Deliverability Assessment Methodology
Draft Final Proposal Paper

Deliverability Assessment Methodology Straw Proposal Paper Stakeholder Meeting

October 4, 2019

Introduction

Neil Millar
Executive Director, Infrastructure Development

Why is there a need to change the study scenarios for assessing deliverability?

- The need for 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 contributed to 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

Issue Paper – May 2, 2019 Stakeholder Call

- The CAISO posted an issue paper and discussed it with stakeholders on May 2, 2019 to garner additional stakeholder input needed to develop a straw proposal that addresses the comments provided on the proposed on-peak generation deliverability methodology revisions

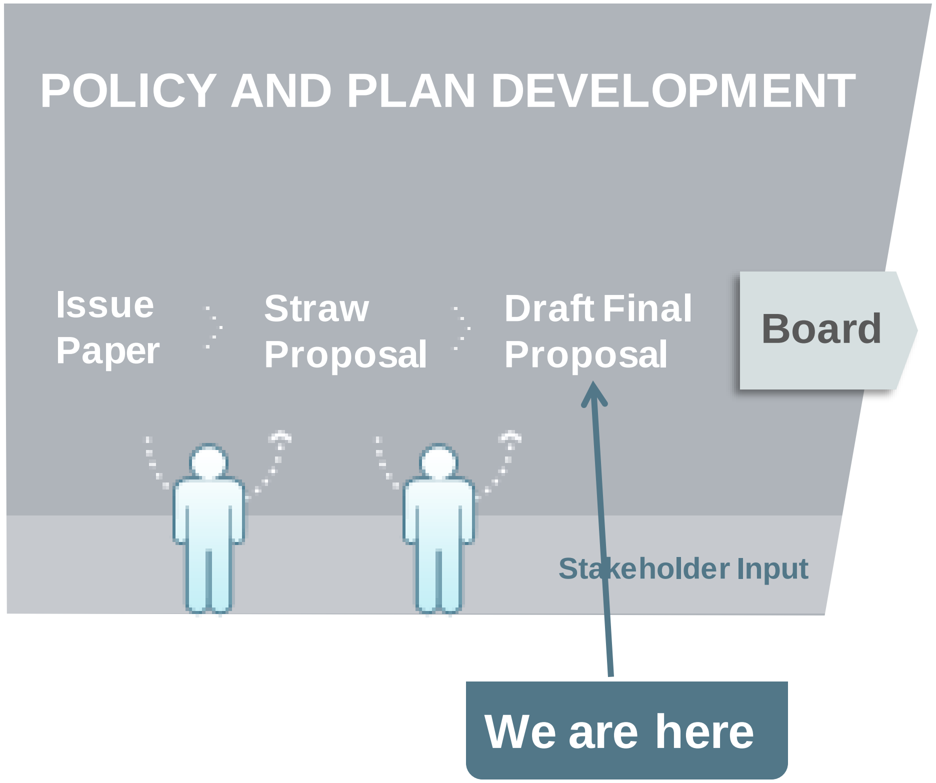
- In response to the Issue Paper, stakeholders agreed that the deliverability methodology needs to be changed and with the ISO's reasoning on why it needs to be changed

- The majority of stakeholders raised concerns with increased curtailment that would result from the revisions in the deliverability methodology focused on addressing resource adequacy needs

Straw Proposal – August 5, 2019 Stakeholder Meeting

- The CAISO continued to recommend the revisions to the deliverability methodology that were proposed in 2018 with some adjustments
- We also recommended that an off-peak deliverability assessment be included in the interconnection studies to address excessive curtailment risks
  - This is a balance between ratepayer and generator concerns, and needs to be considered in concert, as opposed to two separate proposals
- Further refinements have been made in preparing this draft final proposal based on comments

CAISO Policy Initiative Stakeholder Process



Objectives for today

- Responses to stakeholder comments on the previously proposed revisions to the Deliverability Assessment methodology

- Proposed revisions to the On-Peak Deliverability Assessment methodology

- Proposed revisions to the Off-Peak Deliverability Assessment methodology

Responses to Stakeholder Comments on the Previously Proposed Revisions to the Deliverability Assessment Methodology

Robert Sparks

Sr. Manager, Regional Transmission - South

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Value and Impact of OPDS to Market Operation

