Introduction and Overview

Neil Millar

Generation Deliverability Assessment Methodology Proposal Call
December 18, 2018

Generation Deliverability Methodology Revision Process

- November 16, 2018: CAISO presented proposed revisions during the third 2018-2019 Transmission Planning Process meeting.
- November 30, 2018: Stakeholder comments due
- December 12, 2018: CAISO posted revised Generation Deliverability Methodology document, along with additional presentation slides addressing stakeholder questions and comments
- December 18, 2018: CAISO hosts a call to present materials posted on the 11th.
- January 7, 2019: Stakeholder comments due
- Based on comments, the ISO will consider scheduling a further technical workshop in early February 2019

Implementation Timeline

- The 2019 Reassessment Study will begin in January 2019.
- If a technical workshop is not required:
  – the revised Generation Deliverability Methodology can be applied in the 2019 Reassessment Study commencing in January 2019, and then in the subsequent Cluster 11 Phase II study
- If a technical workshop is required:
  – the revised Generation Deliverability Methodology can be applied in the Cluster 12 Phase I study

Purpose of the Generation Deliverability Assessment

- The CAISO Generation Deliverability Assessment methodology was developed in 2004
- The methodology has been utilized since then to ensure that resource adequacy resources are deliverable to load during conditions when a resource shortage is most likely to occur
- Deliverability is not tied to market operation - a generator that meets this deliverability test may still experience congestion – even substantial congestion
- The CAISO Transmission Planning Process annually assesses the need for policy-driven and economic-driven transmission projects to ensure sufficient energy from renewable resources needed to meet the state's resource policies can be delivered to load

Why is the ISO changing the study scenarios for assessing deliverability?

- The study changes are driven by the evolving shape of the "net sales" load shape to peaking later in the day, and increasing levels of intermittent resources
- This necessitates more deliberate study of the output of intermittent resources to serve load matched with the load level at the time of output
- The same factors have essentially led the CPUC to move towards an "effective load carrying capability" or ELCC basis for considering "qualifying capacity" values in resource adequacy processes
- As a probabilistic approach is not viable for deliverability assessments, the solution for deliverability is to study specific scenarios matching load with intermittent generation output

Generation Deliverability Assessment Methodology Proposal

Songzhe Zhu

Generation Deliverability Assessment Methodology Proposal Call
December 18, 2018

Current Deliverability Methodology

- Power flow analysis tests deliverability under a system condition when the generation capacity is needed the most assuming 1-in-5 ISO peak load conditions
- Specific levels of intermittent generation output are studied: 50% exceedance values (a lower MW amount) or 20% exceedance values (a higher MW amount) 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 the <u>study amount</u> and reducing generation outside the gen pocket
  - Conducting the power flow analysis

Changes Affecting Deliverability Assessment

- When the capacity resources are needed the most:
  - The time of highest need is moving from the peak consumption hours (Hours 16:00 to 17:00) to peak sales hours (Hour 18:00) due to increased behind-the-meter solar PV distributed generation

- The need to more properly account for the evolving contribution of growing volumes of intermittent resources on resource adequacy
  - For CPUC, moving from exceedance value to effective load carrying capacity (ELCC) approach

CPUC ELCC Based Qualifying Capacity 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 combinations of load shape and weather-influenced generation profiles
  - Each case is run with multiple iterations of random draws of variables such as generator outages

CPUC ELCC Based Qualifying Capacity Calculation for Wind and Solar Resources (continued)

