BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 21-10-002 (Filed October 11, 2021)
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SUBMISSION OF THE FUTURE OF RESOURCE ADEQUACY WORKING GROUP REPORT

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February 28, 2022

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As directed by Decision 21-07-014 and the Assigned Commissioner's Scoping Memo and Ruling of December 2, 2021, the Independent Energy Producers Association, in its role of co-facilitator of the Working Group on the Future of Resource Adequacy, respectfully submits the attached final Working Group Report on the Future of Resource Adequacy. IEP was unable to convert associated Excel files into a form suitable for filing, so parties might find references in the Report to files that are not included with this filing.

DATED: February 28, 2022 Respectfully submitted,

By: */s/ Brian Cragg*

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Future of Resource Adequacy Working Group Report

Track 3.B2 of the RA Proceeding

February 2022

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Introduction

This Workshop Report was ordered in Decision (D.) 21-07-014 in Rulemaking 19-11-009. In that decision, the Commission directed parties to hold a series of workshops to refine Pacific Gas and Electric Company's (PG&E's) slice-of-day proposal for resource adequacy (RA) reform. A series of ten online workshops were conducted from October 20, 2021, to January 19, 2022, addressing the following topics as directed in the decision: (1) Structural Elements; (2) Resource Counting; (3) Need Determination and Allocation; (4) Hedging Component; and (5) Unforced Capacity Evaluation (UCAP) and Multiyear Requirement Proposals. In addition, the decision said that the workshops should also cover the transactability of RA products, multiday reliability event concerns, alignment of RA compliance penalties and California Independent System Operator (CAISO) backstop procurement. These later topics could be covered in separate workshops or as part of the first set of workshops.

All proposals were to be consistent with the principles the Commission set forth in Ordering Paragraph 2 of D. 21-07-014:

- Principle 1: To balance ensuring a reliable electrical grid with minimizing costs to customers.
- Principle 2: To balance addressing hourly energy sufficiency for reliable operations with advancing California's environmental goals.
- Principle 3: To balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity, and transactability.
- Principle 4: To be implementable in the near-term (*e.g.,* 2024).
- Principle 5: To be durable and adaptable to a changing electric grid.

Workshops

There was robust participation in the workshops, with attendance often exceeding 100 participants. Below is a list of the workshops and presenters to the workshop. Originally, the Co-Facilitators had planned nine workshops. Due to a request from parties to have an additional workshop to address storage issues, the Friday December 17, 2021 workshop was added to the schedule.

Workshops	Dates	Presenters
Structural Elements *Facilitators: SCE, WPTF*	9/22	PG&E, CEERT (GridLab and Telio), NP Energy
	10/6	PG&E, Vistra, CAISO, SCE
Resource Counting *Facilitators: CalCCA, IEP*	10/20	PG&E, CAISO, NRDC
	11/3	PG&E, SCE, Gridwell, SEIA, CalWEA
Need Determination and Allocation *Facilitators: SDG&E, CESA*	11/17	PG&E
	12/1	CalWEA, SCE, CEC, Vistra & Gridwell, PG&E, NRDC
Recap on Slice-of-Day *Facilitators: IEP*	12/15	SCE, Gridwell, PG&E, NRDC
Storage *Facilitators: SCE, WPTF*	12/17	Vistra, CESA, LDESAC, CLECA
Hedging Component *Facilitators: LDESAC*	1/5	PG&E, CalWEA, Vistra
UCAP and Multiyear Requirements *Facilitators: PG&E*	1/19	CAISO, Energy Division, SCE, Calpine, WPTF & IEP, CLECA

For the first three workshops on Structural Elements, Resource Counting, and Need Determination and Allocation, the workshops were organized so that the first meeting was a review/presentation by parties to level set on the topic and the second meeting was an opportunity for parties to present proposals on the topic.

The Recap of the Slice-of-Day workshop was the meeting that parties presented their overarching Slice-of-Day proposals (Southern California Edison Company (SCE), PG&E, and Gridwell).

The remaining three workshops on Storage, Hedging Component, and UCAP and Multiyear Requirements were an opportunity for parties to present their proposals on these specific or related topics.

The presentations made at the workshops, along with recordings and workshop chat transcripts are available on the CPUC website. Notes summarizing the Q&A discussions at the workshops are included in an attachment to the workshop report.

Workshop Discussion

While the workshops were set to cover individual topics, several issues were revisited as time went on and parties refined their positions. Over time, PG&E's initial proposal and a new proposal by SCE were refined and converged into a proposal for monthly slices of 24 separate hours. Gridwell proposed monthly slices based on gross peak and net peak hours only. The next two chapters of this report discuss these two sets of proposals in greater detail, while identifying what additional work needs to be done to allow for their implementation.

During the workshops, there was considerable discussion of resource counting resulting in proposals for use of exceedance, effective load carrying capability (ELCC), UCAP (a proposal still under development at the CAISO), and a simplified Effective Net Load Reduction (ENLR), the latter being only for wind and solar. Preferences for counting methodologies tended to align with preferences for overall frameworks, with ELCC being associated with the Gridwell framework and exceedance associated with the PG&E/SCE framework.

Discussions of need determination and allocation focused on whether RA obligations should be based on 1) gross load vs. net load (gross load net of wind and solar) and 2) load ratio shares of system peak load vs. load-serving entity (LSE) specific loads. A large majority of parties preferred the use of gross load as a starting point. Many parties were supportive of a proposal by the California Energy Commission (CEC), which would take into account LSE-specific load shapes but adjust these so that when aggregated they match the CAISO system-level load forecast.

While there was a workshop on hedging, there was general agreement that this is more of an issue related to energy price risk rather than capacity need per se and would require additional work. The issue of transactability came up periodically in the context of 1) whether procurement could be transacted at the slice level as opposed to a full diurnal share of a resource, 2) whether load requirements could be traded among LSEs, and 3) how to accommodate existing contracts. Many parties stated that trading obligations or load responsibility would add complexity and might be addressed once the new framework is in place.

Organization of the Report

The following table provides the chapters of proposals made at the workshops as written by their proponents. The Co-Facilitators asked proponents to submit their proposals and to receive feedback directly from workshop participants. The reason for this was to ensure that the Co-Facilitators did not unintentionally misrepresent a party's proposal or position. To remain neutral, the Co-Facilitators have minimally summarized the content of the proposals and instead provide a map of the content and organization of this workshop report.

Chapter Topic / Section	Authors
Slice-of-Day Proposal	SCE
	PG&E
	Gridwell
Element-Specific Proposals	SEIA-LSA-VS – Resource Counting for Solar and Hybrid Resources
	CalWEA – QC Counting Proposal for Wind-Solar
	CEC – Forecast Proposal
	CAISO – UCAP
	Calpine – CPN Penalties
	CLECA – DR Counting Proposal for Slice of Day
	Vistra – Need Determination
Hedging	PG&E
	Vistra
Multiyear Requirements	WPTF & IEP
Party Positions	Various
Appendix	A – Workshop Materials and Meeting Notes
	B – Informal Comments and Parties' Position Matrix (Excel)

The slice-of-day proposals from SCE, PG&E, and Gridwell are the overarching framework proposals that describe the number of slices, the frequency of the compliance obligation (e.g., seasonal or monthly), and resource counting methodologies associated with the framework. The element-specific proposals do not address the number of slices or frequency of compliance obligations but instead address only elements such as resource counting or need determination that differ from or complement those aspects of the overarching slice-of-day proposals. These chapters follow the order in which they were presented at the workshops.

Informal Comments and Party Positions

Lastly, parties provided their final sets of informal comments and position matrices to the Co-Facilitators. Overall, 28 parties submitted informal comments and 23 parties submitted party position matrices, with the following table listing all parties that submitted feedback. Not all parties that submitted informal comments submitted party position matrices, and vice versa. Some submissions represented multiple parties, which are listed within the parentheses.

Party	Informal Comments	Position Matrix
ACP-CA	Yes	Yes
AReM	Yes	Yes
CAISO	Yes	Yes
CAISO DMM	Yes	No
Calpine	Yes	Yes
CalWEA	Yes	Yes
CalCCA	Yes	No
Collective CCAs (CPA, EBCE, MCE, PCE, Pioneer Community Energy, SJCE, and SCP)	Yes	Yes
Joint CCAs (3CE, SDCP, and SVCE)	Yes	Yes
Joint CCA Parties (CESA, PCE, and SJCE)	Yes	No
CEDMC	No	Yes
CESA	Yes	Yes
CLECA	Yes	Yes
Form Energy	Yes	No
GPI	Yes	Yes
GSCE	Yes	Yes
IEP	Yes	Yes
Joint Parties (NRDC, CEERT, CESA, SEIA, LSA, ACP-CA, CEDMC, CLECA, SCE, and PG&E)	Yes	No
LDESAC	Yes	Yes
MegaWatt Storage Farms	Yes	No
MRP	Yes	Yes
Pattern Energy	No	Yes
PG&E	Yes	Yes
Public Advocates Office	Yes	Yes
REV Renewables	Yes	Yes
SCE	Yes	Yes
SDG&E	Yes	Yes
Joint Solar Parties (SEIA and LSA)	Yes	Yes
Vistra	Yes	No
WPTF	Yes	Yes

The party position matrix is not summarized because of concerns about imposing interpretations on party positions. The details of party positions can be found in their informal comments, which are included in Appendix B.

List of Acronyms

ACP-CA – American Clean Power - California
AReM – Alliance for Retail Energy Markets
BTM – behind the meter
CAISO – California Independent System Operator
CAISO DMM – California Independent System Operator Department of Market Monitoring
CalCCA – California Community Choice Association
CalWEA – California Wind Energy Association
CCA – Community Choice Aggregator
CEC – California Energy Commission
CEDMC – California Efficiency and Demand Management Council
CEERT – Center for Energy efficiency and Renewable Technology
CESA – California Energy Storage Association
CLECA – California Large Energy Consumers Association
CPA – Clean Power Alliance
CPE – Central Procurement Entity
CPM – Capacity Procurement Mechanism
CPUC – California Public Utilities Commission
DMM – Department of Market Monitoring
DR – demand response
EBCE – East Bay Community Energy
ELCC – effective load carrying capability
EUE – expected unserved energy
GPI – Green Power Institute
GSCE – Golden State Clean Energy
IEP – Independent Energy Producers Association
IEPR – Integrated Energy Policy Report
IRP – Integrated Resource Planning
LDESAC – Long Duration Energy Storage Association of California
LOLE – loss of load expectation
LSA – Large Scale Solar Association
LSE – load-serving entity
MCC – maximum cumulative capacity
MCE – Marin Clean Energy
MOO – must-offer obligation
MRP – Middle River Power
MW – MegaWatt
NQC – net qualifying capacity
NRDC – Natural Resources Defense Council
OASIS – open access same-time information system
PCE – Peninsula Clean Energy
PG&E – Pacific Gas and Electric Company

PRM – planning reserve margin
QC – qualifying capacity
RA – resource adequacy
SCE – Southern California Edison Company
SCP – Sonoma Clean Power
SDCP – San Diego Community Power
SDG&E – San Diego Gas & Electric Company
SEIA – Solar Energy Industries Association
SJCE – San Jose Clean Energy
SOD – slice-of-day
SVCE – Silicon Valley Clean Energy
SWPG – Southwest Power Group
TAC – Transmission Access Charge
UCAP – Unforced Capacity
VS – Vote Solar
WPTF – Western Power Trading Forum
3CE – Central Coast Community Energy

Southern California Edison Slice-of-Day Proposal: 24-Hourly Slice

Southern California Edison: Jeff Nelson, Brent Buffington

I. Southern California Edison's 24-Hourly Slices Proposal

Southern California Edison's (SCE) slice-of-day framework with 24-hourly slices ("24-hourly slices framework"), as described in SCE's presentations[1] and detailed in this chapter, best satisfies the key principles established in Decision (D.) 21-07-014. The 24-hourly slices framework effectively maintains grid reliability while supporting California's transformative carbon reduction objectives. It efficiently addresses solar, wind, storage resources, demand response, and conventional resources, and recognizes each resource's contribution to reliability. It is durable because it addresses both gross and net load peaks, regardless of where they fall, their durations, and how they evolve over time. By design, it adapts to a changing resource mix, can be implemented in the near term, will be compatible with most existing contracts, and supports bilateral contracting and trading.

For these reasons, SCE recommends the CPUC adopt the 24-hourly slices framework, provide guidance on specific details, and establish a process to resolve any remaining issues. To allow the implementation of this new framework for the 2024 compliance year, the CPUC should render its decision adopting this framework and outlining next steps as early as possible. SCE recommends an initial decision prior to summer 2022. Remaining open items that must be addressed for 2024 compliance year implementation should be determined in a narrowly focused forum after the CPUC has established this framework.

Load and renewable supply can change dramatically hour to hour, and variation across months is even more significant. SCE has demonstrated that frameworks with multiple-hour slices and/or multiple-month seasons create costly procurement inefficiencies because they (1) "penalize" renewable output by only counting the lowest production within the slice; (2) fail to give run-hour limited resources full credit when the resources don't neatly fit into the slice definition; and (3) fail to recognize variation in hourly requirements because the requirement has to be set based on the highest demand within the slice.[2] Moreover, slice definitions under such frameworks would need to be periodically revised as the generation fleet and load evolve. On the other hand, a 24-hourly slices framework avoids over-procurement by effectively addressing challenges related to resource and load variability and eliminates the need to define and regularly update slice and season definitions.

A slice-of-day framework with 24-hourly slices both supports contracting and reasonable administration. It largely works within the existing Resource Adequacy (RA) qualifying capacity (QC) framework without creating new non-capacity products and requires minimal changes to the existing California Independent System Operator (CAISO) processes, including deficiency checks and the backstop process. Additionally,

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[1] SCE presented at the following workshops: October 6, 2021 - "Structural Elements;" November 3, 2021 - "Resource Counting;" December 1, 2021 - "Need Determination;" December 15, 2021 - "Recap on Slice of Day" workshop; and January 19, 2022 - "UCAP and Multi-Year RA."

[2] October 6, 2021 presentation at pp. 6-8.

the monthly California Public Utilities Commission (Commission or CPUC) compliance showings can be implemented using a standard template to reduce administrative burden.

The following table, which is based on that presented at the December 15, 2021 "Recap" workshop, summarizes the key elements of SCE's proposal.

Component	SCE's 24-Hourly Slices Proposal[3]
Slice Definition	24-Hourly Slices
Showings	Single monthly using a standardized template (to be developed)—LSEs must meet their load + PRM in all 24-hours and show sufficient capacity to offset battery usage to pass showing. Similar template will be used for the year-ahead showing.
Resource Capacity Counting	**Resource Adequacy Capacity must be deliverable** **Solar and wind** will count based on their hourly expected capacity profiles—**specific methodology** (*e.g.*, exceedance, hourly ELCC, or other) **to be determined in subsequent forum** **Standalone batteries** count based on their capacity and duration as shown by the LSE; Must demonstrate there is sufficient "excess capacity" in other hours to support their dispatch (plus losses) **Hybrid resources:** Requires additional stakeholder discussion due to the unique and complex issues **Use-limited resources** count based on their capacity and available duration as shown by the LSE **Other resources** will have a single counting value (e.g., NQC is eligible to be used in every slice) **Imports** must be shown in their available hours
Load Forecast	Gross
Need Allocation	Consistent with CEC proposal. Bottoms up; retain existing coincident peak process and shape based on LSEs' historical load and adjusted by the CEC to ensure system demand is met in each hour on the monthly worst-day.
Market Product	Resource attributes and capabilities are bundled (*i.e.,* no unbundling of hourly slices) but resource capacity can be split (e.g., 70% to LSE 1, 30% to LSE 2); SCE is not proposing "load trading" but does not oppose others proposing it as a potential enhancement to SCE's 24-hourly slices framework
Energy Market Obligation	"Full capability/all-hour" must offer obligation (MOO)

[3] SCE's proposal applies to the CPUC's RA showing process and does not govern how resources are dispatched by the CAISO.

Use-limitations	Use-limited 24-hour allocation; retain min 4-hour daily output availability requirement; eliminate flex requirements and MCC buckets
Penalties for Non-Compliance	Same principles as today: CPUC penalty for failing showing based on the hour where the LSE's showing is the most deficient; CAISO first allocates backstop costs to LSEs who fail their showing and remaining costs (if any) to all impacted LSEs

A. Structural Elements

1. Load Serving Entity (LSE) Requirements

The 24-hourly slices framework requires each LSE to demonstrate it has enough capacity to satisfy its specific gross load profile (including planning reserve margin) in all 24hours on the CAISO's "worst day" in that month. Additional details follow:

a) "Worst Day"

SCE proposes to initially define the "worst day" as the day of the month that contains the hour with the highest coincident peak load forecast. This could evolve over time if some other attribute (*e.g.,* steepest ramping requirement) is found to be more challenging to reliability than the coincident peak.

b) Need Determination and Allocation[4]

SCE supports the development of LSE-specific need determinations, provided that the final values are adjusted by the California Energy Commission (CEC) on a pro-rata basis to match the system demand forecast in each hour.[5] SCE suggests using historical 24-hour load shapes for each LSE as a starting point because it is transparent and verifiable, but ultimately defers to the CEC processes on how to implement the bottoms-up need determination.

c) Planning Reserve Margin (PRM)

LSEs must demonstrate sufficient capacity to meet their load requirements plus a Planning Reserve Margin (PRM) percentage in each hour ("Load+PRM"). SCE has proposed that the CPUC initiate a stakeholder process on reliability metrics in the Integrated Resource Plan (IRP) proceeding, Rulemaking (R.) 20-05-003, to confirm the appropriate reliability standard (*e.g.,* one event in ten years or something else) and calculate the corresponding PRM necessary to achieve that standard using a loss of load expectation (LOLE) study. SCE believes that IRP discussion should inform the PRM used in the RA program. As a starting point, SCE proposes there be one PRM that applies to all hours of the year. The CPUC can refine the application of the PRM to the

[4] SCE's December 1 "Needs Determination Under 24-Hourly Slices Framework" presentation outlined a potential option based on semi-custom LSE shapes. SCE has revised its position based on feedback from the CEC on the feasibility of bottoms-up LSE-specific need determinations.

[5] For example, assume an LSE is 3% of the load in HE 12 and the sum of the bottoms up forecast exceeds the system forecast by 10 MW in HE-12. That LSE should receive a pro-rata share of the excess 10 MW by having their load forecast adjusted downward by 0.3 MW. Similarly, assume the LSE is 7% of the load in HE-19 and the sum of the bottoms up forecast is short of the system forecast by 50 MW in HE-19. That LSE should receive a pro-rata share of the 50 MW shortfall by having their load forecast adjusted upward by 3.5 MW.

RA program (*e.g.,* whether the same PRM should be used in both IRP and the RA program, whether the PRM should vary by hour and/or by month) in a subsequent forum.

d) Capacity Required to Offset Storage Usage

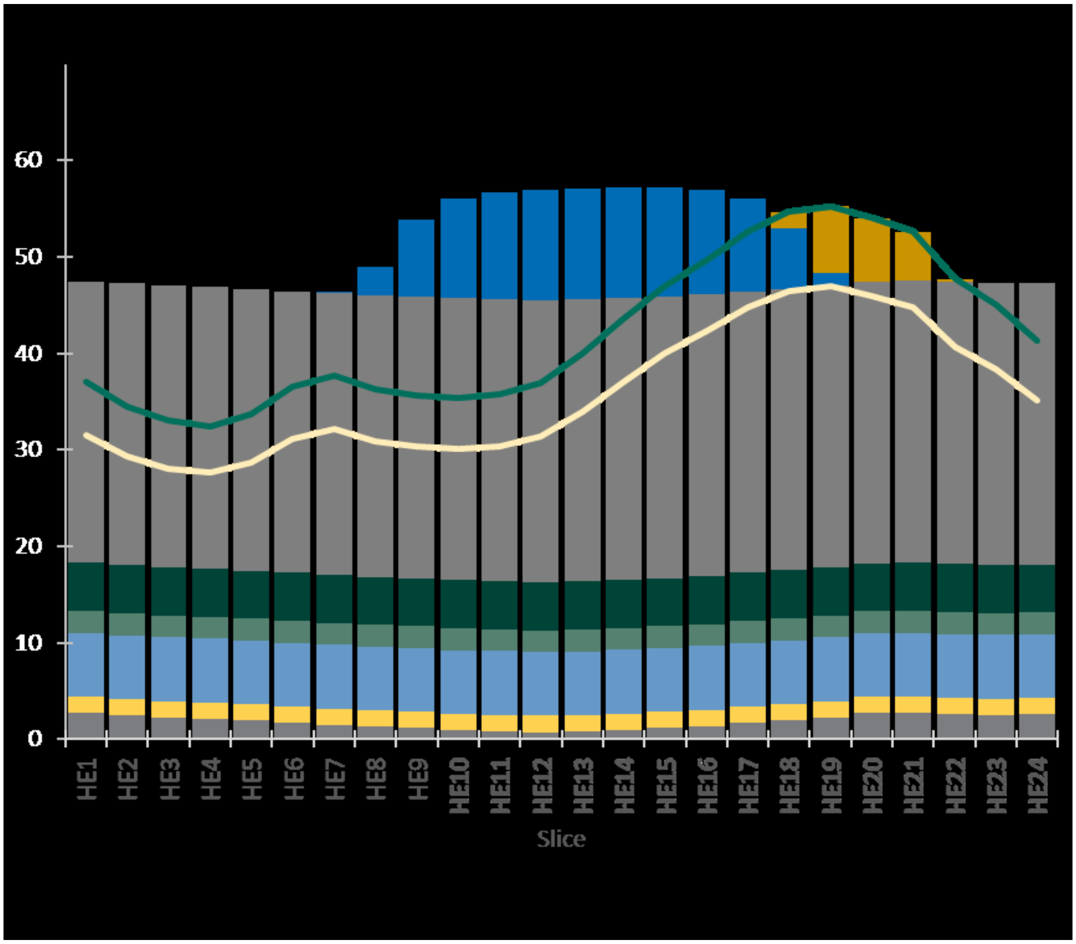
To the extent an LSE uses (closed loop) energy storage to meet its Load+PRM requirement, the LSE must demonstrate it has excess capacity *(i.e.,* capacity that exceeds the LSE's hourly RA requirement) that offsets the storage capacity plus efficiency losses. In other words, LSEs must bring enough extra capacity to serve their own batteries.[6] This requirement ensures there is sufficient resource adequacy capacity to charge storage as the grid becomes increasingly reliant on this technology.

e) Resource Counting

Renewable resources from wind and solar will be assigned a production profile based on expected production during the associated showing period. Conventional resources have a single counting value((*e.g.,* net qualifying capacity (NQC) or contracted amount) and must be shown within their capability and/or in their available hours. Additional checks will be applied to confirm run-hour feasibility of use-limited resources (*e.g.,* standalone batteries must demonstrate there is sufficient "excess capacity" in other hours for their dispatch; hydro must have sufficient energy to support the shown capacity).

The following chart depicts an illustrative LSE resource showing under SCE's proposal, where the green line represents the LSE's 24-hour requirement (load profile plus PRM) and the stacked bars represent the LSE's portfolio by resource type. Here, the LSE passes the showing because it has satisfied its requirement in all 24-hours.

[6] In actual market operations the CAISO's optimization will dispatch the most efficient resources available to meet the needs of all demand, including the charging demand of the batteries. That is, the excess capacity in the RA Showing is not required to be used to charge the batteries during daily operations.



2. Applicability of 24-Hourly Slices Framework to System, Local, and Flexible Requirements

SCE proposes to apply the 24-hourly slices framework to the CPUC's System RA program. The granularity of this approach eliminates the need for both the Flexible RA requirement and the maximum cumulative capacity (MCC) buckets by directly accounting for resource capabilities and use limitations.

SCE does not propose changes to the local RA program at this time but believes the CPUC should consider whether and/or how a slice-of-day framework could be incorporated into the local RA program. Local RA treatment is further discussed in the Open Items section.

B. Resource Capacity Counting[7]

The principal underlying SCE's resource capacity counting proposal is that resource capacity counting should be consistent with expected capacity contribution in the slice. The expected capacity contribution in a slice will depend on resource size, general type, special operational characteristics or limitations, deliverability status, and potentially location.

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[7] The following section expands upon and clarifies positions described at the November 3, 2021 Resource Counting workshop.

1. Requirements of RA Resources

a) *No Unbundling of Attributes*

A foundational assumption under the 24-hourly slices framework is that resource attributes and capabilities remain bundled and the existing full-capability/all-hour must-offer obligation (MOO) is retained. Bundling resource attributes (*i.e.,* system, local, flex) and capabilities aligns with the existing must-offer-obligation because it ensures resources that have sold capacity also have a must-offer obligation equal to the sold amount for all hours they can produce. Resources can continue to sell portions of their capacity to different LSEs (*e.g.,* 70% of capacity sold to LSE 1 and 30% of capacity sold to LSE 2), but they cannot sell separate hourly products because that would effectively sell the same RA capacity multiple times. SCE reiterates that it is critical to maintain this element of the current RA market and program under ***any*** slice option so that existing contracts remain commercially viable and new contracts are administratively feasible.

b) *Full-Capability Must-Offer Requirement*

An RA resource must offer all its capability to the CAISO for the quantity of RA shown by LSEs. The CAISO's market will optimize resources consistent with bids and resource limitations. Resources without daily restrictions have a must-offer obligation in all 24-hours. A resource that has defined hours of operation (*e.g.,* a DR program that is only available from HE13-HE19) has a must-offer obligation in those hours. A resource that has operating hour limitations (*e.g.,* a generator that has noise permits which prevent operation between HE22-HE6) has a must-offer obligation for all hours allowed under the permits (*e.g.,* between HE7-HE21 for the same unit).

c) *Resources Must Be Deliverable to Provide RA*

Like today, resources must be deliverable to qualify to sell RA (and be included in the RA showing). Resources that are partially deliverable can only provide RA for the portion of the resource that is deliverable, which is further discussed in the Open Items section of this proposal.

2. Details for Specific Technologies

The expected capacity contribution of intermittent resources such as wind and solar can vary significantly across the day. This variability can be directly accounted for under slice-of-day. Each resource technology can have a unique profile that matches the expected reliability contribution (*i.e.,* load carrying capability)[8] of that technology in that slice. Along with allowing intermittent resources to count in each slice based on their expected corresponding capability, the synergies between conventional, renewable, and storage resources can be utilized directly by LSEs in their showings. LSEs will be able to combine the capabilities of their chosen resource mix and, because the showings cover all 24-hours for each LSE, the CPUC and the CAISO can be sure the aggregated RA portfolio meets its 24-hour capacity needs.

The current single-monthly Effective Load Carrying Capability (ELCC) approach does not provide any indication of the expected capacity contribution in any given slice and thus cannot be used in any slice-of-day framework. The single-monthly ELCC that is used in the current RA program attempts to represent the reliability contribution of a resource across an entire month with a single MW value. This single value is relative to a modeled portfolio that may ultimately differ from the actual shown portfolio

[8] This is not the defined term Effective Load Carrying Capability (ELCC) discussed below).

of RA resources. This single MW value is important and useful in single-point RA programs like the current CPUC RA program, but the complicated calculations and single monthly results are inapplicable for slice-of-day as they do not represent the capacity contributions to the system in any slice.

Under SCE's 24-hourly slices framework resource counting will generally be defined in the following manner, with resource-specific performance addressed through NQC adjustments and, as noted, only resources that are deliverable counting as RA:

- **Solar and wind** count based on their expected hourly capacity contribution (hourly profile). Showings will use hourly profiles relative to the assigned NQC value for the resource;
- **Standalone batteries** count based on their capacity and duration as shown by the LSE;
- **Use-limited resources** count based on their capacity and available duration as shown by the LSE;
- **Other resources** will have a single counting value for all hours (*e.g.,* NQC);
- **Imports** (*e.g.,* 16-hour imports) must be shown in their available hours.

As noted above, additional discussion is needed to finalize details on how each resource type should be counted. The following table was presented at the November 3, 2021 Resource Counting workshop and has been edited and clarified to reflect SCE's current position:

Resource Type	Approach/Considerations and Open Questions[9]
Non-use-limited dispatchable (combined cycle, steam)	• QC based on Pmax or Unforced Capacity (UCAP)/UCAP light • No showing restrictions (typical 24x7 resources)
Use-limited dispatchable (peaker)	• QC based on Pmax or UCAP/UCAP light • Restricted to showing within the daily run-hours
Solar	• Monthly hourly profiles based on technology and/or general geographic region to be determined by the CPUC • Profiles should be hourly (appropriate level and/or methodology to be determined in subsequent forum)[10]
Wind	• Same as solar
Imports	• Contracted amount and duration where showing shape matches contract type
Storage	• QC based on Pmax or UCAP/UCAP light • Restricted to showing within daily resource capabilities (*e.g.,* maximum daily run hours, maximum continuous energy, and storage efficiency) • Multiple cycles possible but must consider downtime for another full charge • Excess capacity must be shown to cover shown battery capacity with efficiency losses

[9] Resources must continue to be deliverable and available for four consecutive hours to count for RA.

[10] SCE proposes that the ELCC methodology must be newly tailored to conform to the new 24-hourly slices framework, as opposed to the current single-point ELCC methodology. Public Utilities Code 399.26(d) gives the CPUC the discretion to determine how the ELCC methodology will work and therefore the CPUC can conform the definition to any adopted framework, including the 24-hourly slices proposal set forth by SCE.

