Agenda
Preliminary Policy and Economic Assessments

Kristina Osborne
Lead Stakeholder Engagement and Policy Specialist

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

2018-2019 Transmission Planning Process Stakeholder Meeting Agenda

Topic	Presenter
Introduction	Kristina Osborne
Overview	Jeff Billinton
Policy Assessment and Deliverability Methodology	Sushant Barave Songzhe Zhu
Overview of Economic Modeling Requirements	Neil Millar
Economic Assessment and Production Cost Modeling	Yi Zhang
LCR Alternative - North System - South System	Regional Transmission Engineers
Reliability Projects on Hold	Binaya Shrestha
Pacific Northwest Informational Special Study	Jeff Billinton
Next Steps	Kristina Osborne

Introduction and Overview
Preliminary Reliability Assessment Results

Jeff Billinton
Manager, Regional Transmission - North

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

2018-2019 Transmission Planning Process

January 2018 | **April 2018** | **March 2019**

Phase 1 – Develop detailed study plan

State and federal policy

CEC - Demand forecasts

CPUC - Resource forecasts and common assumptions with procurement processes

Other issues or concerns

Phase 2 - Sequential technical studies

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

Publish comprehensive transmission plan with recommended projects

Phase 3 Procurement

ISO Board for approval of transmission plan

California ISO

2018-2019 Transmission Plan Milestones

- Draft Study Plan posted on February 22
- Stakeholder meeting on Draft Study Plan on February 28
- Comments to be submitted by March 14
- Final Study Plan to be posted on March 31
- Preliminary reliability study results to be posted on August 15
- Stakeholder meeting on September 20 and 21
- Comments to be submitted by October 5
- Request window closes October 15
- **Today: Preliminary policy results and economic study update on November 16**
- Comments to be submitted by November 30
- 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

- Update on policy assessment and deliverability methodology proposal
- Overview of economic modeling requirements and preliminary economic assessment results
- Alternatives for Potential LCR Reduction
- Update reliability projects on hold – PG&E Area
- Update and preliminary results of Pacific Northwest informational special study

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

- Load forecast based on California Energy Demand Revised Forecast 2018-2030 adopted by California Energy Commission (CEC) on February 21, 2018
- RPS portfolio direction for 2018-2019 transmission planning process was received from the CPUC and CEC
  - The CPUC IRP default portfolio – 50% RPS – is used for the reliability assessment and economic assessment
  - No base portfolio was transmitted for the policy-driven assessment
  - The IRP 42 MMT Scenario portfolio - CPUC IRP Reference System Plan - is being studied as a sensitivity in the 2018-2019 TPP policy-driven assessment to identify Category 2 transmission
  - Any issues identified in the 42 MMT Scenario would be examined to test if they are also issues for the lower 50% RPS scenario

Update on reliability assessment - 2018-2019 Ten Year Reliability Assessment

- ISO recommended projects have two paths for approval:
  - For management approval, reliability projects less than $50 million can be presented at November stakeholder session
  - For Board of Governor approval of reliability projects over $50 and projects not approved by management, are included in draft plan to be issued for stakeholder comments by January 31, 2019
- No management approval of reliability projects less than $50 million is being sought in the 2018-2019 planning cycle
  - Any less-than-$50 million projects will be part of the approvals sought from the Board of Governors

Interregional projects will be addressed as per tariff-defined processes:

- Interregional transmission planning process being documented in a separate chapter in this cycle and going forward.
- Interregional Transmission Project submissions will continue to be assessed against regional “needs” as identified in the reliability/policy/economic study framework.
- The ISO is not planning additional “special study” efforts at this time focusing on out-of-state renewables

Special study issues in 2018-2019 Transmission Plan cycle:

- Special studies targeting:
  - Potential for increasing opportunities for transfers of low carbon electricity with the PAC Northwest, and for PAC Northwest Hydro to play role in reducing dependence on resources impacted by Aliso Canyon
  - ISO support for CPUC proceeding re Aliso Canyon
- In addition to previously identified special studies,
  - Updating the assessment of the ***system*** risks to reliability of economically driven early retirement of gas fired generation – using the 42 MMT Scenario portfolio from the CPUC IRP Reference System Plan
  - Production cost modeling benefits of large storage was being considered as a potential simple sensitivity – but now required to address certain (system) economic study requirements

Study Information

- Stakeholder comments to be submitted by November 30
  - 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

2018-2019 TPP Policy-driven Assessment

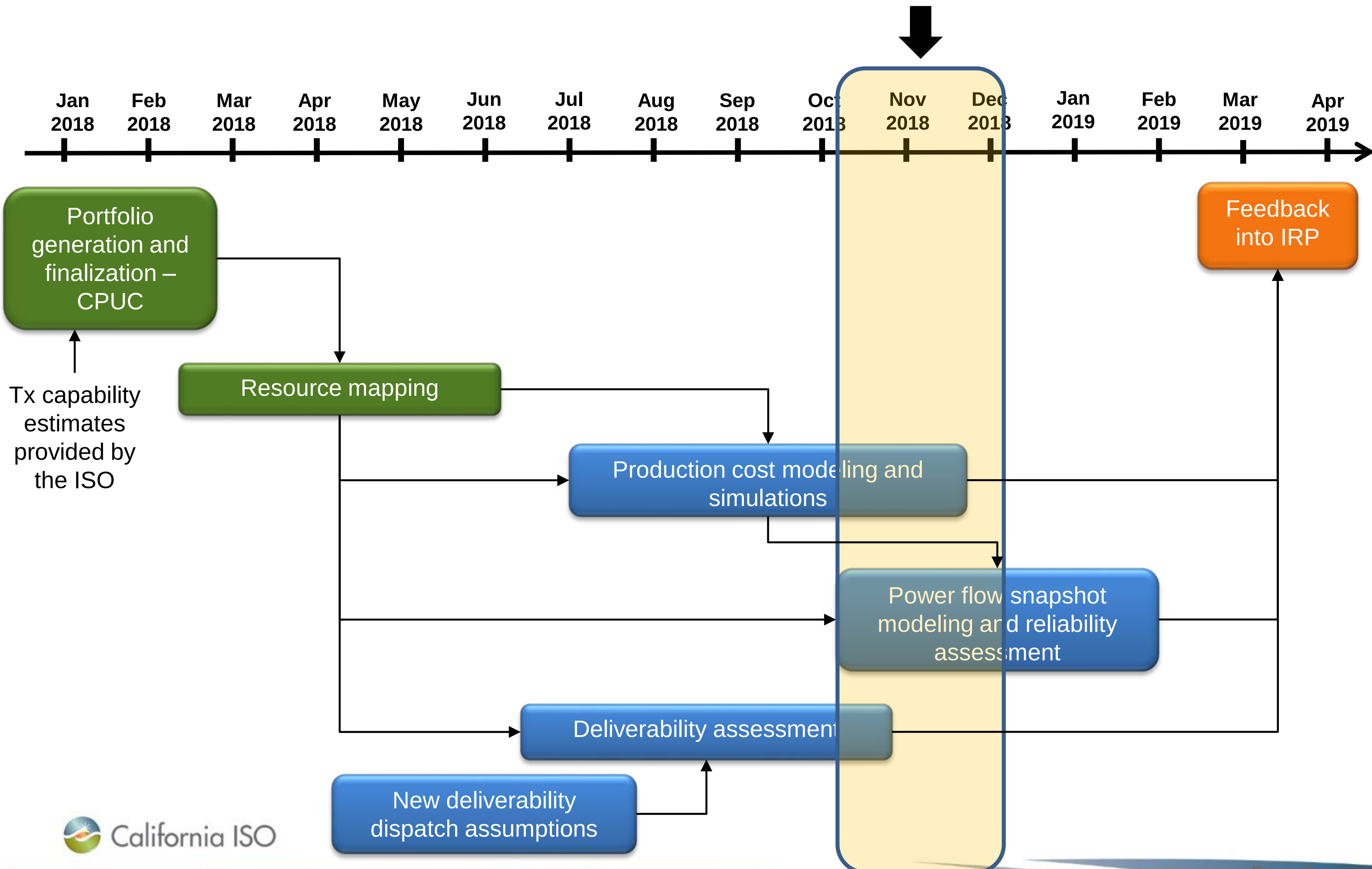
Sushant Barave and Songzhe Zhu

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

Agenda

- Policy-driven assessment status update
- Deliverability methodology modification and test results of 42 MMT portfolio
- 42 MMT portfolio production cost simulation results (to be presented as part of the economic assessment)
- Next steps and timeline

Timeline and current status



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Four key objectives of policy-driven assessment in 2018-2019 TPP

1. Study the transmission impacts of the sensitivity portfolio transmitted to the ISO by CPUC
   a. Capture reliability impacts
   b. Test the deliverability of resources selected to be full capacity deliverability status (FCDS)
   c. Analyze renewable curtailment data
2. Evaluate transmission solutions (only Category 2 in this planning cycle) needed to meet state, municipal, county or federal policy requirements or directives as specified in the Study Plan
3. Test the transmission capability estimates used in CPUC's integrated resource planning (IRP) process and provide recommendations for the next cycle of portfolio creation
4. Test deliverability of FCDS resources in the portfolio using new renewable output assumptions that take into account the new qualifying capacity calculations for solar and wind

Two of the next steps identified during September 2018 stakeholder meeting will be discussed today

Next steps

- Capture and analyze renewable curtailment based on production cost simulation runs; if required, run sensitivities to gain more insights
- Select power flow snapshots for reliability assessment; model these snapshots and run contingency analyses
- Document deliverability results

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California ISO Public

Draft results to be presented today

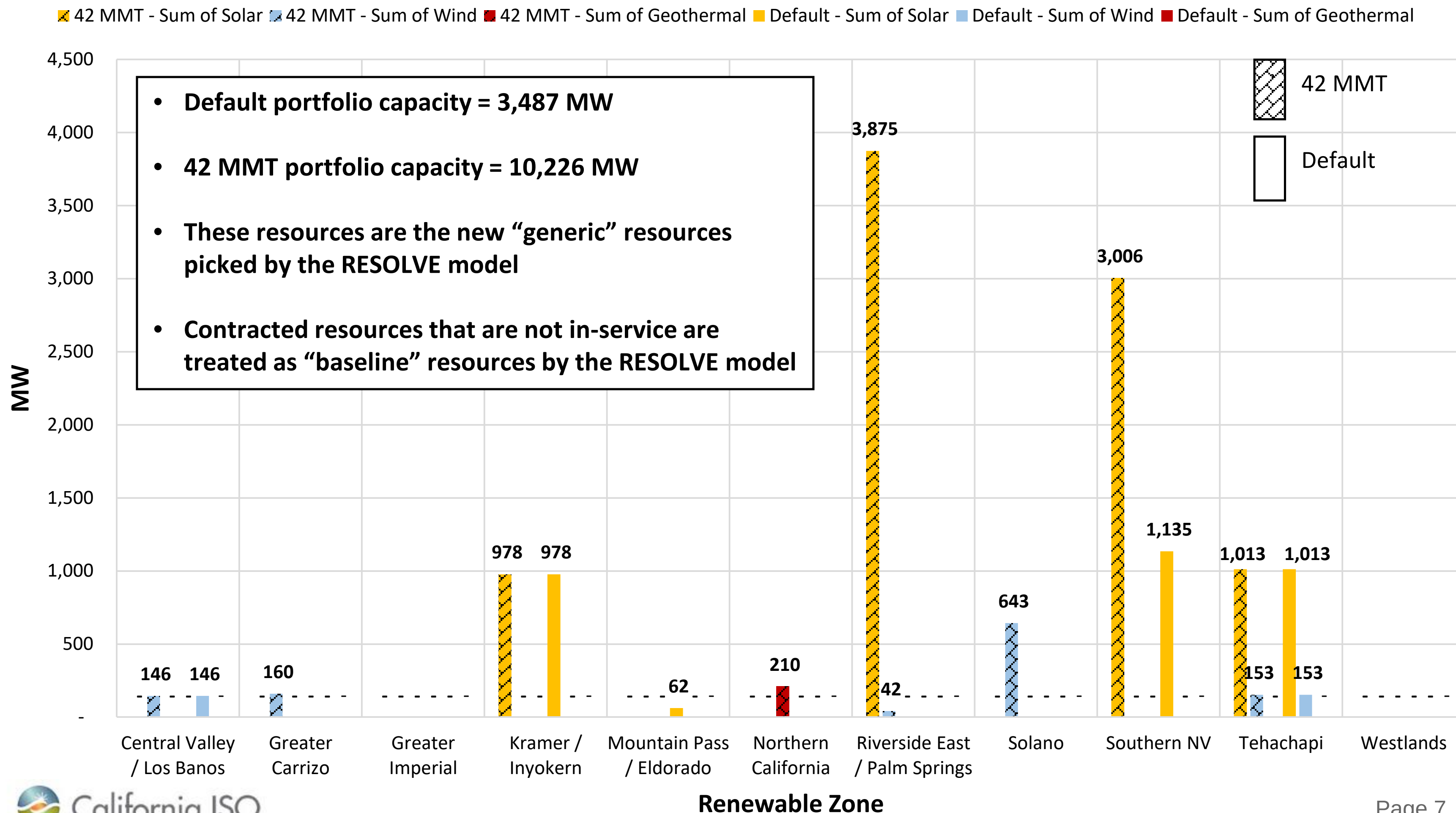
In-progress

Draft results and methodology to be presented today

Key points to remember while interpreting PCM and deliverability results

- The 42 MMT sensitivity portfolio selected by the RESOLVE model is a combination of resources with full capacity deliverability status (FCDS) and energy only deliverability status (EODS).
- Portfolio resources selected as EODS do not require full deliverability, so the deliverability assessment modeled only the FCDS resources.
- FCDS and EODS resources are treated the same way in PCM studies because deliverability is a capacity construct; the economic dispatch is agnostic to deliverability status.
- Renewable curtailment identified in PCM studies can be caused by two main drivers – (i) over-generation or (ii) transmission congestion.
- 2,000 MW of energy storage selected in the portfolio is not modeled in the initial PCM run due to lack of locational information; the results are expected to inform us about optimal locations that could help reduce renewable curtailment

Default portfolio modeled in the year-10 TPP reliability case is a subset of the 42 MMT portfolio which includes FCDS and EODS resources



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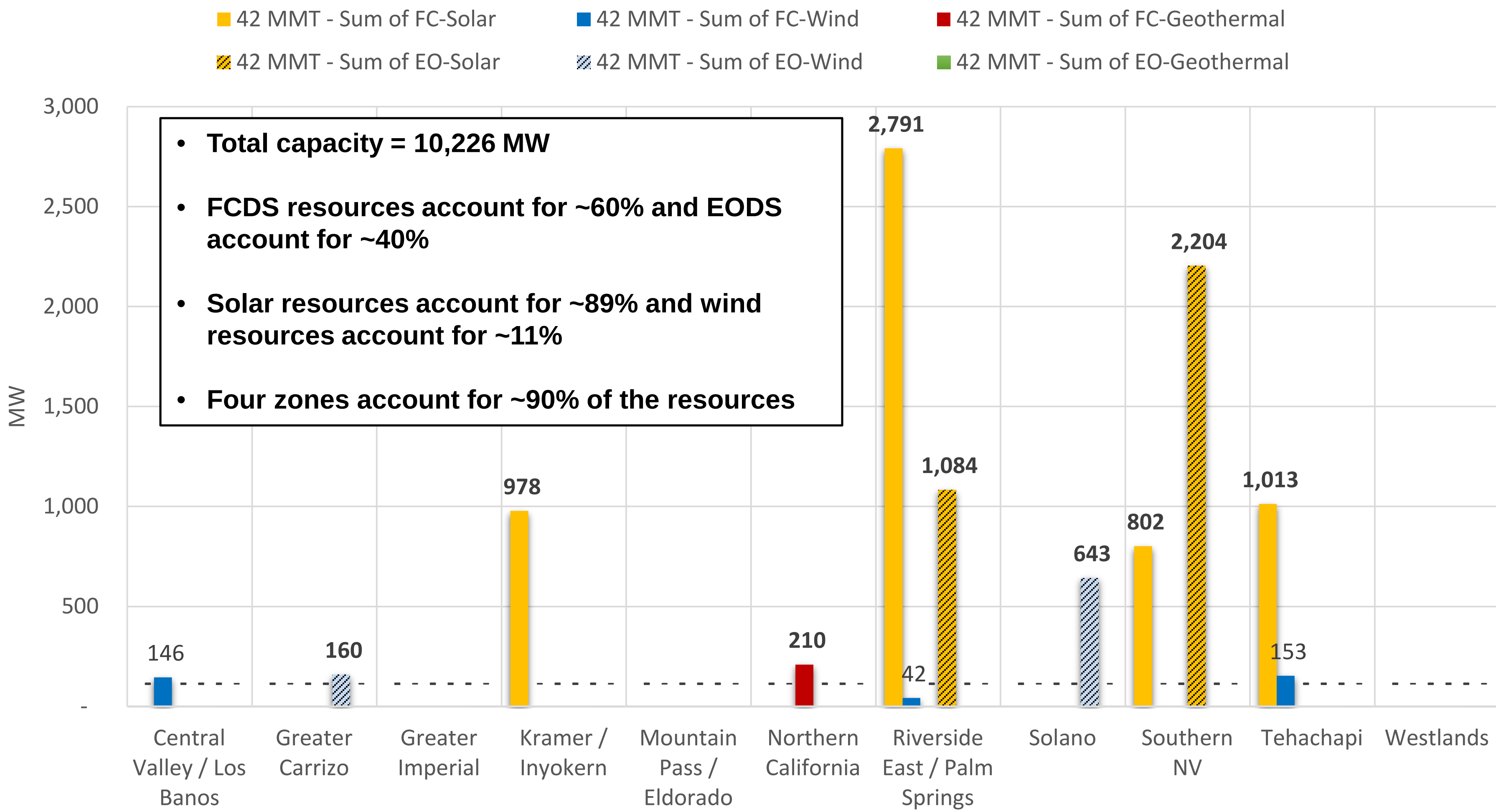
EO resources are selected in Greater Carrizo, Solano, Riverside East and Southern NV zones



Deliverability Assessment Methodology Proposal

Current Deliverability Methodology

- Power flow analysis assuming 1-in-5 ISO peak load condition: test deliverability under a system condition when the generation capacity is needed the most
- An equivalent “QC” is tested for intermittent resources: 50% or 20% exceedance value from 1 PM to 6 PM during summer months.
- Deliverability is tested by
  - Identifying potential gen pockets from which delivery of generation to the ISO grid may be constrained by transmission
  - increasing generators in the gen pocket to 100% of “QC” and reducing generation outside the gen pocket.

Changes Affecting Deliverability Assessment

- When the capacity resources are needed most
  – Moving from peak consumption to peak sale due to increased behind-the-meter distributed generation

- How wind and solar resources are counted for RA
  – Moving from exceedance value to equivalent load carrying capacity approach

ELCC Based QC Calculation for Wind and Solar Resources

- QC = ELCC (%) * Pmax (MW)

- Probabilistic reliability model
  - 8760-hour simulation for a study year
  - Each study consists of many separate cases representing different combination of load shape and weather influenced generation profiles
  - Each case is run with multiple iterations of random draws of variables such as generator outages

ELCC Based QC Calculation for Wind and Solar Resources

- Reliability impacts of the wind or solar resources are compared to the reliability impacts of perfect capacity
  - Calibrate the CAISO system to weighted average LOLE = 0.1
  - Remove the solar or wind resources and replace with perfect capacity
  - Adjust perfect capacity until LOLE = 0.1
  - ELCC (%) = perfect capacity / removed solar or wind resources

- Aggregated by technology and region

Deliverability Methodology Review

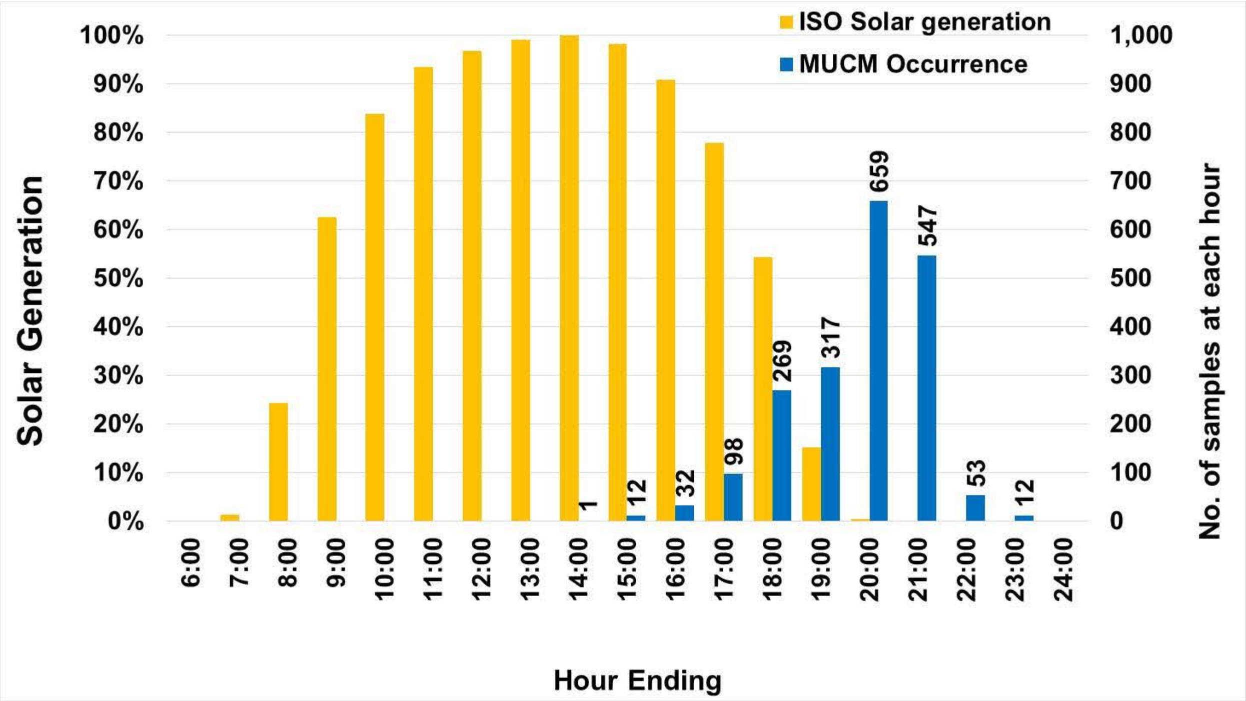
Issues identified in deliverability methodology review:

- Selection of system conditions to test deliverability
- Seasonal and monthly implications – and impact on delivery network upgrades
- Implications of "vintaging"
- Modeling Energy Only generators

Selection of System Conditions

- Need to expand study scenarios to capture a broader range of combinations of modeling quantities – load, generation and imports.
- At a minimum the deliverability should test multiple critical system conditions.
- Data source
  - CAISO summer assessment
  - CPUC ELCC data

Review of Minimum Unloaded Capacity Margin Hours from 2018 Summer Assessment



Source: http://www.caiso.com/Documents/2018SummerLoadsandResourcesAssessment.pdf

Review of Loss of Load Hours from CPUC Monthly LOLE Summary

- For summer peak days, loss of load events occur in HE16 – HE21

SCE

Day/Hour	June	July	August	September
Peak Day - Hour 17	-	1.66%	0.24%	-
Peak Day - Hour 18	-	1.12%	0.26%	0.08%
Peak Day - Hour 19	0.55%	4.34%	2.56%	3.66%
Peak Day - Hour 20	4.11%	7.02%	1.86%	0.29%
Peak Day - Hour 21	1.99%	0.12%	0.03%	-

PG&E Valley

Day/Hour	June	July	August	September
Peak Day - Hour 16	0.02%	-	-	-
Peak Day - Hour 17	0.08%	1.21%	0.06%	-
Peak Day - Hour 18	0.02%	1.18%	0.04%	0.08%
Peak Day - Hour 19	0.83%	2.87%	1.02%	2.68%
Peak Day - Hour 20	3.37%	3.35%	2.09%	0.02%
Peak Day - Hour 21	1.01%	0.07%	0.04%	-

Critical System Conditions

- Highest system need scenario (peak sale)
  - HE18 ~ HE22 in the summer

- Secondary system need scenario (peak consumption)
  - HE15 ~ HE17 in the summer

Highest System Need Scenario – Study Assumptions

Load	1-in-5 peak sale forecast by CEC
Non-Intermittent Generators	Pmax set to QC
Intermittent Generators	Pmax set to 20% exceedance level during the selected hours (high net sale and high likelihood of resource shortage)
Import	MIC data with expansion approved in TPP

Highest System Need Scenario – Assumptions for Intermittent Generation

- Time window of high likelihood of capacity shortage
  - High net sale
  - Low solar output
  - Unloaded Capacity Margin < 6% or Loss of Load hours
- 20% exceedance level to ensure higher certainty of wind and solar being deliverable during the time window

Wind and Solar Output Percentile for HE18~22 & UCM<6% Hours

Exceedance		50%	40%	30%	20%	10%
wind	SDG&E	11.1%	16.3%	23.0%	33.7%	45.5%
	SCE	27.6%	36.9%	46.3%	55.7%	65.6%
	PG&E	29.8%	38.2%	52.5%	66.5%	78.2%
solar	SDG&E	0.0%	0.1%	1.7%	3.0%	7.6%
	SCE	1.9%	3.9%	7.0%	10.6%	14.8%
	PG&E	0.9%	4.1%	6.8%	10.0%	13.7%

Secondary System Need Scenario – Assumptions

Load	1-in-5 peak sales forecast by CEC adjusted by the ratio of highest consumption to highest sale
Non-Intermittent Generators	Pmax set to QC
Intermittent Generators	Pmax set to 50% exceedance level during the selected hours (high gross load and likely of resource shortage)
Import	Import schedules for the selected hours

Secondary System Need Scenario – Assumptions for Intermittent Generation

- Time window of high gross load and high solar output
  - High gross load
  - High solar output
  - UCM < 6% or LOL hours
- 50% exceedance level due to mild risk of capacity shortage

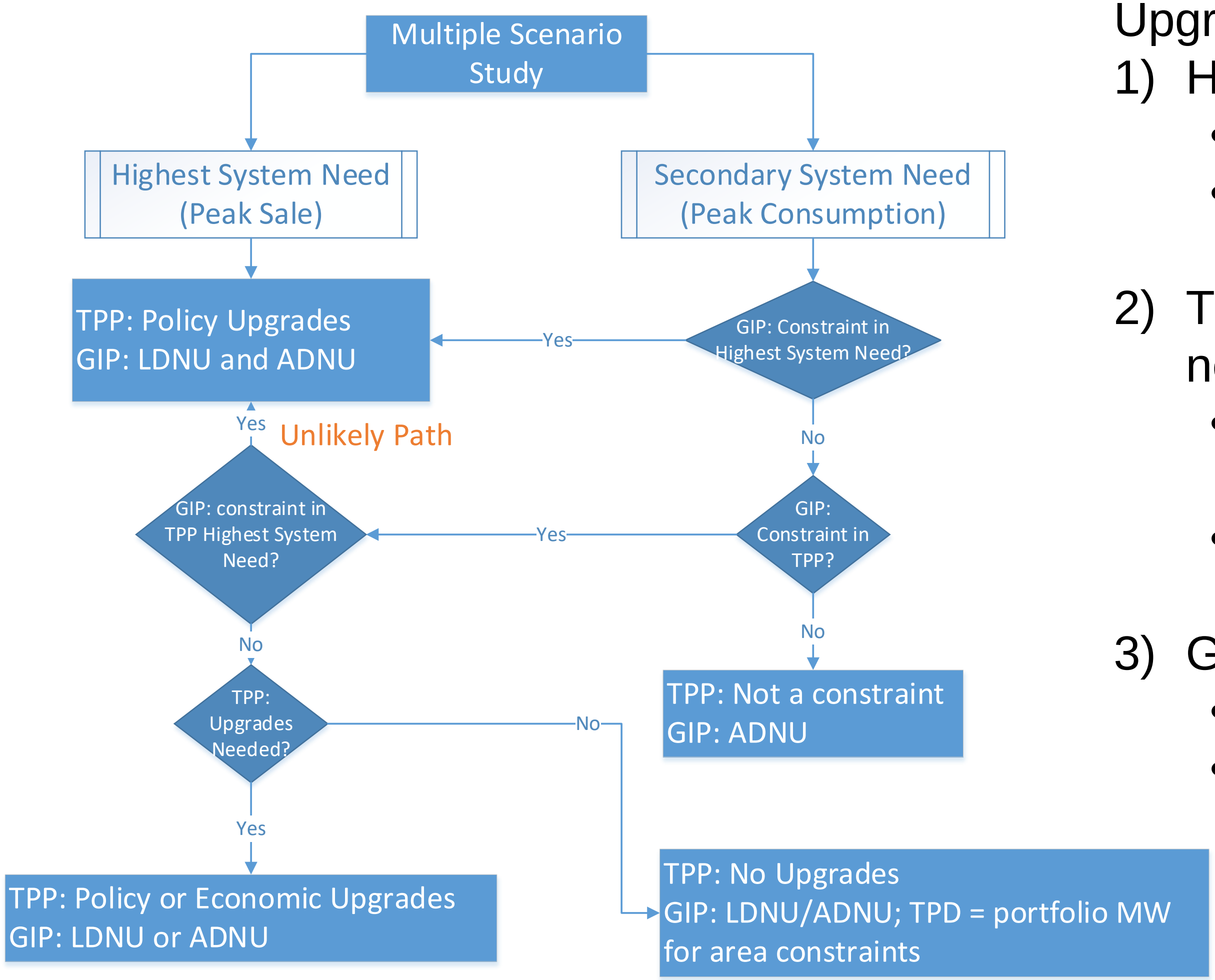
Wind and Solar Output Percentile for HE15~17 & UCM<6% Hours

Exceedance		50%	40%	30%	20%	10%
wind	SDG&E	11.2%	16.6%	26.5%	40.8%	47.9%
	SCE	20.8%	24.8%	34.9%	57.4%	64.8%
	PG&E	16.3%	21.4%	44.7%	69.7%	76.8%
solar	SDG&E	35.9%	44.7%	58.0%	72.1%	75.4%
	SCE	42.7%	49.6%	51.8%	61.9%	86.3%
	PG&E	55.6%	61.6%	63.2%	74.6%	75.9%

Intermittent Generation Assumptions

- The exceedance values were derived from 2018 Summer Assessment data
- These values will be examined and updated with the latest available data periodically in the future

Network Upgrade Identification



Upgrades needed in:

1) Highest system need
   - TPP – policy upgrades
   - GIP – LDNU/ADNU
2) TPP secondary system need
   - Policy/economic upgrades
   - No upgrade
3) GIP secondary system need
   - LDNU/ADNU
   - TPD = portfolio if area constraint and TPP no upgrade

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NQC Determination

- NQC study includes both scenarios
- Deliverable % is calculated from both scenarios
- For deliverability constraints in the secondary system need scenario, if the TPP identified constraint and determined no upgrades are required, such constraints do not reduce FCDS generator deliverability
- The lower deliverable % between the two scenarios is the resource deliverable %

Test Proposed Methodology

- Cluster 10 Phase I – 2023 summer peak
- 2018-2019 50% RPS 42MMT portfolio

Renewable zones	FCDS (MW)			EODS (MW)		
	Solar	Wind	Geothermal	Solar	Wind	Geothermal
Central Valley / Los Banos	-	146	-	-	-	-
Greater Carrizo	-	-	-	-	160	-
Greater Imperial	-	-	-	-	-	-
Kramer / Inyokern	978	-	-	-	-	-
Mountain Pass / Eldorado	-	-	-	-	-	-
Northern California	-	-	210	-	-	-
Riverside East / Palm Springs	2,791	42	-	1,084	-	-
SoCal Desert	-	-	-	-	-	-
Solano	-	-	-	-	643	-
Southern NV	802	-	-	2,204	-	-
Tehachapi	1,013	153	-	-	-	-
Westlands	-	-	-	-	-	-
Grand Total	5,584	341	210	3,288	803	-

SCE-VEA-GWT Area Results – 42MMT Portfolio

- No deliverability constraints in primary system need scenario
- RAS required in second system need scenario

Contingency	Overloaded Facilities	Flow	Comments
Kramer – Victor 230 kV No. 1 & 2	Kramer – Raodway 115 kV	123.62%	North of Lugo RAS (Kramer RAS and Mohave RAS)
Kramer – Victor 230 kV No. 1 & 2	Kramer - Victor 115 kV	119.01%	
Kramer – Victor 230 kV No. 1 & 2	Kramer 230/115 kV No. 1 & 2	114.43%	

SCE-VEA-GWT Area Results – Cluster 10 Phase I

- No deliverability constraints in primary system need scenario
- RAS and ADNU required in second system need scenario

Contingency	Overloaded Facilities	Flow	Comments
Base Case	Calcite – Lugo 230kV	107.04%	Calcite Area Deliverability Constraint
Calcite – Lugo 230kV	Lugo – Pisgah 230kV No. 2	107.73%	Calcite RAS
Calcite – Lugo 230kV	Calcite – Pisgah 230kV	129.63%	
Calcite – Lugo 230kV & Lugo – Pisgah 230kV No. 2	Calcite – Pisgah 230kV	129.89%	

SCE-VEA-GWT Area Results – Cluster 10 Phase I (Cont.)

Contingency	Overloaded Facilities	Flow	Comments
Base Case	Victor – Kramer 230 kV No. 1 & No. 2	101.30%	North of Lugo Area Deliverability Constraint
Kramer – Victor 230 kV No. 1	Kramer – Victor 230 kV No. 2	128.72%	NOL RAS
Kramer – Victor 230 kV No. 1 & 2	Victor – Roadway 115 kV	diverged	
Kramer – Victor 230 kV No. 1 & 2	Kramer - Roadway 115 kV	diverged	
Kramer – Victor 230 kV No. 1 & 2	Kramer - Victor 115 kV	diverged	
Kramer – Victor 230 kV No. 1 & 2	Kramer 230/115 kV No. 1 & 2	diverged	
Lugo – Victor 230 kV No. 3 & 4	Lugo – Victor 230 kV No. 1	139.65%	
Lugo 500/230 kV No. 1	Lugo 500/230 kV No. 2	113.72%	

SCE-VEA-GWT Area Results – Cluster 10 Phase I (Cont.)

Contingency	Overloaded Facilities	Flow	Comments
Base Case	Alberhill - Serrano 500 kV	100.51%	Desert Area Deliverability Constraint; West of Colorado River CRAS; Devers RAS
Base Case	Alberhill - Valley 500 kV	114.80%	
West Wing - Palo Verde 500 kV No. 1 & 2	SNVLY - Delaney 500 kV	109.11%	
Devers - Red Bluff 500 kV No. 1 & 2	Mead - Perkins 500 kV	diverged	
Devers - Red Bluff 500 kV No. 1 & 2	Mead - Market Place 500 kV	diverged	
Devers - Red Bluff 500 kV No. 1 & 2	Eldorado - Lugo 500 kV	diverged	
Devers - Red Bluff 500 kV No. 1 & 2	Eldorado – Moenkopi 500 kV	diverged	
Devers - Red Bluff 500 kV No. 1 & 2	West Wing - Perkins 500 kV	diverged	
Devers - Red Bluff 500 kV No. 1 & 2	N Gila – Q1286 – IV 500 kV	diverged	
Lugo – Vincent 500 kV No. 1 & 2	East ST – West ST 500 kV	111.09%	
Devers - Red Bluff 500 kV No. 1	Devers - Red Bluff 500 kV No. 2	134.52%	
Devers – Vista 230kV No. 2 & TOT185 – Vista 230 kV	San Bernadino – Vista 230kV No. 2	111.78%	
Devers – Vista 230kV No. 2 & Devers – TOT185 230 kV	San Bernadino – Vista 230kV No. 2	110.58%	
San Bernadino – Vista 230 kV No. 2	Etiwanda – San Bernadino 230 kV	102.84%	
Eldorado 500/230 kV No. 5	Bob – Mead 230 kV	157.24%	Ivanpah RAS

SCE-VEA-GWT Area Results – Summary

- Generators are required to participate in RAS
  - Calcite RAS, NOL RAS, Ivanpah RAS, West of Colorado River RAS, Devers RAS
- Area Deliverability Constraints
  - Calcite
  - North of Lugo
  - Desert

San Diego Area Results – RPS 42MMT Portfolio

- No deliverability constraints in the primary and secondary system need scenarios

San Diego Area Results – Cluster 10 Phase I

- RAS required in the primary system need scenario

Contingency	Overloaded Facilities	Flow	Comments
Encina-San Luis Rey-Palomar 230 kV and Encina-San Luis Rey 230 kV	Melrose Tap-San Marcos 69 kV	120%	Encina RAS
Encina-San Luis Rey 230 kV	Encina Tap-San Luis Rey 230 kV #1	120%	
Encina-San Luis Rey-Palomar 230 kV	Encina-San Luis Rey 230 kV #1	108%	
Monserate Tap-Monserate 69 kV	Avocado Tap-Avocado 69 kV	165%	Avocado RAS
Avocado-Pendleton-Monserate 69 kV	Avocado-Monserate Tap 69 kV	131%	
Avocado Tap-Avocado 69 kV	Avocado-Monserate Tap 69 kV	134%	
San Luis Rey-San Onofre 230 kV #2 and #3	San Luis Rey-San Onofre 230 kV #1	110%	San Luis Rey - San Onofre RAS

San Diego Area Results – Cluster 10 Phase I (Cont.)

- RAS required in secondary system scenario

Contingency	Overloaded Facilities	Flow	Comments
Encina-San Luis Rey-Palomar 230 kV and Encina-San Luis Rey 230 kV	Melrose Tap-San Marcos 69 kV	140%	Encina RAS
Encina-San Luis Rey 230 kV	Encina Tap-San Luis Rey 230 kV #1	123%	
Encina-San Luis Rey-Palomar 230 kV	Encina-San Luis Rey 230 kV #1	110%	
Avocado-Monserate-Pala 69 kV	Avocado Tap-Avocado 69 kV	131%	Avocado RAS
Monserate Tap-Monserate 69 kV	Avocado Tap-Avocado 69 kV	177%	
Avacado-Monserate Tap 69 kV	Avocado Tap-Avocado 69 kV	136%	
Avocado-Pendleton-Monserate 69 kV	Avocado-Monserate Tap 69 kV	133%	
Avocado Tap-Avocado 69 kV	Avocado-Monserate Tap 69 kV	138%	
Monserate Tap-Monserate 69 kV	Avocado-Monserate Tap 69 kV	101%	

San Diego Area Results – Summary

- Generators are required to participate in RAS
  - Encina RAS
  - San Luis Rey – San Onofre RAS
  - Avocado RAS
- No LDNU/ADNU

PG&E Area Results – 50% RPS 42MMT

- No deliverability constraints in the primary and secondary system need scenarios

PG&E Area Results – Cluster 10 Phase I

- LDNU and RAS required in the primary system need scenario

Contingency	Overloaded Facilities	Flow	Comments
Round Mountain-Table Mountain #2 500 kV Line or Round Mountain-Table Mountain #1 500 kV Line	Round Mountain-Table Mountain #1 500 kV Line or Round Mountain-Table Mountain #2 500 kV Line	104%	RAS (2018 Reassessment)
Delevan-Vaca Dixon # 2 & # 3 230 kV	Delevan-Cortina 230 kV overload	104%	Cluster 10 Phase 1 LDNU
Delevan-Vaca Dixon # 3 230 kV overload	Delevan-Vaca Dixon # 2 230 kV overload	103%	Cluster 10 Phase 1 RAS

PG&E Area Results – Cluster 10 Phase I (Cont.)

- LDNU/ADNU required in secondary system need scenario (Performed only for PG&E South Area)

Contingency	Overloaded Facilities	Flow	Comments
GATES-HURON-FIVEPOINTSSS 70kV	Schindler-Coalinga #2 70 kV Line (Schindler-Q526 Jct-Pleasant Valley-Coalinga #2)	134%	C10-LDNU
Los Banos 500/230 Bank	Gates 500/230 kV bank # 11 & # 12	111%	Fresno Area Deliverability Constraint
Wilson A-Q1395SS #1 115kV	Merced Falls-Exchequer 70 kV Line	112%	C10-LDNU
PANOCHE-TRANQUILLITY SW STA #1 & #2 230 KV LINES	30825 MCMULLN1 230.00 kV to 30830 KEARNEY 230.00 kV CCT 1	104%	Gates Bank Area Deliverability Constraint
Westley-Q1244SS #1 230 kV Line	Los Banos 500/230 kV Bank #1	125	C10-RAS
LOSBANOS-Q779SS #1 230 KV	Los Banos-Mercy Spring 230 kV Line (Now Dos Amigo-Mercy Spring was cancelled)	103%	Fresno Area Deliverability Constraint

Comparing to Current Methodology

Upgrades in QC10 Phase I reports which would not be needed for deliverability if the new proposed methodology is applied

PG&E South area	SCE-VEA-GWT area	SDG&E area
LDNU: Warnerville-Wilson 230 kV	RNU: Lugo – Victorville RAS expansion	RNU: Sycamore-Penasquitos 230 kV RAS
LDNU: Borden-Wilson Corridor 230 kV OLs	RNU: Bob RAS	RNU: Mission-San Luis Rey 230 kV RAS
LDNU: ElCapitan-Wilson 115 kV	RNU: Innovation RAS	
LDNU: Panoche-Mendota 115 kV Line	ADNU: Desert Area Deliverability Constraint substantially alleviated	LDNU: Silvergate-Bay Boulevard 230 kV series reactor
LDNU: GWF-Kingsburg 115 kV line	ADNU: North of Lugo Area Deliverability Constraint substantially alleviated	ADNU: East of Miguel Area Deliverability Constraint (IV – Valley 500 kV line)
LDNU: Helm-Crescent SW Station 70 kV line	ADNU: Barre-Lewis 230 kV Area Deliverability Constraint (Talega-Santiago 230 kV line)	
RNU: 4 RAS (3 in Fresno and 1 in Kern) not needed		

Summary of Proposed Deliverability Assessment Methodology

- Selection of system conditions to test deliverability
  - Highest system need scenario (peak sale)
  - Secondary system need scenario (peak consumption)
- Delivery network upgrades and NQC determination
  - TPP approve upgrades to mitigate peak sale deliverability constraints; approve upgrades or no-upgrades for peak consumption constraints
  - TPP no-upgrade determination means MWs up to the portfolio amount can be allocated for FCDS for the peak consumption constraint
  - GIP identifies LDNU/ADNU in both scenarios

Next Steps pertaining to deliverability methodology

- Seek feedback from the stakeholders on the proposal
- Finalize the methodology
- Implement the methodology in the generation interconnection studies and the transmission planning studies
  – 2019 reassessment
  – Queue Cluster 11 Phase II study
  – Queue Cluster 12 Phase I study
  – 2019-2020 TPP deliverability study

PCM results: Renewable curtailment in 42 MMT portfolio

(to be presented as part of the Economic Assessment presentation)

Key takeaways from deliverability assessment and PCM simulations
&
Next steps

Key observations – Deliverability

FCDS resources are deliverable based on the proposed approach but could result in higher curtailment

- FCDS resources selected as part of the 42 MMT portfolio can be fully deliverable with RAS upgrades.
- The proposed dispatch assumptions model solar PV at lower dispatch levels compared to the dispatch levels under the existing deliverability methodology.
- Lower dispatch assumptions may translate into FCDS for more resources but could also result in higher renewable curtailment.

Key observations: Renewable curtailment
Further investigation of PCM simulations and exploration of options

- Transmission constraints in Southern NV and Kramer/Inyokern renewable zones caused distortions in PCM simulations due to significant local congestion
- Further analysis of the preliminary results is needed.
- Options will also be considered to mitigate curtailment driven by local transmission congestion
  - Explore potential local transmission mitigations to alleviate congestion
  - Consider updating the EODS transmission capability estimates to refine RESOLVE assumptions

Next steps

1. Re-run PCM simulations to investigate Southern NV and North of Lugo constraints

2. Explore and test if conceptual mitigation (including locating energy storage) for relieving congestion in Southern NV and Kramer/Inyokern renewable zones eliminates PCM simulation issues

3. Select power flow snapshots for reliability assessment; model these snapshots and run contingency analyses

4. If needed, revise the EODS capability estimates and provide an update to transmission capability assumption in IRP

5. Document the policy-driven assessment in 2018-2019 TPP

Emerging Economic Study Considerations
Transmission Planning Process

Neil Millar
Executive Director, Infrastructure Development

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

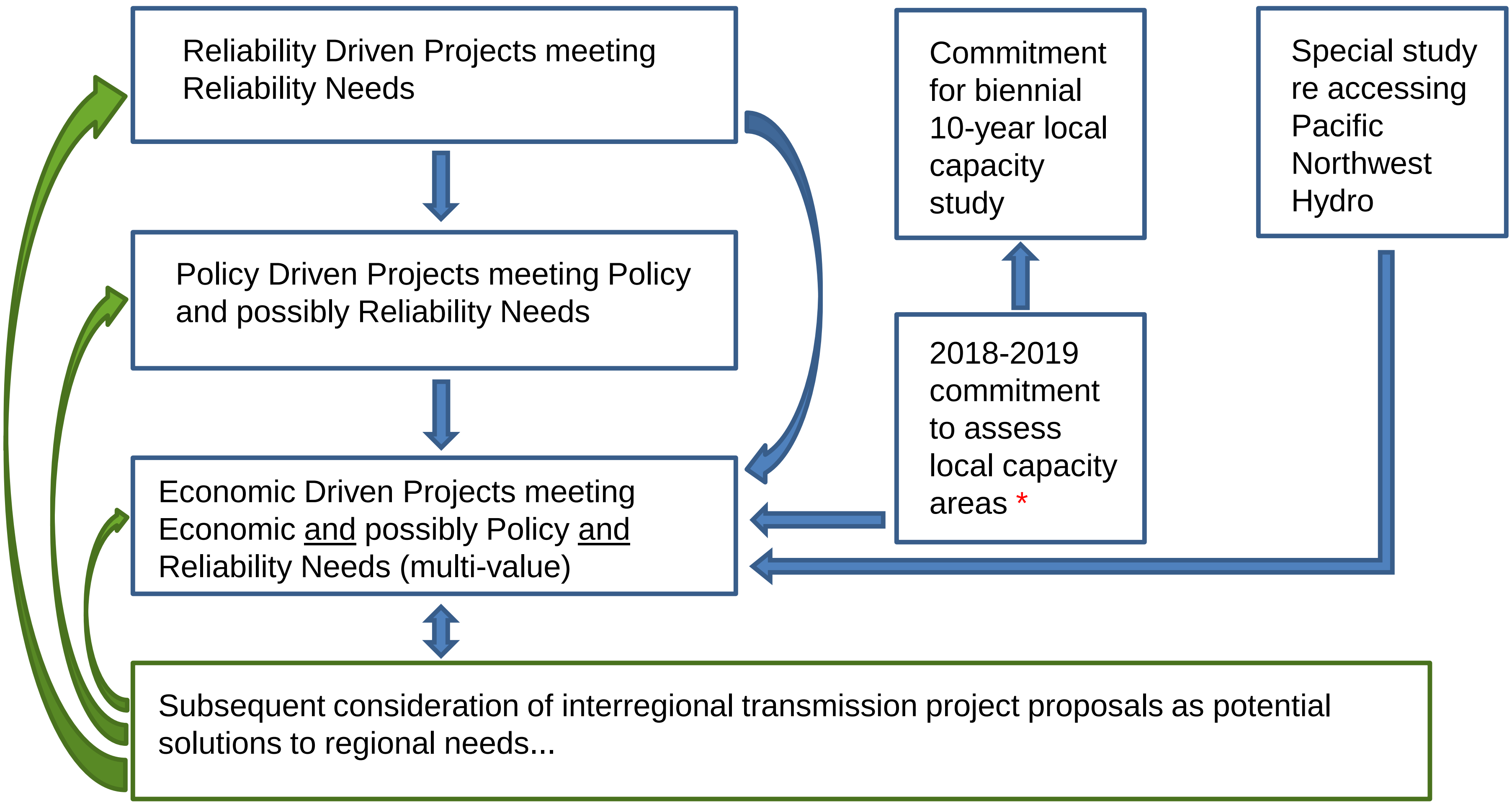
Economic study requirements are being driven from a growing number of sources and needs, including:

- The ISO's traditional economic evaluation process and vetting of economic study requests focusing on production cost modeling
- An increasing number of reliability request window submissions citing potential broader economic benefits as the reason to "upscale" reliability solutions initially identified in reliability analysis or to meet local capacity deficiencies
  - An "economic driven" transmission project may be upsizing a previously identified reliability solution, or replacing that solution with a different project…
- Opportunities to reduce the cost of local capacity requirements – considering capacity costs in particular
- Considering interregional transmission projects as potential alternatives to regional solutions to regional needs.

The existing study framework remains viable, with flexibility in specific approaches:

- Selection of preferred solutions at “reliability” and “policy” stages are initially based on more conventional cost comparisons to meet reliability needs, e.g. capital and operating costs, transmission line loss savings, etc.
- Consideration of more comprehensive benefits, e.g. broader application of the TEAM, are conducted at the economic study stage, and can lead to replacing or upscaling a solution initially identified at the reliability or policy stage.
- The relationship between ISO transmission planning, and CPUC-led resource procurement needs to be respected and properly managed

The 2018-2019 economic analysis is therefore heavily coordinated with other study activities:



The scope of the local capacity requirement reduction study is to:

- provide profiles to help develop characteristic of potential preferred resources alternatives.
- identify potential alternatives - conventional transmission upgrades and preferred resources - to reduce requirements in at least <u>half</u> of the existing areas and sub-areas
- prioritize areas and sub-areas based on the attributes of the gas-fired generation to provide other system benefits and on the gas-fired generation being located in disadvantaged communities
- base recommendations for approval of the identified transmission upgrades on the results of economic assessments

Issues in considering alternatives to eliminate or reduce local capacity requirements:

- Given the current planning assumptions over the ISO planning horizon, there is generally not a reliability requirement or policy requirement in the planning horizon that must be addressed as set out in the ISO tariff in most if not all areas and sub-areas
- The studies therefore focus on economic analysis
- The in-depth local capacity study is expected to be largely informational, providing detailed need analysis and consideration of alternatives
- There may be some limited low cost alternatives with sufficient support for moving forward as economic-driven projects – and we need to consider how to value the benefits of those alternatives

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

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

Also, FERC's policy statement on storage requires broader consideration of how storage is assessed in general:

- The ISO considers preferred resources including storage, as well as storage as a transmission asset, as potential alternatives
- When would a transmission need for storage move from the market - local Resource Adequacy - framework to being a transmission asset? Should the economic assessment of storage differ between the two approaches?
- Note that the "competitive" preference is clearly to treat storage consistent with other preferred resources, so there needs to be (1) a reason in each case to move to transmission asset treatment <u>and</u> (2) no restrictions standing in the way
  - High reliance on production cost benefits, and, especially, market revenues benefiting ratepayers, leans to solutions being market resource solutions rather than transmission asset solutions

Re (1), to date, the ISO has identified limited compelling reasons for particular storage to be needed to be a transmission asset, such as:

- Visibility needed through real time operations (of complete path to device)
- Heavily constrained operations expected - e.g., would otherwise be exceptionally dispatched a great deal of the time
- Procurement as a local capacity resource not considered feasible or much less viable to meet specific need;
  – Resource Adequacy must-offer obligations not consistent with transmission system needs
- Overly complex interconnection as a market resource
- Accessing market revenues on behalf of ratepayers is <u>not</u> considered a reason to pursue transmission asset treatment as that leans more to market services, not transmission services.