- 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

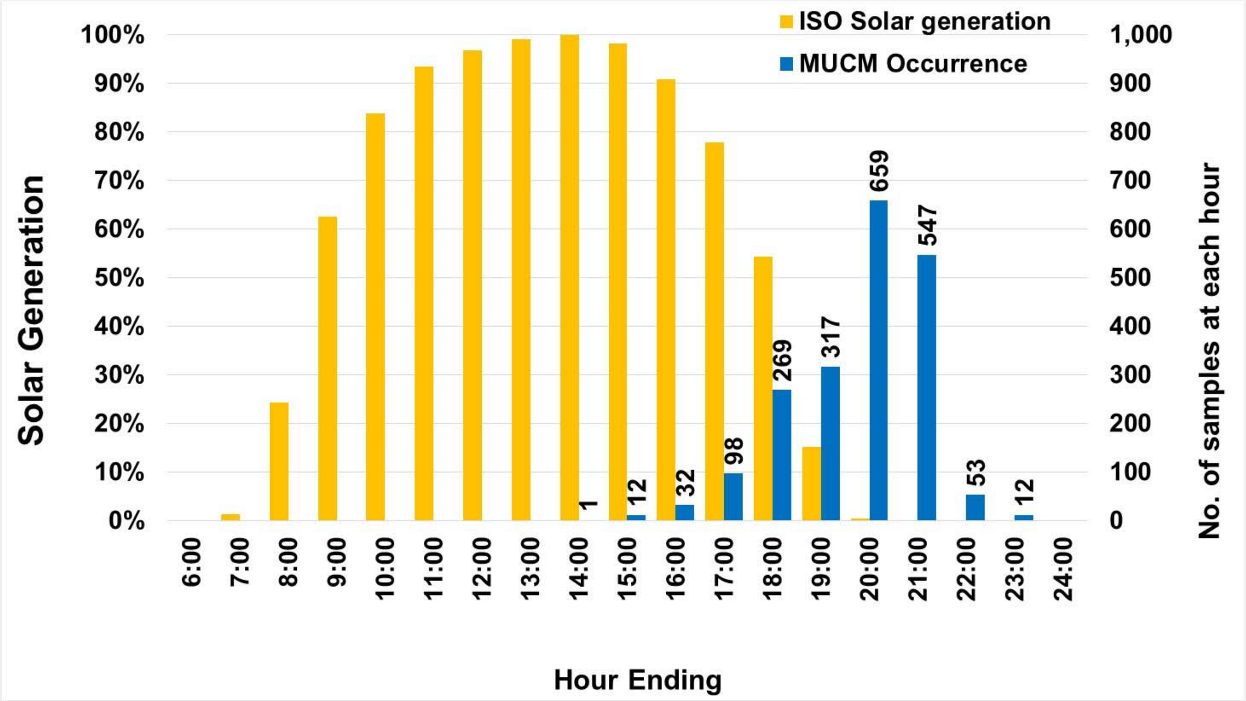
Issues identified and considered in Deliverability Methodology Review:

- Selection of system conditions to test deliverability
- Implications of “vintaging”, e.g resources receiving average or incremental results for each resource type
  - The same solar and wind resource output assumptions are made for all resources regardless of “vintage”
  - The revised methodology would be applied in the next reassessment study and subsequent cluster studies so that network upgrade requirements would be reduced
  - Changes to existing resources would need to go through the queue, as is currently required

Selection of System Conditions

- The deliverability test itself is not changing, but;
- We need to expand study scenarios to capture a broader range of combinations of modeling quantities – load, generation and imports
- At a minimum, the deliverability analysis should test multiple critical system conditions
- Data sources for identifying critical system conditions:
  - CAISO summer assessment
  - CPUC ELCC data (http://www.cpuc.ca.gov/General.aspx?id=6442451973)
    - CPUC unified RA and IRP Modeling Datasets
    - Latest CPUC output data from QC calculation for wind and solar resources

Critical Conditions per Review of Minimum Unloaded Capacity Margin Hours from 2018 Summer Assessment



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

Critical Conditions per 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 derived from these sources:

- Highest system need scenario (peak sale)
  - HE18 ~ HE22 in the summer
- Secondary system need scenario (peak consumption)
  - HE15 ~ HE17 in the summer
- These are the two critical system conditions the ISO selected in which generation will be tested for deliverability

Highest System Need (HSN) 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*

* The MIC is calculated from the highest imports during the summer hours when the load is above 90% of the annual peak load. In the last five years, the highest import hours are between HE18 and HE21.

HSN Scenario – Basis for 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 when capacity shortage risk is highest

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 (SSN) 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

SSN Scenario – Basis for 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%

Data Sources for 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
- The exceedance values apply to all intermittent generation in the study – existing or future.