Hybrid	• Follow the principle that their RA counting must be within their actual capabilities; additional details to be determined in a subsequent process
Co-located	• Consider showing both resources separately with capacity constraints • Follow the principle that their RA counting must be within their actual capabilities; additional details to be determined in a subsequent process
Non-dispatchable cogeneration and biomass	• QC based on current approach (or UCAP/UCAP light if adopted) • No showing restrictions (typical 24x7 resources)
Dispatchable hydroelectric and inflow-fed open-loop pumped storage hydro	• QC based on current approach (or UCAP if adopted) • No showing restrictions (typical 24x7 resources)
Non-dispatchable hydroelectric and geothermal	• QC based on current approach (or UCAP/UCAP light if adopted) • No showing restrictions (typical 24x7 resources)
Closed-loop pumped storage hydro or other storage technologies	• Same as standalone battery
Demand Response	• QC based on their capabilities as determined in CPUC/CAISO DR processes • Restricted to showing within daily resource capabilities

a) Capacity Contribution Profiles for Wind and Solar

SCE does not offer a specific proposal for determining wind and solar capacity contribution profiles but recommends the following principles:

- The profiles should not be facility specific. Instead, a single profile should apply to a group of resources of the same technology that are reasonably represented by the profile;
- The profiles should reasonably represent the expected capacity contribution of the resources during the "worst day" conditions used to set the monthly capacity requirements;
- Different technologies (e.g., wind and solar) will require different profiles; different profiles may be needed within a technology (e.g., fixed solar vs. tracking solar, broad geographic profile differences) if a single profile cannot reasonably describe all resources;
- Final hourly profile shapes should be derived relative to NQC and applied to the resources' NQCs to determine the capacity that can count in each hour;
- As a starting point, SCE recommends using as few profiles as is reasonably necessary to ease administration and implementation. Profiles can be refined, or additional profiles created in the future, as appropriate.

b) *Profiles and Net Qualifying Capacity (NQC)*

All resources will still have a single monthly NQC value representing the deliverability-adjusted peak-hour contribution. Most resource types will continue to utilize this NQC for their showing (and for CAISO deficiency determinations) while solar and wind will utilize hourly profiles and NQC in their CPUC RA showings. Initially, the CAISO can continue to utilize a single monthly "NQC" for wind and solar (where the "NQC" is the peak hour deliverable capacity based on their profile for that hour) for deficiency determinations but should work to eventually assess needs in all hours of the day, as described in Section I.C.4.

c) *Deliverability*

SCE supports continuing the current on-peak deliverability study process and using the outputs in the 24-hourly slices framework. Under the current RA program, a resource's single monthly NQC that can be counted to meet RA requirements is the minimum of the CPUC's QC value (which focuses on load and generation parameters) and the NQC based on CAISO's on-peak deliverability study (which accounts for transmission system limitations). The CAISO on-peak deliverability study uses hourly modeled resource output and forecast demand to determine whether the studied resources can supply their full modeled output during critical system hours. Intermittent renewable output is modeled at a very high output – 20% exceedance (output will be higher 20% of the time). A resource is deemed to be "fully deliverable" if its full modeled output can deliver to system load under summer peak load conditions, and "partially deliverable"[11] if something less than its full modeled output can reach the grid. It should be noted this "full deliverability" amount is not dependent on the CPUC resource counting, only CAISO's modeling.[12]

As described in Section I.B.2 above, SCE proposes that wind and solar resources' hourly capacity contribution values be based on deliverability status and hourly expected capacity contribution profiles. Because the CAISO deliverability study process models intermittent renewable resources at a very high output using 20% exceedance, the proposed deliverability hourly capacity values already account for the amount that is actually deliverable during critical system hours. It is thus reasonable to maintain the current on-peak deliverability study process as a starting point; the deliverability test can and should evolve over time to consider grid conditions in other hours.

C. Showing Mechanics

1. RA Resource Master Database

The CPUC will maintain an official database of resources eligible to sell RA that includes their key attributes, as listed below (RA Resource Master Database). Resources must be fully represented in the RA Resource Master Database to be eligible for use in the CPUC's 24-hourly slices RA showing.

- Resource ID
- Available MW of RA capacity
- Hours available for production—represents the hours of its must-offer obligation and will set the parameters on how it can be shown in the CPUC RA showing
- Other use-limitations (*e.g.,* peaker permit limits)

[11] See Section I.F.3 for an additional discussion on "partially deliverable."

[12] SCE notes that under current rules, the CPUC periodically updates ELCC values (both upwards and downwards) that ultimately change the NQC values for certain resources. Irrespective of changes, these updates do not result in or require additional deliverability tests.

- Continuous MWh run energy and charging efficiency (storage)
- Configuration (hybrid and co-located)
- Applicable hourly profile (solar and wind) [13]

Representative hourly profiles will be developed for wind and solar technologies based on the final resource counting rules. The details of each profile will be publicly available to allow LSEs to determine how any wind and/or solar resource will "fit" within their existing portfolio, how they would be represented in an RA showing, and to facilitate RA trading.

a) Consistency Between CAISO and the CPUC

The CAISO and the CPUC should utilize the same unit information for both the RA showings and CAISO market operations (e.g., aligned with the CAISO's Master File) where possible. SCE recommends the CPUC and CAISO formalize a process to agree on a common data set.

b) Confidentiality

The RA Resource Master Database will be public. It will not contain confidential cost-related information such as heat rates (for conventional resources) or variable and O&M costs. If a resource owner considers any information described above as "confidential" and is unwilling to provide actual data to the CPUC for public use, the CPUC should have the authority to use a conservative (*i.e.,* a value that will under-represent a unit's actual ability to provide RA) safe-harbor value for the RA Resource Master Database and as the basis for RA counting.

2. Showing Template

SCE proposes a single CPUC system RA showing covering all 24 slices. LSEs will use a standard template that lists basic resource characteristics (*e.g.,* technology and total contracted capacity that is being shown by the LSE) and tallies how many MW of capacity are being counted in each hour. The following is an illustrative template that includes the information that should be included in the CPUC RA compliance showings:[14]

[13] Each resource will only have one profile per month.

[14] SCE proposes that the CPUC maintain its requirements for the year-ahead system showings, where LSEs are required to demonstrate they have procured 90% of the total forecasted load plus planning reserves for the five summer months of May through September. Both the year- and month-ahead showing templates should be modified to include the specified resource characteristics and 24 separate hours. Actual showings included data for each of the 24-hours. The chart above omits HE4-14 and HE19-24 only for presentation purposes within this document.

Resource Characteristics											
Resource Name	Technology	Shown NQC MW	HE1	HE2	HE3	...	HE15	HE16	HE17	HE18	...
Resource 1	HL IMPORT	150	-	-	-	...	150.0	150.0	150.0	150.0	...
Resource 2	BIOMASS	15.00	15.0	15.0	15.0	...	15.0	15.0	15.0	15.0	...
Resource 3	SUN	31.36	-	-	-	...	29.7	28.3	25.1	16.5	...
Resource 4	SUN	17.92	-	-	-	...	16.9	16.1	14.3	9.4	...
Resource 5	SUN	15.68	-	-	-	...	14.8	14.1	12.6	8.2	...
Resource 9	WATER	19.02	19.0	19.0	19.0	...	19.0	19.0	19.0	19.0	...
Resource 10	WATER	2.29	2.3	2.3	2.3	...	2.3	2.3	2.3	2.3	...
Resource 11	WATER	50.00	50.0	50.0	50.0	...	50.0	50.0	50.0	50.0	...
Resource 15	WIND	30.52	14.5	13.2	12.0	...	6.0	7.2	9.0	10.4	...
Resource 16	WIND	40.32	19.1	17.5	15.9	...	8.0	9.6	11.9	13.7	...
Resource 25	GEOTHERMAL	85.00	85.0	85.0	85.0	...	85.0	85.0	85.0	85.0	...
Resource 26	GEOTHERMAL	85.00	85.0	85.0	85.0	...	85.0	85.0	85.0	85.0	...
Resource 27	NATURAL GAS	200.00	200.0	200.0	200.0	...	200.0	200.0	200.0	200.0	...
Resource 63	DR	0.90	-	-	-	...	-	-	-	0.9	...
Resource 64	DR	0.90	-	-	-	...	-	-	-	0.9	...
Resource 65	LESR	20.00	-	-	-	...	-	-	-	20.0	...
Resource 68	LESR	100.00	-	-	-	...	-	-	100.0	100.0	...

3. Compliance Verification

The CPUC will verify the following to confirm an LSE has satisfied its RA requirements:

- **Resources are being shown within their capability.** The RA Resource Master Database is used to validate that LSEs have represented their contracted resources accurately. Any inconsistencies between an LSE's showing and the RA Resource Master Database must be immediately corrected by the LSE to "pass" the monthly showing. Showings that fail to accurately represent resources within their capability are incomplete and the CPUC will have the authority to quantify the associated deficiency and penalize accordingly.
- **Hourly requirements must be met or exceeded.** The standard template should include a pass/fail function to indicate whether the LSE has met its load plus PRM requirement.
- **Excess capacity must be shown to cover shown battery capacity.** The standard template should also include a pass/fail function to indicate whether the LSE has enough excess capacity to cover all shown battery capacity (plus efficiency losses), including any necessary charging time to support multiple cycles.

4. Penalty Process

a) CPUC Penalties

SCE proposes to use the current CPUC penalty framework when an LSE fails its monthly showing. An LSE "fails" the CPUC showing if it fails to meet its requirement in any of the 24-hours; if the LSE fails in multiple hours, the penalty should be assessed based on the hour with the largest deficiency.

b) CAISO Backstop and Cost Allocation

In addition to potential CPUC penalties, LSEs failing the CPUC showing should be the "first in line" to receive CAISO backstop costs resulting from showing deficiencies.

The CAISO currently tests a single hour when checking showings for a deficiency and utilizes a single NQC base value. SCE supports the continued use of a single-hour CAISO deficiency test initially, but certain changes are necessary to harmonize it with the new CPUC showing requirements. Specifically, SCE proposes the CAISO publicly identify the hour it will test for a deficiency and agree to use the CPUC hourly profile value for solar and wind for that hour, as well as the corresponding load level for that hour, in its test.[15] Continuing to use the NQC base value could result in CAISO incorrectly identifying and quantifying a deficiency.[16] SCE believes this deficiency test may need to evolve over time to test multiple hours and recommends those implementation details be developed at a later time.

The CAISO should first allocate any deficiency-related backstop costs to LSEs that fail their CPUC showings (and that failed the showings of any other Local Regulatory Authority (LRA), irrespective of the hour that is being tested. In other words, LSEs that fail their CPUC showing in any hour are responsible for backstop costs even if they have shown sufficient capacity in the hour that CAISO is testing. This is reasonable because LSEs have great flexibility in how they show use-limited resources in the CPUC RA showing; without this rule, an LSE could rearrange resources to avoid failing the CAISO's tested deficiency hour yet still fail the CPUC showing in other hours. The CPUC should communicate to the CAISO if any LSE has failed the showing, as well as the MWs the LSE failed to show based on the maximum failure in any hour. The CAISO should use this information to first allocate costs directly to LSEs that failed the showing on a MW-to-MW basis.[17]

D. Contracting Mechanics

The 24-hourly slices framework has several objectives concerning contracting. First, it is designed to preserve the structure of existing contracts to the greatest degree possible. It does this by continuing with a full capability must-offer obligation and allowing these contracts to be shown in all 24 hours consistent with their capabilities. It avoids the complexities of "unbundling" either attributes or hours, and instead ensures that any resource that sells RA has a must-offer obligation based on its full capabilities (limited by the quantity of RA it has sold). It also allows LSEs the flexibility to "shape" use-limited resources, consistent with resource capabilities, to efficiently match their RA needs.

Second, it is designed to allow new bilateral contracting going forward. It does this by maintaining the same general RA capacity/must-offer requirement that has resulted in successful contracting within the current RA process.

Finally, it is designed to preserve existing bilateral trading mechanics by allowing LSEs to "fine tune" their portfolios. It does this by allowing the trading of "portions of a resource" and continues to allow LSEs to "swap" resources (e.g., trade a use-limited resource for a 24-hour resource) to meet their load

[15] SCE notes the value used by CAISO for its deficiency test will likely need to differ from the value used to validate compliance with the must-offer obligation.

[16] For example, consider a 100 MW solar facility with a current NQC of 15 MW. Assume the capacity in HE-18 based on this facility's hourly profile is 41 MW. If CAISO tests HE-18 for deficiencies, it should count this solar facility based on the 41 MW hourly profile value, not the 15 MW NQC value; otherwise it may incorrectly conclude there is a 26 MW (*i.e.,* 41 MW-26 MW) deficiency.

[17] In a simplified example, LSE1 failed its showing by 5MW, LSE2 failed its showing by 30MW. The CAISO finds a deficiency of 20MW and backstops 20MW. Each LSE should receive a pro-rata allocation of the backstop cost (*i.e.,* LSE1 receives 5/35 and LSE2 receives 30/35 of the backstop cost). If the CAISO finds a deficiency of and backstops 50 MW, the cost of the first 35 MW should be allocated to LSEs 1 and 2 and the cost of the remaining 15 MW should be allocated pro-rata based on peak load share to all impacted LSEs (including LSEs 1 and 2).

shapes.[18] The flexibility for bilateral trading should allow for efficient portfolios without the need for additional trading mechanisms.

1. Existing Contracts

SCE expects existing contracts to continue either without modification or with relatively minor changes under the new 24-hourly slices framework. As noted above, RA attributes must continue to be bundled and contracted resources continue to have a must-offer requirement based on their operational capability and the amount of RA capacity sold.

2. Transactability

The proposal will result in highly transactable RA products. RA capacity will continue to trade as it does today because it keeps all attributes "bundled." Moreover, all market participants will know the RA capability of all resources on a 24-hour basis because the RA Resource Master Database will be public. This transparency will facilitate both direct contracting and secondary trading and will allow LSEs to pursue RA resources that best fit their needs. SCE expects that resources with like capacity characteristics (*e.g.,* 24-hour resources, batteries of like duration) will continue to trade in a fungible manner.

E. Tools Required for Implementation

As noted throughout this summary, several new administrative tools must be developed to implement the 24-hourly slices framework. The tools ensure that all parties agree on the RA capability of each resource, have sufficient information to design RA portfolios, can submit the showings, and can demonstrate compliance to the CPUC. SCE believes something as simple as an Excel spreadsheet could be used to develop and maintain the necessary administrative tools described below:

1. RA Resource Master Database

- Contains a list of all resources (within the CAISO) eligible to sell RA, their resource ID, their maximum RA capacity, and hours of availability within a 24-hour window
- For solar and wind, identifies the profile associated with the resource. Each solar and wind resourcewill utilize only one profile; however, multiple resources may ultimately wind up using the same profile. For example, the CPUC might decide to start with only two different solar profiles, in which case all solar facilities would be mapped to either profile 1 or profile 2.
- For storage, includes the charging efficiency and maximum continuous energy
- For hybrid and co-located resources, includes configurations to describe capabilities
- Contains data for each month
- Information is public and available to inform trading and resource portfolio development

2. Solar and Wind Profile Master Database

- Provides normalized, 24-hour values for all wind and solar profiles

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[18] For example, LSE1 may control 100MW of RA from Resource 1. However, if LSE1 only needs 85MWs of RA, they can sell the extra 15MW from Resource 1 to another interested party. It also allows LSEs to meet their 24-hour "shape" by trading or swapping resources. For example, LSE1 has excess capacity in morning hours and just enough capacity during the peak while LSE2 is only short in the morning hours. The proposal allows LSE1 to trade some of its extra "base load" capacity (that covers all 24-hours) in exchange for some of LSE2's use-limited capacity that is available during the peak. LSE1 and LSE2 can efficiently meet both of their 24-hour capacity requirements by "swapping baseload for flexible."

- Each profile has a unique identifier
- Contains data for each month
- Information is public and available to inform RA trading and resource portfolio development

3. LSE Requirement Database

- Contains the official requirements of each LSE (hourly load + PRM), by month, for all 24 hours
- Is used by each LSE to determine its monthly 24-hour showing requirement
- Is used by the CPUC to ensure each LSE meets its monthly 24-hour showing requirement
- Is developed by the CPUC in communication with the CEC after the CEC finalizes the monthly, 24-hour load shape for each LSE
- Database is non-public. Each LSE has access to only its requirements; the CPUC has access to all data

4. LSE Showing Tool

- Spreadsheet tool used by each LSE to submit their monthly, 24-hour showing to the CPUC
- Contains a standard format for listing the resources in an LSE's portfolio including the resource ID found in the Master Data Base, their MW quantity associated with the must-offer requirement, and the capacity used in each of the 24 hours of the showing
- LSEs submit just this basic information to the CPUC for its showing
- For convenience, SCE recommends the tool mimic the pass/fail logic that will be used in the CPUC Verification Tool so LSEs know in advance if they will pass CPUC verification
- This showing can also be used to provide the CAISO the information it will need to 1) determine the must-offer requirements of all resources, 2) the correct RA capacity values to use when performing their single-hour deficiency test

5. CPUC Verification Tool

- The tool is designed to use the data submitted through the LSE Showing Tool
- The CPUC uses the data submitted by the LSE, in conjunction with the RA Master Data Base, the Solar and Wind Profile Master Database, and the LSE Requirement Database to determine if an LSE passes the 24-hour RA requirement in each month
- The tool contains basic logic to ensure the showing is consistent with the capabilities of the resources submitted, that sufficient capacity has been brought to meet the LSE's requirement in all 24-hours, and that sufficient excess capacity has been shown to meet the capacity requirements for storage
- LSEs must pass all 24-hours, all logic tests, and the excess capacity requirement to pass the showing
- The tool notes any hour(s) of failure along with the maximum capacity shortfall within the 24 hours

F. Open Items

SCE proposes that the CPUC move swiftly to approve the 24-hourly slices framework as described above. However, there are several items that are not expressly included in SCE's proposal that must be addressed for implementation of 24-hourly slices in the 2024 RA compliance year. As such, the decision approving the specific slice-of-day proposal should also identify the remaining implementation details to be addressed in a subsequent forum and approve any approaches that can be used on an interim and/or permanent basis.

The following is a list of open items that require action to implement SCE's 24-hourly slices framework. SCE offers preliminary thoughts and potential approaches on certain implementation questions.

1. Determination of Hourly Profiles for Wind and Solar

The CPUC will need to decide how many profiles are needed for each technology based on variations in technology type and location. SCE recommends starting simple with a limited number of CPUC-defined profiles. This can be refined over time.

2. Counting Rules for Hybrid and Co-Located Resources

SCE does not offer a specific method but proposes to follow the general principle that they be shown within their capabilities on the RA Showing.

3. Profile Scaling for Partially Deliverable Solar and Wind

SCE proposes that partially deliverable solar and wind receive profiles that reflect their deliverable capacity, rather than their fully installed capacity. In effect, they will look like smaller units compared to a similar unit that is fully deliverable. That is, their shapes will be the same, but they will have less capacity in each hour of their profile. Details of determining the profile require further discussion.

4. CAISO RA Program Administration

CAISO can currently only verify one value per month per resource. SCE proposes CAISO consider the CPUC resource counting value in the peak hour to be the NQC and the resource counting values in other hours as "hourly load carrying sufficiency." Similarly, CAISO's "Monthly Demand and Reserve Margin requirements" should continue to be based on each LSE's coincident peak determined by the CEC. SCE suggests these distinctions be added to the CPUC RA program documentation to aid CAISO's transition to the slice-of-day RA program. With this consideration in place, there will be very limited initial changes to CAISO rules, systems, and processes to administer their part of the RA program. Specifically, SCE expects no immediate material changes to the following CAISO processes:

- Bid insertion rules – No changes
- Outage and substitution rules – No changes
- Capacity procurement mechanism (CPM) checks, triggers, and cost allocation rules – Limited changes.[19]

5. CAISO Backstop Cost Allocation Process Changes

To ensure that entities that fail their CPUC showing are properly allocated CAISO backstop costs, the CPUC may need to coordinate the exchange of additional information to the CAISO and the CAISO may need to make minor tariff modifications. For example, the CPUC may want to communicate information on LSE showing failures (such as maximum failed MW by LSE) so the CAISO can use this information to properly allocate backstop costs.

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[19] *See* CAISO's February 7, 2022 Informal Comments on the RA Framework Working Group Process at p. 5, which flagged these three rules and processes as items that need to be revisited under the 24-hourly slices proposal.

6. Confirmation of the Appropriate Loss of Load Expectation (LOLE) Standard

The appropriate LOLE (*e.g.,* 1:10) planning standard is outside of the scope of this proposal but is necessary to calculate the PRM. As noted above, SCE believes this policy discussion on the appropriate reliability standard should occur in the IRP proceeding (R.20-05-003).

7. Determination of the Proper PRM

The determination of the appropriate PRM to use for the RA program is beyond the scope of this proposal but is a necessary input in determining LSE requirements. SCE proposes that the CPUC first focus on establishing a single PRM (*i.e.,* applies to all hours and months) for the 2024 compliance year RA program, which should be informed by IRP discussions. The CPUC can refine the application of the PRM to the RA program (e.g., whether the same PRM should be used in both IRP and the RA program, whether the PRM should vary by hour and/or by month) in a subsequent forum.

8. Local Capacity Process – Explore Potential Changes

SCE recommends no changes be made to the current local RA program for 2024 compliance year, but notes this may result in different counting mechanisms for local and system RA. As such, the CPUC may need to consider if any long-term changes to local RA would be desirable in light of the 24-hourly slices framework.

9. Planned Outage Substitution Rules

For simplicity, the substitution requirement should be based on the hour that was tested by the CAISO for deficiencies. LSEs should provide a similar amount of capacity that the CAISO assumed in that hour. This would benefit from additional discussion with the CAISO and this process should be refined over time.

10. Cost Allocation Mechanism (CAM) Process Changes

The CPUC's current CAM process effectively allocates system RA benefits to all LSEs by reducing non-IOU LSEs' single point peak requirements by the MW that should be allocated to them (which is based on peak load share) and commensurately increasing IOUs' single point peak requirements; the IOUs are then responsible for showing the CAM-eligible resources on behalf of all LSEs. This process will need to be modified under any slice-of-day framework to consider the availability and capability of the CAM-eligible resources and LSEs' load share during those slices. SCE recommends the CPUC develop a standardized methodology for use-limited technologies that will govern how LSEs' hourly requirements are adjusted for the CAM resources. A standardized methodology will reduce the administrative complexity of the CAM allocation process and provide certainty to non-investor-owned-utility LSEs on the specific hourly system RA benefits that will be provided by the CAM-eligible resources. For example, an allocation of a CAM-eligible peaker should reduce non-IOU LSEs' requirements in pre-defined hours (hours to be determined by the CPUC) based on their hourly load share and commensurately increase the IOU's requirements in those same hours.[20] The details of this process change, including the allocation of charging requirements for CAM-eligible storage resources, must be developed for implementation of 24-hourly slices in the 2024 compliance year.

[20] Under this approach—and consistent with the current process—the IOUs would have discretion on how (and which hours) the CAM-eligible resources are shown.

11. Incorporation of UCAP or Resource Adequacy Availability Incentive Mechanism (RAAIM) Into the Framework

SCE does not take a position on UCAP and RAAIM as part of the proposal.[21] Whatever penalty structure is ultimately adopted will need to be integrated into the final framework.

G. Items Outside of the Scope of the Proposal

The following issues, while potentially in-scope for the workshops, are not part of the 24-hourly slice framework. As such, they do not need to be addressed to implement SCE's proposal for the 2024 compliance year and can be addressed later based on CPUC guidance:

- Multi-year requirements
- Hedging

H. Conclusion

The current RA framework requires major revisions to ensure grid reliability. Minor changes to the existing program are likely to prove unsuccessful in the near-term and will be wholly inadequate as the grid continues to evolve through 2045 and beyond. In contrast, SCE's 24-hourly slice framework recognizes the dramatic change in grid technologies, the crucial role and unique attributes of renewable resources and storage, and the need to maintain reliability in all hours of the day—not just the hours that have proved challenging in the past. California's transformative carbon reduction objectives require a reliability structure that efficiently addresses ***all*** resources and recognizes their unique contributions to reliability. SCE's proposal is durable and addresses both gross and net load peaks, regardless of where they fall, their durations, and how they evolve over time. And as described in the chart below, it best meets all of the CPUC's guiding principles for a RA framework. By design, it adapts to a changing resource mix, can be implemented in the near term, will be compatible with most existing contracts, and supports bilateral contracting and trading.

The CPUC should act expeditiously to adopt the SCE 24-hourly slices framework and establish a process to resolve all outstanding implementation details in time for a 2024 implementation.

CPUC's Guiding Principles	**Hourly Slices**
1. Balance ensuring a reliable electrical grid with minimizing costs to customers	• Ensures sufficient capacity for each hour of the day while reducing risk of over-procurement • Preserves value of resources that do not fit neatly into longer pre-defined slices
2. Balance addressing hourly energy sufficiency for reliable operations with advancing California's environmental goals	• LSE requirements match hourly load+PRM • Allows all resources (including renewables) to count at their expected hourly capacity • Incorporates additional capacity needed to charge storage

[21] SCE may take a position on this topic later if and when this issue arises with additional information available such as from the CAISO UCAP proposal.

3. Balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity and transactability	• Retains existing transactions and products where possible • Single showing (Pass/Fail)
4. Be implementable in the near-term (2024)	• Existing contracts and resource types can be used in showings • Measures to standardize showing can be implemented in the near term
5. Be durable and adaptable to a changing electric grid	• Robust to peak and net peak needs • Robust to changes in grid resource mix • Eliminates need to update slice definition as grid evolves

PG&E Slice-of-Day Proposal: 24 Slice

Pacific Gas and Electric, Company (PG&E) Peter Griffes, Luke Nickerman

I. PG&E supports 24 slice approach as outlined by SCE

PG&E's original slice-of-day proposal from early 2021,[1] while not taking a position on slice or season length, was introduced with slice lengths longer than one hour and seasons longer than one month to balance granularity and administrative simplicity. The total number of showings was an important consideration in this initial version of slice-of-day, as many showings could make the framework administratively infeasible. It is important to note that this early version of the slice-of-day proposal anticipated that transactors would be able to trade slices.

During the workshops, PG&E and other parties explored trade-offs of different options for the slice-of-day program design. These included different approaches for slice lengths, season lengths, showing frequency, resource counting options, storage charging requirements, potential load forecast changes, needed requirement allocation changes, Planning Reserve Margin (PRM) determination, Maximum Cumulative Capacity (MCC) buckets, bundling or unbundling of supply and load, showing mechanics, alternative resource counting approaches, penalties, and backstop considerations. These trade-offs were also discussed within the context of the principles the California Public Utilities Commission (Commission or CPUC) outlined in D.21-07-014.

In the second workshop on October 6, 2022, Southern California Edison Company (SCE) introduced the idea of a framework with 24-hourly slices and continuing the monthly compliance obligation. SCE proposed that slices be bundled for each month level, meaning that capacity from any given facility would have to be procured for all 24 slices (although facilities could still sell portions of the total capacity to different load-serving entities (LSEs), as is the case today). Keeping the slices bundled enabled the possibility of hourly granularity, while maintaining administrative simplicity.

PG&E's thinking on the best framework evolved from investigating various parameters for slice-of-day with larger slices and potentially larger seasons to supporting the 24-hourly slice/monthly obligation approach, which SCE describes in more detail in their chapter. PG&E concluded that this framework best meets the Commission principles for RA reform for a number of reasons, including:

- It ensures reliability while minimizing excess procurement and customer costs, as renewable generation and load vary significantly across hours and months. If slices are greater than an hour in length or seasons greater than a month, there is a greater likelihood of excess procurement in these multi-hour slices or months due to the need to set requirements at the maximum demand during the slice. For instance, peak periods would require maintaining high RA levels across all slice hours, even if some of the hours have a substantially lower load.
- It simplifies resource counting for several resources by avoiding slice mismatch for resources like storage, which would have to commit to a larger hourly block (in a larger slice framework) even if the storage is not needed in every hour of the block, as well as imports and DR, which could potentially result in a mismatch for those resource start and end times with the start and end

[1] Second Revised Track 3B.2 Proposals of Pacific Gas & Electric, R.19-11-009, February 26, 2021

times of the larger slices. For instance, a five-hour demand response (DR) product could end up only being credited for four of the hours under a four-hour slice design.

- It obviates the issue of using gross load vs. load net of solar and wind output, as the net accounting was intended to be on an hourly basis; in a 24-hourly slice framework an LSE could show the full renewable output for each hour while keeping renewables on the supply side instead of the additional complications introduced if renewables are on the load side (e.g., potentially two showings and restrictions on renewable transactions).
- It results in a more durable framework, as there is a reduced need to redefine slices in the future.
- SCE's tool demonstrated 24-hour showings to be administratively workable, ensuring the additional detail does not result in an overly complex showing process.

In SCE's section of this workshop report, SCE summarizes its 24-hourly slice approach. PG&E supports this approach for the reasons outlined above. SCE's proposal is fairly comprehensive, but lacks some detail on resource counting, load forecasting, and MCC buckets. PG&E provides proposed details on these elements in the next section, which together with SCE's proposed framework would constitute a complete framework with minimal additional unresolved issues.

II. PG&E's Proposals on 24 Slice Details

A. Resource Counting

1. Solar / Wind: Exceedance

PG&E recommends using an exceedance-based methodology for solar and wind counting. Effective Load Carrying Capability (ELCC) is complicated at a monthly level, let alone an hourly level, and it is unclear that an hourly ELCC value, if it could be produced, would provide a meaningful result. Exceedance is less administratively burdensome and more accurately reflects the hourly generation profile of the resources. Exceedance also facilitates easier bucketing of resources (e.g., by technology type and/or geography) enabling greater levels of granularity without significant increases in administrative burden. The ELCC methodology could still be performed in the Integrated Resource Planning (IRP) proceeding to inform the needed resource mix where the planning horizon is longer and larger time periods are used. ELCC values could potentially be used as an additional check to ensure the chosen exceedance levels are appropriate.

To identify a reasonable exceedance level to determine Qualifying Capacity (QC) values for solar and wind, PG&E performed analysis of how solar and wind resources performed on days with high load, using high load days as a proxy for stressed grid conditions. Using six years of publicly available load and total wind and total solar generation data on an hourly basis from the California Independent System Operator (CAISO) Open Access Same-Time Information System (OASIS) database, PG&E compared the performance of aggregated wind resources and aggregated solar resources on those days to the values for these resource types at different exceedance levels. To determine high stress days, PG&E identified "Peak Days." A peak day is defined as the day in each month and for each year (of the included dataset), which had the highest hourly gross load. After identifying the peak day in each month and year of the six-year period, the corresponding solar and wind generation on those peak days was pulled from the OASIS database (this amounts to six observations for each hour in each month, one for each year during the peak day of the month). Solar and wind generation from the identified peak days was then averaged across the included years to produce a 12x24 profile. These profiles should reasonably estimate how solar and wind resources have performed on days with high demands on the system, establishing actual generation capability during days with the greatest need. Below is an example of this profile based on load and generation data from years 2015 to 2020, with darker shades of green representing hours with more generation.

