	Big Creek/Ventura, El Nido Subarea, Western LA Basin Subarea, overall LA Basin, San Diego-Imperial Valley			√	$ 1,850
3	Devers – Lighthipe DC Line	CAISO	N/A	El Nido, Western LA Basin, overall LA Basin			√	$ 1,100
4	Lugo area to LA Basin DC Line	CAISO	N/A	El Nido, Western LA Basin, overall LA Basin			√	$ 1,100
5a 5b 5c	Lake Elsinore Advanced Pumped Storage (LEAPS) Project – Options 1 and 2	Nevada Hydro	2018-2019 and prior transmission planning processes	Overall LA Basin, San Diego-Imperial Valley	√	√		Option1a: $829 Option 1b: $ 2,040 Option 2: $ 1,760

Alternative 1: 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 the LA Basin: 1137 MW
- Adverse impact to the San Diego – Imperial Valley LCR: - 465 MW



Alternative 1: Local Capacity Reduction Benefit Assessment

	Alternative 1: Reconductor La Fresa-La Cienega 230kV Line and Install Line Series Reactor on the Mesa-Laguna Bell 230kV Line	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (LA Basin) (MW)	1137	
Capacity value (per MW-year)	$10,800	$15,360
LCR Reduction Benefit ($million)	$12.3	$17.5
LCR increase (San Diego-Imperial Valley) (MW)	-465	
Capacity value (per MW-year)	$3,720	$8,280
LCR increase cost ($million)	-$1.7	-$3.9
Net Total LCR Saving ($million/year)	$10.5	$13.6

Alternative 1: 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)	$10.5	$13.6
PV of LCR Savings ($million)	$140.65	$181.50
Capital Cost		
Capital Cost Estimate ($ million)	$119	
Estimated "Total" Cost (screening) ($million)	$155	
Benefit to Cost		
PV of Savings ($million)	$140.65	$181.50
Estimated "Total" Cost (screening) ($million)	$154.70	
Benefit to Cost	0.91	1.17

- The local capacity benefits' benefit-to-cost ratio ranges from 0.91 to 1.17.
- The overall benefit-to-cost ratio will be updated pending availability of the production cost simulation results.

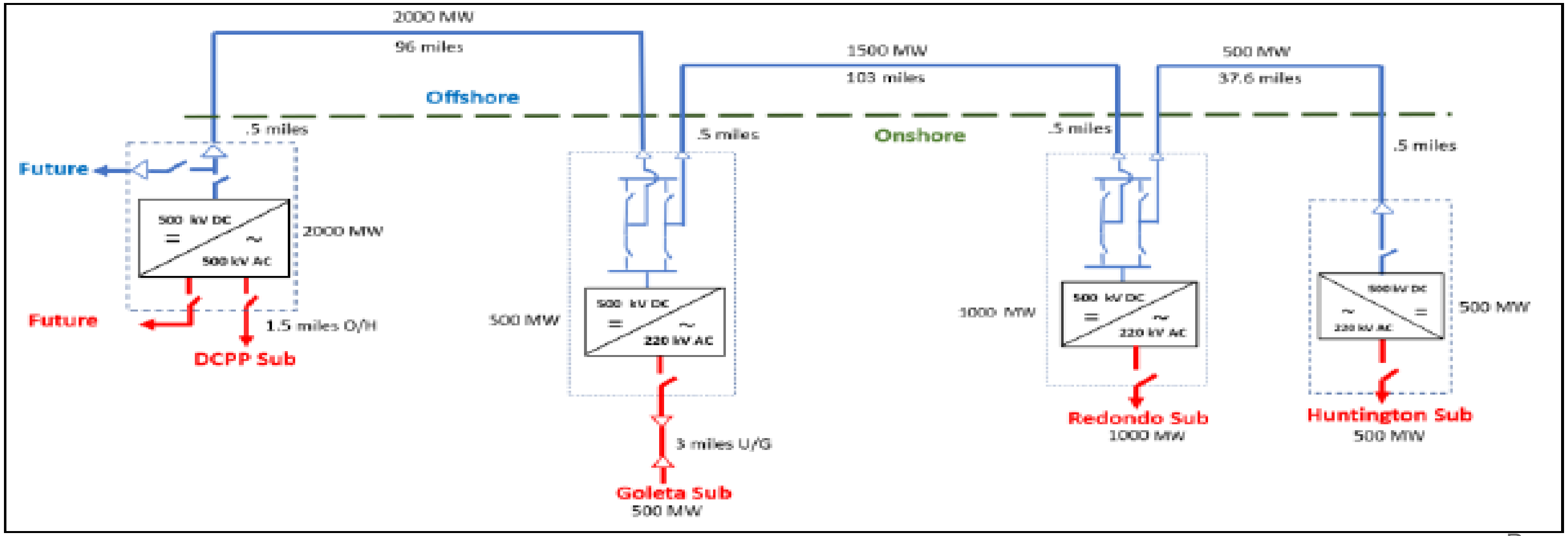
Alternative 2: Pacific Transmission Expansion Project

