Track 3.B Workshops: Day 2

November 23rd, 2020

9:30 – 4:30 p.m.

California Public
Utilities Commission

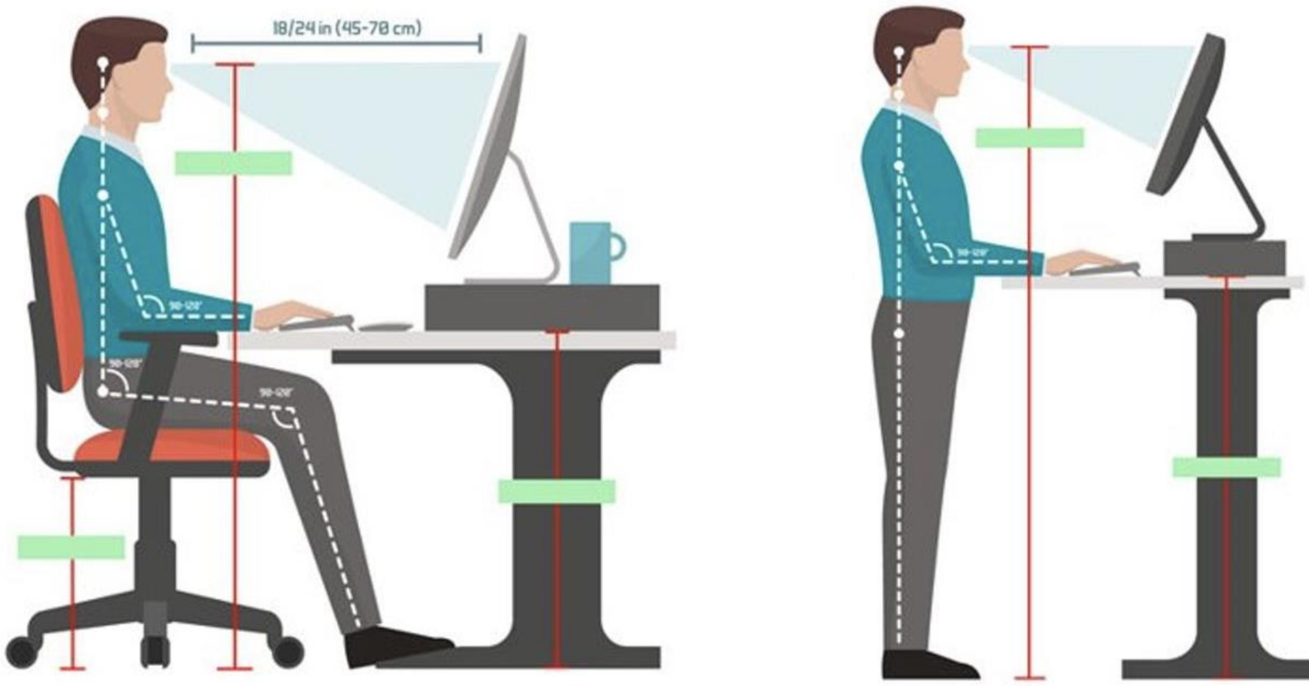
Logistics

- Online and will be recorded
  - Audio through computer or phone
  - Toll-free 415-655-0002 or 855-282-6330
    Access code: 146 128 1440

- Today's presentations & agenda are available on the WebEx link under "Event Material"
- They will be uploaded onto RA history website
  - WebEx password : track3b2
  - Click "View Info" to download

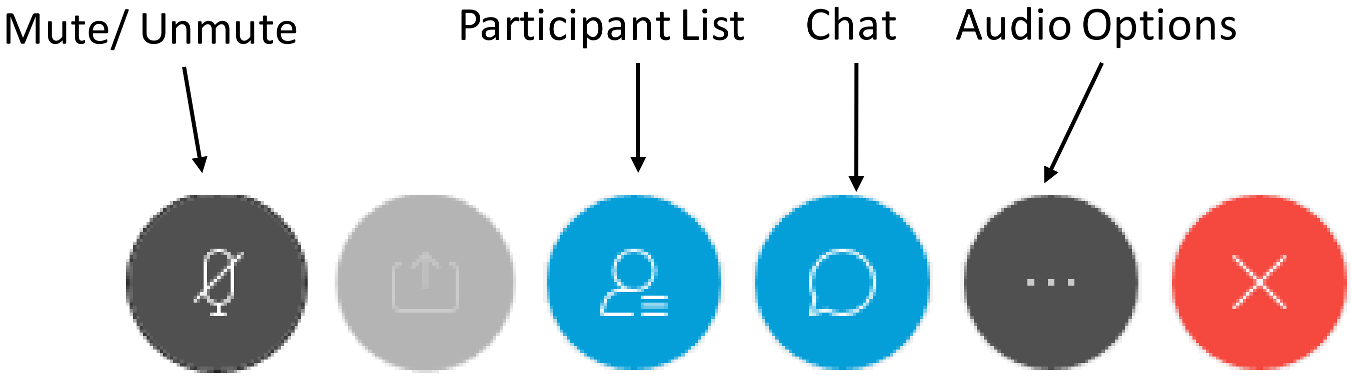
- Hosts (Energy Division Staff)
  - Jaime Rose Gannon
  - Linnan Cao

- Safety
  - Note surroundings and emergency exits
  - Ergonomic check

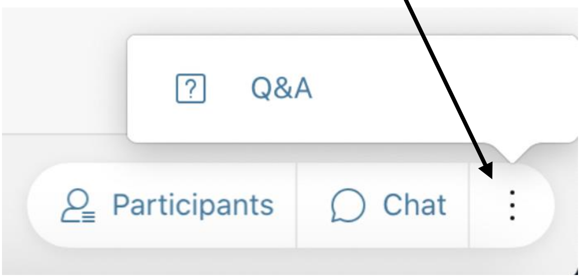


Logistics

- All attendees have been muted
- Presenters for each topic will be identified as panelists only when their topic is being addressed
- To ask questions please use the "Q&A" function (send "To All Panelists") or raise your hand
- Questions will be read aloud by staff; attendees may be unmuted to respond to the answer. (Reminder: Mute back!)



"Q&A": on the bottom right of screen, click "3 dots"



Ground Rules

- Workshop is structured to stimulate an honest dialogue and engage different perspectives.
- Keep comments friendly and respectful.
- Please use Q&A feature only for questions, or technical issues.
- Do NOT start or respond to sidebar conversations in the Chat.

Day 2 Agenda

Time	Topics	Presenters/Time Duration
9:30-9:40 a.m.	Introduction	CPUC, 10 min.
9:40-10:25	1. Availability Limited Resource Procurement Proposal	CAISO, 25 min. **Discussion:** 20 min.
10:25-11:40	2. Multi-year System & Flex RA requirement	SDG&E, PG&E, IEP, WPTF, 60 min. **Discussion:** 15 min.
11:40-11:55	Stretch Break	
11:55-12:30 p.m.	3. 2022 Loss of Load Expectancy Study Preliminary Results	CPUC, 20 min. **Discussion:** 15 min.
12:30-1:30	Lunch	
1:30-2:30	4. UCAP	CAISO, 40 min. **Discussion:** 20 min.
2:30-2:50	5. Incentives for YA filings Deficient LSE	AReM, 5 min. **Discussion:** 15 min.
2:50-3:20	6. QC - RA Import Rules	CAISO, 20 min. **Discussion:** 10 min.
3:20-3:30	Stretch Break	
3:30-3:50	7. CAISO ELCC Proposal	CAISO, 10 min. **Discussion:** 10 min.
3:50-4	8. Hybrid QC Methodology Overview	CPUC, 10 min.
4-4:30	9. Various Parties QC Proposal	CEERT, AWEA-CA, SWPG, 20 min. **Discussion:** 10 min.

Track 3B Scoping / Schedule and Expectations

1. Examination of the broader RA capacity structure to address energy attributes and hourly capacity requirements, given the increasing penetration of use-limited resources, greater reliance on preferred resources, and rolling off of a significant number of long-term tolling agreements.
2. Other structural changes or refinements to the RA program identified during Track 1 or Track 2, including:
   a. Incentives for load-serving entities that are deficient in year-ahead RA filings, as discussed in D.20-06-031
   b. Multi-year system and flexible RA requirements, as stated in D.20-06-002
   c. Refinements to the MCC buckets adopted in D.20-06-031
   d. Other time-sensitive issues identified by Energy Division or by parties

MODIFIED TRACK 3.B CALENDAR	
EVENT	**DATE**
Workshop on draft Track 3.B proposals submitted August 7, 2020	November 2020
Revised Track 3.B proposals due	December 18, 2020
Comments on revised Track 3.B proposals due	January 15, 2021
Workshop on revised Track 3.B proposal	February 2021
Second revised Track 3.B proposals and comments on additional process due	March 9, 2021
Proposed decision on Track 3.B and Track 4	May 2021
Final decision on Track 3.B and Track 4	June 2021

Presentation 1: Availability Limited Resource Procurement Proposal

Catalin Micsa, Senior Advisor Regional Transmission Engineer, Transmission Infrastructure Planning, CAISO

Karl Meeusen, Senior Advisor, Infrastructure and Regulatory Policy, CAISO

John Goodin, Senior Manager, Infrastructure and Regulatory Policy, CAISO

9:40-10:25 a.m.

Availability Limited Resource Procurement

Catalin Micsa
Senior Advisor Regional Transmission Engineer

CPUC workshop
November 23, 2020

Changing Landscape

- Historically RA procurement was mostly based on nuclear and gas resources that can produce 24 hours per day, currently are being replaced with renewable (wind and solar) resources plus battery storage technology that can produce limited hours per day.
- Intermittent resources like wind and solar are almost entirely non-dispatchable (at least not in the upward direction).
- Battery storage is highly dispatchable, however it has limitations both in MW and MWh output, it also has to charge (more than discharge) – can be highly constrained especially in local areas that have limited transmission and/or other resources.

Capacity and Energy Procurement

- Reliability must be maintained 24 hours a day and it will become more and more challenging without resources that can produce 24 hours a day
- Battery storage development (especially local) can be guided to areas of the grid that permit charging as well as discharging both under normal and under emergency conditions
- Future local capacity procurement must account for LSEs' capacity and energy needs, including ability to charge battery storage

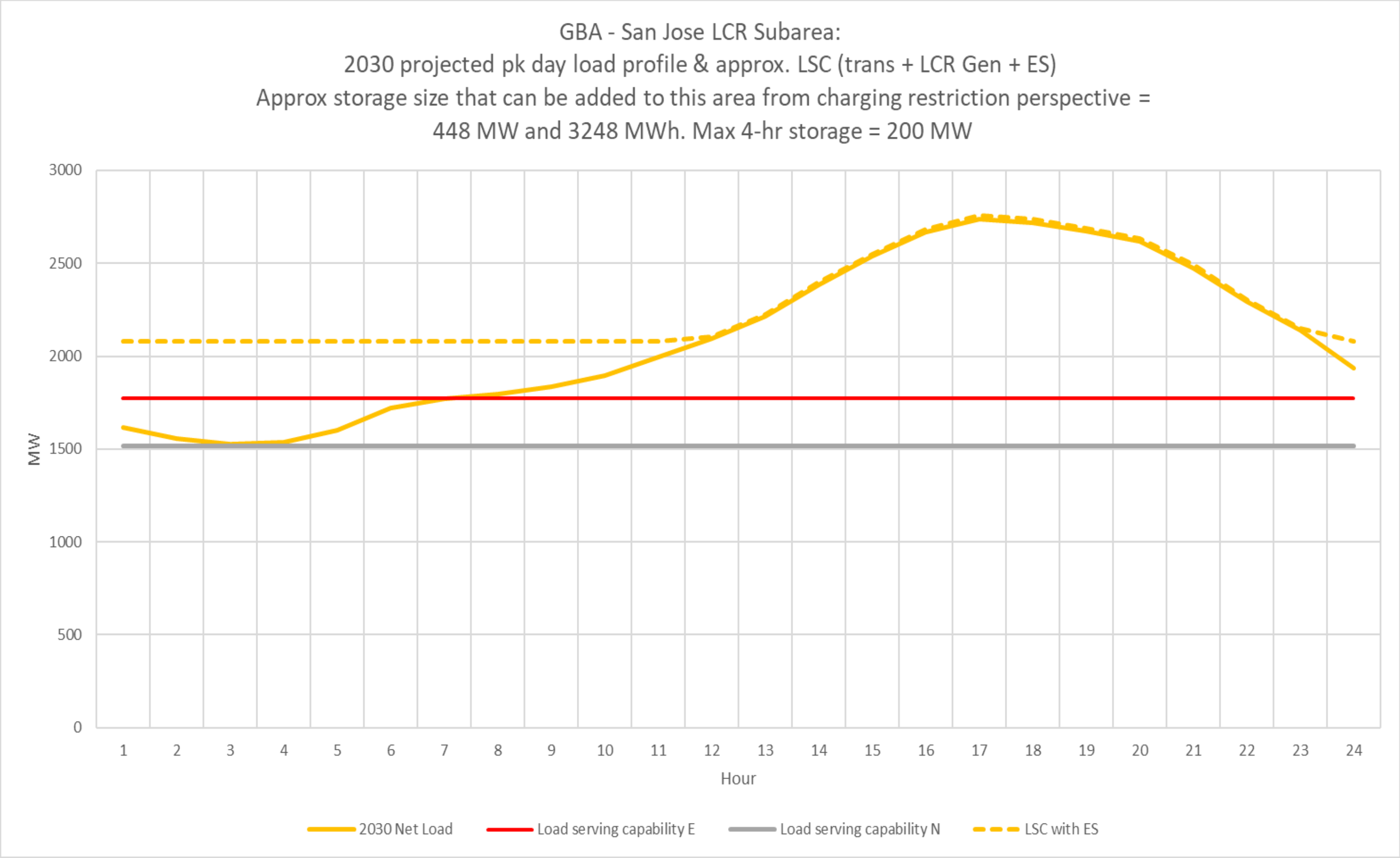
Battery Storage

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

Battery Storage Characteristics - Assumptions

- Storage replacing existing resources are assumed to have the same effectiveness factors
- Charging/discharging efficiency is 85%
- Daily energy charging required is distributed to all non-discharging hours proportionally using delta between net load and the total load serving capability (transmission + remaining resources)
- Hydro resources are considered to be available for production during off-peak hours
- The study assumes perfect dispatch; however, this is not possible in reality given all operational uncertainties
- Capped maximum charging at the capacity of storage added
- Amount of storage added is limited to the LCR need
- Includes the greater of 5% or 10 MW margin for both charging and discharging
- Deliverability for incremental capacity is not evaluated

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



Battery Storage – Local Graph

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

RA Counting or Qualifying Capacity

- Local Regulatory Authorities (LRAs) can set the Qualifying Capacity:
  - CAISO has default rules (in case LRAs don't have their own rules)
- Per CPUC rulings and CAISO Tariff, each resource ***must*** have a single QC (NQC) value.
- The only reason a resource counts for local is because it is located inside a local area.
- CAISO can decrease the QC to NQC, for testing (Pmax), performance criteria (not used) and deliverability.

The Local Capacity Technical Study

- Does not establish RA counting
- Does establish the local RA resources (by delineating the local area boundaries); as long as the resource can be pre-dispatched or can be dispatched up after the contingency in the time allowed for readjustment
- Does establish the individual local RA requirement for each LSE based on their load share ratio within the TAC vs. the total LCR requirement for that TAC
- Does establish the technical requirements.
  - Total MW need by TAC (RA individual enforcement + ISO back stop)
  - MW need by local area or sub-area (RA guidance only + ISO back stop)
  - Effectiveness factors (RA guidance only + ISO back stop)
  - Load charts (RA guidance only + ISO back stop)
  - Battery charging parameters (RA guidance only + ISO back stop)

CAISO local CPM enforcement

- Total MW need by TAC + MW need by local area or sub-area + effectiveness factors
  - First, costs are allocated to individual deficient LSEs on their month by month deficiency bases as available in their year ahead annual showing
  - Second, remaining costs are allocated to all LSEs
- The technical requirements (justification for the local CPM) are public in the LCR report
- Currently energy needs (like load charts and battery charging) are not used to CPM
- During RA Enhancement initiative, the CAISO is seeking authority to enforce local CPM for energy needs. Potentially starting as early as RA year 2022.

CAISO local RMR enforcement

- RMR is not automatic – a resource must be non-RA and must ask (by submitting a signed affidavit) for retirement or mothball
- CAISO can enforce any reliability need (Total MW need by TAC + MW need by local area or sub-area + Effectiveness factors + Load charts + Battery charging limits)
- Costs are divided to all the LSEs in the appropriate TAC(s) that drive the local need.
- The technical requirements (justification for these local RMR contracts) must be made public (if not already public in the LCR reports).

Example:

- A new battery resource with Pmax of 800 MW and energy of 800 MWh is located in a local area
- The local area has an LCR need of 800 MW (with other 1,000 MW of available resources), and a maximum battery charging capability of 110 MW (780 MWh) and a maximum 4-hour battery of 35 MW.
- The new resource will count towards each LSEs individual RA responsibility as 200 MW (both system and local).
- Technically for local only 110 MW (780 MWh) can be used. If the total RA showings (including this resource) is above 890 MW (assuming all units just as effective) then the technical needs are met; else the CAISO could RMR and hopefully in a few years CPM additional resources.