Solar Generation on Worst Day 2015-2020

Hour Ending

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	592	2,280	3,494	3,877	3,851	3,708	3,475	2,958	1,860	450	3	0	0	0	0	0	0
Feb	0	0	0	0	0	0	49	1,514	4,042	5,258	5,768	5,906	5,805	5,618	5,148	4,252	1,814	134	3	3	4	4	4	4
Mar	2	2	0	0	0	0	197	1,908	4,430	5,884	6,457	6,615	6,606	6,548	6,175	5,357	3,649	1,417	258	0	0	0	0	0
Apr	0	0	0	0	0	0	369	3,113	6,238	7,536	8,166	8,389	8,437	8,406	8,289	7,885	6,942	5,285	2,123	214	51	4	0	0
May	0	0	0	0	0	1	1,087	4,157	6,503	7,612	8,129	8,312	8,252	8,229	8,036	7,621	6,792	5,391	2,824	447	4	0	0	0
Jun	0	0	0	0	0	4	1,094	4,046	6,113	7,249	7,817	8,139	8,091	7,933	7,703	7,256	6,483	5,329	3,126	701	15	9	0	0
Jul	0	0	0	0	0	0	607	3,166	5,717	6,940	7,424	7,645	7,778	7,592	7,245	6,763	6,047	5,036	2,844	573	5	5	6	6
Aug	2	2	2	2	2	1	206	2,275	5,239	6,709	7,604	7,835	7,995	7,841	7,459	6,752	5,945	4,451	1,839	171	15	15	15	15
Sep	1	2	2	1	1	0	76	1,912	5,117	6,774	7,466	7,727	7,719	7,737	7,493	6,914	6,015	3,940	1,003	49	12	2	1	1
Oct	1	1	1	1	1	1	4	920	4,084	6,371	7,065	7,178	7,125	7,072	6,852	6,290	4,788	1,644	80	13	7	0	0	0
Nov	0	0	0	0	0	0	157	2,111	4,908	6,240	6,566	6,429	6,277	5,882	5,295	3,316	865	116	1	0	0	0	0	0
Dec	1	1	1	1	1	1	8	1,097	3,655	5,083	5,655	5,703	5,553	5,341	4,588	2,424	258	3	2	2	3	2	0	0

12x24 profiles were then created at varying exceedance levels for aggregate solar and wind data. The standard output-based exceedance approach involves pulling generation data for all 8760 hours for each year (e.g., each hour in August would have 31 observations x 6 years of data or 186 observations). Output is then ranked, and a percentile is applied that is associated with the chosen exceedance level (e.g., in the example above, a 50% exceedance would select the value between observations 93 and 94, the median of the 186 observations).

PG&E conducted comparisons of exceedance levels from 50%-75%. PG&E produced profiles based on each exceedance level identified, again using six years of publicly available data from OASIS. At each exceedance level, hourly/monthly generation values were compared to generation values in the average peak day profiles. In comparing the profiles, PG&E manually looked for values in the exceedance profiles that were close to those in the average peak day profiles. Ideally, hourly generation at the chosen exceedance level should be equal to or slightly less than that of the peak day, which would indicate selecting an exceedance level that approximates expected output on peak days. If generation values under an exceedance level are consistently much lower than those on peak days, resources will be undervalued. This balance must also be weighed against performance in periods of greatest concern, such as summer months and ramp periods. PG&E found that for solar resources, a 60% exceedance level showed average hourly generation below peak day performance by a reasonable level, with very few hours exceeding generation on the peak day. PG&E also analyzed 50% exceedance but found far too many hours exceeded what can be expected on a peak day. At 75% exceedance, peak day generation was greater at every hour, resulting in an overly conservative counting methodology. Below is an example of a comparison done between the peak day and the 60% exceedance level for solar, with red cells representing hours where generation in the exceedance level profile exceeded generation in the average peak day profile and green cells representing hours where the exceedance level was less than the average peak day profile.

60% Exceedance vs. Avg Worst Day

Hour Ending

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	-64	-218	-211	-1	150	292	368	297	232	22	-3	0	0	0	0	0	0
Feb	0	0	0	0	0	0	-31	-218	-544	-507	-488	-564	-485	-403	-349	-392	-56	-22	-3	-3	-4	-4	-4	-4
Mar	-2	-2	0	0	0	0	-197	-1,070	-1,197	-1,091	-987	-921	-904	-949	-938	-558	87	481	150	0	0	0	0	0
Apr	0	0	0	0	0	0	-255	-1,360	-2,061	-1,933	-1,872	-1,930	-1,680	-1,847	-1,901	-2,034	-1,880	-1,682	-853	-170	-51	-4	0	0
May	0	0	0	0	0	-1	-379	-1,042	-1,160	-1,455	-1,147	-1,064	-996	-979	-1,273	-1,207	-1,329	-1,171	-634	-160	-4	0	0	0
Jun	0	0	0	0	0	-4	111	147	53	-42	-41	38	439	692	557	620	635	545	338	-18	-15	-9	0	0
Jul	0	0	0	0	0	0	-35	-360	-550	-310	-81	88	42	118	320	419	441	121	105	30	-5	-5	-6	-6
Aug	-2	-2	-2	-2	-2	-1	-28	-98	-196	-45	274	363	274	258	307	239	198	93	66	-23	-15	-15	-15	-15
Sep	-1	-2	-2	-1	-1	0	-57	-295	-513	-319	-192	-87	65	-53	-4	-301	-404	-563	-484	-49	-12	-2	-1	-1
Oct	-1	-1	-1	-1	-1	-1	-4	-224	-193	-249	-123	65	48	48	167	-10	-64	-364	-58	-13	-7	0	0	0
Nov	0	0	0	0	0	0	-59	-367	-774	-756	-612	-414	-354	-252	-675	-747	-552	-116	-1	0	0	0	0	0
Dec	-1	-1	-1	-1	-1	-1	-8	-303	-840	-930	-996	-783	-702	-711	-683	-341	-37	-3	-2	-2	-3	-2	0	0

PG&E also performed this analysis for wind and found that a 70% exceedance level resulted in balanced counting of wind generation capability.

While PG&E selected the years 2015-2020 as the data horizon for this analysis, any time horizon can be used. This methodology for determining exceedance level is a relatively simple approach to resource counting but creates a critical link between exceedance level and expected performance on the most critical days. The methodology can be updated easily and adjusted as risk tolerances change. It is also very adaptable and could, for instance, be modified to provide greater weight to recent years, or change the data horizon to get narrower or broader representations of system conditions. By focusing specifically on historical performance of solar and wind under peak load conditions, this methodology is most likely to result in qualifying capacity (QC) values for solar and wind resources which reasonably represent their load reducing capabilities in times of greatest system need.

PG&E is proposing a single exceedance level be used across all hours and months, at least to start. PG&E also offers this approach as one that is sufficiently robust to be adopted now and refined over time, or, if the Commission directs additional work to determine the appropriate exceedance level or renewable profiles, PG&E recommends that the Commission include this approach as a starting point for creating a linkage between the final exceedance level or renewable profiles and their performance on stressed days.

2. Dispatchable: Pmax with ambient derates (or UCAP-light)

PG&E recommends pursuing incremental improvements for counting dispatchable resources. Maximum capacity (Pmax) with adjustments for ambient de-rates would account for some performance issues and would be an improvement over the status quo. A fuller Unforced Capacity (UCAP)-type framework could be further refined and implemented later, given that there are still several open questions on how UCAP would work and it is unclear whether UCAP could be implemented in time for the 2024 RA compliance year.

a) Energy-limited thermal units

PG&E recommends that hourly limits due to noise, pollution or other permit-related limits be included in a broader set of data that Energy Division (ED) would make available on RA units. Load serving entities (LSEs) would then be required to observe these hourly limits in their RA showings. PG&E recognizes that resources with annual limits may be addressed through variation in monthly QC values. Further, resources with monthly limitations like starts or run hours would not be captured in this framework. PG&E recommends considering how monthly limitations could be captured as part of a fuller UCAP at a later date.

3. Storage: Pmax subject to energy storage and interconnection limits

Pmax allows for full output to be counted, subject to interconnection limits, but does not require that the LSE show it in this way. For instance, if an LSE has a 100 MW, 4-hr resource (i.e., 400 MWh energy storage limit), the LSE could show it for 100 MW over four hours but could also use a portion of the capacity over a longer period, e.g., 50 MW over eight hours. To clarify, this treatment applies to whole units and pieces of storage resources - i.e., pieces of a storage resource can be used by each purchasing LSE in the manner that best suits their needs. LSEs would be required to show sufficient capacity to charge storage in other slices, plus a gross up for charging loss rates specific to that resource. As noted by SCE, additional parameters would need to be reported to the CPUC to ensure technical and contractual limits are observed by the showing LSE. Lastly, PG&E does not object to allowing multiple cycles per day, if contract language allows for this. However, additional showing constraints would need to be included to account for charging between cycles for multi-cycle showings.

4. Hybrid: Existing methodology, but use exceedance for excess renewable generation

PG&E recommends maintaining the existing methodology that tests whether sufficient energy exists to charge the storage component and applies exceedance to any excess energy captures the storage component while crediting excess energy in the same way as standalone resources. This approach is administratively simple, as it does not require major methodological changes and can be implemented for 2024. Additional considerations include: 1. the test to determine if sufficient energy exists to charge the storage should be based on the exceedance values used for the underlying resource, including any excess energy that is not deliverable to the grid; and 2. should insufficient energy exist to fully charge the storage component in a given month, the unavailable storage component would either need to not be shown (potentially the case for resources with grid charging restrictions) or, if grid charging restrictions do not exist, would need capacity in other hours to charge, consistent with the requirement for standalone storage. Lastly, the existing methodology should be updated to account for charging losses.

5. Hydro: Existing exceedance methodology applied on an hourly basis

The recently adopted exceedance methodology for hydro should be used, at least initially, for slice-of-day. It gives more weight to poor hydro years and can be adapted to an hourly framework by changing the exceedance calculation process to yield hourly values instead of one gross-peak value.

6. Demand Response: Defer to California Energy Commission (CEC) process

The RA Reform Track lacks the bandwidth to study DR counting methodology changes independent of the ongoing CEC process and still meet the goal to have a reform framework implemented by 2024. PG&E recommends deferring determination of the DR counting methodology to the ongoing CEC process, but notes that the adopted framework needs to provide hourly data of DR program availability for use in the slice-of-day framework.

7. Imports: Updated for resource-specific, contract values for non-resource-specific

Resource-specific imports can use updated counting rules applicable to that particular resource type (e.g., exceedance would be used for solar and wind resources) to accurately reflect the RA value of that resource. Non-resource-specific imports could be counted at the contract value, subject to the RA requirement that resources be at least 4 hours in duration. The 4-hour requirement is important to ensure that imports are not used to circumvent the hourly bundling requirement.

8. Non-dispatchable: Current methodology

This is a small and fairly static resource type; therefore, the current QC methodology could continue to be used for this resource type, with a single value being applied to all hours, subject to availability constraints.

B. Load forecasting

1. Maximum hourly values

PG&E identified two approaches for setting requirements based on the CEC Integrated Energy Policy Report (IEPR) forecast. The first is based on the "worst day" in each month, which identifies the maximum load across all hours in the month and using the forecast values for that particular day. The second is based on the "maximum hourly values" regardless of the day in which they occur (i.e., the requirement is set based on the maximum observed value for each hour in the month). PG&E recommends using "maximum hourly values" to set requirements in each hour. PG&E's analysis shows that the peak hour in each month does not always fall on the day with the maximum load; and the spring months had unexpected anomalies in late morning hours. PG&E recommends use of the "maximum hourly values" to provide an extra level of assurance that load will be met in all hours. PG&E's discussions with the CEC indicate that such an approach is feasible.

C. MCC Buckets: Eliminate, but keep a cap for demand response

The 24-hourly slice framework eliminates the need for the MCC buckets, which largely ensures that LSEs are bringing a mix of resources that once aggregated would ensure reliability across peak condition hours. With a framework that considers all hours, the need for MCC buckets should be eliminated, with one exception for a DR cap. Should the new framework not have a cap on DR and if DR were to expand significantly, system reliability issues could develop during multi-day reliability events, either due to program call limitations or customer fatigue. Maintaining a cap on DR would ensure the system does not rely too much on DR to meet needs during prolonged reliability events.

Gridwell Slice-of-Day Proposal: Two-Slice Proposal

Gridwell, Carrie Bentley

Two-Slice Overview

Gridwell offers the two-slice proposal for consideration.[1] The two-slice proposal enhances the existing RA rules into a durable RA program that ensures hourly energy sufficiency for a rapidly decarbonizing grid. It prioritizes reliability, market transactability, and importantly, accurate requirements and counting rules using robust statistical analysis. By relying on accurate resource counting rules that capture resources' contributions to reliability throughout the year, the two-slice proposal ensures hourly reliability without costly over- or under-procurement.

This proposal has evolved over three formal presentations in the 4th, 6th, and 7th 3B.2 workshops to incorporate feedback and other party presentations. While the proposal below closely resembles the framework discusses in Gridwell's December presentation, it also includes details and clarifications based on further party feedback. Notably, there is almost universal consensus among parties that there should be a regular process to conduct a Loss of Load Expectation (LOLE) study to support the RA program requirements. Vistra has put forth a detailed LOLE study proposal that works in concert with the two-slice proposal, and we propose to use their LOLE study plan as the system RA gross load requirement.

In addition to a gross load requirement, Gridwell proposes a "second slice", which is an additional assessment closer to real-time that evaluates the aggregate system RA showing's ability to meet the aggregate net peak load requirement. This assessment will provide a check on reliability and will be important in the instances where real-world conditions are significantly different from study assumptions. Given the impacts of climate change on the electricity grid, studies may not perfectly capture outage risks from wildfires or highly variable weather conditions. Thus, Gridwell believes a "real-world" assessment second slice is vital to ensuring reliability.

Ultimately, the RA requirement and resource counting rules will progress during the study processes themselves; however, the two-slice proposal below provides sufficient details to address already observed reliability concerns by the 2024 RA compliance year and provides an RA program structure that will dynamically and automatically adapt to the grid's future reliability needs.

Two-Slice Proposal Summary

The two-slice proposal has six key elements:

1. Maintain the monthly showing requirement and a single monthly Net Qualifying Capacity (NQC) construct,[2]

[1] While Gridwell is not a party, numerous parties, including Calpine and Vistra, have continually supported the consideration of the proposal.

[2] The original proposal had seasonal requirements; however, during the workshop, an overwhelming number of participants supported maintaining the current monthly structure.

2. Perform a biennial one-day-in-ten-years LOLE study to determine a system monthly RA gross load requirement that evaluates loss of load potential across all hours
3. Update the Qualifying Capacity methodologies for all use-limited resources[3] using the Effective Load Carrying Capacity (ELCC) methodology and derate all thermal resources by historical ambient derate due to temperature-forced outages,
4. Add an aggregate monthly net load peak assessment to ensure continuous reliability,
5. Maintain the CPUC penalty structure and penalize each short Load Serving Entity (LSE) for the higher of its gross load deficiency or net peak deficiency in the month, and
6. Remove the MCC buckets 1-4 in the 2024 RA compliance year and remove the demand response bucket the next year after demand response counting rules are refined.

The following table provides an overview of the two-slice proposal details.

Component	Two-Slice Proposal
Slice Structure	2 slices, a gross load requirement and net peak need assessment
Compliance Periods and Showings	Existing showing timelines for the monthly compliance periods
Planning Standard Threshold	A specified reliability threshold that is at least One Day in Ten Years
Need Determination and Allocation	gross Load Slice: LOLE produces total generation capacity required to maintain the Planning Standard Threshold across all hours Allocation: to all LSEs based on peak load share (existing allocation rules) net Load Slice: LOLE or other methodology identifies the net peak hour for the assessment Allocation: Same as gross load slice (peak load share)
Energy Sufficiency for Charging Storage	RA LOLE and ELCC studies will directly capture any hours with loss-of-load expectations from lack of sufficient storage charging. Insufficient charging energy will increase the RA requirement and impact ELCC values of solar, storage, etc. in order to maintain a one-day-in-ten-years LOLE Storage charging needs should be incorporated into CPUC IRP process to ensure sufficient *renewable* charging

[3] A use-limited resource is a resource that has its energy limited by number of starts, minimum run time, or energy (MWh limit), also called an "operationally-limited" resource.

Qualifying Capacity Granularity	One NQC value for the compliance period (month), this value will be adjusted in the net peak assessment for wind and solar resources based on resource-specific historical output
Resource Counting: Wind, Solar, Storage, Hybrid	Effective ELCC by classes that reflect specific technology, location, and duration. Hybrid and co-located resource ELCC will be adjusted for any ITC and/or intertie limitations
Resource Counting: Dispatchable Thermal	Unforced Capacity (UCAP)-light, i.e., deliverable Pmax with ambient derate due to temperature adjustments
Resource Counting: Use-Limited Dispatchable Thermal	UCAP-light until ELCC methodology or UCAP methodology is determined
Resource Counting: Imports	Resource-specific system resource imports: NQC based on underlying resource type supporting the import Non-resource-specific system resources: Existing rules until ELCC or UCAP can be determined
Resource Counting: Dispatchable Hydro, Non-Dispatchable Resources, Demand Response, and Other	Existing rules until ELCC methodology or UCAP methodology is determined
MCC Buckets	None. The availability limitations that MCC was designed to limit will be captured in the ELCC methodology. Demand response will need to retain a cap if not covered by ELCC or other methodology that captures its use-limitations
Net Peak Resource Assessment	The CPUC and CAISO will use historical output profiles in the net peak assessment to cap solar contribution to ensure the net peak assessment only counts resources reasonably expected to operate in the test hour. Wind may adjust in either upward or downward direction as it typically produces more during the net peak Any system net peak shortage will be assigned to short LSEs
CPUC System RA Penalties	Maintain CPUC penalty structures with an enhancement where the CPUC would apply system penalties to the maximum the LSE is short on either its share of the gross load need or its share of the net peak need
CAISO Rules: Capacity Procurement Mechanism (CPM), RA Availability	Minor updates will be needed, notably to accommodate the addition of a net peak load assessment. The CAISO may also consider changes related to its CPM backstop authority and

Incentive Mechanism (RAAIM), Must-offer rules, and outages rules	RAAIM rules for forced outage due to ambient derates due to temperature. The existing must-offer obligation and outage replacement rules can be maintained and there are no changes proposed to import resources must-offer/must-flow rules

The remaining sections (1) describe the two-slice alignment with Commission principles, (2) provide details on the two-slice proposal, and (3) link the proposal to other RA program considerations.

Alignment with Commission Goals

The proposal results in RA reform that meets the CPUC principles ordered in Decision (D.) 21-07-014:

Principle 1: To balance ensuring a reliable electrical grid with minimizing costs to customers

The two-slice proposal ensures a reliable electric grid using robust statistical measures of reliability via a LOLE study and enhanced counting rules. These methods assure both a one-day-in-ten years planning threshold and that operationally limited resources have comparable and accurate counting methodologies. The two-slice proposal addresses foreseeable reliability concerns, such as load remaining high in the evening hours after the sun has set and multi-day reliability events. The two-slice proposal has the unique advantage of both targeting the immediate hours of concern via a net peak load assessment and being able to capture reliability events across multiple days via the proposed LOLE study process and updated ELCC values, which will give less qualifying capacity to short-duration storage and other use-limited resources as the need to ensure energy sufficiency in winter morning hours arises. Currently, the only way to attempt to address multi-day events is to increase the PRM, but this approach will increase costs and cannot necessarily ensure reliability if the capacity procured is unable to provide sufficient energy during a multi-day event.

The two-slice framework will also help to contain RA costs by maintaining a single monthly capacity value, which produces a fungible RA product that can be efficiently transacted by LSEs of any size. This is important given the significant increase in small LSEs over the last 5 years. In addition to lowering transaction costs, the two-slice proposal is designed to prevent over- or under- procurement using robust statistical analysis. Within the LOLE study process, risks associated with loss of load are being tested for all 8,760 hours within the study year and the hours where there is concern with reliable operations inform the fleet needed to meet a one-day-in-ten-years planning standard.

Principle 2: To balance addressing hourly energy sufficiency for reliable operations with advancing California's environmental goals

Hourly energy sufficiency is ensured by modeling all hourly demand needs in a periodic LOLE study updating the ELCC values accordingly. As already reflected in IRP ELCC modeling, additional use-limited resources contribute relatively less to grid reliability as similar resources (e.g., four-hour energy storage) begin to saturate the grid. Over time, as the grid becomes more fully saturated with solar, wind, and storage of different technologies and durations, the two-slice proposal will dynamically capture their contribution to grid reliability within and across multiple days.

The ELCC methodology eliminates the need for the current RA MCC bucket construct because use-limited resources have their Qualifying Capacity value directly discounted, while preserving California's diversity benefits of having a portfolio rich in hydro, wind, solar, and storage. This interaction among resources is important because the LOLE study is able to directly assess whether there is sufficient energy to charge storage resources and, if not, may increase the total generation capacity needed in the system RA gross peak requirement. Further, if additional loss of load periods are identified, then the ELCC results would discount the capacity value of storage resources directly. While this would be a worst-case scenario, as the IRP process should ensure sufficient renewables are built to charge storage, it is a capability within the LOLE study and the following ELCC study. It is only the IRP; however, that can ensure sufficient renewables are available to charge storage. If the LOLE study identifies storage charging deficiency, there will be insufficient time to bring additional renewables online and thus either storage QC will have to be discounted or it will have to be charged by non-renewable resources via a higher gross load requirement. Thus, in order to advance California's environmental goals, it is imperative the IRP directly consider the need for renewables to charge storage.

Finally, in order to address the immediate reliability concerns that RA "may not address other hours of the day when load may still be high and variable resources provide little or no value," the two-slice proposal has a net peak assessment that validates that the monthly shown RA resources are able to meet periods where renewable output is low, but load is still high. Gridwell anticipates that once there is a regular process in place to conduct a LOLE study and use-limited resources have their capacity discounted consistent with the LOLE studies, the net peak load assessment will rarely, if ever, identify a shortage. The assessment should only trigger additional capacity needs if near-term load forecasts and operational availability significantly differ from the LOLE and ELCC study assumptions.

Principle 3: To balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity and transactability

The RA program is already fairly complex with monthly system, local, and flexible RA requirements and counting rules by technology type. The two-slice proposal attempts to maintain simplicity in the product itself. Even though the ELCC studies to determine the counting rules are themselves complex, the ultimate result is a single MW NQC value for each month that preserves RA transactability and ability to contract across resource types. As discussed above in Principle 2, the LOLE study ensures that hourly RA needs are met to maintain a specified reliability standard for each month and the net peak assessment is added to assess whether the worst hour with unserved energy risks is sufficient.

Principle 4: To be implementable in the near-term (e.g., 2024)

The two-slice proposal provides sufficient details such that the Commission can adopt this proposal by the summer of 2022, as stipulated in the R.21-10-002 Scoping Ruling. Although the LOLE and ELCC studies are complex, they are also established studies that do not need novel process or software development. After the Final Decision adopting the two-slice proposal is issued, the CPUC can lead a transparent stakeholder process that allows feedback on inputs, assumptions, and final results by mid-2023. The two-slice proposal is set up so that the most important resources – wind, solar, and storage – are assessed using ELCC. Then, over time, other resource types like hydro, imports, and demand response may be included in the ELCC study as well.

The two-slice proposal also minimizes the impact to commercial negotiations and contracting. It also does not change the logistical process of RA showings or must-offer obligations, avoiding CAISO implementation concerns. The proposal avoids changes to the CAISO's RA user interface, which was a concern brought up by the CAISO during the workshops. While the CAISO may need to make limited changes to accommodate the net peak slice assessment, these changes are minimal, and CAISO has stated could be accommodated prior to the 2024 compliance year.

Principle 5: To be durable and adaptable to a changing electric grid

The design is durable because any unpredicted risks confronting the system will dynamically be captured with each LOLE iteration and the fleet identified will reflect contemporaneous needs to meet the one-day-in-ten-years standard. As described above in principle 2, the Two Slice proposal relies on recurring LOLE studies using updated load and generation assumptions to identify the high LOLE hours. Further, these LOLE updates and their outputs will be used in the ELCC studies, which could also have availability assumptions tweaked as experience is gained, to reflect resources' ability to meet reliability needs across current resource and load conditions in light of the current operational challenges facing the grid.

Two-Slice Proposal Details

Monthly net Qualifying Capacity (NQC) Showings

The two-slice proposal retains the annual and monthly showings timelines with a monthly granularity. It also retains the concept of a single NQC each month as described in the Qualifying Capacity section. Many existing contracts use the existing CAISO and CPUC RA rules as a basis for commercial transactions. In particular, the RA showing process is often a trigger for providing replacement capacity or for liquidated damages to occur. In order to minimize shocks to the RA market or costly contract renegotiations, the two-slice proposal maintains the current showing process and timelines.

System RA requirements (See Vistra Proposal)

The two-slice framework uses a robust method for determining RA requirements through a biennial Loss of Load Expectation (LOLE) study process, as proposed by Vistra. Establishing RA requirements through a regularly updated probabilistically determined LOLE study that incorporates uncertainty risks ensures reliability and results in a more equitable outcome for ratepayers than any other alternative discussed in the workshops.

The LOLE study will be leveraged to set the system RA gross requirement. These requirements will be allocated on a peak-load-share basis to LSEs and allow for CPUC and CAISO to perform sufficiency assessments on both needs. The two-slice proposal details for performing the LOLE study are described in detail by Vistra in Chapter 3.

The second slice, net peak load requirement can be established within the LOLE study process as proposed by Vistra or be determined by the CAISO using their planning studies to determine the hour of greatest risk.

System RA Counting Rules

The two-slice proposal relies on Effective Load Carrying Capability (ELCC) for use-limited resources, which is an established and analytically robust method to determine operationally limited resources' contribution to grid reliability. We propose to use ELCC for solar, wind, storage, hybrid, and all operationally-limited resources, UCAP-light for thermal assets, and eventually updated DR and hydro counting rules using either ELCC or another statistically appropriate approach.

ELCC – Variable and Use-limited Resources

The two-slice proposal is to use the ELCC study using the Loss of Load risks identified in the LOLE study to assess what capacity contribution a use-limited resource provides based on its ELCC class. The ELCC study can produce either average, incremental, or marginal ELCC for each class. Gridwell's initial proposal focused on incremental ELCC, and we continue to believe incremental ELCC similar to the existing IRP process will provide the most market certainty. However, as pointed out by several parties, the two-slice proposal will provide equal reliability using a consistently updated average ELCC and the determination of what ELCC type to choose is an implementation detail. The ELCC values will be refreshed after the LOLE study is performed at least biennially as ordered by the Commission in D21-06-029, Ordering Paragraph 14.

Although other areas of the country have only recently moved toward ELCC for resource capacity counting, California has used ELCC for wind and solar since 2015. The move from exceedance for solar and wind qualifying capacity counting to ELCC was necessitated by high levels of renewable penetration. This move was required by California statute. To support the integration of the high levels of renewable penetration, the State statutes also directed battery energy storage development. The state has even larger amounts of renewables on the grid currently and is developing battery energy storage to better integrate these renewables more rapidly than any new technology in recent history. Further, low hydro conditions have raised increasing concerns about the ability of hydro resources to perform at historic levels.

The RA program must keep pace, and the two-slice proposal expands the existing ELCC construct to the valuation of all use-limited resources in two phases:

- Phase one will expand the ELCC study to include more classes that cover variable energy resources (e.g., solar and wind) and use-limited resources (e.g., energy limited storage) while deferring applying ELCC to hydro resources, imports, or demand response to a later phase. Regardless of whether the state implements incremental or average ELCC, Gridwell proposes to group resources by technology type, duration, location, or other attributes, as practical.
- Phase two would explore using ELCC for dispatchable hydro, non-dispatchable resources, demand response, and non-resource specific system imports.

Although the ELCC calculations themselves are complex, the concept is intuitive for stakeholders used to the challenges of a high-renewables grid. The ELCC methodology establishes a resource's QC value based on equivalent reliability to a perfect resource considering all hours studied. Conceptually, if the LOLE study produces loss of load values where there is a loss of load probability expected at 4 pm, a resource's QC will be impacted by whether or not the resource's dispatch is expected to be there in this hour. If the LOLE study produces an expected loss-of-load probability at 4 pm, 6 pm, 7 pm, 8 pm, and 9 pm, then its expected dispatch during these hours will drive the resource's QC value.

In this simple example, there are 5 loss of load hours within the day that do not allow for four-hour storage to fully recharge in between. The intuitive impact for four-hour storage is that its QC will be less than 100% to reflect that it could not be dispatched in all five loss-of-load hours, but only four. The more loss-of-load hours that the LOLE study produces, the more the storage resource's value would be derated. An 8-hour storage resource; however, would still be able to fully discharge during all hours and so would not have its QC derated.

ELCC also captures the impact of resource diversity modeled in the LOLE study. Resources may change the amount of Loss of Load Hours identified or may shift when these occur. Depending on how resource diversity is accounted for, the ELCC study could share the capacity benefits among the resources due to these interactions between resource types and LOLE hours. Resources that shift reliability risk to hours where the resource itself does not produce could still increase reliability via the shifting the LOLE hours to lower load hours. The consequence of this is that solar can have a positive average ELCC even if it does not generate in any of the LOLE hours. To put it simply, solar gets “credit” within its QC for shifting the hours of greatest reliability risk to hours where there is less demand for energy.

Finally, resources that can support the assumption that their actual performance is superior to the class performance can seek a unit performance adjustment. The resource’s ELCC would be set by the product of the class ELCC times its unit performance adjustment factor. The class would be determined by technology, location, duration, or other attributes as needed.

One downside of using an ELCC methodology is that it compares use-limited resources to a perfect resource – and of course there is no such thing as a perfectly available resource. This currently benefits thermal resources as their capacity is assumed to be perfectly available. While theoretically the ELCC methodology could be used for non-use limited resources, it would be overly complicated. To better capture thermal availability, the two-slice proposal uses an alternative and more straightforward method to discount thermal resources as described below.