- Stakeholder inputs
  - The value of OPDS is not clear
  - OPDS scheduling priority is not understood and could create adverse incentives

- CAISO response
  - OPDS encourages siting new generation projects in good locations from a transmission perspective
  - The IC could proactively manages excessive curtailment risk
  - The scheduling priority addresses “free-ride” concern

Scheduling Priority under All Conditions

- Stakeholder inputs
  - OPDS scheduling priority is not limited to time period associated with off-peak study, including oversupply conditions
  - OPDS scheduling priority is not limited to transmission constraints that the resource will fund the upgrade
- CAISO response
  - Local constraints, to be mitigated by the off-peak local NUs, would be binding before and during over-supply.
  - Accurate association of generation curtailment priority with a transmission upgrade is not feasible during the market runs

Funding Off-Peak Deliverability Upgrades

- Stakeholder inputs
  - Full reimbursement of off-peak deliverability upgrades may lead to upgrades not in the ratepayer’s interest.
- ISO response
  - The cost being reimbursable is a strong incentive for generators to elect OPDS and up-front fund inexpensive local upgrades.
  - Such upgrades, due to low cost and only moving forward together with generation development, are expected to improve the market efficiency and benefit the ratepayers.
  - Procurement processes take into account the cost of identified upgrades in their selection process of renewable generation contracts, so the combined cost of the resource and the upgrades are considered and the transmission costs are only triggered if they are in the ratepayer’s interest.

Transition into the Revised Methodology

- Stakeholder inputs
  - EO (converted from FC due to not allocated TPD) should have a one-time opportunity to receive a TPD allocation ahead of other queue projects seeking TPD.
  - A one-time option for EO to get OPDS
- CAISO response
  - The incremental TPD created by the on-peak deliverability assumption changes will be allocated to eligible generators in the priority order recently updated in the tariff.
  - A one-time opportunity will be provided for the EO generation projects to request OPDS in the next cluster window upon approval and implementation of the proposal.

Proposed Revisions to the On-Peak Deliverability Assessment Methodology

Songzhe Zhu
Sr. Advisor Regional Transmission Engineer

Deliverability Assessment Methodology Straw Proposal Paper Stakeholder Meeting

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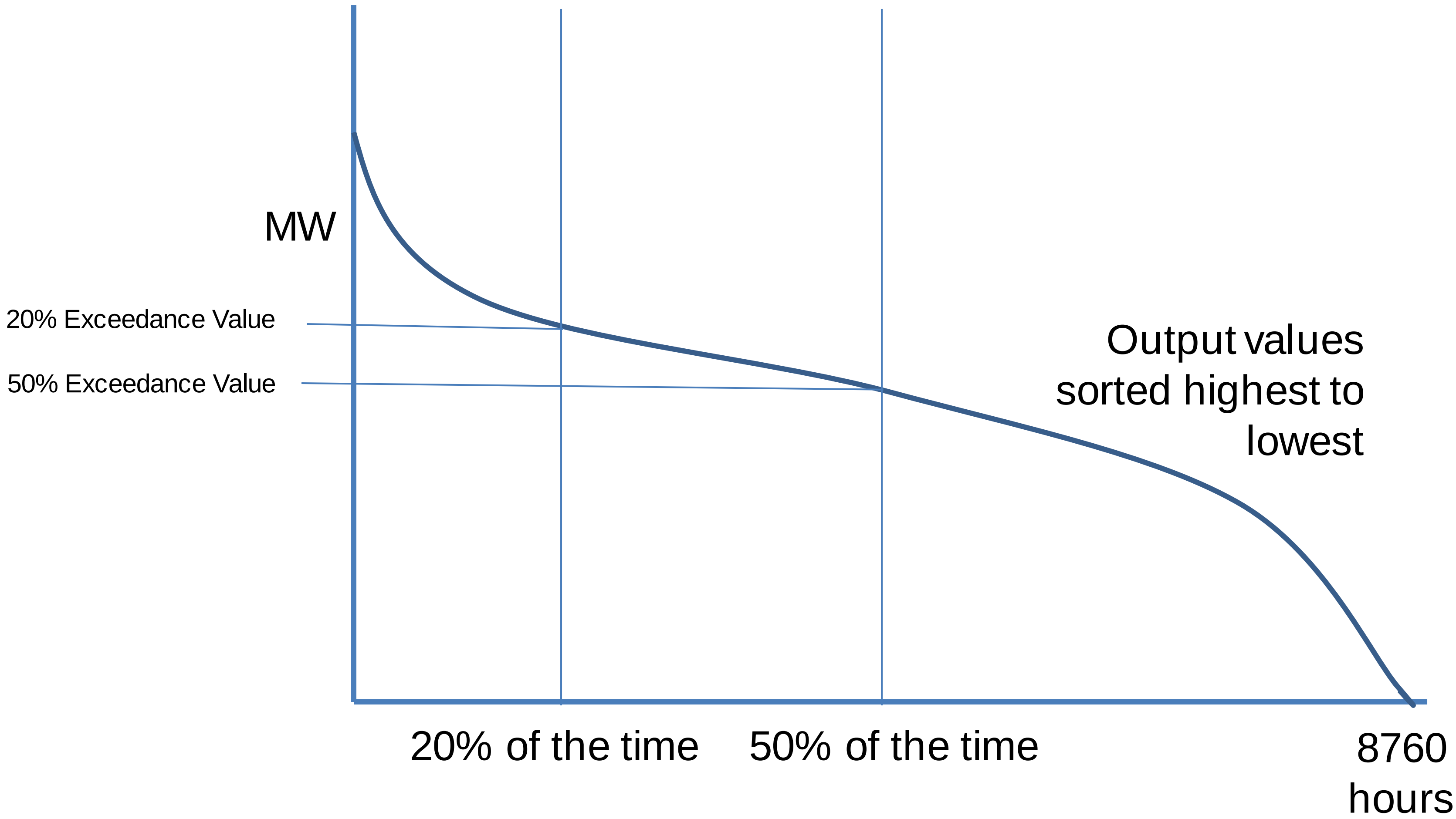
Current On-Peak Deliverability Methodology