Re (2), considering the Energy Policy Act and past FERC direction, storage as a transmission asset, must:

- **Provide a transmission service (*e.g.*, voltage support, mitigate thermal overloads)**
- Meet an ISO-determined need under the tariff (reliability, economic, public policy)
- **"Increase the capacity, efficiency, or reliability of an existing or new transmission facility"**
- Be the more efficient or cost-effective solution to meet the identified need
- Be subject to competitive solicitation if it is a regional transmission facility

The 2018-2019 Transmission Plan will have to be completed without the benefit of a FERC decision

- The SATA initiative is targeting a February Board of Governor decision on a SATA framework accessing market revenues
- This will not result in a FERC decision before the late-March decision on the 2018-2019 Transmission Plan
- This creates additional uncertainty, supporting conservative approaches in this planning cycle beyond the need for increased coordination with CPUC procurement processes

Therefore, at this time…for the 2018-2019 cycle, the ISO:

- Will continue evaluating preferred resources including storage as possible solutions and considering “ratepayer benefits” on a case-by-case basis
- Will calculate ratepayer benefits on both on production costs as well as potential market revenues
- Will continue to rely on GridView modeling for assessing transmission congestion benefits, and may supplement with PLEXOS analysis for system – e.g. market – benefits.
- Will assess preferred resources and storage – whether storage is considered an RA resource or transmission asset – on an equal basis, in selecting preferred solutions in Phase 2
  - Potential market revenue benefits to ratepayers of storage as a transmission asset may be taken into account and only if similar benefits to ratepayers can be attributed to preferred resources including storage procured as a market resource

Economic Planning-
Preliminary Production Cost Simulation Results

Yi Zhang
Regional Transmission Engineering Lead

2018-2019 Transmission Planning Process Stakeholder Meeting
November 16-17, 2018

Summary of key database development steps since September stakeholder session

- Incorporated changes identified in ADS PCM
  - Resource and load assumptions in other states or provinces
  - Transmission topology, DC model, etc.
- Network models in ISO Reliability and Policy power flow cases
  - Transmission topology and ratings
  - Load allocation to buses
  - Generator location and Pmax
- Updated California areas load and load modifiers based on CEC load forecast
  - Mid forecast gross load (peak demand is 1-in-2 peak)
  - BTM DG, AAEE, AAPV

Summary of key database development steps (cont.)

- System constraints
  - Net export limit- 2000 MW in base case, no export limit in sensitivity case
  - A/S requirements
- Transmission constraints
  - Contingencies and SPS in optimization
  - Nomograms – COI (planning), Path 15 and Path 26 (operation)
  - Scheduled outage/derate of major paths (COI, EOR, Path 15, Path 26)
- Two renewable portfolios
  - Default 50% RPS portfolio – reliability and economic studies
  - 42 MMT scenario portfolio – sensitivity for policy analysis

Congestion results in the default portfolio case

Summary of congestions (1)

Area or Branch Group	Cumulated hours
SCE NOL-Kramer-Inyokern-Control	14,541
VEA	6,127
PG&E Westland-Fresno-Kern	6,873
PG&E Fresno Giffen	1,912
Path 26	1,284
SDGE San Diego-IV	538
COI Corridor	175
Path 45	1,688
Path 15/CC	59
PG&E/TID Exchequer	1,603

Summary of congestions (2)

Area or Branch Group	Cumulated hours
PG&E POE-RIO OSO	174
SCE J.HINDS-MIRAGE 230 kV line	212
SCE LCIENEGA-LA FRESA 230 kV line	12
PG&E Delevn-Cortina 230 kV	26
PG&E Quinto - Los Banos	30
PG&E Solano	13
PG&E GBA	26
SCE Magunden-Omar 230 kV line	8
PG&E Table Mt.-Palermo 230 kV line	17
Path 61/Lugo - Victorville	2

SCE North of Lugo (NOL)-Kramer-Inyokern areas

Constraints	Duration_T (Hrs)
VICTOR-KRAMER 115 kV line, subject to SCE N-2 Kramer to Victor 230 kV lines with RAS	2,935
KRAMER-VICTOR 230 kV line #1	1,952
KRAMER-VICTOR 230 kV line #2	1,914
LUGO-lugo 2i 500 kV line, subject to SCE N-1 Lugo Transformer #1 500-230 kV	586
INYO 115/115 kV transformer #1	7,051
VICTOR-LUGO 230 kV line #1	49
VICTOR-LUGO 230 kV line #2	16
LUGO-lugo 1i 500 kV line, subject to SCE N-1 Lugo Transformer #2 500-230 kV	16
VICTOR-LUGO 230 kV line #3	13
VICTOR-LUGO 230 kV line #4	9

- 1767 MW of existing and future solar generators are modeled in this area in the PCM
- In this areas, there are still existing geothermal, hydro, and thermal generators, which also contribute to the congestions

VEA system

Constraints	Duration_T (Hrs)
MEAD S-BOB SS 230 kV line #1	2,586
INNOVATION-DESERT VIEW 230 kV line #1	1,577
IS TAP-MERCRYSW 138 kV line #1	1,734
AMARGOSA 230/138 kV transformer #1	230

- 1113 MW of existing and future solar generators are modeled in this area in the PCM
- Congestion was observed in the direction of sending power out of the VEA system

PG&E Westland-Fresno-Kern

Constraints	Duration_T (Hrs)
HURONJ-CALFLAX 70 kV line, subject to PG&E FRESNO N-2 Panoche-Excelsior SW STA #1 and #2 115 kV	2,474
Q526TP-PLSNTVLY 70 kV line, subject to PG&E FRESNO N-2 Panoche-Excelsior SW STA #1 and #2 115 kV	1,390
FIVEPOINTSSS-CALFLAX 70 kV line, subject to PG&E FRESNO N-2 Panoche-Excelsior SW STA #1 and #2 115 kV	1,082
PLSNTVLY-COLNGA 2 70 kV line, subject to PG&E FRESNO N-2 Panoche-Excelsior SW STA #1 and #2 115 kV	774
SCHLNDLR-Q526TP 70 kV line, subject to PG&E FRESNO N-2 Panoche-Excelsior SW STA #1 and #2 115 kV	602
SCHLNDLR-FIVEPOINTSSS 70 kV line, subject to PG&E FRESNO N-2 Panoche-Excelsior SW STA #1 and #2 115 kV	389
PANOCHE1-KAMM 115 kV line #1	109
KAMM-CANTUA 115 kV line #1	52
CHENYT-PANOCHE2 115 kV line #1	1
QUINTO_SS-LOSBANOS 230 kV line #1	30
BORDEN-GREGG 230 kV line, subject to PG&E N-2 Mustang-Gates #1 and #2 230 kV	7

* 3358 MW of existing and future solar generators are modeled in this area in the PCM, as proposed in the CPUC default portfolio

PG&E Fresno Giffen

Constraints	Duration_T (Hrs)
GFFNJCT-GIFFEN 70.0 kV line #1	1,912

- 55 MW of existing and future solar generators are modeled in this area in the PCM
  - The congested line is the radial connection of these generators to the system

Path 26 and Path 15 corridors

- Path 26 congestion

Constraints	Duration_T (Hrs)
P26 Northern-Southern California	1,123
MW_WRLWND_31-MW_WRLWND_32 500 kV line #3	124
MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #2 500kV	27
MW_WRLWND_32-WIRLWIND 500 kV line, subject to SCE N-1 Midway-Vincent #1 500kV	10

- Path 15 congestion

Constraints	Duration_T (Hrs)
GATES-GT_MW_11 500 kV line #1	59

- All congestions are in the direction from South to North

SDGE San Diego and IV

Constraints	Duration_T (Hrs)
SILVERGT-BAY BLVD 230 kV line, subject to SDGE N-2 Miguel-Mission 230 kV #1 and #2 with RAS	169
SDGE IV-SD Import (multiple constraints)	93
SANLUSRY-S.ONOFRE 230 kV line, subject to SDGE N-2 SLR-SO 230 kV #2 and #3 with RAS	217
SDGE-CFE OTAYMESA-TJI 230 kV line	55
SDGE-CFE IV-ROA 230 kV line and IV PFC	4

- 3200 MW of existing and future solar or wind generators are modeled in Imperial Valley area and AZ in the PCM, 105 MW in other areas in SDGE territory
- Renewable generators in these areas also contribute to Path 45 congestion from North to South

COI and its downstream corridor

- COI planning nomograms and annual scheduled outages/derate were modeled

Constraints	Duration_T (Hrs)
TBL MT D-RIO OSO 230 kV line, subject to PG&E N-2 TableMtn-Tesla and TableMtn-VacaDixon 500 kV	39
P66 COI	136

- COI flow and congestion depend heavily on the load and resource balance on both side of COI. Load forecast data and resource assumptions of some areas outside the ISO are under review in the ADS PCM validation process.

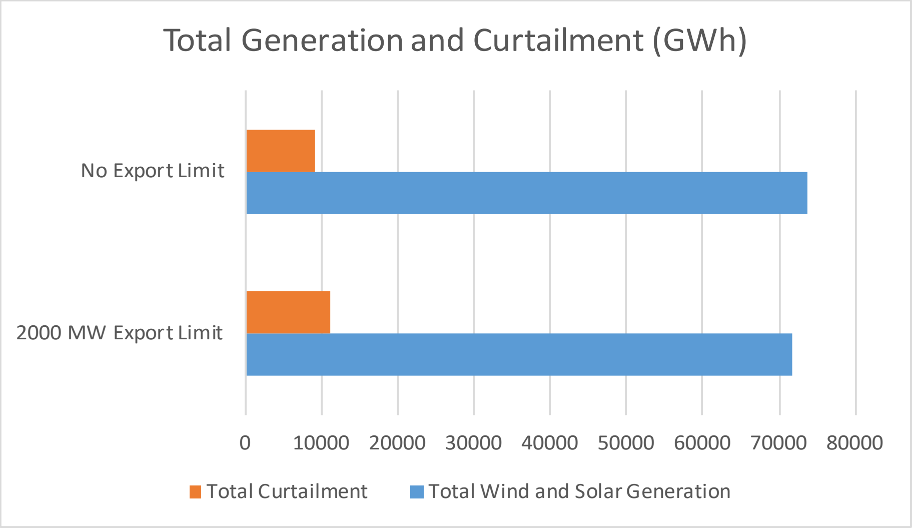
Renewable curtailment in the default portfolio case

Renewable curtailment prices

- CPUC recommended multi-tiers curtailment prices
- Historical data of LMP were used to develop a curtailment price profile
- Floor price is still -$300/MWh

Aggregated Supply Curve	Segment 1	Segment 2	Segment 3	Segment 4	Floor price
Offer Price ($/MWh)	-15	-25	-50	-150	-300
Segment Capacity to be curtailed (MW)	0~2000	2000~7000	7000~12,000	12,000~18,000	>18,000

Comparison of renewable generation and curtailment

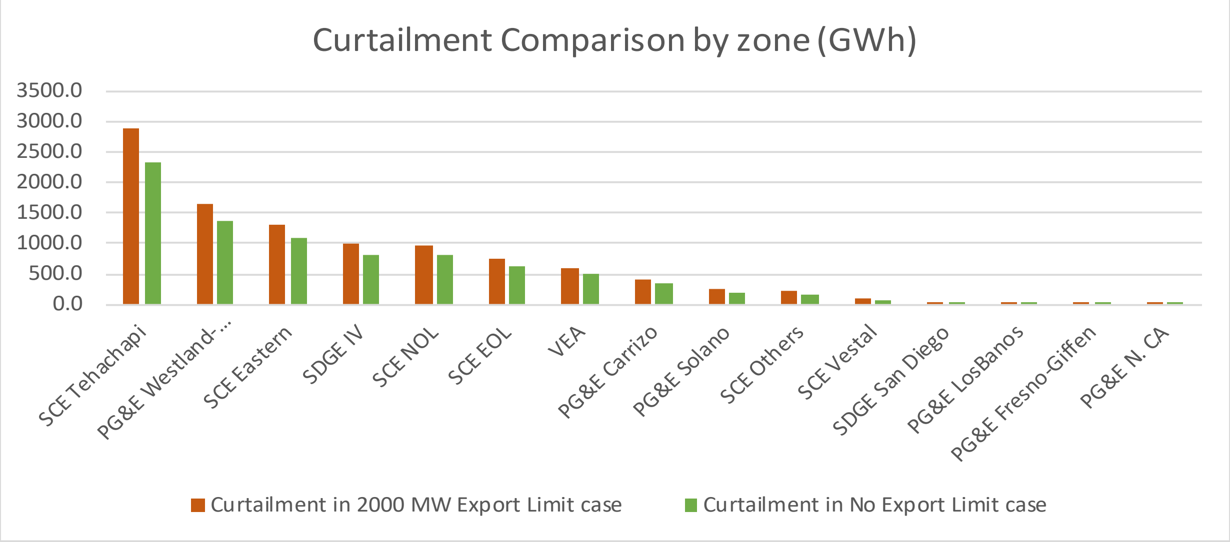


Local transmission constraints are the main driver of renewable curtailment

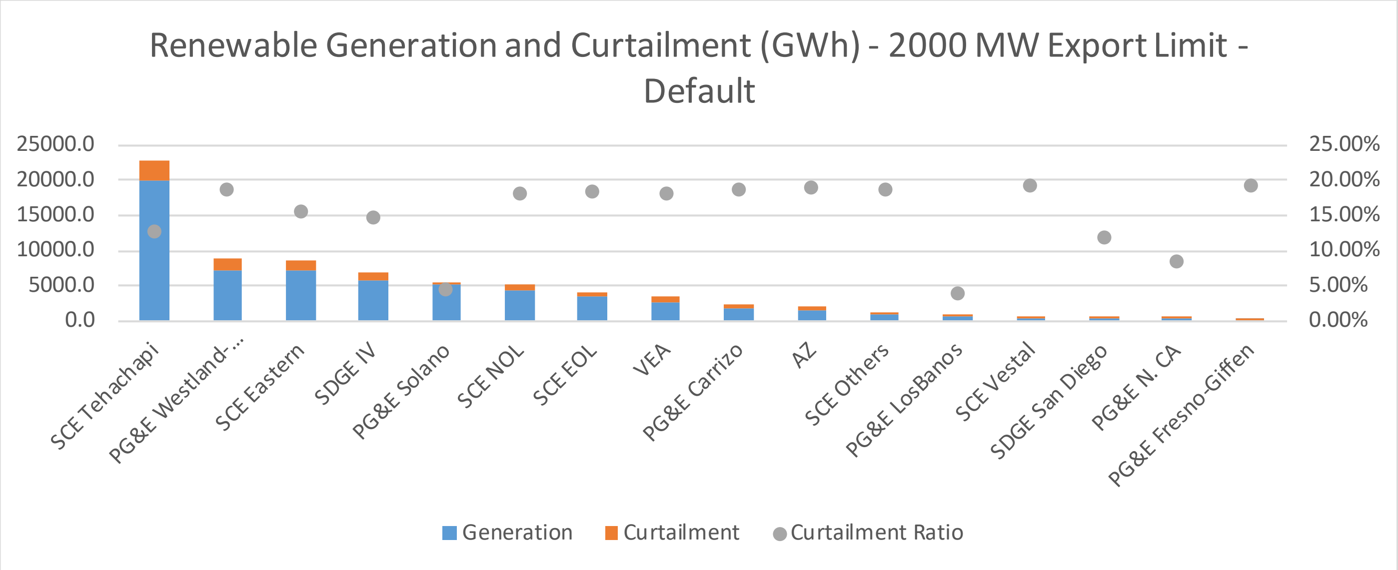
Local constraints may mask other system issues

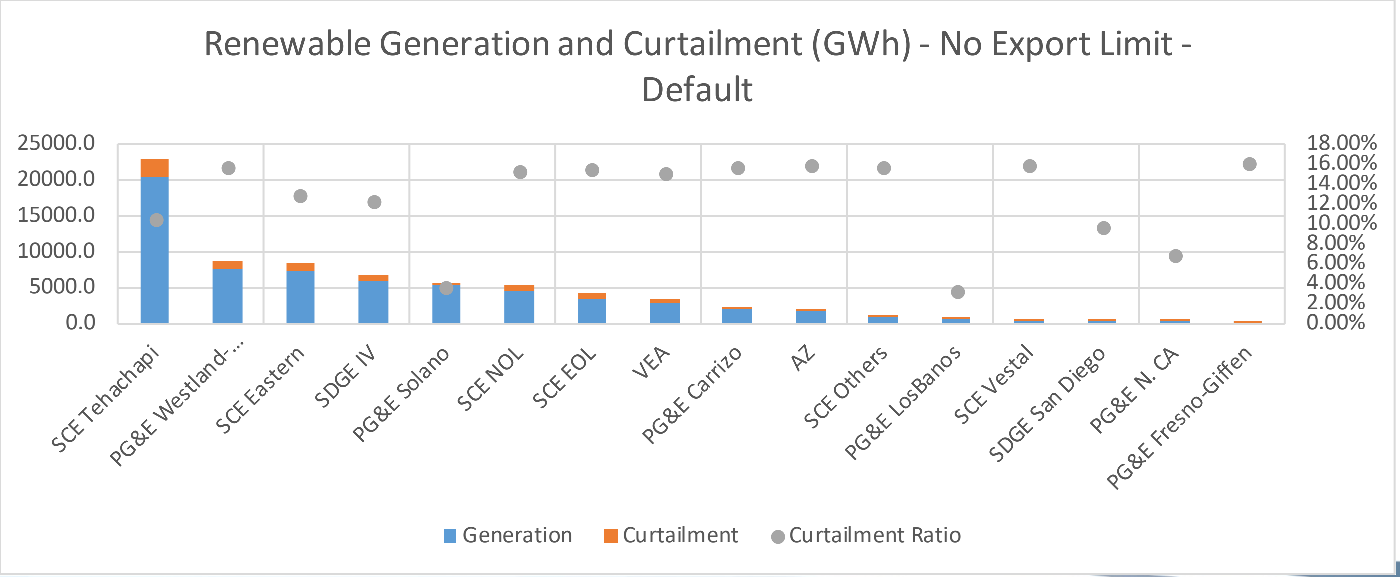
Export limit still has impact on curtailment

Other system constraints such as A/S requirements may also cause curtailment



Renewable curtailment analysis by zone





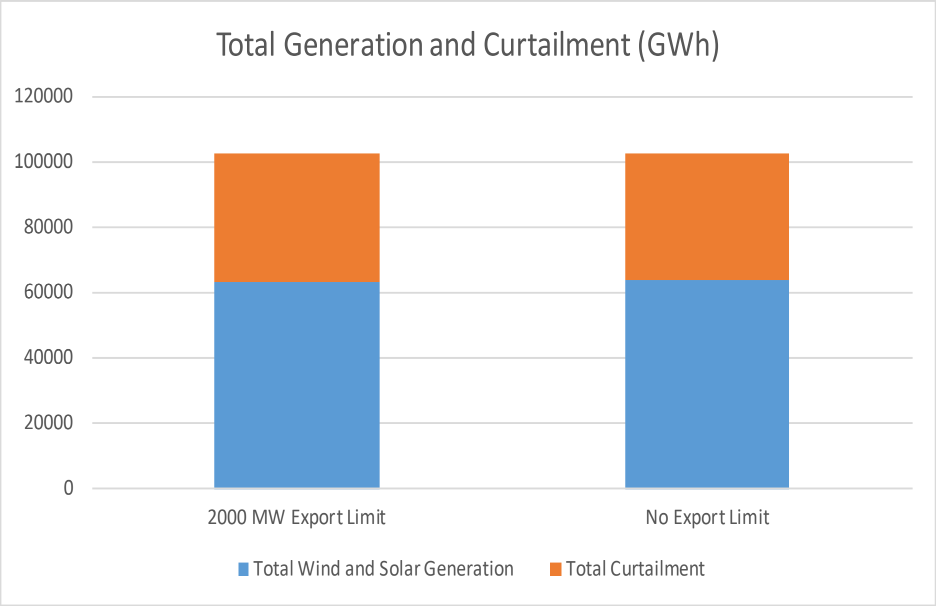
42 MMT Portfolio

42 MMT portfolio incremental resources in the model

CPUC Zone	Electrical Zone to be modeled	Type	Pmax (MW)
Greater Carrizo	PG&E Carrizo	Wind	13
Greater Carrizo	SCE Others	Wind	24
Greater Carrizo	PG&E Carrizo	Wind	26
Greater Carrizo	PG&E Carrizo	Wind	56
Greater Carrizo	PG&E Carrizo	Wind	41
Northern California	Round Montain	Geo	210
Reviserside East	SCE Eastern	Wind	42
Reviserside East	SCE Eastern	Solar	2820
Reviserside East	SCE Eastern	Solar	1055
Solano	PG&E Solano	Wind	42
Solano	PG&E Solano	Wind	55
Solano	PG&E Solano	Wind	247
Solano	PG&E Solano	Wind	18
Solano	PG&E Solano	Wind	281
Southern NV	VEA	Solar	330
Southern NV	VEA	Solar	446
Southern NV	SCE EOL	Solar	-62
Southern NV	VEA	Solar	277
Southern NV	VEA	Solar	616
Southern NV	SCE EOL	Solar	203

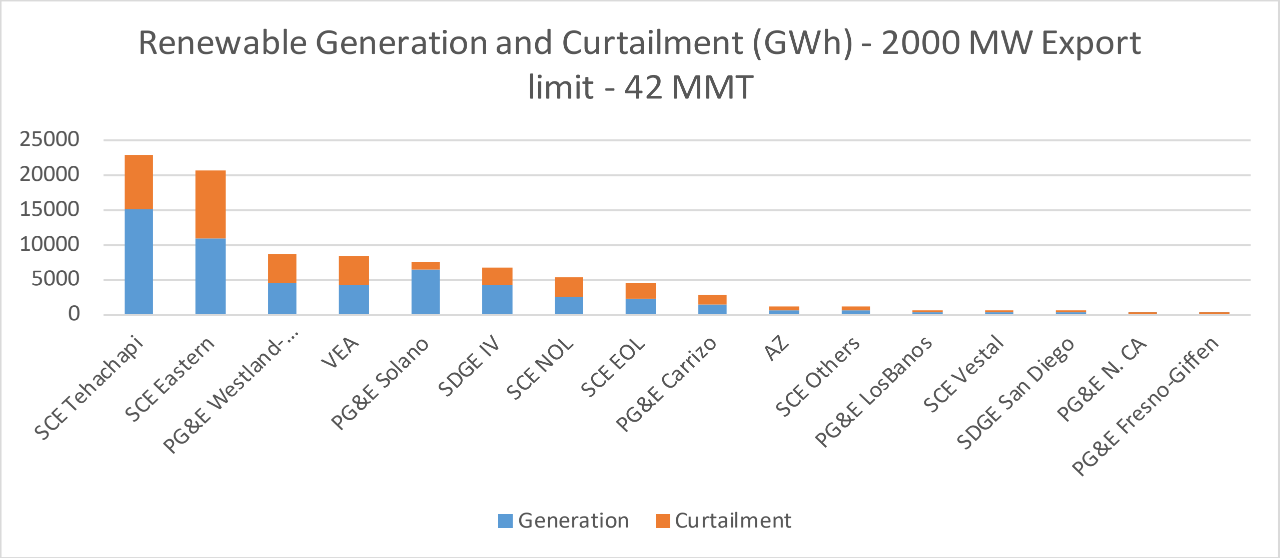
Renewable generation and curtailment (GWh) in 42 MMT portfolio

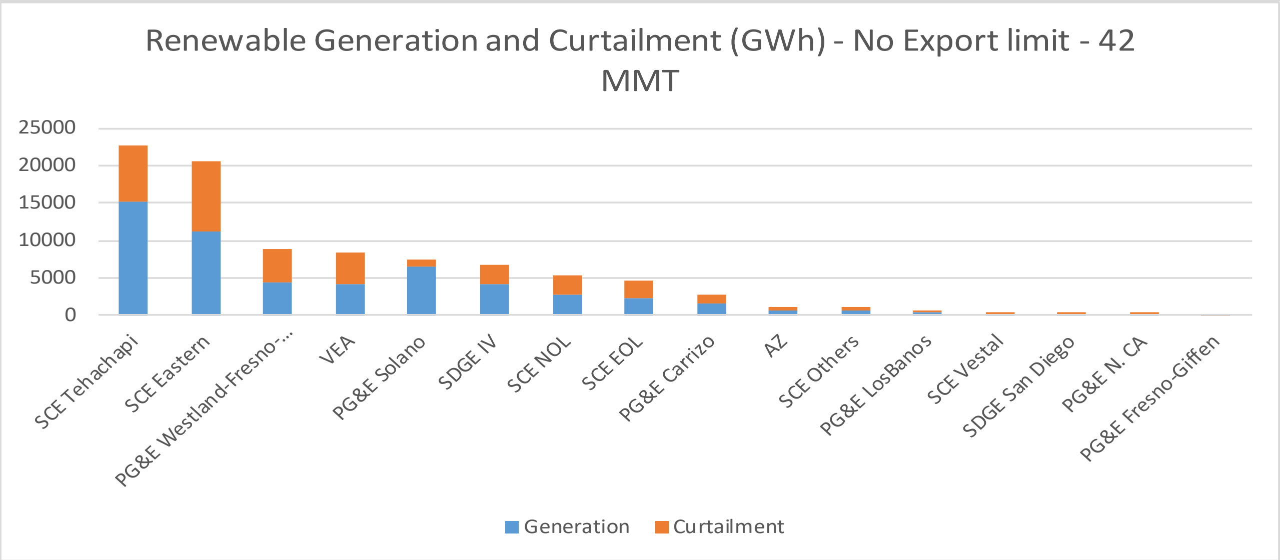
- Similar to the default portfolio case, transmission constraints are the main driver of renewable curtailment
- Renewable energy in highly congested areas cannot be delivered to the system
- Local constraints may mask other system issues



- Multi-tiers curtailment price model and parameters may need to be adjusted for high renewable penetration and high transmission congestion scenarios

Curtailment by zone





Malin500 (PACI) day-ahead congestion investigation summary

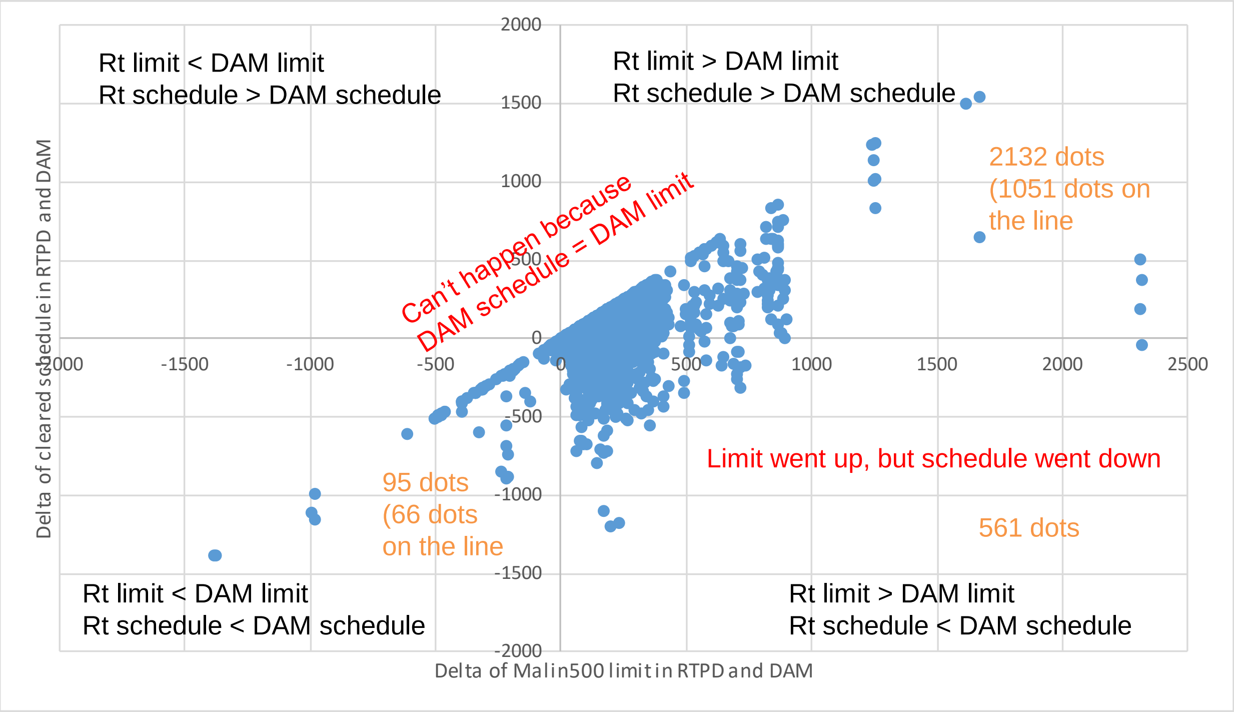
Concerns regarding of Malin500 Day-ahead congestion and the ISO investigation of this congestion

- Malin500 is an ISO inter-tie that includes two 500 kV lines between Malin and Round Mt. 500 kV buses.
- Day-ahead scheduling congestion has consistently been reported in ISO's DMM report but congestion is normally less in Real Time than in the DA market
- We have been looking at reconciling congestion in the day ahead market with our production simulation results
- PCM does look at physical limits, not schedule limits

Concerns regarding of Malin500 Day-ahead congestion and ISO investigation (cont.)

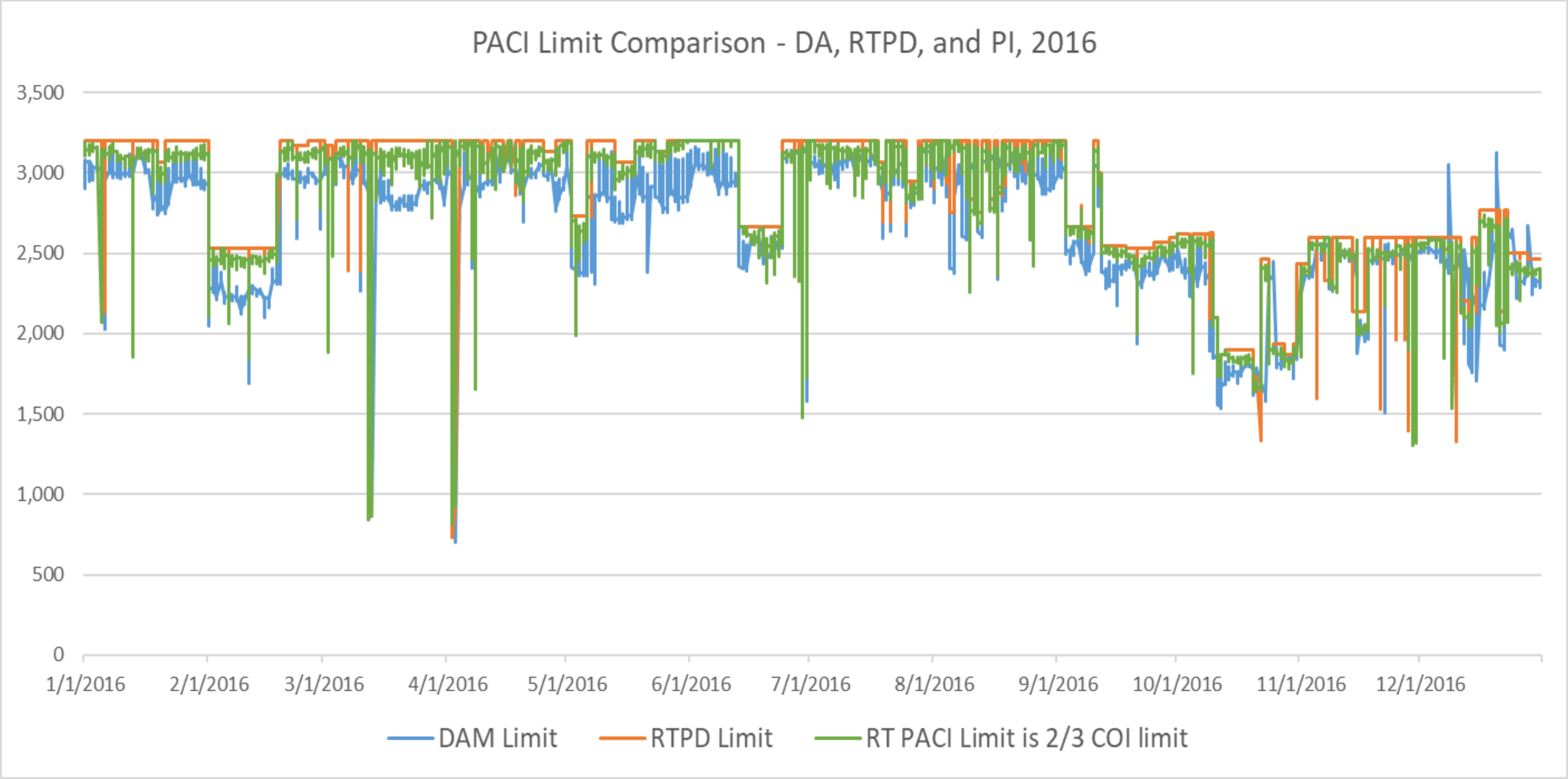
- Four main reasons of DA market congestion
  - Transmission scheduling limits are respected as well as physical limits
  - Over scheduling in DA market more than the limits
  - Transmission scheduling limit derates due to unused ETC (released in Real Time)
  - Incomplete information of outside system and the locations of resources could impact calculation of physical flows, but physical flows are not generally binding, so this is likely not material

Delta of Malin500 cleared schedule vs. Delta of Malin500 limit in RTPD and DAM when DAM is binding



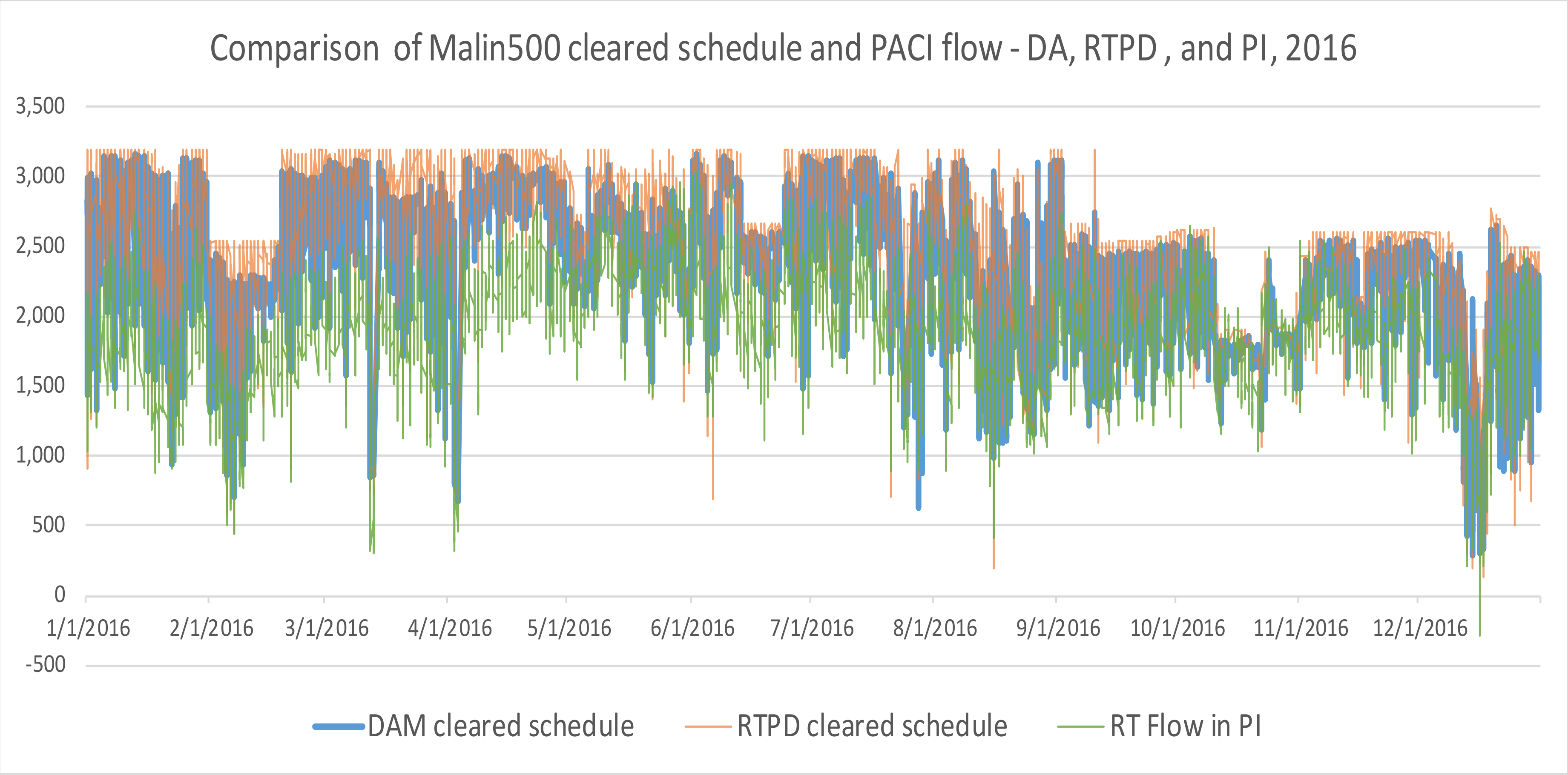
- When DAM is binding (the cleared schedule is equal to the limit), RTPD may not be binding
- The changes in cleared schedules from DAM to RTPD are always less then the changes in limits (when DAM is binding)

Historical data plots – Malin500 (PACI) scheduling limits in DA and Real Time, and the actual limit in PI



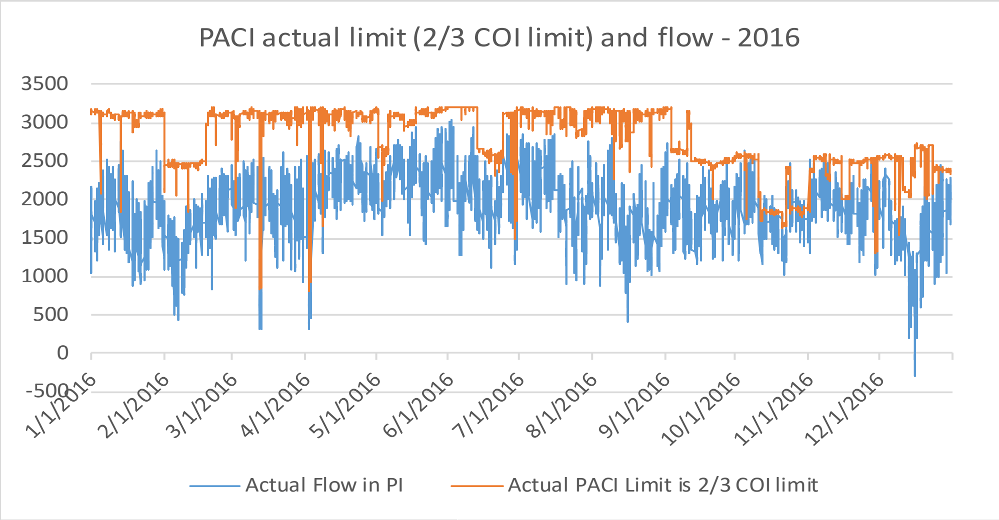
California ISO

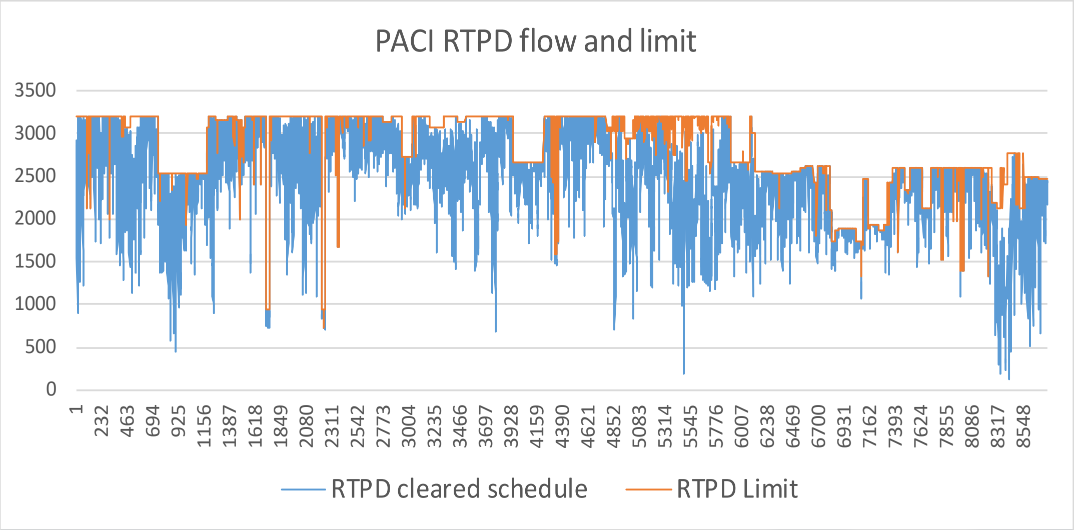
Historical data plots – Malin500 cleared schedules in DA and RTPD, and the PACI flow in PI



California ISO

Historical data plots – PACI actual flow and limit, and RTPD flow and limit





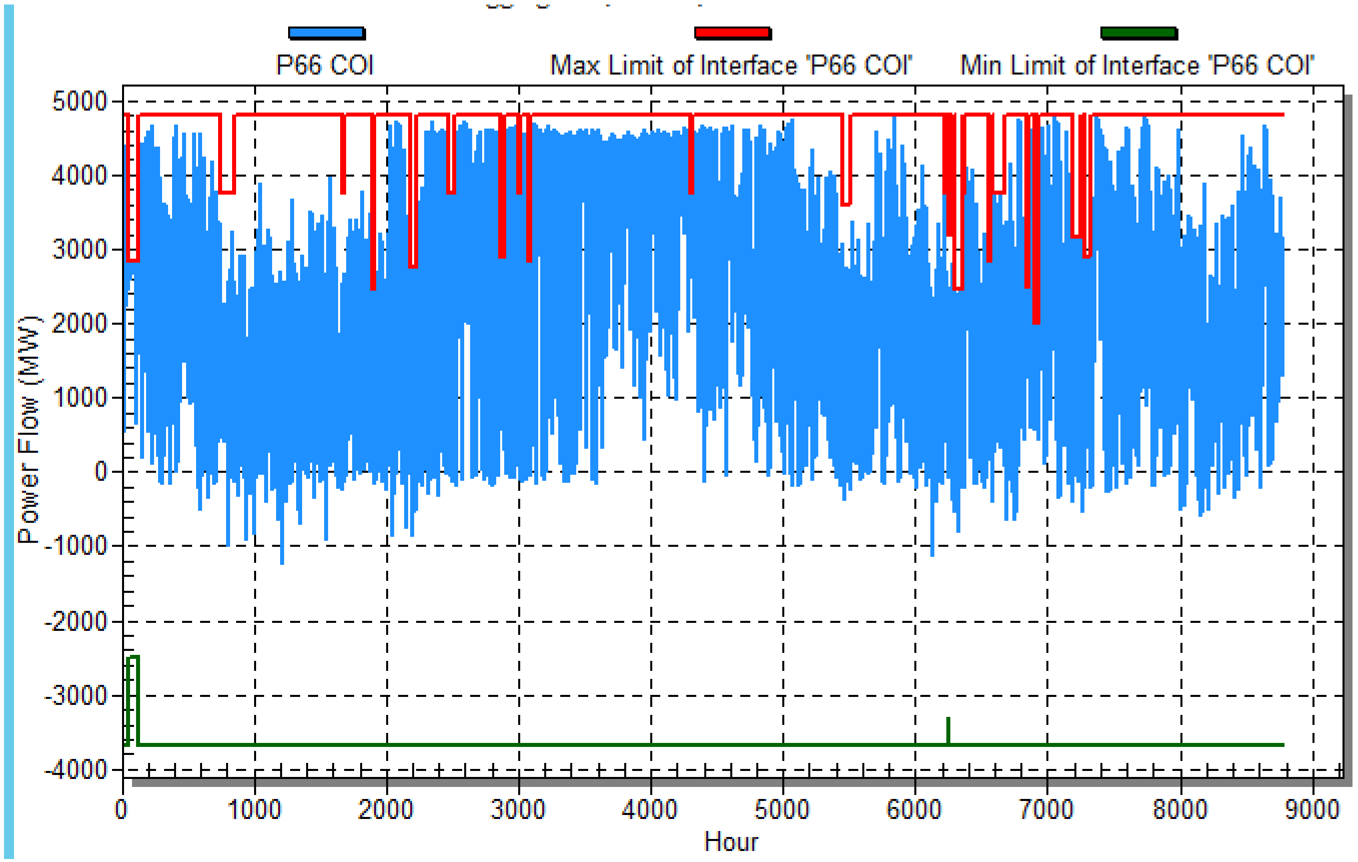
California ISO

Historical data – Congestion hours

	DAM Malin500 (PACI)	RTPD Malin500 (PACI)	PACI Actual	COI Actual
2016 Congestion hours	2788	1766	122	5
2017 Congestion hours	2455	677	115	366

*PACI and COI actual flows were compared against their physical limits based on ISO's PI database data. PACI limit was 2/3 of COI limit

Preliminary simulation result (GridView output) – COI flow and limit



California ISO

Observations

- RT market congestion is normally less than in the DA market because
  - Day ahead scheduling limits are generally lower than real time
  - Sometimes less is scheduled than in day ahead
  - Sometimes the limit increases and schedules do not increase accordingly
- Real time actual flow is normally less than the market schedule
- Models and actual flows both show lack of physical limits being approached, suggesting underutilized paths on parallel systems
- ISO is investigating access to the parallel underutilized capacity

Other factors may lead to different future outcomes than past experience:

- CA areas including ISO's load and resources (in the model)
  - DG, AAEE, 50% RPS portfolio
- Energy surplus in NW/BC/AB and other NTTG areas
  - Coal retirements may reduce the surplus (in the model)
  - New renewable in these areas may increase the surplus
    - Transmission upgrades in the northwest may make additional remote resources deliverable to CA border
    - This would in turn drive up congestion without other reinforcement

More work is required to consider in PCM issues that impact COI flow and congestion results

- COI nomogram and derates (in the model)
- BPA's outages and derates
- Wheeling rate charges in NW and NTTG systems increase the cost of remote generators
  - ADS PCM modeling review in collaboration with WECC RAC PCM Modeling Work Group and Data Work Group

Future model developments and modeling enhancements

PCM development and modeling enhancement

- Continuous effort is required to reflect today's market and grid operation, and to meet the need of the planning study for future years
- On top of the preliminary database and the enhanced planning models implemented by the ISO, three groups of new enhancements are identified:
  - Expect to implement Group A before the next stakeholder meeting
  - Groups B and C may require longer time for modeling design, data collection, and software enhancements
    - Will take step by step approach, and may implement interim solutions before the next stakeholder meeting

A: PCM network and renewable modeling

- Coordinate with reliability and LCR studies for updating transmission model and constraints
- Coordinate with policy study for updating RPS generator model and the associated transmission model
  - Especially, in the areas with high renewable curtailment
  - Curtailment in local areas may mask bulk system issue
- Coordinate with ADS process for updating areas models outside the ISO
  - Update generator retirement and replacement plans
  - Update load forecast

B: Consider modeling developments related to inter-tie capability derates due to import upward A/S

- In ISO's market the inter-tie constraint is

  Inter-tie schedule + inter-tie A/S award <= inter-tie limit
- From power flow perspective, it is equivalent to derate the inter-tie limit with the A/S award
- Imported A/S is not allowed to exceed a percentage of the total requirement, so the derate is not significant most time
- Still, the derate may impact inter-tie congestion when the margin is small
- Some key technical issues need to be considered and resolved in PCM in order to model such derates

B: Inter-tie derate due to imported A/S (cont.)

- ISO remote generators (dynamic schedules and pseudo-ties) models and dispatch
  - Capability and cost of providing A/S
  - Model and dispatch of remote generators partially scheduled to ISO
- Need to consider all ISO inter-ties
  - Inter-ties may be different from WECC path, need to know inter-tie limit if it is just a subset of a path
- A/S award is capacity award instead of actual flow, need to map A/S awards to inter-ties
- Define the constraint that limit the imported A/S below the pre-determined percentage of total requirements

C: Modeling developments to reflect future renewable interconnection and integration

- Market model
  - Refinement of A/S requirements as needed based on market design and operation
  - Working with the software vendor to review the multi-tiers curtailment price model and parameters for high renewable penetration and high transmission constraint scenarios
  - Remote generators
  - Wheeling charge rate model
- Renewable integration
  - Renewable integrate renewable (with recognizing the difference between the operation and the simulation model)
  - Integration resource model and dispatch including energy storage and hydro generator

C: Modeling developments to reflect future renewable interconnection and integration (cont.)