Unforced Capacity (UCAP)-Lite – Thermal Resources

UCAP-Lite will derate thermal resources’ NQCs by their unit-specific historical average ambient derates due to temperature. This ensures that thermal resources are capable of providing reliable capacity they are contracted for as RA across the day. These values would be based on a weighted average of three years of actual data submitted to the CAISO during the peak 5 hours of the day or another identified constrained period. A generator that has made improvements to its plant to decrease its needed derates due to ambient temperature should also be able to demonstrate its improved performance through documentation or testing.

Phased-in ELCC - Demand Response

The NQC methodology for DR resources is being discussed in other workshop processes at this time. The two-slice proposal does not include an alternative proposal and defers the demand response proposal until the Demand Response working group recommends DR counting rules. Generally, Gridwell believes E3’s ELCC Delta Method approach is the most reasonable way presented to date to allocate diversity benefits. Once adopted, a final methodology will incorporate the DR QC methodology into the framework to allow for a fungible product and removal of any DR caps within the MCC buckets or otherwise.

Phased-in ELCC – Hydro Resources

The NQC methodology for hydro resources was recently adopted by the Commission. In phase one, the two-slice proposal will use the same values to set its NQC. In phase two, it would explore using ELCC for dispatchable hydro as an enhancement to the phase one ELCC, where the ELCC study would have a hydro class added where it could distinguish between run-of-river hydro and pumped hydro to capture these variances.

Phased-in ELCC – Non-dispatchable Resources

The two-slice proposal would phase in ELCC for these types of resources as well. Phase one would apply existing rules. Phase two would explore an additional non-dispatchable resource class in a further enhanced ELCC study.

Phased-in ELCC or applicable QC – Imports

All imports will continue to require CAISO's maximum import capability (MIC) to count as RA resources. Resource-specific system resources, including those dynamically scheduled or pseudo-tied, will have their NQCs set using the resource-specific methodology appropriate to the resource's technology type. Non-resource-specific system resources will have their NQCs set by ELCC on a phased-in basis, where the ELCC study will be further enhanced in phase two to include classes based on import availability.

Backstop Rules

CPUC deficiency Penalties

deficiency penalties assessed by the Commission will largely remain the same as today. If an LSE is unable to meet its system gross peak requirement, then it will be penalized by the Commission under the same pricing construct as today for its gross peak deficiency amount. If an LSE meets its gross peak requirement, but is deficient for the system net peak requirement, then the LSE would be penalized based on the same pricing construct as today for its net peak deficiency amount. If the LSE were deficient for both, then the LSE would be penalized based on the same pricing construct as today for the larger deficiency volume between the two requirements. The LSE would not be doubly penalized for the same MW of deficiency being identified in both assessments; the greater of the two deficiencies will be used.

CAISO CPM Backstop

CAISO backstop procurement is outside of the scope of this proceeding, but generally the CAISO has the authority to procure backstop capacity for deficiencies. The two-slice proposal does not propose to modify the CAISO authority. The CAISO rules allow it to backstop if an LSE fails to procure sufficient RA resources to meet demand and reserve margin requirements. The Demand and Reserve Margin requirements under the two-slice proposal will be set by the gross peak need and net peak need. While the CAISO rules will largely be unimpacted since the CPUC requirements, once updated, can be accommodated with existing Tariff language, there will be implementation needed to add the net peak validation to the CAISO's system RA sufficiency assessments.

Bundled Products

The two-slice proposal simplifies and considers transactability of RA capacity because RA capacity will be procured as a bundled product. The two-slice Framework keeps the existing RA framework and enhances the idea of a standard capacity product that can be easily traded as a commodity. A single MW of NQC from one resource is just as valuable as another MW of NQC from another resource – even if it uses a different technology. The proposal maintains the status quo that RA contracts procure bundled RA with all applicable attributes. Under this proposal, the RA product would now bundle a system net peak attribute into the bundled RA product. It maintains the status quo between the CPUC and the CAISO processes, which also ensures consistency with programs of other LRAs.

Ultimately, capacity is transacted in a highly diversified bilateral market with many buyers and sellers and paid for in terms of $/kW-month. The impact of a resource being available to meet both the system gross peak requirement and system net peak requirement under a bundled RA product will be reflected in the pricing, where there may be a premium in the $/kW-month prices for providing both system net peak attribute and system gross peak attributes in the bundled RA. This is like a local resource with a local RA attribute may receive a premium for its bundled system and local attributes. Therefore, we would expect resources that can provide a relatively higher net peak value to have a premium compared to resources with a relatively lower net peak value.

Hedging component

There were multiple hedging components proposed during the Hedging workshop. Both PG&E and Vistra proposed that any hedging components should be an option within the RA framework – not a requirement. These (and other mechanisms) are compatible with the two-slice proposal. While no specific proposal is essential to the two-slice proposal, these or other hedging mechanisms can be added to the two-slice RA program.

Cost Allocation Mechanism (CAM) and Central Procurement Entity (CPE) Procurement

Currently, the Energy Division provides credits to LSEs for capacity procured on behalf of all customers as part of the Cost Allocation Mechanism process or Central Procurement Entity process. The two-slice proposal does not make any changes to how Energy Division facilitates these processes and Gridwell believes both CAM and local procurement via the CPE are compatible from both a process and market perspective with the two-slice proposal.

SEIA, LSA, and VS Elements Proposal: Resource Counting for Solar and Hybrid Resources, under the SCE 24-hourly slices Proposal

SEIA, LSA, VS, Tom Beach

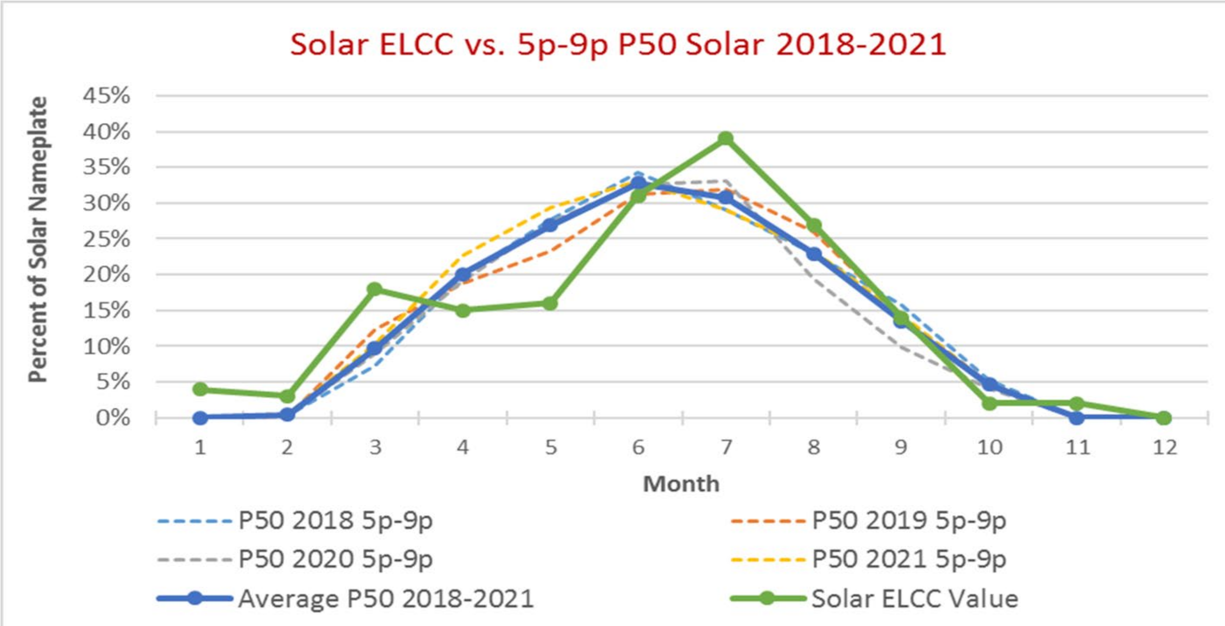
Proposal

Resource Counting for Solar and Hybrid Resources under the SCE 24-hourly slices Proposal

At the November 3, 2021, workshop, three solar parties (the Solar Energy Industries Association [SEIA], the Large-Scale Solar Association [LSA], and Vote Solar [VS]) presented a proposal to use an exceedance methodology for determining the hourly qualifying capacity (QC) values to use for solar and hybrid projects in the SCE 24-hourly slice-of-day proposal. That presentation supported a recommendation to use a P50 (i.e. 50%) exceedance value for solar technologies, including the solar portion of hybrid or co-located solar-plus-storage projects.

SEIA / LSA / VS recommend choosing an exceedance value for solar technologies that results in the resource adequacy (RA) value for solar during net load peak hours closely tracking the average effective load carrying capability (ELCC) of solar. In essence, the choice of an exceedance value for solar is benchmarked to the current ELCC for solar. The ELCC measures a resource's capacity contribution in the hours most important to reliability, which in California today are the net load peak hours. Our presentation showed that the P50 output of the solar resources on the CAISO system during the net load peak hours of 5 p.m. to 9 p.m. reasonably tracks the current RA capacity value of the CAISO solar portfolio using the average ELCC of solar. Here is the figure showing this comparison, using solar output data for the four years 2018-2021.[1]

[1] This use of ELCC to benchmark the choice of the exceedance value also will satisfy P.U. Code Section 399.26(d), which requires the Commission to use the ELCC values for wind and solar "in establishing the contribution of wind and solar energy resources toward meeting the resource adequacy requirements established pursuant to Section 380."



The SEIA / LSA / VS analysis also showed that P50 solar output in off-peak hours (i.e. in hours other than 5pm-9pm) reasonably tracks the CAISO solar output, including on high-demand summer days when reliability is most likely to be in question. Further, there is little difference in solar output during the summer off-peak hours across a wide range of exceedances, from P50 (50% exceedance) to P25 (75% exceedance). The use of P50 will avoid the portfolio issues raised if an exceedance value significantly higher than 50% is used. At high exceedances, such as the 70% exceedance previously used in the RA program, the sum of the 70% exceedances of individual solar or wind projects is less than the 70% exceedance of the entire solar or wind portfolio, necessitating a further portfolio adjustment to the individual RA qualifying capacities (QCs). This complexity is avoided with the use of the P50 value.

It is critically important that the counting rules developed in the RA Reform process recognize the flexibility and adaptability of hybrid resources. The SCE proposal at this stage recognizes that solar plus storage hybrids are more than the sum of their parts and can provide more capacity through internal charging and co-optimization of both resources. The details on how this understanding will be translated into a detailed accreditation process will be further elaborated in this proceeding. A hybrid resource should be responsible for the services that the market clears it to provide. Market rules should encourage owners/operators to develop sophisticated battery state-of-charge management and forecasts of solar production to meet market offer obligations. SEIA / LSA / VS submit that the current "additive" counting rule for hybrid and co-located resources adopted in D. 20-06-031 is a good starting point. Here are the important considerations in developing QC values for both the storage and solar components of a hybrid or co-located resource under a 24-hourly slice-of-day framework:

- **Storage:** determine the MWh of solar energy that can be stored each day, including losses, by two hours before the net load peak. This calculation should recognize that DC-coupled solar-plus-storage units can store energy that otherwise would be lost, or "clipped," in the inverter. The stored energy that can be discharged (after losses) should be counted for RA purposes in any hour, up to the maximum hourly discharge capacity, with the storage capacity across all hourly slices limited by the amount of energy that can be stored on that day. This provides the LSE with flexibility in showing in which slices it will use the capacity from energy in storage.

- **Solar:** use the hybrid project's P50 solar output minus the solar production needed to fill storage by two hours before the net load peak. The amount of solar that can be counted in each hour will depend on (1) whether the hybrid is alternating current (AC)- or direct current (DC)-coupled, (2) the amount of solar needed to fill the onsite storage, (3) the LSE's choice for the hours in which to fill storage, and (4) the size of the solar array relative to the capacities of the inverter(s) and the common point of interconnection. DC-coupled hybrids will allow solar output that would otherwise be clipped in the inverter to be stored and used in a later hour, raising the amount of solar output that can be used during peak hours in comparison to AC-coupled systems.

The sum of the storage and solar QCs in any hour should not exceed the deliverable capacity at the hybrid resource's point of interconnection with the CAISO grid.

CalWEA Elements Proposal: QC Counting for Wind and Solar Resources

CalWEA: Nancy Rader

Effective Net Load Reduction (ENLR) Qualifying Capacity Counting Proposal for Wind and Solar Resources

CalWEA's proposed Effective Net-Load Reduction (ENLR) methodology calculates the Qualifying Capacity (QC) of wind and solar resources based on the correlation between the historical output of wind and solar (variable energy resources, or VERs) and actual system load. Capturing this correlation better represents the impact of VERs on overall grid reliability, similar to the ELCC method which counts VERs' capacity only if the resources actually help reduce the grid's capacity needs.

CalWEA is recommending ENLR for determining QC values for each slice and month under the SCE/PG&E 24-slice per month approach. For Gridwell's two-slice approach, the ELCC methodology is appropriate for determining monthly QC values of all resources. However, the ENLR method could be used by the CAISO to calculate the QC of VERs for compliance monitoring purposes for the gross peak and net peak periods.

Methodology Description

The ENLR methodology calculates a simple average of historical hourly VER output during those hours of the year when load is higher than a defined threshold level. VERs' QC values could be calculated as granularly as desired and as is practical (e.g., by zone, state or region, by sub-technology, and/or specific project).

The calculation would rely on CAISO's OASIS data from the previous three to five historical production years, with three years requiring less computational work and five years capturing more annual variation. For simplicity, this proposal summary will assume the use of three years' historical data.

A threshold load level must be selected to focus on the hours that are evaluated at or above a particular level of load. For example, a 50% threshold load level would average VERs' production only for the hours during which load is at 50% of maximum load or higher. (The maximum load during the entire historical period being evaluated would be used.) Interestingly, as is shown in the example results below, the results are remarkably stable between 50% and 80% of load. This stability in results, for both wind and solar resources, further supports the use of this methodology for both resources. Given that consistency in results, and to provide further assurance that variable energy resources will be available, CalWEA proposes a 70% threshold load level for both wind and solar.

Example Results

CalWEA used CAISO's OASIS data from 2019-2021 to generate ELNR values for the 4-p.m. and 8-p.m. hours in August to generate the following results as an example. (CalWEA has offered its spreadsheet to parties upon request.) We show results for various possible threshold load levels that could be used, as discussed above.

ENLR-Based QC for 4 p.m. August Time Slice Under Various Load Threshold Levels

	Possible Threshold Load Levels (% of maximum load)			
	50%	**60%**	**70%**	**80%**
Solar QC	70.1%	70.2%	69.1%	67.1%
Wind QC	26.6%	26.6%	28.0%	26.3%

ENLR-Based QC for 8 p.m. August Time Slice Under Various Load Threshold Levels

	Possible Threshold Load Levels (% of maximum load)			
	50%	**60%**	**70%**	**80%**
Solar QC	2.2%	2.2%	2.3%	2.1%
Wind QC	44.1%	44.1%	44.3%	43.2%

Comparison to Other Approaches and Need for Statutory Change

Exceedance: The ENLR method is superior to the exceedance method, which establishes no relationship between historical VER production and capacity-needs reduction at the time of actual system need. By contrast, the ENLR method would consistently reflect the historical correlation between actual load and wind and solar production.

Furthermore, exceedance-based QC numbers could be extremely volatile under a small sample size and for largely varying numbers. CalWEA provided a simple example, in its January 5, 2022, presentation to the workgroup, illustrating how the exceedance approach produces erratic results when small changes are made to a limited dataset (which we will have if a slice is just one hour during a month).

ELCC: Calculating ELCCs, in theory, produces the most accurate results for the QC values of various resources. Using ELCC is appropriate under Gridwell's approach, which would calculate ELCCs monthly. However, calculating ELCCs on a more granular level, such as for 24 hourly slices per month, would have to be done with a small sample of data and would be too resource-intensive to conduct. In addition, conducting ELCC calculations is complex, and different variations can lead to different results. The ENLR method, by contrast, is simple and data-driven once the threshold load level is agreed upon (and produces relatively stable results for different load threshold levels).

The basic principle of the ELCC method is to value generation only when it reduces load (i.e., reduces the need for capacity); the ENLR approach is similar because it also values production when load is high (capacity is needed).

Because the technical definition of ELCC (for a particular generator) is "the amount by which the system's loads can increase when the generator is added to the system while maintaining the same system reliability,"[1] the ENLR approach does not meet this definition. Therefore, the provision of state law[2] that requires the Commission to use the ELCC method to value wind and solar resources in the RA program (which was sponsored by CalWEA in 2011) should be amended. Assuming sufficiently broad consensus for the ENLR method, CalWEA anticipates that it will be readily possible to strike that statutory provision through legislative action.

[1] https://www.nrel.gov/docs/fy15osti/63038.pdf
[2] P.U. Code Sec. 399.26(d).

CEC Elements Proposal: Load Forecasting

CEC, Lynn Marshall

CEC Staff Load Forecast Proposal

At the December 2, 2021, workshop, CEC staff discussed how the RA load forecast process could work under a slice-of-day structure. Under a two-slice framework, impacts on the RA forecast process are minimal, so most of the discussion focused on the 24-hour slice approach.

Reference forecast

The reference forecast for CPUC-jurisdictional RA forecasts begins with the forecasted monthly transmission access charge (TAC) area coincident peaks from the Integrated Energy Policy Report (IEPR) mid-demand, mid-additional achievable energy efficiency scenario demand forecast. Beginning with RA 2023, the forecast will also include fuel substitution from the mid-additional achievable fuel substitution scenario. The SCE and PG&E TAC-area monthly coincident peak forecasts are then disaggregated to CPUC and non-CPUC jurisdictional load using the CEC service area annual forecast, and LSE forecasts and historic hourly loads. This forecast serves as the control total for the aggregate LSE forecasts.

Since the IEPR forecast includes an 8760 forecast for each TAC area and year, extracting the monthly peak day or worst day load profile is straightforward. For the jurisdictional disaggregation, a method would be needed to develop hourly IOU distribution service area forecasts. CEC staff is planning to develop data for and run the CEC hourly load model (HLM) model at the IOU service area level, but results will have to be evaluated. The HLM applies econometric methods to estimate hourly load ratios given temperature and day-type effects. Additional adjustments are made for incremental load impacts from behind-the-meter solar and storage, electric vehicles, climate change, and other load modifiers.

Coincidence Adjustments

Each year, LSEs submit their previous years' hourly recorded loads, and the load of new customers expected to be served in the forthcoming year if applicable. CEC conducts a statistical analysis of each LSE's hourly loads relative to the CAISO monthly system peak to estimate a coincidence adjustment to apply to monthly peak demand. Coincidence adjustments are typically based on the median coincidence factor for the top 3 to 5 system peak days. A similar analysis can be developed to adjust multiple hours or slices.

LSE Forecast Submittals

Currently LSEs submit forecasts of monthly noncoincident peak demand and monthly energy by TAC area, and LSEs may include as part of their forecast the impacts of load modifiers such as solar PV, electric vehicles, or behind-the-meter (BTM) storage.

Under any slice-of-day framework, LSEs would still need to submit a forecast that includes their monthly noncoincident peak demand so that the CEC, not the LSE, is accounting for load diversity. Noncoincident peak forecasts are also the basis for allocating CAISO congestion revenue rights (CRRs). Under the 24-hour slice construct, LSEs should submit at a minimum a 24-hour forecast of the LSE's own peak day, although an 8760 forecast would provide the greatest visibility on total energy usage, effects of load modifiers, and other forecast assumptions. However, this may be challenging for some LSEs. A 24-hour submittal would be less burdensome; CEC staff would need to rely more on analysis of recorded loads for evaluating forecasts. Forecasts of load modifier assumptions, when applicable, would also need to be submitted on a 24- or 8760-hourly basis.

LSE-Specific Forecast Adjustments

As part of the current forecast review process, CEC sets a benchmark for each LSE based on recorded loads, load migration activity, LSE forecast submittals, and weather-adjusted loads to guide its evaluation. LSE forecasts may be adjusted based on this analysis. CEC would likely have to expand this benchmarking analysis to all slices. CEC plans to explore applying its hourly forecasting methodologies at the LSE level for those LSEs that are weather-sensitive. Other LSEs (primarily ESPs) typically forecast based on recent load profiles of current and expected customers, so recorded loads and load migration data would suffice for evaluation.

Pro-Rata Adjustment

The final step in the forecast development process is to adjust all forecasts so that the sum is within 1% of the reference forecast. This could easily be applied to all hours, but the percentage adjustment may be larger in nonpeak hours than is typical for the peak period due to differences in CEC versus LSE load data. CEC calibrates its forecasts to CAISO system load; LSEs use settlement loads, with forecasts adjusted for transmission losses.

Schedule and Products

The current schedule for forecast determinations may need to be reevaluated. The CAISO would still require annual peak load ratio shares by July 1 so CEC must have the adjusted forecasts for at least the peak month of the year. If a multi-slice framework is adopted for 2024, a dry-run forecast process in 2022, in which LSEs submit hourly forecasts for 2023, would allow CEC to test new methods and identify technical and resource challenges.

CAISO Elements Proposal: UCAP

CAISO, Bridget Sparks

I. Resource Counting (Unforced Capacity Evaluation)

For any Resource Adequacy (RA) framework the CPUC adopts, the CPUC should ensure LSEs show sufficient resources to meet demand plus the planning reserve margin (PRM) across all hours of the day, and that the PRM and counting rules work in tandem to enable reliable system operation. To effectuate this goal, the California Independent System Operator (CAISO) recommends the CPUC examine counting rules that both accurately reflect availability and use limitations, and provide a strong incentive for resources to be available for dispatch, particularly in critical hours.

The CAISO has been evaluating the Unforced Capacity Evaluation (UCAP) resource counting methodology as a viable RA capacity counting approach for dispatchable thermal resources, which can work in conjunction with other counting methodologies (*e.g.*, for demand response, wind, solar, hydro, etc.) that appropriately incorporate availability and use limitations, while providing incentives to be available. UCAP is a capacity valuation methodology that is widely accepted and applied broadly in the industry, and it provides buyers with important insight about a resource's recent reliability and availability. The use of UCAP as a counting methodology also has the potential benefit of allowing the CPUC to account for outages on a more granular basis rather than applying an assumed fleet-wide average forced outage rate in its PRM for these resource types.

A UCAP methodology could be compatible with either the SCE/PG&E hourly-slice proposal or the Gridwell two-slice proposal. The CAISO recommends the CPUC examine how a UCAP methodology could fit into a comprehensive counting proposal and PRM analysis in its upcoming decision as a complement to these slice-of-day RA reforms.

II. Background

In 2006, at the onset of the RA program in California, natural gas, nuclear, and hydroelectric resources were the predominant generation technology types. Although some of these resources were subject to use limitations due to environmental regulations, start limits, or air permits, they were generally available to produce energy when needed given that they all had fairly dependable fuel sources. However, as the fleet transitions to achieve the objectives of SB 100, the CAISO must rely on a much different resource portfolio that is more variable and use-limited to reliably operate the grid. A vastly more robust capacity assessment framework is needed to ensure future reliability as system conditions change rapidly, resources retire, and there is increased competition for limited capacity in the West.

The slice-of-day proposals considered by the working group are important first steps in reforming California's RA program to reflect this grid evolution. However, each of these proposals has been light on details about certain aspects of resource counting methodology. From a grid reliability perspective, it is essential to understand how these RA reforms impact the counting of resources' contribution to reliability, how this interacts with the PRM, and how to account for saturation effects, use limitations, and the diversity benefits, or lack thereof, that different resource types provide.

For instance, the CAISO is observing a growth in the number of registered use limitations even within the natural gas fleet. In 2021, 25-28% of the natural gas fleet was registered as use-limited.[1] The CAISO believes it is prudent to factor these use limitations into the resource counting framework for thermal resources, and to question whether continuing to model thermal and energy storage resources as generally available 24x7 with only minor use limitations is still a prudent assumption going forward.

When the RA program was originally developed, the estimated forced outage rate for RA resources was approximately 4% to 6% of the 15% planning reserve margin. However, forced outage rates can exceed what is accounted for in the PRM, especially during critical summer months. Table 1 provides the monthly average hourly forced outage rate for the gas fleet for November 2018 through October 2021. This table shows that the average hourly outage rate has increased from 2019 to 2021 and can be double the 4-6% currently assumed in the PRM in some months, even up to 12.7% in June 2021

Table 1: Average Hourly Forced Outage rate of the Natural Gas Fleet, November 2018-October 2021

	2018	2019	2020	2021	3-year avg.
January		5.2	6.0	5.5	5.6
February		6.9	4.5	6.3	5.9
March		4.7	5.8	5.9	5.5
April		7.4	8.3	10.0	8.6
May		7.0	7.4	8.6	7.7
June		8.1	8.0	12.7	9.6
July		5.6	6.7	8.9	7.1
August		6.3	7.9	7.6	7.3
September		5.9	10.3	6.9	7.7
October		5.3	8.9	7.2	7.2
November	6.2	7.4	5.6		6.4
December	7.0	8.5	8.0		7.8
Yearly Avg.	6.6	6.5	7.3	8.0	7.2

Under the CAISO's current market structure, RA resources are subject to substitution rules after an outage occurs and to the Resource Adequacy Availability Incentive Mechanism (RAAIM) during the operational timeframe. Both these mechanisms ensure the capacity that is procured is available in the operational timeframe. UCAP provides a mechanism for appropriately qualifying the capacity that is

[1] For full data on registered use limited thermal resources see slide 5 in https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-9-ucap-proposal_caiso.pdf

procured for RA by taking into consideration its past performance. Therefore, the CAISO recommends the CPUC closely examine capacity qualification processes and consider allowing for resource availability to be incorporated upfront in the RA procurement and planning process timeline. Recognizing a unit's contribution to reliability based on historical forced outage rates allows the market to value a specific resource's contribution to the overall system (relative to that resource's peers) by accounting for important differences in forced outage rates.

III. Potential UCAP Methodology

In the following section, the CAISO discusses particular elements of the UCAP design that the CPUC can consider if the CPUC adopts UCAP as a part of its resource capacity counting reforms.

An unforced capacity evaluation methodology uses a derating or availability factor that is informed by certain outage types that impact a resource's unplanned availability, discounting its capacity value for RA valuation purposes. The primary input needed to calculate a resource's UCAP value is accurate forced outage and derate data. A seasonal availability factor counting methodology the CAISO has recommended could be based on a resource's forced and urgent outages and derates during the hours of tightest supply conditions.[2]

The CPUC could consider calculating seasonal availability factors for UCAP determination purposes utilizing two seasons for this availability factor determination, on-peak (summer) and off-peak (winter). UCAP values would not be affected by CAISO-approved planned or opportunity outages

UCAP Methodology: Outage Definition

The following classifies the type of outages taken by generating resources:

Forced Outage – Facility/equipment that is removed from service in real-time with limited or no notice

Urgent Outage – Facility/equipment that is known to be operable yet carries an increased risk of a forced outage occurring. Facility/equipment remains in service until personnel, equipment and/or system conditions allow the outage to occur.

Planned Outage – Facility/equipment outage with enough advance notice to meet short-range submittal requirements.[3]

Opportunity Outage – A Facility/equipment outage that can be taken due to a change in system conditions, weather, or availability of field personnel. Opportunity outages do not meet the short-range window requirements.

For the purposes of UCAP, CAISO recommends the CPUC's potential design could incorporate forced and urgent outages in a resource's forced outage rate calculation, but not include approved planned and

[2] Outage and derate data are the key information necessary to calculate the expected value (in terms of MW) of a capacity resource's unforced capacity. In Reliability Coordinator Procedure RC0630, the CAISO defines outage types, their priorities, and the study windows with timelines for outage submission. RC Procedure RC0630, p. 13-15 can be found at: http://www.caiso.com/Documents/RC0630.pdf.

[3] Outage management BPM Section 7.2 describes the short-range outage submittal requirements for planned outages for the CAISO BAA.

opportunity outages. A UCAP design could also choose to exempt transmission-induced outages and outages caused by natural disasters, and other force majeure events.[4] A more complete discussion and comparison of what outage types are incorporated by other ISOs and RTOs into their UCAP calculations and what types of outages fall under forced and urgent outages can be found in Section V, Appendix A.

A. UCAP Methodology: Seasonal Availability Factor

If the CPUC adopts a UCAP methodology, the CAISO would work closely with the CPUC to help fully operationalize the methodology. This could require that the CAISO create a new two-step process to generate values accurately reflecting a resource's capacity value within the existing net qualifying capacity (NQC) process. The first step would be to conduct a resource deliverability assessment to adjust the resource's capacity value for deliverability on-peak to determine the deliverable qualifying capacity (DQC).[5] The second step would consider the resource's forced and urgent outages and derates to calculate seasonal availability factors to determine the UCAP value of the resource. This would result in applying the weighted seasonal average availability factors (described in detail below) to the resource's DQC, which would result in the final NQC of the resource. The resource's must-offer obligation (MOO) would be set at its DQC.

The CAISO recommends the CPUC evaluate a seasonal approach to UCAP because outages of thermal units, and to some degree storage resources, are correlated with weather patterns. Monthly UCAP values may not be as predictive as seasonal values would be. For instance, May or June may experience heat waves in some years and relatively mild weather in others. Looking at outages over a longer period can better identify a resource's performance under different weather patterns no matter when in the season they might occur. Additionally, because California is likely to retain monthly RA requirements, an annual UCAP could lead to oversampling of winter months simply because the starting RA requirements would be lower than in summer months. Although a seasonal availability factor methodology is flexible enough to be applied on a monthly or annual basis, a seasonal approach would strike a better balance and would lead to more robust UCAP values.

To establish the proposed Peak (May-October) and Off-Peak (November- April) Month Seasonal Average Availability Factors (SAAFs) used to calculate the seasonal UCAP values for each resource, the CPUC could establish a process that includes the following steps and underlying calculations. UCAP could be designed to calculate hourly availability factors for each resource during the tightest RA supply cushion hours in each season. The RA supply cushion is a measure of real-time system RA risk in critical periods during the year when the system is most stressed and particularly dependent on all RA resources being available to the CAISO. A large RA supply cushion indicates less real-time system RA risk because more energy supply remains available to the CAISO to respond to unplanned events. A low RA supply cushion indicates the system has fewer assets available to the CAISO to respond to unexpected outages or load increases, leaving the system at greater reliability risk. Evaluating the historical performance of a

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[4] Transmission-induced outages could be used if a transmission outage on equipment not owned by the resource curtails a generator's output. In this case, the generator outages normally would not count against a resource's UCAP. However, if a resource disconnects from the grid due to outages on equipment owned by the resource, those outages could be included in the UCAP calculation.