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)
  - Option 1: Install 500kV DC submarine cables connecting Diablo Canyon switchyard to Goleta, Redondo Beach and Huntington Beach substations
  - Option 2: same as Option 1, but with connections to El Segundo and San Onofre instead of Redondo Beach and Huntington Beach
- Estimated Total Cost: $1.85 billion

LCR Reduction Benefits and Impacts:

	Option 1 (MW)	Option 2 (MW)
Amount of gas-fired generation reduction in the Big Creek-Ventura area	393	393
Total amount of gas-fired generation reduction in the overall LA Basin	1,740	655
Adverse impact to the San Diego – Imperial Valley LCR	-140	0



Alternative 2a: Local Capacity Reduction Benefit Assessment for PTEP Option 1

	Pacific Transmission Expansion Project (PTEP Option 1)	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Big Creek-Ventura Area) (MW)	393	
Capacity value (per MW-year)	$5,160	$9,720
LCR Reduction Benefit ($million)	$2.0	$3.8
LCR reduction benefit (LA Basin) (MW)	1740	
Capacity value (per MW-year)	$10,800	$15,360
LCR Reduction Benefit ($million)	$18.8	$26.7
LCR increase (San Diego-Imperial Valley) (MW)	-140	
Capacity value (per MW-year)	$3,720	$8,280
LCR increase cost ($million)	-$0.5	-$1.2
Net Total LCR Saving ($million/year)	$20.3	$29.4

Pacific Transmission Expansion Project (PTEP Option 1)		
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$20.3	$29.4
PV of LCR Savings ($million)	$270.62	$391.78
Capital Cost		
Capital Cost Estimate ($ million)	$1,850	
Estimated “Total” Cost (screening) ($million)	$2,405	
Benefit to Cost		
PV of Savings ($million)	$270.62	$391.78
Estimated “Total” Cost (screening) ($million)	$2,405.00	
Benefit to Cost	0.11	0.16

- The local capacity benefits’ benefit-to-cost ratio ranges from 0.11 to 0.16.
- The overall benefit-to-cost ratio will be updated pending availability of the production cost simulation results.

Alternative 2b: Local Capacity Reduction Benefit Assessment for PTEP Option 2

	Pacific Transmission Expansion Project (PTEP Option 2)	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (Big Creek-Ventura Area) (MW)	393	
Capacity value (per MW-year)	$5,160	$9,720
LCR Reduction Benefit ($million)	$2.0	$3.8
LCR reduction benefit (LA Basin) (MW)	655	
Capacity value (per MW-year)	$10,800	$15,360
LCR Reduction Benefit ($million)	$7.1	$10.1
LCR increase (San Diego-Imperial Valley) (MW)	0	
Capacity value (per MW-year)	$3,720	$8,280
LCR increase cost ($million)	$0.0	$0.0
Net Total LCR Saving ($million/year)	$9.1	$13.9

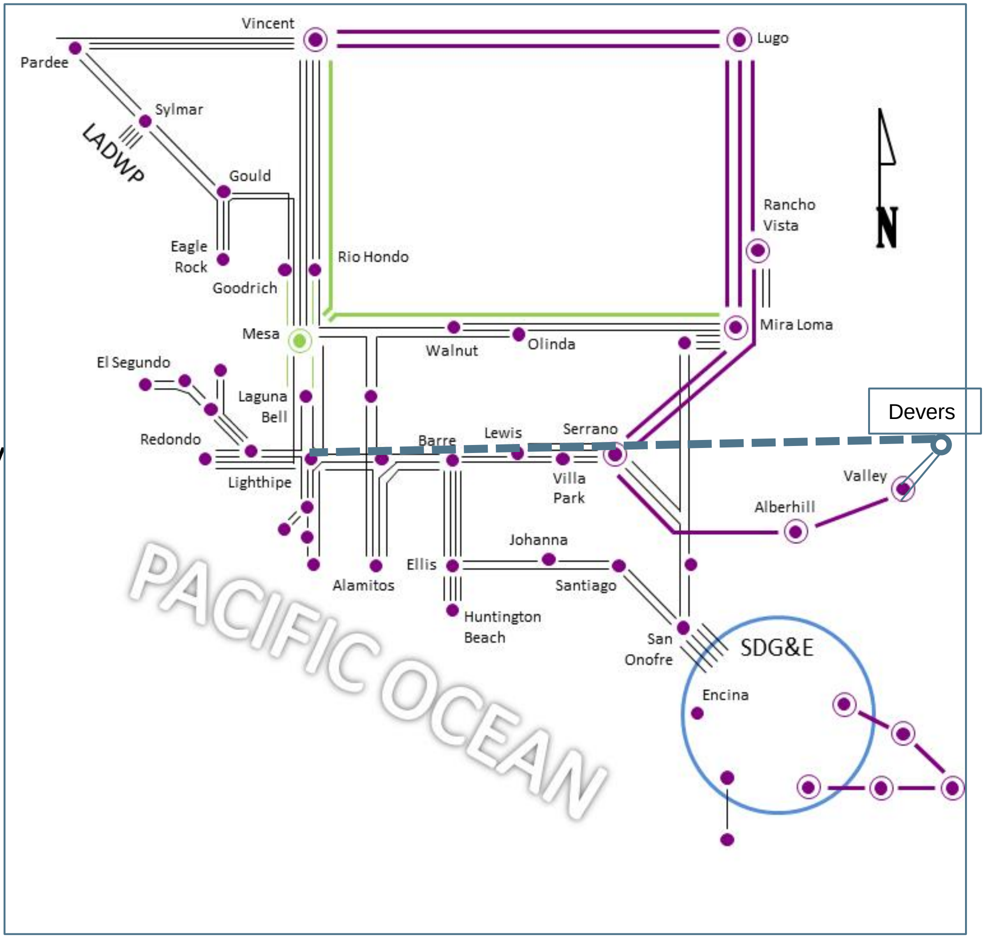
Pacific Transmission Expansion Project (PTEP Option 2)		
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$9.1	$13.9
PV of LCR Savings ($million)	$121.34	$185.05
Capital Cost		
Capital Cost Estimate ($ million)	$1,850	
Estimated “Total” Cost (screening) ($million)	$2,405	
Benefit to Cost		
PV of Savings ($million)	$121.34	$185.05
Estimated “Total” Cost (screening) ($million)	$2,405.00	
Benefit to Cost	0.05	0.08