Summary

- Technical needs have not and will not equal RA counting
- CAISO is not advocating for changes in local RA counting at this juncture.
- CAISO suggests LSEs use the analysis as guidance for their future local procurement.
- CAISO’s LCR analysis is provided annually for year one and five as well as every other year for year ten.
- CAISO proposes that the local energy analysis becomes enforceable under CAISO local CPM authority starting with RA year 2022.

Summary (con't)

- CAISO does advocate that both the LSEs and LRAs be mindful of local constraints when purchasing new battery storage resources if they want to both maximize the RA value and minimize CAISO back-stop
- While CAISO's proposal is explicitly targeted to local capacity, the same trend is observed at the system level.
- Therefore, CAISO advocates that both capacity and energy be accounted for in future procurement of both local and system resources, that meets both the gross and net peaks as well as meets energy needs 8760 hours a year.

Q&A/Discussion

Presentation 2: Multi-year System & Flex RA Requirement

Nuo Tang, Market Policy Manager, SDG&E
Peter Griffes, Chief, Comprehensive Procurement Framework, PG&E
Brian Cragg, Outside Counsel to IEP
Gregg Klatt, Attorney for WPTF
10:25-11:40 a.m.

RA TRACK 3B WORKSHOP

DAY 2

MULTI-YEAR PROPOSALS

AGENDA

- Principles
- Multi-Year RA
- MCC Bucket Refinements
- Annual RA Compliance Framework
- Immediate Needs and Long-term Discussion

PRINCIPLES

Generally agreed upon principles:

- Regulatory certainty
- Simplify complexity
- Maintain reliability across all months and hours
- Consistency between CPUC and CAISO rules
- Equitable cost allocation

WPTF's suggests these additional principles

- Promote competition and facilitate customer choice
- Yield prices that reflect supply and demand fundamentals
- Compatibility with broader regional approaches to reliability

SDG&E's Principles

- Promotes tradability
- Equitable allocation of costs
- Provides for procurement autonomy
- Affordability

PG&E also filed principles to guide the examination of the broader RA capacity structure:

- Support public policy objectives
- Promote efficient electric-resource investment and operations
- Assign risk fairly and efficiently
- Mitigate the exercise of market power
- Promote innovation and be robust to alternative futures

MULTI-YEAR RA REQUIREMENTS

Why multi-year system RA requirements?

Forward certainty promotes:

- Supply Reliability (revenue certainty)
- More rational pricing (smooths out long-cycle maintenance costs)

Acknowledge multi-year framework introduces issues

- Load migration
- Evolving QC counting (UCAP, marginal v. average ELCC)

What about multi-year flexible RA requirements?

- Commission has been reluctant to implement multi-year flexible RA requirements without durable product definition
- No durable product definition appears imminent
- In lieu of separate multi-year requirements for flex, Commission could recognize that at lease some flex RA (however defined) will be secured through multi-year forward procurement of system and local RA

MCC BUCKET REFINEMENTS

MCC bucket limitations were updated in 2020

MCC buckets should be refined regularly to match the needs of the grid and ensure reliability is maintained across all hours

CURRENT RA COMPLIANCE FRAMEWORK

Current RA Compliance Framework is separated into two phases

Year ahead Showing	Month ahead Showing
• 100% Local • 90% of 115% System (May – Sept) • 90% Flexible (Jan – Dec)	• 100% Local • 100% of 115% System • 100% Flexible • True-ups and load migration

ANNUAL RA COMPLIANCE FRAMEWORK

Annual RA Compliance Framework would have a single showing

- Year Ahead Showing
  - 100% Local
  - 100% of 115% System (Jan – Dec)
  - 100% of Flexible (Jan – Dec)

Benefits

- Provides contractual certainty for resources
- Reduces program complexity to procure on a month-ahead basis
- Provides CAISO with necessary information to evaluate reliability for the compliance year

Challenges

- Granularity – Annual, Seasonal, Monthly
- Intra-year load migration

IMMEDIATE NEEDS AND LONG-TERM DISCUSSION

Immediate Needs (Track 3B)	Long-Term
• Need to know if the current program is reliable • Additional MCC refinements	• Restructuring • Alignment with Integrated Resource Plan • Appropriate resource mix to meet future reliability needs

Q&A/Discussion

COFFEE BREAK

Stretch a bit and ...

https://www.showeet.com/19/06/2016/templates/title-slide-templates-for-powerpoint-and-keynote/

Presentation 3: 2022 Loss of Load Expectancy Study Preliminary Results

Donald Brooks, Supervisor, Energy Resource Modeling, CPUC

11:55-12:30

PRM calculation based on LOLE results for 2022

Donald Brooks
Energy Resource Modeling / Energy Division
CPUC

November 23, 2020

Overview of Presentation

Staff performed modeling of 2022 study year to test establishing the RA obligation with a LOLE study. This slide deck describes our study, assumptions and preliminary results.

- Objective of today's presentation
- Overview of study and methods
- Study Results – LOLE results and MW capacity required to meet LOLE target
- Hours of Risk – Portfolio of resources needed to maintain reliability
- Next Steps
- Questions/Discussion

Objective of Presentation

Directives- D.19-06-031 OP 9

"Energy Division is authorized to facilitate a working group to develop a set of assumptions for use in a loss of load expectation (LOLE) study to support review of the planning reserve margin. Energy Division shall perform the LOLE study, which will be submitted into this proceeding."

Objectives-

- Start an initial technical discussion on use of a LOLE to set a planning reserve margin (PRM) for system RA requirements
  - Present current assumptions used to produce 2022 LOLE results
- Coordinate with CAISO's RA enhancement initiative which is seeking a UCAP framework and a portfolio sufficiency test using stochastic modeling
  - Compare UCAP and ICAP methods to calculate capacity contribution from dispatchable thermal generators
  - Demonstrate the higher risk of LOLE in net peak hours in the late evening
    - Explain a possible portfolio limitation to add on top of the existing overall RA obligation to ensure meeting needs during evening net peak load hours.

LOLE modeling overview

LOLE modeling is a probabilistic system-reliability planning and production cost study. The primary objective is to meet the reliability risk and minimize the costs.

- Configured to assess a given portfolio in a target study year under a range of future weather (20 weather years), economic output (5 weighted levels), and unit performance (30+ random outage draws)
- Hourly economic unit commitment and dispatch
  - Individual generating units and all 8,760 hours of year are simulated
  - Unit operating costs and constraints
  - Generating units are modeled individually across all of the Western Electricity Coordinating Council (WECC) area
- Zonal representation of transmission system
  - 8 CA regions, 16 rest-of-WECC regions
  - Includes region-to-region flow limits and hurdle rates as well as simultaneous flow limits

Review of LOLE Reliability Metrics

- Staff validates the reliability of portfolios through Loss-of-Load Expectation (LOLE) studies
  - Staff studies expected frequency of events (LOLE), expected duration of unserved energy (Loss-of-Load Hours or LOLH), and expected volume of unserved energy (Expected Unserved Energy or EUE)
  - Staff considered the electric system sufficiently reliable if the probability-weighted LOLE is less than or equal to 0.1. This corresponds to about 1 day in 10 years where firm load must be shed to balance the grid. Firm load includes spin and regulation reserves.
  - The current Planning Reserve Margin construct has become increasingly divorced from a LOLE study framework.
    - PRM is applied to month specific electric peak forecasts, when a LOLE study tends to result in a capacity margin applied annually to annual peak load
    - Current PRM calculated in 2004 with a very different mostly thermal electric fleet, which is more dispatchable and less complicated to plan for.

Summary of Preliminary Findings

Staff performed LOLE modeling for 2022 study year primarily focusing on the CAISO region in California.

- The fleet as expected to be in 2022 (including some new storage buildout) is expected to be reliable. LOLE is about equal to 0.1
- There may be an NQC shortage relative to different possible PRM levels.
- Reliability risk continues to move to the evening, particularly in July and August with a smaller risk in September.
- Additional capacity investment is supported by the findings here.

2022 LOLE Study Assumptions

Staff performed LOLE modeling for 2022 study year primarily focusing on the CAISO region in California.

- Modeling based on IRP Reference System Plan
- OTC units extended per CPUC decision D.19-11-016
- Updated to 2019 IEPR demand forecast
- Current fleet of CAISO resources, nothing under construction except storage to meet mandate coming online by 2022. Additional storage to meet D.19-011-016 may provide additional resources to meet future RA targets, and also may cause CAISO to be more reliable than our study results presented here
- NQC calculated from most recent technology factors posted in NQC list
- 5,000 import limit imposed during summer HE 18-21

CAISO LOLE results for 2022 study year

LOLE (expected outage events/year)	0.12208
LOLH (hours/year)	0.18693
LOLH/LOLE (hours/event)	1.531242
EUE (MWh)	136.23
annual load (MWh) – CAISO total	245,818,857
normalized EUE (%)	0.00005542%
Non-spin loss of Reserve Energy (MWh)	47,137.4
Spin loss of Reserve Energy (MWh)	0.0
Spinning Reserves Shortage (Hours)	0.0001
Normalized Non-spin loss of reserve energy (%)	0.01918%

Month	LOLE
1	0
2	0
3	0
4	0
5	0
6	0
7	0.035828
8	0.084415
9	0.001835
10	0
11	0
12	0

Monthly Calculation of PRM based on 2022 LOLE modeling

Unit Category Aug	Capacity (MW)	NQC/Outage %	UCAP	ICAP
Battery Storage	1,607	0.97	1,557	1,557
Biogas	292	0.94	274	274
Biomass/Wood	527	0.94	495	495
CC	16,081	0.87	13,991	16,081
Coal	15	0.95	14	15
Cogen	2,307	0.87	2,007	2,007
CT	8,263	0.87	7,188	8,263
DR	1,822	0.75	1,367	1,367
Geothermal	1,588	0.88	1,397	1,397
Hydro	5,546	1.00	5,546	5,546
ICE	255	0.88	224	224
Nuclear	2,300	0.99	2,282	2,300
PSH	1,899	0.86	1,338	1,338
Solar	13,886	0.27	3,749	3,749
Steam	2,883	0.87	2,505	2,883
Wind	7,056	0.21	1,482	1,482
Interchange			6920	6,920
Total Capacity			52,337	55,898
2019 IEPR 2022 sales forecast (MW)	44,509	44,509	44,509	44,509
Capacity Margin			117.6%	125.6%

Unit Category Sep	Capacity (MW)	NQC/Outage %	UCAP	ICAP
Battery Storage	1,607	0.97	1,557	1,607
Biogas	292	0.94	274	292
Biomass/Wood	527	0.94	495	527
CC	16,081	0.87	13,975	16,081
Coal	15	0.95	14	15
Cogen	2,307	0.83	1,915	2,307
CT	8,263	0.87	7,180	8,263
DR	1,769	0.75	1,327	1,769
Geothermal	1,588	0.87	1,381	1,588
Hydro	5,125	1.00	5,125	5,125
ICE	255	0.88	224	255
Nuclear	2,300	0.99	2,282	2,300
PSH	1,899	0.86	1,338	1,338
Solar	13,886	0.14	1,944	1,944
Steam	2,883	0.87	2,508	2,883
Wind	7,056	0.15	1,058	1,058
Interchange			6,994	6,994
Total Capacity			49,592	54,346
2019 IEPR 2022 sales forecast (MW)		45,280	45,280	45,280
Capacity Margin			109.52%	120.02%

- **UCAP = Unforced Capacity**
  ICAP = Installed Capacity
- **UCAP= ICAP*(1 - Outage Rate)**
- **Yellow highlight means used existing NQC tech factors for these resource types.**

The chart compares a resource portfolio that meets LOLE of 0.1 relative to NQC and UCAP outage derates against monthly peak load from the 2019 IEPR.

ICAP is calculated from NQC technology factors and nameplate MW for thermal facilities.

UCAP is calculated from NQC factors and outage factor derates for thermal generators.

From results for the two peak months, Aug and Sep, average of 9.5% and 17.6% UCAP is a **13.5% PRM** or average of 25.6% and 20% equals a **22.8% PRM** in a ICAP calculation.

Comparison of Capacity Available versus needed under UCAP

	UCAP LOLE	UCAP NQC Aug	UCAP LOLE	UCAP NQC Sep
Battery Storage	1,557	1,019	1,557	1,078
Biogas	274	192	274	191
Biomass/Wood	495	353	495	356
NatGas	25,915	25,386	25,802	25,322
Coal	15	15	15	11
DR	1,367	1,367	1,327	1,327
Geothermal	1,397	1,061	1,381	1,063
Hydro	5,546	6,020	5,125	5,129
Nuclear	2,300	2,262	2,300	2,280
PSH	1,338	1,417	1,338	1,417
Solar	3,749	2,948	1,944	1,560
Wind	1,482	1,224	1,058	873
Interchange	6,920	6,335	6,994	6,335
2019 IEPR 2022 forecast	44,509	44,509	45,280	45,280
Capacity Margin	117.63%	111.43%	109.56%	103.67%
Total Capacity	52,356	49,598	49,611	46,942
Total without interchange	47,296	43,263	44,548	40,607

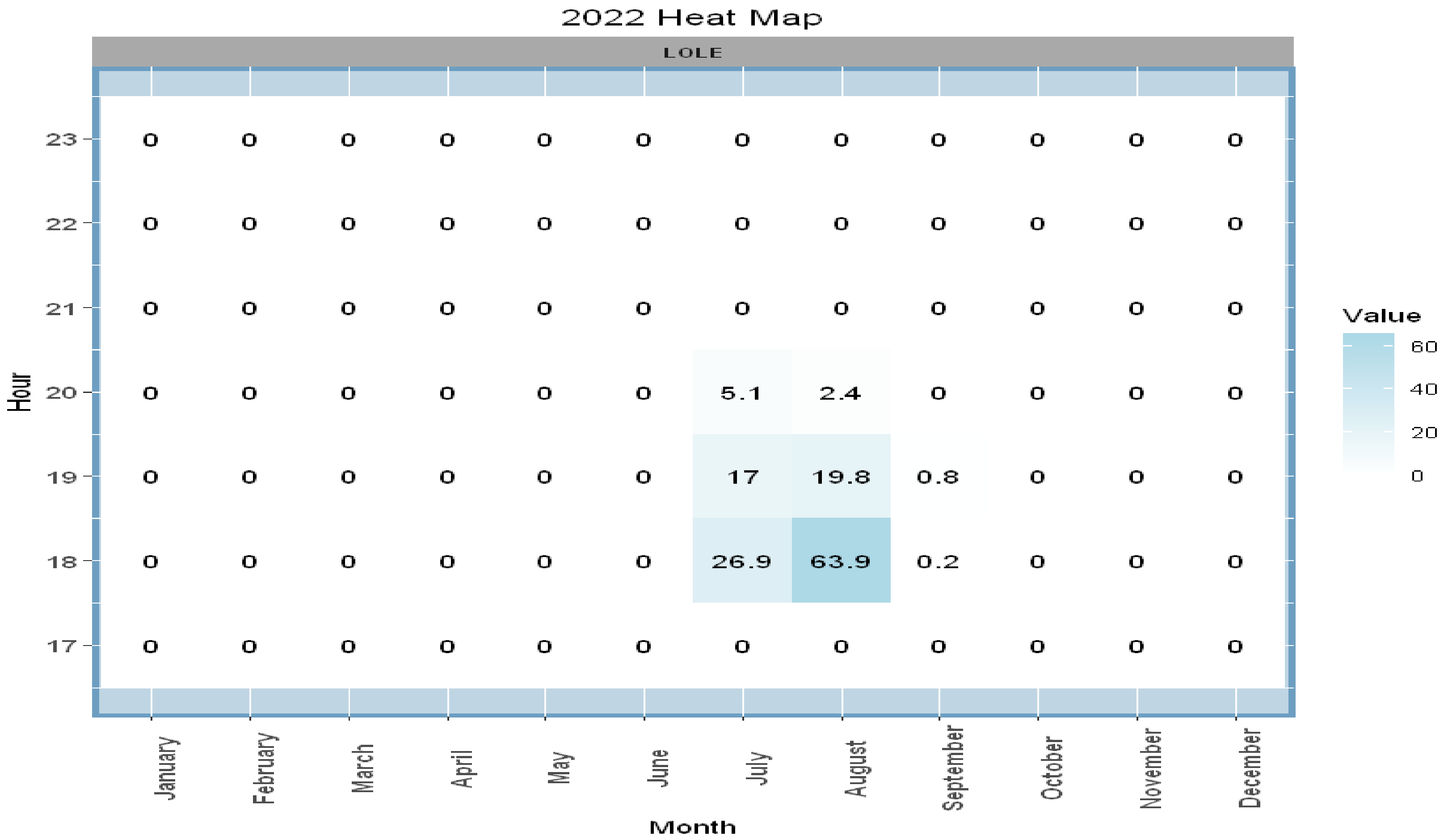
This is a comparison of NQC on the NQC list versus NQC derated capacity used in LOLE model.