[5] Some stakeholders have questioned how deliverability studies may need to evolve under a slice-of-day framework. The CAISO would need to consider any modifications to the deliverability study in a stakeholder process. This proposal assumes the status quo applies, but UCAP would be compatible with further changes to the deliverability study process.

capacity asset during a subset of tight RA supply cushion hours captures the correlation of the asset's availability and capability with all other system factors that drive the tightest supply cushion hours. This technique provides insight into how the asset is likely to perform in the future under similar conditions when capacity is tight and needed.

When looking at the distributions of the seasonal RA supply cushion, there is no obvious cut-off point in which to determine how many hours to evaluate (see Figure 1 below, and Section V, Appendix A for underlying data). Evaluating the top 20% of tightest RA supply cushion hours would provide a robust sample that covers the majority of days, and concentrates UCAP assessment hours during the peak and net load peak (see Table 2 for comparison of different sampling frames, and the Appendices for underlying data). However, different sampling frames can be considered. The advantages to this approach are that 1) it appropriately penalizes resources for being unavailable during tight system conditions; 2) unlike RAAIM, UCAP assessment hours can occur at any point during the operating day and thus this approach provides better incentives to be available when the grid needs capacity the most; 3) it allows the CAISO to leverage existing data through its outage management system, rather than requiring new data reporting from resources; 4) it is simpler than the Equivalent Forced Outage Rate Demand (EFORd) methodology or weighting all hours, while still providing an accurate snapshot of a resource's true available capacity to the grid; and 5) it utilizes a percentage of hours rather than a specific number of hours, which provides consistency across seasons and years, and ensures that outages are weighted evenly across the two seasons.

The RA supply cushion is defined as:

$$\begin{aligned}&\boldsymbol{Resource\ Adequuacy\ (RA)\ Supply\ Cushion}\\&\quad= \boldsymbol{Daily\ Shown\ RA(excluding\ wind\ and\ solar) - Planned\ Outage\ Impacts}\\&\quad\boldsymbol{- Forced\ Outage\ Impacts - Urgent\ Outage\ Impacts}\\&\quad\boldsymbol{- Opportunity\ Outages - Net\ Load - Contingency\ Reserves}\end{aligned}$$

The RA supply cushion thus represents how much shown RA remains after serving net load, meeting contingency reserves, and accounting for all outages. We propose to exclude wind and solar resources from the shown RA because their capacity value is much lower than their actual production in real-time. Also looking at net load rather than gross load, this approach can further account for the actual production of these variable resources. Net load values are taken from the 5-minute market. The average of the RA supply cushion of all 12 five-minute intervals is taken to convert the RA supply cushion into an hourly measure.

Figure 1: Percentile Distribution of RA Supply Cushion by Season

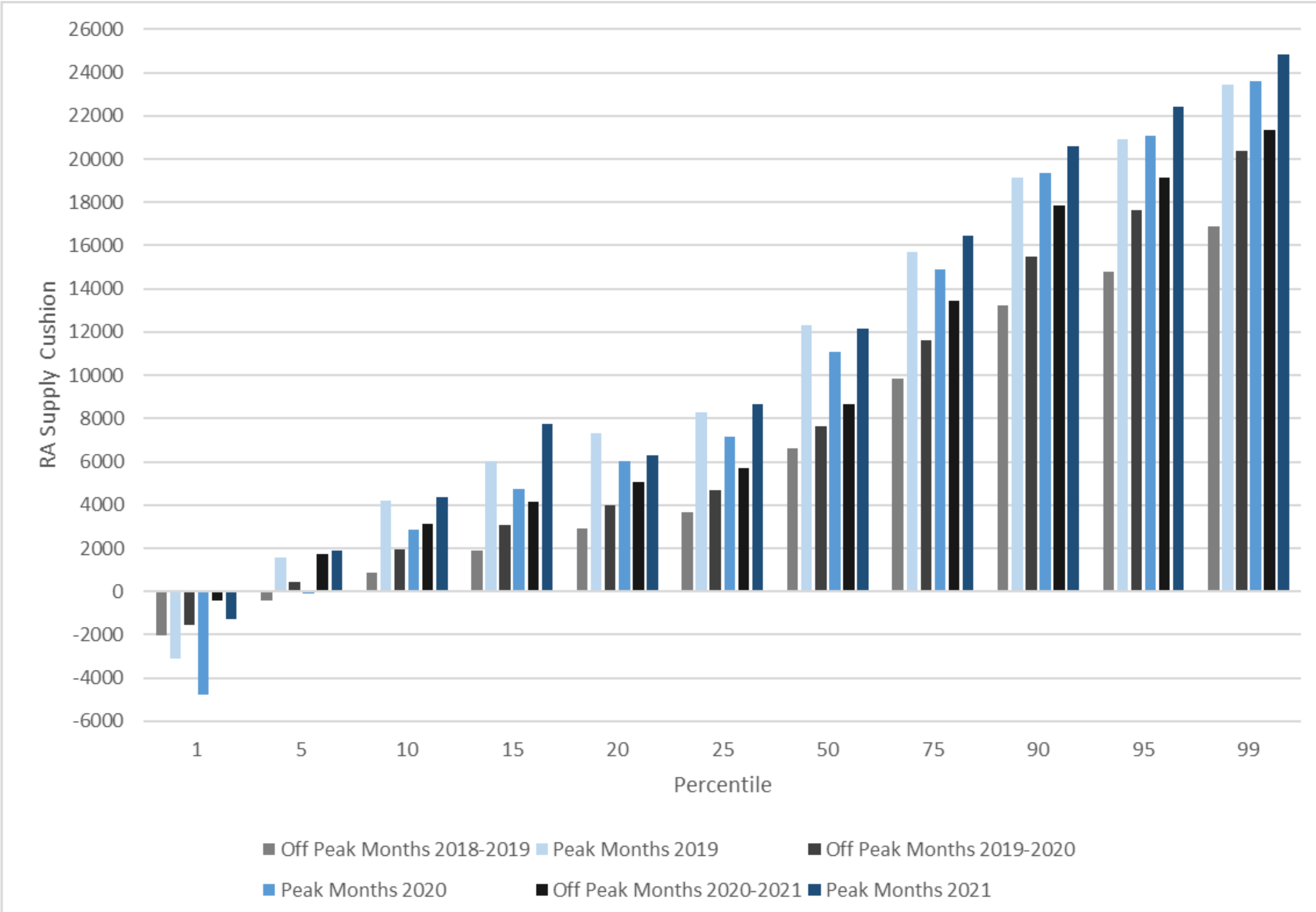

Table 2: Comparison of three suggested assessment windows for UCAP by assessment hours (AH)[6]

	Top 20%	Top 15%	Top 10%
Number of UCAP AH during Peak Months	883	662	442
Number of UCAP AH during Off Peak Months	874/869	651/655	434/437
% of UCAP AH between HE 17-22	74.5%	82.3%	89.1%
Median Number of UCAP AH during Peak Months	4.6	3.3	1.7
Median Number of UCAP AH during Off Peak Months	4.6	3.7	2
% of Day covered by sample	84%	73%	58%

Once the CPUC determines which hours are UCAP assessment hours (AH), the CAISO would calculate an hourly unavailability factor using forced and urgent outages and derates for each hour studied, divided by the resource's maximum capability (Pmax) for each of the top % of tightest RA supply cushion hours in the summer season, May-October (on-peak), and the top % of tightest resource adequacy supply cushion hours in the winter season, November-April (off-peak), for the past three years. To determine each resource's Hourly Unavailability Factor (HUF) for each of the tightest supply cushion hours per season the CAISO proposes the following approach:

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

The calculation could utilize the average of the Hourly Unavailability Factor (HUF) for each season for each of the past three years to create a Seasonal Average Availability Factor (SAAF) for each resource:

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

To ensure the UCAP provides more up-to-date performance information, the CPUC could place greater weight on the most recent year's performance and less weight on prior periods in determining a resource's UCAP values. This can drive the right incentives if a resource invests in maintenance upgrades as the most recent years are more heavily weighted to determine the plant's UCAP. For example, the CPUC could place the following percentage weights on 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 for the second year, and 20% for the third year. The process could then

[6] Median number of UCAP Assessment Hours (AH) measures on average how many hours are included in the same each day. A higher median number of UCAP AH indicates that there will be more observations per day in the sample. % Of days covered by the sample indicates how much coverage of the possible days are included in the sample. A higher percentage indicates that the sample covers a larger portion of possible observed days. Therefore, resources have more of an incentive to keep their outage rates low since the majority of days will affect their future UCAP value.

apply this proposed weighting approach to each of the three previous annual periods (for each on-peak and off-peak season) to create Weighted Seasonal Average Availability Factors (WSAAF) as follows:

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

Once the Weighted Seasonal Average Availability Factors (WSAAF) are established for each season of each of prior three years, the calculation could sum the factors and apply them to each resource's DQC to determine the resource's seasonal UCAP ratings that will represent its new NQC value as follows:

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

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

Therefore, a resource's NQC/UCAP value would never be greater than its deliverable capacity. The resulting NQC values could be used in contracting and incorporated into the RA showings process at the CPUC.

Table 3 provides an illustrative example of the UCAP calculation steps for all gas-fired thermal resources. It also illustrates how UCAP provides a pool of excess capacity that can be used in the operational timeframe (*i.e.*, real-time) to cover forced outages in the thermal fleet. For example, assuming thermal resources were 100% deliverable, the collective MOO would be 30,808 MW. But because the fleet is only valued at 28,144 MW in Peak Months, the system would have a cushion of 2,664 MW to cover any outages that may occur in real-time. Therefore, if the CPUC adopted a UCAP counting framework for thermal and storage resources, a portion of the forced outage rate could be removed from the PRM, since it would be accounted for in advance through the resource counting methodology.

Table 3: UCAP calculation steps

Year	Peak Months SAAF	Annual Weight	Weighted SAAF (Summer / On-Peak)
3	0.925	20%	0.416
2	0.908	35%	0.318
1	0.899	45%	0.180
		Total = 100%	0.914
Year	**Off Peak SAAF**	**Annual Weight**	**Weighted SAAF (Winter / Off-Peak)**
3	0.933	20%	0.420
2	0.933	35%	0.327
1	0.9331	45%	0.186
		Total = 100%	0.933

Natural gas fleet WSAAF (Peak Months)	Natural gas fleet WSAAF (Off Peak Months)	Natural Gas Fleet	On-Peak NQC	Off-Peak NQC
0.914	0.933	30,808 MWs	28,144.42 MWs	28,737.38 MWs

Table 4 provides illustrative WSAAF values for seven different illustrative resources of different technology types for each of the different sampling frames. Table 4 also provides the class average for all gas-fired thermal fuel type resources. This chart shows how UCAP can provide more transparent signals about the resource's contribution to reliability.

Table 4: Example Resources WSAAF values by different sample of UCAP Assessment Hours

Resource	Top 20%		Top 15%		Top 10%		Top 5%		Top 1%	
Season	Off Peak	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak	Peak	Off Peak	Peak
Combined Cycle 1	0.985	0.975	0.985	0.975	0.984	0.977	0.987	0.975	0.976	1.00
Combined Cycle 2	0.899	0.867	0.896	0.860	0.886	0.851	0.869	0.827	0.856	0.768
Steamer 1	0.859	0.794	0.866	0.790	0.873	0.784	0.876	0.773	0.882	0.766
Steamer 2	0.986	0.926	0.985	0.924	0.983	0.918	0.978	0.908	0.980	0.915
CT 1	0.956	0.927	0.955	0.938	0.949	0.938	0.945	0.928	0.949	0.912
Peaker 1	0.883	0.940	0.890	0.937	0.900	0.940	0.912	0.931	0.949	0.867
Peaker 2	0.953	0.973	0.959	0.740	0.943	0.978	0.945	0.980	0.970	0.991
Total Gas Fleet	0.933	0.914	0.933	0.918	0.933	0.910	0.933	0.904	0.930	0.890
Assessment Hours per season	874	883	651	662	434	441	217	221	44	45

B. UCAP Methodology: New Resources

For resources without three years of historic outage data, there are two possible approaches to calculate their UCAP value. Option 1 would apply the class average UCAP value based on the size and technology type of the resource. As new resources begin to build an operational history, the CAISO will blend their actual performance data with class average data, beginning with the class average and maintaining constant weights over time. Under Option 2, resources would begin with their DQC the first year, and heavier weights would be placed on actual performance in the initial years. Under this approach, resources will start with a higher capacity value, but actual performance will have a more significant impact early on.

Since energy storage appears to represent a large share of new resources, if the CPUC decided to subject energy storage to UCAP, the CPUC would need to establish methodologies for new resources particularly as energy storage is an evolving technology with different battery chemistries and different non-chemical storage technologies emerging. The CAISO proposes the CPUC consider the following weights in its process:

- Year 0 (i.e., before operational data is available): DQC
- Year 1 70% Year 0 SAAF; 30% DQC
- Year 2 55% Year 1 SAAF; 45% Year 0 SAAF
- Year 3 45% Year 2 SAAF; 35% Year 1 SAAF; 20% Year 0 SAAF

Such an approach could balance the concern that Option 2 would overvalue the resource's UCAP value by not sufficiently derating it for its availability (by rolling off the DQC value more quickly). It would also provide an incentive to keep outage rates low to maintain high UCAP/NQC values. This approach also eases implementation by allowing new technology types to be integrated faster into the CAISO and decreases the arbitrariness of defining the class for these new technology types.

C. UCAP Compatibility with SCE/PG&E 24-Hourly Slice Framework

UCAP is compatible with the slice-of-day framework, and through integration with the 24-hourly slice proposal would provide for more robust counting of thermal resources. While the 24-hourly slice proposal retains the monthly construct, it would be prudent to calculate UCAP values on a seasonal basis. Because UCAP relies on historic data, and many outages (such as thermal derates) are driven by ambient temperatures, having a sampling frame that covers multiple months would ensure that UCAP values reflect resources' average availability. While later summer months (August-October) are trending warmer, the early summer months have more volatility (for example May 2021 had more 100 + degree days in parts of California than is typical), and so a seasonal approach to UCAP could provide more accurate predictions of resources' availability in peak months than would be derived if averaging forced outages monthly. Thus, thermal resources would apply the seasonal UCAP value in each of the relevant months covered by the season. In other words, units would use the same Peak Months UCAP value from May through October, and the same Off-Peak Months UCAP value from November through April.

For the majority of thermal resources, whether or not they were registered as use-limited, they would use the same UCAP value in each of the hourly slices an LSE planned to use the resource to meet its requirements. For 24x7 dispatchable thermal resources, an LSE could count up to the UCAP value of the resource in each hour. For storage resources, an LSE could count the storage resource up to the UCAP value of the resource in each hour it planned to use the resource to meet its requirement capped at the duration of the resource (*e.g.*, a 4-hour battery could only be counted in 4 slices). The CAISO believes the UCAP methodology could reasonably account for a thermal resource's use limitations that are dependent on the resource's use in prior periods (*e.g.*, annual use limitations, maximum run hours, etc.). Where it is less effective is for use limitations that occur consistently and do not depend on the resource's use in prior periods (*e.g.*, units that have noise or environmental restrictions during set time periods), especially if they fall outside of peak load hours. It may be more prudent to capture these use limitations in the energy profile of the resource and set the resource's value to zero in the relevant hours in the LSE's compliance showings. Outage types that are captured through the energy profile could be exempted from the UCAP calculation of the resource to avoid double penalties.

UCAP Compatibility with the Gridwell 2-Slice Framework

To the extent that thermal resource counting values are not derived using an ELCC methodology, UCAP could be used to determine the peak and net load peak capacity values of these resources through the design of a seasonal availability factor methodology. UCAP can also pick up the same correlations among loads, weather, and interactions with the entire resource portfolio that the ELCC methodology does by measuring a resource's forced outage during conditions when the system was at times of greatest system RA risk.

IV. Other issues to be considered

While the CAISO has offered a potential UCAP design framework the CPUC can consider in this proceeding, the CPUC would also need to solicit additional feedback in two areas that would need to be resolved before adopting UCAP. The first is the selection of the percent of top RA supply cushion to identify the number of UCAP assessment hours. The second is how much of the forced outage rate can be taken out of the PRM.

The CPUC can examine different percentiles of tightest RA supply cushion hours and should solicit input from participants that may have data/analysis to support different percentile cut-offs. See Section V-VIII for the Appendices for more information on the different sampling frames and their impact on the number and distribution of hours selected.

One of the key benefits of moving to a UCAP resource counting framework is the ability to take a portion of the forced outage rate out of the PRM since it is already accounted for in the upfront capacity values of resources. However, since UCAP likely would only be applicable to thermal resources, to the extent that exceedance or ELCC does not capture the outage rates of other resource types, some portion of the forced outage rates should be included in the PRM.

V. Appendix A: Outage Exemptions

There are several approaches other RTO/ISO's take for determining which outages to include in the outage rate of the resource for the UCAP calculation. Midcontinent Independent System Operator (MISO) includes forced outages and derates, but excludes outages caused by events deemed "outside of management control" including transmission outages, natural disasters, and fuel quality problems.[7] The New York Independent System Operator (NYISO) exempts outages caused by equipment failure that involves equipment located beyond the generator, including the step-up transformer. The exemption does not apply to other outages that might be classified as outside management control.[8] The PJM Interconnection (PJM) also includes forced outages and derates, and appears to exclude only outages due to natural disasters that PJM determines have a low probability of recurrence.[9] For the 2018/2019 Delivery Year and all subsequent Delivery Years, PJM considers outages deemed to be outside of plant management control within NERC guidelines in determining the forced outage rate.[10] Alberta Electric System Operator (AESO), which uses a similar availability factor method as considered by the CAISO, and includes all historical derates, forced outages, planned outages, and force majeure outages in availability factors with the ability for the asset owner to dispute the UCAP value calculated by AESO in certain circumstances.[11]

Table 1 below shows the existing nature-of-work categories for forced outages. The CAISO recommends that for each outage, the scheduling coordinator for the resource would submit the outage type (forced, urgent, planned, or opportunity) and the outage's nature of work. The nature-of-work designation and outage type could be used to determine whether or not an outage will be incorporated in the UCAP calculation.

[7] BPM 011 – Resource Adequacy, MISO: https://www.misoenergy.org/legal/business-practice-manuals/#:~:text=BPM%20011%20addresses%20MISO's%20and,have%20an%20appropriate%20reserve%20margin.

[8] Installed Capacity Manual, NYISO: https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338

[9] Manual 22, PJM: https://www.pjm.com/-/media/documents/manuals/m22.ashx

[10] PJM Reliability Assurance Agreement, Schedule 5, Section B.

[11] 3 Calculation of Unforced Capacity (UCAP), AESO: https://www.aeso.ca/assets/Uploads/CMD-2.0-Section-3-Calculation-of-UCAP.pdf

Table 1: Nature of Work Categories

Nature of Work	Impacts UCAP?
Ambient Due to Temperature	Yes
Ambient Not Due to Temperature	Yes
Ambient due to Fuel insufficiency	Yes
AVR/Exciter	Yes
Environmental Restrictions	Yes
Short term use limit reached	Yes
Annual use limit reached	Yes
Monthly use limit reached	Yes
Other use limit reached	Yes
ICCP	Yes
Metering/Telemetry	Yes
New Generator Test Energy	No
Plant Maintenance	Yes
Plant Trouble	Yes
Power System Stabilizer (PSS)	Yes
Ramp Rate	Yes
RTU/RIG	Yes
Transitional Limitation	Yes
Transmission Induced	No
Technical Limitations not in Market Model	No
Unit Supporting Startup	Yes
Unit Testing	No – if CAISO initiated Yes- if other test
Off Peak Opportunity	N/A – included as separate outage type under RC definitions
Short Notice Opportunity	N/A – included as separate outage type under RC definitions
RIMS testing	Yes
RIMS Outage	Yes

VI. Appendix B: Distribution of RA Supply Cushion Hours (in MW)

In response to stakeholder requests for further data analysis, the CAISO calculated the hourly RA supply cushion values for November 2019-October 2021. The table below provides the percentile distribution of the supply cushion for peak and off-peak months. A negative value indicates that in that hour there was not enough shown RA to serve net load, and to cover contingency reserves and planned and forced outages. Although there was likely economic energy to cover the capacity shortfalls in these hours, the goal of the RA program is to ensure that the CAISO has enough capacity to meet demand. Thus, by accounting for a resource's forced outage rates from the beginning, LSEs will be able to procure sufficient, reliable capacity to cover real-time operational needs.

Percentile	Off Peak Months 2018-2019	Peak Months 2019	Off Peak Months 2019-2020	Peak Months 2020	Peak Months 2021	Off Peak Months 2020-2021
1	-2020	-3089	-1559	-4791	-1289	-416
5	-429	1573	457	-110	1908	1739
10	897	4218	1954	2874	4358	3147
15	1918	6022	3051	4716	7748	4175
20	2904	7295	4010	6051	6273	5047
25	3649	8313	4700	7171	8689	5687
50	6615	12302	7658	11080	12180	8641
75	9835	15720	11614	14877	16462	13425
90	13249	19133	15463	19331	20615	17833
95	14786	20920	17637	21068	22440	19123
99	16887	23459	20384	23580	24818	21336

VII. Appendix C: UCAP Assessment Hour Distributions by Sampling Frame

Top 20% HE	Off Peak Months 2018-2019		Peak Months 2019		Off Peak Months 2019-2020		Peak Months 2020		Off Peak Months 2020-2021		Peak Months 2021	
	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.
1	2	0.23	11	1.25	8	0.92	19	2.15	16	1.84	23	2.60
2	2	0.23	5	0.57	3	0.34	9	1.02	13	1.50	11	1.25
3	1	0.12	1	0.11	1	0.11	2	0.23	7	0.81	5	0.57
4	1	0.12	0	0.00	1	0.11	2	0.23	7	0.81	2	0.23
5	1	0.12	2	0.23	2	0.23	1	0.11	9	1.04	3	0.34
6	11	1.27	8	0.91	21	2.40	1	0.11	22	2.53	5	0.57
7	54	6.22	18	2.04	53	6.06	10	1.13	45	5.18	3	0.34
8	36	4.15	10	1.13	32	3.66	11	1.25	25	2.88	1	0.11
9	5	0.58	3	0.34	9	1.03	0	0.00	2	0.23	0	0.00
10	2	0.23	3	0.34	4	0.46	0	0.00	0	0.00	0	0.00
11	0	0.00	1	0.11	2	0.23	0	0.00	0	0.00	0	0.00
12	0	0.00	2	0.23	1	0.11	1	0.11	0	0.00	0	0.00
13	0	0.00	4	0.45	0	0.00	6	0.68	0	0.00	0	0.00
14	0	0.00	10	1.13	2	0.23	12	1.36	1	0.12	3	0.34
15	1	0.12	18	2.04	3	0.34	27	3.06	1	0.12	11	1.25
16	8	0.92	25	2.83	15	1.72	34	3.85	5	0.58	23	2.60
17	41	4.72	42	4.76	52	5.95	46	5.21	43	4.95	35	3.96
18	102	11.75	69	7.81	104	11.90	80	9.06	96	11.05	72	8.15
19	135	15.55	112	12.68	129	14.76	121	13.70	129	14.84	115	13.02
20	149	17.17	151	17.10	137	15.68	143	16.19	141	16.23	141	15.97
21	143	16.47	149	16.87	131	14.99	146	16.53	127	14.61	150	16.99
22	109	12.56	128	14.50	103	11.78	115	13.02	99	11.39	131	14.84
23	55	6.34	82	9.29	47	5.38	70	7.93	57	6.56	99	11.21
24	10	1.15	29	3.28	14	1.60	27	3.06	24	2.76	50	5.66
Total	874	100.0	883	100.0	874	100.0	883	100.0	869	100.0	883	100.0

Top 15% HE	Off Peak Months 2018-2019		Peak Months 2019		Off Peak Months 2019-2020		Peak Months 2020		Off Peak Months 2020-2021		Peak Months 2021	
	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.
1	1	0.15	3	0.45	1	0.15	8	1.21	6	0.92	7	1.06
2	2	0.31	1	0.15	1	0.15	2	0.30	6	0.92	0	0.00
3	1	0.15	0	0.00	0	0.00	0	0.00	4	0.61	0	0.00
4	1	0.15	0	0.00	0	0.00	0	0.00	4	0.61	0	0.00
5	1	0.15	0	0.00	0	0.00	0	0.00	6	0.92	0	0.00
6	1	0.15	1	0.15	5	0.76	0	0.00	13	1.99	0	0.00
7	24	3.69	5	0.76	40	6.11	1	0.15	28	4.29	0	0.00
8	21	3.23	5	0.76	22	3.36	1	0.15	12	1.84	0	0.00
9	3	0.46	2	0.20	5	0.76	0	0.00	0	0.00	0	0.00
10	0	0.00	0	0.00	2	0.31	0	0.00	0	0.00	0	0.00
11	0	0.00	0	0.00	1	0.15	0	0.00	0	0.00	0	0.00
12	0	0.00	0	0.00	0	0.00	1	0.15	0	0.00	0	0.00
13	0	0.00	4	0.60	0	0.00	2	0.30	0	0.00	0	0.00
14	0	0.00	6	0.91	0	0.00	8	1.21	0	0.00	0	0.00
15	0	0.00	15	2.27	1	0.15	15	2.27	1	0.15	5	0.76
16	2	0.31	20	3.02	6	0.92	28	4.23	3	0.46	15	2.27
17	28	4.30	32	4.83	44	6.72	40	6.04	30	4.60	27	4.08
18	87	13.36	56	8.46	92	14.05	64	9.67	85	13.04	52	7.85
19	113	17.36	92	13.90	111	16.95	100	15.11	103	15.80	100	15.11
20	135	20.74	127	19.18	115	17.56	125	18.88	119	18.25	126	19.03
21	121	18.59	125	18.88	105	16.03	119	17.98	105	16.10	123	18.58
22	84	12.90	106	16.01	75	11.45	88	13.29	79	12.12	111	16.77
23	23	3.53	50	7.55	25	3.82	45	6.80	37	5.67	71	10.73
24	3	0.46	12	1.81	4	0.61	15	2.27	11	1.69	25	3.78
Total	651	100.0	662	100.0	655	100.0	662	100.0	651	100.0	662	100.0

Top 10% HE	Off Peak Months 2018-2019		Peak Months 2019		Off Peak Months 2019-2020		Peak Months 2020		Off Peak Months 2020-2021		Peak Months 2021	
	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.
1	1	0.23	0	0.00	0	0.00	0	0.00	1	0.23	0	0.00
2	1	0.23	0	0.00	1	0.23	0	0.00	0	0.00	0	0.00
3	1	0.23	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
4	1	0.23	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
5	1	0.23	0	0.00	0	0.00	0	0.00	1	0.23	0	0.00
6	0	0.00	0	0.00	3	0.69	0	0.00	6	1.38	0	0.00
7	12	2.76	0	0.00	16	3.66	0	0.00	15	3.46	0	0.00
8	8	1.84	0	0.00	10	2.29	0	0.00	8	1.84	0	0.00
9	0	0.00	0	0.00	2	0.46	0	0.00	0	0.00	0	0.00
10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
11	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
13	0	0.00	1	0.23	0	0.00	1	0.23	0	0.00	0	0.00
14	0	0.00	3	0.68	0	0.00	3	0.68	0	0.00	0	0.00
15	0	0.00	8	1.81	0	0.00	10	2.26	1	0.23	0	0.00
16	0	0.00	15	3.39	3	0.69	20	4.52	1	0.23	5	1.13
17	20	4.61	19	4.30	28	6.41	29	6.56	22	5.07	16	3.62
18	60	13.82	35	7.92	69	15.79	48	10.86	64	14.75	33	7.47
19	86	19.82	73	16.52	91	20.82	72	16.29	79	18.20	71	16.06
20	101	23.27	97	21.95	95	21.74	94	21.27	91	20.97	100	22.62
21	88	20.28	96	21.72	72	16.48	85	19.23	79	18.20	102	23.08
22	46	10.60	69	15.61	39	8.92	50	11.31	49	11.29	76	17.19
23	7	1.61	22	4.98	8	1.83	22	4.98	15	3.46	34	7.69
24	1	0.23	4	0.90	0	0.00	8	1.81	2	0.46	5	1.13
Total	434	100.0	442	100.0	437	100.0	442	100.0	434	100.0	442	100.0

Top 5% HE	Off Peak Months 2018-2019		Peak Months 2019		Off Peak Months 2019-2020		Peak Months 2020		Off Peak Months 2020-2021		Peak Months 2021	
	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.
1	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
2	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
3	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
4	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
5	1	0.46	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
6	0	0.00	0	0.00	0	0.00	0	0.00	1	0.46	0	0.00
7	3	1.38	0	0.00	4	1.83	0	0.00	4	1.84	0	0.00
8	2	0.92	0	0.00	2	0.92	0	0.00	4	1.84	0	0.00
9	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
11	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
13	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
14	0	0.00	0	0.00	0	0.00	1	0.45	0	0.00	0	0.00
15	0	0.00	3	1.36	0	0.00	3	1.36	0	0.00	0	0.00
16	0	0.00	6	2.71	0	0.00	10	4.52	1	0.46	0	0.00
17	3	1.38	12	5.43	12	5.50	14	6.33	8	3.69	3	1.36
18	35	16.13	23	10.41	49	22.48	27	12.22	37	17.05	12	5.43
19	55	25.35	41	18.55	58	26.61	47	21.27	48	22.12	42	19.00
20	66	30.41	64	28.96	51	23.39	51	23.08	53	24.42	70	31.67
21	39	17.97	42	19.00	34	15.60	41	18.55	43	19.82	58	26.24
22	11	5.07	24	10.86	8	3.67	19	8.60	16	7.37	32	14.48
23	2	0.92	6	2.71	0	0.00	8	3.62	2	0.92	4	1.81
24	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Total	217	100.0	221	100.0	218	100.0	221	100.0	217	100.0	221	100.0