- The local capacity benefits’ benefit-to-cost ratio ranges from 0.05 to 0.08.
- The overall benefit-to-cost ratio will be updated pending availability of the production cost simulation results.

Alternative 3: Devers – Lighthipe DC Line

Alternative:

- Install approximately 100 mi. of +/- 320 kV between Devers and Lighthipe Substations
- Install RAS to trip the bipole DC line under N-2 contingency of Devers – Red Bluff 500kV lines
- Estimated Total Cost: $1.1 billion
- Amount of gas-fired generation capacity reduction in the LA Basin: <u>849 MW</u>
- Adverse impact to the San Diego – Imperial Valley LCR: - <u>211 MW</u>



Alternative 3: Local Capacity Reduction Benefit Assessment

	Alternative 3: Devers - Lighthipe DC Line	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (LA Basin) (MW)	849	
Capacity value (per MW-year)	$10,800	$15,360
LCR Reduction Benefit ($million)	$9.2	$13.0
LCR increase (San Diego-Imperial Valley) (MW)	-211	
Capacity value (per MW-year)	$3,720	$8,280
LCR increase cost ($million)	-$0.8	-$1.7
Net Total LCR Saving ($million/year)	$8.4	$11.3

Alternative 3: Devers - Lighthipe DC Line		
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$8.4	$11.3
PV of LCR Savings ($million)	$111.78	$150.56
Capital Cost		
Capital Cost Estimate ($ million)	$1,100	
Estimated “Total” Cost (screening) ($million)	$1,430	
Benefit to Cost		
PV of Savings ($million)	$111.78	$150.56
Estimated “Total” Cost (screening) ($million)	$1,430.00	
Benefit to Cost	0.08	0.11

- The local capacity benefits’ benefit-to-cost ratio ranges from 0.08 to 0.11.
- The overall benefit-to-cost ratio will be updated pending availability of the production cost simulation results.

Alternative 4: Lugo area to LA Basin DC Line

Alternative:

- Install approximately 80 - 100 mi. of +/- 320 kV DC line between the Lugo area and the LA Basin
- Estimated Total Cost: $1.1 billion
- Amount of gas-fired generation capacity reduction in the LA Basin: 618 MW
- Adverse impact to the San Diego – Imperial Valley LCR: - 75 MW

Alternative 4: Local Capacity Reduction Benefit Assessment

	Alternative 4: Lugo area to LA Basin DC line	
	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (LA Basin) (MW)	618	
Capacity value (per MW-year)	$10,800	$15,360
LCR Reduction Benefit ($million)	$6.7	$9.5
LCR increase (San Diego-Imperial Valley) (MW)	-75	
Capacity value (per MW-year)	$3,720	$8,280
LCR increase cost ($million)	-$0.3	-$0.6
Net Total LCR Saving ($million/year)	$6.4	$8.9

Alternative 4: Lugo area to LA Basin DC Line		
Local Capacity Benefits		
	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$6.4	$8.9
PV of LCR Savings ($million)	$85.26	$118.27
Capital Cost		
Capital Cost Estimate ($ million)	$1,100	
Estimated "Total" Cost (screening) ($million)	$1,430	
Benefit to Cost		
PV of Savings ($million)	$85.26	$118.27
Estimated "Total" Cost (screening) ($million)	$1,430.00	
Benefit to Cost	0.06	0.08

- The local capacity benefits' benefit-to-cost ratio ranges from 0.06 to 0.08.
- The overall benefit-to-cost ratio will be updated pending availability of the production cost simulation results.