It appears there is currently a shortage of NQC to meet these higher LOLE based PRM targets.

- These results support need for additional procurement from D.19-11-016.
- Shortage of about 6% in August and September relative to the LOLE study results. This translates to about 2,700 MW. The low available margin in September reflects lower ELCC values.
- Available NQC depends heavily on ELCC values. Month specific ELCC values may lead to uncertain capacity margins that appear more dire than realistic.

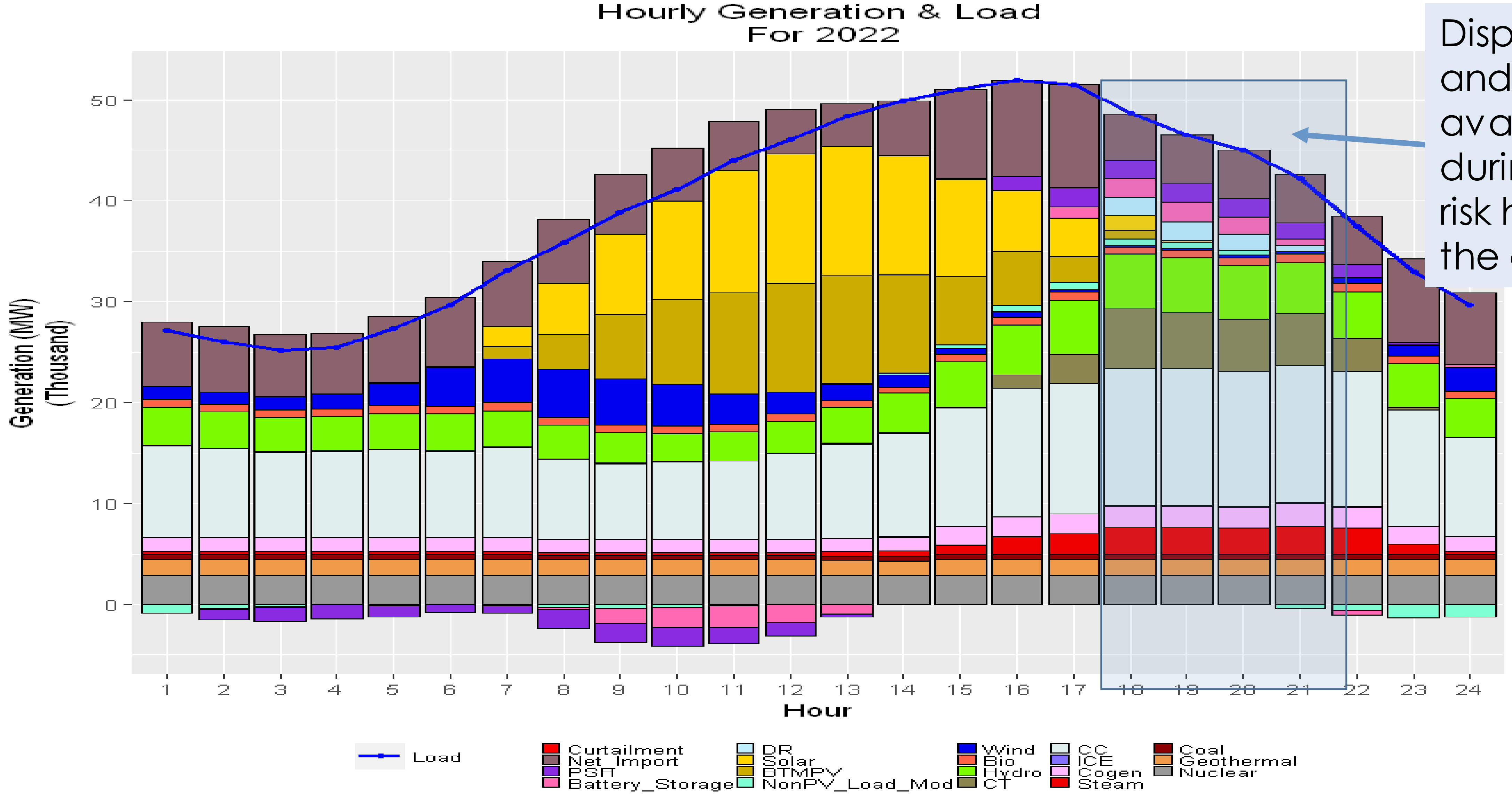
It may be reasonable to calculate a PRM averaged across two peak months, and also to average ELCC values. Maybe Peak and Off peak PRM or ELCC. From results for the two peak months, Aug and Sep, average of 9.6% and 17.6% UCAP is a **13.6% PRM** or average of 25.6% and 20% equals a **22.8% PRM** in a ICAP calculation.

Heat Maps – August and July are riskier than September and risk is focused in late afternoon



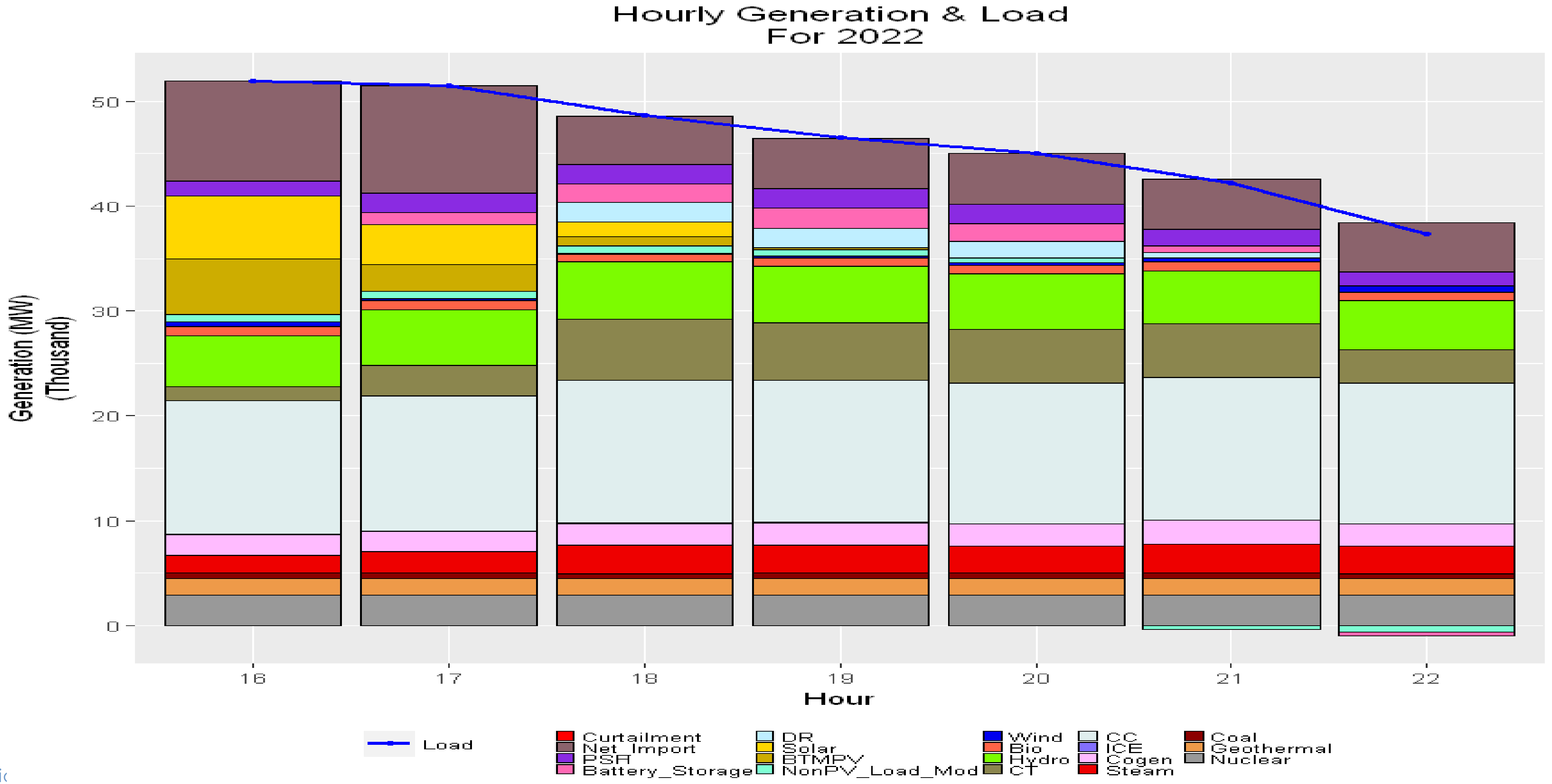
- Heat maps illustrating the month-hour where Expected Unserved Energy (EUE) occurs is an intuitive way of showing when loss-of-load events are likely to occur and quantifying the likely magnitude of those events
- Likely LOLE and EUE hours are consistently in the summer evening hours of 6-8pm and shift later for each study year – an expected outcome as solar PV penetration shifts the peak hour later in the evening
- Increase in EUE in July and August.

Hourly Generation for a day with high EUE



Dispatch and energy available during high risk hours of the day

Hourly Generation for a day with high EUE HE 16-22



Preliminary Conclusions

- Investment in additional RA capacity is warranted by study results as currently there is a shortage of NQC relative to PRM targets
- Reliability problems remain focused on evening hours HE18-HE20 and will become more pronounced as penetration of solar and storage increases
- The CAISO fleet is overall reliable on an annual basis right now, but particular months exhibit shortages relative to counting NQC towards an RA obligation

Next Steps

- Take comment on the proposed LOLE methods
  - PRM averaged cross peak months
  - Peak/Off peak ELCC values instead of month specific ELCC
- Refer to IRP dataset posted to the CPUC website for most of the inputs used here
- Perform a more final study after comments?

Appendix

Energy Balance and Dispatch by resource type

Unit Type	MWh generated
CCGT	43,274
CT	1,532
Steam	846
Coal	1,286
Biomass	5,689
BTMPV	24,407
All Solar: fixed PV, tracking PV, solar thermal	31,965
Wind	17,886
Scheduled Hydro Plus ROR Hydro	25,391
Geothermal	12,133
Cogen	10,005
Nuclear	25,711
ICE	71
Generation Subtotal Before Curtailment	200,196
Non-PV Load Modifiers (net effect of AAEE, EV load, TOU)	-1,316
Curtailment not included inline above	-253
TOTAL not including Non-PV load modifiers	199,944

CAISO System balance, GWh	RA_LOLE_2022
In-region Generation serving CAISO load, including BTMPV, and excluding storage discharge	197,465
Direct imports from remote Solar	3,791
Direct imports from remote Wind	666
Non-PV Load Modifiers (net effect of AAEE, EV, TOU)	-1,316
Unspecified carbon-emitting imports netted hourly (no NW Hydro)	34,247
NW Hydro Imports	11,000
Total energy to serve load	245,852
Load (not including net effects of non-PV load modifiers: AAEE, EV, TOU)	245,819
Non-PV Load Modifiers (net effect of AAEE, EV, TOU)	-1,316
Unspecified carbon-emitting exports netted hourly	**867**
Battery and Pumped Storage Hydro losses (net of charge and discharge)	1,516
Curtailment	253

Q&A/Discussion

Lunch **Break**

Until1:30 p.m.

https://www.slidecamp.io/home

Presentation 4: Unforced Capacity Proposal

Lauren Carr, Infrastructure and Regulatory Policy Specialist, Infrastructure and Regulatory Policy
Bridget Sparks, Infrastructure and Regulatory Policy Developer, Infrastructure and Regulatory Policy
Karl Meeusen, Senior Advisor, Infrastructure and Regulatory Policy, CAISO
John Goodin, Senior Manager, Infrastructure and Regulatory Policy, CAISO

1:30-2:30 p.m.

Unforced Capacity Evaluation Proposal

Lauren Carr

Bridget Sparks, Ph.D.
Infrastructure and Regulatory Policy

CPUC Track 3.B Proceeding

November 23, 2020

CAISO proposes an unforced capacity construct to ensure resources' capacity values reflect availability

- CAISO observes a 10% average system forced outage rate
- Current PRM, forced outage substitution rules, and RAAIM have proven inadequate to replace capacity on forced outage
- UCAP dynamically changes with the fleet's forced outage rate
  - Relying solely on the PRM, which is a static value, may lead to over/under procurement if future outage rates change
  - PRM would only need to cover 6% operating reserves plus forecast error based on load levels
- Unforced capacity evaluations promote procurement of the most dependable and reliable resources up front by accounting for historical unavailability in their capacity value
  - Allows the CAISO to eliminate complicated and ineffective forced outage substitution rules

CAISO proposes to integrate unforced capacity evaluations into the NQC process

- CAISO will conduct a two step process to assess resources' QCs that include resources' deliverability and availability
  - Step 1: Conduct resource deliverability assessment and adjust QC for deliverability, creating Deliverable QC (DQC) for the resource
  - Step 2: Apply non-availability factor to DQC, resulting in the NQC value for the resource under the UCAP construct
    - Capacity value will still be expressed in terms of NQC, addressing stakeholder concerns about existing contracts
    - Must Offer Obligation will be in terms of DQC

CAISO proposes a seasonal availability factor methodology to determine UCAP values

- CAISO proposes to utilize a seasonal availability factor based approach for UCAP determinations during the tightest system conditions by looking at the hourly RA Supply Cushion
- Resource availability factors will incorporate historical forced and urgent derates and outages to determine the resource’s expected future availability and contributions to reliability
- Basic UCAP methodology will be used for thermal and storage resources
- The ISO recognizes that this baseline methodology will not be appropriate for all resource types and provides augmented methodologies to determine these resource’s average availability

CAISO will consider only forced and urgent outages in the UCAP calculation

- Outage types and their priorities (from highest to lowest)
  - Forced outage, urgent outage
  - Planned outage
  - Opportunity outage
- Forced and urgent outages will be considered in UCAP calculation, planned and opportunity outages will not
- Establish incentives to conduct resource maintenance to avoid unplanned outages

Defining top 20% tightest RA supply cushion hours

- **RA Supply Cushion = Daily Shown RA** (excluding wind and solar) **– Planned Outages – Opportunity Outages – Urgent Outages – Forced Outages – Net Load – Contingency Reserves**
- RA Supply cushion represents how much shown RA MWs are leftover after taking into account outages, serving net demand, and covering contingency reserves
  – A low RA supply cushion indicates the system has fewer assets available to react to unexpected outages or load increases, indicating a high real-time system resource adequacy risk
- Contingency reserves represents regulation up, spin and non-spin reserves
- Proposal to calculate seasonal UCAP values for:
  – Peak Months: May - October
  – Off-Peak Months: November - April

CAISO completed data analysis on the RA supply cushion hours for May 2018 through October 2020

- There is a significant difference in top 20% supply cushion MW threshold
  - Peak months tight supply cushion hours are ≤ 8800 MWs
  - Off-peak months tight supply cushion hours are ≤ 2800 MWs
- A majority UCAP assessment hours fall during evening net load ramp (68% of hours fall between HE 18-22), and morning ramp during off-peak months (10% of hours fall between HE 6-8)
- The median number of UCAP assessment hours per day are 4 hours during peak months and 5 hours during off peak months
- Supply cushion covers 81% of days per season on average

Summary of UCAP steps (formulas in appendix)

1. Determine UCAP assessment hours by identify which hours fall into the top 20% of tightest supply cushion hours for each season
2. Determine hourly unavailability factors (HUF) by looking at outages for each UCAP assessment hours each season
3. Determine seasonal average availability factors (SAAF) using one minus the average HUFs for each season of prior year
4. Determine weighted seasonal average availability factors (WSAAF) by multiplying the prior three year SAAFs by (45% Y1, 35% Y2, 25% Y3)
5. Apply WSAAFs for each season to deliverable capacity (DQC) to determine monthly NQC (On-peak and Off-peak) values for each resource

- This baseline methodology will apply to thermals and storage resources

CAISO proposes the following UCAP methodologies for non-conventional generation

- Wind and Solar: Use ELCC values as NQC
- Demand response: Use ELCC if adopted, otherwise use historic performance and test events relative to dispatch at DRP level
- QFs: Historic performance relative to dispatch
- Hydro: Longer term historical year weighted average assessment
- Hybrids: Consider dynamic limits in the HUF calculation
- Imports: Consider transmission curtailments for non-frim transmission in addition to outages
- Non-dispatchable resources: If QC methodology takes into historic account forced outage rates, DQC will equal NQC

RA showings converted to from DQC to NQC (UCAP)

Fuel Type	Peak Month WSAAF	June DQC Shown	June NQC Estimate
Battery	0.964	110.00	106.04
Biomass	0.849	540.00	458.46
Coal	0.965	18.00	17.37
Demand Response*	0.984	235.00	231.24
Gas	0.875	27,002.00	23,626.75
Geothermal	0.868	984.00	854.11
Hydro*	0.816	5,544.00	4,523.90
Nuclear	0.940	1,640.00	1541.60
Pump Hydro*	0.816	1,285.00	1048.56
Interchange*	0	4,118.00	4118.00
Solar	ELCC	3,303.00	3,303.00
Wind	ELCC	1,688.0	1,688.0
HRCV	0.933	29.00	27.06
Other	0.984	0.13	0.13
Pumping Load		59.00	59.00
Total		46,555.13	41,603.22