VIII. Appendix D: Number of UCAP Assessment Hour per Day by Sampling Frame

Top 20% HE	Off Peak Months 2018-2019		Peak Months 2019		Off Peak Months 2019-2020		Peak Months 2020		Off Peak Months 2020-2021		Peak Months 2021	
# of UCAP AH per day	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.
0	23	13	28	15	39	22	31	17	23	13	33	18
1	5	3	6	3	3	2	10	5	14	8	2	1
2	6	3	14	8	9	5	16	9	13	7	15	8
3	19	10	25	14	17	9	20	11	27	15	17	9
4	25	14	25	14	18	10	21	11	18	10	21	11
5	28	15	17	9	24	13	21	11	18	10	21	11
6	26	14	18	10	17	9	14	8	14	8	21	11
7	22	12	13	7	12	7	12	7	16	9	18	10
8	12	7	13	7	15	8	7	4	15	8	11	6
9	7	4	5	3	10	6	7	4	6	3	11	6
10	3	2	7	4	5	3	7	4	4	2	6	3
11	5	30	3	2	5	3	5	3	5	3	2	1
12	0	0	4	2	4	2	4	2	3	2	1	1
13	0	0	0	0	1	1	3	2	1	1	1	1
14	0	0	2	1	1	1	2	1	3	2	1	1
15	0	0	1	1	0	0	2	1	2	1	1	1
16	0	0	2	1	0	0	1	1	0	0	0	0
17	0	0	1	1	0	0	0	0	0	0	0	0
18	0	0	0	0	1	1	0	0	0	0	2	1
19	0	0	0	0	0	0	1	1	0	0	0	0
Total	181	100	184	100	181	100	184	100	181	100	184	100

Top 15% HE	Off Peak Months 2018-2019		Peak Months 2019		Off Peak Months 2019-2020		Peak Months 2020		Off Peak Months 2020-2021		Peak Months 2021	
# of UCAP AH per day	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.
0	38	21	49	27	55	30	53	29	47	26	53	29
1	3	2	7	4	8	4	10	5	9	5	4	2
2	12	7	17	9	13	7	20	11	15	8	10	5
3	19	16	23	13	12	7	17	9	26	14	23	13
4	18	15	24	13	17	9	28	15	19	10	18	10
5	18	15	22	12	17	9	18	10	18	10	27	15
6	16	14	11	6	20	11	12	7	18	10	19	10
7	9	5	7	4	17	9	7	4	10	5	13	7
8	6	3	6	3	13	7	12	7	8	4	5	3
9	2	1	7	4	5	3	3	2	4	2	5	3
10	0	0	6	3	2	1	7	4	4	2	5	3
11	0	0	1	1	1	1	1	1	0	0	2	1
12	0	0	3	2	0	0	4	2	2	1	0	0
13	0	0	1	1	1	1	2	1	1	1	0	0
14	0	0	0	0	0	0	0	0	1	1	0	0
Total	181	100	184	100	181	100	184	100	181	100	184	100

Top 10% HE	Off Peak Months 2018-2019		Peak Months 2019		Off Peak Months 2019-2020		Peak Months 2020		Off Peak Months 2020-2021		Peak Months 2021	
# of UCAP AH per day	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.
0	64	35	80	43	76	42	88	48	73	40	78	42
1	12	7	7	4	5	3	7	4	12	7	7	4
2	14	8	15	8	21	12	10	10	16	9	11	6
3	27	15	23	13	19	10	10	5	21	12	26	14
4	26	14	24	13	14	8	20	11	18	10	18	10
5	27	15	14	8	19	10	9	5	17	9	23	13
6	5	3	4	2	15	8	10	5	16	9	9	5
7	4	2	5	3	7	4	5	3	2	1	5	3
8	2	1	5	3	3	2	6	3	4	2	4	2
9	0	0	2	1	1	1	4	2	2	1	3	2
10	0	0	3	2	1	1	3	2	1	1	0	0
11	0	0	1	1	0	0	3	2	0	0	0	0
12	0	0	1	1	0	0	0	0	0	0	0	0
Total	181	100	184	100	181	100	184	100	181	100	184	100

Top 5% HE	Off Peak Months 2018-2019		Peak Months 2019		Off Peak Months 2019-2020		Peak Months 2020		Off Peak Months 2020-2021		Peak Months 2021	
# of UCAP AH per day	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.	# of Obs.	% of Obs.
0	105	58	119	65	112	62	127	69	115	63	111	60
1	9	5	12	7	10	5	9	5	10	5	6	3
2	22	12	19	10	20	11	10	5	11	6	25	14
3	15	14	7	4	11	6	9	5	18	10	20	11
4	11	6	11	6	11	6	14	8	16	9	12	7
5	9	5	5	3	13	7	1	1	8	4	6	3
6	0	0	4	2	3	2	5	3	2	1	1	1
7	0	0	2	1	0	0	2	1	1	1	3	2
8	0	0	2	1	1	1	4	2	1	1	0	0
9	0	0	3	2	0	0	2	1	0	0	0	0
10	0	0	0	0	0	0	1	1	0	0	0	0
Total	181	100	184	100	181	100	184	100	181	100	184	100

Calpine Elements Proposal: Penalty and Backstop Procurement

Calpine: Matthew Barmack

Calpine penalty and backstop procurement proposal

Calpine generally supports preserving the incentives for LSEs to satisfy RA requirements that are provided by the current combination of CPUC penalties and potential exposure to CAISO backstop (CPM) procurement costs. In order to preserve these incentives under the 24-slice approach, Calpine's proposal with respect to CPUC penalties includes the following elements:

(1) An LSE will be penalized for deficiencies equal to the largest deficiency in any slice.
(2) Any deficiency in any slice will be treated similarly to how monthly deficiencies are currently treated under the points system that was adopted in D.20-06-029.

Calpine understands that at least the first element of this proposal has been incorporated by SCE into its full 24-hourly slice proposal.

Calpine believes that this structure will provide the same incentives to LSEs to meet RA obligations in the most challenging slices that they currently have to meet monthly RA requirements. In addition, by basing penalties on the maximum deficiency in any slice rather than compounding penalties for deficiencies in multiple slices, the proposal recognizes that an LSE's alternative to non-compliance is probably not procuring multiple resources to cure separate hourly deficiencies, but a single resource or resource type that likely could address deficiencies in multiple hours.

With respect to backstop procurement, Calpine's presentation at the ninth workshop noted the potential for misalignment between how the CPUC and CAISO might assess LSE compliance under the 24-hourly slice approach. For example, if the CAISO only validates a single slice, as it has indicated that it would initially, then the CAISO might not identify LSE deficiencies in slices other than the slice that it is validating. Consequently, LSEs might not face exposure to CPM costs for failures to procure for those slices. To address this issue, Calpine proposes that the CPUC and CAISO eventually assess LSE compliance and assign penalties and CPM costs tied to LSE deficiencies consistently, i.e., on a slice-by-slice basis.

CLECA Elements Proposal: Resource Counting of DR

CLECA: Paul Nelson

Supply-Side Demand Response Resources

The Commission currently uses the Load Impact Protocols (LIP) to provide capacity values for the Resource Adequacy (RA) program. The output of the LIP is a value for each demand response (DR) program for each of 12 months (in MW). Each monthly value is an average of the hourly load reductions from an assumed call from 4 – 9 pm. The load assumption is a monthly peak with a 1-in-2 weather assumption. Since the slice-of-day framework will no longer use a single monthly load target, but have multiple load targets, the status quo of a single MW value would not be compatible.

The Commission requested the California Energy Commission (CEC) to hold a series of workshops to recommend a methodology to determine the qualifying capacity (QC) for demand response.[1] The CEC workshop report issued in February 2022 reflected DR counting recommendations for only the 2023 RA Compliance Year.[2] The CEC report proposes issuing an additional report in the fourth quarter of 2022 for proposals consistent with RA Reform Track and slice-of-day.[3] Assuming the report is issued in December, there would be very little time for the CPUC to issue a decision and for parties to implement any new counting mechanism by April 2023 that could be used for RA compliance year 2024.[4] The proposal presented here is to avoid a gap in resource counting that might delay the implementation of slice-of-day for the 2024 RA year. A future CEC process can review this and other proposals for slice-of-day for future CPUC consideration.

An expected load reduction is required for each hour

Under either the Gridwell 2-slice (monthly peak and net-peak) proposal or the 24-hourly slice (24 hours by 12 months) proposal, the expected load reduction of a DR program during those hours is required to build up an accurate resource stack to meet the forecasted load and planning reserve margin requirement.[5] The slice-of-day framework will need a profile of load reductions over time for each month instead of single monthly values. The expected load reduction in an hour should incorporate demand response performance history and, if applicable, the weather conditions. The regressions and supporting data from the existing LIP already produce hourly expected load reductions that can be

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[1] D. 21-06-029 Ordering Paragraph 11, at 77-78.

[2] CEC, (February 16, 2022), 21-DR-01, [Commission Interim Report - Qualifying Capacity of Supply-Side Demand Response Working Group]() at 1, 35.

[3] CEC, (February 16, 2022), 21-DR-01, [Commission Interim Report - Qualifying Capacity of Supply-Side Demand Response Working Group]() at 37.

[4] The current schedule requires load impacts for demand response to be filed with the CPUC by April 1 of each year, which are the basis to determine DR program capacity for the following year..

[5] Since the load forecast is at the CAISO level, the current practice is to gross up the hourly load impacts at the customer delivery point to yield the impact at the CAISO grid. In addition, the customer load impacts are grossed up for the avoidance of the planning reserve margin.

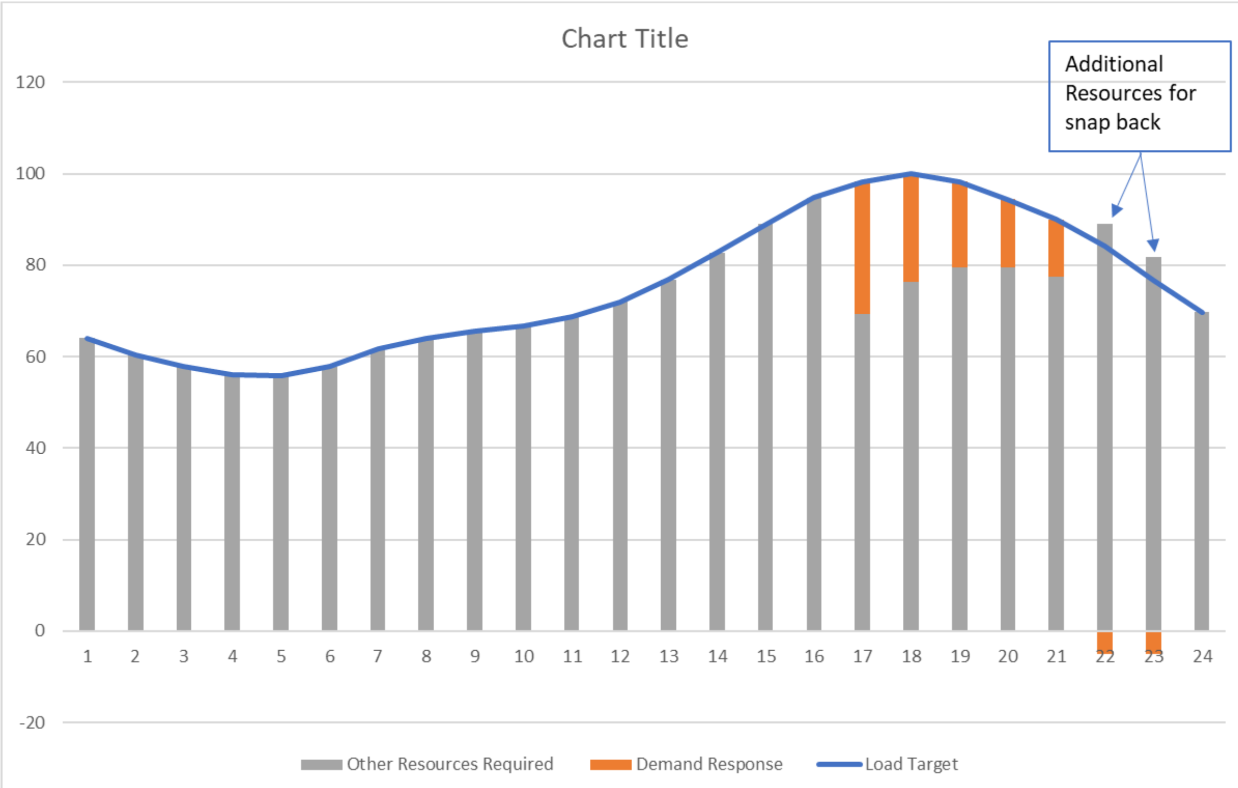
utilized. For example, the table below shows the hourly load impacts for a load reduction from 4 – 9 pm from the LIP for SCE's Summer Discount Plan, which is an air conditioner (A/C) cycling program.[6] Other methods can be used, provided they can produce hourly expected values with sufficient accuracy and granularity for the 2-slice or 24-hour slice-of-day proposals.

SCE-SDP-Commerical		
	Load Impact	
HE	MW	
16	0	
17	28.95	
18	23.72	
19	18.78	
20	14.90	
21	12.61	
22	-2.81	
23	-1.21	

For the 24-hourly slice proposal, the hourly values for the assumed 4 – 9 pm DR call period, including any snap back which increases load after the event, would be used in the resource stack. As shown in the table below, the hourly load impacts from HE 17-23 (or 4-9 pm, the 5-hour call plus the two hours of snap back) are applied to each hour. For HE 22-23, the amount of other resources required to meet the load target will increase because of the negative snap back effect. This is also shown in the figure below. For the Gridwell 2-slice proposal, assuming the peak is at HE 18 and the net-peak is at HE 20, respectively the capacity values would be 24 MW and 15. MW. For the Gridwell 2-slice proposal, no snap back adjustments would be applied.

	HE	Load Target	Demand Response	Other Resources Required
	16	95	0	95
	17	98	29	69
Peak	18	100	24	76
	19	98	19	79
Net Peak	20	94	15	80
	21	90	13	77
	22	84	-5	89
	23	77	-5	82
	24	70	0	70

[6] The program is available for a 6-hour duration and other call hours are possible. The negative values represent snap back impacts due to increased load after the demand response event that would have not otherwise occurred.



What is the preferred expected capacity shape for demand response?

There are two options to determine the demand response load shape in the RA program:

1. Optimize system reliability, which is currently roughly 4 – 9 pm to represent expected times of system shortage
2. Optimize the DR for the LSE's load shape

Under option 1, all DR programs would have a predetermined call window (currently assumed from 4 – 9 pm). Due to changing load shapes and resource mixes, the call window would require revision based upon loss of load expectation (LOLE) studies. This option would encourage the development of demand response programs to be available during the time periods when they would improve system reliability.

Under option 2, the LSE is allowed to optimize its DR programs around its load shape and resource mix. For example, a LSE with commercial accounts with load from 8 am – 6 pm could optimize an A/C cycling program during 2 – 6 pm. This option would encourage more DR programs to be developed that might not otherwise be developed under option 1. This option is consistent with the State's loading order policy to use DR and energy efficiency before acquiring other resources.

Single monthly values will send the wrong signal for resources under slice-of-day

Using a single monthly value from the status quo or using an effective load carrying capability (ELCC) approach as recommended in the CEC report will not work with slice-of-day and will produce the wrong signal to acquire resources to match the load shape. The figure below compares the hourly values of a hypothetical DR program whose load reduction rapidly diminishes after the time of the peak. The current load impact protocols would calculate 128 MW, which is the hourly average from HE 17-21. In this example, an LSE would incorrectly conclude it has insufficient resources at the time of the peak because the 250 MW is only being counted as 128 MW. Yet, at the time of the net peak the resource is being over-counted at 128 MW instead of 20 MW, and the LSE would incorrectly conclude that it has sufficient resources at the time of the net peak. The concern is that the LSE might procure more peak-time resources (such as solar) at the time of the peak that would not address the resource need at the net-peak.

The use of ELCC does not resolve the problem of using a single monthly value. In the figure below, the ELCC of the hypothetical resource is 115 MW which incorporates the impact of the hourly LOLE.[7] This also results in the same incorrect procurement incentives as the use of a simple average of the hourly impacts.

The use of the hourly values, 250 MW for the peak and 20 MW for the net peak, would send the correct signals to correct any resource shortfall under the 2-slice peak and net-peak approach. This result is also applicable to the 24-hourly slice-of-day proposal.

		Hypothethcial Load Impact	
HE	LOLE	MW	
16	0.0%	0	
17	1.4%	250	
18	25.2%	250	Peak
19	42.1%	100	
20	22.5%	20	Net Peak
21	7.5%	20	
22	1.4%	0	
23	0.0%	0	
	100.0%		
	Avg of HE17-21	128	
	ELCC	115	
(weighted by LOLE HE17-22)			

[7] The LOLE provided in the figure is from the CAISO's DR ELCC study provided in July 2021. The LOLE is for 2020. The ELCC value is the average of the load impacts using the LOLE as weights.

Vistra Proposal, Need Determination

Cathleen Colbert, Vistra Corp.

Need Determination Proposal

The need determination proposal is to establish RA requirements through an annual[1] Loss of Load Expectation (LOLE) study process to set Gross Load Requirements and Net Load Requirements. Establishing RA requirements through a regularly updated probabilistic LOLE study that incorporates uncertainty risks ensures reliability and results in a more equitable outcome for ratepayers than continuing to rely on a fixed, predetermined deterministic planning reserve margin (PRM). The LOLE study will be leveraged to set the minimum system RA requirements across all hours and to identify hour(s) for performing a new net load assessment. Vistra proposes that the system RA requirements should be allocated on a peak-load-share basis to load-serving entities (LSEs) and any system net load deficiency should also be allocated on a peak-load-share basis. Vistra's proposal will also allow for CPUC and California Independent System Operator (CAISO) to perform sufficiency assessments on these needs, and if any deficiencies are identified then the CPUC should apply the existing deficiency penalty rules to the greater of any deficiency amount.

The need determination proposal below details a proposal for establishing system RA gross load requirements across all hours and system net load requirements for hour(s) with identified Expected Unserved Energy (EUE) risks. If the Commission adopts the 24-hourly slice framework, Vistra provides a conceptual proposal for how this need determination could be integrated into a 24-hourly framework and commits to working with SCE to refine these concepts into an approach that is consistent with Commission's direction. If the Commission adopts the two-slice framework, fewer details will need to be developed to implement this need determination approach.

The remainder of the chapter will describe the need determination proposal in three phases:

- Perform Loss of Load Expectation Study
- Perform Gross Load Assessment
- Perform Net Load Assessment

Perform Loss of Load Expectation Study

Both the Gross Load Assessment and the Net Load Assessment will be performed using different outputs of the LOLE study. The steps for performing the LOLE study are:

- Step 1: Forecast hourly system-wide gross demand
- Step 2: Estimate generation capacity and dispatch assumptions
- Step 3: Develop uncertainty scenarios needed to perform the stochastic study
- Step 4: Calculate Loss of Load Hour values
- Step 5: Find capacity to meet the reliability standard across all hours

[1] Certain parties raised concerns that annual updates may not be feasible and instead a bi-annual process should be adopted. Vistra's proposal is for the LOLE study to be updated annually to ensure the LOLE information that contributes to the system RA requirements are as accurate as possible to maximize reliability. Alternatively, the Commission could implement this proposal on a bi-annual basis if it determines annual is not feasible.

- Step 6: Find EUE to identify largest net peak hour at risk
- Step 7: Update the inputs and perform LOLE every one to two years

Step 1: Forecast hourly system-wide gross demand

To perform a probabilistic LOLE study that addresses hourly energy sufficiency for reliable operations, the LOLE study needs hourly demand targets. The Vistra need determination proposal proposes to set the hourly load target for all 8,760 hours using the hourly CAISO mid-mid case from the most recent California Energy Commission's (CEC's) full Integrated Energy Policy Report (IEPR) or updated IEPR as the basis for projected load. The 8,760 hours will be assessed in the LOLE study, which will meet the Commission's direction to address hourly energy sufficiency (Principle 2) and to meet hourly system needs (Principle 3).

Step 2: Estimate generation capacity and dispatch assumptions

The generation resources that will be included in the study and their applicable dispatch assumptions must also be set. The Vistra need determination proposal intends that the RA LOLE study should include all online resources (e.g., base line resources) and any projects with executed RA contracts for the target year expected to achieve commercial operation date in that year (e.g., planned resources). The latter enhancement is needed to ensure that resources that are contracted under Central Procurement Entity or Integrated Resource Planning directives that have an executed and approved contract that will span the year being studied are appropriately included. This step also should include structuring the model to include the specified dispatch assumptions for specific resource types included in the generation fleet being modelled.

Step 3: Develop uncertainty scenarios needed to perform the stochastic study

Under the Vistra need determination proposal, the LOLE study will stochastically assess the varying risks the system faces. The CAISO and CPUC should coordinate to set up the probability scenarios in the model. The CAISO has the best available information about operational challenges the CAISO system is facing and should ensure the uncertainty risk scenarios are structured to address real needs. Under this proposal, the CAISO would provide the uncertainty scenarios that should be included in the LOLE study. The LOLE study will incorporate these operational risks by producing distributions of outcomes for the following uncertainty risks:

- Demand variation
- Forced outage risks from outages that are unforeseen
- Substitution risk for planned outages where a resource cannot find substitute capacity
- Resource availability risks (e.g., solar, wind, hydro, qualifying facilities, imports etc.) that affect the ability to deliver sufficient energy to serve load.
- Conservative resource availability risk scenario (i.e. sensitivity) that is designed to limit the energy needed to directly serve load including the energy needed to charge the storage fleet to be able to directly serve load.

On the last uncertainty, this sensitivity to the resource availability uncertainty scenarios of insufficient resources available to supply both energy to serve load and charging energy to charge the storage fleet will produce a total generation capacity requirement that includes an additional MW amount needed to maintain reliability under this condition. This ensures there is sufficient generation to serve load and charge storage fleet even under a conservative limited energy supply scenario. Limited energy supply conditions are a factor of a combination of risks that will need to be assessed to develop this conservative scenario including reduced solar output, reduced hydro output, or import deliverability risks. The additional generation needed under RA to address this specific risk is complex and requires multiple risks to materialize, and likely simultaneously, to result in the concern raised. Given the complexity of the simultaneous risks, the generation needed to address this risk is best identified through a LOLE.

The Vistra need determination proposal explicitly includes modeling this limited energy supply risk to account for the concerns raised regarding whether there will be sufficient generating resources under RA contract to ensure that RA storage resources can fully charge. While IRP studies and procurement requirements should result in sufficient installed capacity being available to ensure there is sufficient charging energy for the RA storage resources, the RA program ensures the generation capacity needed to charge this RA storage fleet is also under a RA obligation to offer its generation to the CAISO market. The RA requirement here will be determined with a generation fleet that includes the baseline and planned (under contract) resources only, such that if there is insufficient generation to mitigate this risk under contract the LOLE results will show this impact. By using the LOLE's total generation capacity needed to meet a one-day-in-ten-years reliability threshold[2] to set the Gross Load Requirement, the Gross Load Requirement will cover the generation needed to ensure there is sufficient charging energy.

Step 4: Calculate Loss of Load Hour values

The Vistra need determination proposal would calculate Loss of Load Hour values across all 8,760 hours modelled. The Loss of Load Hours is the sum of all hourly Loss of Load Probabilities in a year. The LOLE study includes 8,760 hourly probabilities ρ that range between 0 to 1 for various probability scenarios that include the uncertainty scenarios described above. These would result in a range of outcome distributions (X_i) and the probabilities associated with these outcomes.

Step 5: Find capacity to meet the reliability standard across all hours

The Vistra need determination proposal would identify the capacity requirement (MW) needed to meet a specified reliability threshold. The LOLE study can be set to meet any defined reliability threshold. We propose that at a minimum, the reliability threshold should maintain a one-day-in-ten-years threshold, although a stricter standard could be considered by the Commission. The reliability threshold would be maintained across all 8,760 hours studied. This step would identify the total capacity values on both a monthly and annual basis.

Step 6: Find EUE to identify largest net peak hour at risk

The Vistra need determination proposal identifies the hours within the 8,760 hours studied that the LOLE study shows a risk of EUE. The hourly EUE amounts are the expected amount of energy not supplied by the generating system during those hours. This is an input to Step 11: Identify the worst hour at risk using EUE.

[2] One-day-in-ten-years reliability threshold refers to one non-contiguous day such that the threshold is that a system supports a level of reliability where there is less than 24 hours across a ten-year period at risk of loss of load.

Step 7: Update the inputs and perform LOLE every one to two years

The Vistra need determination proposal would require the LOLE study to be updated regularly so that it is capturing changes to the fleet, demand behavior, and operational challenges facing the system. We propose that the LOLE be performed annually. By regularly updating the LOLE and updating the RA requirements, this proposal meets the Commission Principle 5, durable and adaptable to a changing electric grid. As noted below, if the Commission determines that bi-annual is the feasible implementation choice this is compatible with the proposal albeit will not meet as well Principle 5 to capture the changing electric grid.

Perform Gross Load Assessment

The Vistra need determination proposal improves the RA program's ability to support reliability concerns during the Gross Load hours and Net Load hours. It improves the process for establishing the RA Requirements by using the total generation capacity in MW needed to meet the one-day-in-ten-years reliability threshold to set the RA requirement. The improved Gross Load Assessment would compare the total RA NQC shown by a LSE against the LSE's peak load share of the total generation capacity requirement set by the LOLE to identify any LSE deficiencies.

Under the two-slice proposal, the Vistra need determination proposal will enhance the California RA program by shifting away from setting the system RA requirements using a deterministic PRM that is a percentage target above a demand forecast. Instead, the RA program would shift towards a probabilistically determined requirement in total MW that matches capacity requirements to the reliability standard. This MW generation requirement can be translated into a PRM to track the amount of generation above a demand forecast, but this is performed ex post and does not drive the requirement. This probabilistically determined effective reserve margin metric may change over time and may be higher or lower than the static PRM they replace. The key is that this proposal does not utilize a percentage above a monthly demand forecast but instead uses the LOLE output for total generation MW to set the system RA requirement to cover the amount of generation needed to maintain reliability standard across all hours.

Under the 24-hourly slice proposal, the Vistra need determination proposal will enhance the California RA program by shifting away from a static PRM to a probabilistic PRM. The probabilistic PRM will be set by determining an effective reserve margin based on the ratio of the LOLE's total generation capacity MW amount compared to the monthly managed system coincident peak. Under this implementation, the effective reserve margin sets the PRM and the PRM is used to increase hourly requirements to include this margin.

The Gross Load assessment will be performed in the following steps:

- Step 8: Identify the system Gross Load Requirement
- Step 9: Allocate the system Gross Load Requirement to each LSE
- Step 10: Track the effective reserve margin requirement

Step 8: Identify the system Gross Load Requirement

The Gross Load Requirement must be calibrated to ensure the shown RA fleet can meet at a minimum a one-day-in-ten-years standard, otherwise the system would need to lean on non-RA capacity to meet a one-day-in-ten-years threshold. This leaning would ultimately lead to CAISO backstop and make the RA program fail to meet its overall goal of maintaining reliability. The Vistra need determination proposal updates the Gross Load Requirements annually. This step performs the LOLE study to identify the MW of total capacity needed to maintain the reliability threshold, described in Step 5 above.

Under the two-slice proposal, the monthly system Gross Load Requirement is the monthly MW value for the total capacity needed to meet at a minimum a one-day-in-ten-years standard. Under the 24-hourly slice framework, the system Gross Load Requirement is set by SCE's proposal for demand forecast with the effective reserve margin determined in Step 10 applied to increase the requirement for each hour to include carrying this probabilistically determined PRM. Note, the main difference in implementation is that the two-slice proposal would use the LOLE output for total generation capacity needs, avoiding the need for a PRM since the LOLE identifies that reserve margin in its study where the 24-hourly slice would use a PRM on SCE's proposed forecast to set system RA requirements hourly.

Step 9: Allocate the system Gross Load Requirement to each LSE

The Vistra need determination proposal is to maintain the existing requirement allocation approach. The system Gross Load Requirement would be allocated to each LSE on a peak load share basis.

Step 10: Track the effective reserve margin requirement

Under the two-slice framework, the Vistra need determination proposal shifts the PRM from being used to set a deterministic RA requirement to being an after-the-fact metric. The LOLE determines the stochastic RA requirement using the total generation capacity output described above in Step 8. The key is that any effective reserve margin is an after the fact metric under this proposal. The after-the-fact tracking metric is like a Key Performance Indicator whose purpose is to track changes in the ratio of the LOLE's generation requirement relative to the CEC's Managed 1 in 2 monthly CAISO coincident peak forecasts. The "effective reserve margin" metric is the ratio of the LOLE's output for monthly total generation capacity needed to meet a specified reliability threshold (Step 5 above) to the CEC Managed 1 in 2 Monthly CAISO Coincident Peak forecast. The equation is shown below:

$$"effective\ reserve\ margin" = \frac{LOLE\ Capacity\ to\ Meet\ One{-}Day{-}in{-}Ten{-}Years\ Standard}{Managed\ 1in2\ Monthly\ CAISO\ Coincident\ Peak}$$

Under the 24-hourly slice framework, this transitions back to a more similar implementation to today where a PRM, the effective reserve margin, is used to establish a static PRM that would apply to SCE's proposed forecast.

Perform Net Load Assessment

The Vistra need determination proposal addresses reliability concerns during the net load hours as well by performing the LOLE study across ***all hours*** based on gross load hourly forecasts. The Vistra proposal adds assessments to the slice(s) of the day where a credible reliability risk has been identified within the LOLE study. The assessment will ensure reliability during the net load slice(s) by limiting the MW amount that intermittent resources can count toward the net load assessment based on an assumed output profile. The assessment during the net load slice(s) will ensure sufficient capacity is able to serve load during all hours of the day including those impacted by a reduction of intermittent resources' output.

Under a two-slice framework, the proposal will perform a net load assessment during the hour with the largest EUE identified by the LOLE or a default hour. Under a 24-hourly slice framework, the proposal would likely be implemented by performing the energy sufficiency assessments in the hours within the

24-hourly slices that the LOLE study identified risks of loss of load. The remainder of this section will describe how this approach can be implemented under either framework.