Intermittent Generation Maximum Study Amount Assumptions and QC Values

Calendar Year 2018
Summer Month ELCC

Month	Wind	Solar
6	47.5%	44.8%
7	29.7%	41.7%
8	26.5%	41.0%
9	26.5%	33.4%

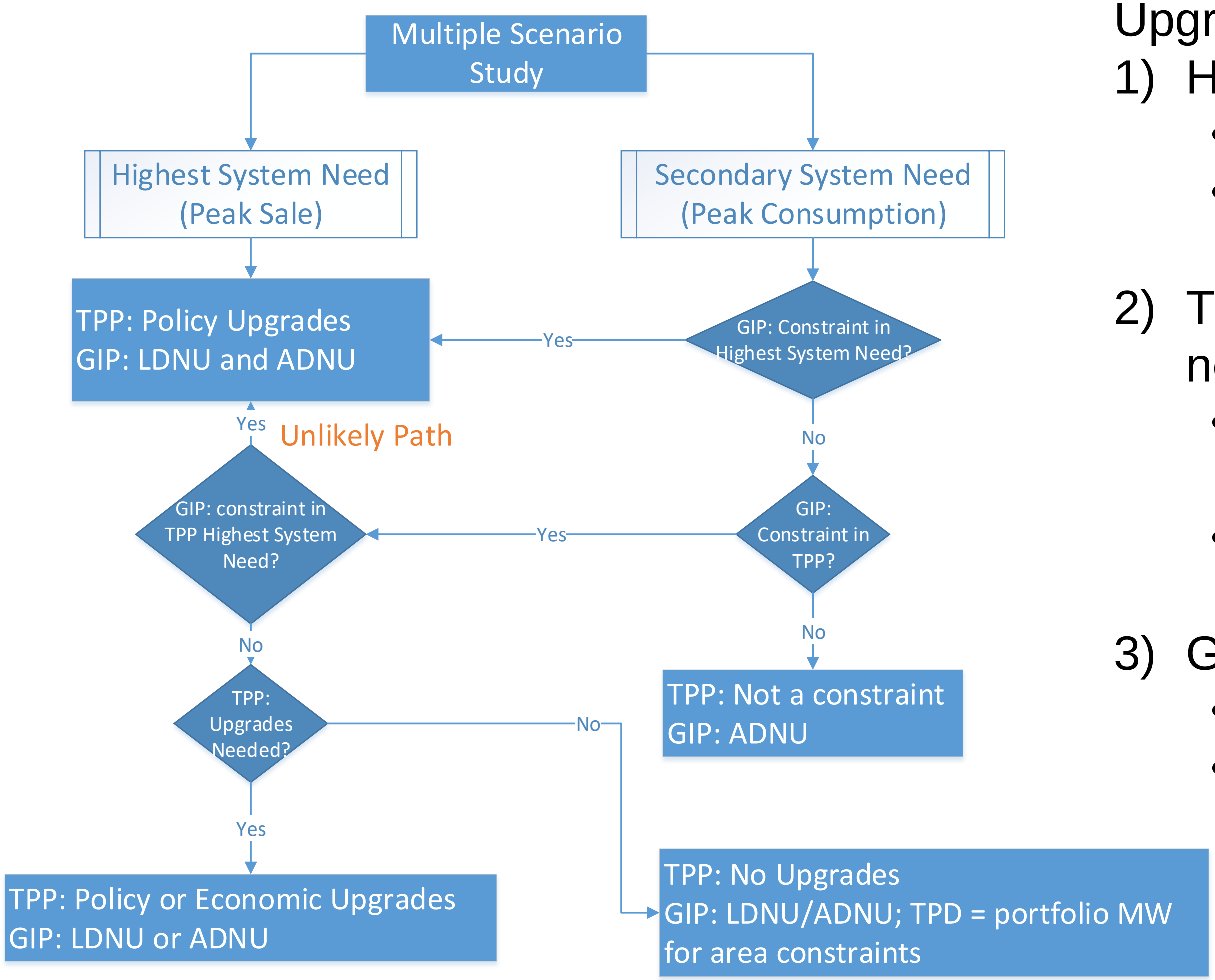
Current Modeling Assumptions

		50% Exceedance	20% Exceedance
wind	SDG&E	37%	51%
	SCE	38-47%	61-73%
	PG&E	32% - 47%	58-71%
solar	SDG&E	87%	96%
	SCE	92-93%	99-100%
	PG&E	92%	99%