- Taking the RA showings for June 2020, we applied the Peak Month WSAAF to estimate the new NQC value of the June 2020 RA Showings
- Shows a 10.64% reduction, which matches the roughly 10% force outage rate of the system.
- Note DR, Hydro, and interchange resources are estimates based on forced outage rates, which differs from the proposed methodologies
- Does not distinguish b/ween dispatchable and non dispatchable resources
- Appendix slides provides more details on WSAAF calculations by Fuel Type

APPENDIX- UCAP METHODOLOGY FORMULAS

Proposed UCAP calculation steps

- ISO will determine each resource's hourly unavailability factor (HUF) for each of the 20% tightest supply cushion hours per season

$$\textbf{Hourly Unavailability Factor} = \frac{\textbf{Forced} + \textbf{Urgent Outage Impacts}}{\textbf{Pmax}}$$

- ISO will utilize the average of hourly unavailability factors (HUF) for each season for each of the past 3 years to create a seasonal average availability factor (SAAF) for each resource

$$\textbf{Seasonal Average Availaility Factor} = \mathbf{1} - \frac{\sum \textbf{Hourly Unavailability Factors}}{\textbf{Number of Observed Hours}}$$

Proposed UCAP calculation steps (continued)

- ISO also proposes a weighting method for determining a resource's UCAP values over three year period
- ISO proposes the following percentage weights for the availability factor calculation by year from most recent to most historic: 45-35-20%
- In other words, the following percentage weights will be applied to the seasonal availability factors:
  - 45% weight for the most recent year's seasonal availability factor
  - 35% weight on the second year
  - 20% on the third year

Proposed UCAP calculation steps (continued)

- Seasonal average availability factors (SAAF) will be calculated for each of the 3 prior historical years (for both on-peak and off-peak seasons)
- SAAFs will based on each hourly unavailability factor (HUF) derived by assessing forced and urgent outages compared to the Pmax value for each resource
- ISO will then apply proposed weighting to each of the three previous annual periods (for each on-peak and off-peak season) to create weighted seasonal average availability factors (WSAAF)

$$\textbf{Weighted Seasonal Average Availability Factor} = \textbf{Annual Weighting} * \textbf{Seasonal Average Availability Factor}$$

Proposed UCAP calculation steps (continued)

- Once the weighted seasonal average availability factors (WSAAF) are established for each season of each of prior 3 years, ISO will sum the factors and apply them to each resource's DQC to determine the resource's seasonal NQC ratings

$$\textbf{On Peak } \boldsymbol{NQC} = \sum \textbf{Weighted Seasonal Average Availability Factors}^{\textbf{Summer}} * \boldsymbol{D}\textbf{QC}$$

$$\textbf{Off Peak NQC} = \sum \textbf{Weighted Seasonal Average Availability Factors}^{\textbf{Winter}} * \boldsymbol{D}\textbf{QC}$$

APPENDIX: SUPPLY CUSHION ANALYSIS

Monthly distribution of the hourly supply cushion

P	1	2	3	4	5	6	7	8	9	10	11	12
1%	-692	-2641	-2268	-2127	1529	-3097	-4213	-2691	1937	-23	-3354	-3136
5%	1132	-597	-590	711	3704	955	-1518	1059	4650	2390	-1804	-720
10%	2158	626	662	2314	5229	3777	1050	3252	6884	4330	-609	400
20%	**4019**	**2444**	**2325**	**4924**	**7333**	**7228**	**4726**	**6678**	**10612**	**6648**	**1270**	**2432**
25%	4674	3308	3075	5855	8143	8230	6368	7981	11690	7634	2221	3279
50%	7801	6434	5798	9494	10949	11827	10836	12446	15627	11314	5257	6338
75%	10589	10624	9943	13299	14290	15630	16346	15942	18782	14353	7945	9469
90%	13697	14120	13794	17412	16958	19670	20620	18893	21739	17864	10827	12595
95%	15230	15570	15207	19164	17969	21436	23144	20680	23664	20227	12544	14348
99%	17753	18402	16842	20782	20325	23246	26594	24368	28161	22911	14710	17509
Mean	7857	6988	6549	9590	11068	11712	11097	11816	15099	11166	5178	6455

- The October distribution of hourly supply cushion looks more similar to peak/summer months than an off peak month.
  - It has a similar high mean of 11,000+ MWs, and
  - The 20th percentile tends to be above 5000 for peak months and under 5000 for off peak month, and October is over 5000 MMs, and thus similar to peak months.

Seasonal distribution of supply cushion hours (in MWs):

Percentile	Peak Months 2018	Off Peak Months 2018-2019	Peak Months 2019	Off Peak Months 2019-2020	Peak Months 2020
1.0	-2985	-2318	-1109	-2868	-3598
5.0	554	-439	3545	-697	1251
10.0	2752	967	5866	628	4377
20.0	5806	2878	8759	2734	7653
25.0	6843	3639	9820	3573	8800
50.0	10551	6687	14217	6715	12990
75.0	13895	10030	17923	10790	16939
90.0	16709	13478	21237	14322	20696
95.0	18298	14993	23135	16741	22473
99.0	20999	17376	26522	20018	24829
Hours	4416	4344	4416	4367	4416

Note: A negative value indicates there was a capacity shortfall- did not have enough shown RA to cover outages, net load, and contingency reserves

Distribution of the top 20% of supply cushion hours by operating hour shows

- The following table shows the distribution of the top 20% of tight supply conditions hours by operating hour
- As expected, the majority of tight supply cushion hours are around the evening ramp/peak-HE 18-22, averages 68.8% of hours. In off peak months, we also see a spike during the morning ramp
- However, because there are hours that fall outside these ramps, it further incentivizes resources to be available for all hours, b/c there is a chance a tight supply cushion hour could fall outside these predictable periods
- This approach will include a majority of the possible days (averages 81%)

HE	Peak Months 2018		Off Peak Months 2018-2019		Peak Months 2019		Off Peak Months 2019-2020		Peak Months 2020	
	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.
1	3	0.34	4	0.46	18	2.04	5	0.57	16	1.81
2	1	0.11	2	0.23	7	0.79	2	0.23	2	0.57
3	0	0.00	1	0.12	4	0.45	1	0.11	0	0.00
4	0	0.00	1	0.12	4	0.45	1	0.11	0	0.00
5	0	0.00	2	0.23	5	0.57	1	0.11	0	0.00
6	2	0.23	8	0.92	17	1.93	9	1.03	2	0.23
7	12	1.36	54	6.21	26	2.94	51	5.84	12	1.36
8	9	1.02	38	4.37	17	1.93	34	3.89	12	1.36
9	2	0.23	8	0.92	5	0.57	10	1.15	0	0.00
10	2	0.23	2	0.23	4	0.45	5	0.57	0	0.00
11	1	0.11	0	0.00	3	0.34	3	0.34	0	0.00
12	1	0.11	0	0.00	5	0.45	0	0.00	1	0.11
13	7	0.79	0	0.00	6	0.68	0	0.00	7	0.70
14	14	1.59	1	0.12	8	0.91	1	0.11	14	1.59
15	24	2.72	4	0.46	13	1.47	2	0.23	25	2.83
16	33	3.74	8	0.92	23	2.60	12	1.37	35	3.96
17	40	4.52	40	4.60	32	3.62	54	6.19	50	5.66
18	78	8.83	95	10.93	61	6.91	106	12.14	77	8.72
19	119	13.48	127	14.61	106	12.00	127	14.55	119	13.48
20	152	17.21	147	16.92	129	15.74	133	15.23	145	16.42
21	151	17.10	143	16.46	143	16.19	129	14.78	138	15.63
22	125	14.16	114	13.12	125	14.16	112	12.83	110	12.46
23	78	8.83	56	6.44	79	8.95	56	6.41	77	8.72
24	29	3.28	14	1.61	34	3.85	19	2.18	38	4.30
Total	883	100.0	869	100.0	883	100.0	873	100.0	883	100.0

Distribution UCAP assessment hours per day

- The following table shows the distribution of the number of days with how many UCAP assessment hours observed
- 81.53% of days captured
- Peak months have a median of 4 UCAP assessment hours per day and off peak months have a median of 5 UCAP assessment hours per day

# of tight supply hours per day	Peak Months 2018		Off Peak Months 2018/2019		Peak Months 2019		Off Peak Months 2019/2020		Peak Months 2020	
	# of Days	% of Days	# of Days	% of Days	# of Days	% of Days	# of Days	% of Days	# of Days	% of Days
0	25	13.59	28	15.47	36	19.57	46	25.27	34	18.48
1	8	4.35	2	1.10	7	3.80	2	1.10	5	2.72
2	13	7.07	8	4.42	10	5.43	4	2.20	21	11.41
3	26	14.13	24	13.26	23	12.50	10	5.49	21	11.41
4	20	10.87	19	10.50	25	13.59	13	7.14	22	11.96
5	34	18.48	29	16.02	21	11.41	22	12.09	12	6.52
6	9	4.89	23	12.71	15	8.15	29	15.93	14	7.61
7	9	4.89	13	7.18	7	3.80	18	9.89	9	4.89
8	13	7.07	12	6.63	11	5.98	17	9.34	12	6.52
9	6	3.26	14	7.73	12	6.52	6	3.30	9	4.89
10	8	4.35	2	1.10	4	2.17	5	2.75	5	2.72
11	3	1.63	0	0.00	3	1.63	3	1.65	7	3.80
12	4	2.17	4	2.21	1	0.54	3	1.65	5	2.72
13	3	1.63	3	1.66	0	0.00	1	0.55	5	2.72
14	1	0.54	0	0.00	1	0.54	1	0.00	0	0.00
15	1	0.54	0	0.00	1	0.54	0	0.00	1	0.54
16	0	0.00	0	0.00	0	0.00	1	0.55	1	0.54
17	1	0.54	0	0.00	1	0.54	0	0.00	1	0.54
18	0	0.00	0	0.00	3	1.63	0	0.00	0	0.00
19	0	0.00	0	0.00	2	1.09	1	0.55	0	0.00
20	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
21	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
22	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
23	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
24	0	0.00	0	0.00	1	0.54	0	0.00	0	0.00
Total	184	100.00	181	100.0	184	100.0	182	100.0	184	100.0

APPENDIX: WSAAF BY FUEL TYPE

Pulled CIRA data to estimate the fuel type WSAAF to assess fleet impact

- Daily outage rates where taken from CIRA and merged with the UCAP assessment hours for May 2018 - October 2020
- Off Peak Year 3 was estimated as the average of Year 1 and 2
- While individual resource’s outage data may vary from the fleet wide fuel type average, this data can provide some estimation of the impact of moving towards a UCAP paradigm

Estimating fleet UCAP by fuel type: Bio Gas

$$\textbf{NQC} = \sum \textbf{Weighted Seasonal Average Availability Factors}^{\textbf{Season}} * \boldsymbol{DQC}$$

Year	Peak Months SAAF	Annual Weight	Weighted SAAF (Summer / On-Peak)
3	0.854	20%	0.171
2	0.819	35%	0.290
1	0.882	45%	0.397
		Total = 100%	0.864
Year	**Off Peak SAAF**	**Annual Weight**	**Weighted SAAF (Winter / Off-Peak)**
3	0.891	20%	0.178
2	0.882	35%	0.287
1	0.857	45%	0.386
		Total = 100%	0.851

Bio-gas fleet WSAAF (Peak Months)	Bio-gas fleet WSAAF (Off Peak Months)	Example DQC of Bio-gas resource	On-Peak NQC	Off-Peak NQC
0.864	0.851	30 MW	25.92MW	25.53 MW

Note: Based on daily outage rates weighted by the number of UCAP assessment hours, actual resource NQC values will vary

Estimating fleet UCAP by fuel type: Bio Mass

$$\mathbf{NQC} = \sum \mathbf{Weighted\ Seasonl\ Average\ Availability\ Factors}^{\mathbf{Season}} * \boldsymbol{DQC}$$

Year	Peak Months SAAF	Annual Weight	Weighted SAAF (Summer / On-Peak)
3	0.848	20%	0.170
2	0.830	35%	0.291
1	0.872	45%	0.392
		Total = 100%	0.849
Year	**Off Peak SAAF**	**Annual Weight**	**Weighted SAAF (Winter / Off-Peak)**
3	0.838	20%	0.168
2	0.819	35%	0.308
1	0.901	45%	0.405
		Total = 100%	0.891

Bio-mass fleet WSAAF (Peak Months)	Bio-mass fleet WSAAF (Off Peak Months)	Example DQC of Bio-mass resource	On-Peak NQC	Off-Peak NQC
0.849	0.891	50 MW	42.45 MW	44.55 MW

Note: Based on daily outage rates weighted by the number of UCAP assessment hours, actual resource NQC values will vary

Estimating fleet UCAP by fuel type: Coal

$$\mathbf{NQC} = \sum \mathbf{Weighted\ Seasonal\ Average\ Availability\ Factors}^{\mathbf{Season}} * \boldsymbol{DQC}$$

Year	Peak Months SAAF	Annual Weight	Weighted SAAF (Summer / On-Peak)
3	0.915	20%	0.183
2	0.979	35%	0.343
1	0.977	45%	0.430
		Total = 100%	0.965
Year	**Off Peak SAAF**	**Annual Weight**	**Weighted SAAF (Winter / Off-Peak)**
3	0.942	20%	0.188
2	0.901	35%	0.315
1	0.984	45%	0.443
		Total = 100%	0.946

Coal fleet WSAAF (Peak Months)	Coal fleet WSAAF (Off Peak Months)	Example DQC of Coal resource	On-Peak NQC	Off-Peak NQC
0.965	0.946	10 MW	9.65 MW	9.46 MW

Note: Based on daily outage rates weighted by the number of UCAP assessment hours, actual resource NQC values will vary

Estimating fleet UCAP by fuel type: Natural Gas

$$\text{NQC} = \sum \textbf{Weighted Seasonal Average Availability Factors}^{\text{Season}} * DQC$$

Year	Peak Months SAAF	Annual Weight	Weighted SAAF (Summer / On-Peak)
3	0.886	20%	0.177
2	0.869	35%	0.304
1	0.875	45%	0.394
		Total = 100%	0.875
Year	**Off Peak SAAF**	**Annual Weight**	**Weighted SAAF (Winter / Off-Peak)**
3	0.893	20%	0.179
2	0.901	35%	0.315
1	0.884	45%	0.398
		Total = 100%	0.892

Natural gas fleet WSAAF (Peak Months)	Natural gas fleet WSAAF (Off Peak Months)	Example DQC of Natural Gas resource	On-Peak NQC	Off-Peak NQC
0.875	0.892	500 MW	437.5 MW	446 MW

Note: Based on daily outage rates weighted by the number of UCAP assessment hours, actual resource NQC values will vary

Estimating fleet UCAP by fuel type: Geo-Thermal

$$\mathrm{NQC} = \sum \mathbf{Weighted\ Seasonal\ Average\ Availability\ Factors}^{\mathbf{Season}} * \boldsymbol{DQC}$$

Year	Peak Months SAAF	Annual Weight	Weighted SAAF (Summer / On-Peak)
3	0.893	20%	0.179
2	0.848	35%	0.297
1	0.872	45%	0.392
		Total = 100%	0.868
Year	**Off Peak SAAF**	**Annual Weight**	**Weighted SAAF (Winter / Off-Peak)**
3	0.788	20%	0.158
2	0.877	35%	0.307
1	0.699	45%	0.315
		Total = 100%	0.780

Geo-thermal fleet WSAAF (Peak Months)	Geo-thermal fleet WSAAF (Off Peak Months)	Example DQC of Geo-thermal resource	On-Peak NQC	Off-Peak NQC
0.868	0.780	35 MW	30.38 MW	27.3 MW

Note: Based on daily outage rates weighted by the number of UCAP assessment hours, actual resource NQC values will vary

California ISO

Estimating fleet UCAP by fuel type: HRCV (Heat Recovery)

$$\mathbf{NQC} = \sum \mathbf{Weighted\ Seasonal\ Average\ Availability\ Factors}^{\mathbf{Season}} * \boldsymbol{DQC}$$

Year	Peak Months SAAF	Annual Weight	Weighted SAAF (Summer / On-Peak)
3	0.959	20%	0.192
2	0.879	35%	0.308
1	0.962	45%	0.422
		Total = 100%	0.933
Year	**Off Peak SAAF**	**Annual Weight**	**Weighted SAAF (Winter / Off-Peak)**
3	0.876	20%	0.175
2	0.809	35%	0.283
1	0.944	45%	0.425
		Total = 100%	0.883

HRCV fleet WSAAF (Peak Months)	HRCV fleet WSAAF (Off Peak Months)	Example DQC of HRCV resource	On-Peak NQC	Off-Peak NQC
0.933	0.891	15 MW	13.99 MW	13.25 MW

Note: Based on daily outage rates weighted by the number of UCAP assessment hours, actual resource NQC values will vary

Estimating Fleet UCAP by Fuel Type: LESR (Energy Storage)

$$\mathbf{NQC} = \sum \mathbf{Weighted\ Seasonal\ Average\ Availability\ Factors}^{\mathbf{Season}} * \boldsymbol{DQC}$$

Year	Peak Months SAAF	Annual Weight	Weighted SAAF (Summer / On-Peak)
3	0.975	20%	0.195
2	0.964	35%	0.337
1	0.958	45%	0.431
		Total = 100%	0.964
Year	**Off Peak SAAF**	**Annual Weight**	**Weighted SAAF (Winter / Off-Peak)**
3	0.948	20%	0.190
2	0.969	35%	0.339
1	0.927	45%	0.417
		Total = 100%	0.946

Storage fleet WSAAF (Peak Months)	Storage fleet WSAAF (Off Peak Months)	Example DQC of Storage resource	On-Peak NQC	Off-Peak NQC
0.964	0.946	25 MW	24.09 MW	23.65 MW

Note: Based on daily outage rates weighted by the number of UCAP assessment hours, actual resource NQC values will vary.