The Net Load Assessment will be performed in the following steps:

- Step 11: Identify the worst hour at risk using EUE
- Step 12: Forecast system-wide monthly net peak demand
- Step 13: Identify the monthly system net load demand target
- Step 14: Limit MW of certain resources based on its historical output
- Step 15: Perform the monthly system Net Load Assessment

Step 11: Identify the worst hour at risk using EUE

Step 11 leverages the LOLE study to identify the loss of load hour with the maximum EUE seen during the month under a two-slice framework and with any hour with EUE seen during the month under a 24-hourly slice framework. The EUE values produced in Step 6 are the LOLE outputs used for this step. This allows for a precise identification of the hour(s) that should be used for the net load assessment to ensure reliability across all hours.

The entity performing the LOLE would identify the worst EUE hour in the showing period. If the LOLE study does not identify any hourly EUE in the month, the net peak test will be performed on a specified default hour.

To identify the highest EUE hour for this new forecast table, the entity performing the LOLE study can provide a heat map of the EUE identified during the compliance month. This heat map would show when loss-of-load risks are expected to occur and the magnitude of those risks. For example, in the CPUC November 2020 presentation, the CPUC presented a Heat Map for 2022 showing the EUE by month during the net peak hours by hour beginning for Hour Beginning 17 – Hour Beginning 23. In its November 2020 presentation, the Energy Division concluded that "Reliability problems remain focused on evening hours HE18-HE20 and will become more pronounced as penetration of solar and storage increases."[3] The Heat Map provided by the CPUC showed the following hours for the maximum hourly EUE by month:[4]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hour Beginning	N/A	N/A	N/A	N/A	N/A	N/A	18	18	19	N/A	N/A	N/A
Hour Ending	N/A	N/A	N/A	N/A	N/A	N/A	19	19	20	N/A	N/A	N/A
Time Stamp	N/A	N/A	N/A	N/A	N/A	N/A	6-7PM	6-7PM	7-8PM	N/A	N/A	N/A

A heat map of the EUE out of the LOLE increases transparency into the determination of each month's hour for the new forecast table's peak shift.

[3] PRM calculation based on LOLE results for 2022, CPUC Energy Division, November 23, 2020, slide 49.
[4] *Id* at slide 46.

Step 12: Forecast system-wide monthly net peak demand

Today, the CAISO is performing a similar type of net peak test to ensure it can meet local reliability during a net peak slice. The CAISO does this by:[5]

- Using the managed peak demand in the CEC's California Energy Demand (CED) 2020 - 2030 Baseline Forecast for the State Mid Demand Case
- Using as the demand target the Final Net Peak value in the Baseline Forecast Form 1.4 table for "Net Peak Demand (peak end use load plus losses minus self-generation)" that provides an annual value for final net peak demand after peak demand is shifted to a net peak hour.

Under the two-slice proposal, the net peak need would be tested during the identified hour found in Step 11 above. Vistra proposes that the CEC expand its IEPR forecasts to provide a monthly forecast that includes a peak shift that shifts the peak to the Final Net Peak hour using the hour identified in the LOLE with the largest EUE. This forecast is intended to replicate the equivalent of Form 1.4: Net Peak Demand (peak end use load plus losses minus self-generation) data included in the Baseline Forecast "STATE" forecast tables with a monthly granularity. The monthly shifts would be to the specific hour identified as the highest EUE risk in the LOLE study or if no LOLE hour is identified in the month, then to a default hour. In recognition that the CEC forecast experts are best suited to advise on the best approach to determine the appropriate Final Net Peak forecast value for each month, the recommendation is to defer the details of this new forecast methodology to allow CEC to contribute to the implementation details.

Under a 24-hourly slice proposal, the Net Load Assessment conceptually could be tested for each hour with EUE risk identified in Step 11. The CEC's CED Forecast hourly forecast results for managed net load in the hours with observed EUE risks.

Step 13: Identify the monthly system net load demand target

The Vistra need determination proposal adds a nested monthly system Net Load Assessment that is performed to ensure there is sufficient expected capacity output during the identified net peak hour(s) in Step 11. The Net Load Assessment will use a demand target from Step 12 to set the amount of energy needs that must be met even in hours with reduced intermittent resource output below the NQC based on those resources' ability to carry load across all hours.

Step 14: Limit MW of certain resources based on its historical output

The Net Load Assessment would leverage the CAISO method of capping the capacity value of intermittent resources such that its capacity contribution is limited by the lower of its Net Qualifying Capacity (NQC) or its historical output shape during the hour(s) assessed. For the local RA net load assessment, the CAISO adjusts the MW counting value of solar provided by the CEC, or if the CEC solar shape is not available then the CAISO determines the solar output shape to use. For wind and qualifying facilities, the CAISO uses assumptions from its Transmission Planning Process regarding output shapes which could be used for wind and qualifying facilities for the local RA net load assessment.

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[5] 2023 ISO LCR Study Criteria, Methodology, and Assumptions, CAISO, October 27, 2021, slide 35, http://www.caiso.com/InitiativeDocuments/Presentation-2023LocalCapacityTechnicalStudyCriteriaMethodologyandAssumptions.pdf.

The Vistra need determination proposal is that the CAISO should make publicly available its output shape assumptions for resources that should be limited in this Net Load Assessment. This is similar to how the CAISO and CPUC both publish the NQC lists including the relevant technology characteristics (i.e., ELCC). The Vistra need determination proposal uses the public output profile assumptions made available by CAISO in the CPUC's Net Load Assessments.

There are advantages to the CAISO providing the output shapes for solar, wind, and potentially qualifying facilities for better alignment between CPUC and CAISO for a net peak test that uses the same output shapes for both system and local RA tests. This is particularly useful since the RA products are bundled products and a given resource should not have two different output assumptions during the same hour based on whether it is being tested in a system or local test.

The Vistra need determination proposal is to cap the capacity value of variable energy resources at assumed output values made publicly available by the CAISO during the hour(s) being assessed. The formula proposed is:

$$\min(\mathrm{NQC}, Output_{shiftedpeakhour})$$

A resource that can support its historical performance at greater than the assumed output shape during the hour(s) tested should be able to request a unit-specific performance adjustment. Making the assumed profiles publicly available will aid resource owners in identifying when they should request that the CAISO update its profile with a unit-specific shape instead of the assumed shape.

Step 15: Perform the monthly system Net Load Assessment

The final step after adjusting the capacity values of the solar, wind, and qualifying facilities to the lower of the NQC or the publicly available output shapes for the hour(s) assessed is to perform the system RA net load assessment in those hours. The sum of all NQC values and all adjusted capacity values (Step 14) is compared to the net load demand target (Step 13). If the amount of adjusted capacity from Step 14 is less than the demand target from Step 13, then there is a system-wide deficiency. Otherwise, there is no system-wide deficiency. Any system-wide deficiency would be allocated on a peak load share basis to each LSE.

Alignment with Commission Goals

The proposal results in RA reform that meets the CPUC principles ordered in Decision (D.) 21-07-014.

Principle 1: To balance ensuring a reliable electrical grid with minimizing costs to customers

The Vistra need determination proposal ensures a reliable electric grid using robust statistical measures of reliability via a LOLE study. Within the LOLE study process, risks associated with loss of load are being tested for ***all 8,760 hours*** within the study year and the hours where there is concern with reliable operations inform the fleet needed to meet the planning standard of one-day-in-ten-years. This approach assures the reliability threshold even under extreme uncertainty scenarios based on challenges facing the system. It is also designed to prevent over- or under-procurement using robust statistical analysis to set the system RA requirements thereby minimizing costs to consumers.

The proposal to include at a minimum the specific uncertainty risk scenarios in the modeling (Step 3) is a key element to this proposal to ensure the system RA requirements account for operating challenges facing the system. The Vistra need determination proposal addresses foreseeable reliability concerns, such as load remaining high in the evening hours after the sun has set, risks that there is insufficient energy to serve load and charge the RA storage resources and operate them through multiday reliability events. The Vistra need determination proposal has the unique advantage of being able to capture reliability events across multiple days via the proposed LOLE study process and being able to capture reliability events due to limited energy supply availability to serve load and charge the RA storage fleet. By capturing these reliability events through the uncertainty risk scenarios, the LOLE study will produce a greater generation requirement to cover these risks than a LOLE that does not include these scenarios.

Principle 2: To balance addressing hourly energy sufficiency for reliable operations with advancing California's environmental goals

Hourly energy sufficiency is ensured by setting a system RA requirement based on modeling all hourly demand needs and resource availability in a regularly updated probabilistic LOLE study. The Vistra need determination proposal will dynamically capture changing system conditions that affect the LOLE whether that is due to change in demand behavior, resource availability, or newly identified operating risks that should be included in the uncertainty scenarios. The ability to reflect contemporaneous system conditions and risks will be reduced if the CPUC only directs the LOLE study to be updated biannually. To best maximize the ability to address hourly energy sufficiency with advancing California's environmental goals, the study should be updated annually to capture new resource penetration and retirement impacts on the LOLE.

The IRP process should ensure sufficient generation is built to serve load and charge RA storage resources. The RA program ensures these resources are under contract with a RA obligation to offer this capacity into the CAISO markets. If IRP or CPE fail to contract for sufficient generating capacity, from either online or planned resources, to meet the LOLE's total generation capacity output where there are existing resources that can make up the shortfall, then the practical outcome is that the increased RA requirement allows LSEs to execute RA contracts to cover the charging energy in addition to their load. If there are insufficient resources available to execute these contracts due to failures in IRP, the practical outcome is that LSEs will not be able to meet the RA requirement and deficiency penalties apply. IRP procurement directives should mitigate the risk of failing to meet the RA requirement, but if this deficiency were to occur, it would be an indicator that IRP changes are needed. This can be used as a feedback loop between IRP and RA.

Through the probabilistic LOLE that captures whether any hour within the 8,760 hours studied are at risk of loss of load based on the proposed uncertainty scenarios, the Vistra need determination proposal ensures the system RA requirement is large enough to cover the system needs in every hour even during events that threaten reliability. Specifically, the proposal also addresses storage charging concerns explicitly in the LOLE study that were discussed by the Commission in the final Track 3B.2 decision under Principle 2.

The LOLE will ensure that if a limited energy supply scenario would increase Loss of Load Expectation that the LOLE would result in an increase to the total generation capacity value produced by the LOLE study needed to meet a one-day-in-ten years reliability threshold, including the energy needed to charge storage resources or other events that threaten reliability. The increased system Gross Load Requirement will include the additional capacity need that must be contracted to mitigate the risk of loss of load under these types of conditions. LSEs may transact with renewable resources to meet this additional capacity need. Further, this uncertainty scenario will capture hours when there is not enough energy to both serve load and fully charge storage than if it were not included in the set of uncertainties. The LOLE will likely identify more loss of load risk hours during the middle of the day.

Principle 3: To balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity and transactability

As discussed above in Principle 2, the probabilistic LOLE study ensures that hourly energy sufficiency is met to maintain a specified reliability standard even through reliability challenges that the uncertainty scenarios will capture. Even though the LOLE study proposed appears complex, for experts performing these studies the proposal herein will be simple to implement. Performing a probabilistic LOLE study is an existing industry practice well known and understood by LOLE modeling experts.

Principle 4: To be implementable in the near-term (e.g., 2024)

The Vistra need determination proposal provides sufficient details such that the Commission can adopt this proposal by the summer of 2022, as stipulated in the R.21-10-002 Scoping Ruling. The CPUC can lead a transparent stakeholder process that allows feedback on inputs, assumptions, and the LOLE study results by mid-2023 for the 2024 RA year.

Although the LOLE studies are complex, they are also established methodologies that do not need novel process or software development. Given the breadth of experts in LOLE study techniques, the CPUC can simplify the implementation of this proposal by leveraging expert consultants to collaborate with the CPUC to establish the proposed LOLE in this proposal and/or to perform the annual updates. Vistra proposes that the CPUC to delegate responsibility to the CAISO the task of setting up the uncertainty risk scenarios. To further simplify implementation, the CAISO could also coordinate with the CPUC and its expert consultants to establish and annually update the uncertainty scenarios based on changing system conditions and challenges.

Principle 5: To be durable and adaptable to a changing electric grid

The design is durable because any changing system conditions, resource mix, or unanticipated risks challenging reliability will be dynamically captured with each LOLE iteration. The system RA requirement will be set to require a generation amount that can cover the risks of loss of load to a minimum reliability standard that reflects contemporaneous conditions, challenges, and needs to meet at a minimum a one-day-in-ten-year standard. As described above in Principle 2, the Vistra need determination proposal relies on recurring LOLE studies using updated load forecasts, generation assumptions, and uncertainty risk scenarios that reflect the changing electric grid in the LOLE study. The changing electric grid's needs will be modeled in the probabilistic LOLE study in each iteration such that that iteration will identify LOLE given that changing electric grid. Determining the system RA need based on contemporaneous electric grid conditions and challenges is a key benefit of this proposal.

PG&E Proposal: Hedging

Pacific Gas and Electric, Co. Peter Griffes, Luke Nickerman

I. PG&E proposals on hedging

A. Background

Energy Division indicated that it is concerned with the relationship between capacity markets and energy markets, as outlined in its initial Track 3B2 proposal.[1] In the past, RA showings were dominated by tolling arrangements where the buyer essentially assumed operation of the resource, being responsible for the procurement of fuel as well as participation in the energy markets as the scheduling coordinator. These arrangements, combined with a least-cost dispatch requirement by the Commission for the investor-owned utilities (IOUs), assured that generating suppliers contracted with the IOUs would bid at their incremental production costs into the California Independent System Operator (CAISO) energy markets.

With the proliferation of load-serving entities (LSEs) over the last several years, not all of whom have experience in participating in the CAISO energy markets, there has been a reduced appetite for tolling arrangements, particularly with the responsibilities that scheduling coordinators representing suppliers have at the CAISO.

Previously, PG&E offered two separate proposals, each of which is designed to create an incentive for generators that count for RA to bid the RA capacity into the CAISO energy markets at levels that produce an efficient energy market outcome.[2] PG&E's proposals respond to options outlined in Energy Division's August 2020 filing, which explored including a least-cost dispatch requirement or bid cap on RA contracts, as well as the options that explored changing RA requirements to forward energy showings instead of capacity showings.[3] These proposals were aiming to achieve similar results, without going as far as a forward energy showing.

In the workshop on hedging, PG&E re-introduced these proposals and provided greater detail as to how each would work. PG&E's intent was to illustrate different mechanisms that could be used to implement the means to achieve the Commission's goals and offered no opinion regarding the steps that may be needed to achieve the impact the Commission desires if adopting this type of mechanism. PG&E believes the Commission should provide clearer guidance on the objectives these measures are intended to achieve. Each of the two proposals, Variable Cost Hedge and Price Cap Rebate, are described in greater detail below.

B. Variable Cost Hedge Proposal:

PG&E's variable cost hedge proposal ties compensation for capacity to the unit's performance in the energy market, on an ex-post basis. Variable operating costs for fossil-fired generators generally consist of fuel, variable operations and maintenance (O&M) costs, and emissions costs. Therefore, the contract could identify the heat rate, variable O&M, and emissions costs upfront and require a rebate to the LSE

1 See Energy Division Issue Paper and Draft Straw Proposal for Consideration in Proceeding R.19-11-009, Track 3B, dated August 7, 2020, pp. 18-26.
2 Second Revised Track 3B.2 Proposals of Pacific Gas & Electric, R.19-11-009, February 26, 2021.
3 Ibid, pp. 38-39.

of any energy market revenues that exceed these costs. If the generator does not participate in the CAISO markets, or bids at levels higher than the specified contract price, it still would have the obligation to rebate the contracted energy revenue back to the buyer. The Commission would require that RA showings conform to this type of contract to qualify for RA. By including these rebate requirements, the mechanism would provide an incentive for the generator to participate in the CAISO's energy markets by bidding its costs.

This approach works well for natural gas units, but likely could also be applied to other types of resources like energy storage. For energy storage resources, the contract could be based on the spread between the charging costs and discharging revenues. Approaches for other resources would need to be addressed in discussions with stakeholders.

1. Thermal Example:

To elaborate on the contract hedge proposal, PG&E provides the following example of a generator with a heat rate of 9,000 MMBtu/MWh and a variable O&M cost of $5/MWh. With a fuel price of $3.20/MMBtu and an emissions cost of $1.00/MMBtu, the variable costs would be $43/MWh. The resource should run when the CAISO market price paid to the generator, its Locational Marginal Price (LMP), is above this cost and should not run when the LMP is below this cost. The relation of these costs to market prices can then be incorporated into the contract for capacity with the seller rebating a portion of what could be considered the unit's energy margin, MW * (LMP - specified variable cost), back to the seller when the LMP is above this level. No rebate would be paid if the LMP were below the specified variable costs. Note that this is an illustrative example and specifics would need to be developed in conjunction with mechanisms for other resource types.

2. Feedback on Variable Cost Hedge

PG&E has talked with numerous parties about the variable cost hedge proposal since it was first introduced in December 2020. A number of concerns were raised, which we discuss below.

One concern expressed was that this is an administratively cumbersome approach to providing an incentive to bid in the energy markets. This observation has merit as implementing this approach would require an LSE to understand the cost components of each resource it contracts with. Similarly, under this approach, Energy Division would have the burden of checking whether the terms of contracts, including the cost specifications, were compliant with this rebate requirement.

Another concern raised was that setting marginal costs for some resources could be difficult and not easily captured in straight-forward terms. This may be the case for resources with use limitations such as limited fuel or operating restrictions that are not easily verified.

Concerns were also expressed that this type of mechanism leaves the seller with operating risks associated with the cost parameters being different than specified in the RA contract. Of course, the seller would have the opportunity to recover the costs of bearing such risks in the upfront RA contract.

Parties also pointed out that this approach would require renegotiation of most current RA contracts if applied retroactively. It is unlikely that existing contracts have these provisions. PG&E suggests a transition period so that this requirement would apply only to new contracts.

3. PG&E Experience with Variable Cost Hedge

PG&E has been testing the variable cost hedge concept in the IRP and central procurement entity ("CPE") procurements. PG&E has executed contracts with variable cost hedge provisions in both the emergency reliability and mid-term reliability OIRs. PG&E has also included the variable cost hedge concept as an option in CPE solicitations, as was ordered in D.20-06-002.[4] PG&E's experience is that these types of mechanisms are possible, albeit not preferred by all stakeholders.

C. Price Cap Rebate Proposal

In Track 3B.2, Energy Division proposed a bid-cap mechanism that would direct that all RA contracts require resources to bid into the energy markets at a price no greater than the higher of $300/MW hour (MWh) or the resource's default energy bid as defined by the CAISO.[5] PG&E subsequently suggested considering an alternative to the bid cap approach that would require a rebate-type of mechanism. PG&E believes this approach would meet the objective of limiting market power while enabling more efficient administration of compliance with the requirement. This mechanism would work the same at the variable cost hedge proposal above, but instead of having the rebate trigger and amount be based on the specified variable cost in the contract, it would be based on a price cap value. Consequently, whenever the LMP for the resource were to go above the trigger value, a rebate would be paid by the resource to the LSE for an amount equal to the quantity of the contract times the difference between the LMP and the price cap value.

Several questions should be addressed before this mechanism could be put into place. These include: Should LSEs be allowed to set the level of the cap for their own contracts, or should it be determined by the Commission for all LSEs? Should the cap apply to all RA contracts or only to a portion of an LSE's portfolio? Should the cap be set at the same level for all LSEs? Again PG&E believes the Commission should provide clearer guidance on the objectives these measures are intended to achieve in order to better inform whether a mandatory hedge mechanism is necessary and, if so, the type of mechanism most likely to achieve the Commission's objectives.

1. Example Price Cap Rebate

The rebated amount = MW * (LMP – Price Cap), if LMP > Price Cap. If the LMP is below the price cap, then no rebate would be paid. As an example, assume the price cap is $500/MWh and contract is for 50 MW. If the LMP is, say, $550/MWh, the rebate would be 50*($550 -$500) = $2500. Similarly, if the LMP is, say at $450/MWh, there would be no rebate.

2. PG&E Experience w/ Price Cap Rebate

PG&E does not have experience signing contracts under a price cap rebate as it does with a variable cost hedge. However, the price cap rebate approach would be simpler and likely easier to implement than the variable cost hedge mechanisms implemented to date.

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4 Decision 20-06-002, Ordering Paragraph 8e. D.20-06-002, which established CPEs for the PG&E and Southern California Edison Company distribution service areas, requires CPEs to include dispatch rights, or other means that stipulate how local resources bid into the energy markets, in their solicitations as an optional term that bidders are encouraged to include.

5 Addendum to Energy Division Issue Paper and Draft Straw Proposal for Consideration in Track 3B.2 of Proceeding R.19-11-009, filed December 18, 2020, pp. 15-16.

Vistra Proposal: Hedging Component

Vistra Corp., Cathleen Colbert

In the final Track 3B.2 decision, the Commission directed parties to consider a hedging component in the RA reform workshops.[1] In doing so, the Commission stated: "We find it critical that a future framework include a component that links RA to a resource's energy bidding behavior so as to increase the cost-effectiveness of RA."[2] The Commission also expressed concern that "a decline in IOU-held tolling contracts… tightening supply in the West and the lack of adequate market mitigation measures in the CAISO market" has led to increasing costs to consumers.[3] However, the Commission did not further specify the risks it envisions such a hedging component addressing. While the Commission authorized Energy Division to request data on load-serving entities (LSEs') hedging practices,[4] no information on that topic has been shared with the parties.

Hedging Component Proposal

Load-serving entities (LSEs) already have numerous hedging options at their disposal. In most cases, competitive suppliers and buyers can cost-effectively hedge financial risks through existing financial or physical markets, rather than an RA contract with an energy hedge component. It could be inefficient for the Commission to require LSEs to employ uniform energy hedging practices, as that could increase costs to consumers (by eliminating more cost-effective hedging options). That result would run counter to the Commission's Principle 1 that RA program reforms should balance reliability with minimizing costs. Vistra therefore proposes that LSEs continue to be allowed to exercise their judgment on which offer type produces the best market outcomes for their customers.

If, however, the Commission concludes that some LSEs may not be adequately protected from high wholesale prices, and that linking financial hedges to the RA program is the best solution, Vistra proposes that the Commission formally introduce an ***energy settlement option*** within the RA program[5] by establishing a uniform energy settlement option methodology leveraging the variable cost approach that Pacific Gas and Electric Company (PG&E) has previously incorporated into its procurement processes in its role as a Central Procurement Entity (CPE). This option would not mandate energy price hedging but would require LSEs to solicit for RA-only and RA-plus-energy-settlement. The energy settlement option would formalize the practice of executing contracts for two types of RA contracts: (1) a bundled RA offer combined with other hedging performed by the seller; and (2) a bundled RA product plus an energy settlement option based on variable cost hedges. While these options are available in the market today, the specific formulation of the energy settlement option is not formalized or consistent across LSEs. This proposal would have the Commission establish the principles and rules for calculating the variable cost hedges for the bundled RA-plus-energy-settlement option. This would streamline the methodology across CPUC jurisdictional LSEs when this RA product type is being offered and leverages PG&E's implementation of this approach to do so.

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[1] D.21-07-014, Ordering Paragraph 1, pp. 51-52.

[2] *Id,* p. 27

[3] *Id*, pp. 26-27.

[4] *Id,* pp. 38-39.

[5] See Vistra's presentation on hedging from the January 5, 2022 workshop for more detail.

Developing a standardized energy settlement option will allow LSEs to compare the total cost of RA-only products combined with other hedging strategies to RA-plus-energy-settlement products. The energy settlement may be less effective in many instances to establishing hedges through existing financial or physical markets, such that this bundled RA-plus-energy-settlement offer would be more costly than another bundled RA offer combined with the superior hedges, but less sophisticated LSEs may benefit from the option to buy bundled RA-plus-energy-settlement as a simple, pre-defined hedging product. The buyers can consider which offers are most cost effective to its customers resulting in minimizing costs to customers.

Process Proposals

If the underlying risks the Commission intends a hedging component to address are a function of challenges outside of RA, Vistra proposes that the Commission address these concerns in the appropriate venues. Concerns that LSEs or end-use customers may be overly exposed to commodity price risks boils down to concerns with retail market rules and California Independent System Operator (CAISO) market operations. RA markets should not be used to address these retail policy issues or CAISO market operation concerns.

Is the Commission's concern that there could be physical withholding or economic withholding by generators in the CAISO markets? If so, these concerns are best addressed through CAISO's administration of its must offer obligation, including bid insertion rules, and local market power mitigation. CPUC RA rules to incorporate a financial energy hedging requirement or energy bid cap are not needed, or appropriate, to mitigate market power in the energy markets:

- CAISO is responsible for ensuring energy market is protected from withholding concerns,
- CAISO has a mitigation paradigm set up to address this concern, and
- An energy component already comes with the RA obligation through a must offer obligation.

Vistra believes the existing CAISO market power mitigation rules are working as intended. **Vistra would thus propose the Commission and other parties who are concerned about withholding request the CAISO consider this issue in its stakeholder processes.**

Is the Commission's concern instead that the CAISO clearing price reflects scarcity price signals due to supply scarcity? If so, the Commission should ensure that LSEs have adequate resources online through its Integrated Resources Planning (IRP)-related procurement orders and that LSEs have sufficient capacity under contract through the RA program's system RA requirements to assign sufficient capacity a must offer obligation to mitigate supply shortage risks. **Vistra would thus propose the Commission explore concerns with resource insufficiency in installed capacity in an IRP docket.**

Is the Commission's concern that some LSEs' financial exposure to commodity price increases is not sufficiently hedged, such that the LSEs are overly exposed to this risk? If the concern is that a lack of hedging requirement could lead to LSEs defaulting where customers revert to providers of last resort, that is not a RA issue but rather a retail one. The Commission directly oversees the IOUs' energy and capacity contracting and hedging programs. Non-IOU LSEs are responsible for hedging their own commodity price risks and already have several physical and financial hedging strategies at their disposal to protect themselves from price volatility. **Vistra would thus propose the Commission explore concerns with risks of defaulting LSEs in a retail market docket.**

Is the Commission concerned that end-use customers are being unnecessarily exposed to wholesale clearing prices through the retail products/rates they are being charged? These risks are largely dependent on the type of retail product the consumer is on, where these products should be structured to not unduly impose wholesale risks onto customers. If the concern is with retail products unnecessarily exposing customers to risks resulting from wholesale market outcomes, this is not an RA issue but a retail one. **Vistra would thus propose the Commission explore such concerns in a retail market docket.**

Conclusion

Imposing a uniform hedging *requirement* on LSEs would not be prudent, given that effective hedges are commercially available today, and many LSEs may find those options to be more cost effective than any one-size-fits-all solution. However, there may be value to formalizing the practice that began with CPE solicitations to include the ability for sellers to offer two types of contracts and allow the LSEs to identify which type provides the most value to them and their customers. In some instances, the bundled RA-only offer may better minimize costs over the bundled RA-plus-energy-settlement offer, or vice versa, depending on the specifics of the resource. While this is a practice the CPEs are engaged in, it is unclear whether other LSE procurements include an offering that allows adding an energy settlement option on top of the RA product.

There are also potential efficiencies to be gained in formalizing this option to add a more standardized RA-plus-energy-settlement option to the RA markets that may facilitate execution of this type of contract. Given the opposing concerns that uniform requirements would increase rather than minimize RA costs, the Commission should not require all LSEs to adopt a single hedging strategy. Formalizing the bundled RA-plus-energy-settlement offer *option* is an improvement to the current framework. If formalized, the Commission could provide more guidance on whether the energy settlement methodology should be specified or left to each LSE for negotiation.

Finally, policy discussions on the underlying retail or CAISO market design concerns should occur in the proper venues rather than trying to cure these issues in the RA space. This will lead to a more durable long-term approach. Attempting to address retail or CAISO market power mitigation concerns in RA contracts will reduce the market efficiency of RA, driving up costs to customers.

IEP and WPTF Proposal: Multiyear Forward Requirements

IEP: Scott Murtishaw; WPTF: Gregory Klatt

Multiyear Forward Requirements

IEP and WPTF propose that the Commission adopt a minimum three-year forward contracting requirement for System RA, similar to the three-year forward requirement it adopted for Local RA in D.19-02-022. IEP and WPTF do not recommend applying the three-year requirement to Flexible RA at this time since the Flexible RA requirements are subject to substantial variation over a shorter timeframe and the procurement of Local and System RA will result in most Flexible RA capacity receiving contracts in conjunction with the sale of their Local and/or System RA attributes.

Comparable to the forward Local RA requirements, IEP and WPTF support a 100% of System RA requirement for Year 1 and 2. However, unlike the Local RA requirement of 50% of the forecasted requirement for Year 3, IEP and WPTF strongly endorse a much higher requirement. Low requirements in Year 3 would severely undercut the benefits of multiyear forward contracting, benefits that the Commission has recognized since at least 2010.[1]

Table 1 below summarizes parties' previous positions on the Year 3 Local and System RA requirements. A wide range of parties, representing generators, LSEs, and ratepayers, supported a third-year requirement of 80% or more for Local RA. While support for high Year 3 System RA requirements was more muted, IEP and WPTF encourage parties to consider the benefits of higher System RA forward requirements, which we discuss below, that are enabled by a Year 3 requirement of 80% or more as proposed by various parties.

Table 1. Summary of Parties' Positions on Year 3 Forward Requirement for Local and System RA

Parties	Year 3 Local Requirement	Parties	Year 3 System Requirement
Calpine, NRG, PG&E, SCE, WPTF	100%	CAISO, MRP, CalCCA, Calpine	80%
SDG&E	95%	WPTF	≥ 75%
Energy Division and IEP	90%	IEP	≥ 50%
AReM, CAISO, CalCCA, and Cal Advocates	80%	LS Power, AReM	50%
CLECA and TURN	70%	ACP-CA, Brookfield, Shell	Support
Joint DR Parties and Shell	50%	PG&E, SCE	Concerned about load migration
N/A	N/A	Cal Advocates	Defer consideration
N/A	N/A	PCF	Oppose

[1] D.10-06-018, p. 32.

Sources: D.19-02-022, pp. 25-26; comments on Track 3B.2 proposals of January 15, 2021 and March 12, 2021; comments on Track 3B.2 PD of June 30, 2021.