- 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

Explanation of Exceedance Values



Changes Affecting On-Peak 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 across the whole year
  - For CPUC, moving from exceedance value to effective load carrying capacity (ELCC) approach

CPUC moving to 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)

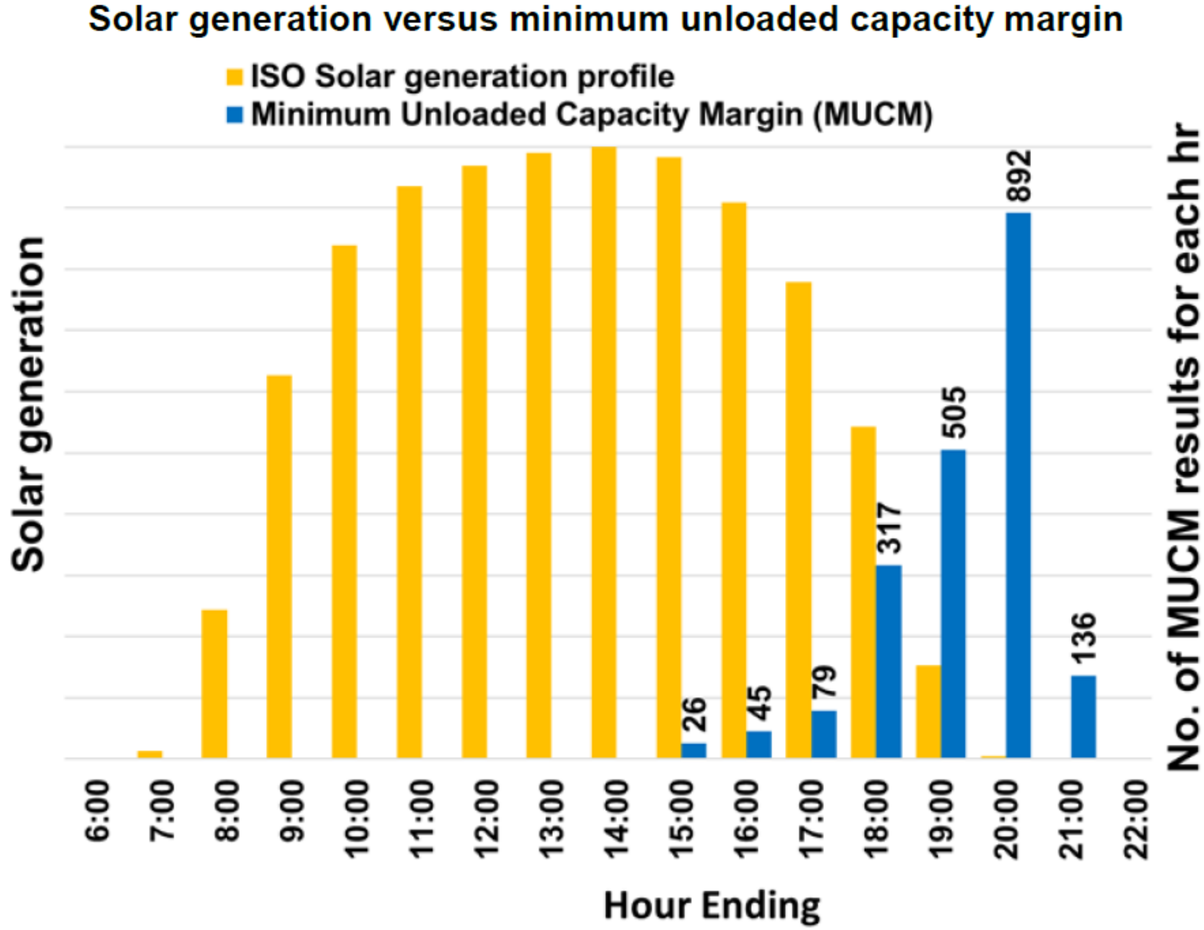
- Reliability impacts of the wind or solar resources are compared to the reliability impacts of “perfect” capacity
  - Calibrate the CAISO system to weighted average LOLE = 0.1
  - Remove the solar or wind resources and replace with perfect capacity
  - Adjust perfect capacity until LOLE = 0.1
  - ELCC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