- Co-operation with other systems (also studied in PAC NW study)
  - Review and adjust the export limit
  - Use remote resources, especially dispatchable hydro, to respond the intermittency of renewable in California
- Renewable (wind and solar) profiles
  - It is important to have realistic and consistent profiles in production cost simulation
  - ISO and WECC have created a library of profiles based on NREL's renewable database
    - It is possible to further refine the profiles based on accumulated historical data

Next Steps

Evaluate economic planning study requests

#	Study request	Location
1	SWIP-North	Idaho-Nevada
2	RedBluff – MiraLoma 500 kV line	Southern California
3	LEAPS	Southern California
4	Alberhill – Sycamore 500 kV line with Miguel-Sycamore loop-in to Suncrest and new Suncrest 500/230 kV transformer	Southern California
5	CTP Offshore wind – DCPP	Southern/Northern California
6	Blythe loop-in project	Southern California
7	Local capacity area studies	LCR areas
8	Request window submissions with economic component/rational	

- Not just looking at congestion, but other benefits as well
- Consideration of ITP submissions will take place as well

Simulation and economic assessment

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

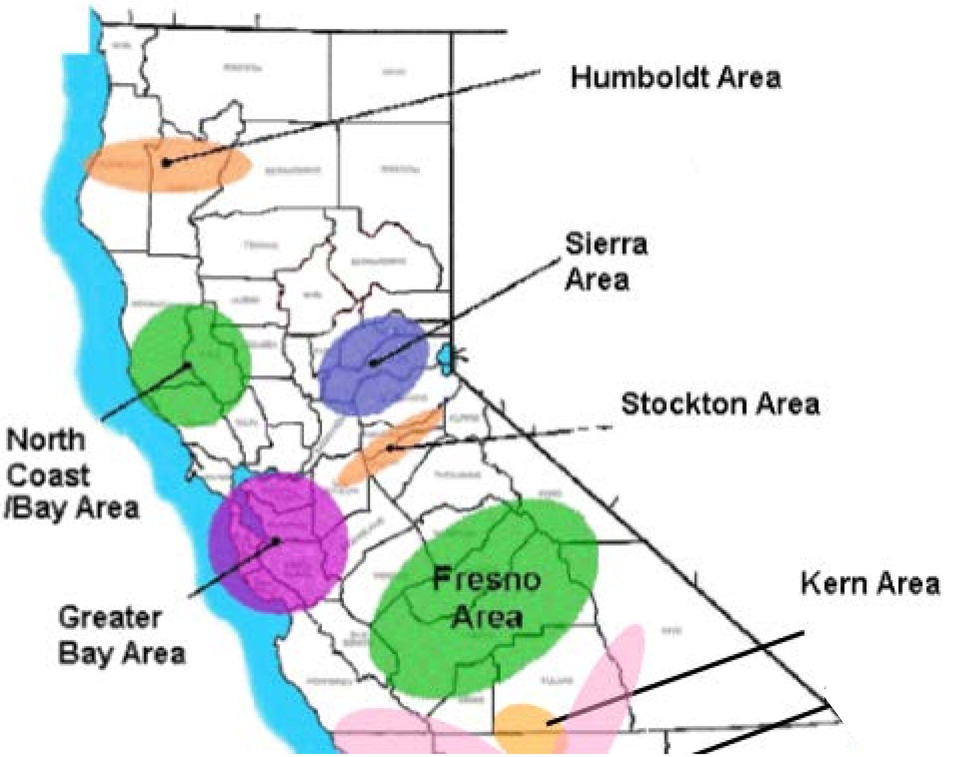
Local Capacity Requirements Potential Reduction Study PG&E Area

Regional Transmission North Group

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

LCR areas and subareas selected for study

LCR Areas / Subareas
Humboldt (removed from original scope)
Sierra - Pease - South of Rio Oso
Greater Bay Area - Llagas - San Jose - South Bay-Moss Landing - Ames/Pittsburg/Oakland (added to the scope) - Overall (if required)
Fresno - Hanford - Herndon - Reedley (special case) - Overall (if required)
Kern - Westpark - Kern Oil



Presentation Format

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

Local Capacity Requirements Potential Reduction Study – Greater Bay Area

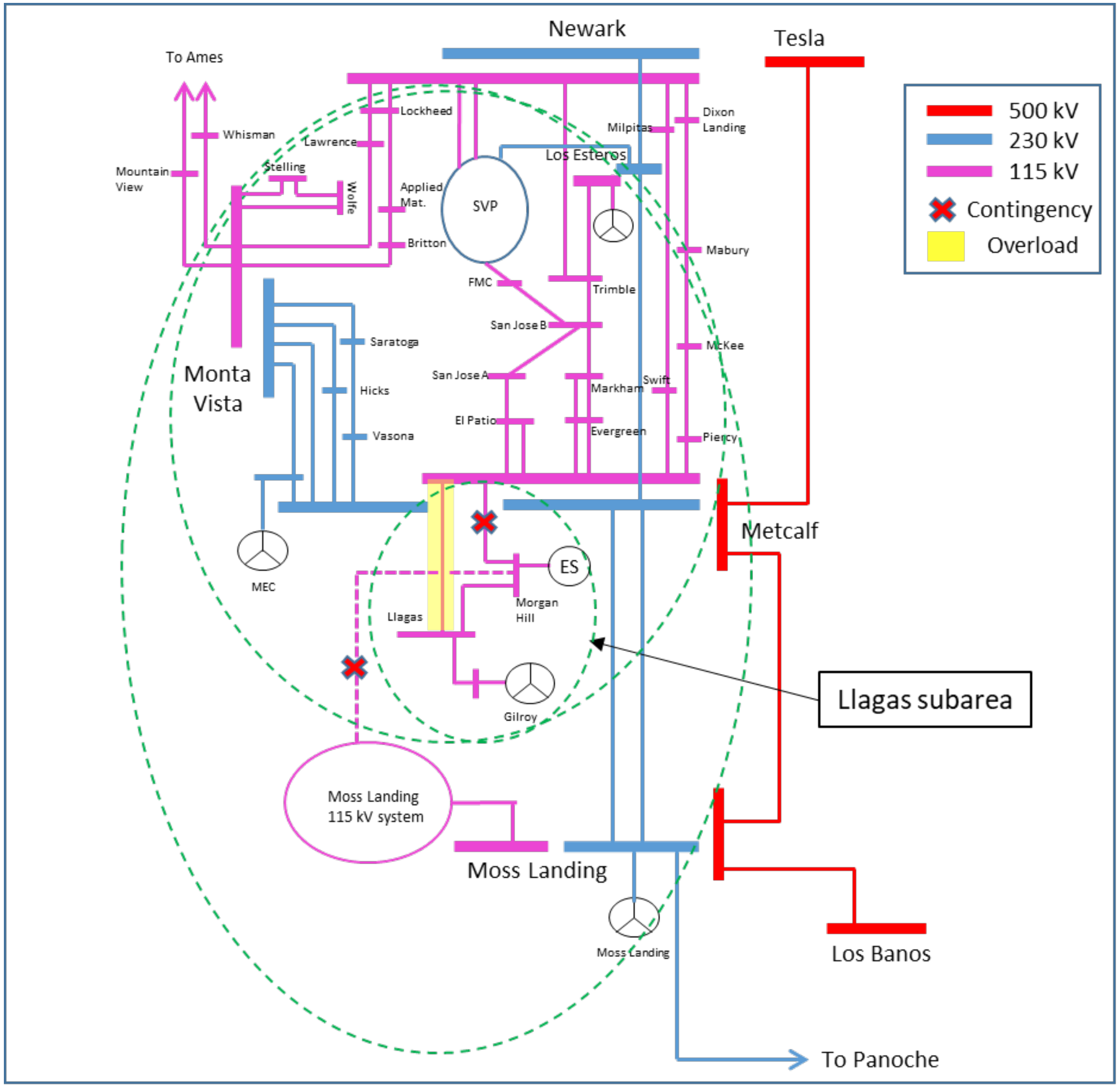
Binaya Shrestha

Regional Transmission Engineer Lead

Llagas Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	212	Market Gas	247
AAEE	-12	Other Gas	0
Behind the meter DG	-9	Non-Gas	0
Net Load	**191**		
Transmission Losses	0	Future preferred resource and energy storage (Resolution E-4949)	75
Pumps	0	**Total Qualifying Capacity**	**322**
Load + Losses + Pumps	**191**		

Llagas Subarea : One-line diagram



Llagas Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First limit	B	None	None	No requirement
2028	First limit	C	Metcalf-Llagas 115 kV line	Metcalf-Morgan Hill and Morgan Hill-Green Valley 115 kV lines	26
Subsequent requirements (layers)					
2028	Second limit	C	Metcalf-Morgan Hill 115 kV line	Metcalf-Llagas and Morgan Hill-Green Valley 115 kV lines	6
2028	Third limit	C	None	None	No requirement
with Resolution E-4949					
2028	First limit	C	Metcalf-Llagas 115 kV line	Metcalf-Morgan Hill and Morgan Hill-Green Valley 115 kV lines	33

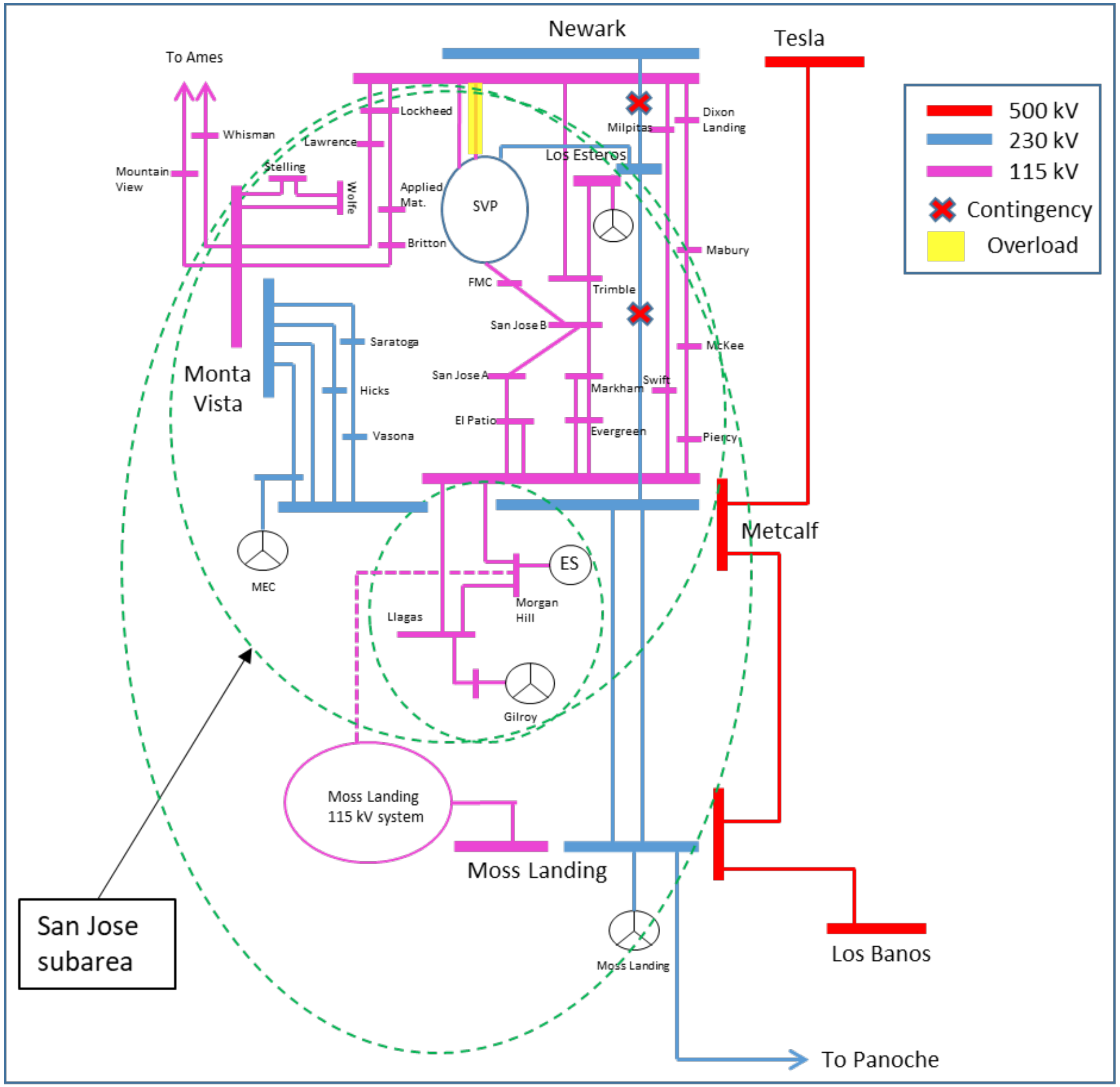
Llagas Subarea : Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
Resolution E-4949	N/A	TBD	33	0	0	33
Reconductor Metcalf-Morgan Hill and Metcalf-Llagas 115 kV lines	ISO	TBD	0	0	0	0

San Jose Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	3101	Market Gas	1139
AAEE	-199	Other Gas	202
Behind the meter DG	-60	Non-Gas	0
Net Load	**2842**		
Transmission Losses	83	Future preferred resource and energy storage (Resolution E-4949)	75
Pumps	0	**Total Qualifying Capacity**	**1416**
Load + Losses + Pumps	**2925**		

San Jose Subarea : One-line diagram



San Jose Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First limit	B	El Patio-San Jose A 115 kV line	Newark-Los Esteros 230 kV line & DVR unit	868
2028	First limit	C	Newark-NRS #1 115 kV line	Newark-Los Esteros & Metcalf-Los Esteros 230 kV lines	1543 (204)
Subsequent requirements (layers)					
2028	Second limit	C	Newark-NRS #2 115 kV line	Newark-Los Esteros & Metcalf-Los Esteros 230 kV lines	1435 (156)
2028	Third limit	C	Newark-Kifer 115 kV line	Newark-Los Esteros & Metcalf-Los Esteros 230 kV lines	1208
Multiple subsequent constraints with limiting facilities within San Jose 115 kV system					

San Jose Subarea : Worst Constraint

Facility	Worst Contingency	Loading (%)					
		sq-max-lecef	sq-min-lecef	sunol-max-lecef	sunol-min-lecef	sunol-loopin-max-lecef	sunol-loopin-min-lecef
El Patio-San Jose Sta. 'A' 115 kV Line	Newark-Los Esteros & Los Esteros-Metcalf 230kV	108	133	111	136	<40	<40
Metcalf-El Patio No. 1 115 kV Line		<40	<40	85	100	<40	<40
Metcalf-El Patio No. 2 115 kV Line		<40	<40	85	100	<40	<40
Newark-Kifer 115kV Line		103	140	101	137	<40	<40
Newark-Northern Receiving Station #1 115kV Line		121	173	117	167	<40	76
Newark-Northern Receiving Station #2 115kV Line		111	159	109	156	<40	70
Newark-Trimble 115kV Line		66	118	64	114	<40	<40
NRS-Mission 60 kV Line (SVP)		<40	116	<40	114	<40	<40
San Jose B bus tie		<40	<40	80	103	<40	<40
San Jose Sta 'A'-'B' 115 kV Line		105	133	109	136	<40	<40

Scenario Definitions:

sq-max-lecef: Status quo with LECEF dispatched to maximum.

sq-min-lecef: Status quo with LECEF offline.

sunol-max-lecef: PG&E proposed Sunol 500/230 kV project with LECEF dispatched to maximum.

sunol-min-lecef: PG&E proposed Sunol 500/230 kV project with LECEF offline.

sunol-loopin-max-lecef: PG&E proposed Sunol 500/230 kV project with Newark-Sunol 230 kV line looped in to Los Esteros and LECEF dispatched to maximum.

sunol-loopin-min-lecef: PG&E proposed Sunol 500/230 kV project with Newark-Sunol 230 kV line looped in to Los Esteros and LECEF offline.

Key Notes:

- Multiple facilities overload for the worst contingency. As such, upgrading limiting facilities is not efficient solution.
- Sunol project exacerbates the extent of issue for the worst contingency.

San Jose Subarea : Remaining issues after addressing the worst contingency

Facility	Worst Contingency	Loading (%)					
		a-sq-max-lecef	b-sq-min-lecef	c-sunol-max-lecef	d-sunol-min-lecef	e-sunol-loopin-max-lecef	f-sunol-loopin-min-lecef
11 facility overloads	**34 separate N-1-1 contingencies**						**146**
New ark-Northern Receiving Station #1 115kV Line	P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032] & P1-2:A18:18:_NEWARK F-ZANKER-KRS 115kV [3040]	118.57	130.48	115.83	125.49	111.75	119.25
New ark-Northern Receiving Station #1 115kV Line	P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032] & P1-2:A18:28:_METCALF-EL PATIO #1 115kV [2500]	101.55	112.14	99.33	108.22	95.83	102.81
New ark-Northern Receiving Station #1 115kV Line	P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032] & P1-2:A18:29:_METCALF-EL PATIO #2 115kV [2510]	101.54	112.14	99.33	108.22	95.83	102.8
New ark-Northern Receiving Station #1 115kV Line	P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032] & P1-2:A18:34:_METCALF-EVERGREEN #1 115kV [2520]	0	0	98.44	0	94.99	101.84
New ark-Northern Receiving Station #1 115kV Line	P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032] & P1-3:A16:5:_NEWARK E 230/115kV TB 11	101.33	111.39	97.84	0	94.11	100.46
New ark-Northern Receiving Station #1 115kV Line	P1-2:A18:18:_NEWARK F-ZANKER-KRS 115kV [3040] & P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032]	118.27	130.48	113.25	123.43	110.66	119.27
New ark-Northern Receiving Station #1 115kV Line	P1-2:A18:28:_METCALF-EL PATIO #1 115kV [2500] & P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032]	100.2	110.92	95.95	104.98	93.86	101.54
New ark-Northern Receiving Station #1 115kV Line	P1-2:A18:29:_METCALF-EL PATIO #2 115kV [2510] & P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032]	100.2	110.91	95.94	104.98	93.86	101.54
New ark-Northern Receiving Station #1 115kV Line	P1-2:A18:34:_METCALF-EVERGREEN #1 115kV [2520] & P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032]	99.24	109.81	94.9	103.77	92.84	100.37
New ark-Northern Receiving Station #1 115kV Line	P1-3:A16:5:_NEWARK E 230/115kV TB 11 & P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032]	101.22	111.39	95.51	103.99	93.1	100.19
New ark-Northern Receiving Station #2 115kV Line	P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032] & P1-2:A18:18:_NEWARK F-ZANKER-KRS 115kV [3040]	120.35	130.28	121.54	129.9	117.76	124.05
New ark-Northern Receiving Station #2 115kV Line	P1-2:A18:18:_NEWARK F-ZANKER-KRS 115kV [3040] & P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032]	120.02	130.28	118.73	127.63	116.58	124.06
El Patio-San Jose Sta. 'A' 115 kV Line	P1-2:A18:33:_STONE-EVERGREEN-METCALF 115kV [2530] & P1-2:A18:34:_METCALF-EVERGREEN #1 115kV [2	79.08	89.47	91.2	102.34	90.72	100.92
El Patio-San Jose Sta. 'A' 115 kV Line	P1-2:A18:34:_METCALF-EVERGREEN #1 115kV [2520] & P1-2:A18:33:_STONE-EVERGREEN-METCALF 115kV [2	79.14	89.52	91.25	102.39	90.64	100.99
El Patio-San Jose Sta. 'A' 115 kV Line	P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032] & P1-2:A18:18:_NEWARK F-ZANKER-KRS 115kV [3040]	81.87	92.11	93.98	104.9	93.62	103.55
El Patio-San Jose Sta. 'A' 115 kV Line	P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032] & P1-2:A18:33:_STONE-EVERGREEN-METCALF 115kV [25	85.57	96.21	99.25	110.8	99.18	109.75
El Patio-San Jose Sta. 'A' 115 kV Line	P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032] & P1-2:A18:34:_METCALF-EVERGREEN #1 115kV [2520]	91.47	102.51	105.21	117.19	105.06	116.03
El Patio-San Jose Sta. 'A' 115 kV Line	P1-2:A18:18:_NEWARK F-ZANKER-KRS 115kV [3040] & P1-2:A18:14:_LOS ESTEROS-NORTECH 115kV [4032]	81.81	92.11	93.48	104.52	93.39	103.56
El Patio-San Jose Sta. 'A' 115 kV Line	P1-2:A18:18:_NEWARK F-ZANKER-KRS 115kV [3040] & P1-2:A18:19:_NEWARK-TRIMBLE 115kV [3120]	0	0	0	0	0	101.96
El Patio-San Jose Sta. 'A' 115 kV Line	P1-2:A18:18:_NEWARK F-ZANKER-KRS 115kV [3040] & P1-2:A18:33:_STONE-EVERGREEN-METCALF 115kV [25	87.51	100.08	101.31	114.59	100.61	112.72
El Patio-San Jose Sta. 'A' 115 kV Line	P1-2:A18:18:_NEWARK F-ZANKER-KRS 115kV [3040] & P1-2:A18:34:_METCALF-EVERGREEN #1 115kV [2520]	93.61	106.62	107.44	121.2	106.45	119.17
El Patio-San Jose Sta. 'A' 115 kV Line	P1-2:A18:18:_NEWARK F-ZANKER-KRS 115kV [3040] & P1-2:A18:6:_LOS ESTEROS-Sunol 230kV [5353]	0	0	93.14	106.18	90.96	102.38

Scenario Definitions:

sq-max-lecef: Status quo with LECEF dispatched to maximum.

sq-min-lecef: Status quo with LECEF offline.

sunol-max-lecef: PG&E proposed Sunol 500/230 kV project with LECEF dispatched to maximum.

sunol-min-lecef: PG&E proposed Sunol 500/230 kV project with LECEF offline.

sunol-loopin-max-lecef: PG&E proposed Sunol 500/230 kV project with Newark-Sunol 230 kV line looped in to Los Esteros and LECEF dispatched to maximum.

sunol-loopin-min-lecef: PG&E proposed Sunol 500/230 kV project with Newark-Sunol 230 kV line looped in to Los Esteros and LECEF offline.

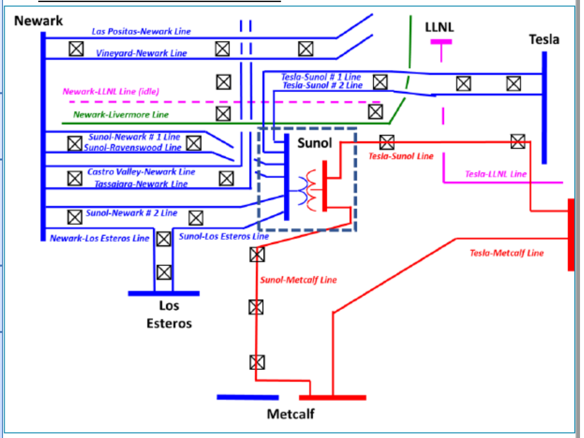
Key Notes:

- Multiple facilities overload under numerous contingencies after addressing the worst contingency. As such, addressing the worst contingency is also not efficient solution.
- Preferred resources or new 230 kV source.
- Sunol project exacerbates the extent of issue after addressing the worst contingency.

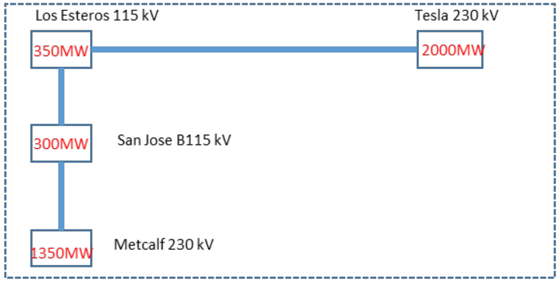
San Jose Subarea : Potential LCR Reduction Alternatives

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
New Sunol 500 kV substation					
2028	First Limit	C	Newark-NRS #1 115 kV line	Newark-Los Esteros & Sunol-Los Esteros 230 kV lines	1021 (271)
Reconductor nine 115 kV lines (~85 miles)					
2028	First Limit	C	Newark-Los Esteros 230 kV line	Newark 230/115 kV bank #9 and Los Esteros-Metcalf 230 kV line	196
With ~600 MW of preferred resource / storage					
2028	First Limit	C	Newark-NRS #1 115 kV line	Newark-Los Esteros & Metcalf-Los Esteros 230 kV lines	100-700
With 4-terminal DC (2000-350-300-1350) & 500 MVAR Reactive Support					
2028	First Limit	C	Kifer-FMC 115 kV line	Los Esteros-Nortech and Newark-Zanker-Kifer 115 kV lines	209
With 4-terminal DC (2000-350-300-1350), 500 MVAR Reactive Support & Eight SVP connecting Facilities Upgrade					
2028	First Limit	C	None	None	None

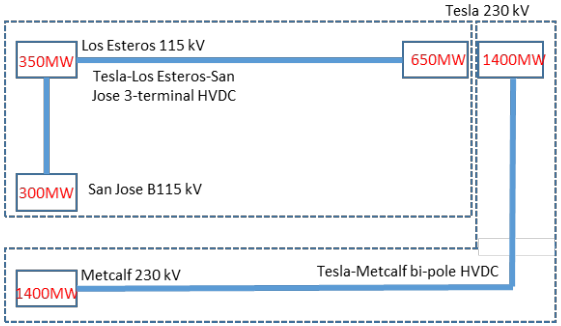
New Sunol 500 kV substation



Tesla-Los Esteros-San Jose-Metcalf 4-terminal HVDC



2 HVDC schemes to connect Tesla to San Jose



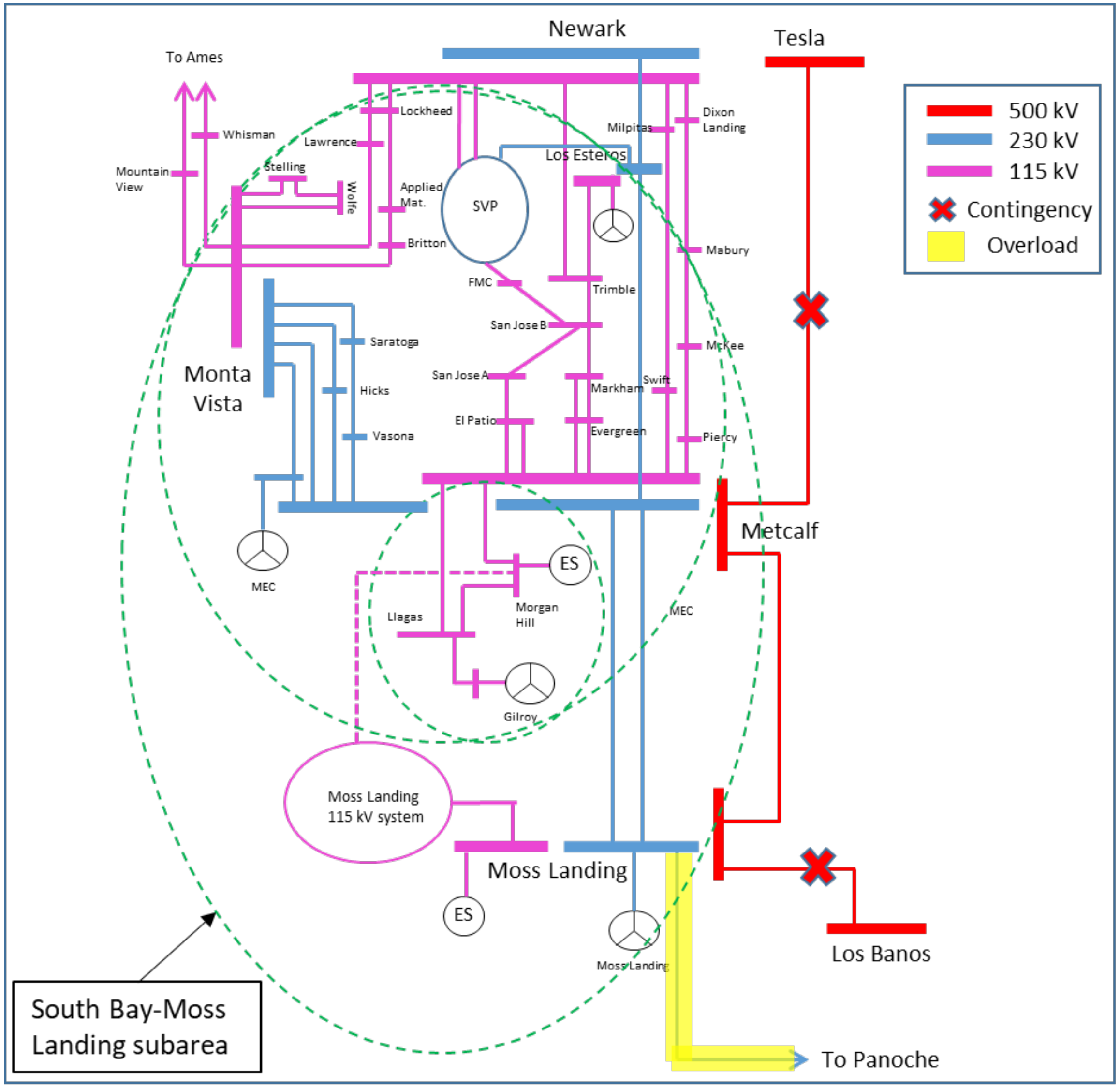
San Jose Subarea : Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
Reconductor nine 115 kV lines (~85 miles)	ISO	TBD	196	0	196	0
~600 MW of preferred resource / storage	ISO	TBD	100-700	0	100	0-600
With 4-terminal DC (2000-350-300-1350)& 500 MVAR Reactive Support	ISO	TBD	209	0	209	0
With 4-terminal DC (2000-350-300-1350), 500 MVAR Reactive Support & Eight SVP connecting Facility Upgrade	ISO	TBD	0	0	0	0

South Bay-Moss Landing Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	4841	Market Gas	2159
AAEE	-294	Other Gas	202
Behind the meter DG	-117	Non-Gas	0
Net Load	**4431**		
Transmission Losses	124	Future preferred resource and energy storage (Resolution E-4949)	557
Pumps	0	**Total Qualifying Capacity**	**2918**
Load + Losses + Pumps	**4555**		

South Bay-Moss Landing Subarea : One-line diagram



South Bay-Moss Landing Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First Limit	B	None	None	No requirement
2028	First Limit	C	Thermal overload of Moss Landing-Las Aguilas 230 kV	Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV	2100
2028	Second Limit	C	Thermal overload of Newark-NRS 115 kV	Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV	2010
Multiple subsequent constraints with limiting facilities within San Jose 115 kV system and extended to Tesla-Newark 230 kV lines					

South Bay-Moss Landing Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
with Resolution E-4949					
2028	First Limit	B	None	None	No requirement
2028	First Limit	C	Thermal overload of Newark-NRS 115 kV	Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV	2051
2028	Second Limit	C	Thermal overload of Moss Landing-Las Aguilas 230 kV	Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV	2030
With new Sunol 500 kV substation					
2028	First Limit	C	Thermal overload of Newark-NRS 115 kV	Tesla-Metcalf 500 kV and Tesla-Sunol 500 kV	400
With Resolution E-4949 & new Sunol 500 kV substation					
2028	First Limit	C	Thermal overload of Newark-NRS 115 kV	Tesla-Metcalf 500 kV and Tesla-Sunol 500 kV	770
With 4-terminal DC (2000-350-300-1350), 500 MVAR Reactive Support at Metcalf and Resolution E-4949					
2028	First Limit	C	Thermal overload of Moss Landing-Las Aguilas 230 kV	Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV	534

South Bay-Moss Landing Subarea : Potential LCR Reduction Alternatives

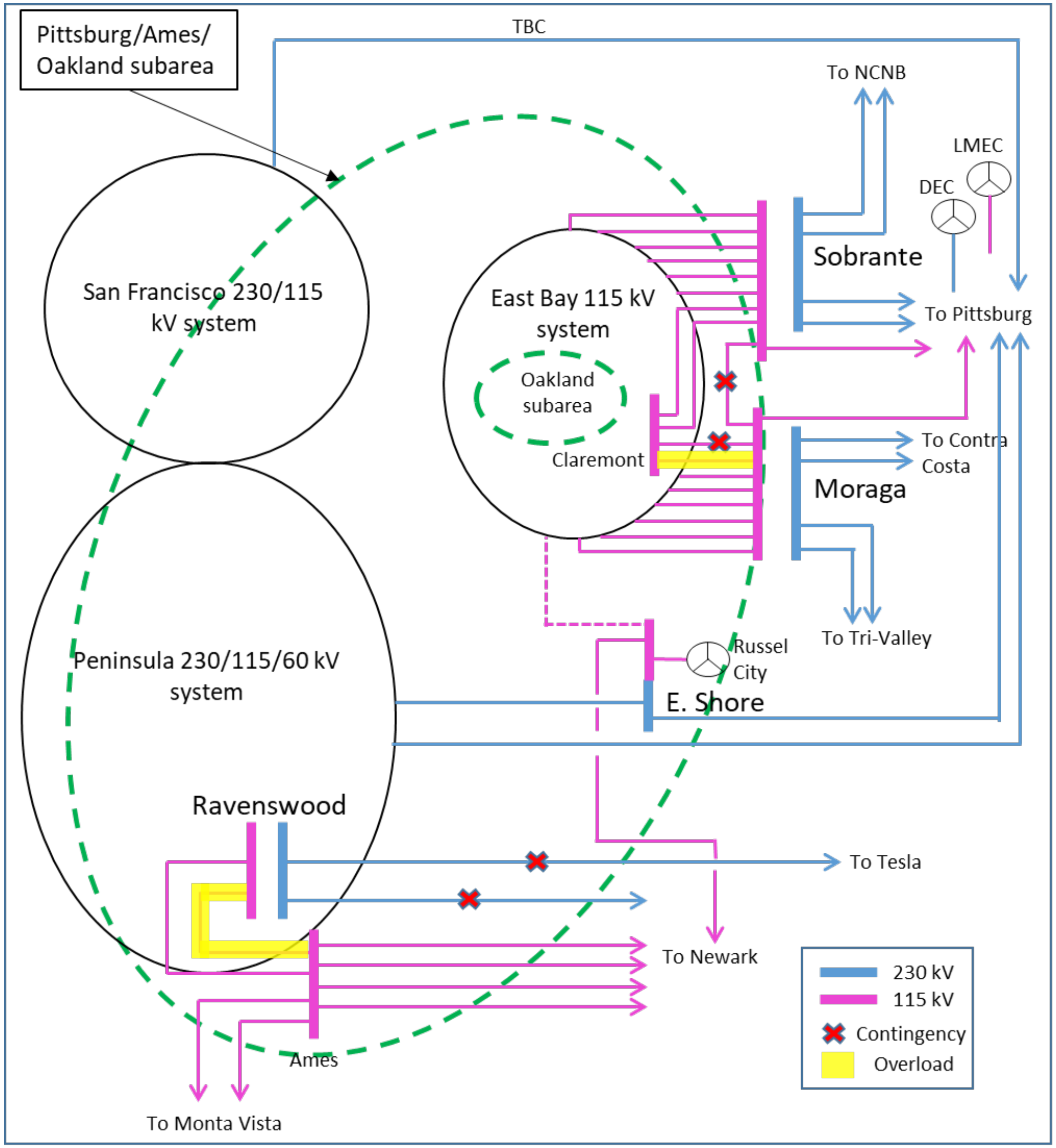
Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
Status Quo	NA	NA	2100	1888	208	4
With E-4949	NA	NA	2051	1282	208	561
New Sunol 500 kV substation only	PGE	$500M-$1B	400	192	208	0
With E-4949 and new Sunol 500 kV substation	PGE	TBD	769	0	208	561
With 4-terminal DC (2000-350-300-1350), 500 MVAR Reactive Support at Metcalf and E-4949 (ES forced)	ISO	TBD	534	0	0	534

Ames/Pittsburg/Oakland Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	NA*	Market Gas	2250
AAEE	NA	Other Gas	345
Behind the meter DG	NA	Non-Gas	0
Net Load	NA		
Transmission Losses	NA	Future preferred resource and energy storage (Resolution E-4949)	0
Pumps	NA	**Total Qualifying Capacity**	**2595**
Load + Losses + Pumps	NA		

Note:
* - Flow through area

Ames/Pittsburg/Oakland Subarea : One-line diagram



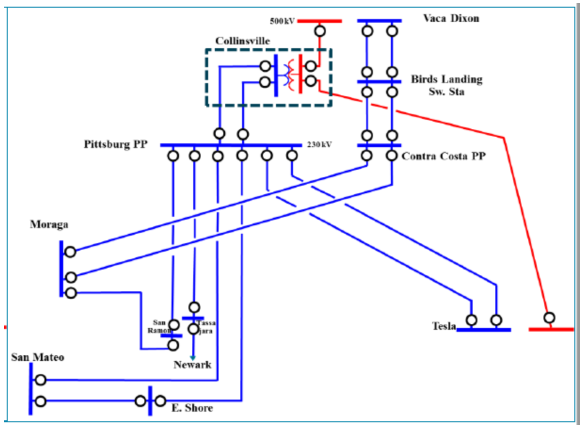
Ames/Pittsburg/Oakland Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First limit	B	None	None	No requirement
2028	First limit	C	Ames-Ravenswood #1 115 kV line	Newark-Ravenswood & Tesla-Ravenswood 230 kV lines	2022
			Moraga-Claremont #2 115 kV line	Moraga-Sobrante & Moraga-Claremont #1 115 kV lines	
Subsequent requirements (layers)					
2028	Worst limit	C	Monta Vista-Mountain View 115 kV line	Whisman-Mountain View115 kV and Jefferson-Martin 230 kV	2237
2028	Third limit	C	Newark-Ames 115 kV lines	Newark-Ravenswood & Tesla-Ravenswood 230 kV lines	1432
2028	Fourth limit	C	Moraga-Sobrante 115 kV and Tesla-Newark 230 kV lines	Tesla-Pittsburg 230 kV lines	1336
Multiple subsequent constraints with limiting facilities within Monta Vista-Peninsula 115 kV path and extended to 115 and 230 kV lines in path between Pittsburg and Peninsula.					

Ames/Pittsburg/Oakland Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
With Collinsville 500 kV substation					
2028	Worst limit	C	Monta Vista-Mountain View 115 kV line	Whisman-Mountain View115 kV and Jefferson-Martin 230 kV	970
Collinsville plus Monta Vista-Mountain View-Whisman and Moraga-Claremont 115 kV lines upgrade					
2028	Worst limit	C	Ames-Ravenswood and Oakland J-E. Shore 115 kV lines	Newark-Ravenswood & Tesla-Ravenswood 230 kV lines	450
Collinsville 500 kV substation, Moraga-Claremont and Moraga-Sobrante 115 kV lines upgrade and 600 MW storage in Peninsula (or 600 MW HVDC from Pittsburg to Peninsula)					
2028	Worst limit	C	Tesla-Newark 230 kV lines	Tesla-Pittsburg 230 kV lines	0-600

New Collinsville 500 kV substation



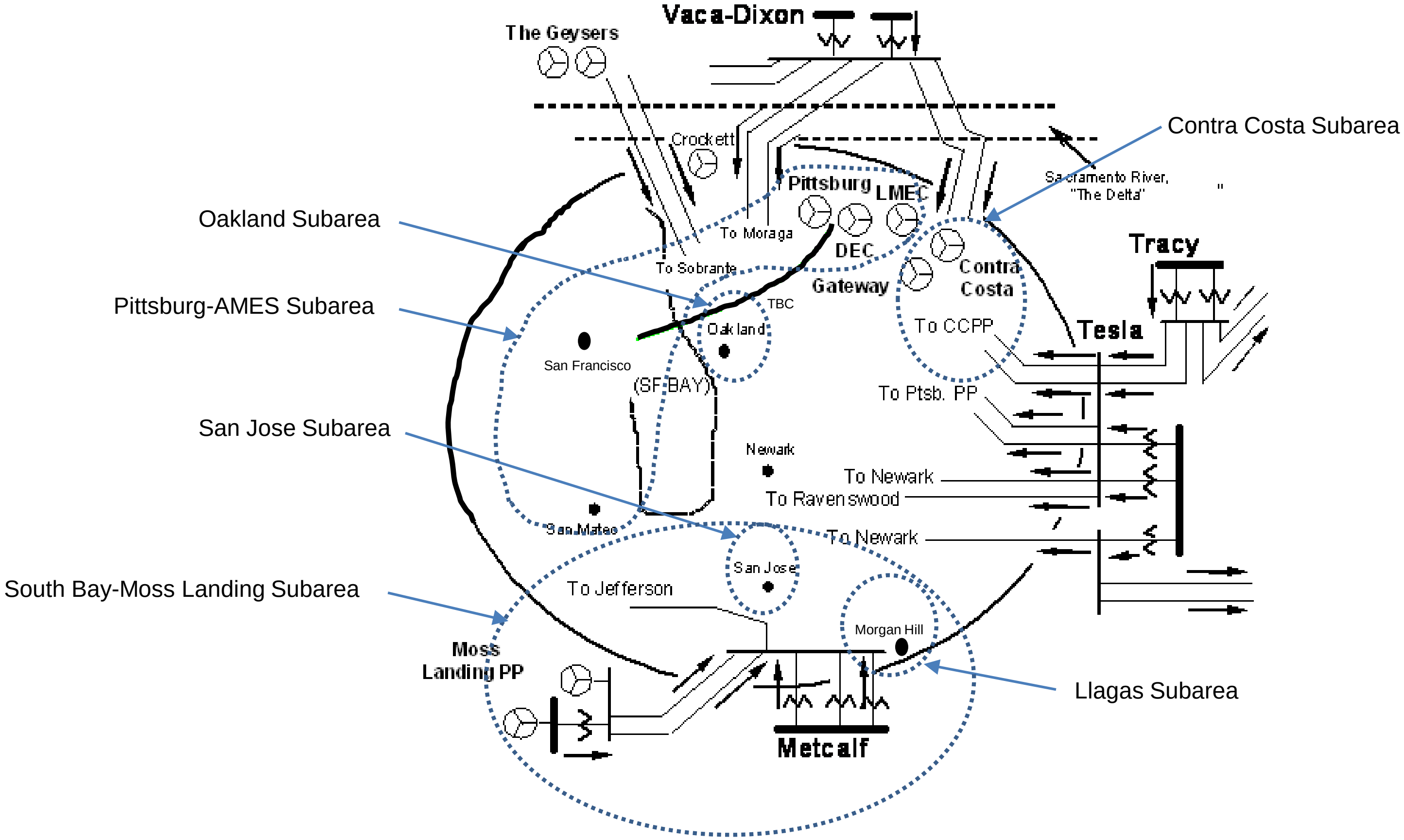
Ames/Pittsburg/Oakland Subarea : Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
Collinsville 500 kV substation	PGE	$0.5B-$1B	970	625	345	0
Collinsville plus Monta Vista-Mountain View-Whisman and Moraga-Claremont 115 kV lines upgrade	PGE, ISO	TBD	450	202	250	0
Collinsville 500 kV substation, Moraga-Claremont and Moraga-Sobrante 115 kV lines upgrade and 600 MW storage in Peninsula (or 600 MW HVDC from Pittsburg to Peninsula)	PGE, ISO	TBD	0-600	0	0	0-600

Greater Bay Area Overall: Load and Resources (2028)

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

Greater Bay Area Transmission System & LCR Subareas



Greater Bay Area Overall : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First limit	B	Reactive margin	Tesla-Metcalf 500 kV line & DEC unit	4795
2028	First limit	C	Aggregate of subareas		6948 (204)
With 4-terminal DC (2000-350-300-1350), 500 MVAR Reactive Support at Metcalf, E-4949 (ES forced), Collinsville 500 kV substation, Moraga-Claremont and Moraga-Sobrante 115 kV lines upgrade and 600 MW storage in Peninsula (or 600 MW HVDC from Pittsburg to Peninsula)					
2028	First limit	A	Reactive margin		2500
2028	First limit	C	Thermal overload of Moss Landing-Las Aguilas 230 kV	Tesla-Metcalf 500 kV and Moss Landing-Los Banos 500 kV	2570

Greater Bay Area Overall : Potential LCR Reduction Alternatives

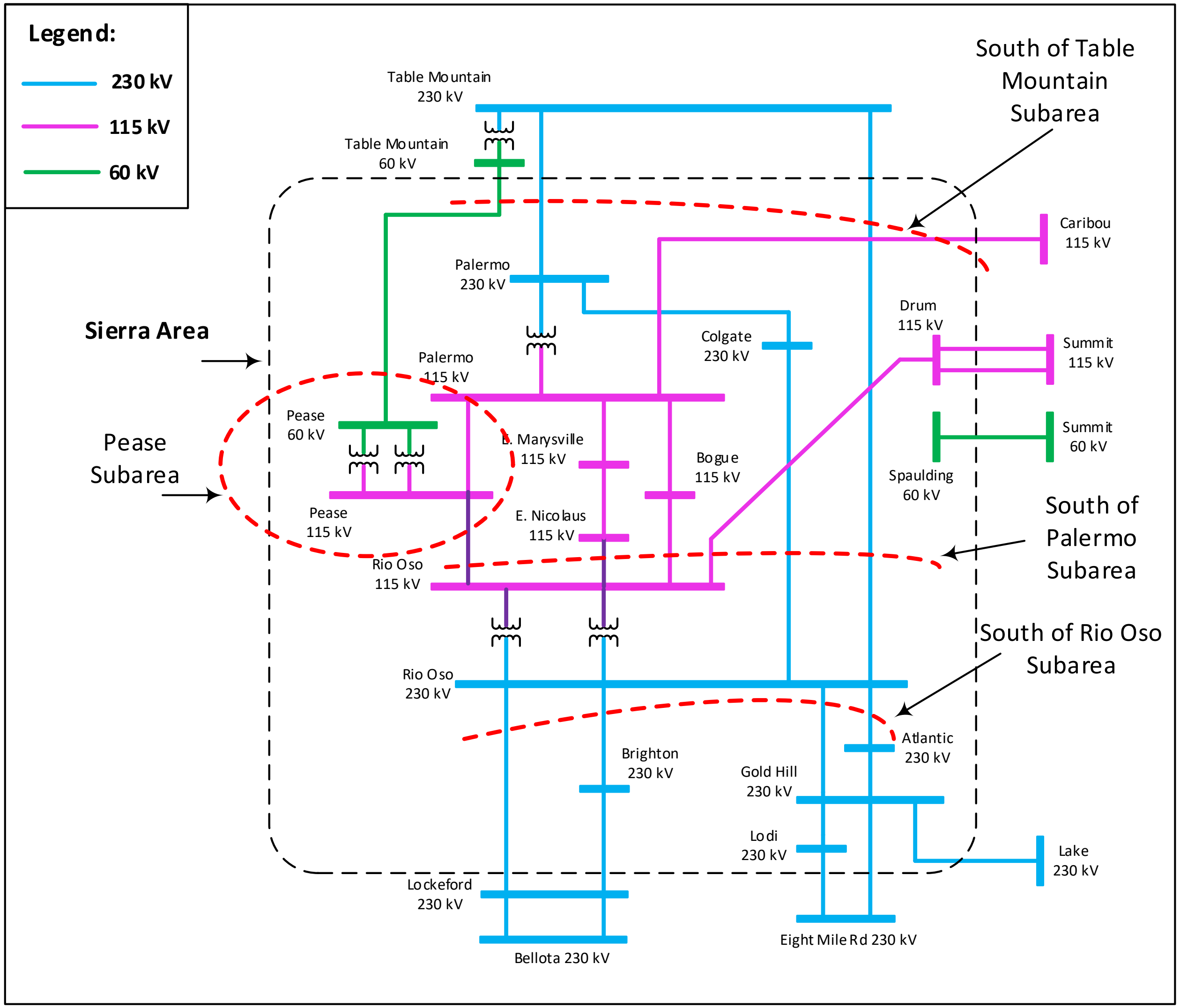
Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)				
			Total	Market Gas (South Bay-Moss Landing & Pittsburg-Ames-Oakland)	Market Gas (Contra Costa)	Other Gas	Non-Gas
With 4-terminal DC (2000-350-300-1350), 500 MVAR Reactive Support at Metcalf, E-4949 (ES forced), Collinsville 500 kV substation, Moraga-Claremont and Moraga-Sobrante 115 kV lines upgrade and 600 MW storage in Peninsula (or 600 MW HVDC from Pittsburg to Peninsula)	PGE, ISO	TBD	2570	0	710	630	1230

Local Capacity Requirements Potential Reduction Study – Sierra

Ebrahim Rahimi

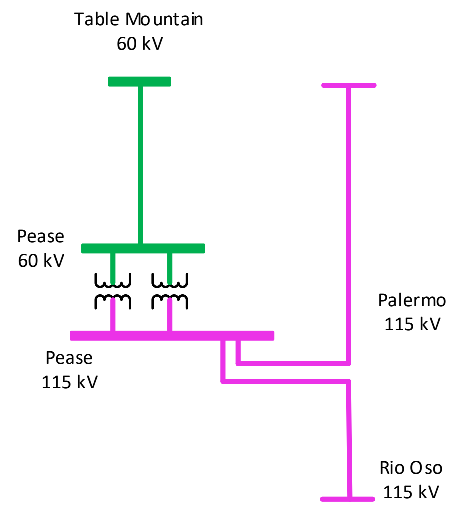
Lead Regional Transmission Engineer

Sierra LCR Area



Pease Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	179	Market Gas	134[1]
AAEE	-11	Other Gas	0
Behind the meter DG	0	Non-Gas	0
Net Load	**168**		
Transmission Losses	1		
Pumps	0	**Total Qualifying Capacity**	**134**
Load + Losses + Pumps	**169**		



[1] The 134 MW Market Gas generation includes the Yuba City Energy Center (YCEC) unit with NQC of 47.6 MW

Pease Subarea : Requirements

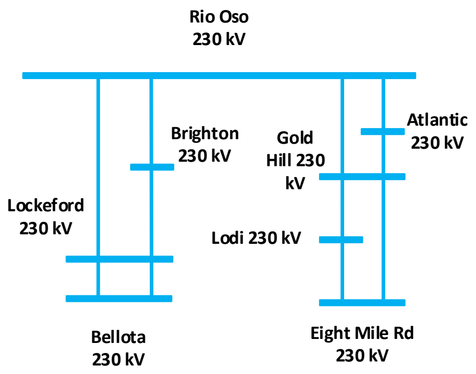
Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First limit	B	None	None	No requirement
2028	First limit	C	Thermal overload of Table Mountain – Pease 60 kV	Palermo – Pease 115 kV and Pease – Rio Oso 115 kV	92
Subsequent requirements (layers)					
2028	Second limit	C	None	None	No requirement
Install a DTT to trip the load at Harter upon the loss of 115 kV Lines plus 25 Mvar voltage support.					
2028	First limit	C	Thermal overload of Table Mountain – Pease 60 kV	Palermo – Pease 115 kV and Pease – Rio Oso 115 kV	50
Convert Table Mountain – Pease 60 kV Line to 115 kV lines					
2028	First limit	C	Thermal overload of Table Mountain – Pease 115 kV	Palermo – Pease 115 kV and Pease – Rio Oso 115 kV	20
Looping Palermo – Nicolaus 115 kV line into Pease 115 kV Bus.					
2028	First limit	C	None	None	No requirement
Loop in Pease – Marysville 60 kV line into E. Marysville 115 kV substation and install a 115/60 kV transformer at E. Marysville substation plus 25 Mvar voltage support.					
2028	First limit	C	None	None	No requirement

Pease Subarea : Potential LCR Reduction Alternatives

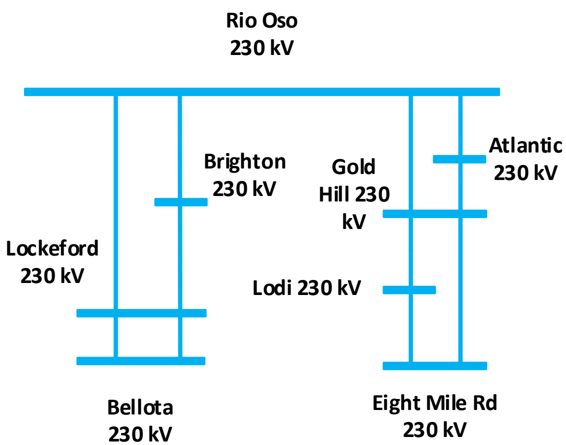
Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
Install a DTT to trip the load at Harter upon the loss of 115 kV Lines plus 25 Mvar voltage support.	PG&E	TBD	50	50	0	0
Convert Table Mountain – Pease 60 kV Line to 115 kV lines	PG&E	TBD	20	20	0	0
Looping Palermo – E. Nicolaus 115 kV line into Pease 115 kV Bus.	PG&E	TBD	0	0	0	0
Loop in Pease – Marysville 60 kV line into E. Marysville 115 kV substation and install a 115/60 kV transformer at E. Marysville substation plus 25 Mvar voltage support.	ISO	$26M-$52M	0	0	0	0

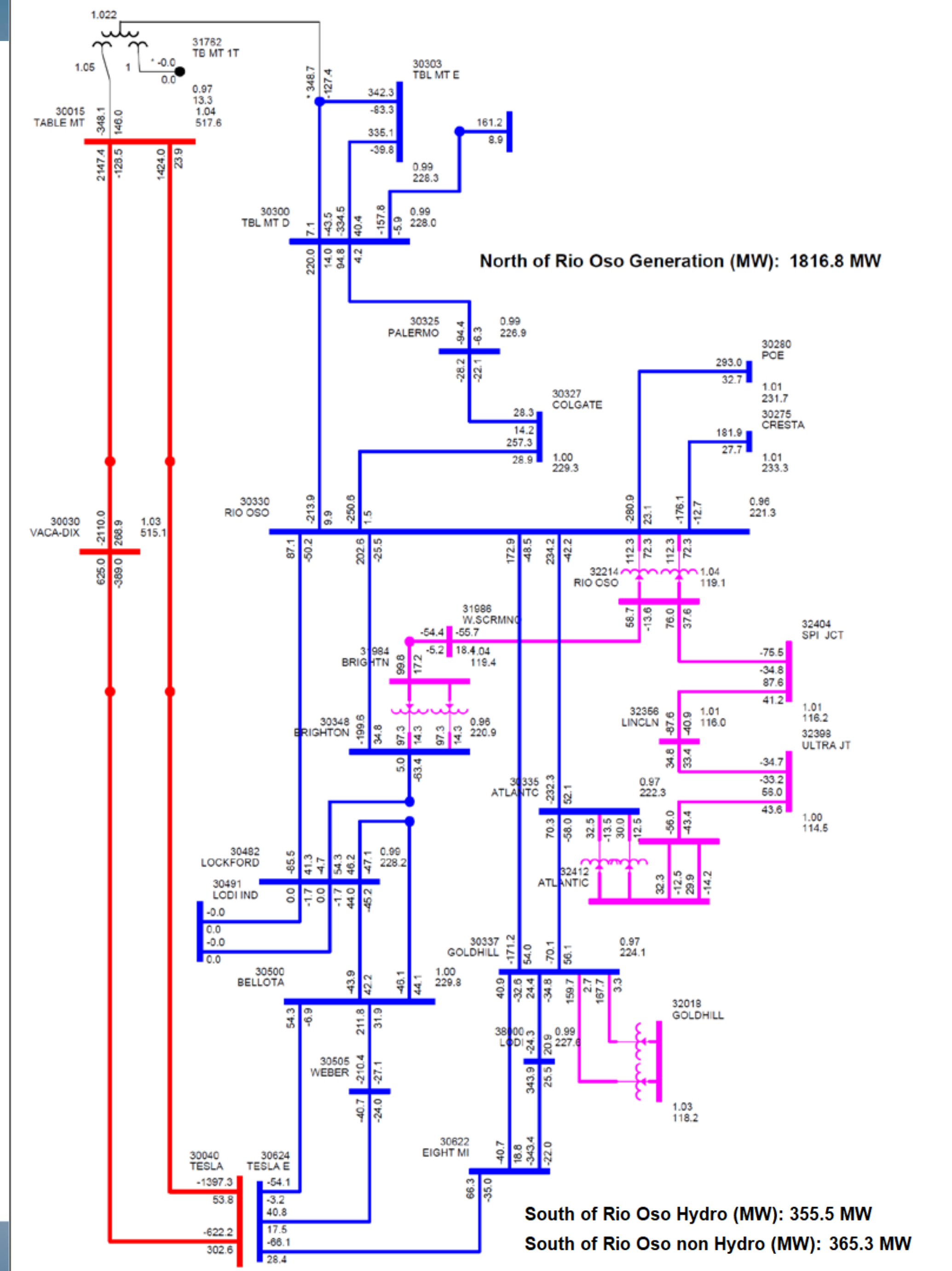
South of Rio Oso Subarea: Load and Resources (2028)