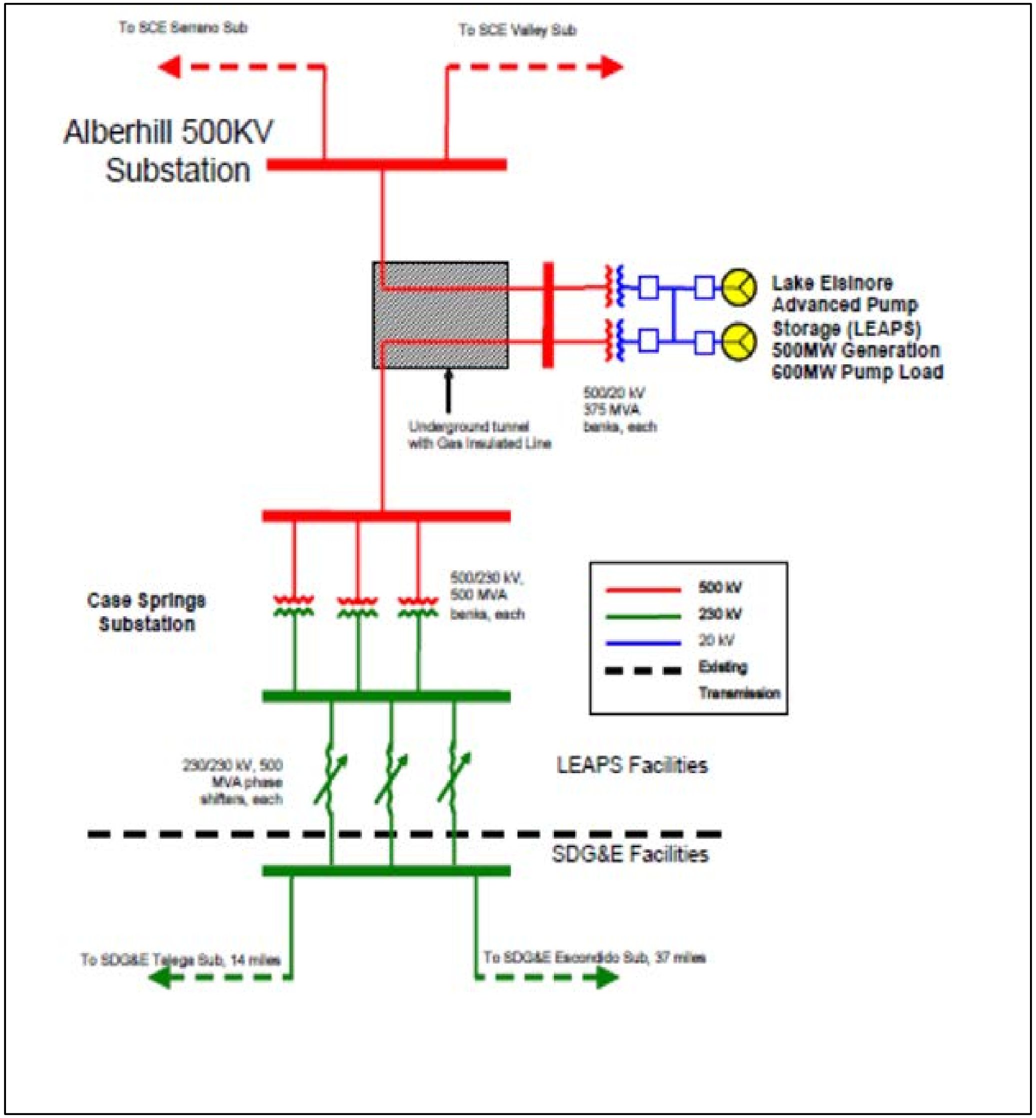
Alternative 5: Lake Elsinore Advanced Pumped Storage Project

<u>Option 5.1a:</u>

- This option interconnects the project at two points: (i) to SCE's transmission system at the proposed Alberhill 500 kV substation (if approved by the CPUC) and (ii) to SDG&E's transmission system by looping in the Talega – Escondido 230 kV line via the proposed Case Springs 230 kV substation. <u>This option does not have the pumped storage.</u>
- Cost: <u>$829 million</u>
- Reduction of gas-fired generation to meet SD-IV local capacity requirement: <u>443 MW</u>
- Adverse impact to the LA Basin LCR: <u>150 MW</u>

<u>Option 5.1b</u>:

- Same as Option 1a but with the <u>addition of the 500 MW</u> pumped storage
- Cost: <u>$2.04 billion</u>
- Reduction of gas-fired generation to meet the SD-IV local capacity requirement: <u>514 MW</u>
- Adverse impact to the overall LA Basin LCR: <u>0 MW</u>