- Aggregated by technology and region

Expanding the Selection of System Conditions

- The on-peak 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 2019 Summer Assessment



Source: http://www.caiso.com/Documents/2019SummerLoadsandResourcesAssessment.pdf

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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 which were 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 Maximum Import Capability 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), but no lower than the average QC ELCC factor during the summer months
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	40.2%	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%

Proposed on-peak deliverability study assumptions for wind and solar

Area	HSN		SSN	
	Solar	Wind	Solar	Wind
SDG&E	3.00%	33.70%	40.20%	11.20%
SCE	10.60%	55.70%	42.70%	20.80%
PG&E	10.00%	66.50%	55.60%	16.30%

Wind/Solar ELCC Factors

Month	CY 2019 ELCC		CY 2020 ELCC	
	Solar	Wind	Solar	Wind
1	0.0%	11.3%	4.0%	14.0%
2	2.4%	17.3%	3.0%	12.0%
3	10.4%	18.3%	18.0%	28.0%
4	33.2%	31.4%	15.0%	25.0%
5	30.5%	30.6%	16.0%	25.0%
6	44.8%	47.5%	31.0%	33.0%
7	41.7%	29.7%	39.0%	23.0%
8	41.0%	26.5%	27.0%	21.0%
9	33.4%	26.5%	14.0%	15.0%
10	29.4%	8.8%	2.0%	8.0%
11	4.1%	8.4%	2.0%	12.0%
12	0.0%	15.2%	0.0%	13.0%

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 being 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		

On-peak deliverability assessment remains focused on system reliability

- Highest system need scenario (HSN)
  - Highest likelihood of capacity shortage
  - Driving local and area delivery network upgrades
- Secondary system need scenario (SSN)
  - Some capacity shortage risk during hours when solar output is reduced
  - Reliability risk if a considerable amount of capacity from a larger area is constrained, i.e. <u>area deliverability constraints</u>

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Summary of Proposed Deliverability Assessment Methodology Revisions – What would Remain the Same:

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

Summary of Proposed On-Peak Deliverability Assessment Methodology Revisions – What would 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 to approve upgrades to mitigate portfolio amounts for peak sale deliverability constraints;
  - TPP to approve 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 on-peak deliverability available in the TPD allocation on the basis of installed MW due to declining QC values stemming from CPUC ELCC methodology
- 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
- Renewable curtailments due to transmission constraints may increase, and would need to be addressed:
  - in the proposed revisions to the Off-Peak Deliverability assessment methodology, and
  - in the transmission planning process as policy-driven or economic-driven upgrades (aligned with TEAM)