Load (MW)	Generation (MW)	
This is a flow through LCR Subarea.	Market Gas	0
	Other Gas	330
	Non-Gas	390
	Total Qualifying Capacity	**720**



South of Rio Oso Subarea





South of Rio Oso Subarea : Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
Current requirements based on 2028 LCR study					
2028	First limit	B	Rio Oso – Atlantic 230 kV	Rio Oso – Gold Hill 230 kV & Ralston Unit	428
2028	First limit	C	Rio Oso – Atlantic 230 kV	Rio Oso – Gold Hill 230 kV Rio Oso – Brighton 230 kV	532
Subsequent requirements (layers)					
2028	Second limit	C	Rio Oso – Atlantic 230 kV	Rio Oso – Gold Hill 230 kV Rio Oso – Lockeford 230 kV	458
2028	Third limit	C	Rio Oso – Gold Hill 230 kV	Rio Oso – Atlantic 230 kV Rio Oso – Brighton 230 kV	300

South of Rio Oso Subarea: Potential LCR Reduction Alternatives

Alternatives	**Submitted By**	**Estimated Cost ($M)**	**Requirement (MW)**			
			Total	Market Gas	Other Gas	Non-Gas
Reduce the hydro generation north of Rio Oso after the first contingency by a maximum of 32 MW for P3 and 71 MW for P6 contingencies.	ISO	N/A	390	0	0	390

Local Capacity Requirements Potential Reduction Study – Fresno

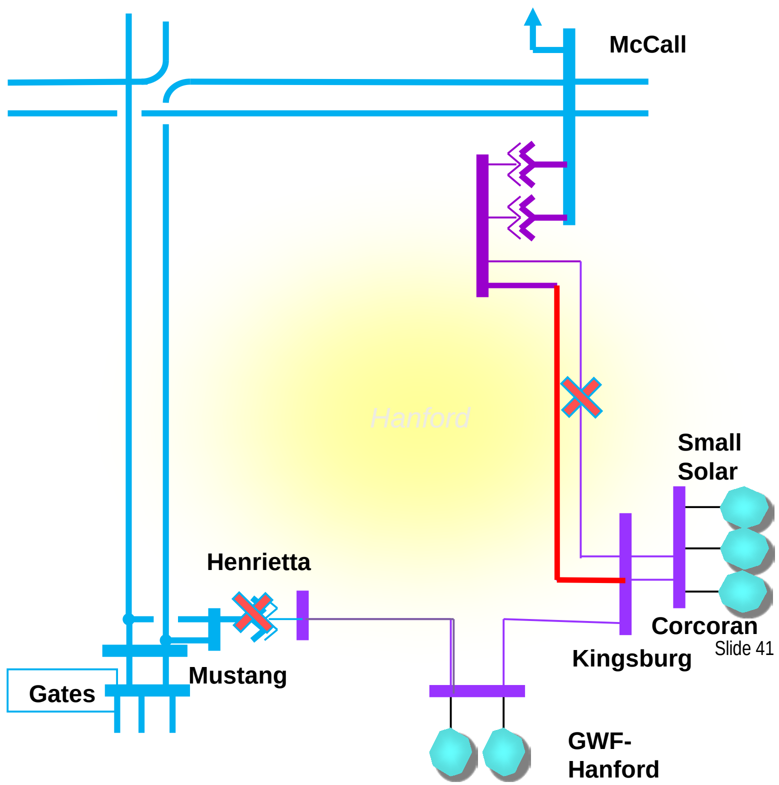
Vera Hart

Sr. Regional Transmission Engineer

Hanford Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	255.3	Market Gas	98
AAEE	-15.3	Other Gas	40
Behind the meter DG	-2.7	Non-Gas	232.9
Net Load	**237.3**		
Transmission Losses	5.2		
Pumps	0	**Total Qualifying Capacity**	**368.9**
Load + Losses + Pumps	**242.5**		

Hanford Sub-Area



Hanford Sub-Area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2028	First Limit	P7	McCall-Kingsburg #1 115kV Line	Mustang-Gates #1 and #2 230kV Lines	125
2028	Second Limit	P6	McCall-Kingsburg #1 115kV Line	McCall-Kingsburg #2 115kV Line and Henrietta #3 230/115kV TB	89
2028	Third Limit	P6	McCall-Kingsburg #2 115kV Line	McCall-Kingsburg #1 115kV Line and Henrietta #3 230/115kV TB	86
Reconductor McCall-Kingsburg #1 line					
2028	Worst Limit	P6	McCall-Kingsburg #2 115kV Line	McCall-Kingsburg #1 115kV Line and Henrietta #3 230/115kV TB	86
Reconductor Mccall-Kingsburg #1 and #2 line					
2028	Worst limit	C	None	None	0

Reedley Sub-Area
Potential LCR Reduction Alternatives

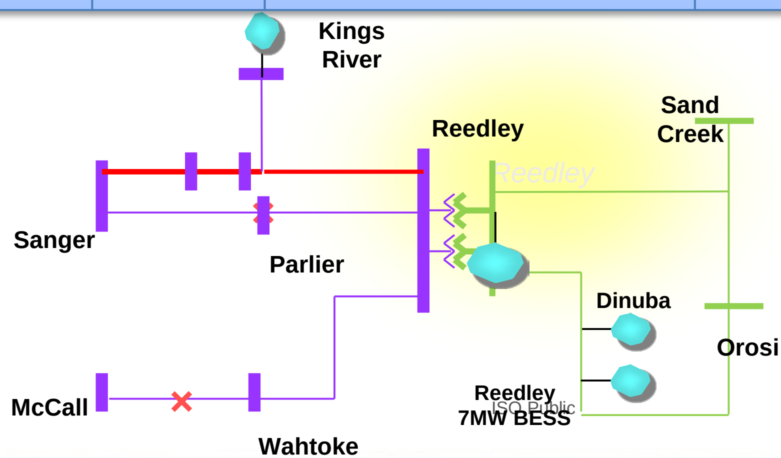
Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)				
			Total	Market Gas	Other Gas	Non-Gas	Solar
Reconductor McCall-Kingsburg #1 115kV line	CAISO	$9M	86	86	0	0	0
Reconductor McCall-Kingsburg #1 and #2 115kV lines	CAISO	$23.5M	0	0	0	0	0

Reedley Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	244.3	Market Gas	0
AAEE	-14	Other Gas	0
Behind the meter DG	0	Non-Gas	120
Net Load	**230.3**		
Transmission Losses	35.3		
Pumps	0	**Total Qualifying Capacity**	**120**
Load + Losses + Pumps	**265.6**		

Reedley Sub-Area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2028	First Limit	C	Kings River-Sanger-Reedley 115kV line(Sanger-Piedra)	McCall-Reedley 115kV Line & Sanger-Reedley 115kV line	39
2028	Second Limit	C	Kings River-Sanger-Reedley 115kV line(Piedra to Reedley)	McCall-Reedley 115kV Line & Sanger-Reedley 115kV line	19
--	--	--	--	--	--
Increase Dinuba Battery to 40MW					
2028	Worst limit	C	None	None	0
Reconductor Kings River-Sanger-Reedley 115kv Line (From Sanger-Piedra)					
2028	Worst limit	C	Kings River-Sanger-Reedley 115kV line(Piedra to Reedley)	McCall-Reedley 115kV Line & Sanger-Reedley 115kV line	19
Reconductor Kings River-Sanger-Reedley 115kv Line (Full Line)					
2028	Worst limit	C	None	None	0
New McCall-Reedley #2 115kV line					
2028	Worst limit	C	None	None	0



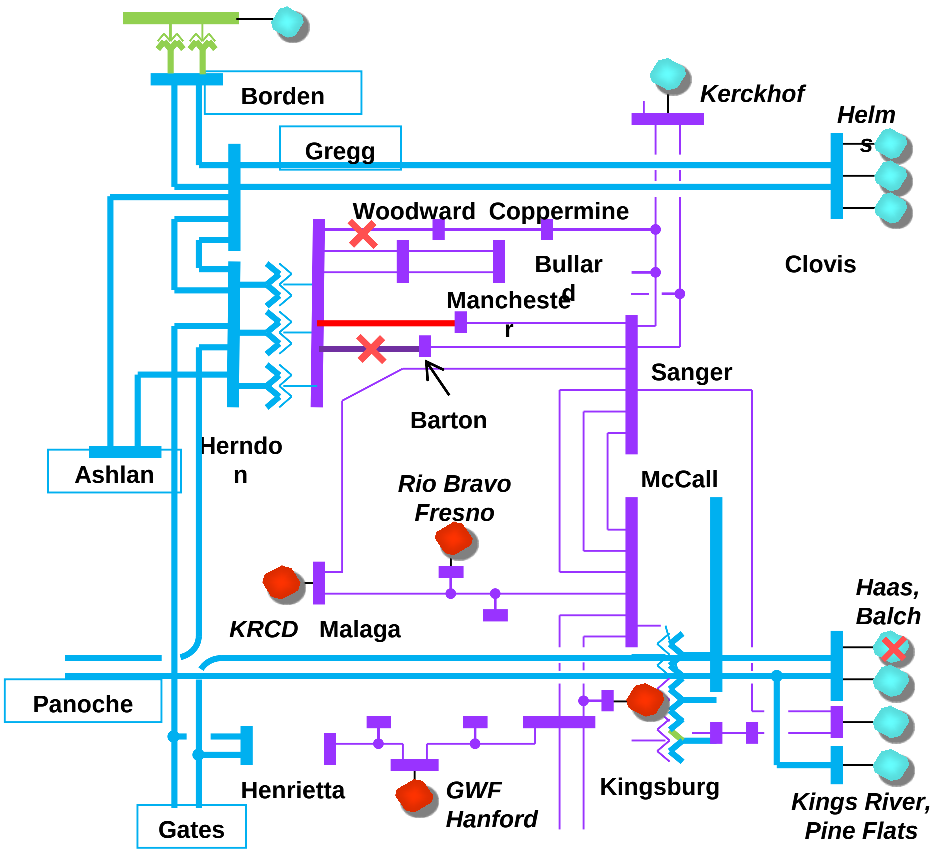
Reedley Sub-Area
Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
Dinuba Battery MW Increase to 40MW	CAISO	TBD	0	0	0	0
Reconductor Kings River-Sanger-Reedley 115kv Line (From Sanger-Piedra)	CAISO	$9M	19	0	0	19
Reconductor Kings River-Sanger-Reedley 115kv Line (Full Line)	CAISO	$9M+TBD	0	0	0	0
New McCall-Reedley #2 115kV line	PGE	$30-$40M	0	0	0	0

Herndon Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	1763	Market Gas	359
AAEE	-102	Other Gas	0
Behind the meter DG	-2.7	Non-Gas	911
Net Load	**1658**		
Transmission Losses	30.5		
Pumps	0	**Total Qualifying Capacity**	**1270**
Load + Losses + Pumps	**1688**		

Herndon Sub-Area



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Herndon Sub-Area Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2028	First limit	B	Herndon-Manchester 115kV line	Balch Unit 1 and Herndon-Barton 115kV line	326
2028	First limit	C	Herndon-Manchester 115kV line	Herndon-Woodward 115kV line and Herndon-Barton 115kV line	830
2028	Second Limit	C	Herndon-Barton 115kV line	Herndon-Woodward 115kV line and Herndon-Manchester 115kV line	784
2028	Third limit	C	Herndon-Woodward 115kV line	Herndon-Barton 115kV line and Herndon-Manchester 115kV line	625

Herndon Sub-Area
Potential LCR Reduction Alternatives

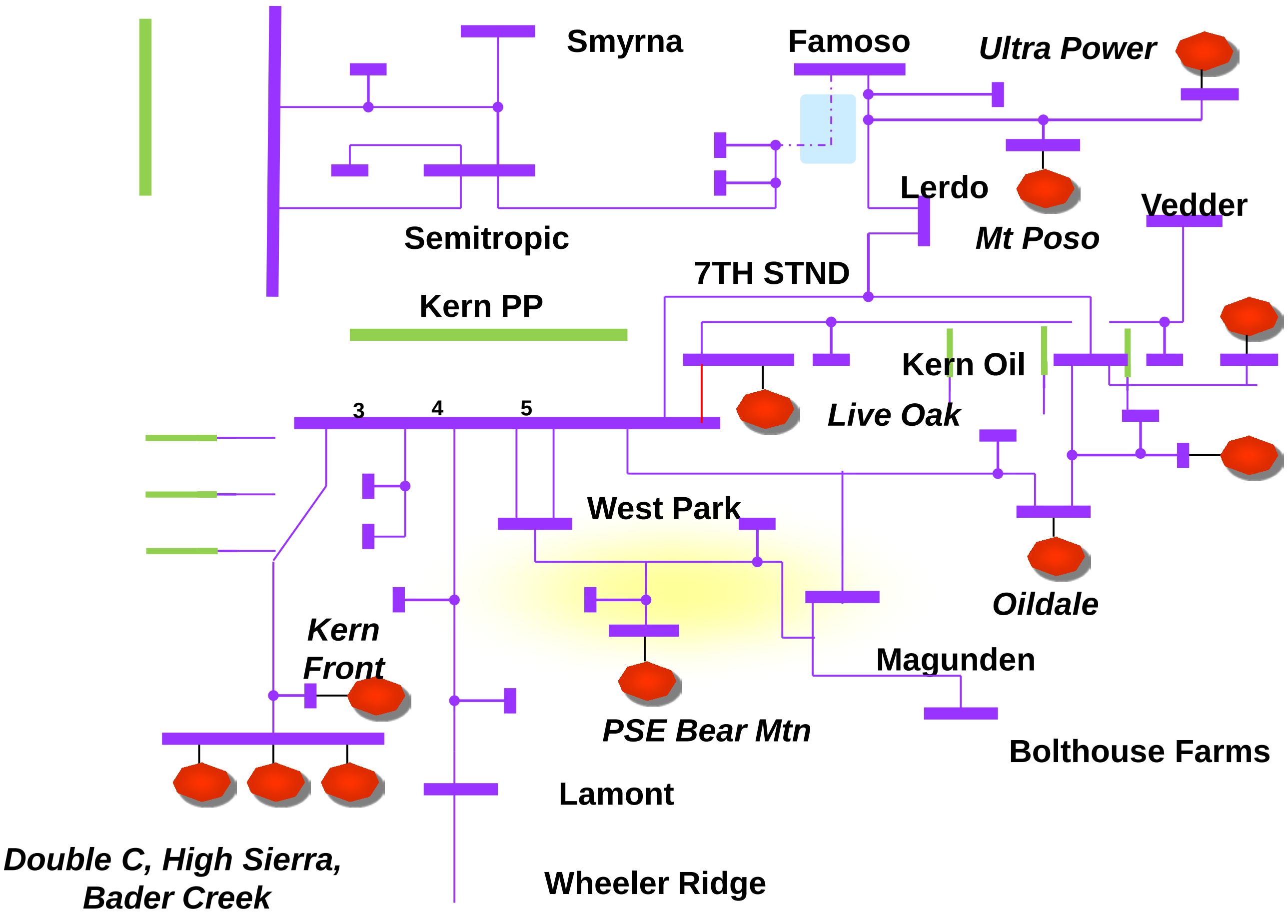
Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
Reduce the Helms Hydro Units after the first contingency by 404 MW for the P6 contingency.	CAISO	N/A	752	0	0	752

Local Capacity Requirements Potential Reduction Study – Kern

Abhishek Singh

Regional Transmission Engineer Lead

Kern-2028 LCR Area



Kern PW 70 kV Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	161	Market Gas	0
AAEE	-8	Non Gas	12
Behind the meter DG	0	**Total Qualifying Capacity**	**12**
Net Load	**153**		
Transmission Losses	2		
Pumps	0		
Load + Losses + Pumps	**155**		

Kern PW Sub Area : Requirements & Proposed Mitigations

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2028	First Limit	C	Kern PW2 to Kern PW1 70 kV Bus Tie	Kern PW2 115/70 T/F # 1 & Kern-Old River 70 kV line	39*(3)

**31 MW in last stakeholder call. Updated to include loss of generation.*

Replace limiting equipment to eliminate this requirement.

Kern PP 70 kV Sub Area : Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
Kern PP 70 kV limiting equipment replacement project	ISO	TBD	0	0	0	0

WestPark Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	183	Market Gas	45
AAEE	-10	Non Gas	0
Behind the meter DG	0	**Total Qualifying Capacity**	**45**
Net Load	**173**		
Transmission Losses	0.1		
Pumps	0		
Load + Losses + Pumps	**173**		

WestPark Sub Area : Requirements & Proposed Mitigations

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2028	First Limit	C	Kern-West Park #2 115 kV	Kern-West Park #1 115 kV and Magunden – Wheeler Junction 115 kV	42

Potential Rerate(in-process) of the Kern-West Park# 1 & # 2 Lines eliminates this sub area requirement.

WestPark Sub Area : Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
WestPark Subarea Rerate	ISO	0	0	0	0	0

Kern Oil Subarea: Load and Resources (2028)

Load (MW)		Generation (MW)	
Gross Load	667	Market Gas	72
AAEE	-42	Non Gas	46
Behind the meter DG	0	**Total Qualifying Capacity**	**118**
Net Load	**625**		
Transmission Losses	7		
Pumps	0		
Load + Losses + Pumps	**632**		

Kern Oil Subarea: Requirements & Proposed Mitigations

Year	Limit	Cat	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2028	First limit	C	Live Oak – Kern Power 115 kV line	Kern-Magunden-Witco and Kern PP-7th Standard 115 kV line	67
2028	Second Limit	C	KernPP-7Standard 115 kV line	Kern-Live Oak 115kV and Kern-Magunden-Witco 115 kV line	62
2028	Third Limit	C	Multiple Sections between Kern Oil and Kern Oil Jn.	Kern-Live Oak 115kV and Kern PP-7th Standard 115 kV line	62
2028	Fourth Limit	C	Kern Oil Jn to Kern Water section	Kern-Live Oak 115kV and Kern PP-7th Standard 115 kV line	10

Kern Oil Subarea Reconductor/Rerates:

- Increase the scope of Kern-Live Oak reconductor
- Reconductor Kern Power-7Standard 115 kV and rerate sections of line between 7 standard and Kern Oil substations.
- Reconductor sections of line between Kern oil and Kern oil Junction.
- Increase the scope of Kern Power-Kern Oil Jn from rerate to reconductor

Kern Oil Subarea: Potential LCR Reduction Alternatives

Alternatives	Submitted By	Estimated Cost ($M)	Requirement (MW)			
			Total	Market Gas	Other Gas	Non-Gas
Increase the scope of Kern-Live Oak reconductor	ISO	TBD	62	16	0	46
Reconductor Kern Power-7Standard 115 kV and rerate sections of line between 7 standard and Kern Oil substations	ISO	TBD	62	16	0	46
Reconductor sections of line between Kern oil and Kern oil Junction.	ISO	TBD	62	16	0	46
Increase the scope of Kern Power-Kern Oil Jn from rerate to reconductor	ISO	TBD	10	0	0	10

Kern Overall

- Kern Area Overall without upgrades to reduce sub-area needs is currently dependent on the sub-area generation
- Transmission solutions for 70 kV and 115 kV push the thermal issues back to 230 kV lines.
- Kern Area would need around 82 MW of generation (Non-gas: 57MW,Gas : 25 MW)
- Alternatively SPS options can be explored to alleviate these issues.

Next Steps

- Finalize cost estimates of alternatives
- Economic assessment of selected alternatives.
- Alternatives found to be economic will be included in the draft Transmission Plan.

Gas-fired Generation LCR Reduction Assessment

Big Creek/Ventura Area

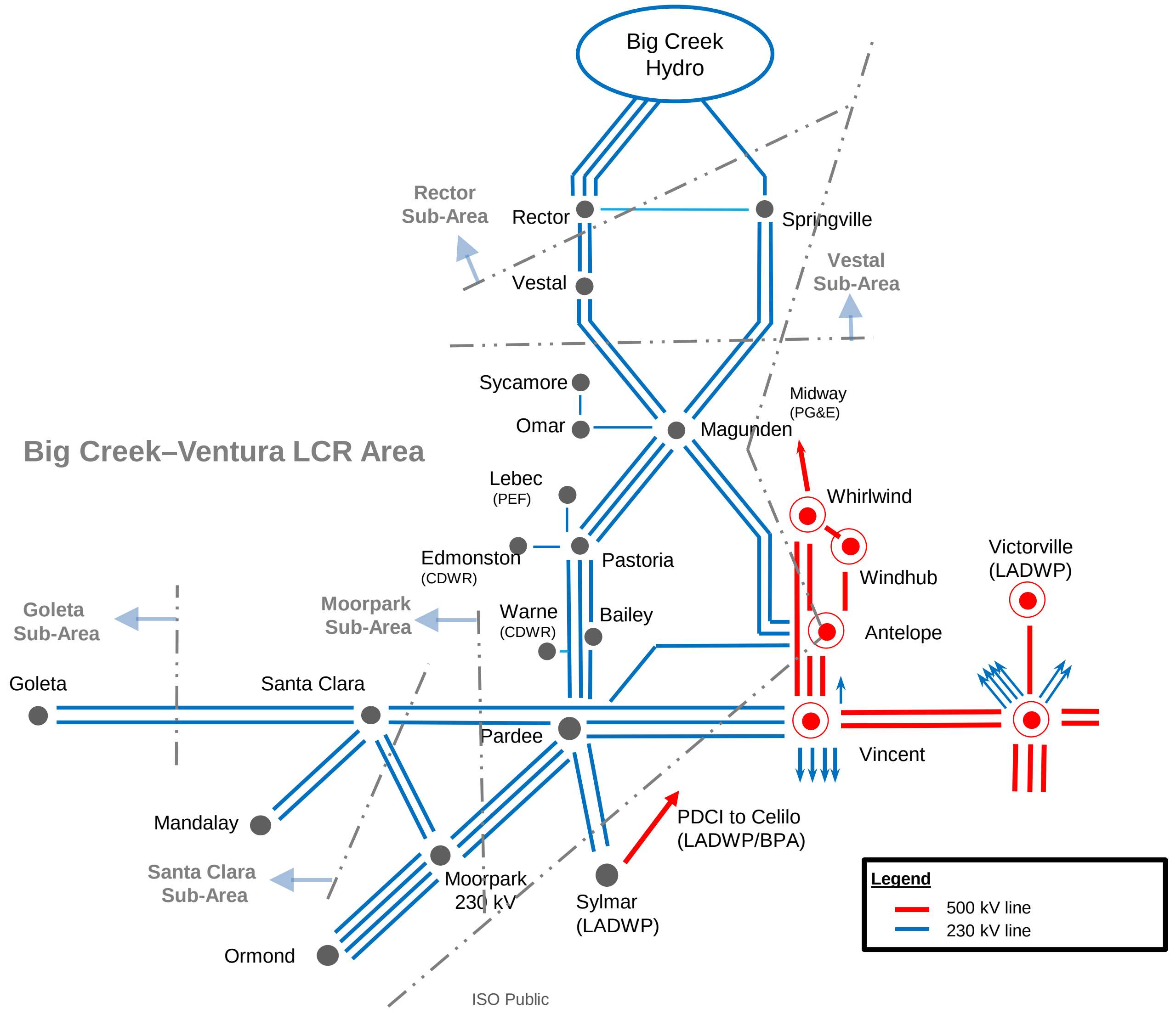
Nebiyu Yimer

Regional Transmission Engineer Lead

Stakeholder Meeting

November 16, 2018

Bic Creek/Ventura Area Transmission System



Recap of Ongoing Gas-fired LCR Reduction Activities

- Pardee-Moorpark 230 kV Transmission Project (ISD 2021) was approved by the ISO Board in March 2018 to avoid the need for a new 262 MW gas-fired facility in the Moorpark area.

- The 262 MW facility was needed to offset the retirement of 1930 MW of gas-fired OTC generation (Ormond Beach, Mandalay Units 1 and 2)

- Procurement of preferred resources and storage is underway in the Santa Clara sub-area to replace a further 184 MW gas-fired generation (Ellwood and Mandalay Units 3)

- ISO posted supplemental LCR studies in June to facilitate the procurement process and will be collaborating with SCE in validating the selected portfolio of resources early next year

2028 Gas-fired Generation Local Capacity Requirements

Sub-Area	2028 LCR (MW)	2028 Total Resource Capacity (MW, NQC)	2028 Gas-fired Generation Capacity (MW, NQC)	2028 Gas-fired Generation Local Capacity Requirement	
				MW	Percent of Gas-fired Capacity
Rector	N/A	1,028	0	0	0%
Vestal	465	1,205	54	0	0%
Goleta	42+	>7 (+RFP)	0	0	0%
Santa Clara	318	>199 (+RFP)	184	184	100%
Moorpark	0	>223 (+RFP)	184	0	0%
Overall Big Creek Ventura	2251	>3505 (+RFP)	1696	<442	<26%

(1) Available capacity includes existing and already procured preferred resources and storage but does not include resources being procured under the current Santa Clara area RFP

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

Selection of Areas for This Assessment

- Rector, Vestal, Goleta and Moorpark sub-areas will have no gas-fired generation requirement in 2028 because of availability of sufficient hydro resources, procurement of preferred resources or the approved transmission project.

- The Santa Clara sub-area the area was selected for this assessment because all of the gas-fired generation in the area is needed.

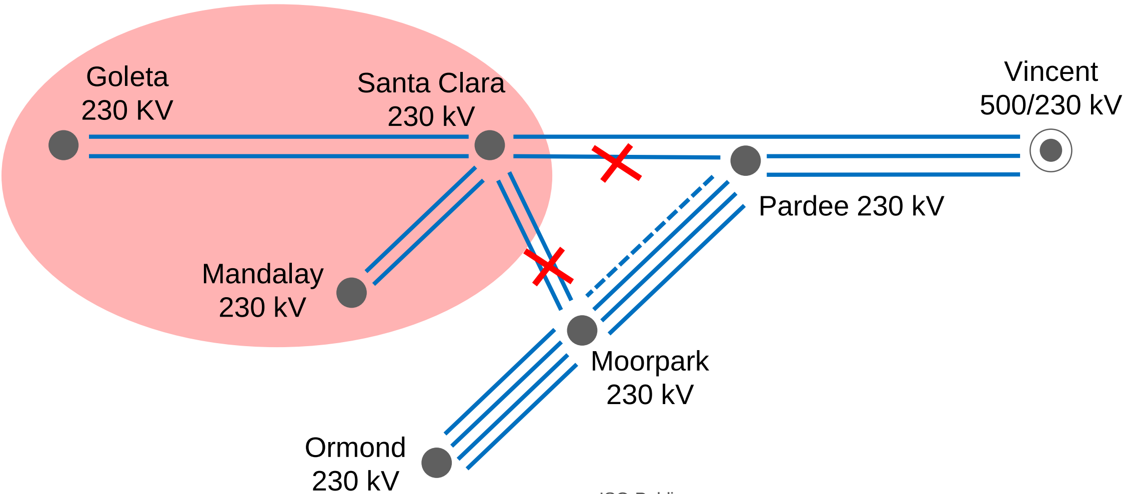
- In the greater Big Creek-Ventura area, less than 442 MW of 1669 MW (or <26%) of existing gas-fired generation will be needed for local RA. The ongoing Santa Clara area RFP is expected to lower the number to the 278-320 MW range (or 17%-19%). As such, the area was not selected for assessment in the current planning cycle.

2028 Santa Clara Sub-Area LCR Requirements

Critical Contingency	Limiting Facility/Condition	LCR (MW)
Pardee–Santa Clara 230 kV line followed by Moorpark–Santa Clara #1 and #2 230 kV DCTL	Voltage Collapse	318[1]

(1) 120 MW of generic resources with reactive capability were assumed at Goleta to meet the local capacity deficiency. For locational and reactive power effectiveness information, see http://www.caiso.com/Documents/2023LocalCapacityTechnicalAnalysisfortheSantaClaraSub-Area.pdf

(2) Consistent with the LCR Criteria, the LCR is sufficient to mitigate voltage collapse but it is not sufficient to mitigate overloading of the remaining line (Overload - 126%).



Alternatives

- Transmission Alternative :
  - Add reactive power device in the area and
  - Increase the rating of the four import lines into the area

- New Resource Alternative:
  - Procure an equivalent amount of additional energy storage or other resources

- Status Quo (Continue contracting existing gas-fired generation)
  - Age of existing generating facilities varies from 6-36 years

Next Steps

- The assessment will be continued when the ongoing LCR RFP is completed and the location and characteristics of the procured resources are known

- Based on the current schedule, SCE's Target Date for CPUC Application Filing for the RFP is March 2019 with CPUC decision coming possibly later in the year

Reducing LCR Need Study for Eastern LA Basin and San Diego-Imperial Valley Areas

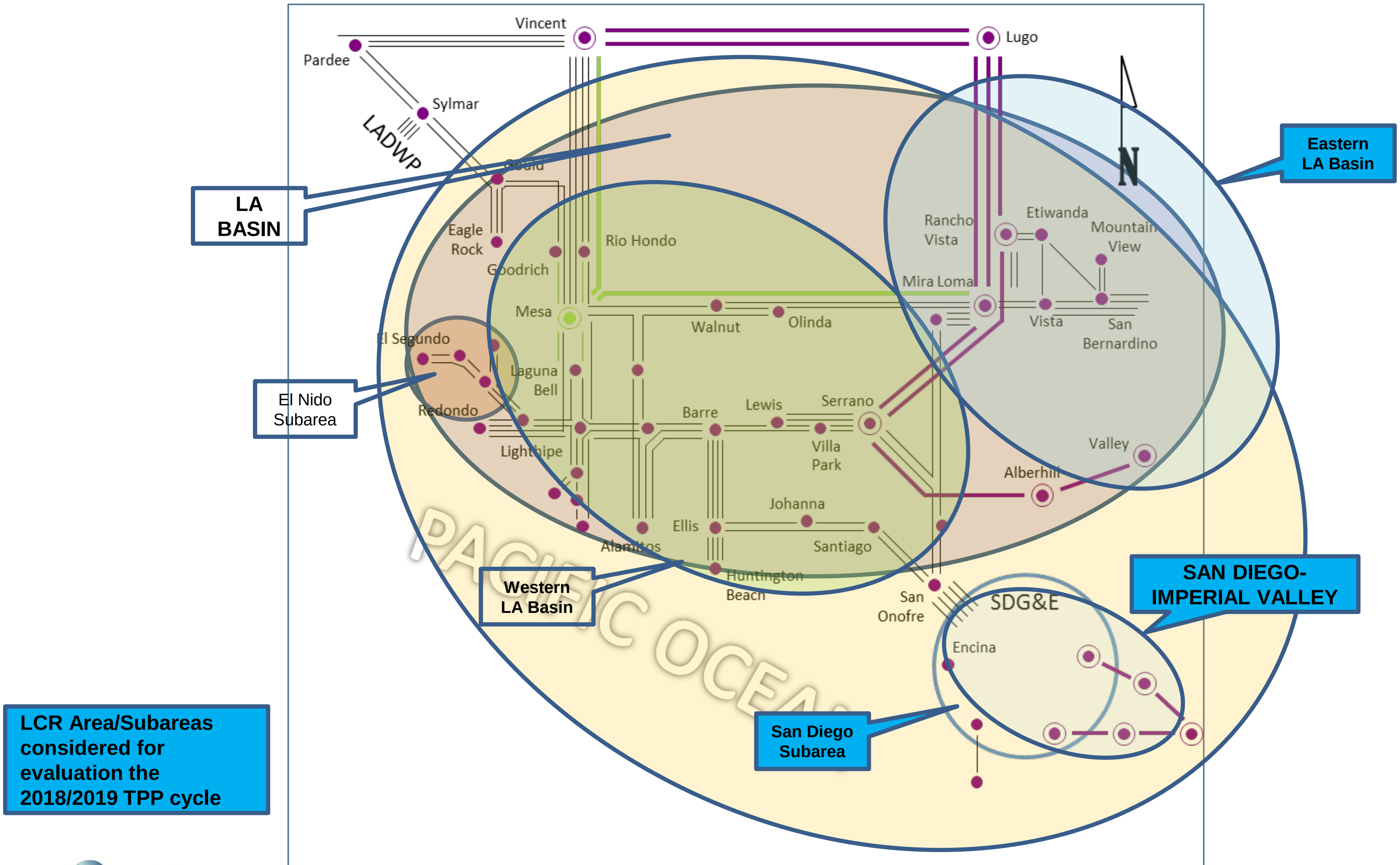
David Le
Senior Advisor, Regional Transmission Engineer

2018-2019 Transmission Planning Process Stakeholder Meeting #3
November 16, 2018

Agenda

- LCR reduction study areas for the 2018-2019 Transmission Planning Process
- Recap of 2028 LCR needs for the study areas
- Request Window project scopes
- CAISO-considered transmission solutions
- Next steps

LA Basin and San Diego-Imperial Valley Areas



LCR areas within the LA Basin and San Diego-Imperial Valley areas to be considered for LCR reduction in this transmission planning cycle

- From the previous ISO presentation on April 18, 2018, the following areas and subareas are to be considered:
  - Eastern LA Basin subarea
  - San Diego bulk transmission subarea and non-bulk transmission subareas
  - Overall San Diego-Imperial Valley area
- The Western LA Basin has been studied in conjunction with previous ISO transmission planning processes, as well as evaluated within the CPUC long-term procurement processes and proceedings related to the shutdown of 2,246 MW of the San Onofre nuclear generation and the retirement, or pending retirement of about 4,600 MW of gas-fired once-through cooled generation. This significant amount of thermal generation retirement is made possible via the following:
  - Procurement of resources, including preferred resources, at the CPUC long-term procurement plan processes for local capacity needs (i.e., LTPP Tracks 1 and 4);
  - Utilization of the existing “fast” demand response program for transmission contingency mitigation purpose that is available within SCE’s LA Basin; and
  - Implementation of transmission upgrades that have low or negligible environmental impact.

Recap of Eastern LA Basin Subarea 2028 LCR

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)	Total gas-fired generation (MW)	Total in disadvantaged community (MW)
2028	First Limit	C	Post-transient voltage stability	Serrano-Valley 500kV line, followed by Devers – Red Bluff 500kV #1 and 2 lines	2,678*	3,006	448**
2028	N/A	B	None-binding	Multiple combinations possible	N/A	3,006	448**

Notes:

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

** Retirement of Etiwanda generation this last summer removes 640 MW of generation in disadvantaged community from the Eastern LA Basin subarea

Recap of San Diego Subarea 2028 LCR

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)	Total gas-fired generation (MW)	Total in disadvantaged community (MW)
2028	First Limit	C	Thermal loading concern on the remaining Sycamore-Suncrest 230 kV line	N-1/N-1 ECO-Miguel 500 kV line, system readjustment, followed by one of the Sycamore-Suncrest 230 kV lines	2,362*	2,825	77
2028	N/A	B	None-binding	Multiple combinations possible	N/A	2,825	77

Notes:

*This includes 79.5 MW of procured BESS, 16 MW existing DR MW, 4.6 MW future DR, 19 MW future EE (beyond AAEE), 77.5 MW of existing BESS

- Recently implemented Remedial Action Schemes trips both thermal and renewable generation connecting to Imperial Valley and vicinity substations. The RAS is needed to help mitigating the loading concern on the Sycamore-Suncrest 230kV line.
- The Imperial Valley phase shifters are also utilized to help mitigating the loading concerns on the Sycamore-Suncrest 230kV lines under identified contingency condition.

Recap of Overall San Diego-Imperial Valley 2028 LCR

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)	Deficiency	Total gas-fired generation (MW)	Total in disadvantaged community (MW)
2028	First Limit (Solar gen at NQC)	B/C	El Centro 230/92 kV transformer thermal loading	G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500kV line (N-1)	3,908 MW*	0 MW	3,744	77
2028	First Limit (No Solar)	B/C	El Centro 230/92 kV transformer thermal loading	G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500kV line (N-1)	4,110 MW**	-133 MW*	3,744	77
2028	First Limit (No Solar)	B/C	El Centro 230/92 kV transformer thermal loading	G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500kV line (N-1)	3,977 MW***	0 MW	3,744	77

Notes:

*This includes 79.5 MW of procured BESS, 16 MW of existing DR, 4.6 MW future DR, 19 MW future EE (beyond AAEE), 77.5 MW of existing BESS

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

- A total of 893 MW of preferred resources (i.e., DR, EE, BESS) in the LA Basin was also utilized for mitigating this thermal loading concern

***Additional LA Basin resources (284 MW), in addition to 893 MW of preferred resources, were dispatched to help mitigating resource deficiency for the San Diego-Imperial Valley area

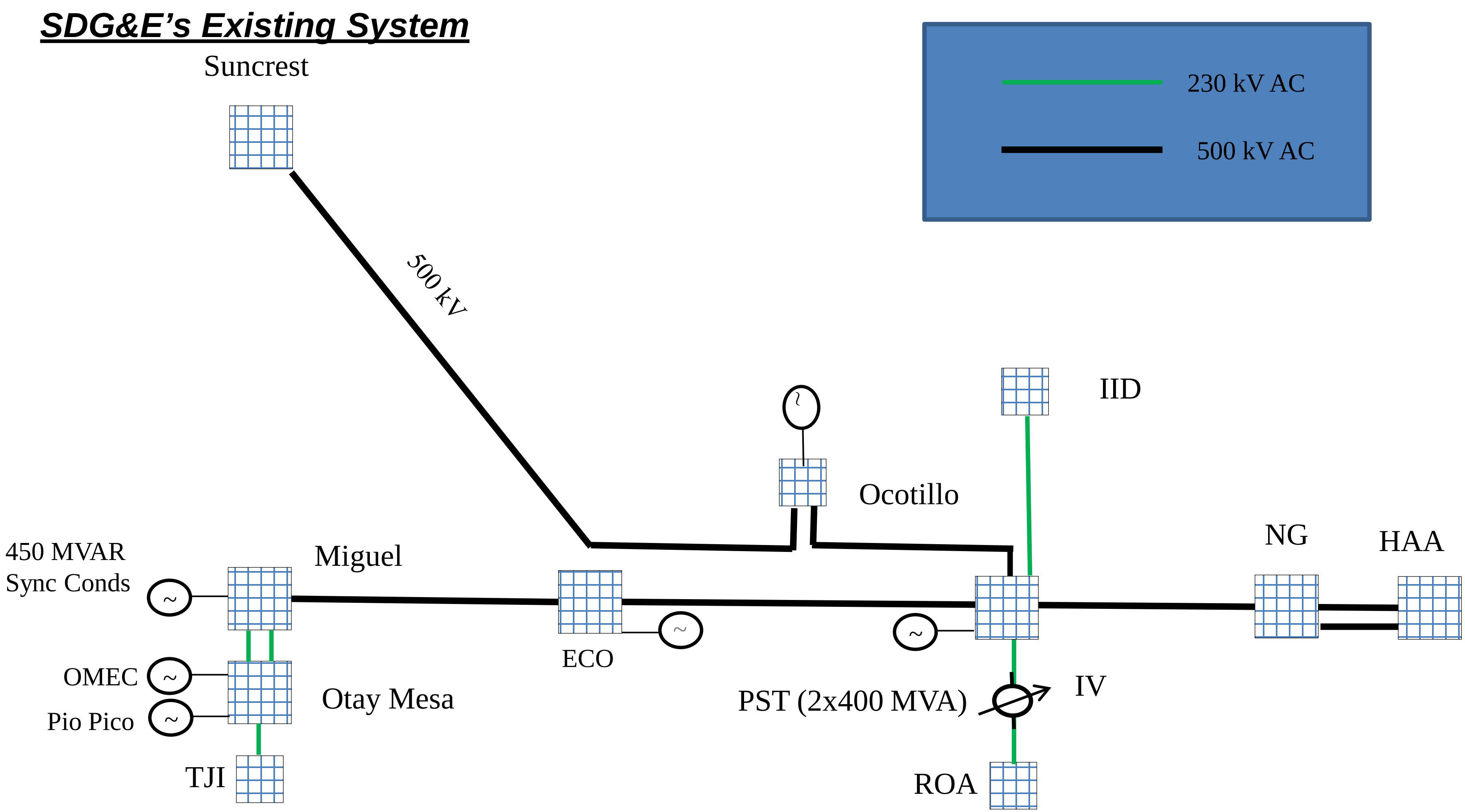
Request Window project submittals

	Name of RW project submittal	Proponents	Submission date	Target LCR reduction areas	500kV Voltage	230kV Voltage	DC Voltage (425kV)	Estimated costs ($ million)
1	Renewable Energy Express HVDC Conversion Project	SDG&E	9/15/2017	Overall San Diego-Imperial Valley	√		√	$1,000 - $2,000
2	Southern California Regional LCR Reduction	SDG&E	9/15/2018	Western LA Basin		√		$100 - $200
3	LEAPS (Lake Elsinore Advanced Pump Storage)	Nevada Hydro	10/1/2018	LA Basin, San Diego subarea, and overall San Diego-Imperial Valley	√	√		$1,760 - $2,040
4	San Vicente Energy Storage Facility	City of San Diego	10/15/2018	San Diego subarea and overall San Diego-Imperial Valley		√		$1,500* - $2,000
5	North Gila – Imperial Valley #2 500kV Line	ITC Grid Development and Southwest Transmission Partners, LLC	10/14/2016	San Diego subarea and overall San Diego-Imperial Valley	√	√		$250 - $400

Notes:

*City of San Diego indicated that the current estimate is at the lower end of the range.

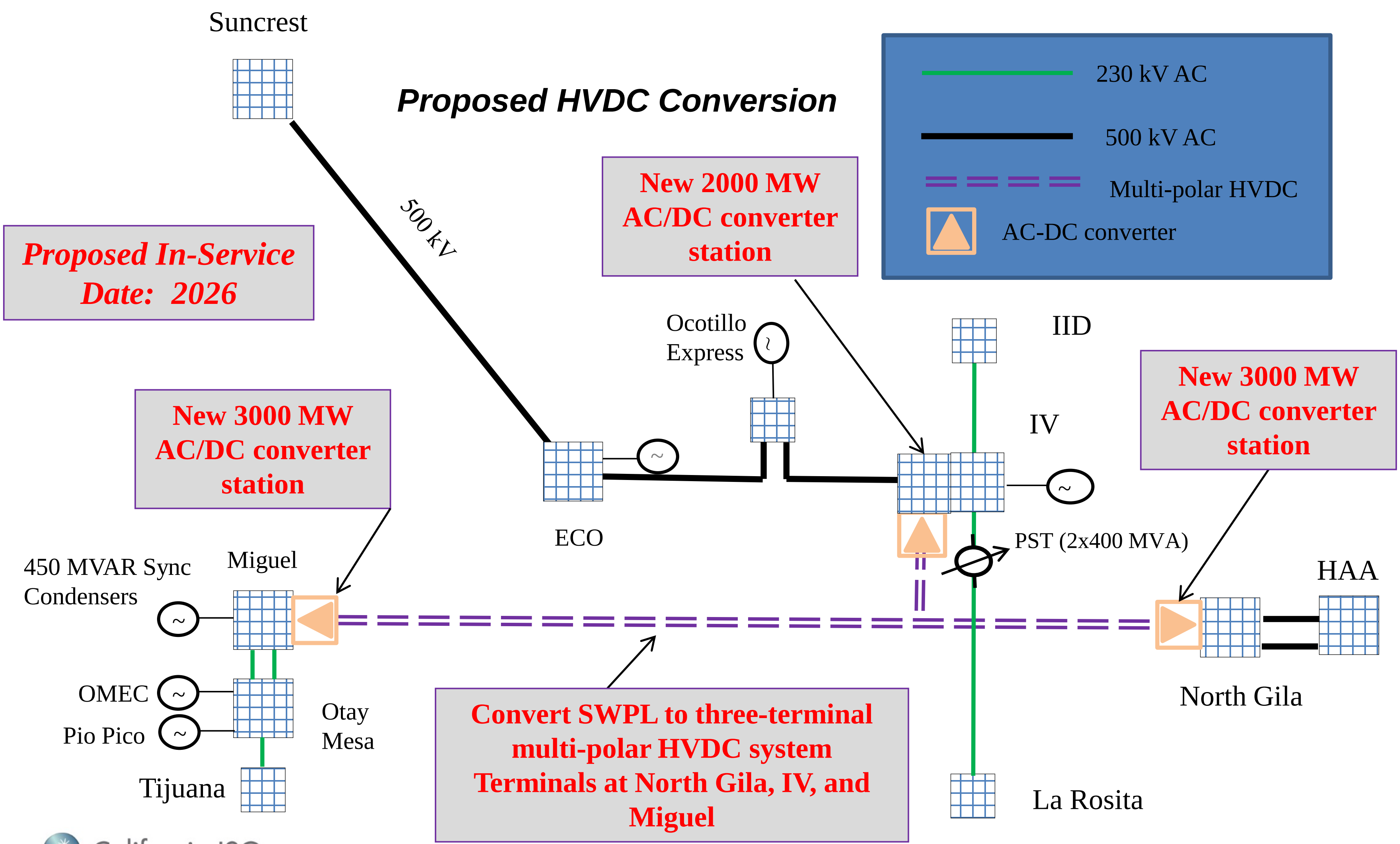
Renewable Energy Express HVDC Conversion Project



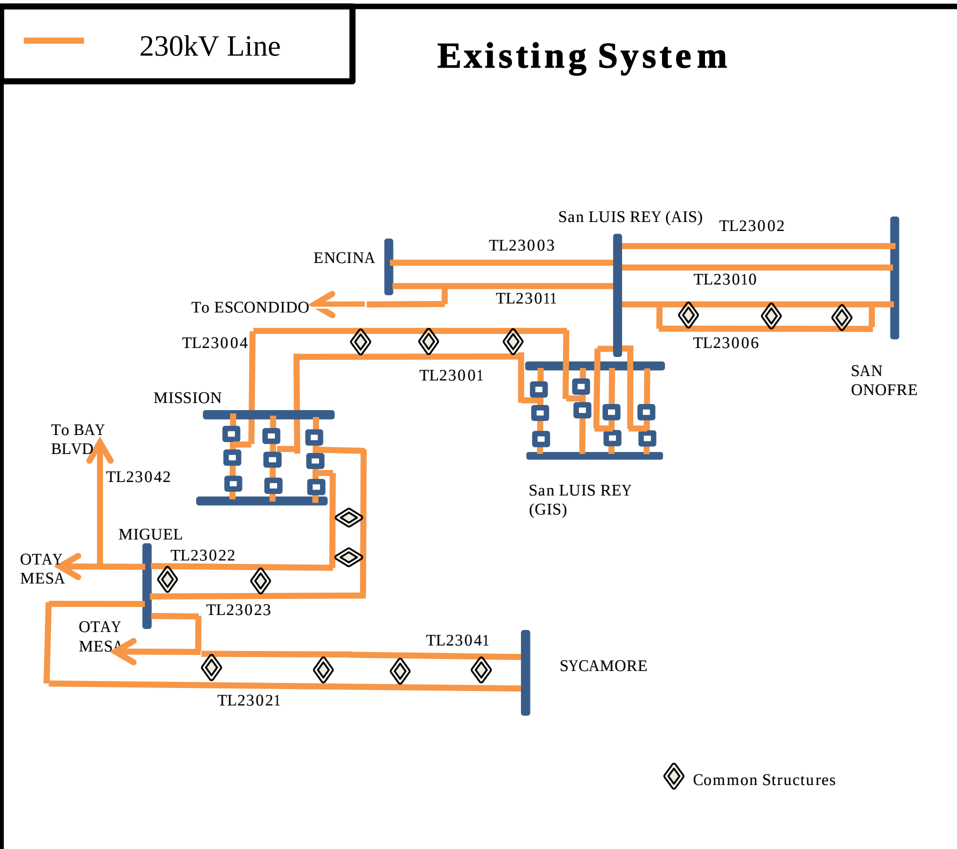
Renewable Energy Express HVDC Conversion Project

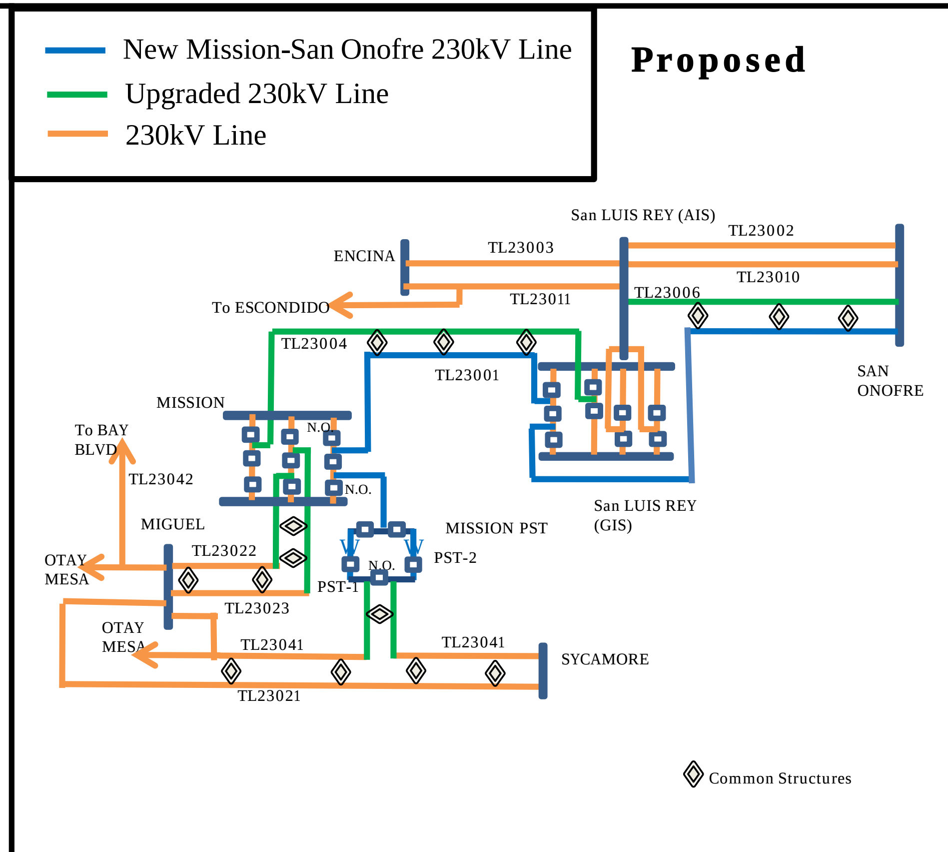
- Convert a portion of the 500 kV Southwest Powerlink (SWPL) to a three-terminal HVDC system with two fully independent poles
- Install terminals at or adjacent to North Gila, Imperial Valley, and Miguel Substations
- Each pole will be capable of fully independent operation at its maximum rated capacity
- The proposed capacity of the proposed HVDC system is 2x1500 MW, bi-directional, for a total transfer capacity of 3000 MW
- Replace existing loop-in of Southwest Powerlink at ECO with Sunrise Powerlink to replace AC connectivity
- The estimated capital cost is between $1 billion - $2 billion

Renewable Energy Express HVDC Conversion Project



Southern California Regional LCR Reduction Project





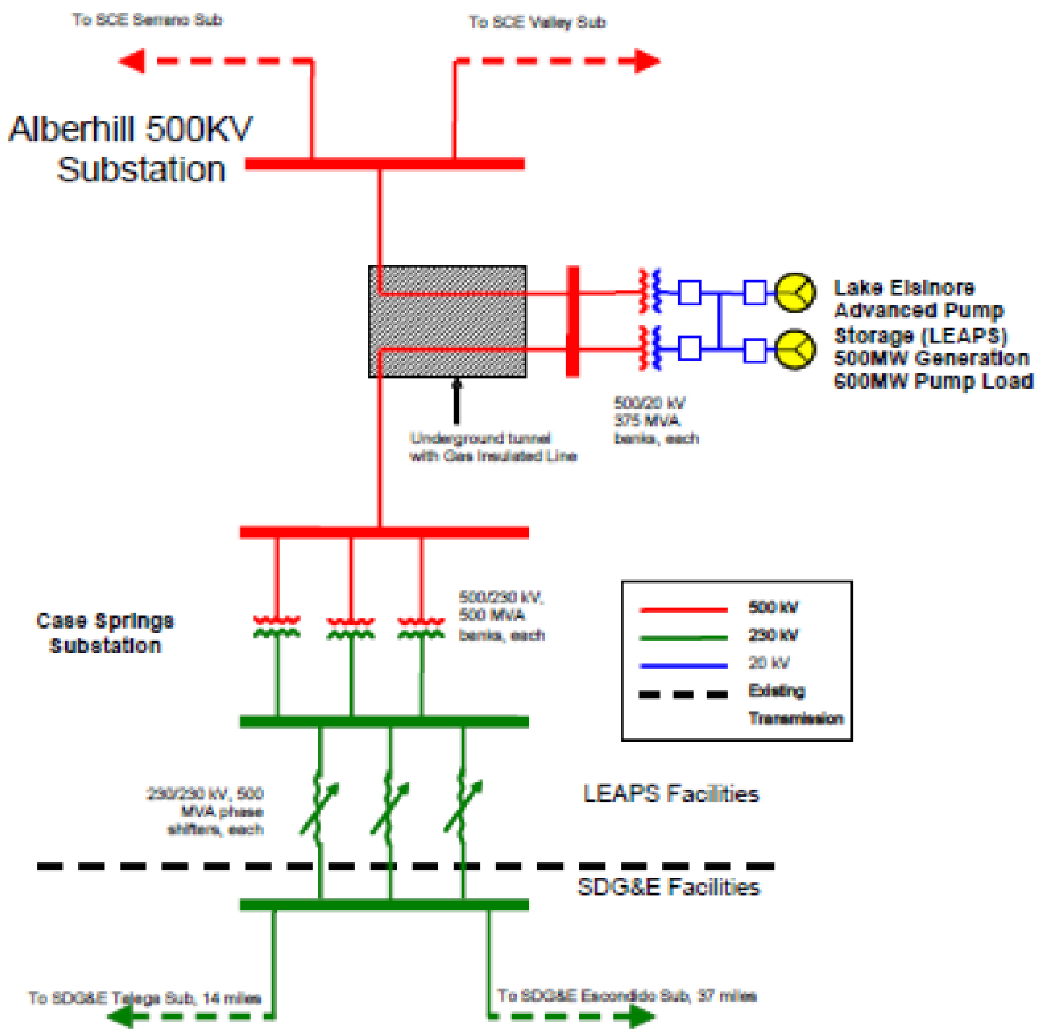
<u>SDG&E-proposed project objectives:</u>

- To provide LCR reduction and congestion mitigation benefits

<u>Scope:</u>

- Construct a new 230kV line (2-1033ACSR), Mission-San Luis Rey- San Onofre, by utilizing the existing 230kV facilities. Convert half of the existing 138kV switchyard (Bay 5 to Bay 9) to a 230kV Phase Shifter Station at Mission Substation (2–600MW PSTs). Upgrade TL23004 (Mission-San Luis Rey), TL23006 (San Onofre-San Luis Rey), TL23022 (Miguel-Mission), and TL23023 (Miguel – Mission) with bundled 1033ACSR.