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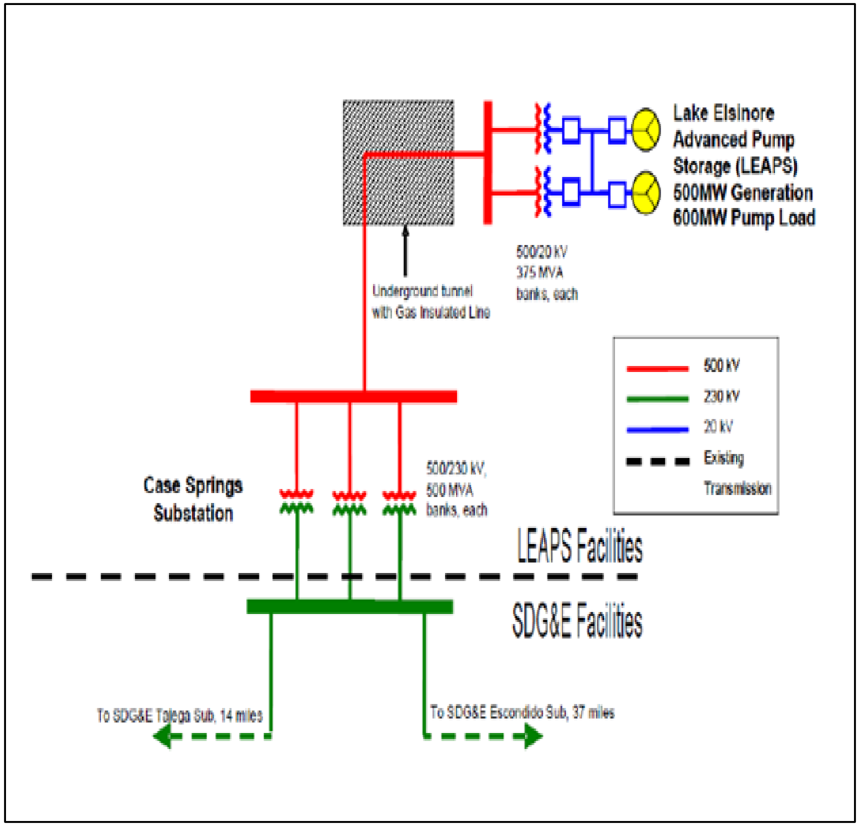
Alternative 5: Lake Elsinore Advanced Pumped Storage

<u>Option 5.2:</u>

- This option interconnects the project to SDG&E only: by looping in the Talega – Escondido 230 kV line via the proposed Case Springs 230 kV substation.
- This option has the 500 MW pumped storage
- Cost: <u>$1.76 billion</u>
- Reduction of gas-fired generation in the SD-IV area to meet the local capacity requirement: <u>533 MW</u>
- Adverse impact to the LA Basin LCR: <u>0 MW</u>



Alternative 5: Local Capacity Reduction Benefit Assessment

	Option 1a		Option 1b		Option 2	
	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26
LCR reduction benefit (San Diego-IV) (MW)	443		514		533	
Capacity value (per MW-year)	$3,720	$8,280	$3,720	$8,280	$3,720	$8,280
LCR Reduction Benefit ($million)	$1.6	$3.7	$1.9	$4.3	$2.0	$4.4
LCR increase (LA Basin) (MW)	150		0		0	
Capacity value (per MW-year)	$10,800	$15,360	N/A	N/A	N/A	N/A
LCR increase cost ($million)	$1.6	$2.3	0	0	0	0
Net LCR Saving ($million/year)	$0.0	$1.4	$1.9	$4.3	$2.0	$4.4

Alternative 5: Local Capacity Reduction Benefit Assessment

	Option 1a		Option 1b		Option 2	
Production Cost Modeling Benefits (from 2018-2019 TPP - subject to change under 2020-2021 TPP)						
Ratepayer Benefits ($million/ year)	$4		-$31		-$34	
LEAPS Net Market Revenue ($million/ year)	$0		$73		$73	
Total PCM Benefits ($million/ year)	$4		$42		$39	
PV of Prod Cost Savings ($million)	$55.20		$579.63		$538.23	
Local Capacity Benefits						
	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26	Local versus System Capacity	Local versus SP 26
Net LCR Saving ($million/year)	$0.0	$1.4	$1.9	$4.3	$2.0	$4.4
PV of LCR Savings ($million)	$0.39	$18.82	$26.39	$58.73	$27.36	$60.91
Capital Cost Estimate ($ million)	$829		$2,040		$1,765	
Estimated "Total" Cost (screening) ($million)	$995		$2,448		$2,118	
Benefit to Cost Ratio						
Benefit to Cost						
PV of Savings ($million)	$55.59	$74.03	$606.02	$638.37	$565.59	$599.14
Estimated "Total" Cost (screening) ($million)	$994.80		$2,448		$2,118	
Benefit to Cost	0.06	0.07	0.25	0.26	0.27	0.28

- The local capacity benefits' benefit-to-cost ratio ranges from 0.06 to 0.28.
- The overall benefit-to-cost ratio will be updated pending availability of the production cost simulation results.