Proposed Modeling Assumptions

		Highest System Need	Secondary System Need
wind	SDG&E	33.7%	11.2%
	SCE	55.7%	20.8%
	PG&E	66.5%	16.3%
solar	SDG&E	3.0%	35.9%
	SCE	10.6%	42.7%
	PG&E	10.0%	55.6%

Network Upgrade Identification in each Stage



Upgrades needed in:

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

Annual Net Qualifying Capacity Determination for Full Capacity Deliverability Status Generation

- Annual process assesses if generation with FCDS is limited to a lower deliverability amount due to system conditions
- The Annual NQC study includes both the HSN and SSN scenarios
- Deliverable % is calculated from both the HSN and SSN scenarios
- For deliverability constraints in the secondary system need scenario, if the TPP identified the same constraint and determined that no upgrades are required, then that constraint would not reduce the FCDS generator's NQC level
- The lower deliverable % between the HSN and SSN scenarios is the resource's deliverable %

Two studies were performed using two different base cases to demonstrate the revised methodology

1. The 2018-2019 50% RPS 42MMT portfolio base case was studied
   – This portfolio generation is described on the next slide

2. The Cluster 10 Phase I – 2023 summer peak base case was studied and compared to the original results from the Cluster 10 GIDAP studies
   – The Cluster 10 Phase I generation list and detailed documentation of the deliverability study of this generation using the current methodology is posted on the ISO market participant portal
   – A comparison of original results developed using the current methodology and the results using the proposed revised methodology is provided in the following slides

2018-2019 50% RPS 42MMT PORTFOLIO STUDY RESULTS USING THE REVISED DELIVERABILITY METHODOLOGY

California ISO

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%	

San Diego Area Results – RPS 42MMT Portfolio

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

PG&E Area Results – 50% RPS 42MMT

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

CLUSTER 10 PHASE I STUDY RESULTS USING THE REVISED DELIVERABILITY METHODOLOGY AND COMPARISON TO ORIGINAL RESULTS USING CURRENT METHODOLOGY

California ISO

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 – 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 – 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 past results using Current Methodology

The new methodology results in the following upgrades identified using the current methodology in QC10 Phase I reports not be needed, and no new requirements:

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 Revisions – What Remains the Same

- Methodology remains fundamentally the same, but study scenarios align load levels with intermittent generation output
- What remains the same:
  - TPP policy study assesses deliverability of the renewable portfolio
  - GIP study assesses deliverability of the generation projects seeking FCDS
  - Energy-only generators are off-line in the study unless needed to balance load

Summary of Proposed Deliverability Assessment Methodology Revisions – What will Change:

- System conditions selected to test deliverability:
  - Highest system need scenario (peak sale)
  - Secondary system need scenario (peak consumption)

- Delivery network upgrades and NQC determination:
  - TPP approves upgrades to mitigate portfolio amounts for peak sale deliverability constraints;
  - TPP approves upgrades based on portfolio amounts (or not) for peak consumption constraints if the need is also identified in the policy/reliability or economic studies
  - TPP no-upgrade determination means MWs up to the portfolio amount is deemed deliverable for the peak consumption constraint in TPD allocation and annual NQC determination
  - GIP may identify LDNU/ADNUs in the primary system need scenario and ADNUs in the secondary system need scenario

Expected Impacts of the Proposed Methodology

- More deliverability available in the TPD allocation on the basis of installed MW.
- Fewer transmission upgrades required for the generators to achieve FCDS
- Fewer transmission upgrades identified from the deliverability assessment in both the generation interconnection study process and TPP process
- Transmission congestion may increase, which would need to be addressed in the transmission planning process as policy-driven or economic-driven upgrades (aligned with TEAM)

Next Steps Pertaining to Deliverability Assessment Methodology

- Seek feedback from the stakeholders on the proposal
- If necessary, schedule a technical workshop in early February 2019
- Finalize the methodology
- Implement the methodology in the generation interconnection studies and the transmission planning studies
  - If no technical workshop, begin with 2019 reassessment and Queue Cluster 11 Phase II study
  - If technical workshop, begin with later Queue Cluster 12 Phase I study and 2019-2020 TPP deliverability study