LEAPS – Lake Elsinore Advanced Pump Storage Project (Option 1 - Connection to SCE and SDG&E)



<u>Option 1: SCE/SDG&E Connections</u>

This option interconnects the project at two points:

(i) SCE's transmission system at the proposed Alberhill 500 kV substation (If Alberhill is not approved, the connection point will be roughly one mile to the north-west at the proposed Lake Switchyard location), and

(ii) SDG&E's transmission system by looping in the Talega – Escondido 230 kV line via the proposed Case Springs 230 kV substation.

The LEAPS project will consist of

(a) 500 / 600 MW advanced pumped storage facility,

(b) two new 500 kV interconnecting transmission lines,

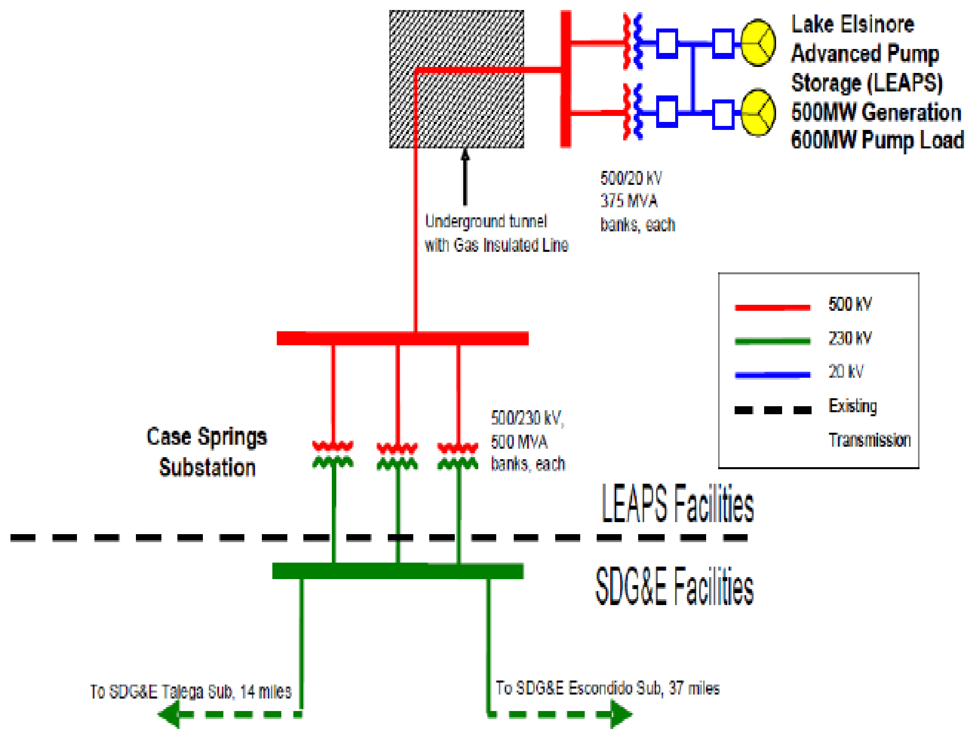
(c) two new 500 kV substations,

(d) three new 500/230 kV transformers, and

(e) three new 230kV phase shifting transformers.

Approximate Project Cost = $2.04 billion

LEAPS – Lake Elsinore Advanced Pump Storage Project (Option 2 - Connection to SDG&E only)



Option 2: SDG&E Connection Only

This option interconnects the project at one point of interconnection:

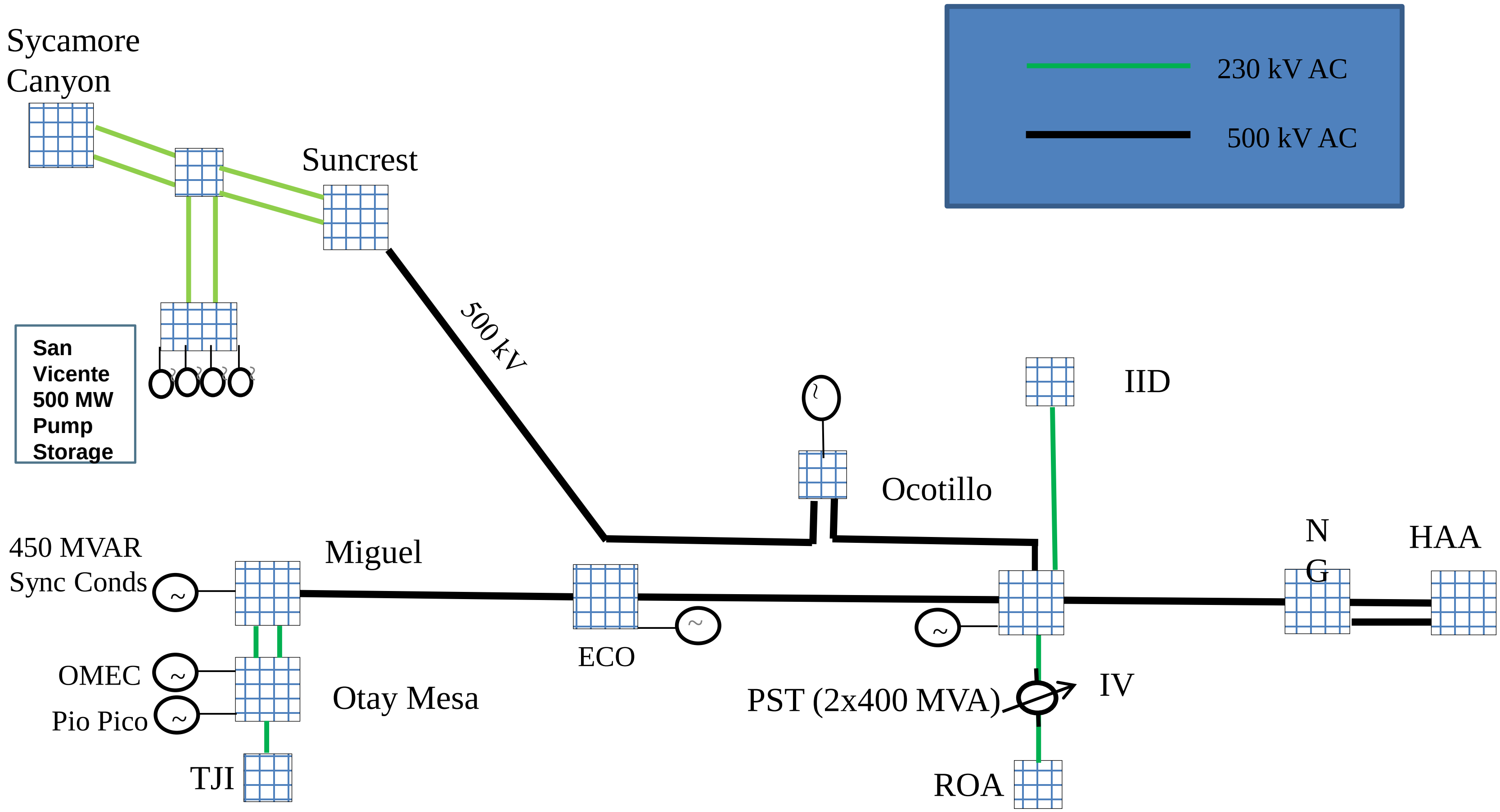
(i) SDG&E's transmission system by looping in the Talega – Escondido 230 kV line via the proposed Case Springs 230 kV substation.

The LEAPS project will consist of

(a) 500 / 600 MW advanced pumped storage facility,
(b) one new 500 kV interconnecting transmission line,
(c) one new 500 kV substation,
(d) three new 500/230 kV transformers

Approximate Project Cost = $1.76 billion

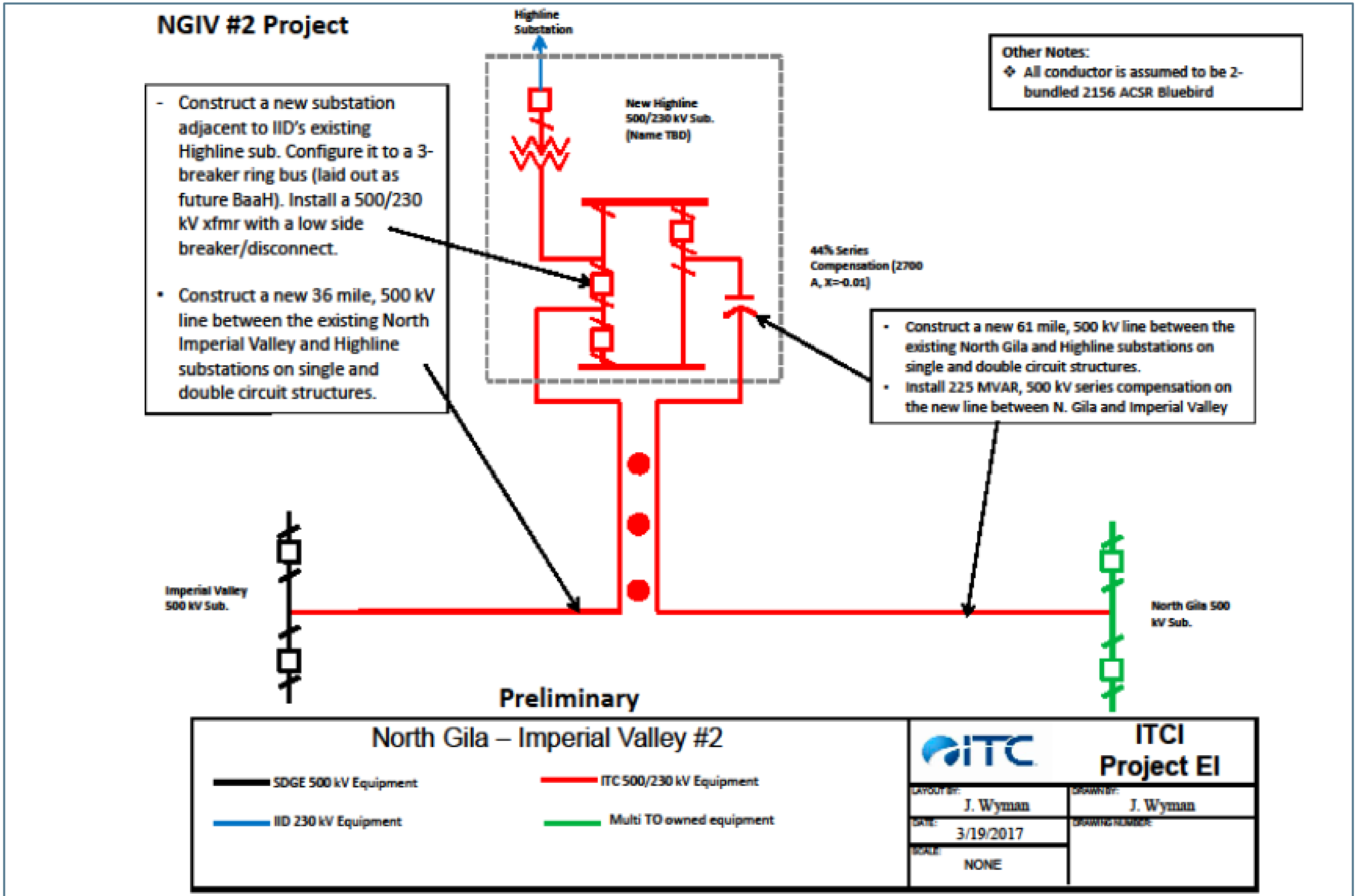
San Vicente Energy Storage Facility



The project consists of the following:

- Four (4) generating units connected into a central 230 kV switchyard via four separate step-up transformers
- Two 230 kV lines connect the project switchyard to a switching station looping into both circuits of the ISO controlled and SDG&E-owned Sycamore Canyon – Suncrest 230 kV lines.

North Gila – Imperial Valley #2 500kV Line



ISO-considered transmission and preferred resource options (cont'd)

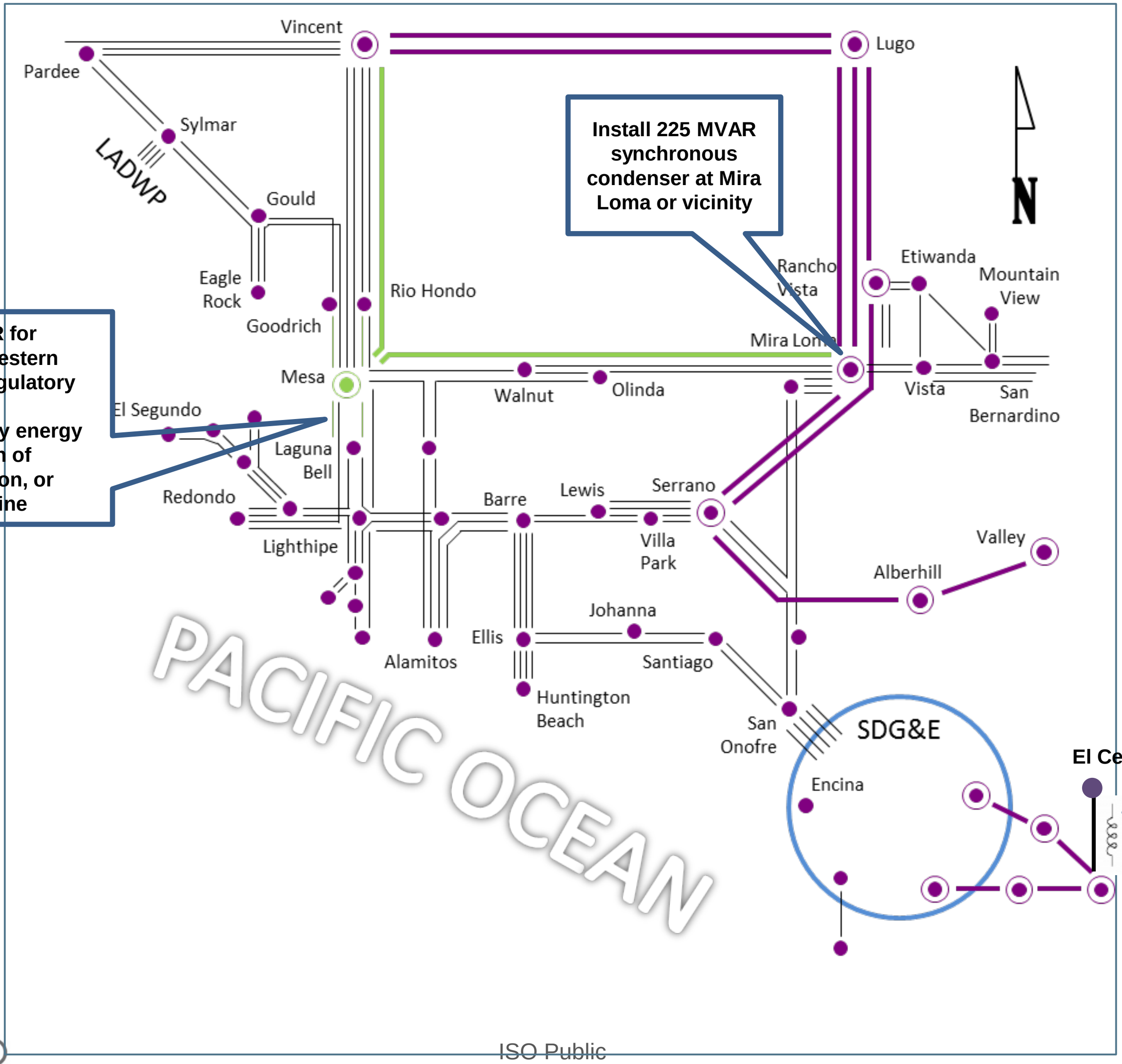
- The ISO is considering the potential cost-effective and minimal environmental impact transmission upgrades for helping to reduce further gas-fired generation requirements in the San Diego subarea/San Diego-Imperial Valley area and the Eastern LA Basin subarea (see the summary table on next slide).
- Please note that these are preliminary assessments subject to further refinement with future new load forecast and whether there are further unexpected generation retirements in the study areas.
- Reduction of LCR resources in the San Diego subarea and San Diego-Imperial Valley area affects the transmission line loadings in the western LA Basin. This will require mitigations as summarized in the table on next slide.
- For the potential utilization of “slow” demand response in the western LA Basin, please note that the suggested potential utilization of “slow” demand response program in the western LA Basin is contingent on further market and regulatory implementation feasibility.
- If the above option is not feasible, other potential options may include installation of battery energy storage system (approximately 200 MW), or 230kV line reconductoring if permitting is feasible.

ISO-considered transmission and preferred resource options

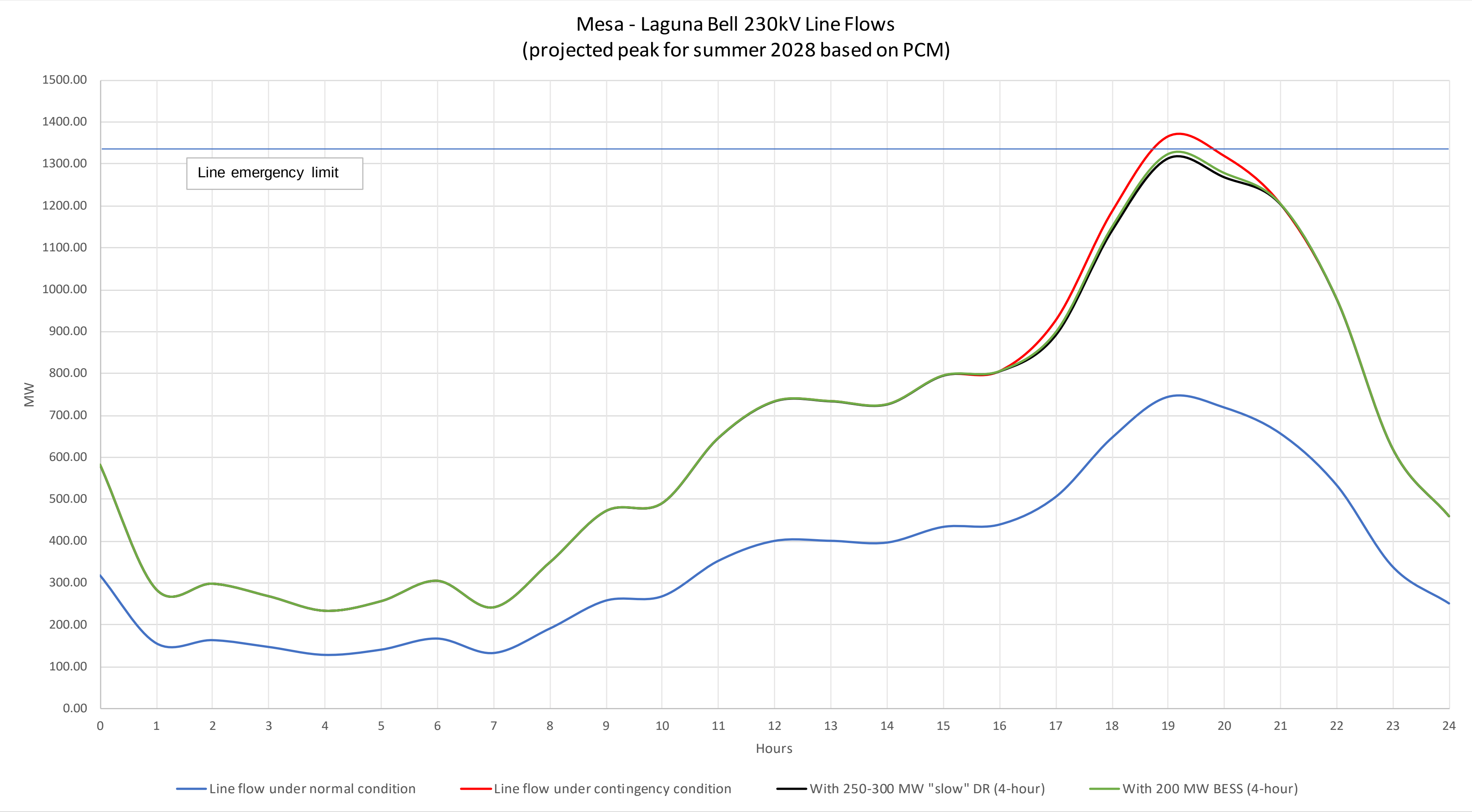
LCR area/Subarea	Potential LCR reduction options	Potential gas-fired resource reduction (MW)	Comments
Overall San Diego-Imperial Valley Area and San Diego subarea	1. Install an equivalent of 25-Ω line series reactor on the upgraded S-line (2x50-Ω if there are 2 lines in parallel); ***and*** 2. Utilize the existing RAS and Imperial Valley phase shifters for mitigating the Sycamore Canyon – Suncrest 230kV line in the San Diego bulk transmission subarea; ***and*** 3. The following are potential mitigations for mitigating the Mesa – Laguna Bell 230kV loading concern in the Western LA Basin: a. Implement the use of "slow" DR (~ 250 – 300 MW) for pre-contingency purpose, ***or if not feasible***, b. Install 200 MW of battery energy storage system in the western LA Basin, ***or*** c. Reconductor Mesa-Laguna Bell 230kV line	Approximately 500 – 600 MW in the San Diego subarea / overall San Diego-Imperial Valley area	Reducing LCR needs in the San Diego subarea and San Diego-IV area affect the western LA Basin subarea; therefore, mitigation (for line loading) is needed in the western LA Basin.
Eastern LA Basin Subarea	- Install approximately 225 MVAR synchronous condenser at Mira Loma 500kV substation	Approximately 350 MW in the Eastern LA Basin subarea	Optimal location can be evaluated further

ISO-considered transmission and preferred resource options (cont'd)

1) Implement "slow" DR for contingency in the western LAB if market and regulatory feasible, or
2) Install 200 MW battery energy storage system south of Laguna Bell Substation, or
3) Reconductor 230kV line



Mesa-Laguna Bell 230kV Line Flows for Various Preferred Resource Options



Next steps

- The ISO will complete LCR analyses for Request Window project submittals to quantify local capacity reduction benefits
  - The study results will be included in the draft 2018-2019 Transmission Plan for informational purpose at this time
- The study results for considered LCR areas/subareas will be reviewed and compared with other studies (i.e., system/flexible capacity requirements) to determine if there are adverse impact or if not, whether there are further economic benefits and justifications for moving forward with some of these considered and evaluated options

Back-up Document

Recap of Overall LA Basin 2028 LCR (*for information purpose*)

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2028	First Limit (IV solar gen at NQC)	C	Mesa – Laguna Bell #1 230 kV line	N-1 of Mesa – Redondo 230 kV line, system readjustment, followed by N-1 of Mesa -Lighthipe 230 kV line out	6,590*
2028	First Limit (solar gen at NQC)	B	El Centro 230/92 kV transformer thermal loading	G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500kV line (N-1)	5,526 MW*
2028	Second Limit (solar gen at NQC)	B	Mesa – Laguna Bell #1 230kV line	G-1 of Huntington Beach CCGT, followed by N-1 of Mesa – Laguna Bell #2 230kV line	5,326 MW*
2028	First Limit (No IV solar generation**)	B/C	El Centro 230/92 kV transformer thermal loading	G-1 of TDM generation, system readjustment, followed by Imperial Valley-North Gila 500kV line (N-1)	6,874 MW*

Notes:

*This includes 294 MW of 20-minute DR, 432 MW of CPUC-approved LTPP LCR preferred resources, 62 MW of existing BESS, 45 MW PRP DR, 60 MW PRP BESS

**This is due to peak shift to later hour (i.e., 20:00 hrs.) for San Diego area

Local Capacity Requirements Potential Reduction Study San Diego-Imperial Valley Non-bulk Subarea

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Senior Regional Transmission Engineer

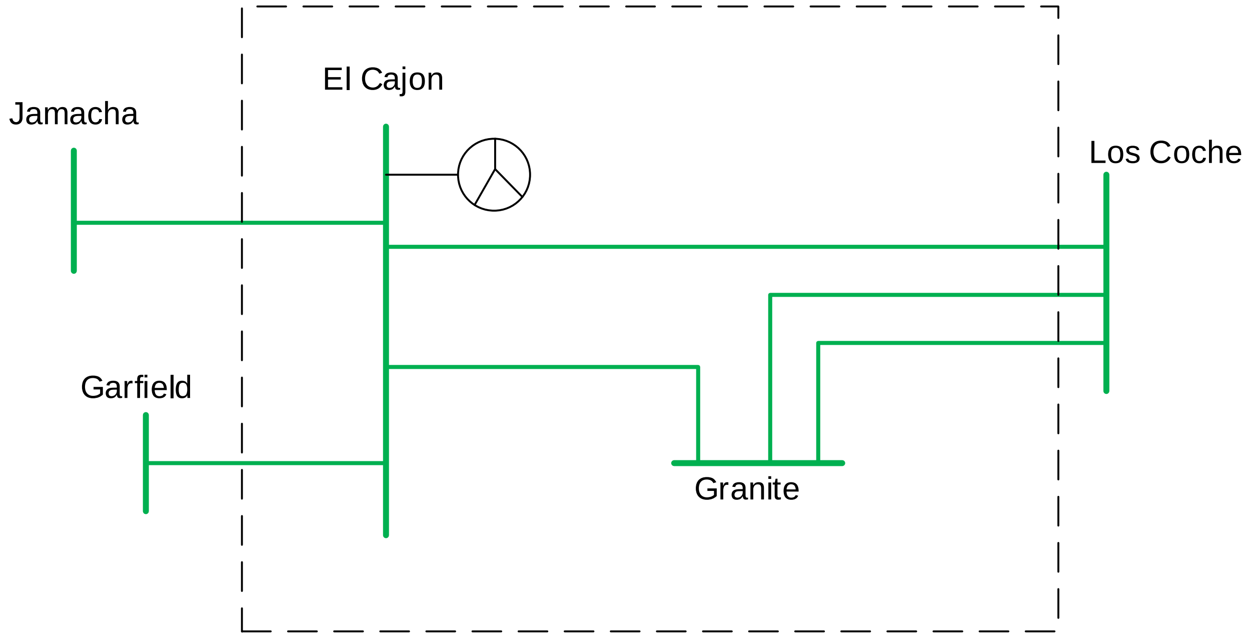
2018-2019 Transmission Planning Process Stakeholder Meeting
November 16, 2018

LCR Subareas Selected for Study

- The 2028 long-term LCR study has identified LCR requirement for the El Cajon, Pala and Border subareas.
- All of these three areas are selected for LCR reduction study
- The ISO has received a few Request Window Submissions that would eliminate/reduce LCR requirements. All of the submissions would be evaluated along with other alternatives

LCR Areas / Subareas
El Cajon
Pala
Border

El Cajon Subarea



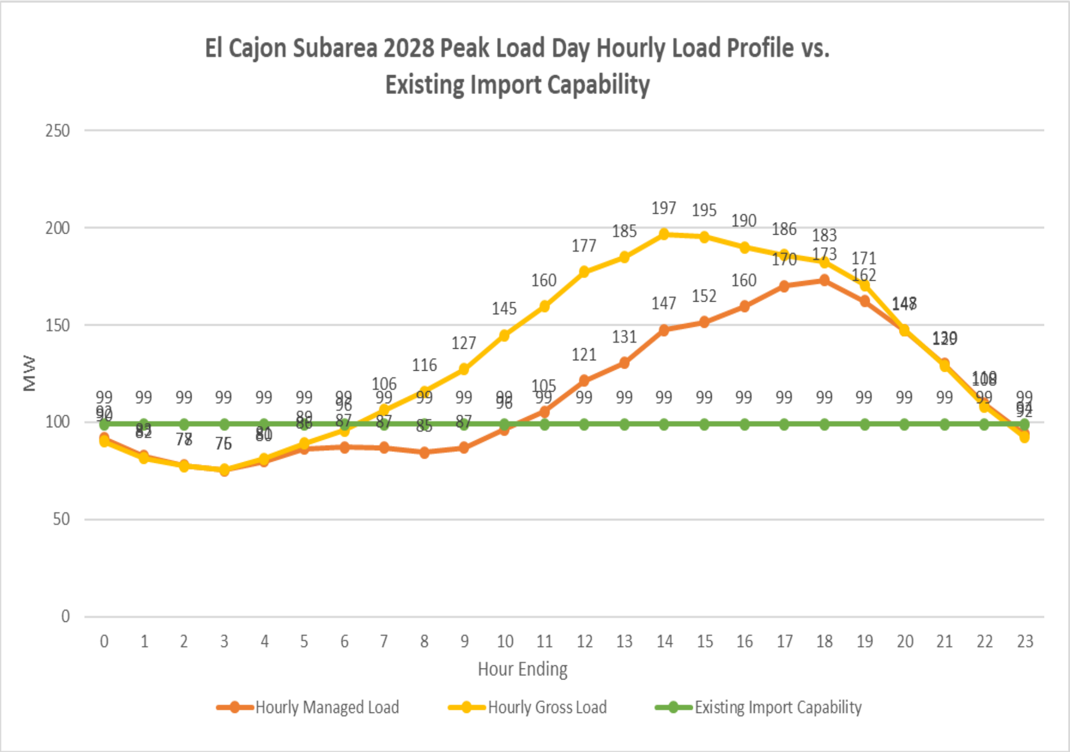
Load and Resources (2028)

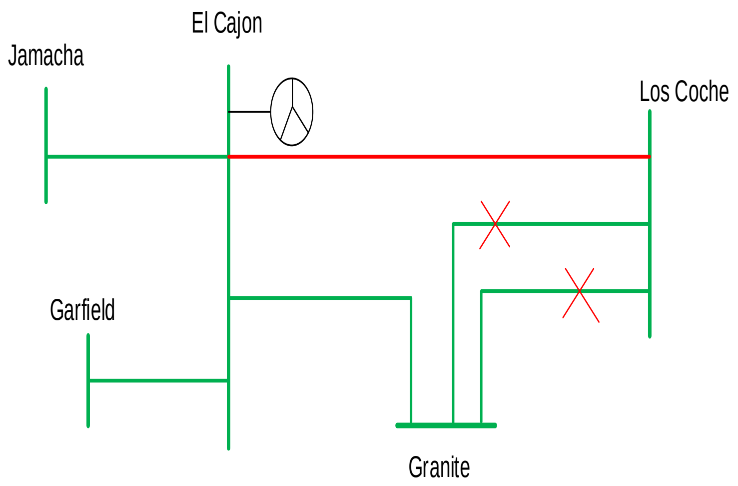
Loads (MW)		Resources (MW)	
Gross Load	177	Market (including solar generation)	93.52
AAEE + AAPV	-6	Wind	0
Behind the meter DG (production)	0	Muni	0
Net Load	**171**	QF	0
Transmission Losses	2	Future preferred resource assumptions (EE, DR)	2.5
Loads + Losses	**173**	Existing 20-Minute Demand Response	4.28
		Total battery energy storage procurement to date	7.5
		Total Qualifying Capacity	**107.8**

LCR Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2028	First Limit	B	None	None	0
2028	First Limit	C	El Cajon-Los Coches 69kV Line	Granite-Los Coches 69kV Nos. 1&2	76

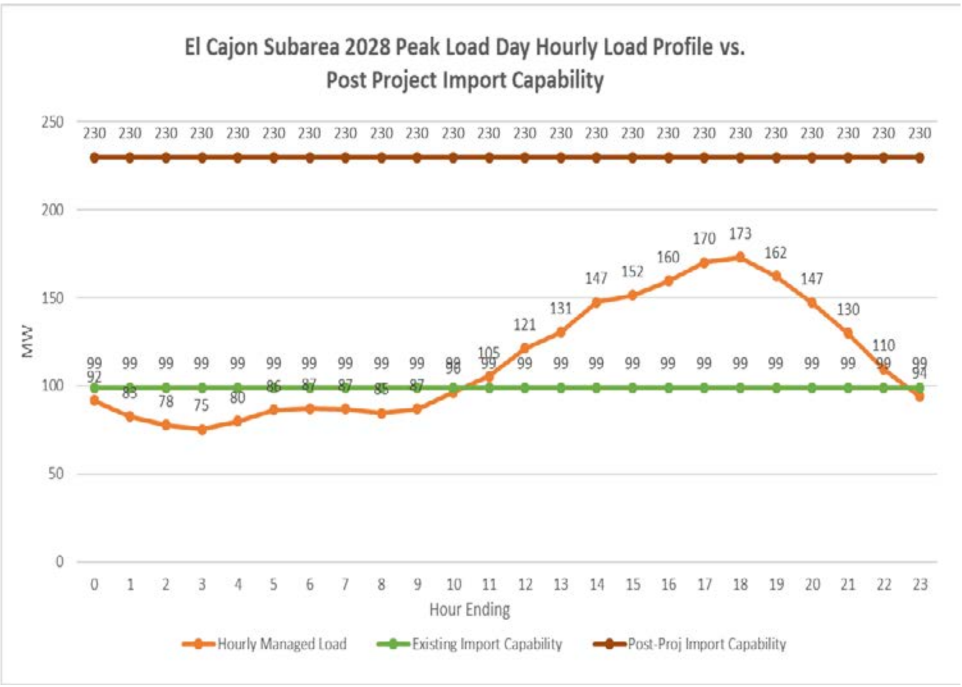
El Cajon Subarea Load Profiles vs. Existing Transmission Import Capability

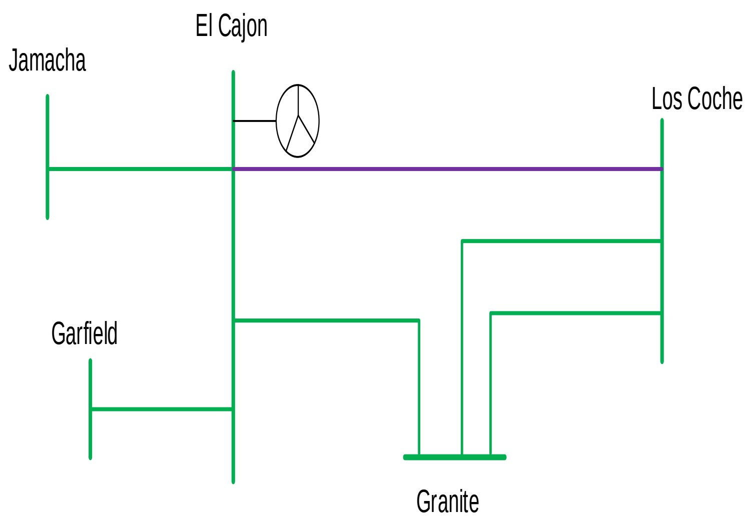




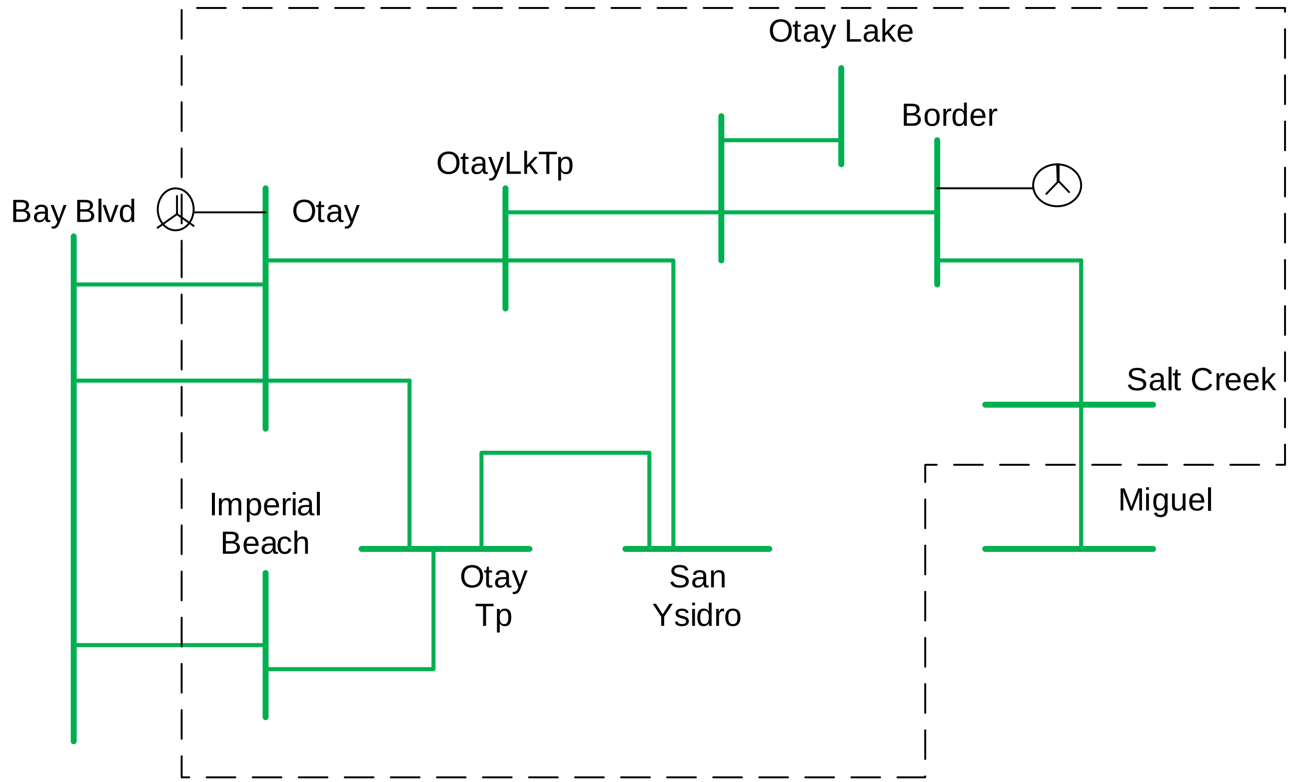
Potential LCR Reduction Alternative

- SDG&E submitted a Request Window Submission to upgrade Los Coches-El Cajon 69kV line to a minimum continuous rating of 77MVA and emergency rating of 90MVA. This alternative would be able to eliminate the LCR need.





Border Subarea



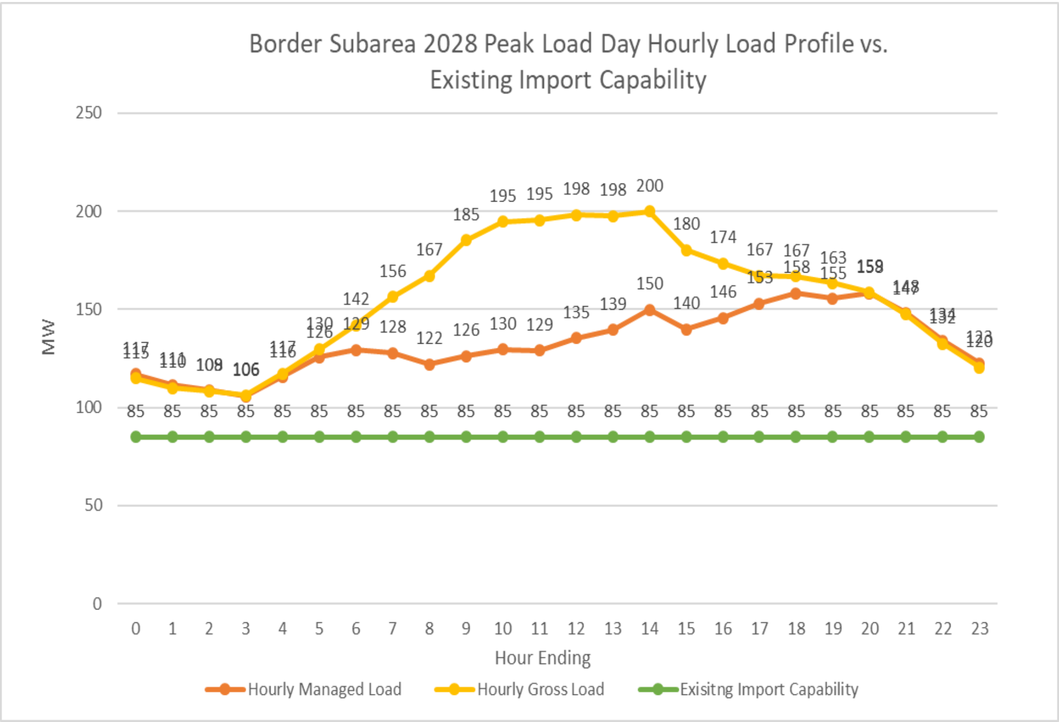
Load and Resources (2028)

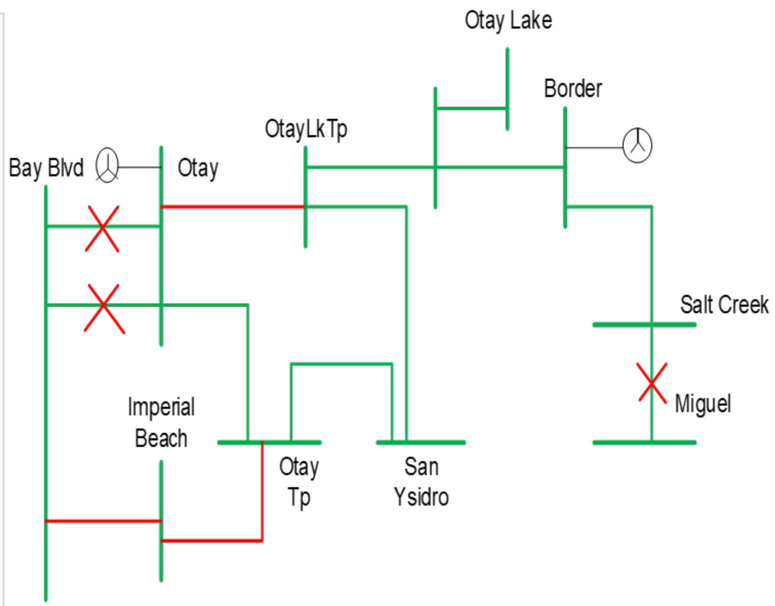
Loads (MW)		Resources (MW)	
Gross Load	175.14	Market (including solar generation)	177.66
AAEE + AAPV	-17.3	Wind	0
Behind the meter DG (production)	0	Muni	0
Net Load	**157.84**	QF	1.78
Transmission Losses	0.46	Future preferred resource assumptions (EE, DR)	0
Loads + Losses	**158.3**	Existing 20-Minute Demand Response	0
		Total battery energy storage procurement to date	0
		Total Qualifying Capacity	**179.44**

LCR Requirements

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW)
2028	First Limit	B	Otay-Otay Lake Tap 69kV line	Miguel-Salt Creek 69kV line	14
2028	First Limit	C	Imperial Beach-Bay Boulevard 69kV line	Loss of Bay Boulevard-Otay 69kV Nos.1&2 lines	70
2028	Second Limit	C	Imperial Beach-Otay TP	Loss of Bay Boulevard-Otay 69kV Nos.1&2 lines	18

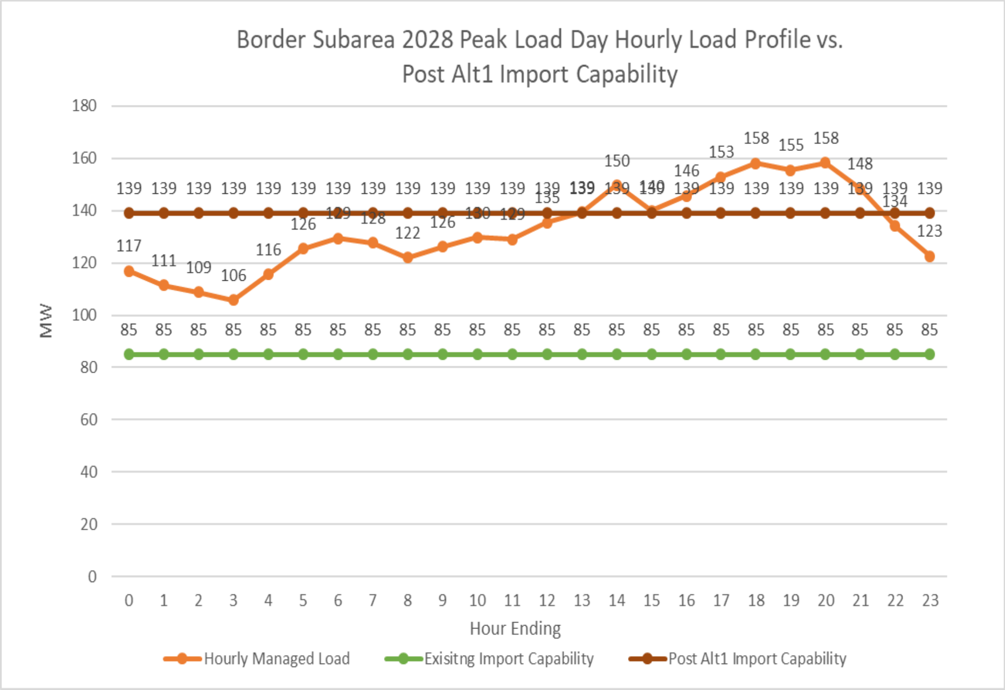
Border Subarea Load Profiles vs. Existing Transmission Import Capability

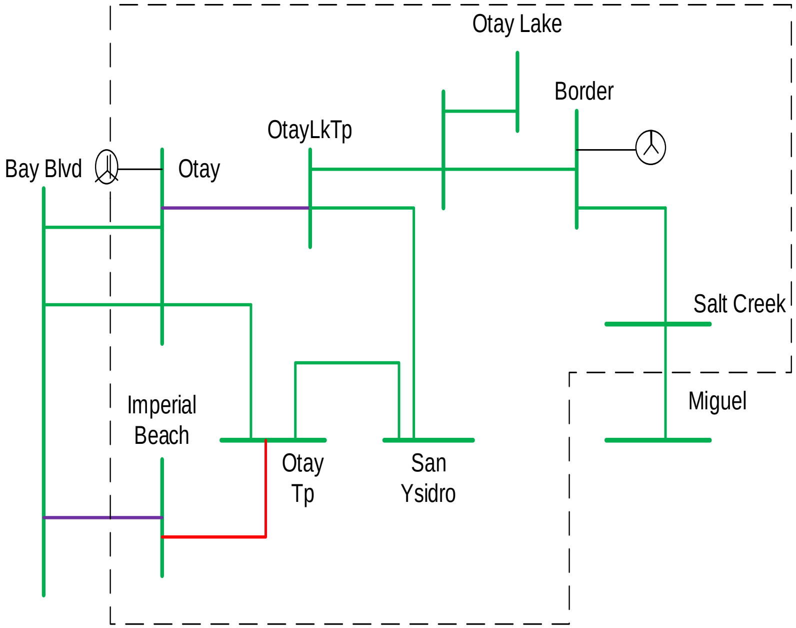




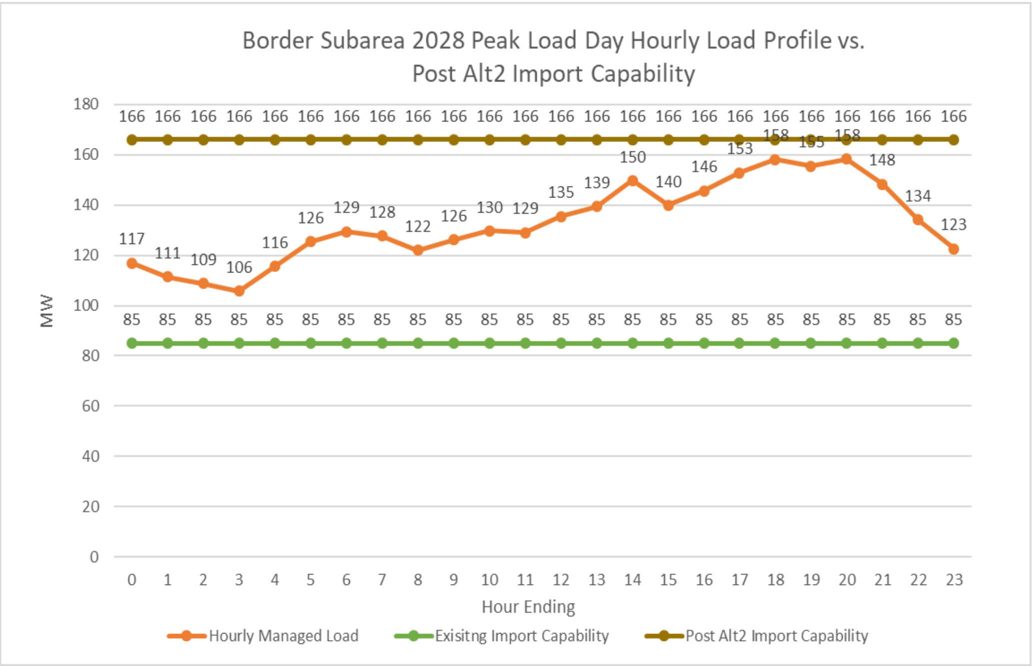
Potential LCR Reduction Alternatives

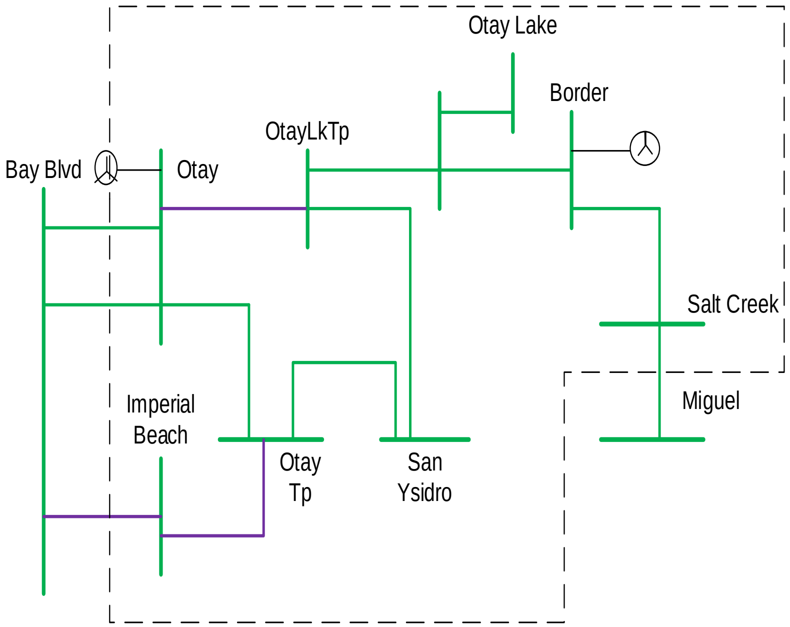
- **Alternative 1**: SDG&E submitted two Request Window Submissions to reconductor the Imperial Beach-Bay Blvd 69kV line to a minimum continuous rating of 110MVA and to reconductor the Otay-Otay Lake Tap to a minimum continuous rating of 64MVA. With these two projects, the LCR would be reduced to 18MW. The LCR requirement would be limited by the Imperial Beach-Otay TP line.