Summary of preliminary estimated storage charging capabilities

	Alternatives	Maximum MW charging capability		Maximum MWh capability		4-hour battery capacity addition (MW)		Comments
		LA Basin	San Diego – Imperial Valley	LA Basin	San Diego – Imperial Valley	LA Basin	San Diego – Imperial Valley	
0	Base case (no alternatives)	3550	1187	27244	6994	1070	680	Base case study results
1	Upgrade La Fresa - La Cienega 230kV Line & Install Series Reactor on the Mesa - Laguna Bell and Mesa - Lighthipe 230kV Lines	4400	0 / 1187 #	29539	0 / 6994	2190	0 / 680	# Due to adverse impact to the San Diego-Imperial Valley LCR need (deficiency), the charging capability is maintained after the deficiency is cured.
2a	Pacific Transmission Expansion (PTE) VSC DC Project – Option 1	5080	0 / 1187 #	29612	0 / 6994	3490	0 / 680	Same comments as above (Alternative #1)
2b	Pacific Transmission Expansion (PTE) VSC DC Project – Option 2	3936	1187	29350	6994	1250	680	
3	Devers – Lighthipe DC Line	4250	0 / 1187 #	29539	0 / 6994	1900	0 / 680	Same comments as above (Alternative #1)
4	Lugo area to LA Basin DC Line	4028	0 / 1187 #	29455	0 / 6994	1460	0 / 680	Same comments as above (Alternative #1)
5a	LEAPS Option 1a	3444	1620	26595	6941	1040	1540	
5b	LEAPS Option 1b	3550	1665	27244	7417	1070	1540	
5c	LEAPS Option 2	3550	1430	27244	4376	1070	1430 (3.1hr)	

SDG&E Area
Sub-transmission Project Re-evaluation

Charles Cheung
Senior Regional Transmission Engineer

2020-2021 Transmission Planning Process Stakeholder Meeting
November 17, 2020

SDG&E Sub-transmission Projects Re-evaluation

No.	Project	In-service Date
1	TL6983 2nd Pomerado – Poway 69 kV Circuit	4/2/2026
2	TL690E Stuart Tap - Las Pulgas 69kV Reconductor	5/1/2026
3	TL600 Kearny – Clairemont Tap Reconductor and Loop into Mesa Heights	7/28/2026
4	Loop Granite – Granite Tap, TL632A, into Granite and Cancel Los Coches – El Cajon Reconductor, TL631	10/22/2026
5	TL605 Silvergate – Urban Reconductor	6/25/2027
6	Open Sweetwater Tap (TL603) and Loop into Sweetwater	12/20/2027

SDG&E Sub-transmission Projects Re-evaluation

1. Evaluate the Reliability and Deliverability need
2. If there is reliability need, determine the amount of battery storage needed to mitigate the need
3. Determine whether battery storage can be charged without other reliability issues in the off-peak case
4. Determine whether <u>4-hour</u> battery storage is sufficient to mitigate the need

SDG&E Sub-transmission Projects Re-evaluation

No.	Project	Reliability Need found?	Battery needed to be added to mitigate
1	TL6983 2nd Pomerado – Poway 69 kV Circuit	No	N/A
2	TL690E Stuart Tap - Las Pulgas 69kV Reconductor	Yes	35 MW
3	TL600 Kearny – Clairemont Tap Reconductor and Loop into Mesa Heights	No	N/A
4	Loop Granite – Granite Tap, TL632A, into Granite and Cancel Los Coches – El Cajon Reconductor, TL631	Yes	10 MW
5	TL605 Silvergate – Urban Reconductor	Yes	30 MW
6	Open Sweetwater Tap (TL603) and Loop into Sweetwater	Yes	75 MW

SDG&E Sub-transmission Projects Re-evaluation

No.	Overloaded Facility	Battery needed to be added to mitigate	Any Charging Violation?
2	Stuart Tap - Las Pulgas 69kV line	35 MW	Yes
4	El Cajon-Los Coches 69 kV line	10 MW	No
5	Silvergate – Urban 69 kV line	30 MW	No
6	Naval Sttion Meter-Sweetwater Tap 69 kV/ Sweetwater-Sweetwater Tap 69 kV	75 MW	No

SDG&E Sub-transmission Projects Re-evaluation next step

- Determine whether 4-hour battery storage is sufficient to mitigate overloads in these projects

No.	Project
4	Loop Granite – Granite Tap, TL632A, into Granite and Cancel Los Coches – El Cajon Reconductor, TL631
5	TL605 Silvergate – Urban Reconductor
6	Open Sweetwater Tap (TL603) and Loop into Sweetwater