Estimating fleet UCAP by fuel type: Nuclear

$$\mathbf{NQC} = \sum \mathbf{Weighted\ Seasonal\ Average\ Availability\ Factors}^{\mathbf{Season}} * \boldsymbol{DQC}$$

Year	Peak Months SAAF	Annual Weight	Weighted SAAF (Summer / On-Peak)
3	0.983	20%	0.197
2	0.999	35%	0.349
1	0.875	45%	0.394
		Total = 100%	0.940
Year	**Off Peak SAAF**	**Annual Weight**	**Weighted SAAF (Winter / Off-Peak)**
3	0.957	20%	0.191
2	0.946	35%	0.331
1	0.968	45%	0.436
		Total = 100%	0.958

Nuclear fleet WSAAF (Peak Months)	Nuclear fleet WSAAF (Off Peak Months)	Example DQC of Nuclear resource	On-Peak NQC	Off-Peak NQC
0.940	0.958	800 MW	751.7 MW	766.4 MW

Note: Based on daily outage rates weighted by the number of UCAP assessment hours, actual resource NQC values will vary

Estimating fleet UCAP by fuel type: Waste

$$\mathbf{NQC} = \sum \mathbf{Weighted\ Seasonal\ Average\ Availability\ Factors}^{\mathbf{Season}} * \boldsymbol{DQC}$$

Year	Peak Months SAAF	Annual Weight	Weighted SAAF (Summer / On-Peak)
3	0.957	20%	0.191
2	0.857	35%	0.300
1	0.846	45%	0.380
		Total = 100%	0.872

Year	Off Peak SAAF	Annual Weight	Weighted SAAF (Winter / Off-Peak)
3	0.865	20%	0.173
2	0.894	35%	0.313
1	0.835	45%	0.376
		Total = 100%	0.862

Waste fleet WSAAF (Peak Months)	Waste fleet WSAAF (Off Peak Months)	Example DQC of Waste resource	On-Peak NQC	Off-Peak NQC
0.872	0.862	15 MW	13.08 MW	12.93 MW

Note: Based on daily outage rates weighted by the number of UCAP assessment hours, actual resource NQC values will vary

Q&A/Discussion

Presentation 5: Incentives for YA filings Deficient LSE

Sue Maria, Consultant to AReM

2:30-2:50 p.m.

Alliance for Retail Energy Markets

Incentive for LSEs to Cure Year-Ahead RA Deficiencies by Their Month-Ahead RA Filings

November 23, 2020

CPUC Track 3.B RA Workshop

R.19-11-009

Presented by: Sue Mara, consultant to AReM, sue.mara@rtoadvisors.com

Background

- Energy Division requested comments in Track 2 on incentives for LSEs to cure year-ahead RA deficiencies by their month-ahead RA filings, including whether additional month-ahead penalties were appropriate for that same year-ahead deficiency if not cured.
- AReM and others opposed such penalties as duplicative and punitive; AReM proposed an incentive instead.
- D.20-06-031 (Track 2) concluded parties' comments were a "useful start" and suggested proposals be submitted in Track 3.
- Track 3.B included as Issue 2.a: *Incentives for load-serving entities that are deficient in year-ahead RA filings, as discussed in D.20-06-031.*

Proposal

- An LSE curing some or all of its year-ahead Local, Flexible or System RA deficiency by no later than the LSE’s applicable month-ahead compliance filing is entitled to relief of half the penalty assessed on its year-ahead deficiencies that have been cured.
- “Applicable” refers to the month of the year in which the LSE had a year-ahead deficiency.

EXAMPLE

- LSE A has a year-ahead System RA deficiency of 10 MW for August and September 2021 with an assessed penalty of $88,800/mo or $177,600 total.
- LSE A would have to cure by June 17 for its August deficiency and July 18 for its September deficiency.
- If LSE A cured the entire 10 MW August deficiency by no later than the June 17th month-ahead compliance filing, it would be entitled to relief of $44,400 of the penalty.
- If LSE A cured 5 MW of the 10 MW August deficiency by no later than its June 17th month-ahead compliance filing, it would be entitled to relief of $22,200 of the penalty.
- The same would apply for the September deficiency, which LSE A would have to cure by no later than July 18.

Benefits of Proposal

- Provides LSEs an incentive to continue to seek to procure RA to cure year-ahead deficiencies.
- Simple to administer.
- Should help reduce what would otherwise be CPM procurement.

Q&A/Discussion

Presentation 6: RA Import Rules

Milos Bosanac, Lead Infrastructure and Regulatory Policy Developer, Infrastructure and Regulatory Policy, CAISO

Karl Meeusen, Senior Advisor, Infrastructure and Regulatory Policy, CAISO

John Goodin, Senior Manager, Infrastructure and Regulatory Policy, CAISO

2:50-3:20 p.m.

Import RA Proposal

Milos Bosanac
Market and Infrastructure Policy

CPUC Track 3.B Proceeding
November 23, 2020

Tightening supply conditions across western interconnection place greater emphasis on internal resources and RA imports

- Recent August and September system conditions point to the need for reliable and dependable capacity, including RA imports.
- CAISO capacity deficiencies place greater emphasis on imports to help manage grid conditions, with particular need during net load peak hours.
- Capacity is tightening across the western interconnection as states enact clean energy policy goals and retire older baseload and coal-fired resources.
- Severe west-wide climate events cause simultaneous tight system conditions across multiple BAAs, impacting once reliable supply diversity benefits.

Continued reliance on non resource-specific import RA contracts adds reliability risk

- Non resource-specific imports do not assure dedicated, physical supply at the time of the RA showings compared to source specific imports.
- Non resource-specific <u>energy contracts</u> do not assure physical capacity nor do they guarantee delivery when system needs are highest.
- A self-scheduling requirement limits market efficiency without providing commensurate reliability benefits or guaranteeing physical supply.
- Absent a clear priority transmission service requirement, imports can further be subject to non-delivery when system needs are the tightest.

Import RA should be dependable and deliverable permitting the ISO to properly plan for and manage reliability

- Real dedicated, physical capacity must support RA imports.
  - Incorporate a source specification requirement and attestation to prevent speculative supply
- RA import capacity should be committed to the LSE, and consequently to the CAISO.
  - Avoid double counting of capacity
- RA imports should be deliverable with a high degree of certainty.
  - Specific transmission delivery requirements will help ensure that RA imports can be delivered during west-wide tight system conditions

RA imports must be resource or BAA specific

- RA Imports must be resource- or BAA-specific and meet source specification information and attestation requirements.
- Resource-specific RA Imports:
  - Pseudo-tied resources
  - Dynamically scheduled resources
  - Non-dynamic resource-specific system resources
    - Individual or aggregations of resources must be resource and BAA specific
    - System resources must be BAA specific
- Non-resource specific imports would no longer be eligible to provide RA import capacity.
  - Can provide beneficial and competitively valued economic energy, but not RA capacity.

Source specification information for RA Imports

- All resource-specific RA imports will be required to provide the following information:
  - Name of resource(s) supporting the RA imports (name of physical resource and source BAA e-tag identifier for resource)
  - Name of single source BAA

- Source information will be required at time of submission of RA supply plan in CIRA.
  - RA supply plan template will include additional columns requiring source information.
  - Validations will not permit submission of RA supply plan unless the source information is provided.

Transmission delivery requirement for RA Imports

- RA imports must be delivered on Firm transmission (7-F curtailment priority) on last transmission leg to the ISO (intertie).
  - 7-F is highest curtailment priority and last type of transmission to be curtailed to manage congestion.
- RA imports must be delivered on transmission no lower than Monthly Non-Firm PTP Service (5-NM curtailment priority) on all upstream transmission legs.
  - Provide flexibility for parties to reserve:
    - Monthly Non-Firm PTP, 5-NM curtailment priority
    - Conditional Firm PTP, 6-CF curtailment priority
    - Firm PTP, 7-F curtailment priority
- Validation - ISO will develop a tool to flag e-tags delivering RA imports on transmission of lower firmness and initiate investigation.

Capacity assurance attestation requirement for RA Imports

- RA imports will be required to meet the attestation requirements:

  1.The capacity shown is owned or contractually secured;

  2. The capacity shown has not been sold or otherwise committed to any other party;

  3. Transmission service of proper firmness (cite tariff section) has been reserved for the delivery of the identified import RA resource(s) to the ISO system; and

  4. The capacity can only be interrupted for reliability reasons as determined under the host BAA's tariff, a transmission curtailment, or a plant outage.

- Attestation will be required at time of submission of Supply plans – annual and monthly timeframes (T-45).
  - Element 3 of attestation will only be required during monthly supply plan submissions.
- Attestation will be a checkbox in CIRA for Scheduling Coordinator submitting supply plan to attest.
  - Validation – if box is not checked, CIRA will not accept supply plan.

RA Imports – Must Offer Obligation

- Pre-*Day Ahead Market Enhancements (DAME)* initiative:
  - Must offer obligation in Day Ahead (DA) and Real Time (RT) up to shown RA amount
  - Subject to bid insertion in DA and RT

- Post-*DAME* initiative:
  - Must offer obligation in DA with bid insertion.
  - The initiative will determine treatment in RT – whether a must offer obligation remains

RA Imports – Bidding Behavior

- Stakeholders have expressed concern with RA imports bidding high in DA to avoid an award in the market and selling the energy elsewhere.

- The proposed RA import rules can mitigate that behavior and set the incentive for competitive economic bidding:
  - Must offer obligation extended to RT with bid insertion.
  - Attestation requirement that capacity has not been committed to any other parties incents supplier to economically bid that committed capacity into the DA and RT markets.
  - Transmission delivery requirement also involves potential additional supplier costs for securing delivery of RA import, and further incentivizes competitive economic bidding.
  - FERC Order 831 further verifies and reduces RA import bids over $1000/MWh.

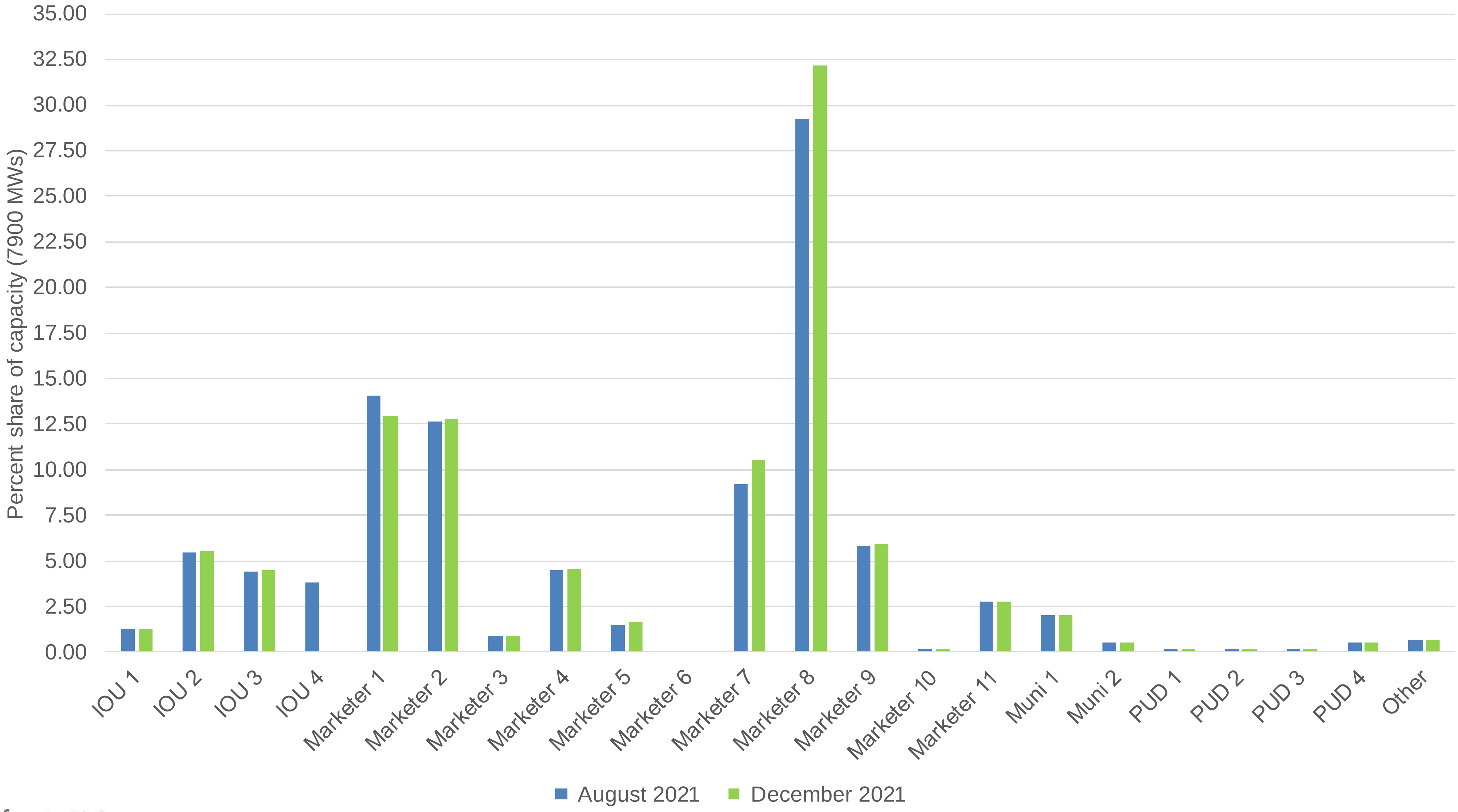
APPENDIX - DATA ON LONG-TERM FIRM TRANSMISSION RIGHTS ON THE NORTHERN INTERTIES

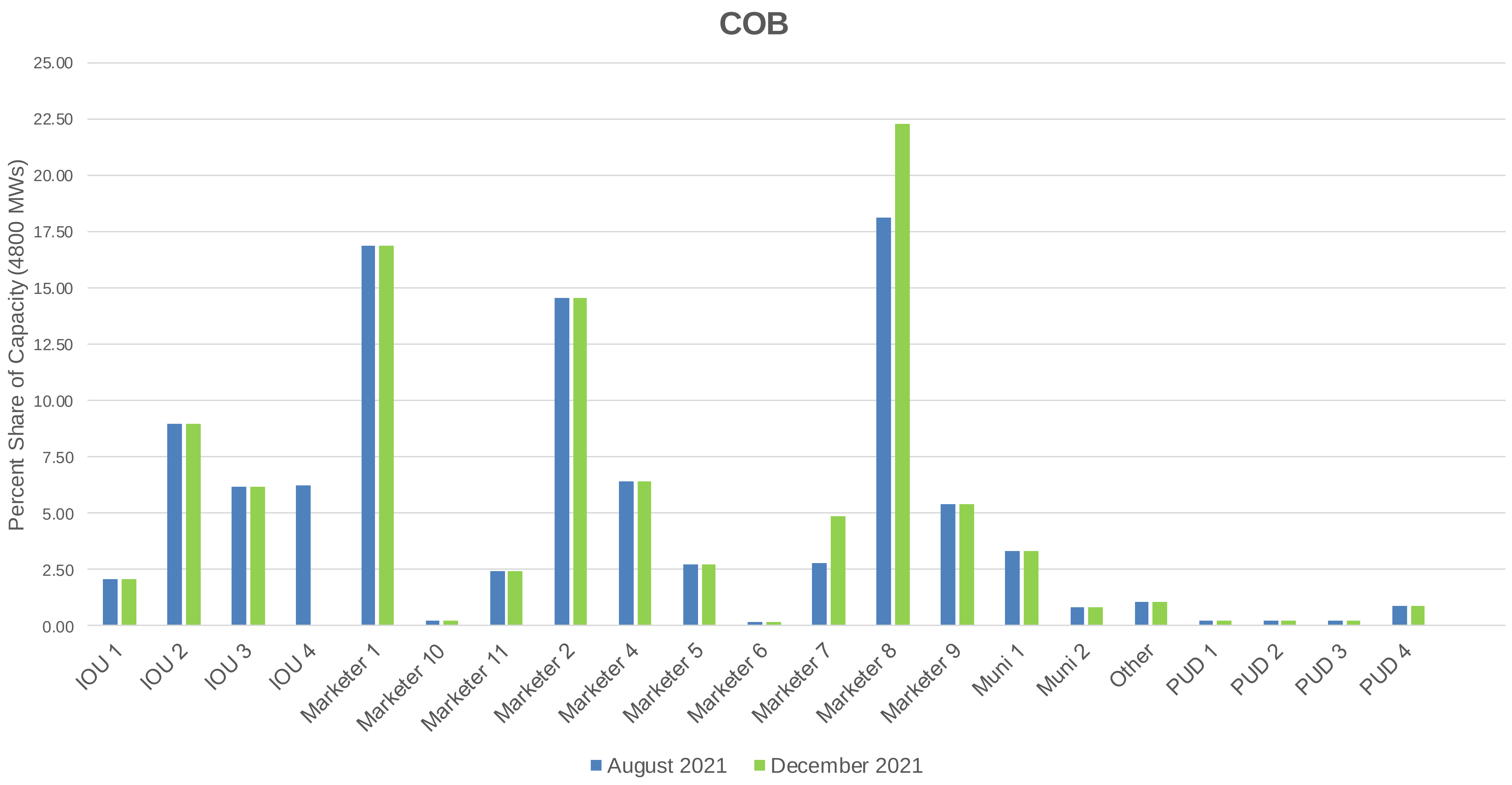
CAISO received information on existing Long-Term Firm transmission rights on COB and NOB from Transmission Providers