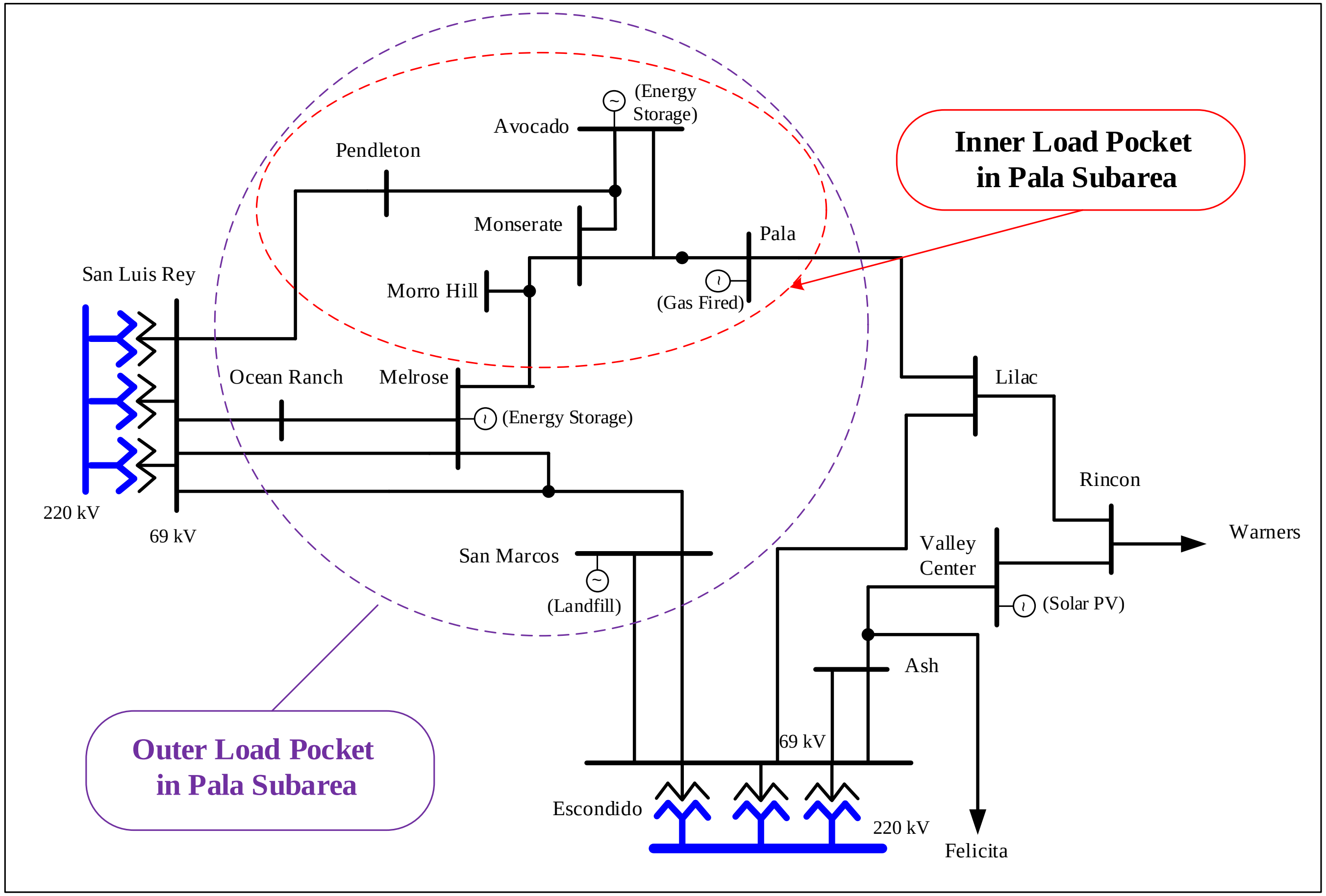


- **Alternative 2**: In addition to reconductoring the Imperial Beach-Bay Blvd and Otay-Otay Lake Tp lines, reconductor the Imperial Beach-Otay TP line to a minimum continuous rating of 110MVA. With all three line sections upgraded, the Border LCR requirement could be eliminated.





Pala Subarea



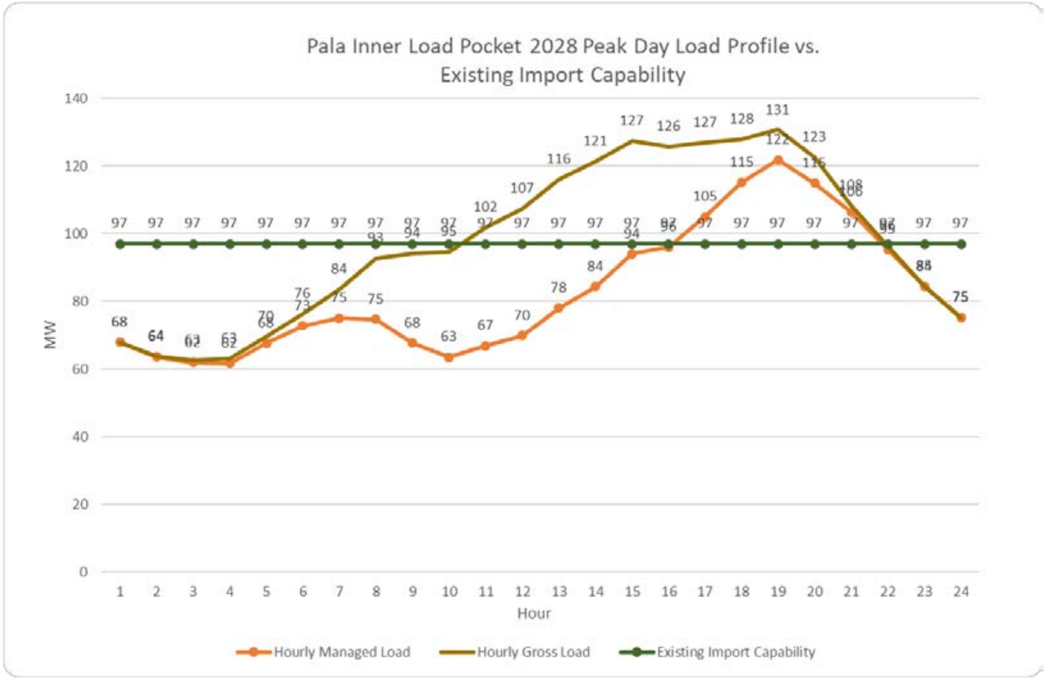
Load and Resources (2028)

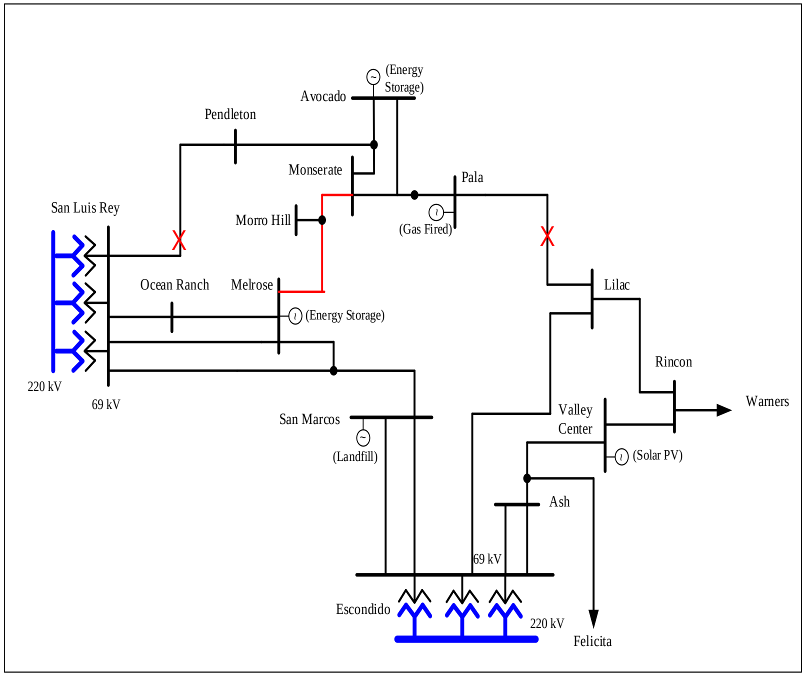
		Inner Load Pocket in Pala Sub-area	Outer Load Pocket in Pala Sub-area	Pala Sub-area
Load (MW)	Gross Load	130.6	325.0	462.0
	AAEE + AAPV	-8.1	-20.4	-29.0
	Behand-The-Meter PV	0.0	0.0	0.0
	Transmission Loss	0.7	1.5	2.0
	Net Load	121.8	303.1	431.0
Resources (MW)	Gas-Fired	99.8	99.8	99.8
	Solar PV	0.0	0	14.5
	Wind	0.0	0	0.0
	Landfill	0.0	1.5	1.5
	Energy Storage	40.0	80	80.0

LCR Requirements for Pala Inner Load Pocket

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2028	First Limit	B	None	None	0
2028	First Limit	C	Melrose-Morro Hill Tap-Monstrate 69kV line	Pendleton-San Luis Rey 69kV and Lilac-Pala 69kV lines	26

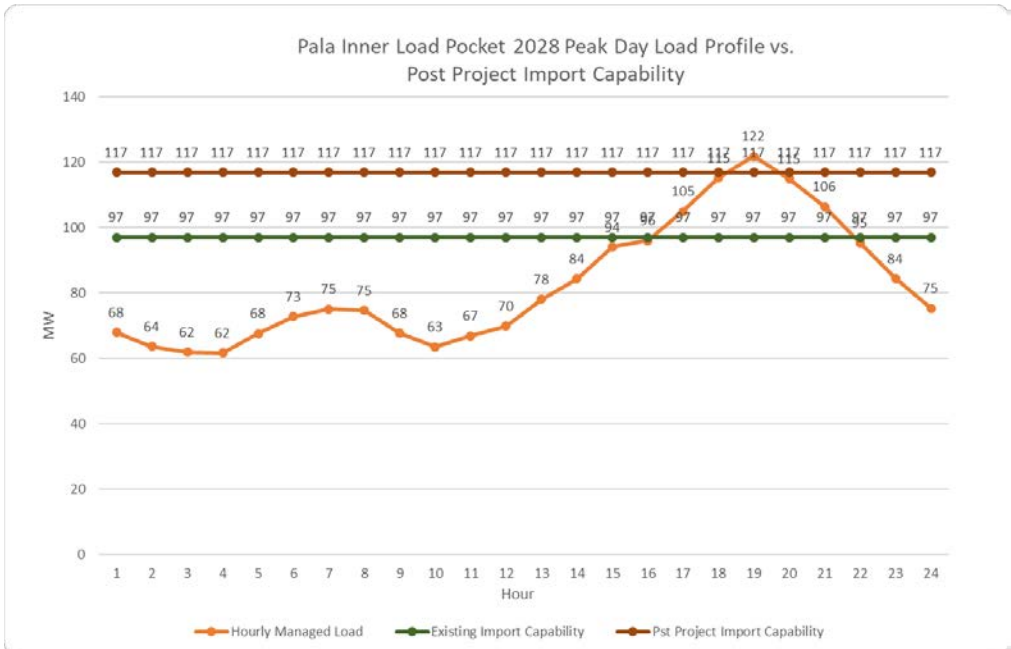
Pala Inner Pocket Load Profiles vs. Existing Transmission Import Capability

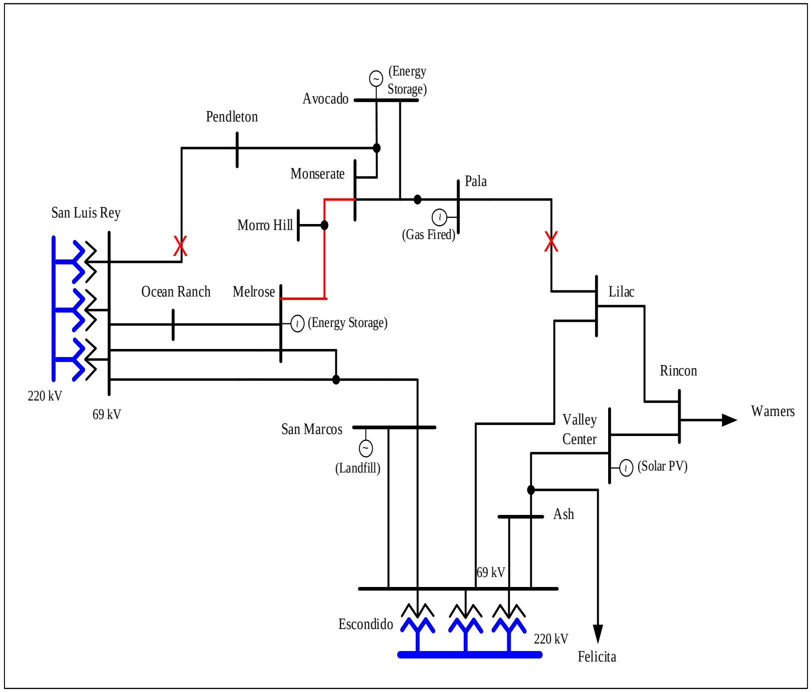




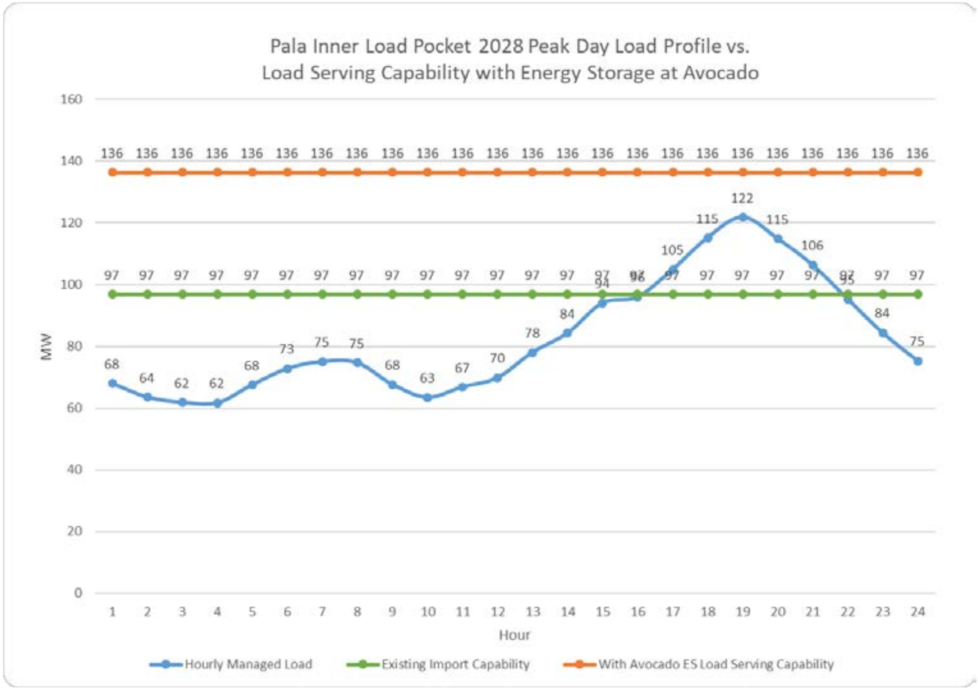
Potential Alternatives to Reduce/Displace the LCR for Gas Generation

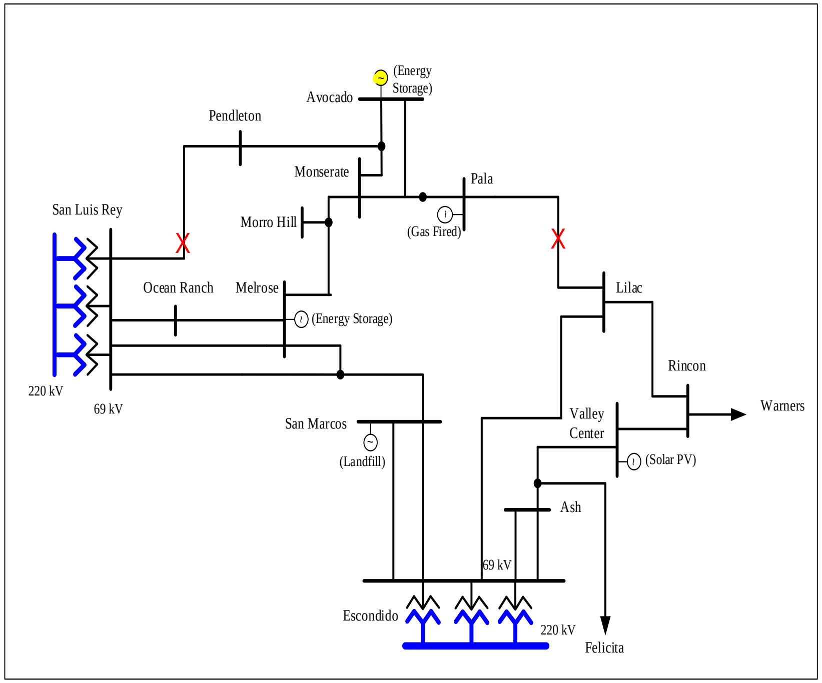
- **Alternative 1**: SDG&E submitted a Request Window Submission to upgrade Melrose-Morro Hill Tap to a minimum continuous rating of 127MVA and to upgrade Monstrate-Morro Hill Tap to a minimum continuous rating of 114MVA. This alternative could reduce the LCR requirement from 26MW to 4MW for the inner load pocket.





- **Alternative 2**: Rely on the existing 40MW battery storage at Avocado to displace the need for the gas generation at Pala. This alternative could potentially provide sufficient capacity and energy to meet the local LCR needs for the inner load pocket without the gas generation.

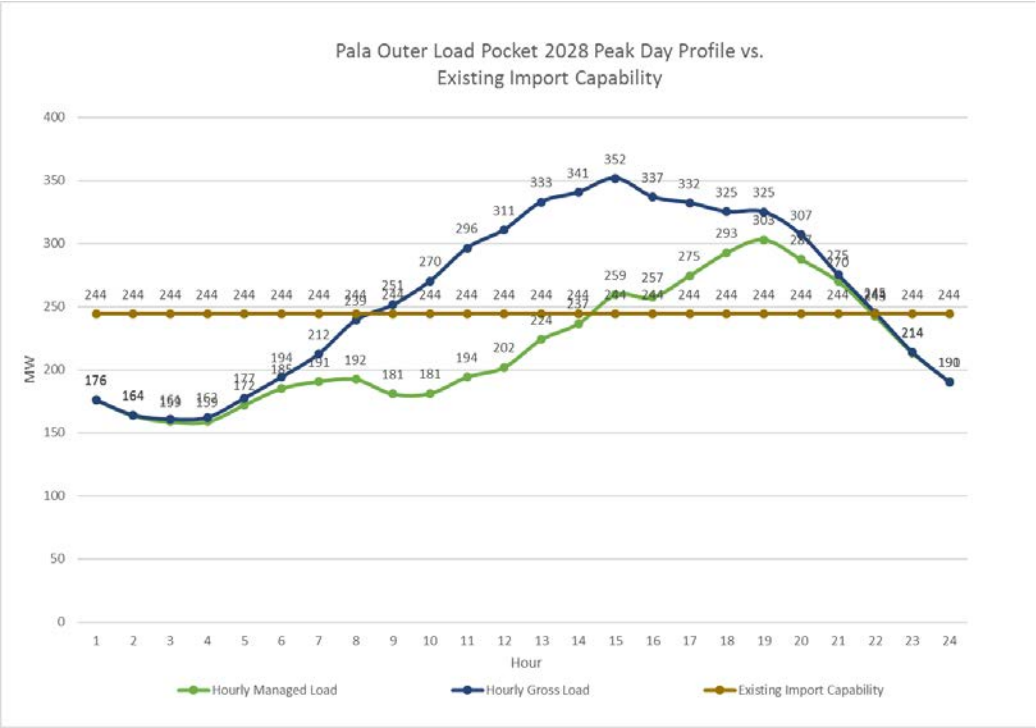


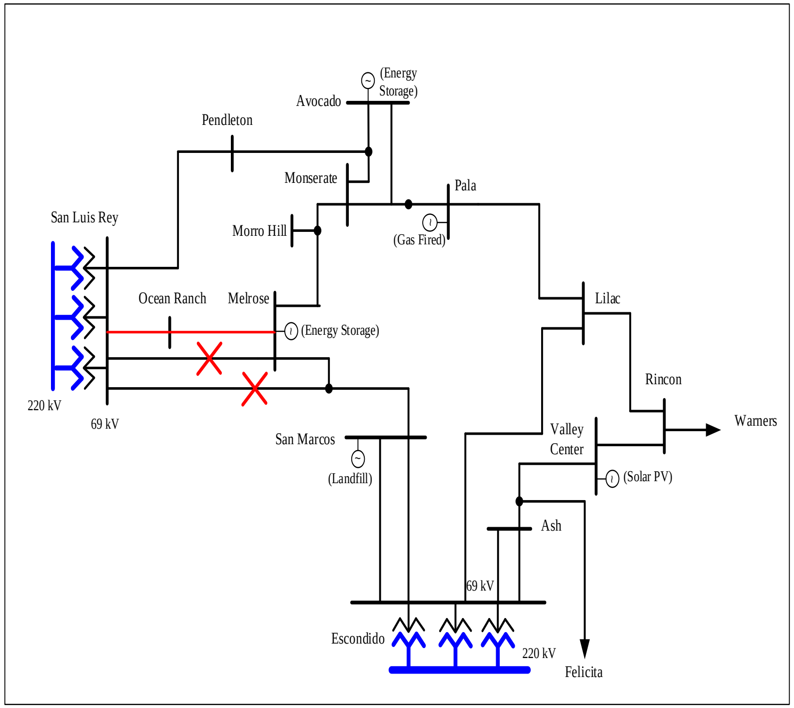


LCR Requirements for Pala Outer Load Pocket

Year	Limit	Category	Limiting Facility	Contingency	LCR (MW) (Deficiency)
2028	First Limit	B	None	None	0
2028	First Limit	C	San Luis Rey-Ocean Ranch-Melrose 69kV line	San Luis Rey-Melrose and San Luis Rey-Melrose-San Marcos 69kV lines	43

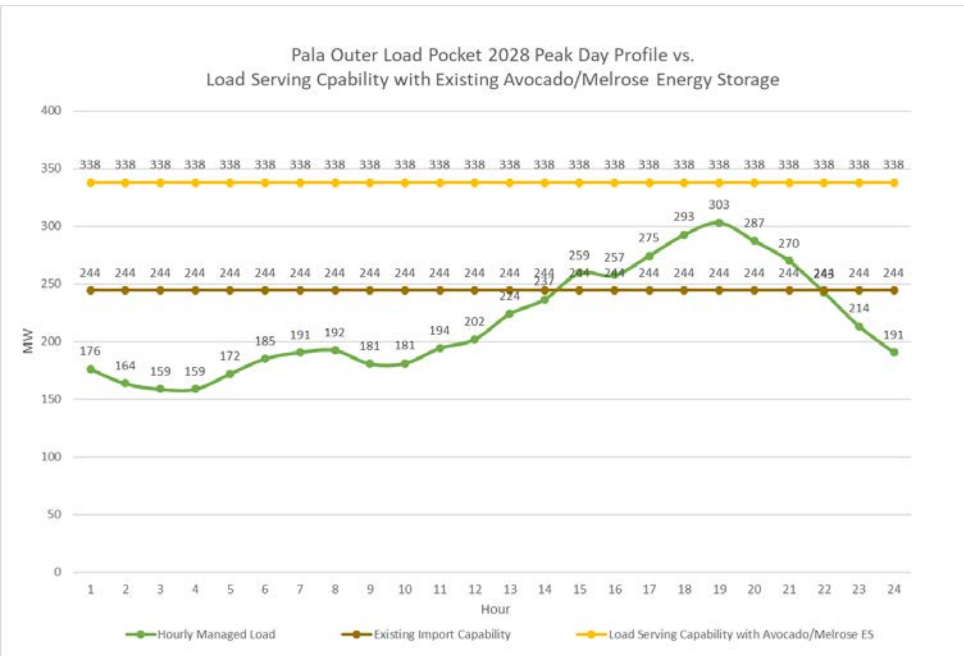
Pala Outer Pocket Load Profiles vs. Existing Import Capability

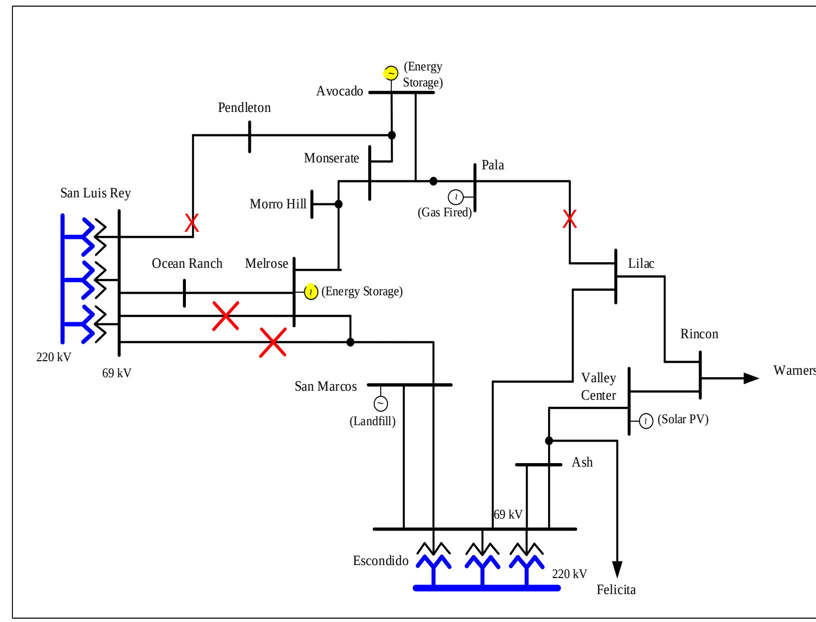




Potential Alternative to Displace the LCR Need for Gas Generation

- Rely on the existing 40MW energy storage at Melrose and 40MW energy storage at Avocado to displace the need for the gas generation at Pala. This alternative could potentially provide sufficient capacity and energy to meet the local LCR needs for the inner and the outer load pockets without the gas generation.





2018-2019 TPP Reliability Projects on Hold – PG&E Area

Binaya Shrestha
Regional Transmission Engineer Lead

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

Jefferson-Stanford #2 60 kV Line

Approved cycle:
- 2010-2011 TPP

Original scope:
- Build a new Jefferson- Stanford #2 60 kV line

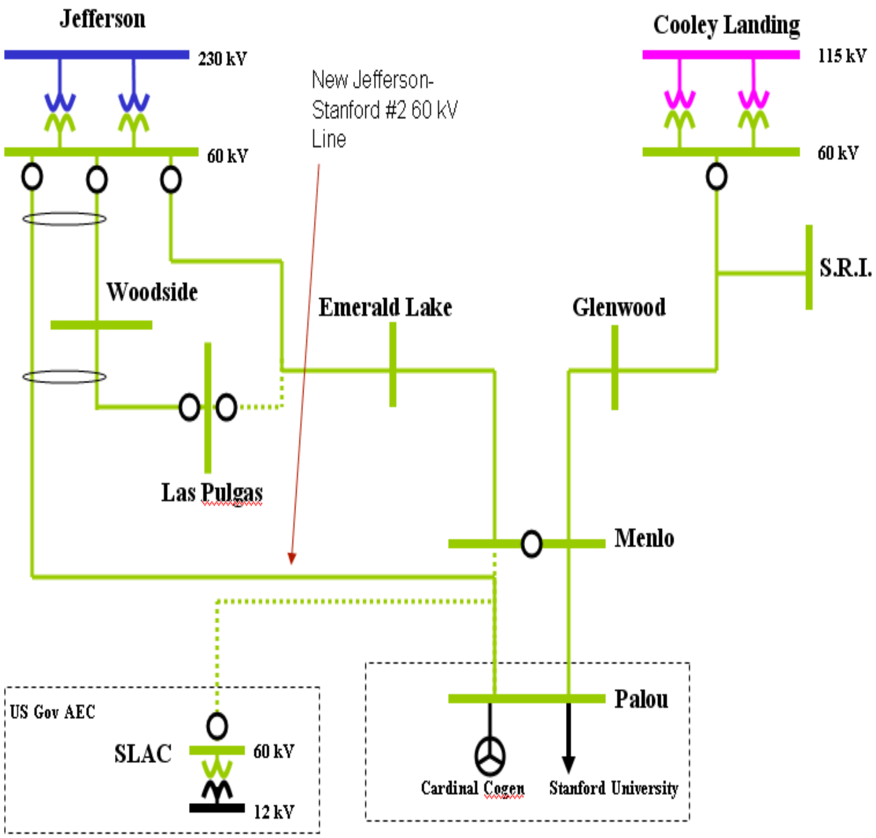
Project cost:
- Original cost: $25M-$35M
- Current estimated cost: $30M-$40M

Current In-service Date:
- On hold

Reliability Assessment Need:
- NERC Category P6 and P7 BES contingencies resulting in overloads on Peninsula 60 kV system.

Mitigation still required {or not}:
- Mitigation required for reliability

Recommendation:
- Cancel the Jefferson-Stanford #2 60 kV line project.
- Recommend SPS to drop load at Cooley landing for P6 overloads on Bair-Cooley Landing #1 & #2 60kV lines or operating solution to radialize the 60 kV system following the first T-1.
- Jefferson 230 kV bus upgrade for P7 overloads on Hillsdale-San Mateo-Jefferson 60 kV lines.
    - 230 kV BAAH Bay #3 ($5M-$9M)
    - Protection upgrade ($1M-$2M)
- Cost of proposed alternative: $6M-$11M



Morro Bay 230/115 kV Transformer Project (CCLP)

Approved cycle:
- 2010-2011 TPP

Original scope:
- Build a new Morro Bay 230/115 kV transformer

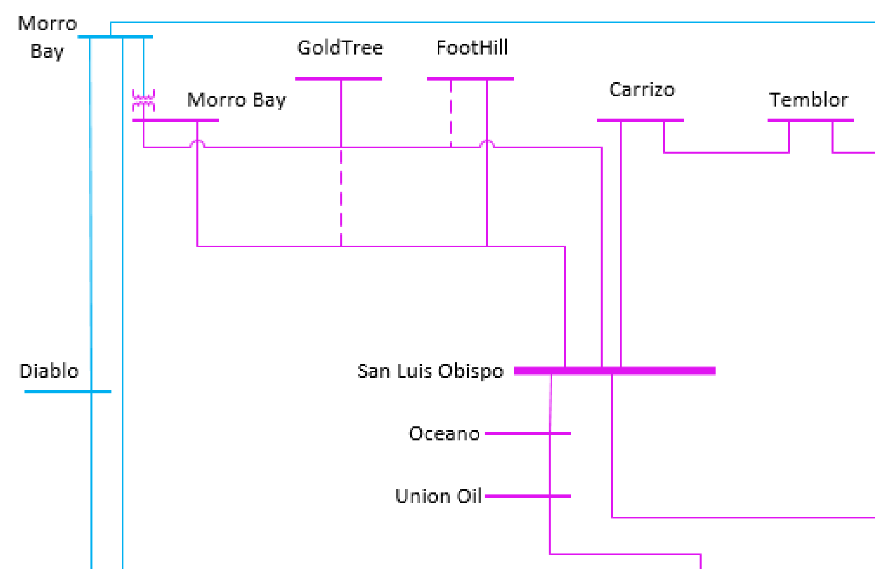
Project cost:
- Original cost: $8M-$10M
- Current estimated cost: $50M-$60M

Current In-service Date:
- On hold

Reliability Assessment Need:
- The reliability assessment identified no P0, P1, or P3 overloads in the area following the loss of the Morro Bay 230/115 kV transformer

Mitigation still required {or not}:
- None

Recommendation:
- Cancel the Morro Bay 230/115 kV transformer project.



Diablo Canyon Voltage Support Project (CCLP)

Approved cycle:
- 2012-2013 TPP

Original scope:
- Install a new static var compensator (SVC) or thyristor controlled switched capacitor bank rated at +150 MVAr at the Diablo Canyon 230 kV substation and construct the associated bus to provide voltage control and support for the Diablo Canyon Power Plant (DCPP)

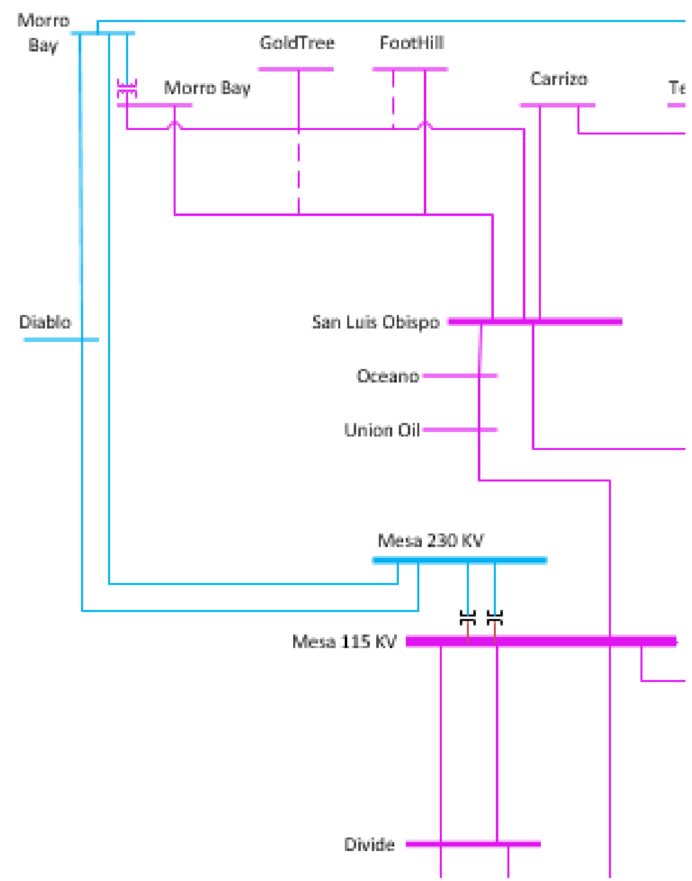
Project cost:
- Original cost: $35M-$45M
- Current estimated cost: $33M

Current In-service Date:
- On hold

Reliability Assessment Need:
- None

Mitigation still required {or not}:
- Comply with Nuclear Power interface requirements, NUC-001-3.

Recommendation:
- Since there are no reliability concerns in the area ISO recommends Canceling the Diablo Canyon Voltage support project.
- To meet NUC-001-3 requirements utilize Local RAS (such as Divide or Paso Robles UVLS) for mitigation until Diablo retires in 2025



Midway – Andrew Project (CCLP)

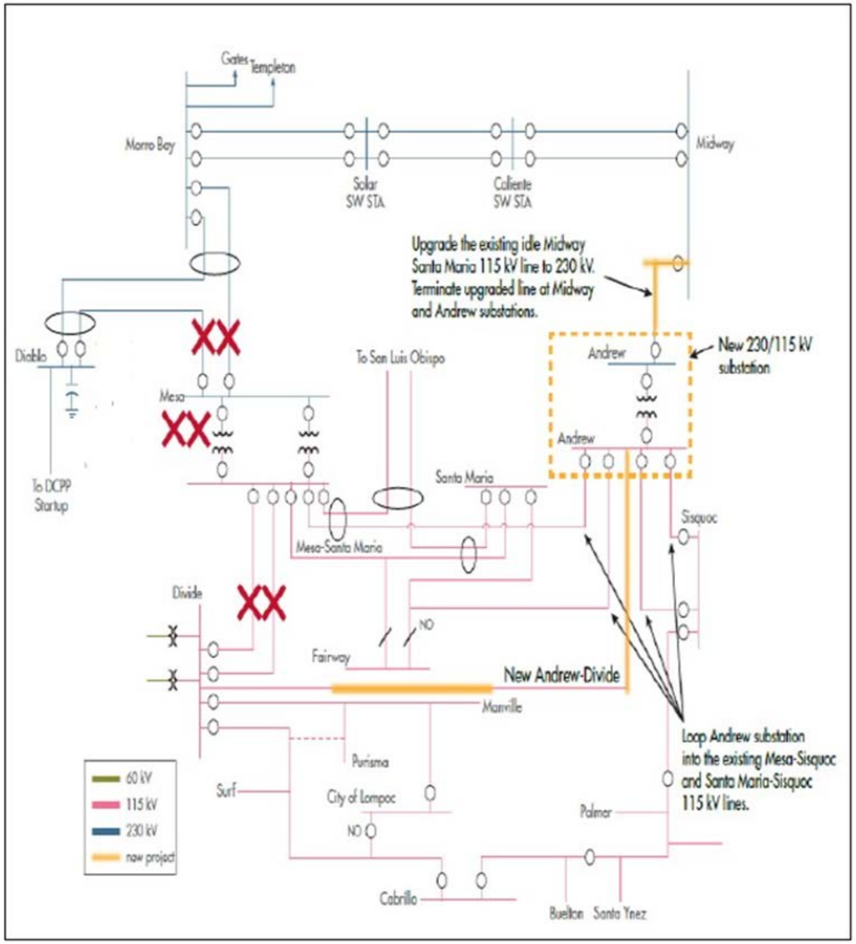
Approved cycle:
- 2012-2013 TPP

Original scope:
- Build new 230/115 kV Andrew substation
- Convert existing Midway-Santa Maria 115 kV Line to a new Midway-Andrew 230 kV Line.
- Installs one 3-phase 420 MVA 230/115 kV Bank at the new Andrew Sub
- Loops Andrew 115 kV bus into Santa Maria-Sisquoc and Mesa-Sisquoc 115 kV Lines.
- Install a new 10-mile Andrew-Divide #1 115 kV Line.

Project cost:
- Original cost: $120M-$150M
- Current estimated cost: $215M

Current In-service Date:
- On hold

Reliability Assessment Need:
- The reliability assessment identified severe thermal P2 and P6 overloads in the 115 kV system supplied from the Mesa substation.



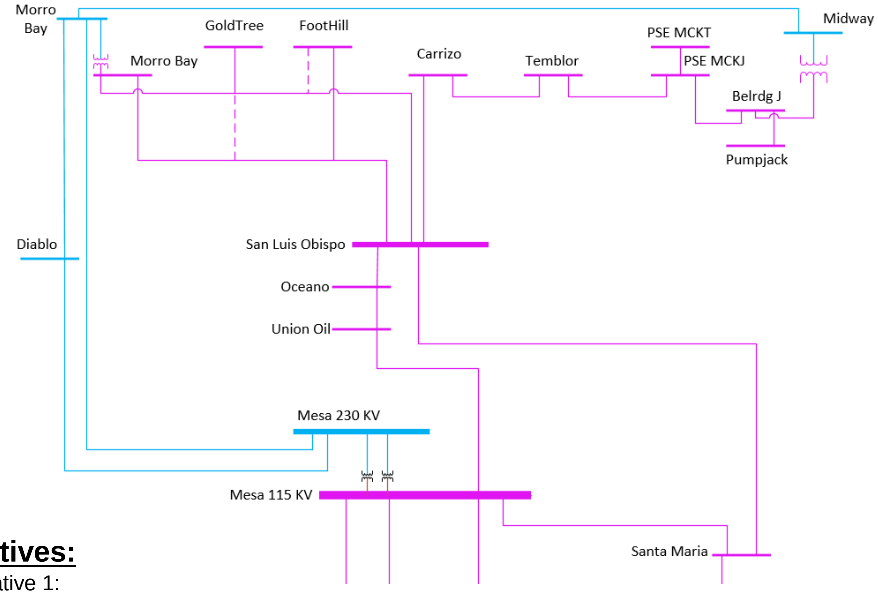
Midway – Andrew Project (CCLP) North of Mesa

Proposed Scope for North of Mesa:
- Build Andrew 230/115 kV substation.
- Energize Diablo – Midway 500 kV line at 230 kV connect to Andrew substation.
- Loop-in the SLO – Santa Maria 115 kV line to Andrew and Mesa substations

Reliability Assessment Need:
- The reliability assessment identified severe thermal P2 and P6 overloads in the 115 kV system supplied from the Mesa substation.
- No reasonable time to take outage for maintenance

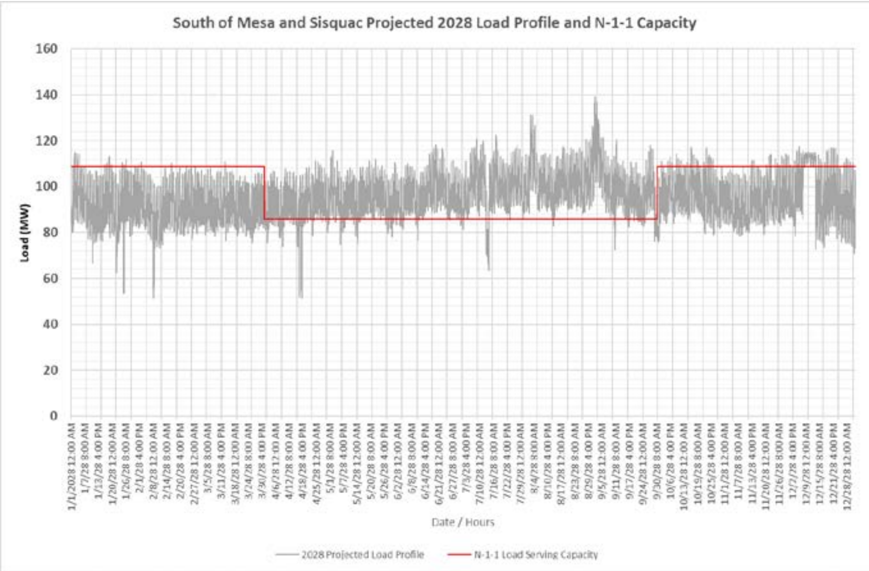
Mitigation still required {or not}:
- Mitigation still required for reliability

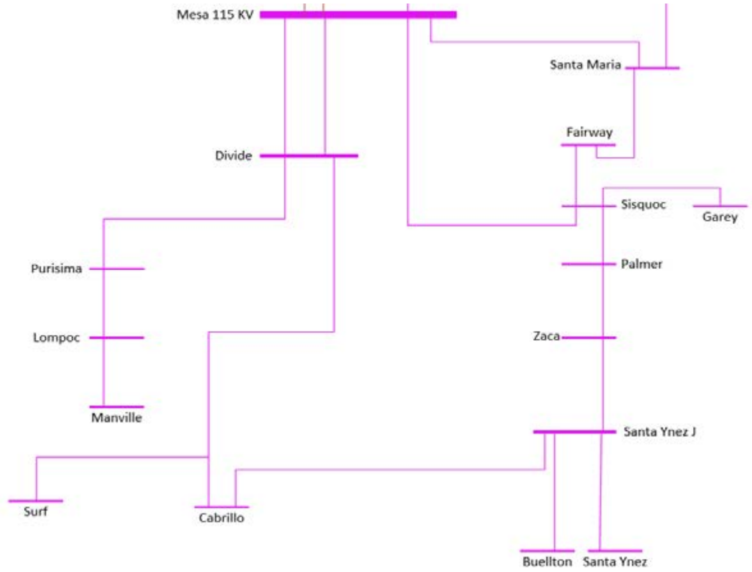
Recommendation:
- Continuing further assessment of the conversion of one of the 500 kV lines from Midway to Diablo to 230 kV



Alternatives:
- Alternative 1:
  - Increase the Winter emergency rating of San Luis Obispo (SLO) – Santa Maria 115 kV line to 170 MVA
  - Increase the Winter emergency rating of SLO – Mesa 115 kV line to 130 MVA
  - Install 50 Mvar capacitor bank at Mesa or SLO, and install SPS to shed load if P6 occurs under peak load
- Alternative 2:
  - Converting a single Diablo Canyon-Midway 500 kV line to 230 kV operation
  - A new Lopez 230kV 3 breaker ring bus looped into the repurposed Diablo Canyon-
  - Midway 230 kV Line
  - A new 230 kV line from the new Lopez substation to the area of the Divide 115
  - kV substation;
  - A new Divide 230 kV bus near the existing PG&E Divide 115 kV substation;
  - A new Divide 230/115 kV transformer
  - A new Divide-Sisquoc 115 kV Line
- Alternative 3:
  - 200 MW of Advanced Compressed Air Energy Storage (“A-CAES”) connected to the PG&E Mesa 230 kV

Midway – Andrew Project (CCLP)
South of Mesa





<u>Reliability Assessment Need:</u>

- The reliability assessment identified severe thermal P6 overloads and voltage collapse in the 115 kV system south of Mesa substation.
- No reasonable time to take outage for maintenance

<u>Recommendation:</u>

- – Increase the Winter emergency rating of Sisquoc - Santa Ynez 115 kV line to 120 MVA
- – Install 20 Mvar capacitor bank at Cabrillo
- – Install SPS to shed load if P6 occurs under peak load

Atlantic – Placer 115 kV Line Project (CVLY)(1/2)

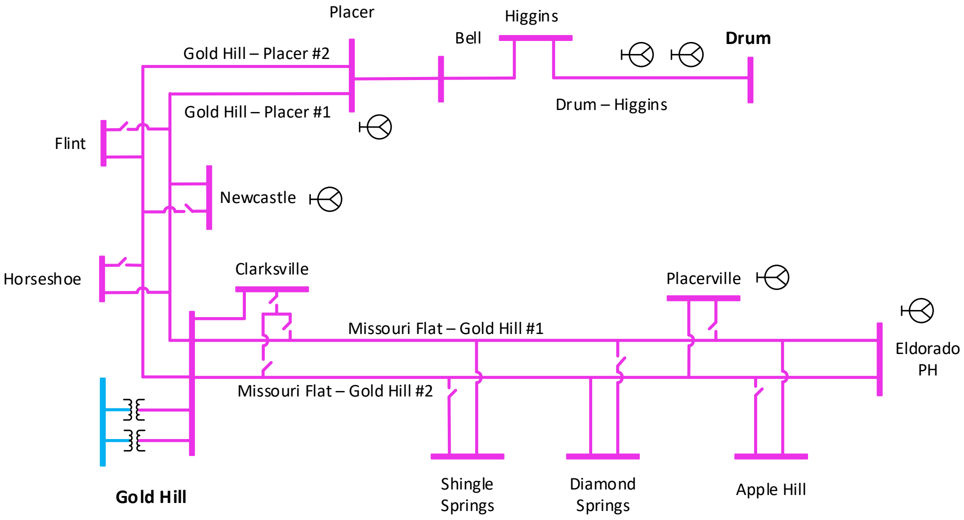
Approved cycle:
- 2012-2013 TPP

Original scope:
- Construct a new 115 kV line between existing Atlantic and Placer 115 kV substations (approximately 14 miles long, capable of 1,100 Amps under emergency conditions)
- Adding a second Placer 115/60 kV three phase transformer rated at 200 MVA and
- Installing an SPS for the loss of two Gold Hill 230/115 kV transformers.

- **Project cost:**
- Original cost: $55M-$85M
- Current estimated cost: $80M-90M

Current In-service Date:
- On hold

Reliability Assessment Need:
- There are no window available to take maintenance outage of Gold Hill 230/115 kV transformers
- Outage of two Gold Hill transformer causes voltage collapse in the area
- P2-1 on Gold Hill Missouri Flats 115 kV line causes overload in the long term



Atlantic – Placer 115 kV Line Project (CVLY)(2/2)

Mitigation still required {or not}:

- Mitigation is required to meet ISO planning standards on maintenance window

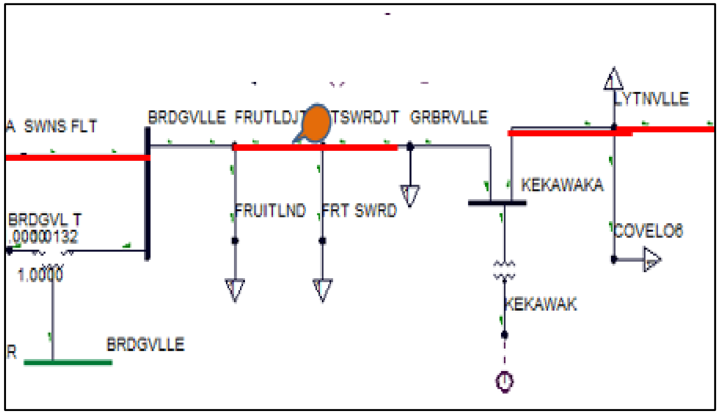
Alternatives:

- Reconductor Drum – Higgins 115 kV line to higher capacity
  - Cost estimate: $81M
- Install a 3rd 230/115 kV transformer at Gold Hill substation
  - Cost estimate: $22M
- Build a 230/115 kV substation next to the existing 230 kV lines in the area, loop-in the 230 kV line into the new substation, and build a 115 kV line from the new substation to Shingle Springs/Placerville area
  - Cost estimate: TBD bus is expected to be > $100M
  - In addition to addressing maintenance issue, this alternative will address P2-1 issue and reduces the load shedding following the P7 contingency of both Gold Hill – Missouri Flats #1 and #2 115 kV lines.
  - Project lifecycle is minimum seven years
- Convert the existing Gold Hill – Oleta 60 kV line to 115 kV to create a new connection from Gold Hill to Shingle Springs
  - Feasibility and cost to be determined

Recommendation:

- Install a 3rd 230/115 kV transformer at Gold Hill substation
  - Cost estimate: $22M
- Continue to monitor load forecast in the area and explore future options if required such as to bring another source to the Shingle Spring/Placerville are to address P2-1 overload in the long term and reduce the amount of load shedding following P7 of Gold Hill to Missouri Flats 115 kV #1 and #2 lines.