SDG&E Sub-transmission Projects Re-evaluation next step

- Evaluate the policy and economic need of these two projects

No.	Project
1	TL6983 2nd Pomerado – Poway 69 kV Circuit
3	TL600 Kearny – Clairemont Tap Reconductor and Loop into Mesa Heights

2020-2021TPP: PG&E On Hold Projects Status Update

Abhishek Singh
Regional Transmission Engineer Lead

2020-2021 Transmission Planning Process Stakeholder Meeting
November 17, 2020

PG&E On Hold Project List

- Wheeler ridge Junction Project
- Moraga-Sobrante 115 kV Line Reconductor
- North Of Mesa

Wheeler Ridge Junction Project

Approved cycle:
- 2013-2014 TPP
- 2018-2019 TPP
- 2019-2020 (On Hold)

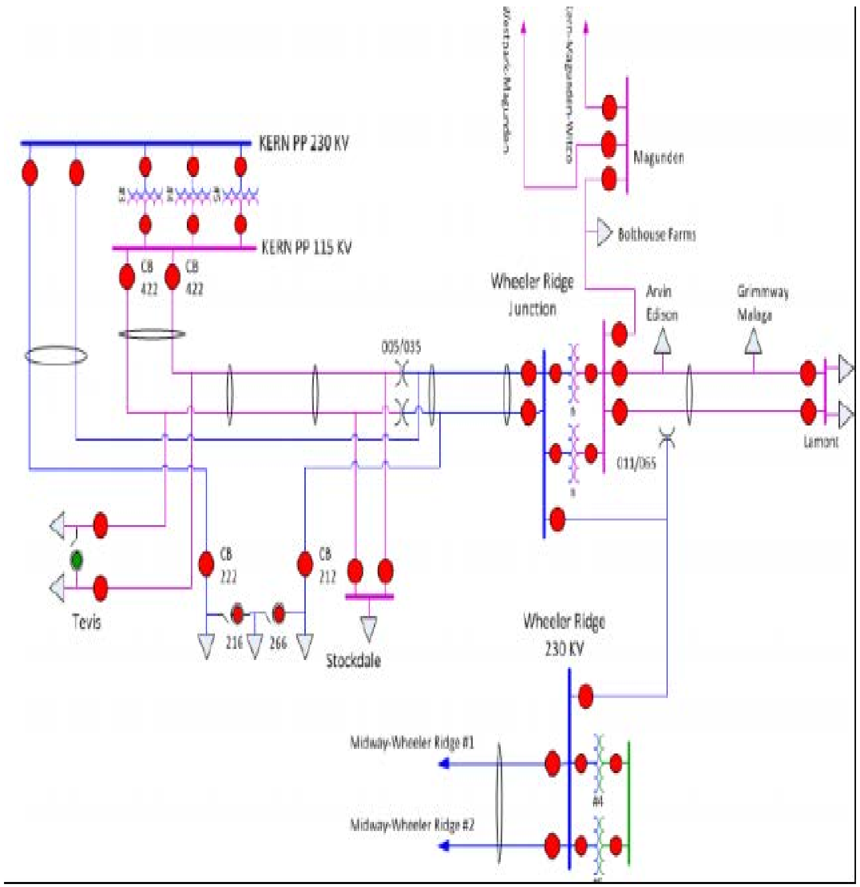
Original scope:
- Build new substation between Kern PP 230kV and Wheeler Ridge 230kV. Convert Wheeler Ridge Lamont 115kV to 230kV operation and terminate at WRJ.

Project cost:
- Original cost: $90M-$140M
- 2019-2020 cost estimate: $250-$300M

Current In-service Date:
- On hold

Reliability Assessment Need:
- Multiple P1, P2, P3 & P6 overloads in both Kern 115 areas and the 230 kV Midway-Wheeler ridge lines

Alternatives under consideration TPP20-21
- Option 1: New Wheeler ridge Jn 115 kV SS, Looping of 115 kV lines to this SS, New 115 kV line from SS to Wheeler 115 kV,Reconductoring of Kern-Tevis-Lamont lines and a BESS at Wheeler 230 kV bus.
- Option 2: New Stockdale 230/115 kV T/F, Wheeler ridge Jn SS, Wheeler ridge 230/115 kV T/F, reconductoring Wheeler ridge-Lamont line with higher capacity and a BESS at Wheeler 230 kV bus.