Transmission Capacity on Northern Interties (in MWs)	Number of Entities Holding Long-Term Firm Transmission Rights
0-19	5
20-49	2
50-99	2
100-499	9
500-999	1
1000-2510	3
Total	21

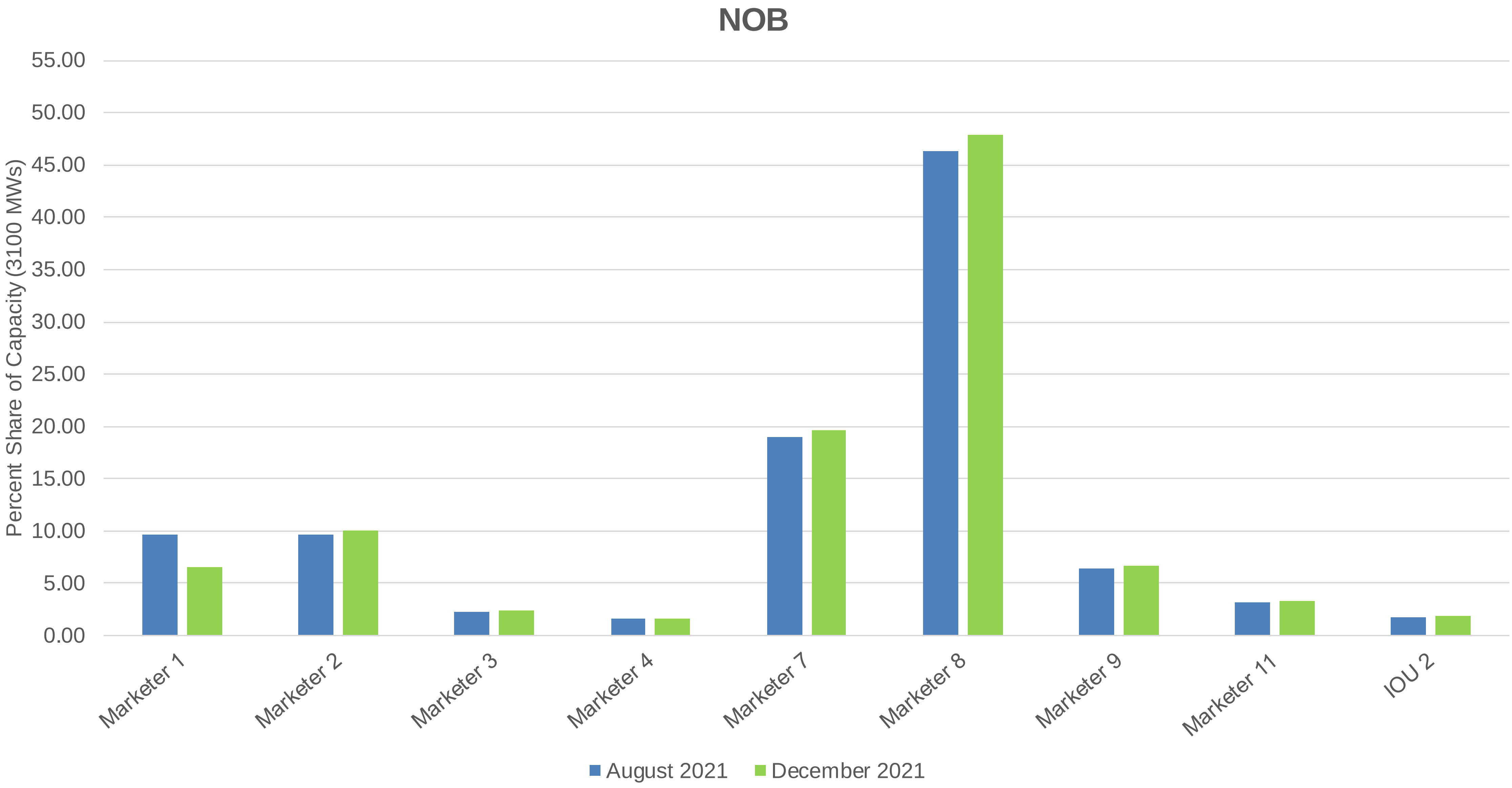
- Thirteen (13) entities hold 100 MWs or more across the two northern interties.
- There is a secondary resale market in which other entities could purchase firm transmission rights on the northern interties.
- While the proposed policy would apply to deliveries across all interties to the CAISO, stakeholders have been mostly concerned with the northern interties where more excess capacity is available for potential RA Importers.

Northern interties (COB+NOB)





COB
Percent Share of Capacity (4800 MWs)
25.00
22.50
20.00
17.50
15.00
12.50
10.00
7.50
5.00
2.50
0.00
IOU 1
IOU 2
IOU 3
IOU 4
Marketer 1
Marketer 10
Marketer 11
Marketer 2
Marketer 4
Marketer 5
Marketer 6
Marketer 7
Marketer 8
Marketer 9
Muni 1
Muni 2
Other
PUD 1
PUD 2
PUD 3
PUD 4
August 2021
December 2021


NOB
55.00
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Percent Share of Capacity (3100 MWs)
Marketer 1
Marketer 2
Marketer 3
Marketer 4
Marketer 7
Marketer 8
Marketer 9
Marketer 11
IOU 2
August 2021
December 2021

Q&A/Discussion

Stretch Break :)

Please be back at 3:30 p.m.

Image Source: iamthinks.blogspot.com
https://www.showeet.com/19/06/2016/templates/title-slide-templates-for-powerpoint-and-keynote/

Presentation 7: CAISO ELCC Proposal

Lauren Carr, Infrastructure and Regulatory Policy Specialist, Infrastructure and Regulatory Policy

Karl Meeusen, Senior Advisor, Infrastructure and Regulatory Policy, CAISO

John Goodin, Senior Manager, Infrastructure and Regulatory Policy, CAISO

3:30-3:50 p.m.

Demand Response Capacity Counting

Lauren Carr
Infrastructure and Regulatory Policy Specialist

CPUC RA Proceeding Track 3B
November 23, 2020

CAISO is considering how to evolve the RA program to ensure the RA fleet can meet capacity *and energy* needs all times of the year

- California will rely more heavily on both variable and availability-limited resources as we move to decarbonize the grid
- It is critical to assess the ability of preferred resources to displace traditional thermal generation while maintaining system reliability and serving energy needs every hour of the year
- Demand response's (DR) load reduction capability can vary over the course of a day, month, or season and has limits on availability, including hours of operability, duration, and number of event calls
- Capacity values must be assessed in the context of other use and availability-limited resources due to saturation effects and how well such resources support system reliability while reducing GHG

The following principles must be incorporated into demand response capacity evaluation

- Must assess DR's contribution to reliability across the year or seasons
  - Should evaluate how DR contributes to system reliability beyond the monthly peak day during peak hours
- Must assess DR's capacity value as a variable resource
  - DR resources are not fixed capacity resources; most have a variable load curtailment nature
- Must assess DR's interactive effects with other resources
  - Use- and availability-limited resources, like DR, can saturate alongside similar resources; incremental amounts of the same resource type adds less and less additional value to the system

A new qualifying capacity methodology must be developed to meet all of these principles

- Load Impact Protocols (LIPs) have a use and purpose but are insufficient in isolation to inform the capacity value of DR
  - Useful in establishing operational capability of DR resources
  - These capabilities can vary, but this variation is not considered when establishing the capacity value
  - Do not address interactive effects of variable and use-limited resources
- An ELCC methodology informs DR’s contribution to system reliability, considering its load reduction profile, availability, and use-limitations
  - Considers interactive effects of variable and use-limited resources
  - This assessment helps inform program design features and overall investment decisions to ensure procuring best resources at lowest cost
  - Use of an ELCC methodology will provide operational flexibility to demand response resources through bidding actual capability

CAISO requests the CPUC develop a new capacity valuation methodology that addresses these principles

- General agreement that DR exhibits variability and use-limitations, and appropriate capacity valuation method has been heavily debated in Energy Storage and Distributed Energy Resources (ESDER) 4 and BPM change process for PRR 1280
- CAISO explored how ELCC could be applied to demand response in the ESDER 4 initiative to better understand its capacity value
  - CAISO is working with E3 and utilities to update ELCC with updated information
  - CAISO plans to include updated study results in Track 3B
- The commission should commit to developing new qualifying capacity methodology for DR with stakeholders in 2021 to enable implementation in 2022
  - A methodology that assesses DR's contribution to reliability would enable the CAISO to revise its tariff to treat DR as a variable resource under the RA rules

Q&A/Discussion

Presentation 8: Hybrid QC Methodology Overview

Simone Brant, Senior Analyst, Resource Adequacy, Energy Division

3:50-4 p.m.

Existing Hybrid QC Methodology

Simone Brant

Energy Division

November 23, 2020

California Public Utilities Commission

Background

- **D.20-06-031 adopted a QC methodology for hybrid and co-located resources receiving the Investment Tax Credit**
  - Applied when both the renewable and storage are deliverable
  - Assumes battery charges solely from the renewable
  - Caps total QC at the interconnection limit

Methodology

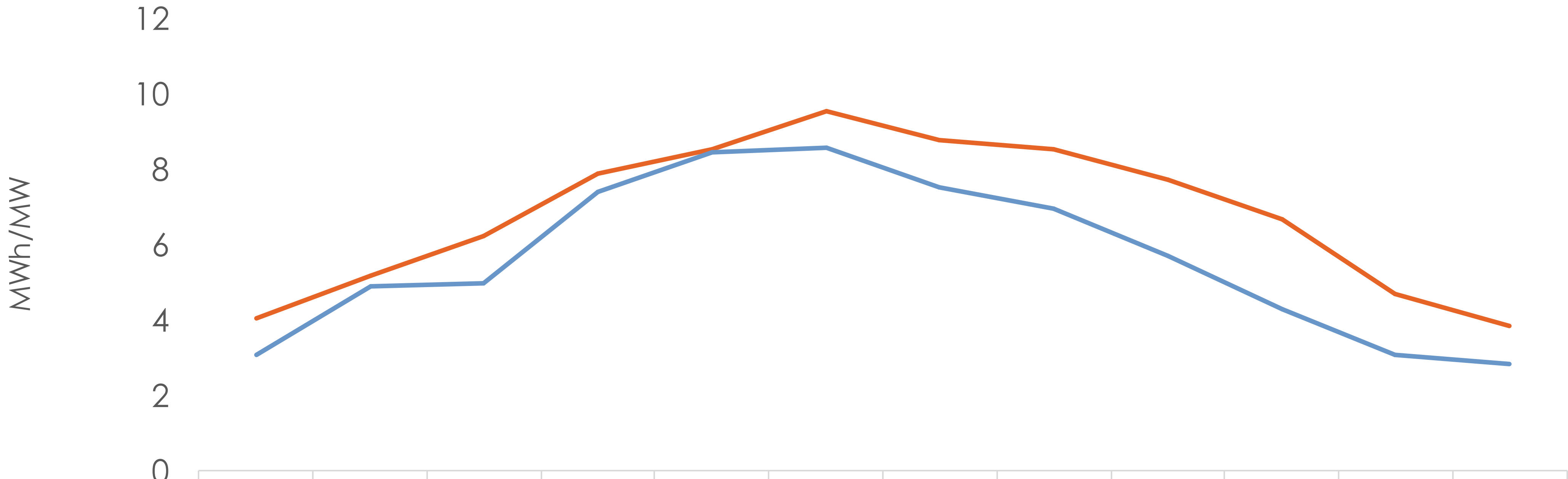
- ***Total QC = Effective ES QC + Effective Renewable QC***
- ***Effective ES QC*** equals the minimum of:
  (1) The energy (MWh) production from the renewable resource from 2 hours after the net load peak until 2 hours before the net load peak assuming charging is done at a rate less than or equal to the energy storage's capacity. This renewable charging energy is then divided by 4 hours to determine the QC; or
  (2) The QC of the energy storage device.
- ***Effective Renewable QC*** equals the remaining renewable capacity, net of the capacity required to charge the battery at a constant rate over the available charging hours, multiplied by the ELCC factor for the month.

Staff Implementation of Methodology

1. Identified hour of net load peak by month using CAISO flexible capacity study for 2021
2. Used three years of settlement data to create production profiles for each month (individual production used for existing renewables)
3. Subtracted MWh needed to charge battery from expected production
4. Converted remaining energy back to MW and apply ELCC

Hour	Months
HE19	January-March, November-December
HE20	September-October
HE21	April-August

Production Profiles per MW Installed Capacity



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
solar	4.05	5.17	6.23	7.89	8.50	9.54	8.78	8.50	7.73	6.65	4.67	3.81
wind	3.07	4.90	4.95	7.41	8.43	8.54	7.50	6.96	5.69	4.29	3.06	2.82

Presentation 9: QC Proposals

Jim Caldwell, Senior Technical Consultant, CEERT
Brian Biering, Attorney for AWEA-California
Ravi Sankaran, Director of Business Development, Southwestern Power Group

4-4:30 p.m.

Hybrid Resource RA Counting Rules

CEERT

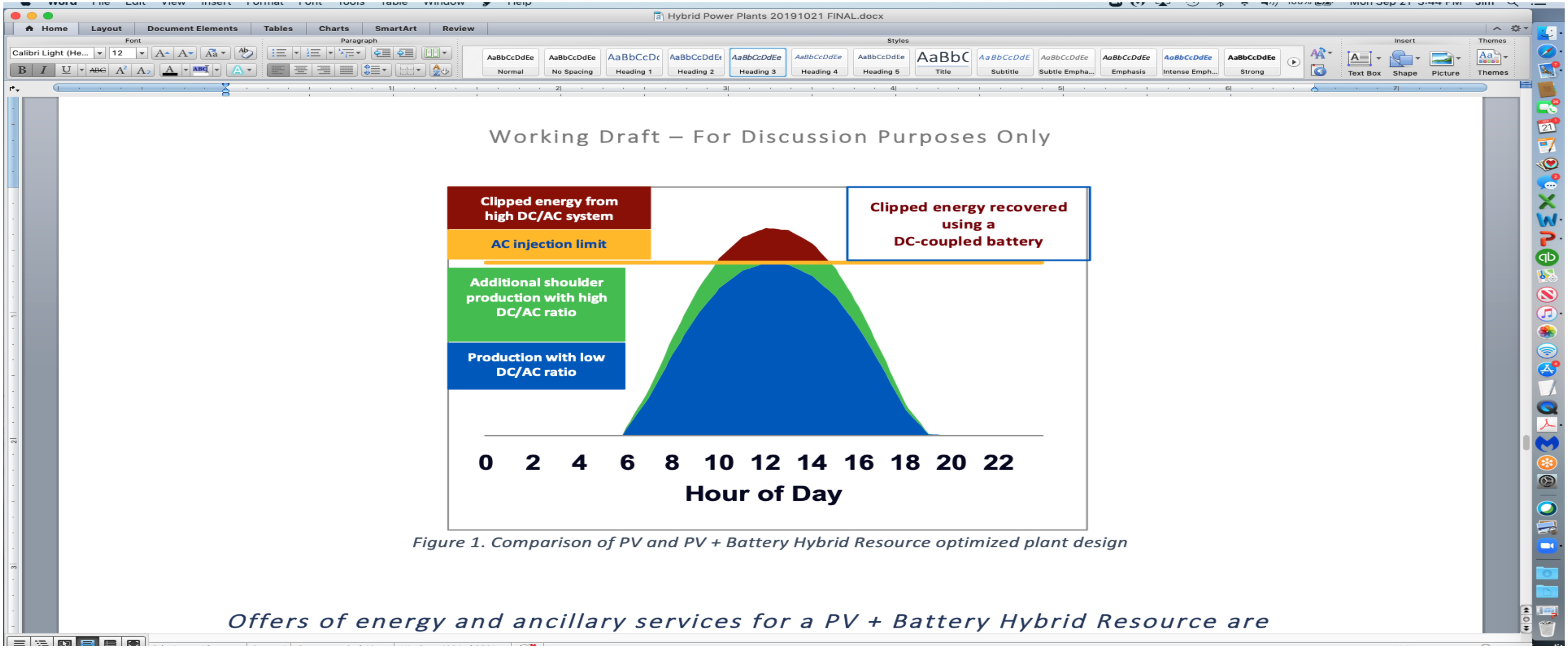
Track 3b Proposal

November 23, 2020

Hybrid Resource RA Counting Rules

- New methodology adopted in R.17-09-020 not yet implemented
  - Improvement over previous method but still undercounts hybrid RA value, but, more importantly, does not reward innovation in project design
- No hybrid solar + storage projects are on line or under construction in CA but dominate CAISO Interconnection queue projects with near term COD.
  - Given near term procurement needs, critical that operating experience be gained with hybrids in next procurement round and that developers be encouraged to offer best available configurations.
- New analytical results published since R.17-09-020 support higher QC values
  - Astrape ELCC study for IOUs in RPS proceeding phase 1: July 1, 2020
  - E3 study for PJM and White Paper on proposed “delta” method for ELCC: Aug, 2020
  - ESIG/NextEra presentations to FERC/MISO: July 2020
- CEERT Track 3b proposal
  - Use marginal ELCC to calculate project specific QC using project specific design parameters coordinated with Interconnection studies.
  - Use “AND” methodology with appropriate consideration for interconnection rights and storage charging restrictions.
  - Provide for acceptance test following synchronization to validate QC value.
  - CPUC adopt CAISO proposed protocols approved on November 18.