Bridgeville – Garberville No.2 115kV Line (Humboldt)



Approved cycle:

- 2011-2012 TPP

Original scope:

- Install new 36 mile long 115kV line between Bridgeville and Garberville substations as a double circuit tower with existing 60kV line.
- Will also require construction of new 115kV bus at Garberville substation and 115/60kV transformer.
- Reliability need, P1 and P2 thermal overloads

Project cost:

- Original cost: $55 - $65 million

Current In-service Date:

- January 2024

Reliability Assessment Need:

- No thermal overloads observed in the 2018-2019 TPP studies

Recommendation:

- Cancel the Bridgeville-Garberville 115kV Line
- Recommend new project to mitigate high voltages in the area

Gates-Gregg 230kV Line

Approved cycle:

- 2012-2013 TPP

Original scope:

- Build a new Gates-Gregg 230kV line to address

Original Need:

- Project was approved as a Reliability-driven project with potential renewable integration benefits
    - Reliability needs identified to start in the 2023 to 2029 timeframe

Project cost:

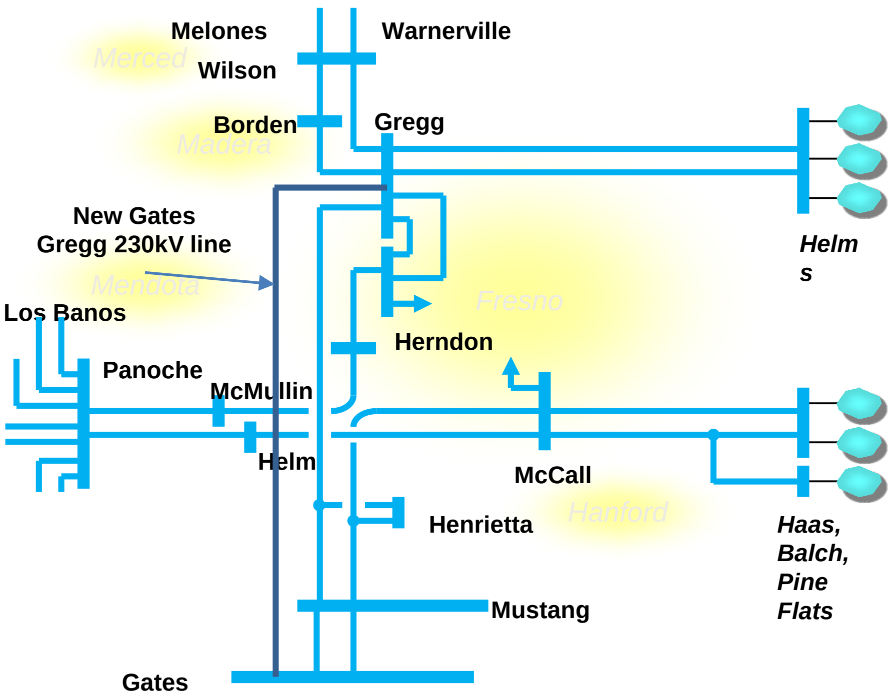
- Original cost: $115M-$145M
- Current estimated cost: $200M-$250M
    - Current expenditures $17M

Current In-service Date:

- On hold

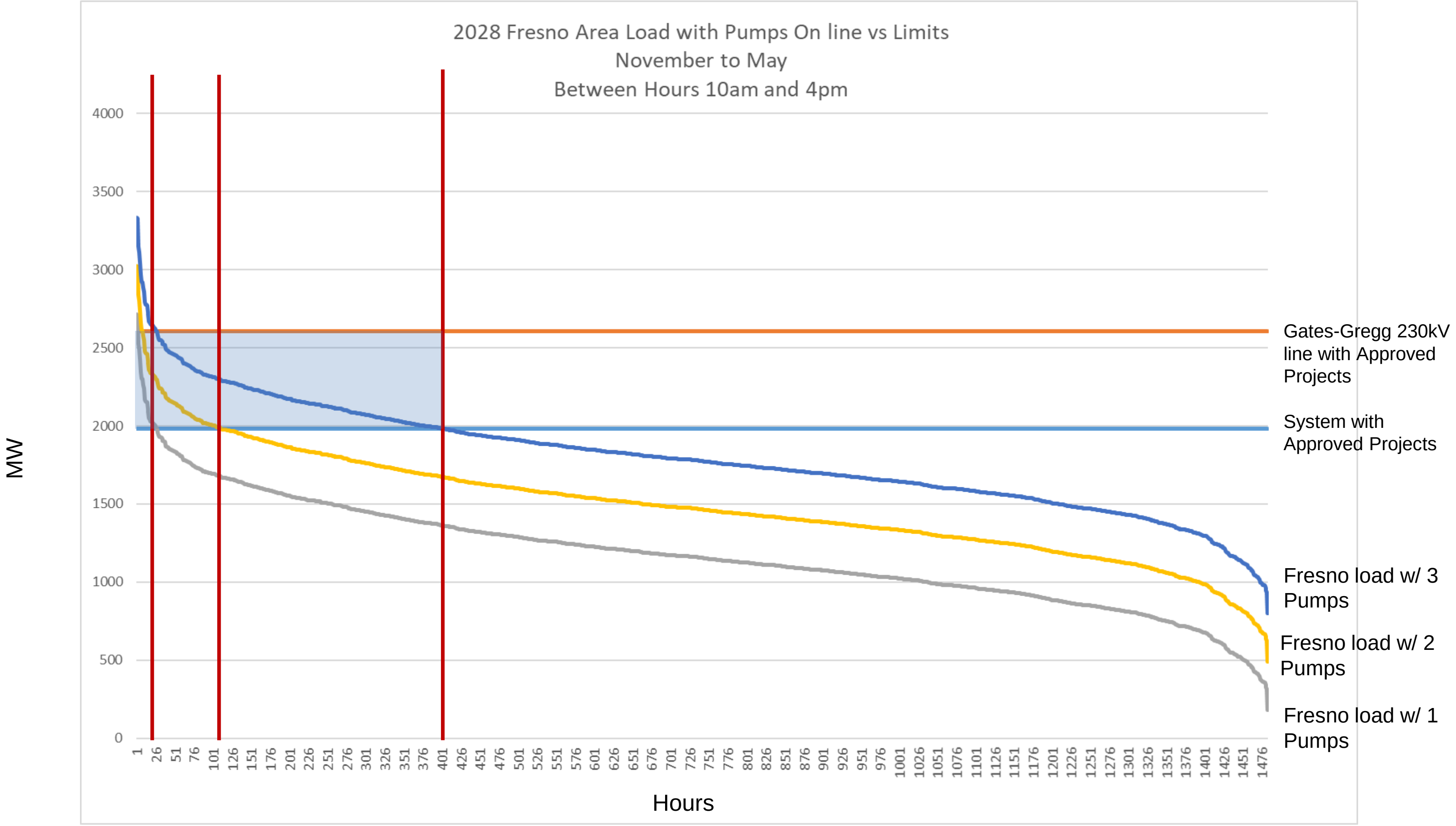
Reliability Assessment Need:

- None



2028 Area Loads with Pumps versus Capability

(Non Summer Months – when oversupply conditions are expected)

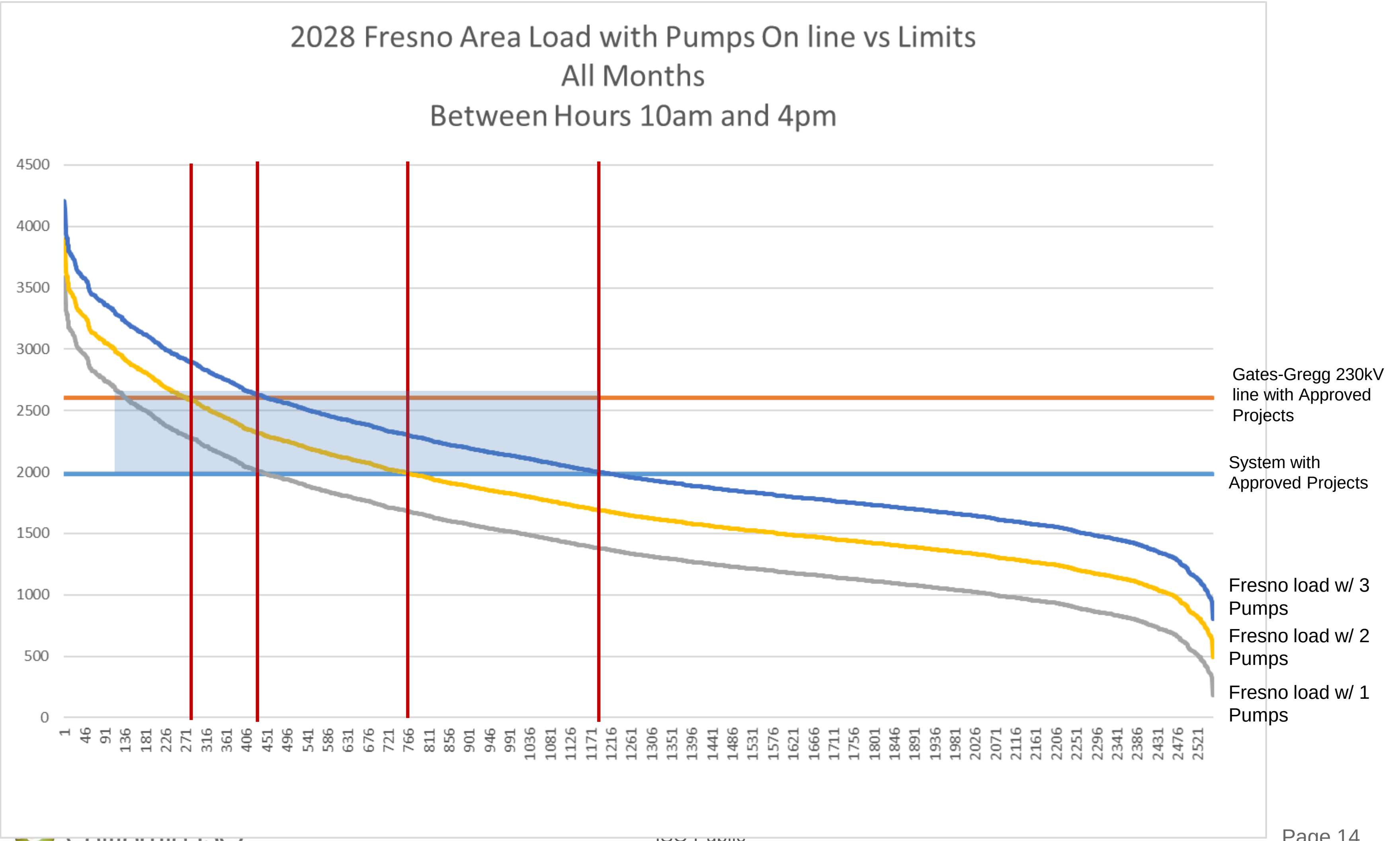


Value of Curtailment
November-May 10am to 4pm
(Non Summer Months – when oversupply conditions are expected)

- Assuming that system over supply conditions occur for all hours pumping not available the economic assessment would be as follows:
  - MWh where pumping not available without Gates-Gregg 230 kV Line
    - (375 hours * 300 MW) + (100 hours*300MW)+ (25 hours * 300 MW)
    - 150,000 MWh
  - Value of Pumping for Avoided Curtailment
    - At $40/MWh 150,000 MWh * $40/MWh = $6 million/year
    - At $66/MWh 150,000 MWh * $66/MWh = $9.9 million/year
    - At $100/MWh 150,000MWh * $100/MWh = $15 million/year

2028 Area Loads with Pumps versus Capability

Bookend Assessment – assuming oversupply appears all year



Value of Curtailment
All Months of the Year 10am to 4pm

- Assuming that system over supply conditions occur for all hours pumping not available the economic assessment would be as follows:

  - MWh where pumping not available without Gates-Gregg 230 kV Line
    - (775 hours * 300 MW) + (470 hours*300MW)+ (275 hours * 300 MW)
    - 456,000 MWh
  - Value of Pumping for Avoided Curtailment
    - At $40/MWh 456,000 MWh * $40/MWh = $18.24 million/year
    - At $66/MWh 456,000 MWh * $66/MWh = $30.1 million/year
    - At $100/MWh 456,000 MWh * $100/MWh = $45.6 million/year

Projected Pumping Limitations Under System Oversupply Conditions

- Load duration curves on previous slides assumes oversupply conditions during all hours pumps not able to operate due to local constrains.

- Using the assessment of hourly projected system curtailment for 2030, only 120,960 MWh of potential reduction of oversupply is projected with the addition of the Gates-Gregg 230 kV line

- With this the following would be the value of curtailment

- Value of Pumping for Avoided Curtailment

  - At $40/MWh 120,960 MWh * $40/MWh = $4.8 million/year
  - At $66/MWh 120,960 MWh * $66/MWh = $8 million/year
  - At $100/MWh 120,960 MWh * $100/MWh = $12.1 million/year

Gates-Gregg 230 kV Transmission Line Project Recommendation

- There does not appear to be sufficient economic benefits to support the Gates-Gregg 230 kV Transmission Line Project
  - With the current estimated cost of the project being $200-250 million dollars and the identified annual benefits only between $4.8-12.1 million.

- The ISO is considering cancelling the Gates-Gregg 230 kV Transmission Line Project in the ISO 2018-2019 transmission planning process

Informational Study: Increased Capabilities for Transfers of Low Carbon Electricity between the Pacific Northwest and California

Jeff Billinton

Manager, Regional Transmission - North

2018-2019 Transmission Planning Process Stakeholder Meeting

November 16, 2018

Background and Objective:

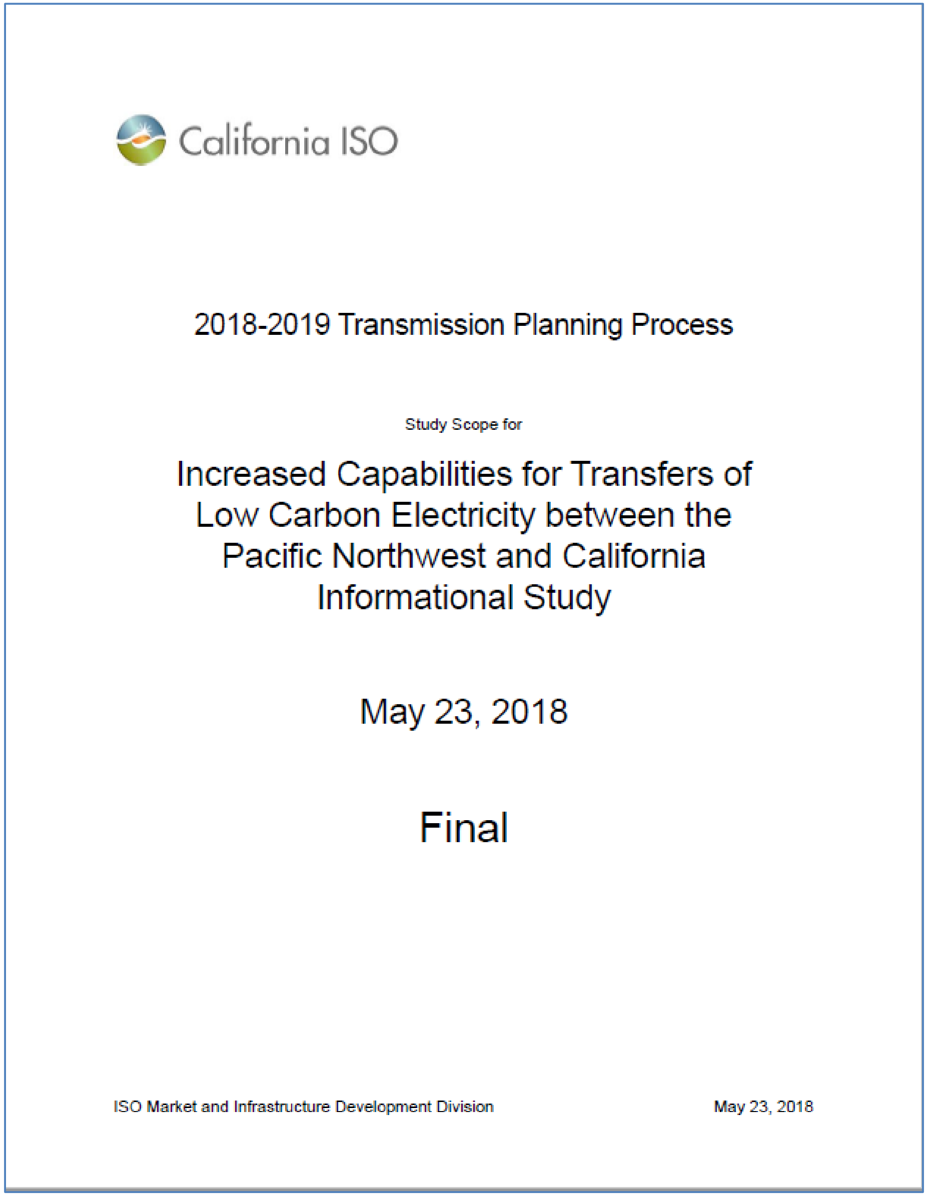
- CEC and CPUC issued a letter to CAISO* requesting evaluation of options to increase transfer of low carbon electricity between the Pacific Northwest and California
- The request included an assessment of the role the AC and DC interties can play in displacing generation whose reliability is tied to Aliso Canyon
- An informational special study was included in the 2018-2019 transmission planning cycle

* http://www.caiso.com/Documents/CPUCandCECLettertoISO-Feb152018.pdf

Study Plan

- Draft Study Plan posted on April 12, 2018
- Stakeholder call on Draft Study Plan on April 18
- Stakeholder comments submitted by April 25
- Final Study Scope posted on May 23

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



2018-2019 Transmission Planning Process

Study Scope for

Increased Capabilities for Transfers of Low Carbon Electricity between the Pacific Northwest and California Informational Study

May 23, 2018

Final

ISO Market and Infrastructure Development Division

May 23, 2018

Study Scope:

- To evaluate the impact of the following on Increased Capabilities for Transfers of Low Carbon Electricity between the Pacific Northwest and California:

  1. Increase transfer capacity of AC and DC interties
  2. Increase dynamic transfer limit (DTC) on COI
  3. Implementing sub-hourly scheduling on PDCI
  4. Assigning RA value to firm zero-carbon imports or transfers

1. Increase transfer capacity of AC and DC interties

Near-term and Long-term Assessments

- Near-term assessment (year 2023)
  - To assess the potential to maximize the utilization of existing transmission system
    - Identify minor upgrades that may be required
- Longer-term assessment (year 2028)
  - To use production simulation to assess the potential benefits of increased transfer capabilities
    - If production simulation results determine that higher capacity on AC and DC interties are beneficial beyond existing path ratings, snapshots to test alternatives to increase the capability will be developed
  - Effective hydro modeling is critical to the study

1. Increase transfer capacity of AC and DC interties

- Near-term Assessment

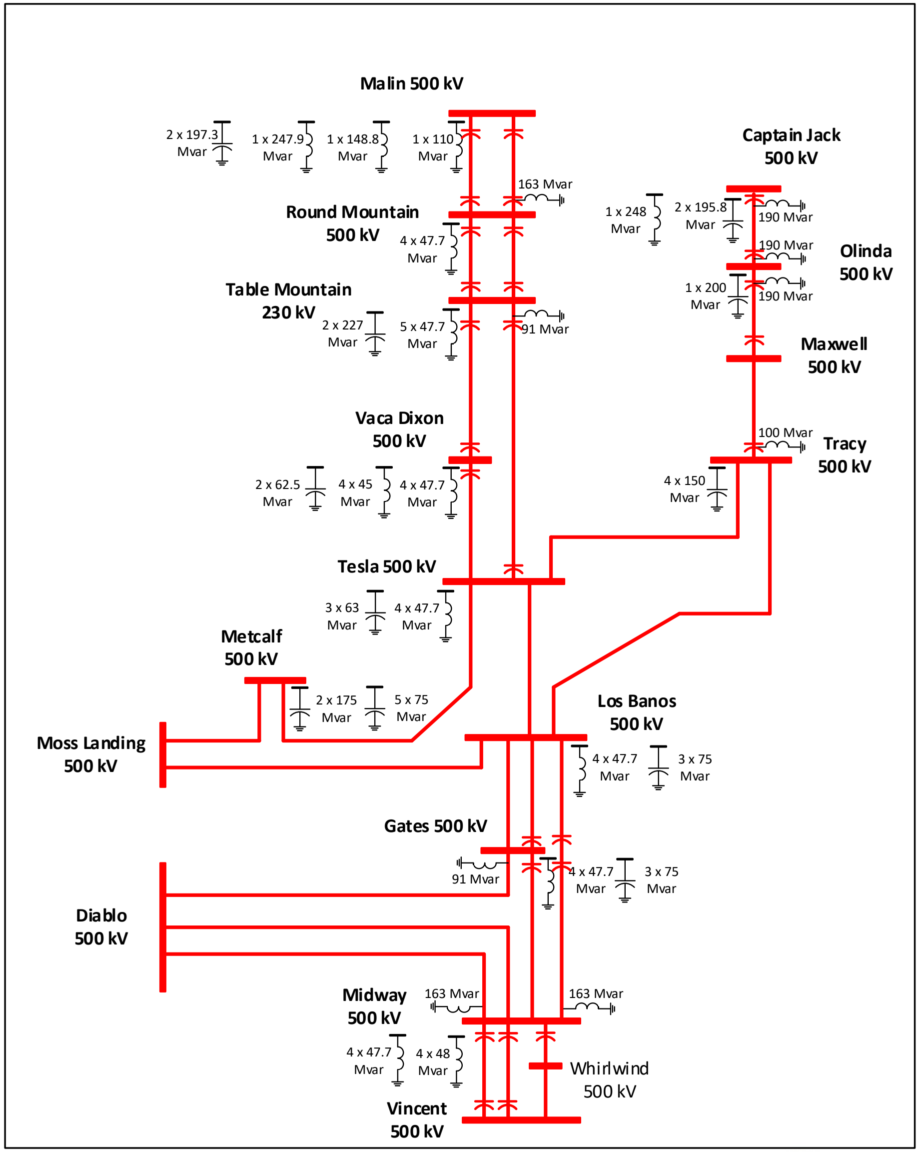
Increase transfer capacity of AC and DC interties in Near-term

- In the North to South direction the objective is to test COI flow at 5,100 MW under favorable conditions in the following scenarios:
  - Energy transfer in Summer late afternoon
  - Resource shaping in Spring late afternoon
- In the South to North direction the objective is to test PDCI flow at 1,500 MW or higher. PDCI is currently operationally limited to around 1000 MW in the S-N direction.
  - Energy transfer in Fall late afternoon
  - Resource shaping in Spring mid-day

Near-term Study Scenarios (North to South Flow)

Case Name	2023HS_ET_N-S_R2.sav	2023SOP_RS_N-S_R2.sav
Case Description	High import from PNW to CA to serve energy in California	High import from PNW to CA for Resource Shaping in early evening in Spring
Year/Season	2023, Late Summer	2023, Spring, early evening
Initial WECC Case	23HS2a1	23HW1a1
COI (66)	5,105 MW (N-S)	5,100 MW (N-S)
PDCI (65)	3,210 MW (N-S)	3,210 MW (N-S)
Path 15	1,520 MW (N-S)	500 MW (N-S)
Path 26	3,490 MW (N-S)	1,540 MW (N-S)
Path 46	7,360 MW (E-W)	4,190 MW (E-W)
Path 76	0 MW	0 MW
IPP (27)	1,720 MW (E-W)	640 MW (E-W)
NW-BC (Path 3)	2,160 MW (N-S)	2,510 MW (N-S)
ISO Load	~ 95% of peak load	~ 60% of peak load
ISO Solar	~ 0	~ 0
ISO Wind	~ 60%	~ 60%
Total ISO Import	13,260 MW	8,900 MW
Northern California Hydro	2,440 MW (60%)	1,700 MW (42%)

500 kV Transmission System



California ISO

COI North to South Path Rating

- Current Path Rating is 4800 MW
- Limiting contingency is N-2 of two 500 kV line of adjacent circuits not on a common tower
  - WECC Regional Criteria used to treat adjacent 500 kV lines (250 feet separation or less) as P7 contingency
  - WECC Path Rating process currently treats as P7
  - NERC TPL-001-4 considers N-2 of adjacent circuits not on same tower as an Extreme Event

- Assessment considers treatment as P7 contingency as well as P6 contingency to assess potential COI capability
  - ISO Operations treating the contingency as a conditionally credible contingency

Near-term Assessments Results (North-to-South Flow) Energy Transfer, Summer Evening

- For all N-1 contingencies and the PDCI bipole outage
  - Meets all the reliability standards
    - The limiting condition is the N-1 contingency of one Round Mountain – Table Mountain 500 kV line overloading the other line
- For N-2 of 500 kV lines in the same corridor but not on the same tower
  - The N-2 outage of Malin – Round Mountain 500 kV #1 & #2 lines causes 10% overload on Captain Jack – Olinda 500 kV line
- No transient or voltage stability issues
- Potential mitigation measures are: reduce COI to 4,800 MW if the contingency is considered credible in operations horizon, additional generation tripping in NW, or Load shedding in California.

Near-term Assessments Results (North-to-South Flow) Resource Shaping, Spring Evening

- For all N-1 contingencies and the PDCI bipole outage
  - No thermal overload issues
    - The limiting condition is the N-1 contingency of one Round Mountain – Table Mountain 500 kV line overloading the other line
  - No voltage issues following switching of shunts.
  - No voltage stability issues
  - No transient stability issues

Near-term Assessments Results (North-to-South Flow) Resource Shaping, Spring Evening - continued

- For N-2 of 500 kV lines in the same corridor but not on the same tower
  - Malin – Round Mountain #1 and #2
    - Causes 18% overload on Captain Jack – Olinda 500 kV line.
    - Voltage at Maxwell 500 kV bus drops to 469 kV
- Potential Mitigation
  - Reduce COI to 4,800 MW if the contingency is considered credible in operations horizon.
  - Increase generation tripping in the Northwest
  - Load shedding in California
  - Voltage support in California
  - Use FACRI to increase the voltage and reduce the overload if the contingency is not credible.

Near-term Study Scenarios (South to North Flow)

Case Name	2023falloffpk_etr_pdci1000sn_v2.sav	2023falloffpk_etr_pdci1500sn_v2.sav	2023sop_rs_pdci1500sn_v2.sav
Case Description	Fall offpeak energy transfer from California to the Pacific Northwest with PDCI flow at 1,000 MW (S-N) and with COI at 3,627 MW (S-N)	Fall offpeak energy transfer from California to the Pacific Northwest with PDCI flow at 1,500 MW (S-N) and with COI at 2,543 MW (S-N)	Spring off-peak energy shaping with PDCI at 1500 MW (S-N direction) and COI at 2,725 MW (S-N)
Year/Season	2023, late fall	2023, late fall	Early spring 2023, around noon
Initial WECC Case	23HW1a1	23HW1a1	23HW1a1
COI (66)	3,627 MW (S-N)	2,543 MW (S-N)	2,725 MW (S-N)
PDCI (65)	1,000 MW (S-N)	1,500 MW (S-N)	1,500 MW (S-N)
Path 15	3,972 MW (S-N)	2,296 MW (S-N)	1,403 MW (S-N)
Path 26	661 MW (S-N)	239 MW (S-N)	1,120 MW (N-S)
Path 46	7,276 MW (E-W)	7,435 MW (E-W)	5,088 MW (E-W)
Path 76	114 MW (N-S)	114 MW (N-S)	115 MW (N-S)
IPP (27)	1,575 MW (E-W)	1,575 MW (E-W)	1,575 MW (E-W)
NW-BC (Path 3)	1,408 MW (S-N)	1,405 MW (S-N)	1,400 MW (S-N)
ISO Load	~ 61% of peak load	~ 61% of peak load	~60% of peak load
ISO Solar	80%	80%	100%
ISO Wind	~ 69% (SoCal), 3% (PG&E)	~ 69% (SoCal), 3% (PG&E)	~ 69% (SoCal), 3% (PG&E)
Total ISO Import	-238 MW (export)	-260 MW (export)	-2,927 MW (export)
Northern California Hydro	1,513 MW (37%)	1,513 MW (37%)	1,513 MW (37%)

Near-term Assessments Results (South-to-North Flow)

- For the overlapping contingencies (N-1-1) or N-2 (WECC Common Corridor) of 500 kV lines in the same corridor but not on the same tower
  - The transmission contingency of Adelanto-Toluca and Victorville-Rinaldi 500 kV lines
    - No overloading concerns
    - No voltage or transient stability concerns
- For the extreme contingency of N-2-1 of Rinaldi-Tarzana 230kV #1 and 2 lines, followed by Northridge-Tarzana 230kV line
  - Thermal loading concerns on various 138kV lines internally within LADWP's BAA
  - These are existing local area reliability concerns due to having no dispatch of local generation
- For 500kV bulk contingencies treated as either P6 or P7 of 500 kV lines in the same corridor but not on the same tower in northern California
  - Various 230kV line constraints were observed
  - Olinda 500/230kV transformer loading for the 1000 MW PDCI S-N study case

Near-term Assessments Results (South-to-North Flows)

- Potential Mitigation
  - Dispatch local generation post first contingency to prepare for the next contingency for the extreme outrage loading concerns
  - For local congestion concerns, there are existing RAS schemes to mitigate (i.e., inserting line series reactor on 230kV line)
  - For other local congestion concerns in northern California, either include generation curtailments to either existing or new RAS schemes to trip generation (as a P7 contingency) or implement system readjustment after first contingency (as a P6 contingency).
  - Further details of study results will be included in the draft Transmission Plan report.

Near-term Assessments Results (South-to-North Flow) Sensitivity Studies

- Three South-North sensitivity studies were also assessed as follows:
  1. 1500 MW PDCI S-N resource shaping, spring off-peak, solar generation at 100% installed capacity, additional loads include 600 MW Castaic pump loads
  2. The above sensitivity study case, but with PDCI flow at 1,050 MW S-N
  3. 1500 MW PDCI S-N resource shaping, spring off-peak, solar generation at 100% installed capacity, high hydro generation in the Northwest, no Klamath Falls generation; this case had an earlier assumption of having local generation dispatch in LADWP's LA Basin.

Near-term Assessments Results (South-to-North Flows) Sensitivity Studies - continued

- For the overlapping contingencies (N-1-1) or N-2 (WECC Common Corridor) of 500 kV lines in the same corridor but not on the same tower
  - The transmission contingency of Adelanto-Toluca and Victorville-Rinaldi 500 kV lines
    - Loading concerns for the Rinaldi 500/230kV Bank H for sensitivity study case 1 above
    - Loading concern for the Century – Victorville 287kV line for sensitivity study case 1

- For the extreme contingency of N-2-1 of Rinaldi-Tarzana 230kV #1 and 2 lines, followed by Northridge-Tarzana 230kV line
  - Thermal loading concerns on various 138kV lines internally within LADWP's BAA
  - These are existing local area reliability concerns due to having no dispatch of local generation
- For 500kV bulk contingencies treated as either P6 or P7 of 500 kV lines in the same corridor but not on the same tower in northern California
  - Various 230kV line congestion occurs
  - Olinda 500/230kV transformer loading concern for sensitivity study cases 2 and 3
  - Round Mountain 500/230kV transformer overloading concern for sensitivity study case 2

Near-term Assessments Results (South-to-North Flows) Sensitivity Studies - continued

- Potential Mitigations for reliability concerns associated with changes to the PDCI flows:
  A. The following conceptual mitigation options could help maintaining PDCI schedules and imports into LADWP under critical contingencies:
     1. Install two 230kV phase shifters with 540 MVA, 0 to -40◦ phase angles on the Sylmar-Gould 230kV line at Sylmar end (notes: there are variations on locations for the phase shifters), OR
     2. Install RAS to trip pump loads (this mitigation option is **not** favored by LADWP)
  B. The following conceptual operating mitigations are provided here for information only. ***It is noted that LADWP System Operations retains jurisdictional responsibility for proposing and implementing operating actions. These options may involve curtailing schedules or loads under critical contingencies.***
     1. Potential operating actions to curtail pump loads after the first contingency, ***OR***
     2. Potential operating actions to reduce PDCI S-N flow to 1,000 MW after the first contingency, ***OR***
     3. Potential operating actions for implementing system operating limit for VIC-LA path

Near-term Assessments Results (South-to-North Flows) Sensitivity Studies - continued

- Potential mitigations for existing reliability or congestion concerns (these are not caused by changes in PDCI flows)
  - Dispatch local generation post first contingency to prepare for the next contingency for the extreme outrage loading concerns to address existing local reliability concerns for LADWP's 138kV lines due to having no dispatch of local resources (notes: this is an existing local area reliability concern).
  - For local congestion concerns in northern California, there are existing RAS schemes to mitigate (i.e., inserting line series reactor on 230kV line, opening 500/230kV circuit breakers at Round Mountain)
  - For other local congestion concerns in northern California, either include generation curtailments to either existing or new RAS schemes to trip generation (P7 contingencies) or implement congestion management protocol for overlapping P6 contingencies.
  - Details of study results will be included in the draft Transmission Plan report.

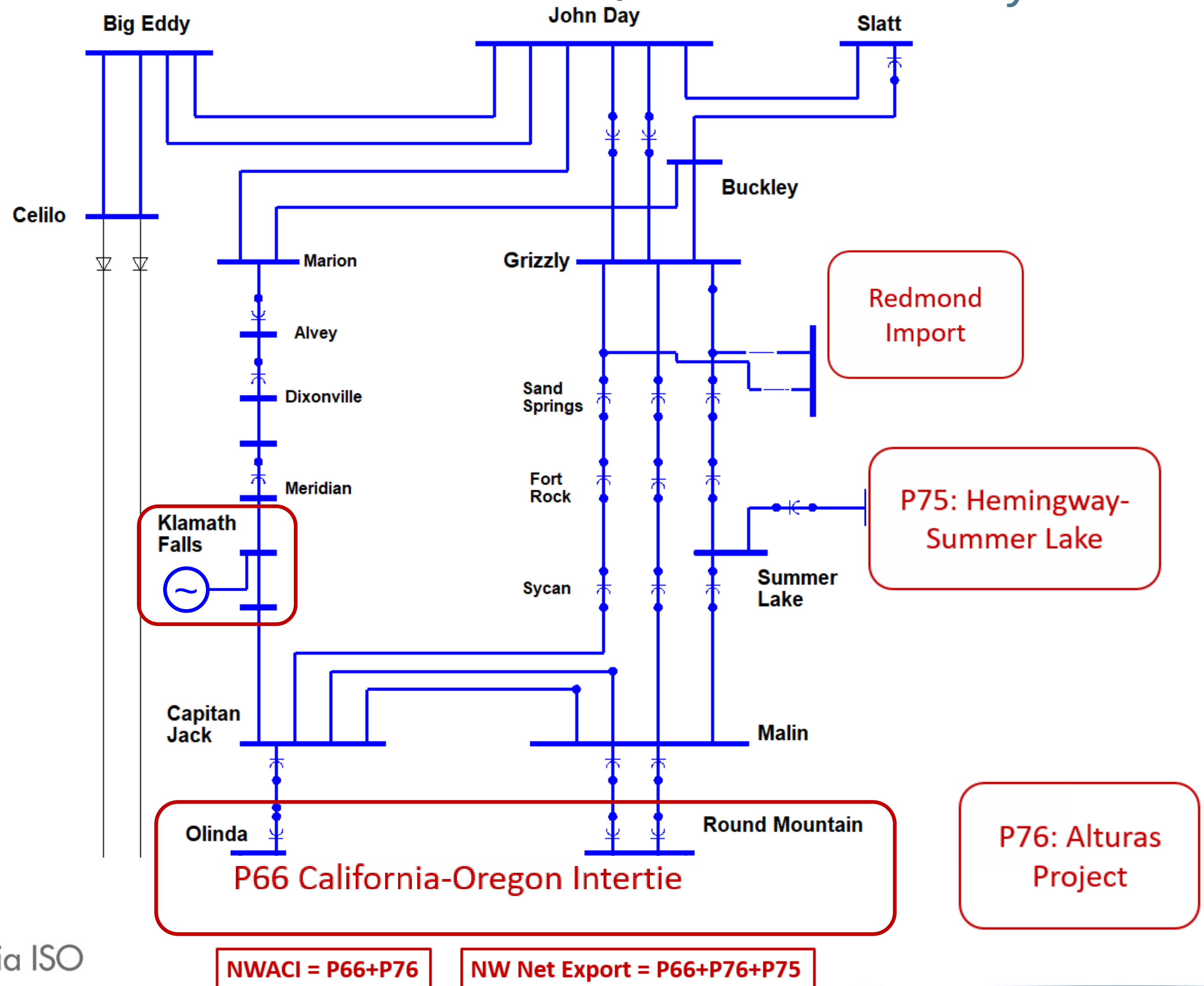
Summary of Near-term Assessments Results

- In the North to South flow:
  - With N-2 of 500 kV lines in adjacent circuits, COI limit will remain 4,800 MW
  - If the outage of two 500 kV adjacent lines where to be considered conditionally credible contingencies (as P6), COI limit could potentially increase to 5,100 MW under favorable condition.
  - Further studies are required for COI limit beyond 5,100 MW

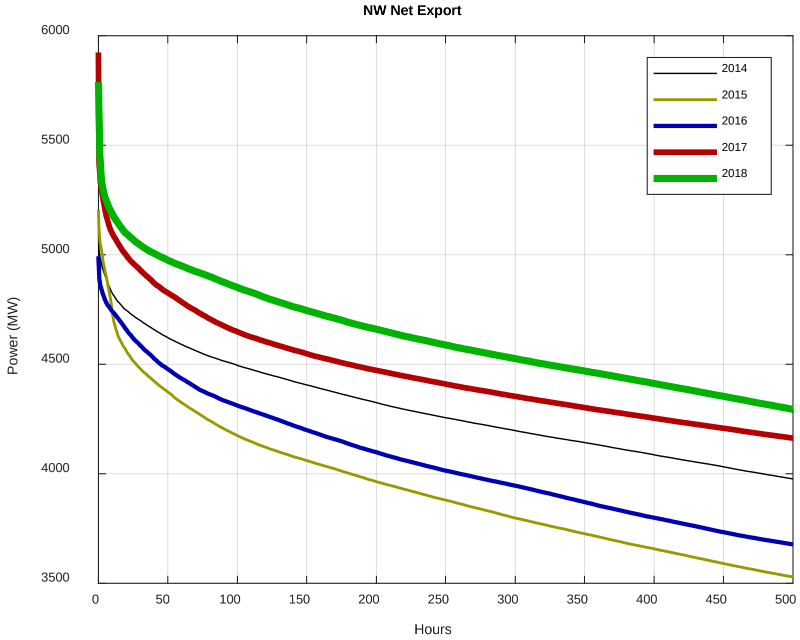
- In the South to North flow:
  - COI flow up to the WECC limit of 3,675 MW S-N is feasible for certain conditions with typical fall and spring off-peak conditions.
  - PDCI flow is currently limited to 1000 MW S-N operationally by LADWP to address most, if not all, winter operating conditions. LADWP is operating agent for the PDCI at the southern terminal.
  - However, under certain fall and spring off-peak light load scenarios, PDCI S-N flow could be operated higher (i.e., 1,500 MW) under normal condition. Under critical contingency conditions, the PDCI S-N flow would need to be reduced to its 1,000 MW limit.
  - Potential transmission upgrades, such as phase shifting transformers, could be an option for providing imports for LADWP via Sylmar path while maintaining PDCI S-N flow at 1,500 MW. This is exploratory at this time and would need further assessment for engineering and operational feasibility.

Near-term Assessments Results
North to South Studies Conducted by BPA on PNW System

Near-term Assessments Results
North to South Studies Conducted by BPA on PNW System

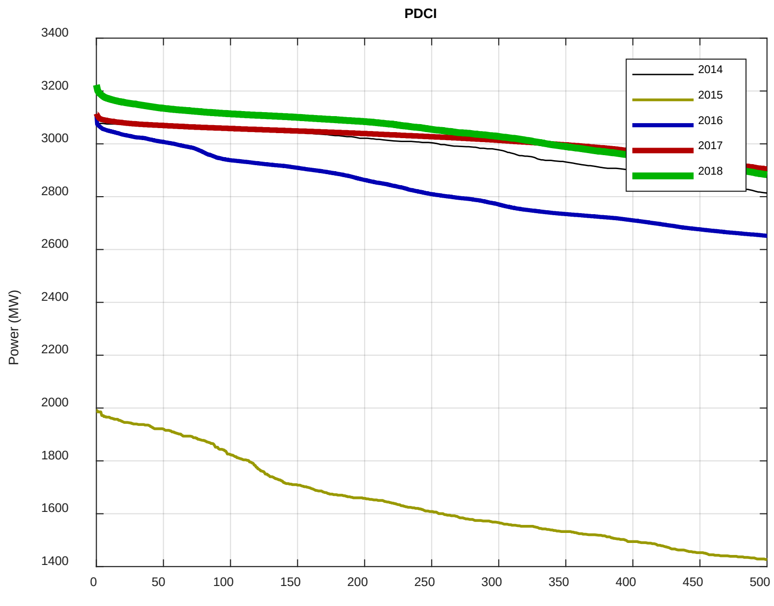


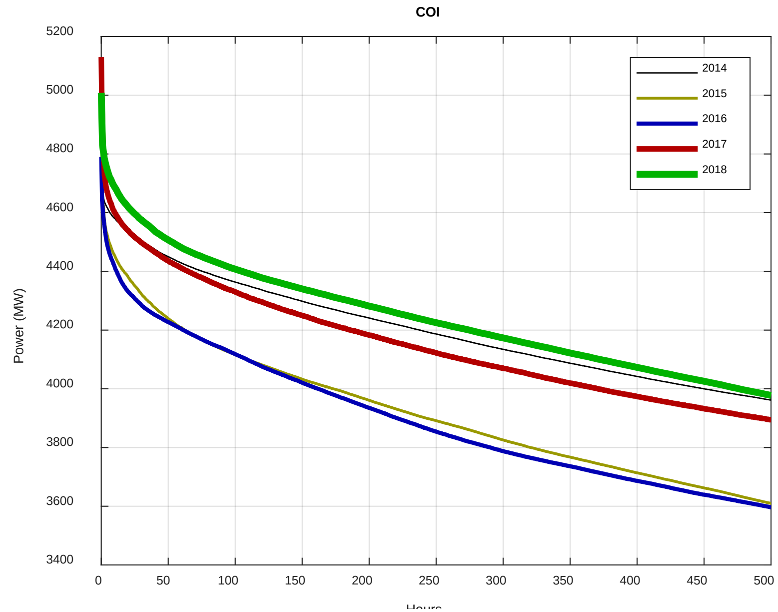
Near-term Assessments Results
North to South Studies Conducted by BPA on PNW System



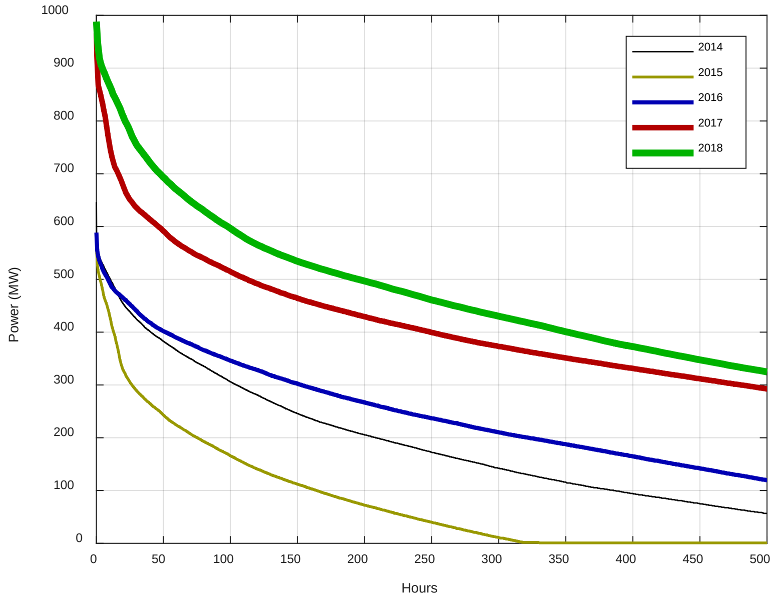
- NW exports on Southern Interties have increased in past two years
- NE Net Export = Path 66 COI + Path 76 Alturas Project + Path 75 Summer Lake
- The increase is primarily due to higher West to East flows on P75 Summer Lake-Hemingway (see next slides)

Data is from June 1 to October 1 each year

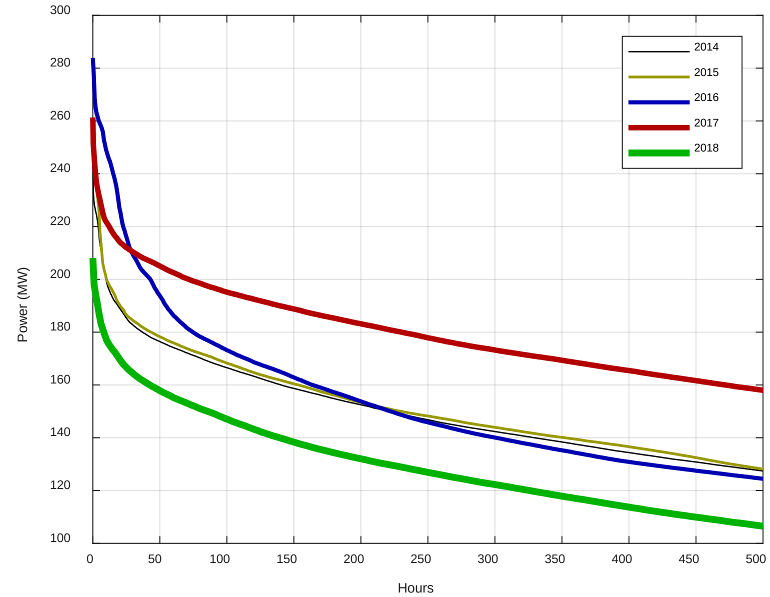




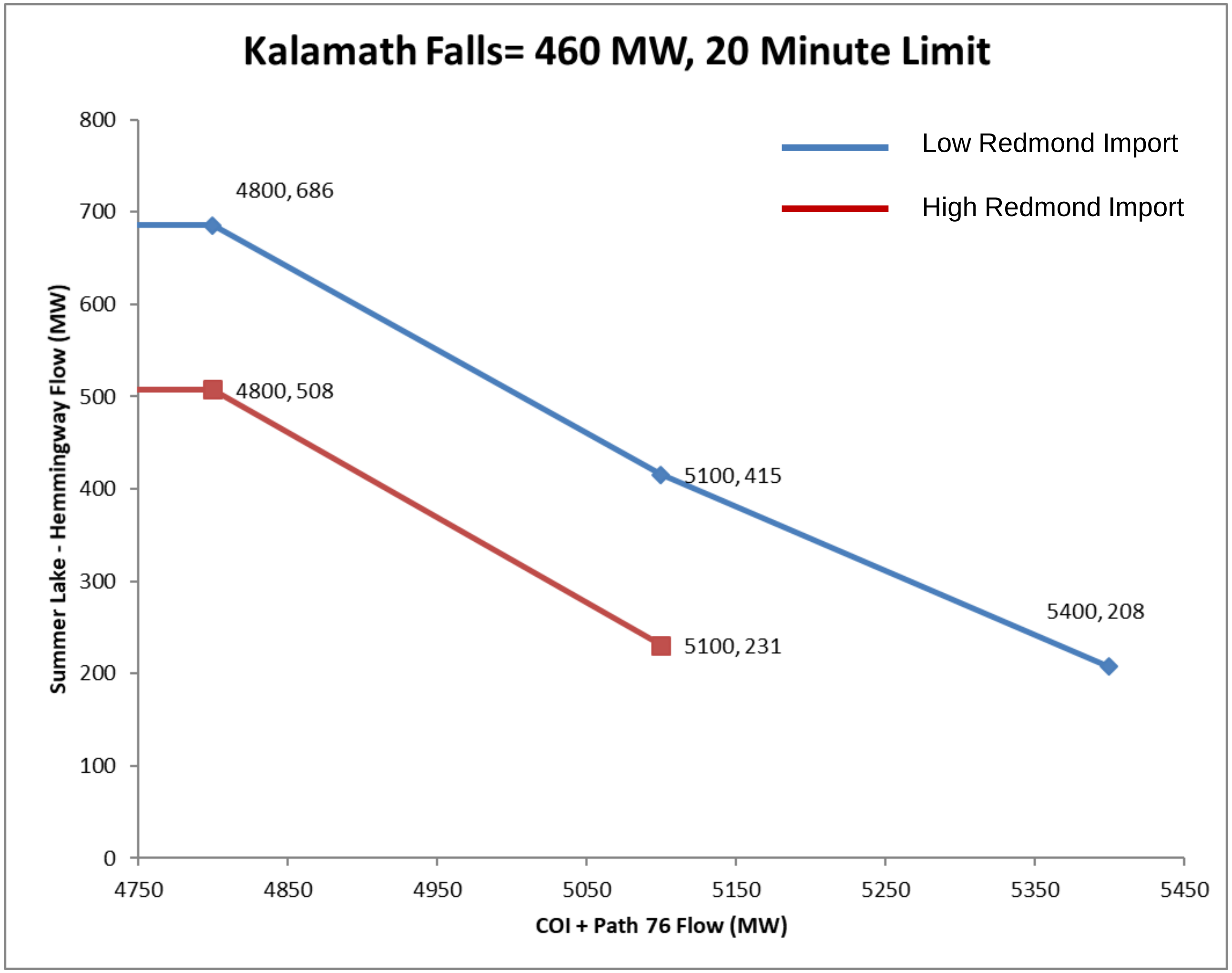
Path 75: Summer Lake to Hemingway (W-E)



Path 76: Alturas Project



Near-term Assessments Results
North to South Studies Conducted by BPA on PNW System



Near-term Assessments Results
Next Steps for Studies Conducted by BPA on PNW System

- Finalize thermal and voltage stability analysis for “N-S “Energy Transfer Cases”
- Finalize thermal and voltage stability analysis for “N-S “Resource Shaping Cases”
- Finalize South to North studies
- N-2 contingency studies
- Transient stability assessment

1. Increase transfer capacity of AC and DC interties

-Longer-term Assessment - Production Cost Simulation

Increase transfer capacity of AC and DC interties Longer-Term Assessment

- Hydro Assumptions in Production Simulation Model
  - WECC Anchor Data Set (ADS) will be used for the production simulation analysis
    - ABB GridView software
  - Hydro assumptions in ADS are based on historical hydro output from 2008/2009
  - Outreach with the Planning Regions and the hydro owners to review modeling and make updates as required
    - The ISO will receive information on typical, high, and low hydro scenarios from NWPCC and BPA
    - GridView study with updated hydro assumptions will provide an insight to potential benefits of higher intertie capacity in the long term

Pacific Northwest Hydro conditions

- The PCM case starting from ADS PCM, hence the ADS hydro condition is used
- We work with NWPCC and BPA to developed High, Medium, and Low hydro conditions based on historical data
  - Aggregated monthly energy from hydro generators
  - Aggregated hourly maximum and minimum hydro generation output
  - The aggregated hydro data were allocated to individual units based on analysis on historical data