Proposed Revisions to the Off-Peak Deliverability Assessment Methodology

Songzhe Zhu
Sr. Advisor Regional Transmission Engineer

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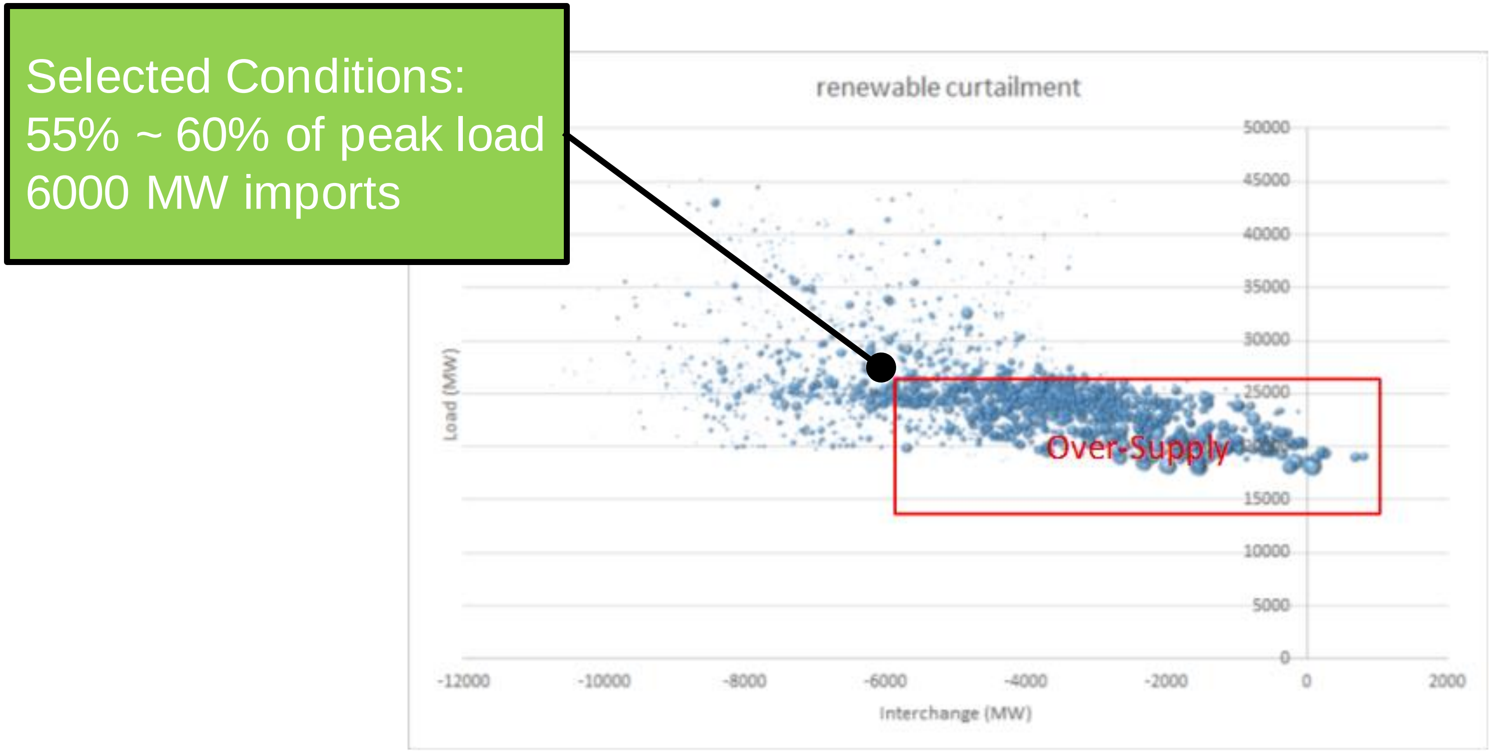
Principles of Off-Peak Deliverability Assessment

- Identify transmission bottlenecks that would cause excessive renewable curtailment.
- Identify transmission upgrades for local constraints that tend to be less expensive.
- Rely on the TPP framework to approve transmission upgrades for area constraints that tend to be expensive.
- The study should consider both full capacity and energy only generators.