Hybrid Resource RA Counting Rules
ESIG/NextEra Results



Indicative Impact of DC Coupled Hybrid with High Inverter Loading Ratio

Comparison of a single axis tracked installation in Central Valley (used Lat/Long of La Paloma) for an average fall day: 2.0 ILR w/ DC coupled storage at 50% of solar AC nameplate (A) vs. 1.2 ILR w/o storage but same DC panel rating (B)

	September	October
Solar only AC capacity factor -- A/B	+37%	+49%
Transmission capacity for FCDS -- A/B	-40%	-40%
Clipped solar energy post sunset – A only	15%	10%

NQC Potential for A: ~115% of battery nameplate (requires "extra" inverter capacity and POI rights plus, potentially, more storage mwh)

Actual changes are highly site/project specific and require project specific cost/benefit analysis of incremental investment required to achieve these results.

Hybrid Resource RA Counting Rules
Astrape RPS Study

- Astrape ELCC for RPS study (Phase 1 published in July, phase 2 results end of 2020).

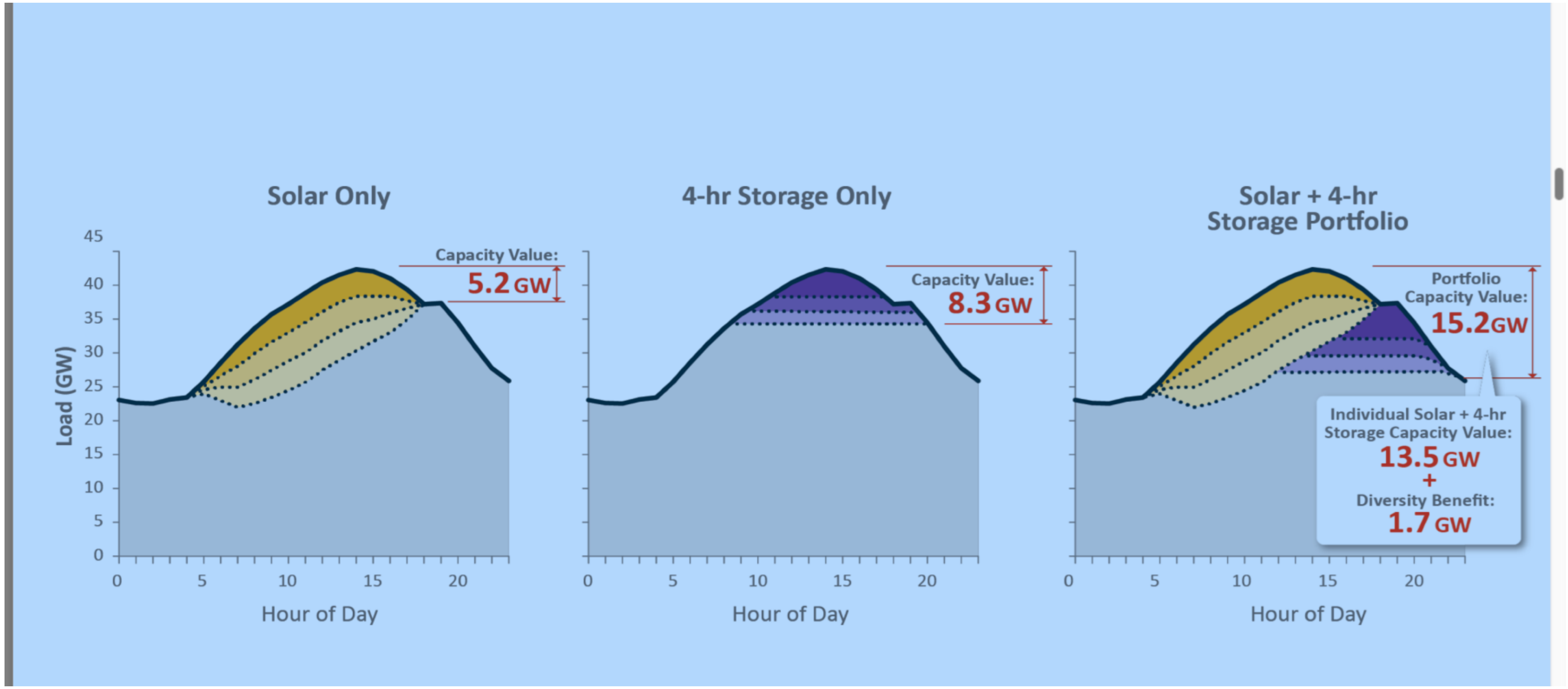
- Phase 1 Results (see, e.g., SCE AL 4243-E, 7/1/20):
  CAISO Ave Project Marginal ELCC Value:

	2022	2030
Tracking PV	6.2%	1.7%
Tracking PV Hybrid	99.8%	93.2%

- Phase 1 results only for AC coupled projects with 1:1 storage/solar capacity with no grid charging. Ignores energy benefit of high inverter loading ratios, other design optimizations available with ability to store "surplus" energy, above average irradiance levels, and efficiency gains/cost reductions from DC coupling.

- "Given the wide range of potential configurations for hybrid facilities a heuristic for calculating a specific project's ELCC may be needed. A general heuristic using the sum of the solar and storage ELCC subject to a cap of the maximum output imposed by interconnection capability is a reasonable approximation at the solar and storage penetrations modeled in 2022-2030." App A, p.21.

Hybrid Resource RA Counting Rules
Recent E3 Results



Not a hybrid project but a "portfolio ELCC" showing the AND impact
Fr :"Practical Considerations for Application of ELCC", Aug 7, 2020, E3, p.7

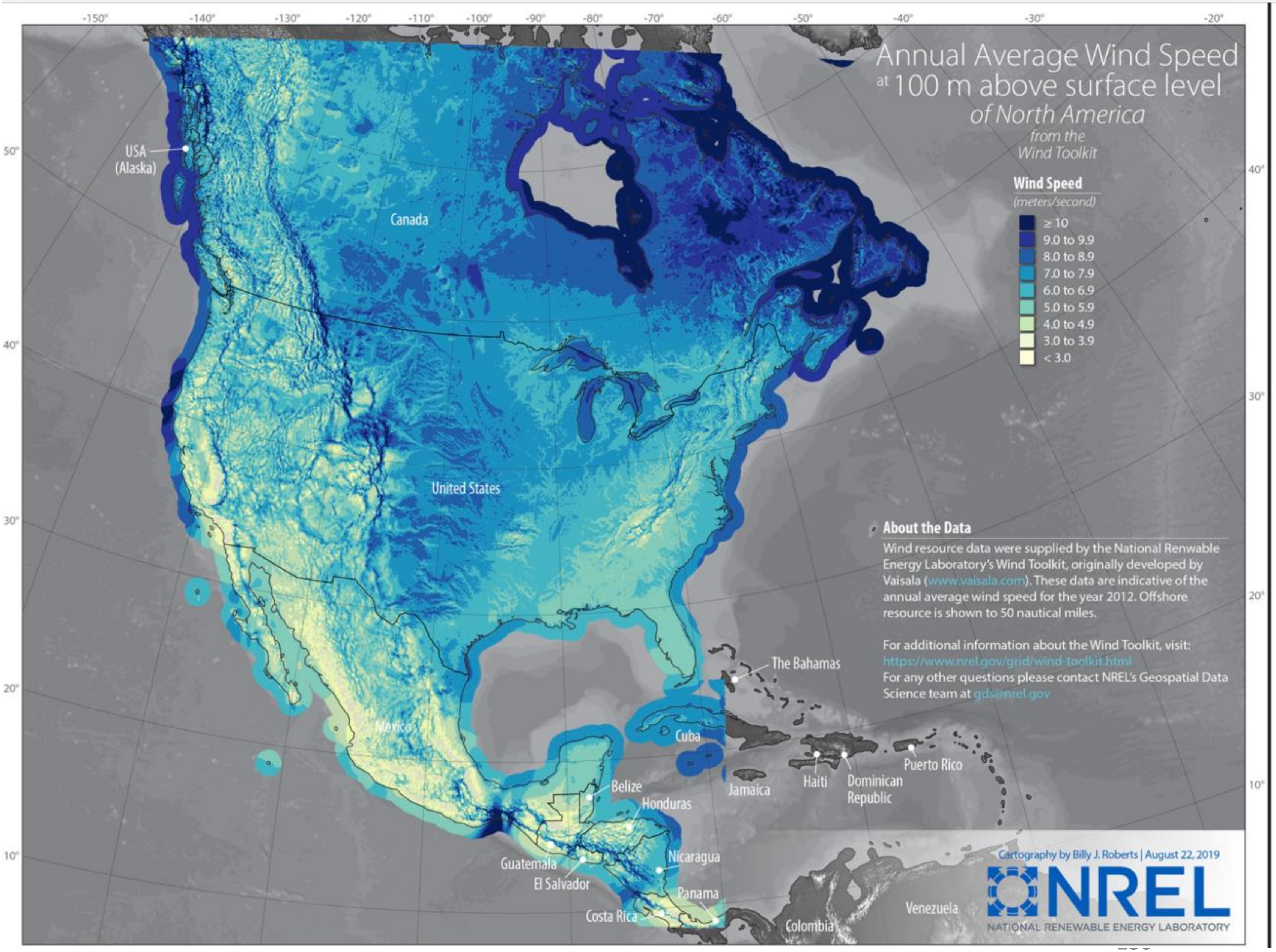
AMERICAN WIND ENERGY ASSOCIATION
CALIFORNIA

AWEA-CA Near-term Proposal for Adjusting Wind ELCCs

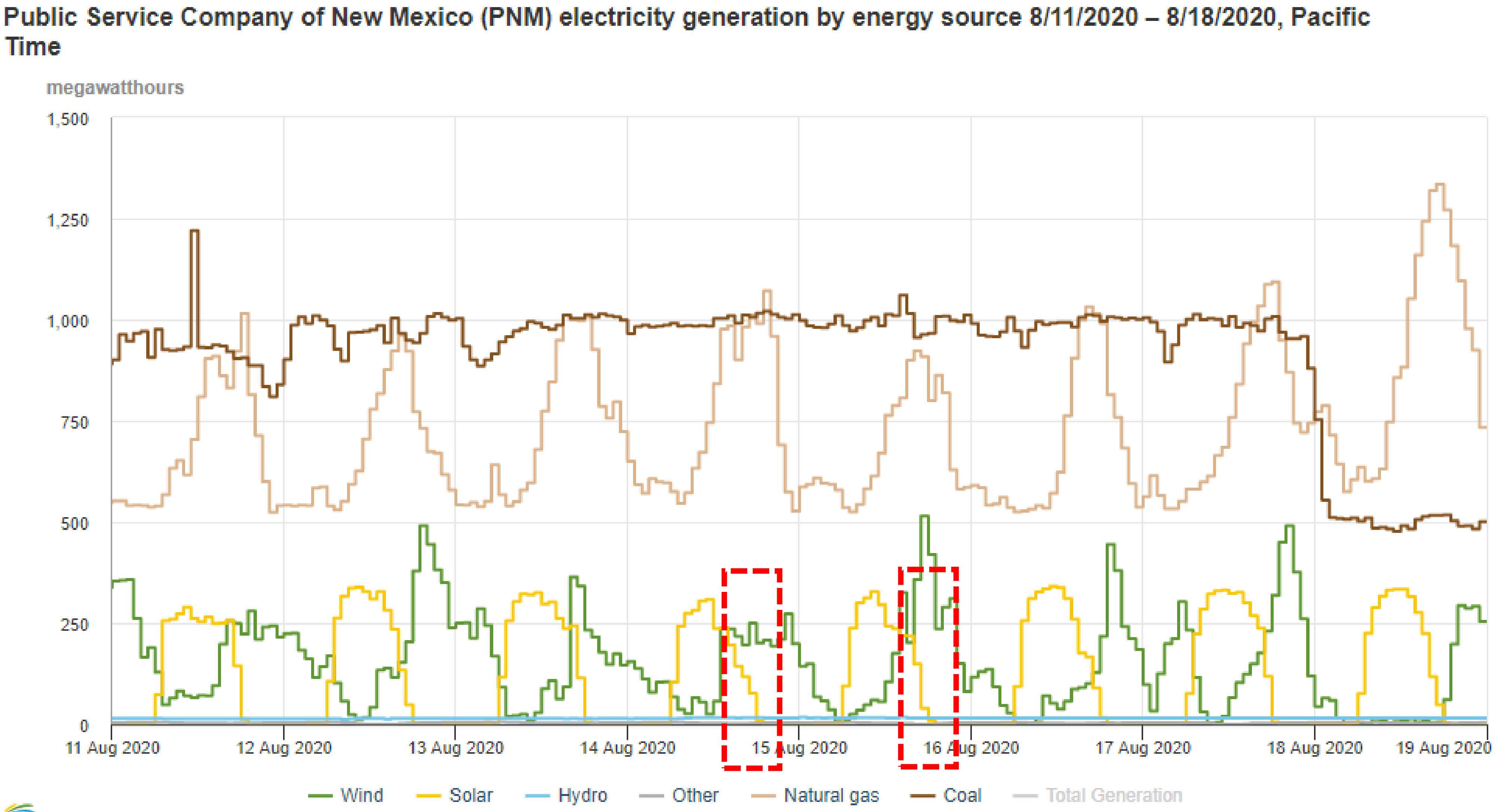
November 18, 2020

AWEA AMERICAN WIND ENERGY ASSOCIATION CALIFORNIA

Wind speeds (100 m hub height) can vary greatly by geographic region. This materially affects corresponding capacity factors / hourly generation profiles



PNM BAA Data shows wind increasing in production at the time of the August 14, 15 Stage 3 events



Source: EIA

AWEA-CA Near-Term Proposal for Track 3b

AWEA-CA proposes that the Commission maximize ratepayer value from investments in the most cost effective intermittent resources by taking a *near-term* step of disaggregating wind resource ELCC factors.

The ELCC is overly generic and does not provide signals for the value of resource diversity. The CPUC has recognized the need to address geographic diversity of resources' contributions to reliability needs:

- "Due to increasing penetration of renewable resources, it is prudent and essential to align procurement under the RPS program with future system reliability conditions for effective planning and procurement of renewables"

- "There is need for granular location and resource type modeling due to wide variation in production profiles for the same technology type in different locations." (See D. 19-09-043, Findings of Fact 3 and 19.)

AMERICAN WIND ENERGY ASSOCIATION

CALIFORNIA

AWEA-California is a project of the American Wind Energy Association, representing companies that develop, own, and operate utility-scale wind, solar, storage, offshore wind, and transmission assets. AWEA-California is focused on driving immediate and sustained development of new utility-scale renewable energy capacity to propel California toward a carbon-free electric future. In January of 2021, AWEA will merge with a new organization to become the American Clean Power Association.