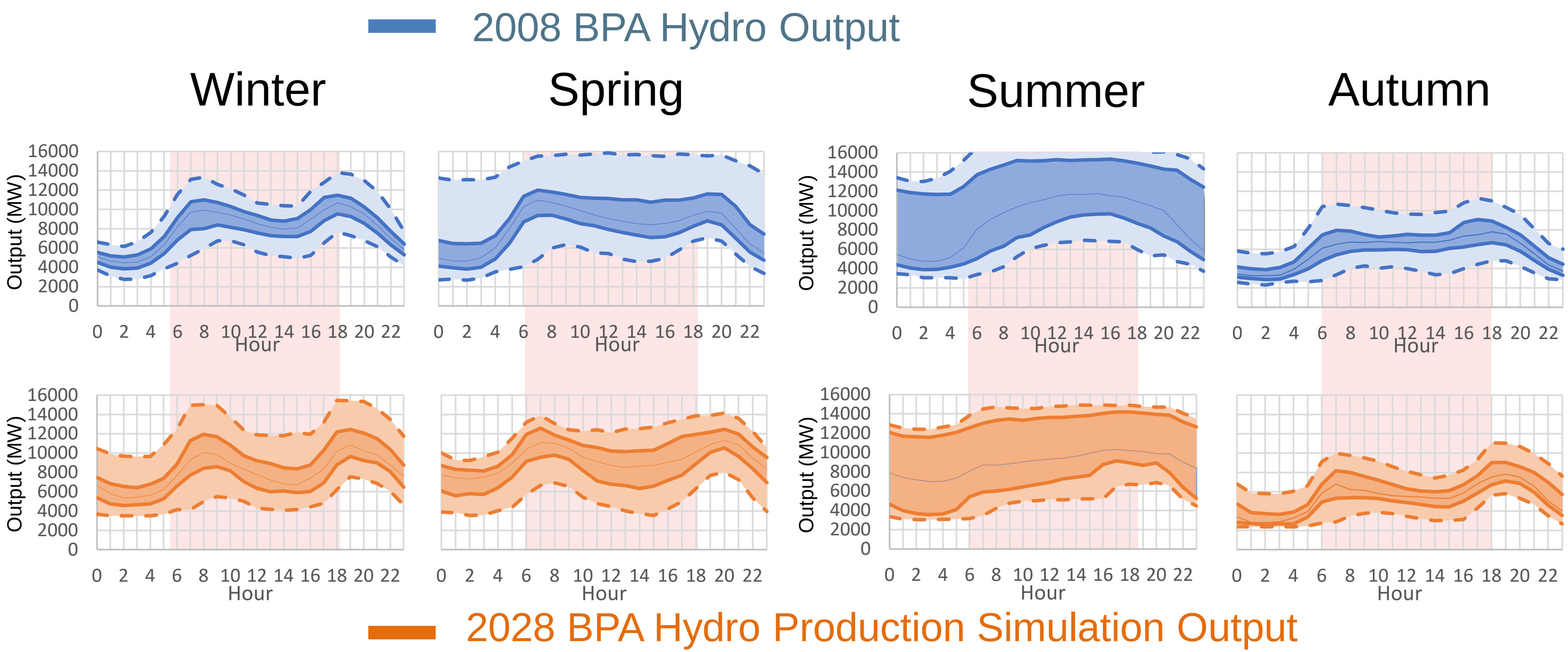
Analysis based on public data

- **California ISO, Northwest Power and Conservation Council and Bonneville Power Authority**. September 6th Portland Stakeholder Workshop. 2018. Available here: https://gridworks.org/wp-content/uploads/2018/09/Sharing-Power_Slide-Deck_Sept-6.pdf

- **BPA**. Wind generation & total load in the BPA balancing authority. 2018. Available here: https://transmission.bpa.gov/Business/Operations/Wind/default.aspx

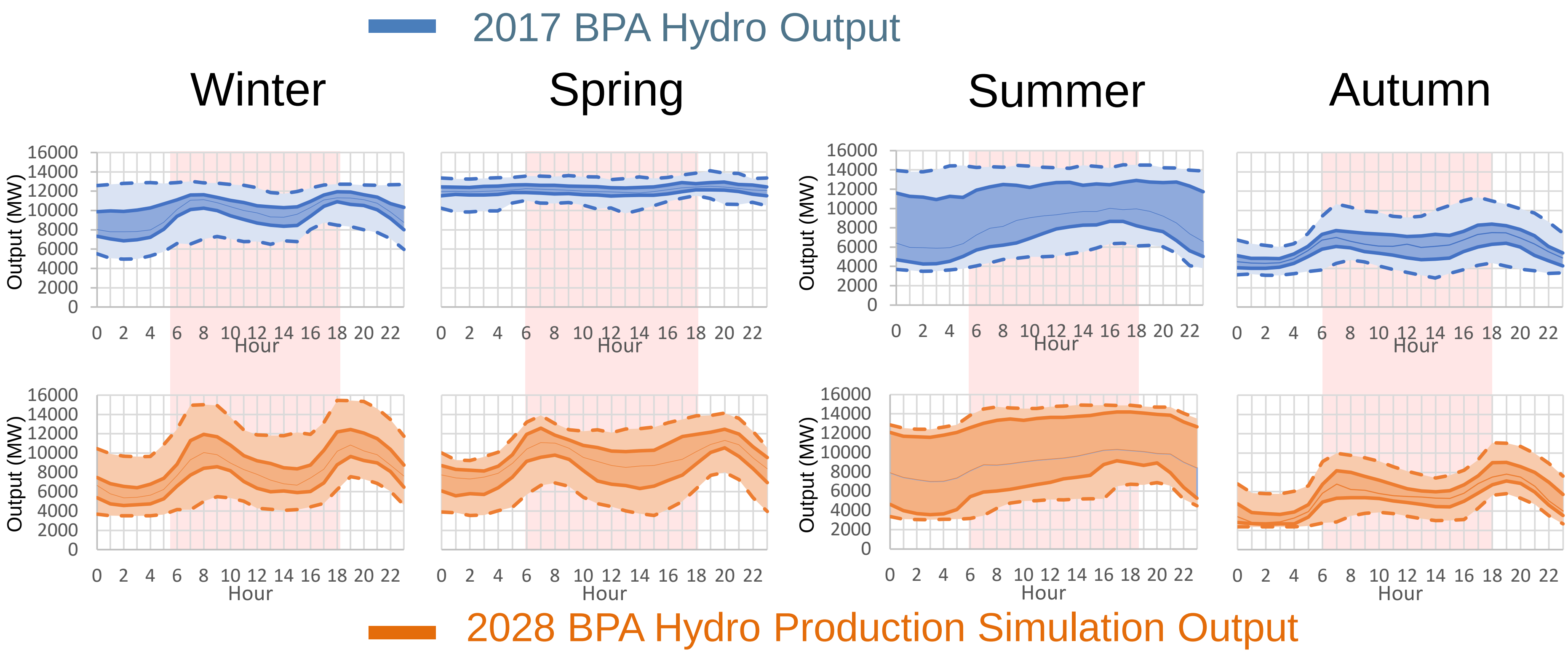
- **US Army Corps of Engineers**. Dataquery 2.0. 2018. Available here: http://www.nwd-wc.usace.army.mil/dd/common/dataquery/www/#

2008 vs 2028 Production Simulation Seasonal output by hour



September 6th Northwest workshop. 2018. Available here: https://gridworks.org/wp-content/uploads/2018/09/Sharing-Power_Slide-Deck_Sept-6.pdf

2017 vs 2028 Production Simulation Seasonal output by hour



Northwest Power and Conservation Council's GENESYS model

- NWPCC's GENESYS model provides a chronological hourly simulation of the Pacific NW power supply (includes ~35GW of installed capacity)
- GENESYS is used for assessing resource adequacy in the Pacific Northwest
- GENESYS considers the non-power requirements of the NW hydro

September 6th Northwest workshop. 2018. Available here: https://gridworks.org/wp-content/uploads/2018/09/Sharing-Power_Slide-Deck_Sept-6.pdf

Northwest hydro energy by month

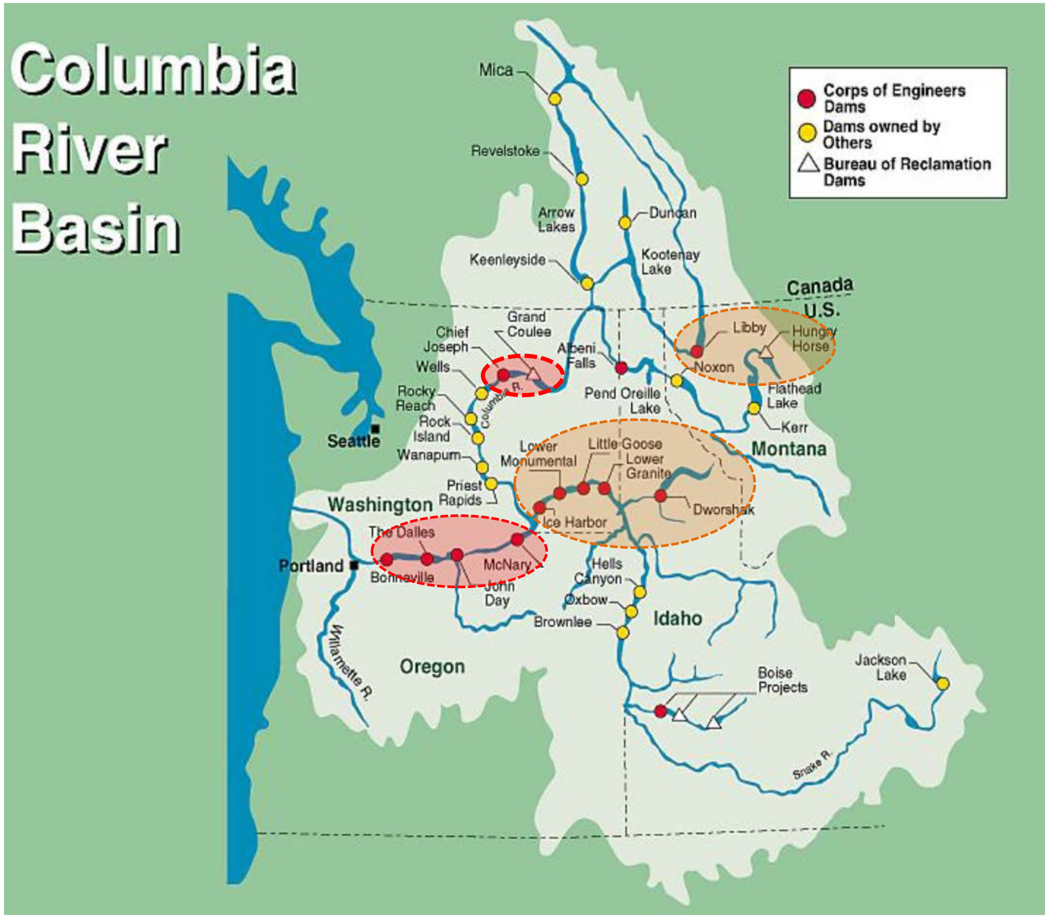
1. High
   - 95th percentile
   - 1997
2. Medium
   - 50th percentile
   - 1960
3. Low
   - 5th percentile
   - 1931

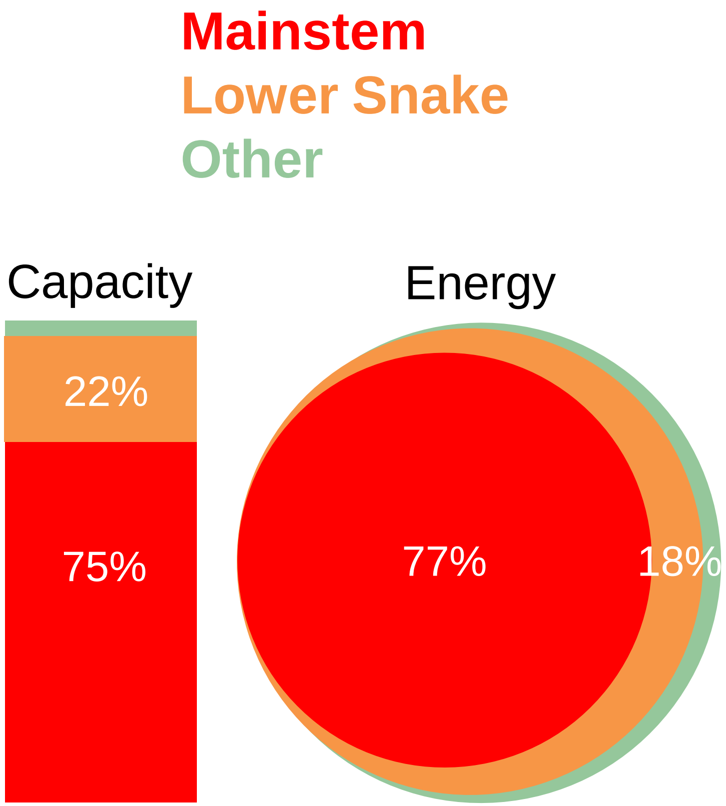
California ISO

Updating ADS hydro modeling parameters

- Rated capacity for **each NW hydro unit** was used to assign
  - o Monthly energy for each year
  - o Monthly max output for each year
  - o Monthly min output for each year
  - o Monthly daily average operating range for each year
- **Exceptions**
  - o Federal Columbia River Power System Mainstem
    - Grand Coulee, Chief Joseph, McNary, Bonneville, John Day and The Dalles.

Federal Columbia River Power System

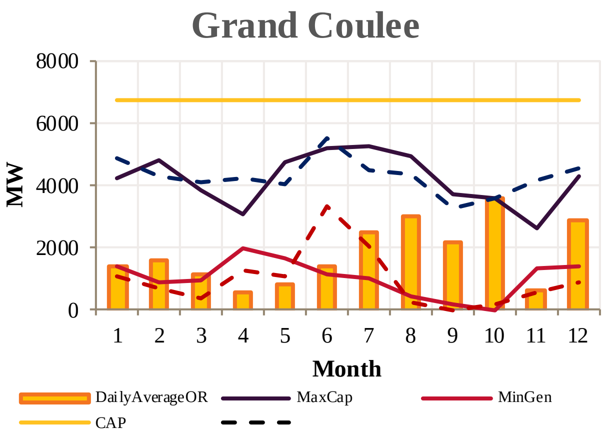


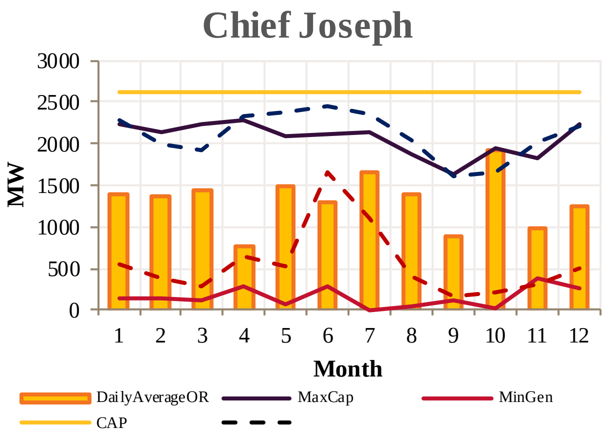


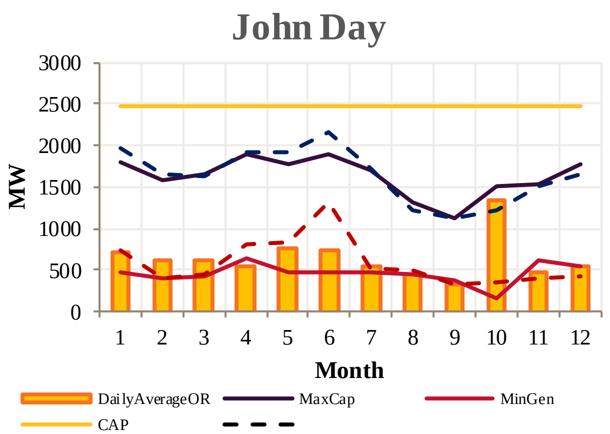
Data source (right): BPA. Asset Category Overview 2017-2030 Hydro Asset Strategy. 2016. Underlying data available here: https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2016IPRDocuments/2016-IPR-CIR-Hydro-Draft-Asset-Strategy.pdf

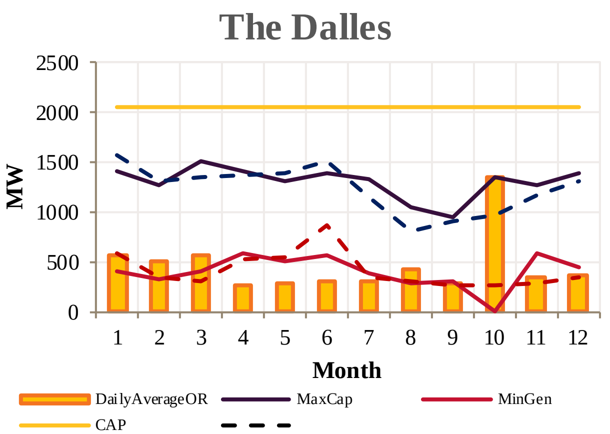
Figure source (left): BPA. 2018. Available here: https://gridworks.org/wp-content/uploads/2018/09/Sharing-Power_Slide-Deck_Sept-6.pdf

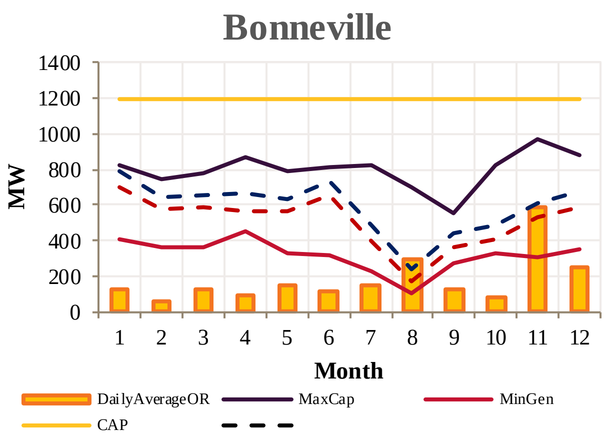
Mainstem modeling parameters - medium

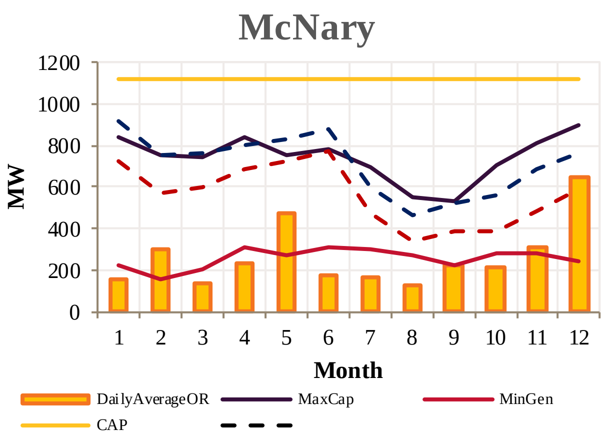




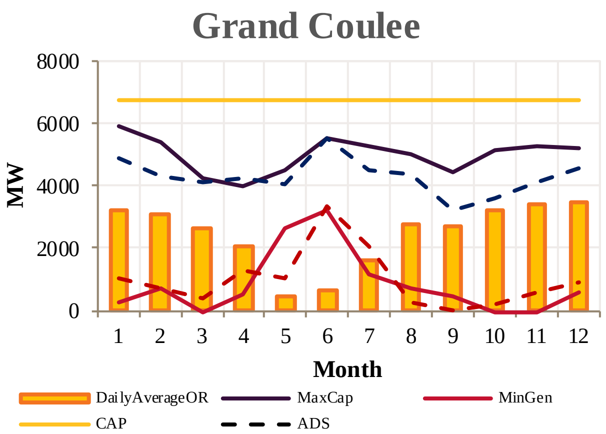


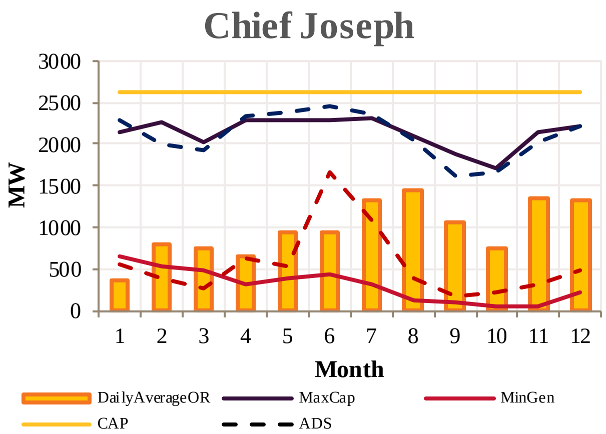


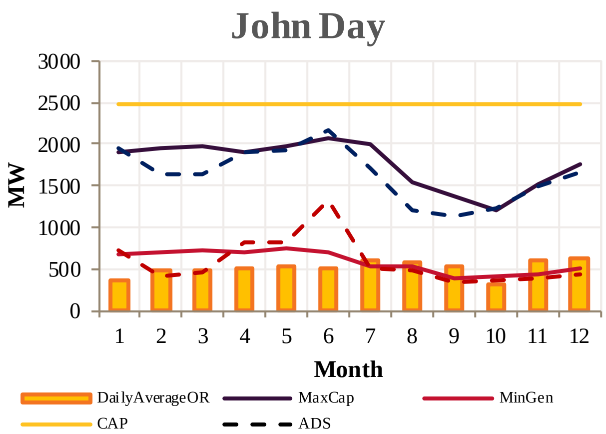


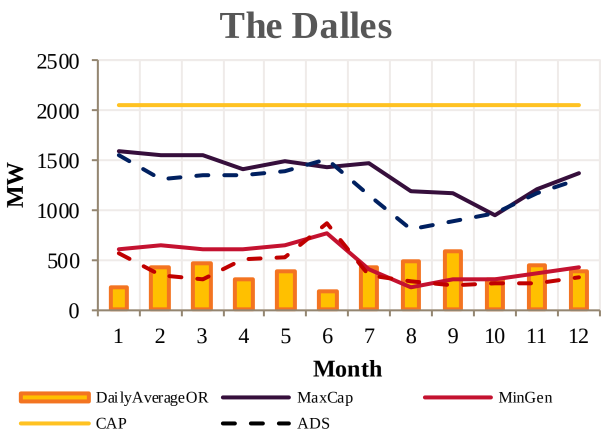


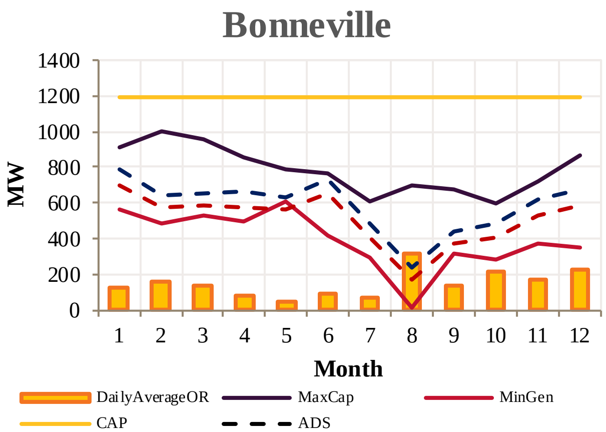
Mainstem modeling parameters - high

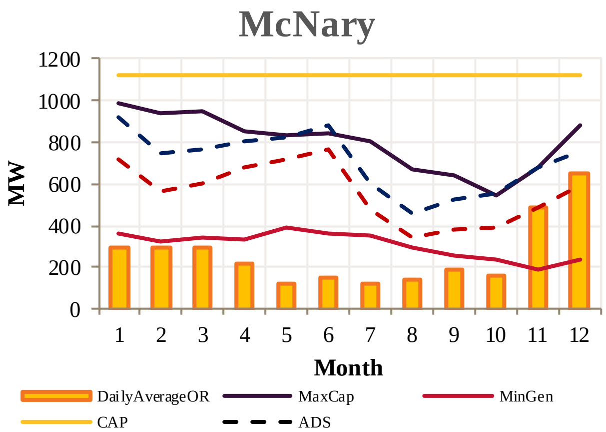




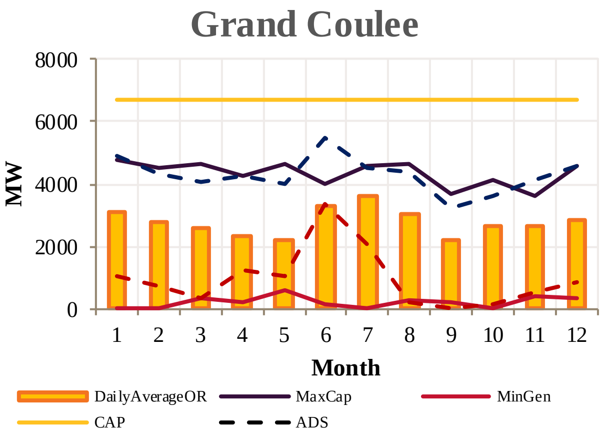


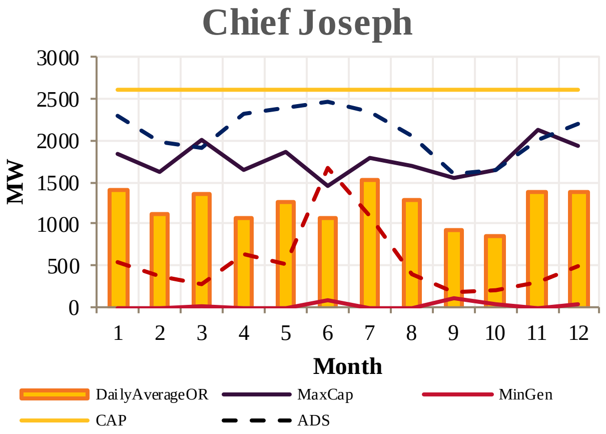


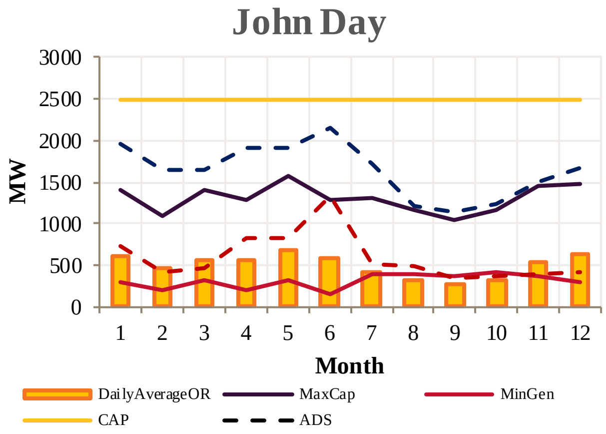


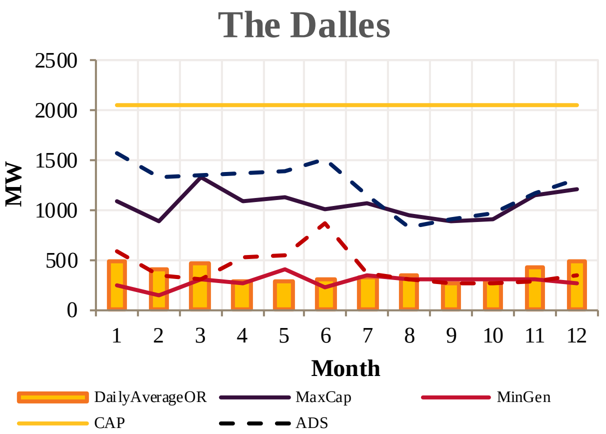


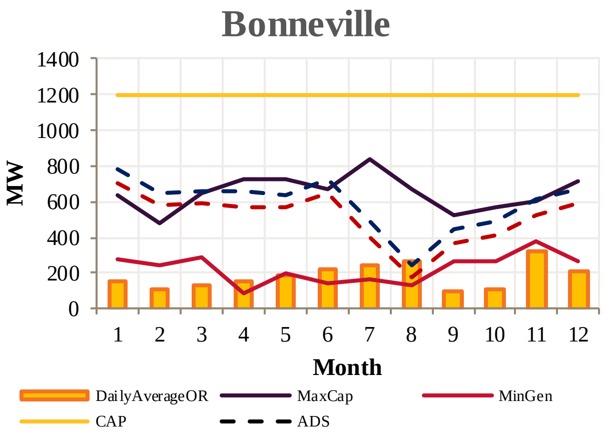
Mainstem modeling parameters - low

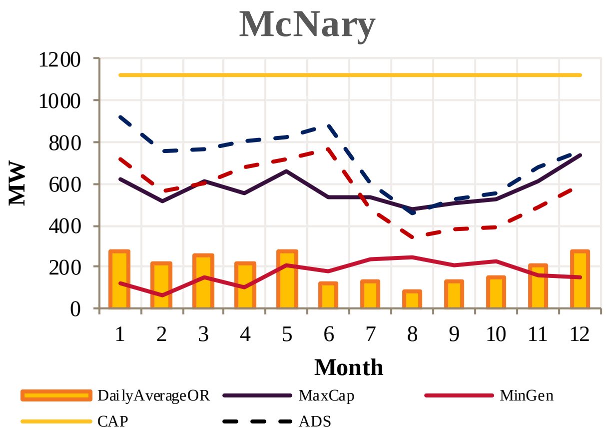












COI congestion with different Hydro conditions (Congestion Hours)

Path	ADS	NWPCC Med	NWPCC Low	NWPCC High
COI	175	349	49	1,597

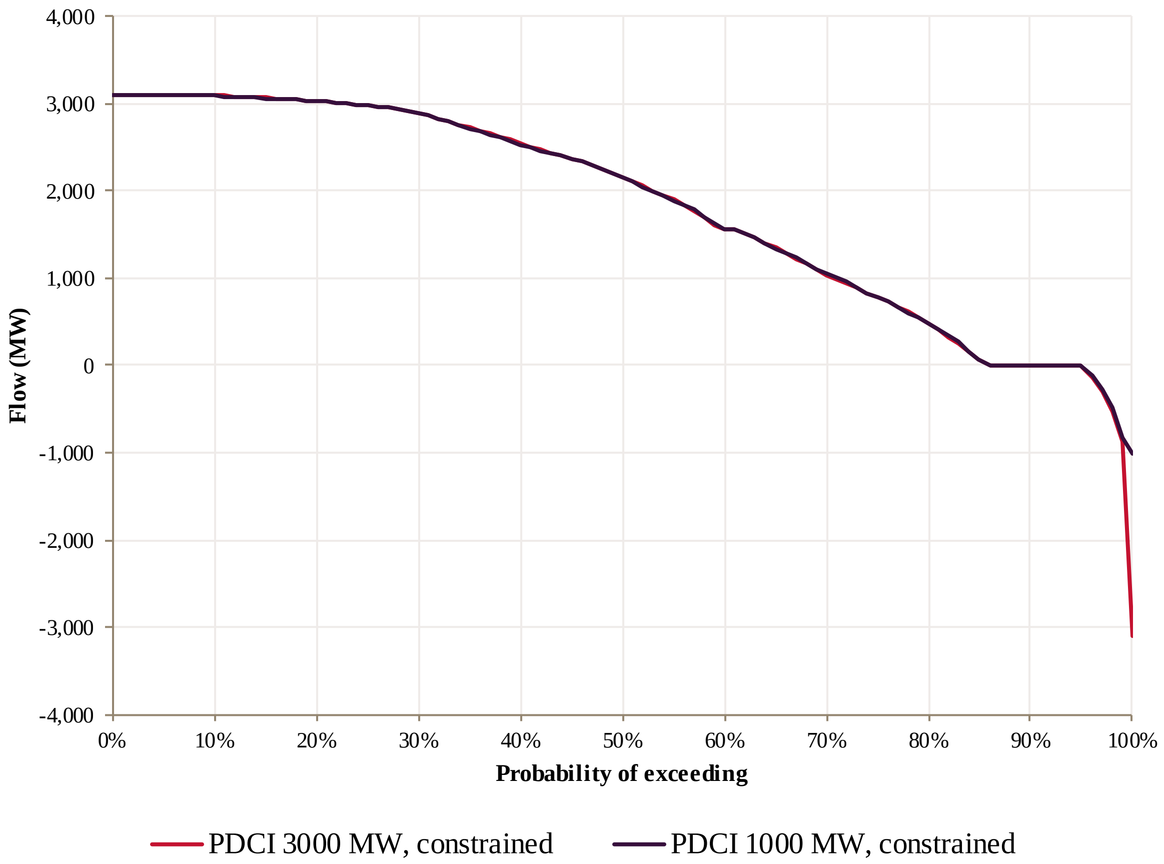
- COI congestion includes congestion of Path 66 (COI) and its downstream lines
- In the base case studies, COI path rating is 4800 MW, and COI scheduled outage and derate are modeled
  - COI congestion mainly happened during the hours COI was derated
- A sensitivity with assuming 5100 MW of COI path rating was conducted using the NWPCC Med Hydro condition
  - In 265 hours COI was congested, comparing to 349 hours in the base case study

Sensitivity of 1000 MW PDCI South to North limit

PDCI Limit	PAC NW Hydro	SCE curtailment (TWh)	Path 26 Congestion Cost ($M)	Path 26 Congestion Hours	PDCI Congestion Cost ($M)	PDCI Congestion Hours
3000	ADS	6.48	41.2	1284	0	0
1000	ADS	6.52	42.6	1289	1.02	102
3000	Med	6.62	35.5	1155	0	0
1000	Med	6.64	38.2	1139	0.665	67

- 1000 MW of PDCI South to North rating assumption is based on LADWP’s operation limit
- Path 26 and PDCI congestions were in from South to North direction in simulation results

PDCI Flow Duration Curves
South to North limit sensitivity



Consideration of other sensitivities

- Adjust hydro dispatch model to allow NW hydro to respond the change of COI flow
- CAISO export limit
- Several hydro model parameters may impact the hydro response for a given the hydro condition
  - Hydro dispatch cost (current NW hydro have -$50 ~ -$75/MW dispatch cost)
  - Hydro daily operating range
  - Hydro banking water capability

Summary of Longer-term Assessments Results

- In the North to South flow:
  - COI congestion occurs in all hydro conditions with highest congestion occurring in “high hydro” scenario in 1,597 hours in a year.
  - No congestion was observed on PDCI in the N-S direction

- In the South to North flow:
  - No congestion on COI was observed in the S-N direction.
  - No congestion on PDCI assuming WECC path rating as limit. There would be congestion on PDCI if the S-N is limited to 1000 MW.
  - Path 26 is congested for more than 1,100 hours in the S-N direction for the medium hydro scenario.

2. Increase dynamic transfer limit (DTC) on COI

Current NWACI DTC and Limitations to Increase DTC

- The Dynamic Transfer Capability (DTC) on the Northwest AC Intertie (NWACI) has increased from 400 MW to 600 MW effective 7/1/2018 *.

- Limitations to Increase DTC beyond 600 MW:
  - Excessive voltage fluctuations and reactive switching
  - RAS Arming
  - Voltage Stability

* https://www.bpa.gov/transmission/Doing%20Business/bp/Redlines/Redline-DTC-Operating-Scheduling-Reqs-BP-V08.pdf

Excessive voltage fluctuations and reactive switching

- Active power flow variations can cause excessive voltage variations VAR switching.

- At 600 MW DTC limits, loads along COI lines may experience voltage change but at higher DTC other areas might be impacted.

- Voltage variability is the limiting DTC factor about 80% of time today.

RAS Arming

- The RAS arming requirements change rapidly with changing system conditions.

- If dispatchers are unable to keep with manual RAS arming, the system can end up in an insecure state.

- RAS arming requirements are very steep between 2,500 and 3,600 MW of COI flow.

- If a generator that is armed for RAS changes its power output because of EIM dispatch, the adjustments to over-all arming amount and its allocation among COI RAS participants are required for the system reliability.

Voltage Stability

- A fast ramp up of the COI power may result in a sub-optimal system state such that it may become voltage unstable for a critical contingency.

- This limitation applies to dynamic transfers when the flows are within 400 MW of the COI voltage stability limit. Voltage stability study was done by BPA Planning with all lines in service and COI limit of 4,800 MW.

- Voltage stability is the limiting DTC factor about 20% of time, mainly under outage conditions.

Potential Solutions to Increase DTC

Limitations	Solutions
Excessive voltage variability and reactive switching	Real-Time Allocation of COI DTC; COI DTC Nomogram; Apply DTC limits to actuals; Coordinated Voltage Control; State Awareness and Analytics Tools
Voltage stability	Synchrophasor RAS
RAS arming	Automate arming of COI and PDCI RAS
	System Performance Studies
	System Performance Monitoring, Baselining and Analytics

Potentially no DTC limit in the long term

- Coordinated voltage control and other measures will address excessive voltage fluctuation issues.

- BPA is in process of automating arming of COI and PDCI RAS. The automation will remove the RAS Arming limitation.

- Synchrophasor RAS will remove the voltage stability limit. BPA's plan is to seek approval of SP RAS as Wide-Area Protection Scheme. Once the RAS is approved, BPA will remove voltage stability limitation.

- Upon implementation of the required measures and completing detailed studies, the objective is to remove the DTC limit.

3. Implementing sub-hourly scheduling on PDCI

Implementing Sub-hourly scheduling on PDCI

- AGC and EMS modifications at BPA end are required to enable 15-minute and 5-minute scheduling on PDCI.

- Automation of PDCI RAS arming is required, the current project is in progress with expected completion date in 2020

- Voltage variability: BPA performed initial system impact studies of PDCI dynamic transfers on the Pacific Northwest system:
  - The studies indicated increased switching of power factor correction capacitors at BPA and LADWP substations, further analysis of switching device duty is required
  - System impact studies of simultaneous COI and PDCI 5-minute scheduling are planned in 2019

Study Plan for sub-hourly schedule

- BPA will perform studies in 2019 to determine AGC and other EMS modifications required.
- A joint BPA/LADWP studies will be performed in order to fully assess what will need to be modified to automate the control of the DC from AGC systems.
- The joint study is expected to be completed in two years.
- The next steps will be decided based on the outcome of the studies

4. Assigning RA value to firm zero-carbon imports

RA Review in CEC/CPUC letter:

- "…Assigning some resource adequacy (RA) value to hydro generation imports that could be shaped through unused storage capacity potentially available in the Northwest…"

- "… Assigning some RA value to firm zero-carbon imports or transfers. Develop a bounding case that assumes maximal utilization of existing infrastructure investments supporting Energy Imbalance Market operations of participating entities in the Northwest, as well as the integration of synchro-phasor data into control room operations. This case will inform further study and explore the maximum annual expected Northwest hydro import capability of the California ISO grid to estimate an upper bound on avoided GHG emissions assuming that RA/RPS counting criteria are not limiting…"

RA procurement process

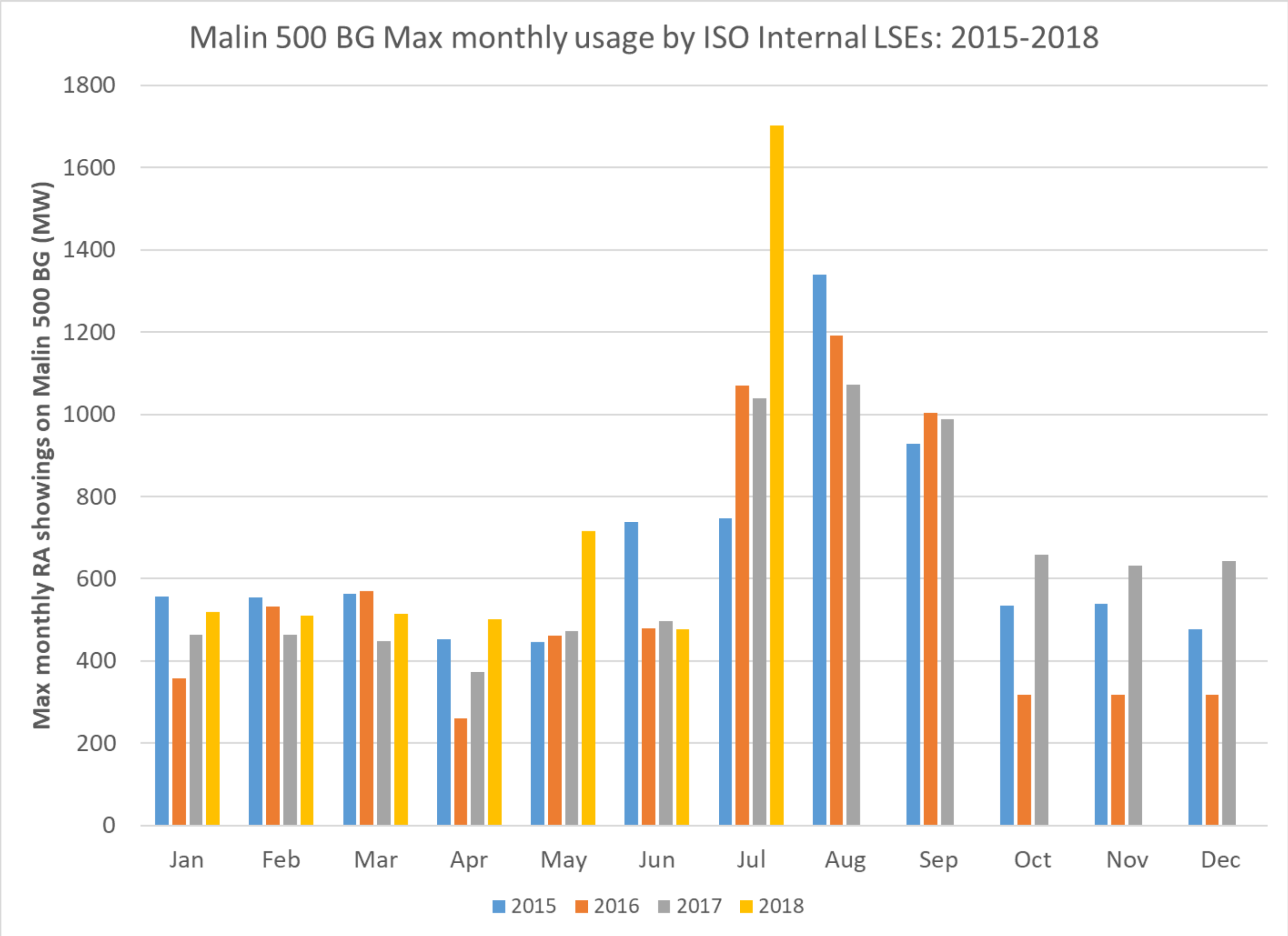
- As part of MIC process, the ISO calculates MIC on all branch groups(BG) based on the historical hour-ahead scheduled import on the BGs.
- The calculation is done annually, using the historical data over the two prior years
- From all the hours in each year, in which CAISO load was higher than 90% of peak load in that year, the highest two scheduled imports will be selected (total of 4 data points for each BG).
- The average of the above four data points determines the MIC for any BG.

Historical MIC allocation on Malin 500 BG

- Malin 500 BG consists of the Malin-Round Mountain #1 and #2 500 kV lines which are part of COI.
- Malin 500 maximum capacity is 3,200 MW which is 2/3 of COI's WECC path rating of 4,800 MW
- Following the above process, the allocated MIC to Malin 500 BG in the last few years:

Year	Max limit on Malin 500 BG MIC (MW) (2/3 of COI limit)	Allocated MIC on Malin 500 BG (MW)	ETCs and TORs on Malin 500 BG held by entities outside the ISO (MW)	Available RA for Internal ISO LSEs (MW)
2015	2,983	2,913	880	2,033
2016	3,133	3,032	880	2,152
2017	3,127	3,008	900	2,108
2018	3,200	3,008	1,200	1,808

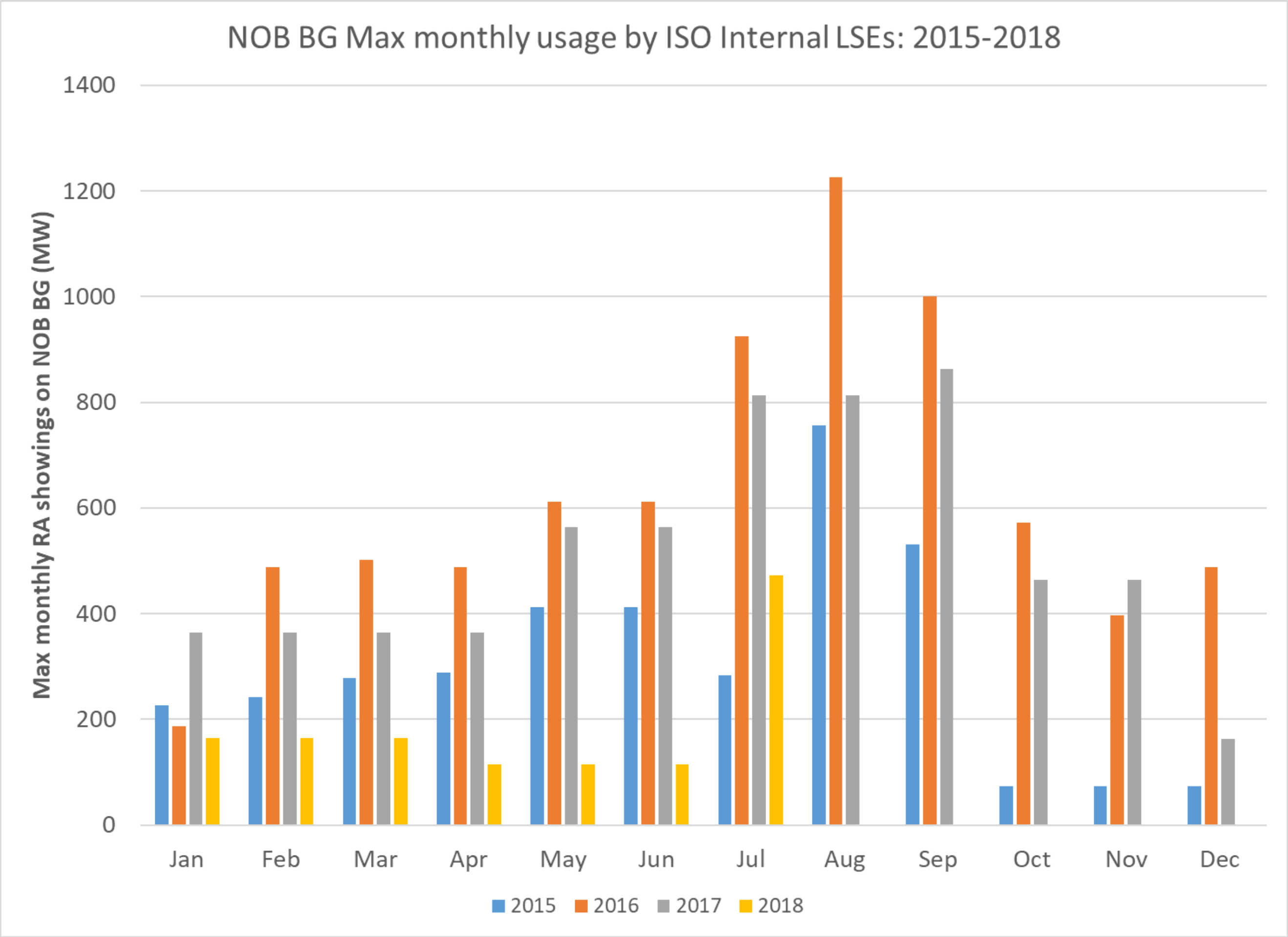
Historical RA showings on Malin 500



Historical MIC allocation on NOB BG (PDCI)

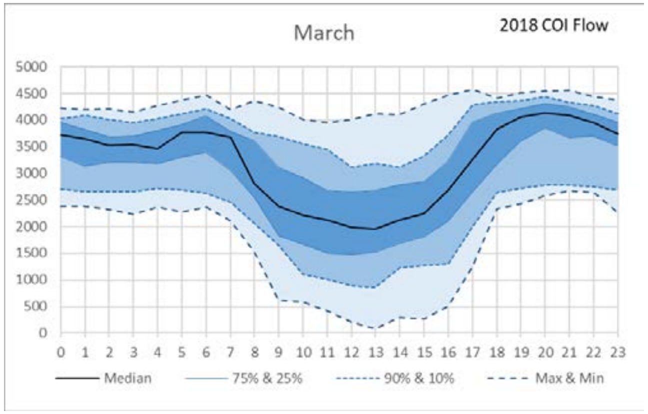
Year	Max limit on NOB BG MIC (MW)	Allocated MIC on NOB BG (MW)	ETCs and TORs on NOB BG held by entities outside the ISO (MW)	Available RA on NOB BG for Internal ISO LSEs (MW)
2015	1,564	1,544	0	1,544
2016	1,564	1,544	0	1,544
2017	1,294	1,283	0	1,283
2018	1,294	1,270	0	1,270

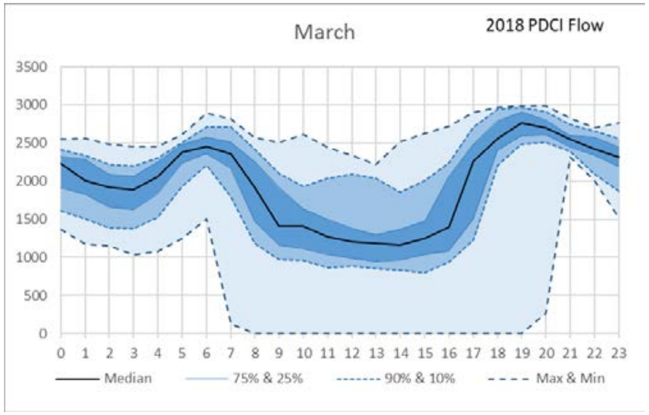
Historical RA showings on NOB BG (PDCI)

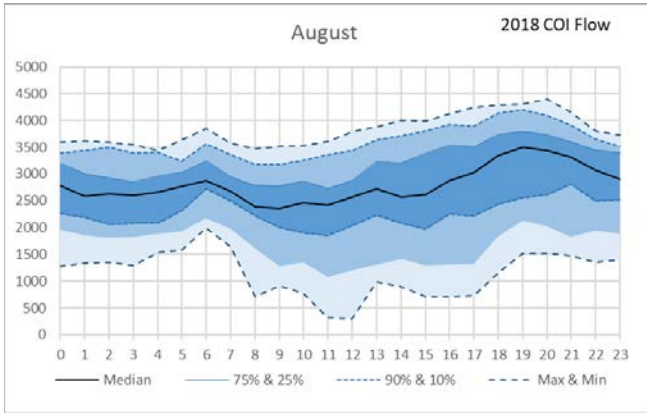


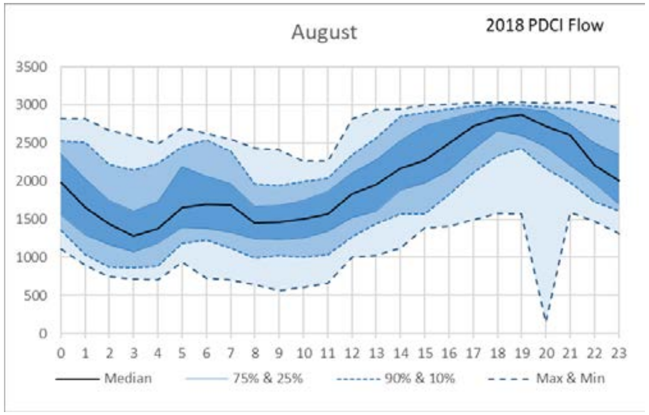
California ISO

COI and PDCI Flows – March and August 2018









Potential barriers for higher RA showings

- As per CPUC/ISO requirements, commitment of firm capacity is required 45 days ahead of the operating month in order to be counted towards RA.
  - Challenges to forecast hydro that far in advance.

- Potential priorities of PNW entities to serve local loads.

- Currently the FERC-approved ISO RA Import allocation process is one year at a time. Some LSEs prefer to sign multi-year contracts.

- In general, firming up capacity and energy going through number of Balancing Authority Areas may results in additional cost compared to internal California resources.

Summary of RA Analysis

- The RA showings are less than available MIC for most of the year,
- The hour-ahead import schedules which are the basis for MIC are close to path rating.
- In real time, and in recent years, COI and PDCI flows have similar trends as California's net load.
- From Carbon/GHG perspective, there seems to be little to no impact if hydro import from PNW has RA assigned to it or not, as hour-ahead scheduling data shows that potentially low-carbon energy is already coming into California.

Next Steps

- January 31, 2019 post draft Transmission Plan
  - Finalize and document the detailed analysis
- February 8, 2019 stakeholder meeting on draft Transmission Plan

Wrap-up
Preliminary Policy and Economic Assessments

Kristina Osborne
Lead Stakeholder Engagement and Policy Specialist

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

Stakeholder Comments

- Stakeholder comments to be submitted by November 30
  - 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