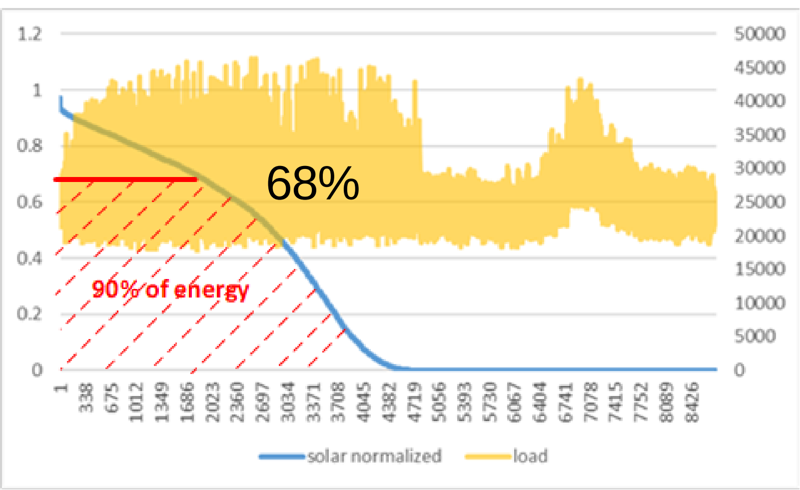
Establish the System Conditions

- Capture reasonable load and import conditions that stress the transmission system with high wind/solar output

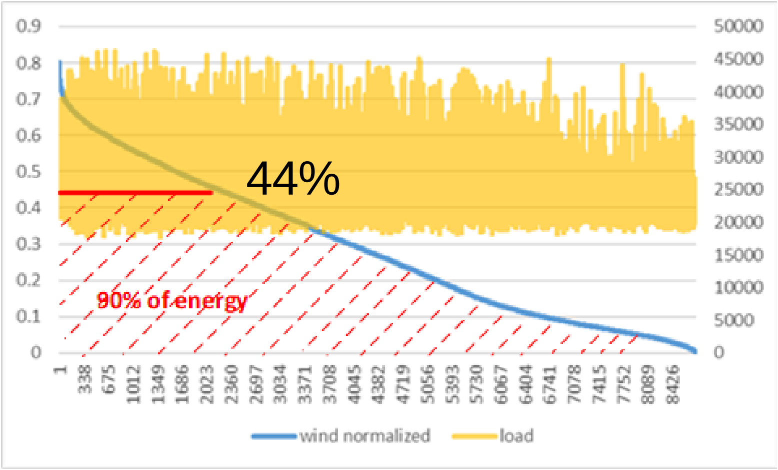


System-Wide Wind/Solar Output Assumptions

- Under the selected load and import condition, renewable outputs vary over a wide range.
- Avoid <u>*excessive*</u> curtailment: select output level corresponding to 90% energy production



Normalized Solar Output Duration Curve



Normalized Wind Output Duration Curve

Summary of Proposed System-Wide Study Assumptions

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

Increase Local Area Renewable Generation

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

Study Area Wind/Solar Dispatch Assumptions

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

Wind/Solar Dispatch Assumptions in Wind Area

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

Wind/Solar Dispatch Assumptions in Solar Area

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

Re-dispatch Order to Balance Increase of Wind/Solar Generation in the Study Area

- Reduce new generation outside the study area with a limitation on Path 26 of 4,000 MW north to south or 3,000 MW south to north.
- Reduce thermal generation inside the study area.
- Reduce import.
- Reduce thermal generation outside the study area.

Off-Peak Deliverability Power Flow Study

- A contingency analysis is performed under the normal and contingency conditions:
  - Normal conditions (P0)
  - Single contingency of transmission circuit (P1.2), transformer (P1.3), single pole of DC lines (P1.5) and two poles of PDCI if impacting the study area
  - Multiple contingency of two adjacent circuits on common structure (P7.1) and loss of a bipolar DC line (P7.2).
  - Two adjacent transmission circuit according to WECC's Project Coordination, Path Rating and Progress Report Processes.