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SouthWestern POWER GROUP

Proposed Wind QC /ELCC Concepts

Ravi Sankaran
Southwestern Power Group (SWPG)
CPUC RA Track 3B Workshop
November 23, 2020

About SWPG

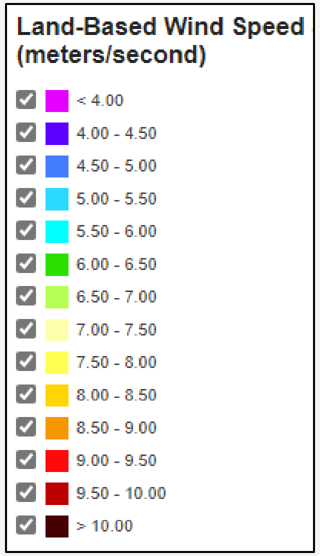
- Independent developer of utility-scale generation and transmission in the Desert Southwest
- Project Manager/Developer of the SunZia Southwest Transmission Project
- Established in 2000, based in Phoenix and Albuquerque, staff of 15
- Owned by MMR Group of Baton Rouge, LA

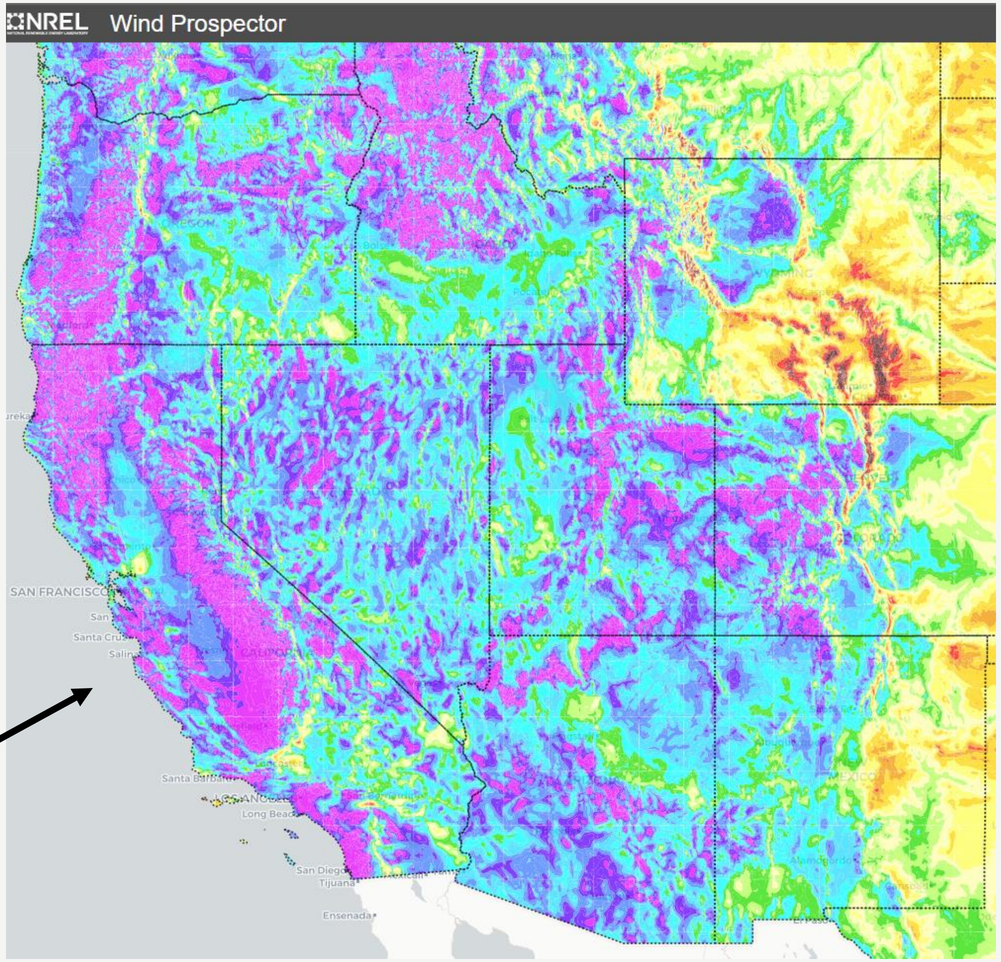
Background

- RA Net Qualifying Capacity (NQC) for all Wind projects currently based on uniform monthly ELCC values for all locations
- CPUC acknowledged need for ELCC locational granularity in RPS Decision 19-09-043 issued October 2019, directed study of seven (7) regions, four (4) CAISO and three (3) out-of-state (OOS) regions
- In July 2020 IOU's released Astrape ELCC Study based on the CPUC-directed regions (SCE AL 4243-E), though more relevant to procurement evaluation than actual NQC allocation
- Current uniform ELCC sends misleading RA price signals to LSEs and limits confidence in RA values. SWPG therefore proposes higher locational granularity using RESOLVE regional Capacity Factors.
- Proposed solution focused on Wind since Wind more location-dependent than other technologies

Current Wind ELCC Technology Factors[1]

Month	CY 2020 Wind ELCC
1	14.0%
2	12.0%
3	28.0%
4	25.0%
5	25.0%
6	33.0%
7	23.0%
8	21.0%
9	15.0%
10	8.0%
11	12.0%
12	13.0%





Current uniform Wind ELCC factors do not capture diversity of wind resource, sending misleading RA price signals

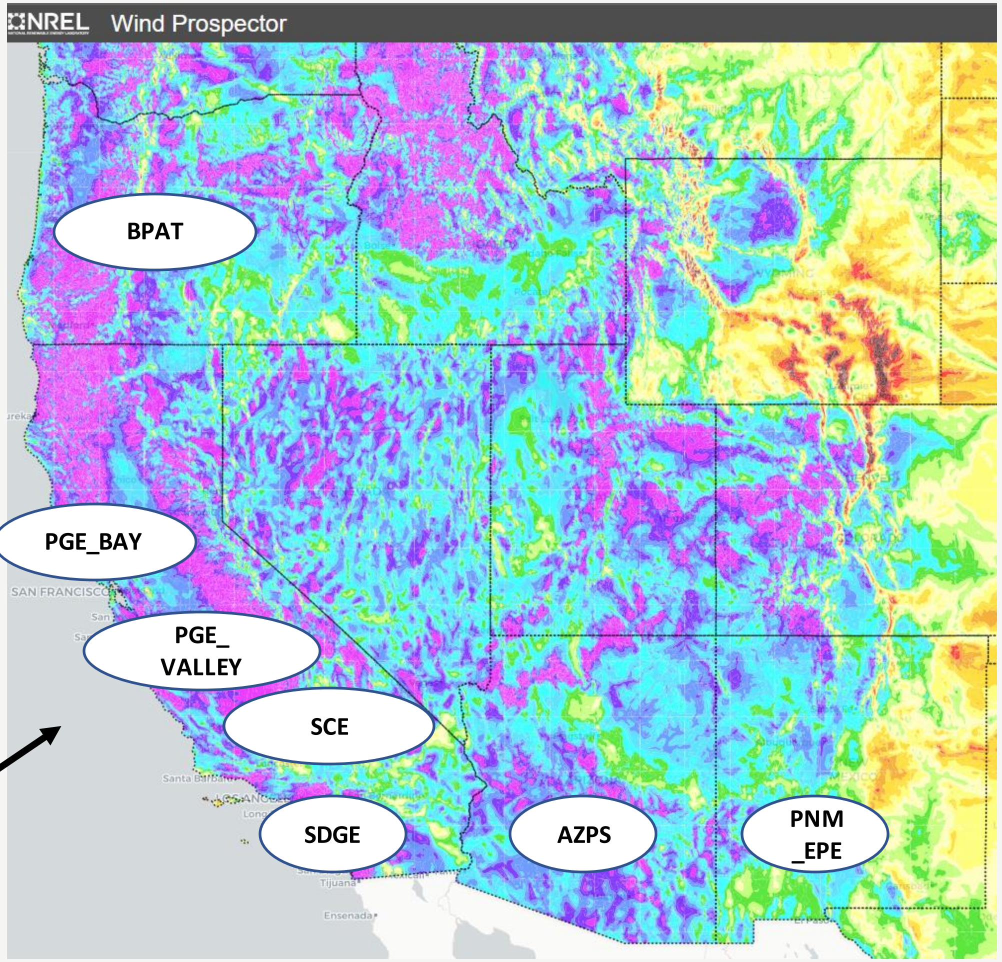
[1] *Source: CAISO Final Net Qualifying Capacity List 2020*

July 2020 Joint IOU Astrape ELCC Study Areas

Astrape Study based on seven (7) regions prescribed in D.19-09-043[2]:

Locations	SERVM Region
Northern CA (CA-N)	PGE_BAY
	PGE_Valley
Southern CA (CA-S)	SCE
	SDGE
Northwest US (OOS-NW)	BPAT
Southwest US (OOS-SW)	AZPS
	PNM_EPE

7 regions studied provide increased granularity, but tied to utility service areas rather than wind resource areas and in limited geographies



[2] *Source: CPUC D.19-09-043, Table II at 20*

IRP Inputs RESOLVE Wind Capacity Factors

Wind shapes taken from NREL Wind Integration National Dataset Toolkit

Candidate Onshore Wind Resources shown below[3]

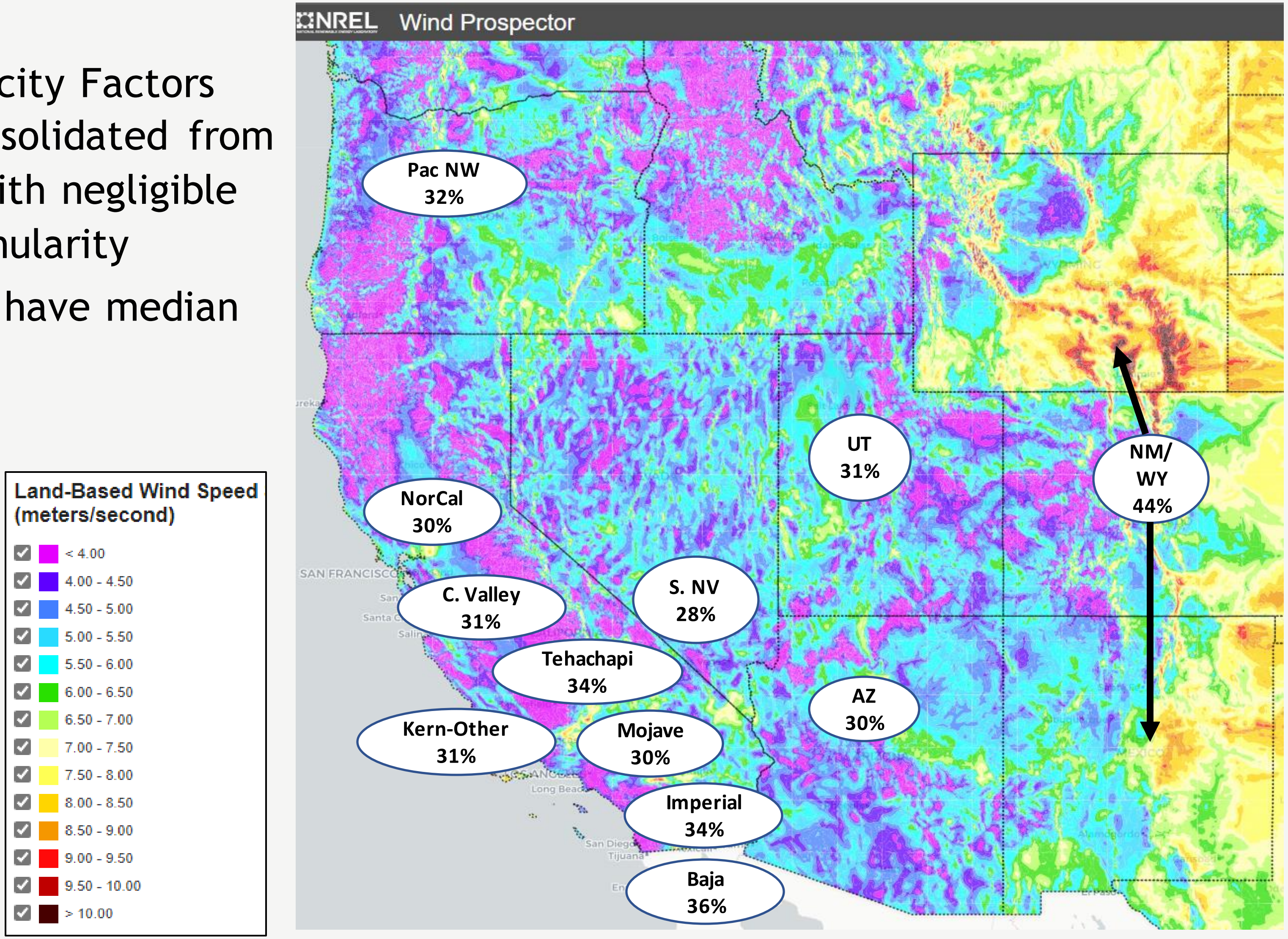
Resource	Capacity Factor	Resource	Capacity Factor
Arizona_Wind	30%	Pacific_Northwest_Wind	32%
Baja_California_Wind	36%	Pisgah_Wind	31%
Carrizo_Wind	31%	Riverside_Palm_Springs_Wind	34%
Central_Valley_North_Los_Banos_Wind	31%	Sacramento_River_Wind	29%
Greater_Imperial_Ex_Wind	34%	SCADSNV_Wind	30%
Greater_Imperial_Wind	34%	Solano_subzone_Wind	30%
Greater_Kramer_Wind	31%	Solano_Wind	30%
Humboldt_Wind	29%	Southern_CA_Desert_Ex_Wind	30%
Idaho_Wind	32%	Southern_Nevada_Wind	28%
Inyokern_North_Kramer_Wind	31%	SW_Ext_Tx_Wind	36%
Kern_Greater_Carrizo_Wind	31%	Tehachapi_Ex_Wind	34%
Kramer_Inyokern_Ex_Wind	31%	Tehachapi_Wind	34%
New_Mexico_Wind	44%	Utah_Wind	31%
North_Victor_Wind	31%	Westlands_Ex_Wind	31%
Northern_California_Ex_Wind	29%	Wyoming_Wind	44%
NW_Ext_Tx_Wind	30%		

Table 48 lists CF% for 31 Candidate Onshore Wind Regions, but can easily be consolidated by proximity (next slide)

[3] *Source: CPUC Inputs and Assumptions: 2019-2020 IRP, November 2019, Table 48*

Consolidated RESOLVE Candidate Wind Resource Areas

- NREL Capacity Factors can be consolidated from 31 to 12 with negligible loss in granularity
- 12 regions have median 31% CF%



Resulting ELCC Values by Wind Region

Based on 31% Median CF%, each of 12 regions given multiplier based on CF% value relative to the median.

Resulting monthly ELCC's shown below:

		REGIONS AND MULTIPLIERS BASED ON MEDIAN CF%											
	Current	S. NV	NorCal	Mojave	AZ	C. Valley	Kern-Other	UT	Pac. NW	Tehachapi	Imperial	Baja	NM/WY
Month	ELCC	0.90	0.97	0.97	0.97	1.00	1.00	1.00	1.03	1.10	1.10	1.16	1.42
1	14.0%	12.6%	13.5%	13.5%	13.5%	14.0%	14.0%	14.0%	14.5%	15.4%	15.4%	16.3%	19.9%
2	12.0%	10.8%	11.6%	11.6%	11.6%	12.0%	12.0%	12.0%	12.4%	13.2%	13.2%	13.9%	17.0%
3	28.0%	25.3%	27.1%	27.1%	27.1%	28.0%	28.0%	28.0%	28.9%	30.7%	30.7%	32.5%	39.7%
4	25.0%	22.6%	24.2%	24.2%	24.2%	25.0%	25.0%	25.0%	25.8%	27.4%	27.4%	29.0%	35.5%
5	25.0%	22.6%	24.2%	24.2%	24.2%	25.0%	25.0%	25.0%	25.8%	27.4%	27.4%	29.0%	35.5%
6	33.0%	29.8%	31.9%	31.9%	31.9%	33.0%	33.0%	33.0%	34.1%	36.2%	36.2%	38.3%	46.8%
7	23.0%	20.8%	22.3%	22.3%	22.3%	23.0%	23.0%	23.0%	23.7%	25.2%	25.2%	26.7%	32.6%
8	21.0%	19.0%	20.3%	20.3%	20.3%	21.0%	21.0%	21.0%	21.7%	23.0%	23.0%	24.4%	29.8%
9	15.0%	13.5%	14.5%	14.5%	14.5%	15.0%	15.0%	15.0%	15.5%	16.5%	16.5%	17.4%	21.3%
10	8.0%	7.2%	7.7%	7.7%	7.7%	8.0%	8.0%	8.0%	8.3%	8.8%	8.8%	9.3%	11.4%
11	12.0%	10.8%	11.6%	11.6%	11.6%	12.0%	12.0%	12.0%	12.4%	13.2%	13.2%	13.9%	17.0%
12	13.0%	11.7%	12.6%	12.6%	12.6%	13.0%	13.0%	13.0%	13.4%	14.3%	14.3%	15.1%	18.5%
AVG	19.1%	17.2%	18.5%	18.5%	18.5%	19.1%	19.1%	19.1%	19.7%	20.9%	20.9%	22.2%	27.1%

Summary and Conclusions

- Urgent need for higher locational granularity in Wind ELCC to improve confidence in RA NQC allocations, especially in light of extreme weather events
- Proposed solution offers following benefits:
  - Utilizes NREL resource data already in RESOLVE and aligned with SERVM
  - Covers all major wind resource areas serving CA market
  - Simple and can easily be “bolted on” to existing NQC factors
  - Good near-term solution while awaiting longer-term solutions
  - Compatible with static or marginal/dynamic ELCC methodologies

Q&A/Discussion

California Public Utilities Commission

Thank you for attending day 2 of Track 3B workshops.
Feedback welcome.

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