Moraga-Sobrante 115 kV Line Reconductor Project

Approved cycle:
- 2018-2019 TPP
- 2019-2020 (On Hold)

Original scope:
- Reconductor the Moraga - Sobrante 115 kV line with a larger capacity conductor

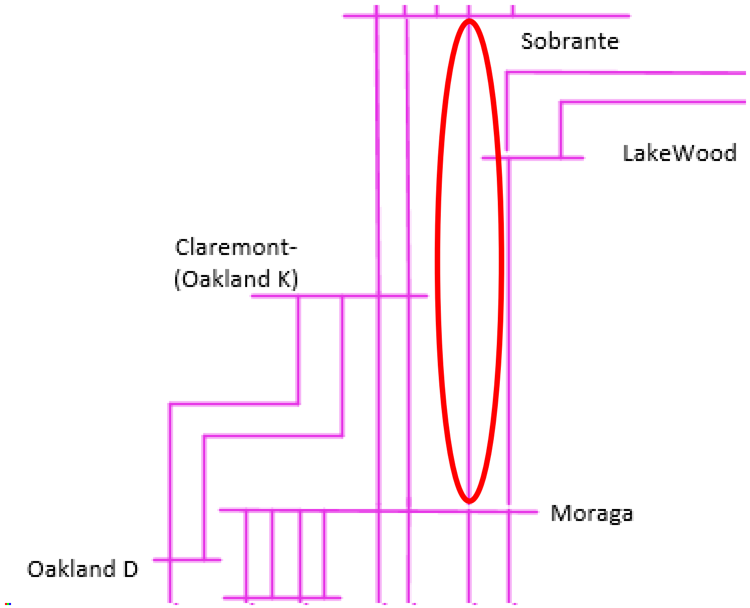
Project cost:
- Original cost: $12-$18M
- 2019-2020 cost estimate: $10-$20M

Current In-service Date:
- On hold

Reliability Assessment Need:
- Multiple P2 overloads at Sobrante substation starting 2030

Alternatives under consideration TPP20-21
- None

Recommendation
- Under review.



North of Mesa Project

Approved cycle:

- 2012-2013 TPP
- 2018-2019 TPP
- 2019-2020 (On Hold)

Original scope:

Build Andrew 230/115 kV substation, energize Diablo – Midway 500 kV line at 230 kV and connect to Andrew substation, and loop-in the SLO – Santa Maria 115 kV line to Andrew and Mesa substations.

Project cost:

- Original cost: $120-$150M
- 19-20 cost estimate: $114-$144M

Current In-service Date:

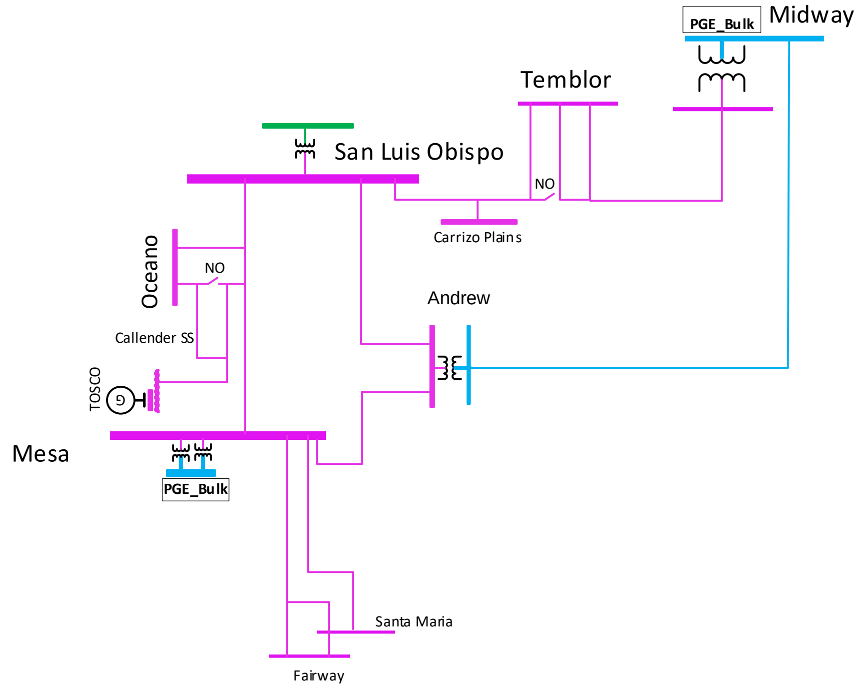
- On hold

Reliability Assessment Need:

- Multiple P2, P6 & P7 overloads in both Mesa 115 kV area. In addition, the load forecast and profile in the area does not provide periods for maintenance to facilities where the next contingency would not result in load loss in the area.

Alternatives under consideration TPP20-21

- Option 1: Add ~100MW BESS at Mesa 115 kV
- Option 2: Install 500/115 kV transformer and loop in to Diablo - Midway 500 kV line, and loop-in the SLO – Santa Maria 115 kV line to Andrew and Mesa substations.



California ISO

2020-2021 TPP Wildfire Impact Assessment Results Update

Binaya Shrestha
Manager, Regional Transmission – North

2020-2021 Transmission Planning Process Stakeholder Meeting
November 17, 2020

Presentations available on Market Participant Portal

Next Steps
Preliminary Policy and Economic Assessments

Isabella Nicosia
Stakeholder Engagement and Policy Specialist

2020-2021 Transmission Planning Process Stakeholder Meeting
November 17, 2020

Stakeholder Comments

- Stakeholder comments to be submitted by December 1
  - 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