Steps to Mitigate Overloads

1. Re-dispatch available resources to relieve the overloads
   - Dispatch existing energy storage resources to full four hour charging capacity
   - Turn off thermal generators contributing to the overloads
   - Reduce imports contributing to the overloads to the level required to support out-of-state renewables in the RPS portfolios
2. If the overloads are not fully mitigated, categorize the overloads to local or area constraints
3. Identify local and area network upgrades to fully mitigate all overloads

Treatment of Off-Peak Area Network Upgrades

- The area upgrades are for information only.
- Provide estimated scope and cost.
- Provide information on generation curtailment needed to mitigate the overloads.
- May be considered in annual transmission planning process

Treatment of Off-Peak Local Network Upgrades

- Off-peak deliverability status (OPDS) for wind and solar resources
- Generators electing OPDS must fund identified off-peak local network upgrades
  - A separate cost category – not impacting cost responsibility for DNUs and RNUs
- The cost of off-peak local network upgrades is fully reimbursable
- The OPDS provides a scheduling priority in the market operation – elaborated on later in this presentation

Interconnection Procedures for OPDS

- The IC elects Off-Peak Deliverability Status (OPDS) when submitting the interconnection request
- The off-peak local network upgrade (OPNU) costs are allocated among interconnection requests in the same cluster electing OPDS in the 5% DFAX circle, in proportion to the flow impacts on the upgrade.
- OPNU for a generation project including both directly triggered and conditionally assigned.
- The lower allocated cost between Phase I and Phase II sets the maximum OPNU cost responsibility.

Interconnection Procedures for OPDS (Cont'd)

- If the OPNU is identified, upsized or reconfigured in a subsequent TPP cycle, the OPNU cost responsibility is removed from the IC.
- OPNU cost could be adjusted in the reassessment, but not exceeding the maximum OPNU cost responsibility.
- The triggered OPNU cost is included in the requirement for interconnection financial security posting.
- OPNU for an earlier cluster could be CANU required for on-peak deliverability for later clusters.

OPDS scheduling priority

- OPDS scheduling priority is achieved by not allowing self-scheduling of non-OPDS resources
  - Changed from the ISO's previous proposal of having different self-schedule penalty prices between OPDS and non-OPDS
- Easily implementable
- Addresses concerns regarding adverse incentives of economic bids, complication associated with the penalty prices, scheduling priority of FCDS resources.

OPDS scheduling priority for hybrid resources

- OPDS-eligible hybrid resources

(4-hour discharging capacity of energy storage) + HSN study amount of solar or wind generation < requested maximum output

- OPDS-non-eligible hybrid resources

(4-hour discharging capacity of energy storage) + HSN study amount of solar or wind generation ≥ requested maximum output-eligible hybrid resources

- This may be refined after the operating and market modeling requirements are established for different configuration of hybrid resources through the CAISO hybrid resources stakeholder initiative

Self-schedule for wind/solar generation and eligible hybrid resources

	FCDS		EO	
	OPDS	Non-OPDS	OPDS	Non-OPDS
Existing wind/solar generation	Self Scheduling allowed (Grandfathered)		Self Scheduling allowed (Grandfathered)	
New wind and solar in the queue prior to the OPDS implementation	Self Scheduling allowed (Grandfathered)		One-time chance to request OPDS	
			Self Scheduling allowed	No-Self Scheduling
New wind and solar to the queue after the OPDS implementation	Self Scheduling allowed	No-Self Scheduling	Self Scheduling allowed	No-Self Scheduling

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Self-schedule for non-wind/solar generation and non-eligible hybrid resources

	FCDS	EO
	OPDS not applicable	
Existing non-wind/solar generation	Self scheduling allowed	
New non-wind/solar in the queue prior to the OPDS implementation	Self scheduling allowed	
New non-wind/solar generation	Self scheduling allowed	No-Self Scheduling

Next Steps

Robert Sparks
Sr. Manager, Regional Transmission - South

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Next Steps Pertaining to Deliverability Assessment Methodology

- Seek feedback from the stakeholders on the Draft Final Paper
- Consider stakeholder feed back and finalize the proposal
- Seek CAISO Board approval on the proposal at the November Board Meeting
- Revise tariff
- Ideally, utilize new methodology in the 2020 Reassessment, Cluster 12 Phase 2, Cluster 13 Phase 1 and all studies afterward

Comments

- Stakeholder comments should be submitted to regionaltransmission@caiso.com by October 18, 2019