Benefits of Multiyear Forward Requirements

Multiyear forward requirements offer several advantages compared to year-ahead contracting. First, longer guaranteed revenue streams will allow generation facility owners to amortize major investments and will provide the certainty that they can recoup those investments. This will help ensure that critical facilities needed for reliability will not retire prematurely or require a Reliability Must Run designation from the CAISO. Second, multiyear forward requirements help to ensure that LSEs secure sufficient capacity into the future as supply conditions tighten across the West. Third, multiyear forward requirements can incentivize LSEs to invest in incremental new capacity at a steady cadence, rather than relying on sporadic procurement orders from the IRP process. Finally, multiyear forward requirements may not only help to retain existing facilities whose long-term contracts have ended, but may also help to facilitate more orderly retirement of assets that are no longer needed. Facilities that fail to secure forward contracts two to three years ahead may determine that it is not worth maintaining the assets and file notices of intent to retire or mothball the facilities with longer lead time than they would have otherwise.

Load Migration Risks

While some other jurisdictions, such as PJM and Independent System Operator-New England (ISO-NE), have three-year forward requirements, there are important differences between the market structures in those regions and California. PJM and ISO-NE operate centralized capacity markets, in which PJM and ISO-NE are the counterparties. Even though contracts are procured three years ahead, costs are allocated to LSEs based on prior year contributions to peak load. Consequently, LSEs do not face large over- or underprocurement risks, both because they are not the direct counterparties and because costs are allocated based on previous year loads rather than multiyear forecasts.

In contrast, California LSEs may find themselves long or short on capacity depending on how their loads change between contract execution and the RA compliance year.[2] IEP and WPTF recommend that, in the time remaining before major RA reforms are implemented, stakeholders engage in focused discussions to develop mechanisms that facilitate assignment of contracts to other parties and continue considering mechanisms that might allow LSEs to swap load and RA obligations in a transactionally efficient manner. (Another, longer-term option may be to allow LSEs to opt out of forward System RA procurement and have the utilities, or another central procurement entity, procure system capacity on their behalf.) Although load obligation proposals to date have been oriented around swapping obligations only for certain slices within the representative day, that level of unbundling is not necessary for purposes of rebalancing capacity obligations to account for load migration. For ease of administration, IEP and WPTF would support swapping MWs of RA obligation on a bundled basis, for all slices in a given month or season.

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[2] IEP and WPTF observe that over- or underprocurement risk is not completely absent under the current RA and IRP constructs. In D.21-06-035, the Commission ordered all LSEs to procure incremental capacity up to five years forward on the basis of their anticipated future load shares.

Remaining Implementation Details

The policy choice to implement a multiyear forward requirement is relatively straightforward. If the Commission were to adopt IEP and WPTF's proposal, stakeholders would only need to resolve two details prior to implementation: (1) setting the RA procurement requirement for the third year; and (2) deciding whether to extend the forward requirement to four or five years. To the first point, IEP and WPTF have previously supported 90% and 100% requirements, respectively, for the third year for Local RA. For System RA, IEP previously supported at least 50%, mostly to align with the Local RA requirement, and WPTF recommended at least 75%. However, we have concluded that if the obligation is set much below 90%, multiyear requirements as a whole will accomplish very little. Most importantly, they will fail to send a scarcity signal (or conversely a surplus signal) to marginal generators regarding whether to invest in improving plant efficiency and/or availability or to consider mothballing or retiring their facilities. Because a lax third-year requirement will not produce tight market conditions, it will not motivate LSEs to invest in new capacity.

To the second point, the benefit of a four- or five-year requirement is that it would transfer primary responsibility for ensuring investment in new capacity from sporadic procurement decision in the IRP proceedings to the RA program. While the RA program would drive investment in new capacity, the Cap and Trade, RPS, and IRP programs could still severely limit, or prohibit, investments in incremental fossil-fueled capacity and ensure that all LSEs invest a proportional share in more expensive resources that possess certain generation attributes. Longer forward requirements could also facilitate investments in deeper plant retrofits at thermal facilities, such as enabling turbines to handle fuel mixes with higher shares of hydrogen or incorporating carbon capture technologies.

Party Position Matrices

Overview of Party Position Matrices

The Co-Facilitators circulated a matrix to the service list and asked parties to fill in their parties' positions.

The following summary matrix compiles all responses received. For the detailed party position matrix, please refer to Appendix B.

	American Clean Power - California	AReM	CAISO	Calpine	CalWEA	Collective CCAs (CPA, EBCE, MCE, PCE, Pioneer,	Joint CCAs (Central Coast Community	CEDMC	California Energy Storage Alliance (CESA)	CLECA	Green Power Institute	Golden State Clean Energy	Independent Energy Producers	Long Duration Energy Storage Association of	Middle River Power LLC	SWPG / Pattern Energy	PG&E	Public Advocates Office at the California Public	REV Renewables	SCE	SDG&E	Solar Energy Industries Association /	WPTF
Elements	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**	**Position**
Load:	Gross	Gross	Gross	Gross	Gross	Gross	Gross	Net of VERs	Gross	Gross	Gross		Gross		Gross	Gross	Gross	Gross		Gross	Gross	Gross	Gross
Compliance Periods:	Monthly	Monthly	Other	2 seasons	Monthly	Monthly	Monthly	Monthly	Monthly	Monthly	Monthly		2 seasons		Other	Monthly	Monthly	Monthly	Monthly	Monthly	Monthly	Monthly	Monthly
Number of slices:	Other	2 slices: gross peak and net load peak	Other	2 slices: gross peak and net load peak	2 slices: gross peak and net load peak	24 hourly slices	2 slices: gross peak and net load peak	24 hourly slices	24 hourly slices	24 hourly slices	24 hourly slices		2 slices: gross peak and net load peak		2 slices: gross peak and net load peak	Other	24 hourly slices	24 hourly slices	24 hourly slices	24 hourly slices	2 slices: gross peak and net load peak	24 hourly slices	2 slices: gross peak and net load peak
Type of load forecast:	Maximum value for each slice	Worst day	Maximum value for each slice	Worst day	Other	Worst day	Other	Worst day	Worst day	Worst day	Worst day		Worst day		Worst day	Maximum value for each slice	Maximum value for each slice	Maximum value for each slice		Worst day	Worst day	Worst day	Maximum value for each slice
Resource Counting NQC value granularity	Multiple (slice-specific NQC values)	Two NQCs-one for peak load and one for net load	One NQC value for the day / month	One NQC value for the day / month	One NQC value for the day / month		Other	Multiple (slice-specific NQC values)	Multiple (slice-specific NQC values)	Multiple (slice-specific NQC values)	Multiple (slice-specific NQC values)		Two NQCs-one for peak load and one for net load		One NQC value for the day / month	Multiple (slice-specific NQC values)	Multiple (slice-specific NQC values)	Multiple (slice-specific NQC values)	Two NQCs-one for peak load and one for net load	Multiple (slice-specific NQC values)	Two NQCs-one for peak load and one for net load	Multiple (slice-specific NQC values)	Other
Resource Counting for VERs	Other	Average ELCC	Other	Incremental ELCC	Incremental ELCC	Exceedance for each slice	Average ELCC	Exceedance for each slice	Exceedance for each slice	Other	Effective Net Load Reduction		Other		Incremental ELCC	Other	Exceedance for each slice	Exceedance for each slice		Exceedance for each slice	Incremental ELCC	Exceedance for each slice	Incremental ELCC
Resource Counting for 24-hour available dispatchable thermal		Pmax for each slice	Other	UCAP-light (only adjust for ambient derates)	UCAP (forced outages in top 20% needed hours and urgent outages)		UCAP-light (only adjust for ambient derates)		UCAP (forced outages in top 20% needed hours and urgent outages)	UCAP-light (only adjust for ambient derates)	UCAP-light (only adjust for ambient derates)		UCAP-light (only adjust for ambient derates)		UCAP-light (only adjust for ambient derates)		UCAP-light (only adjust for ambient derates)	UCAP-light (only adjust for ambient derates)		UCAP-light (only adjust for ambient derates)	Pmax for each slice	UCAP (forced outages in top 20% needed hours and urgent outages)	UCAP-light (only adjust for ambient derates)
Resource Counting for daily energy-limited dispatchable thermal		Pmax for each slice, limited to physical capabilities	Other	ELCC	ELCC		UCAP-light		UCAP	UCAP-light	UCAP-light		Other		UCAP-light		Pmax for each slice, limited to physical capabilities	UCAP-light		UCAP-light	Pmax for each slice, limited to physical capabilities	UCAP	
Resource Counting for dispatchable hydro		Current 10-year exceedance methodology	Current 10-year exceedance methodology	Incremental ELCC	Average ELCC		Average ELCC		Current 10-year exceedance methodology	Current 10-year exceedance methodology	Average ELCC		Other		Current 10-year exceedance methodology		Current methodology modified for hourly exceedance values	Current 10-year exceedance methodology		Current methodology modified for hourly exceedance values	Current methodology modified for hourly exceedance values	Current methodology modified for hourly exceedance values	
Resource Counting for storage	Pmax over number of hours shown, subject to interconnection limits	Pmax over number of hours shown, subject to interconnection limits	Other	Incremental ELCC	Average ELCC		Average ELCC		Pmax over number of hours shown, subject to interconnection limits		Average ELCC		Other		Incremental ELCC	Pmax over number of hours shown, subject to interconnection limits	Pmax over number of hours shown, subject to interconnection limits	Pmax over number of hours shown, subject to interconnection limits	Pmax over number of hours shown, subject to interconnection limits	Other	Incremental ELCC	Pmax over number of hours shown, subject to interconnection limits	
Resource Counting for long-duration storage		Treatment similar to dispatchable hydro	Other	ELCC	ELCC		ELCC		Seasonal Accounting		ELCC		Other	Other	ELCC		Treatment similar to dispatchable hydro	Other		Other	Treatment similar to dispatchable hydro	Treatment similar to dispatchable hydro	
Resource Counting for hybrid resources		Existing treatment using ELCC	Other	Existing treatment using ELCC	Other		Other		Exceedance for each slice for combined elements		Average ELCC combined				Existing treatment using ELCC		Similar to existing treatment using exceedance	Other		Other	Incremental ELCC combined	Other	
Resource Counting for co-located resources	Treat components separately and apply applicable QC for each	Treat components separately and apply applicable QC for each	Other	Incremental ELCC combined	Other		Other		Treat components separately and apply applicable QC for each		Treat components separately and apply applicable QC for each		Other		Treat components separately and apply applicable QC for each	Treat components separately and apply applicable QC for each	Treat components separately and apply applicable QC for each	Other		Other	Treat components separately and apply applicable QC for each	Subtract battery charging from VER, apply exceedance, add remaining exceedance value to Pmax of battery	
Resource Counting for non-dispatchable resources		Historic performance during HE17-21	Historical MW output (exceedance) during each slice	Other	Other		Other		Other		Historic performance during HE17-21		Other		Other		Historic performance during HE17-21	Historical MW output (exceedance) during each slice		Historical MW output (exceedance) during each slice	Historic performance during HE17-21	Historic performance during HE17-21	
Resource Counting for demand response		Load Impact Protocols (LIP)	LIP-informed ELCC (for those following the CEC DR NQC process)	LIP-informed ELCC (for those following the CEC DR NQC process)	Other		Other	Other	Other	Other					LIP-informed ELCC (for those following the CEC DR NQC process)		Other	Other		Other	LIP-informed ELCC (for those following the CEC DR NQC process)	LIP-informed ELCC (for those following the CEC DR NQC process)	
Whether there remains a need for MCC buckets or Caps on certain use-limited resources	No	No	Yes	Yes	No	No	No	No	No	Yes			No		Yes	No	Yes	Yes	No	No	Yes	No	
Methodology preference for how to choose exceedance value	Average of the historical hourly output when load is higher than a threshold value (proposed by CalWEA)	Benchmark to ELCC value (proposed by solar parties)	Other	Other	Other		Based on VER performance on high load days (proposed by PG&E)		Other	Based on VER performance on high load days (proposed by PG&E)			Based on VER performance on high load days (proposed by PG&E)		Other	Average of the historical hourly output when load is higher than a threshold value (proposed by CalWEA)	Based on VER performance on high load days (proposed by PG&E)	Other		Other	Average of the historical hourly output when load is higher than a threshold value (proposed by CalWEA)	Benchmark to ELCC value (proposed by solar parties)	
RA resource transactions	Bundled (LSE purchases all of resource's RA attributes for all slices)	Bundled (LSE purchases all of resource's RA attributes for all slices)	Bundled (LSE purchases all of resource's RA attributes for all slices)	Bundled (LSE purchases all of resource's RA attributes for all slices)	Bundled (LSE purchases all of resource's RA attributes for all slices)	Unbundled (LSEs can purchase RA attributes for individual slices)	Unbundled (LSEs can purchase RA attributes for individual slices)	Load requirements trading	Load requirements trading	Bundled (LSE purchases all of resource's RA attributes for all slices)	Unbundled (LSEs can purchase RA attributes for individual slices)		Bundled (LSE purchases all of resource's RA attributes for all slices)		Bundled (LSE purchases all of resource's RA attributes for all slices)	Other	Bundled (LSE purchases all of resource's RA attributes for all slices)	Bundled (LSE purchases all of resource's RA attributes for all slices)	Bundled (LSE purchases all of resource's RA attributes for all slices)	Bundled (LSE purchases all of resource's RA attributes for all slices)	Bundled (LSE purchases all of resource's RA attributes for all slices)	Bundled (LSE purchases all of resource's RA attributes for all slices)	Bundled (LSE purchases all of resource's RA attributes for all slices)
Need Determination and Allocation	CEC proposal: the CEC-proposed hybrid of top-down and LSE-specific based on LSE forecasts and recorded loads	CEC proposal: the CEC-proposed hybrid of top-down and LSE-specific based on LSE forecasts and recorded loads	Other	CEC proposal: the CEC-proposed hybrid of top-down and LSE-specific based on LSE forecasts and recorded loads	Top-down based on CAISO coincident peak and pro-rata based on load		Bottoms-up based on each LSE's load shape plus an adjustment to CAISO coincident peak	Bottoms-up based on each LSE's load shape plus an adjustment to CAISO coincident peak	CEC proposal: the CEC-proposed hybrid of top-down and LSE-specific based on LSE forecasts and recorded loads	CEC proposal: the CEC-proposed hybrid of top-down and LSE-specific based on LSE forecasts and recorded loads	CEC proposal: the CEC-proposed hybrid of top-down and LSE-specific based on LSE forecasts and recorded loads		CEC proposal: the CEC-proposed hybrid of top-down and LSE-specific based on LSE forecasts and recorded loads		Top-down based on CAISO coincident peak and pro-rata based on load	CEC proposal: the CEC-proposed hybrid of top-down and LSE-specific based on LSE forecasts and recorded loads	CEC proposal: the CEC-proposed hybrid of top-down and LSE-specific based on LSE forecasts and recorded loads	CEC proposal: the CEC-proposed hybrid of top-down and LSE-specific based on LSE forecasts and recorded loads		CEC proposal: the CEC-proposed hybrid of top-down and LSE-specific based on LSE forecasts and recorded loads	CEC proposal: the CEC-proposed hybrid of top-down and LSE-specific based on LSE forecasts and recorded loads	Bottoms-up based on each LSE's load shape plus an adjustment to CAISO coincident peak	Other
Energy Sufficiency for Charging Storage	Other	Other	Explicit requirement to demonstrate energy sufficiency	Rely on ELCC values to ensure procurement of sufficient energy	Rely on ELCC values to ensure procurement of sufficient energy	Explicit requirement to demonstrate energy sufficiency	Rely on ELCC values to ensure procurement of sufficient energy	Explicit requirement to demonstrate energy sufficiency	Other	Explicit requirement to demonstrate energy sufficiency	Explicit requirement to demonstrate energy sufficiency	Explicit requirement to demonstrate energy sufficiency	Rely on ELCC values to ensure procurement of sufficient energy		Rely on ELCC values to ensure procurement of sufficient energy	Other	Explicit requirement to demonstrate energy sufficiency	Explicit requirement to demonstrate energy sufficiency	Explicit requirement to demonstrate energy sufficiency	Explicit requirement to demonstrate energy sufficiency	Explicit requirement to demonstrate energy sufficiency	Explicit requirement to demonstrate energy sufficiency	Rely on ELCC values to ensure procurement of sufficient energy
Should hedging be included?	No	No	Other	No	Other	No	No		No	No			No		No	No	Data request and analysis needed before further action	Yes	No	No	No	No	No
If yes, hedging approach		Other		Bid cap	Other		Other		Other								Price cap rebate	Other	Other				
Forward Requirement	3 years	1 year	Other	3 years	3 years		1 year	3 years	Other	Other	3 years		5 years		3 years	5 years	Other	1 year	3 years	1 year	1 year	1 year	Other

Appendix – A

Workshop Material

Workshop materials are made available on the Commission's website.

Materials include:

- Recordings of the workshop meeting
- Chat
- Presentation material
- Agenda

Link: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-history

Notes

Attached to Appendix A are the notes compiled of each workshop meeting. Please note that these notes should be used as a snapshot of what transpired during the meeting and should not reflect parties' position, as some parties' position evolved throughout the working group meeting process. Readers should instead refer to parties' informal comments and/or position matrix, included in Appendix B.

Notes from September 22 Workshop

The primary goal of the first workshop was to level-set with stakeholders on guiding principles and the issues that would be addressed through the workshop series. Before starting, PG&E clarified that changes being considered here are limited to the CPUC-jurisdictional resource adequacy (RA) program and are not intended to impact the CAISO's monthly showings, must offer obligation (MOO), or other processes.

At CEERT's request, Derek Stenclik of Telos Energy and Rick O'Connell of GridLABS presented on the need to move away from the current RA framework based on the single gross peak load hour. Telos/GridLABS presented six key principles to consider across the reliability planning process and the RA program, described the need to reform the counting rules (*i.e.,* ELCC) for storage and energy-limited resources, and emphasized the importance of decoupling reliability modeling from the counting rules. Relatedly, Nick Pappas of NP Energy presented a primer on how the exceedance methodology can be used within the"Slice-of-Day" (SoD) framework that highlights the need to move away from ELCC. NP Energy also described how exceedance can be effectively applied to portfolios of resources (*e.g.,* aggregated by resource type, like on- and off-shore wind, or geographic region) to capture diversity benefits and avoid losing resource value.

PG&E presented an overview of the key structural elements of the SoD concept (load forecast, use of gross vs. net load, seasons, and slices) and outlined several different options that are being explored (*i.e.,* various combinations of slices and start-times, seasons, gross/net peak basis), including key issues and "trade-offs" with each. PG&E also teed up issues that will be discussed at future workshops, including resource counting, LSE allocations, RA showing process and transactions, the interactions of SoD with local and flex requirements, and CAISO penalties and backstop requirements.

Major issues and recurring themes addressed during the stakeholder discussion/Q&A included:

- **The importance of aligning the RA program with work in the Integrated Resource Plan (IRP)**—Stakeholders identified the need to align forecasting assumptions and resource counting methodology across the two proceedings and noted that ongoing IRP loss of load expectation (LOLE) analysis should help inform the planning reserve margin (PRM) in the future RA framework. Additionally, certain parties expressed a desire for "post-contracting" LOLE analysis to confirm the procurement ordered in IRP and shown in the RA program meets the reliability criteria.
- **How to appropriately address reliability during multi-day events—**There was broad recognition of the increased risk of multi-day events. However, most participants agreed that it is important to first focus on the intra-day issues (*i.e.,* multiple critical periods in a day as noted in the Root Cause Analysis) to ensure SoD can be implemented for 2024 RA compliance. Additionally, parties noted that work in IRP—including the consideration of additional long-duration storage procurement and modeling of multi-day events—could help address this issue.
- **Interactions between the CPUC RA program and CAISO program/rules—**Despite PG&E's disclaimer that the workshops are intended to address changes to the CPUC RA compliance program, several stakeholders flagged the potential impact of the SoD proposals on existing

CAISO rules. There were several comments about the need to consider whether deliverability requirements vary by slice, and questions on whether/how seasonal CPUC RA requirements would impact the monthly CAISO showings. Additionally, stakeholders observed SoD may mitigate the need for an additional flexible capacity requirement and noted how local RA procurement performed could be credited under the SoD framework.

Barbara's notes:

The first workshop started with reviewing the CPUC's principles and provided a refresher on Slice of Day (SoD) by Peter Griffes and Luke Nickerman of PG&E. The RA focus on the peak hour is not working and any methodology must support bilateral transactions.

PG&E noted that the CAISO RA is for the entire balancing authority but the process will focus on CPUC jurisdiction with no impact on CAISO monthly showings, MOO, etc.

At CEERT's request, Derek Stenclik of Telos Energy and Rick O'Connell of GridLABS presented on the need for moving away from a PRM based on peak load to 8760 hours. They also discussed the importance of weather as a driver for RA including wind, solar, load, and climate trends and the importance of correlations, resource sharing, and how resources work sequentially. They said if wind and solar are netted, they don't need to be assigned a capacity value, but multi-day needs must be addressed, e.g., the impact of smoke from wildfires. It is not clear that can be done in time for 2024 RA compliance. There may also be multiple critical periods in a day as noted in the Root Cause Analysis.

The two stated that ELCC is based on a comparison to perfect capacity but that does not exist. For example, you must consider fuel security and black start. ELCC was a quick fix that creates a daily average for the availability of resources including times when they are not available at all. It is too difficult to calculate for each hour.

There was general discussion about the relationship between RA and the IRP. The CAISO can model the RA showings to determine if they meet need and backstop if necessary but it is harder to line up RA and IRP for pre-analysis. Post-showing analysis does not have to be done more often than annually.

SoD has a requirement to show energy/capacity for charging storage over and above meeting load. This might be phased in. There was a discussion of options for load forecasting (see PG&E presentation). Certain methods (like the variation between the maximum forecast value and the worst day) have the largest variability in the winter. Longer seasons have more variation. There was a comment about the relationship between the use of the exceedance methodology and forecasting since each addresses a certain type of day profile.

Gross load vs. net load: CAISO looks at resources from different LRAs and tried to determine if load is covered. It does not use ELCC but rather expected output based on what is on supply plans. If wind and solar are relied on to meet load, they must be on supply plans.

Under SoD, each slice is homogenous, so solar and wind do not appear in every slice where they have output.

Net load reduces variation among seasons due to the variability of wind and solar being removed. Allocation of resources might make more sense if use gross load and bottoms up might make more sense if use net load.

Use of larger slices increases storage requirement on a net basis. Starting hour also affects this.

Nick Pappas of NP Energy provided a brief primer on the exceedance methodology. It is a statistical tool to translate nameplate for resources (it has been used for wind and solar) into an expected value of what will be available for a representative day per month. It is more useful that QC and ELCC and uses statistical techniques, not large propriety models. The percentage of solar and wind output assigned to develop a capacity amount is a judgment call. Exceedance produces fairly consistent results for solar but wind is much more variable. One must consider what do with a lot of energy that is produced but not predictable. It could be used to charge storage. You could count energy differently from capacity for this purpose. It is useful to use exceedance to apply to portfolios of resources like blended onshore and offshore wind. One benefit is capturing diversity effects (both resource mix and geographical) and avoiding lost resource value.

There was a discussion of local and flexible RA, which are CAISO requirements. Both are under redesign. SoD mitigates the focus on flexible capacity, but it does not apply to either local or flexible RA. If the CPE for PG&E and SCE did local procurement, it could be translated into SoD and credited to all LSEs paying for local. There was discussion of whether MCC buckets would no longer be needed but concern they might still be needed for local RA.

There were several comments about the need to consider deliverability requirements if they vary by slice.

Notes from October 6, 2021, Slice of Day (SoD) Workshop

Informal comments may be provided on the topics of this workshop. The next workshop will be on resource counting.

PG&E presented two seasonal straw proposals, which are included in its slide deck. They propose using the maximum hourly value in a month or season for the load forecast, not the worst day, using the IEPR CAISO-level forecast for 2026 and 2030. The IRP has identified hours of concern in 2030, which include summer evenings but also mornings in February-April before there is much solar. They concluded that there is a need to focus on every hour of the day, not just the net peak. Re net vs. gross peak, they wondered whether the rise of co-located resources would change the need to look at the net peak. Net is more complicated that gross because you have to determine how much wind and solar capacity there is and how much credit to give to each hour. The straw proposals are based on net load but there are resource counting issues.

Is net load on an LSE basis or a system basis? This depends on how you do need determination and allocation. Bottoms up is by LSE. Top down assumes generic wind and solar shapes.

They discussed metrics. PG&E proposes to use the coefficient of variation (standard deviation/mean) so that there is not too much variation within a slide of day or season. The goal is not to minimize variance but to balance costs and reliability. Procuring on the basis of maximum demand in a month would lead to excess procurement in most hours but that provides insurance. The gross peak and the net peak might not occur in the same slice. Size of slice and start hour and both important. Metrics can be reviewed as load and resources change over time. Other metrics considered were related to cost and cushion for planned outages. The PRM should be considered relative to the variance metric as it might change over the seasons and slices. Once the seasons and slices are determined LOLE studies should be done on each. PG&E asked for input on seasons and slices. It will make its spreadsheet model to anyone requesting it.

Vistra presented on the various types of RA and commercial considerations (see slide deck). PG&E as central procurement entity (CPE) procures local RA that also provides system RA so the two are not separate. They want consistency between CPUC and CAISO and for the CPUC to delegate the LOLE study to the CAISO. The CAISO said this would be difficult and suggested the CPUC do it. They use different production cost models and the results might differ. The CAISO also said that it had stepped back from a minimum system RA requirement for all LRAs. Vistra wants less regulatory uncertainty.

The CAISO said that its Customer Interface for RA (CIRA) is set up to review annual and monthly Supply Plans for RA, which are used for substitution (see slide deck). Unless resources are shown on supply plans, the CAISO cannot identify them for RA. CIRA can only validate a single forecast and reserve margin and cannot manage SoD. It could modify CIRA to validate showings at net load peak against CEC load forecasts and PRM at 8 pm and wants the CPUC to do checks in other slices. The CAISO might be able to do an ex-post processing review.

CAISO can move RA compliance from monthly to seasonal but the final compliance at T-30 from the first day of the season would have to cover the entire season. If a resource came online mid-season, it could not count for RA until the next season, so it might be good to keep monthly showings.

CAISO is not sure it will do portfolio assessments for all times of the day; it is waiting to see how SoD develops.

CAISO said CIRA could be developed to add slices but the CAISO is thinking of the implications for CPM, MOO, and bid insertion of a resource is RA for a slice. The CAISO was reminded that the RA MOO would still be 24/7 except for use-limited resources.

The CPUC was very concerned about not being able to show for RA during an entire season after T-30, especially with a lot of new capacity coming online in the next few years. It said CPM could be used as a backstop but it would be better to allow it to be shown when commercial operation is achieved. The CAISO responded that its legal team said it needs firm deadlines to call in RA and that resources can be delayed. The CPUC said that a portfolio assessment would be ideal.

SCE presented a 24-hour SoD as a straw proposal (see slide deck). This would be a 24-hour monthly showing of how the LSEs would meet the load profile plus the PRM each hour of the worst day (not yet defined). It would use an hourly renewable capacity profile based on an LSE's resource portfolio (did I get that right?). SCE was concerned that use limitations do not necessarily fit neatly into slices. There would be a single showing of all 24 hours. Solar and wind would be based on hourly profiles. SCE acknowledged that there would be a need to confirm sufficient energy to charge or pump storage. There would be no unbundling of hourly slices. They would use a single NQC for each resource each month but incorporate hourly use limitations. The RA showing would be a stacking exercise using an Excel model.

The CPUC asked how the 24-hour slice would be made binding and compliance would be verified. It also asked if LSEs would specify in contracts the MWh they would get to meet aggregate energy requirements. SCE said the LSE would have to show sufficient capacity in every hour but it is not clear how the energy requirements would be addressed. When asked, SCE said it was not sure if the load forecasts would be bottoms up or top down but that it was leaning toward top-down based on the IEPR forecast. If it is bottoms up, there is a need to address diversity benefits.

PG&E said products need to be defined and that the SCE 24-hour requirement would result in a need to keep products bundled but may forego efficiency in covering multiple LSEs. Both bundling and unbundling have plusses and minusesb.

There was some discussion of comparing slices with the most LOLE to inform on reliability.

Summary of 10/20/21 RA Track 3B.2 Workshop on Resource Counting

PG&E presented first. It discussed objectives. Then it reviewed the current resource counting rules. It offered options for future resource counting for dispatchable generation, for stand-alone energy storage, for solar and wind, for hydro, for hybrid and co-located resources, and for imports. It did not address DR because it thought the CEC-led working group was doing this. During the discussion it became apparent that this group is not addressing DR QC under Slice of Day (SoD) although some parties were encouraging it to do so. This should be resolved so DR is addressed for SoD somewhere.

In response to questions, PG&E said that ELCC is increasingly difficult to administer to predict QC for wind and solar as different resource types are added and hard to fit into SoD because there is a need for more granularity. Also, individual resources may over- or under-perform compared to the aggregate numbers ELCC produces. These are the reasons PG&E proposes to change to the exceedance method.

For hybrid and co-located resources, PG&E asked whether similar methodologies should be used for each and mentioned the importance of having sufficient energy to charge storage if it is co-located. It also noted that imports can be transacted for different hours and may not align with slices.

There was an extensive Q&A session. This included the issue of QC for DR. There was also a lot of discussion of whether round trip efficiency must be dealt with in the QC or whether suppliers have contractually dealt with that. Storage suppliers said they are no longer only providing one cycle per day and that the hours of energy production do not need to be contiguous. Round trip efficiency and MWh after round trip efficiency are registered with the CAISO. The CAISO can calculate running state of charge. Developers can overbuild nameplate above the interconnection limit to meet requirements.

PCE said the ELCC values for renewables were too low and should not be compared to perfect capacity. The ELCC statute does not define ELCC so there may be flexibility to change the methodology but keep the name.

A concern was expressed that a unit on forced outage could drag down the exceedance value if based on history. PG&E said in the past there have been proxy values to fill in for forced outages and the resources on outage could be eliminated from the stack.

CLECA mentioned that exceedance relates to contribution to serve load whereas ELCC looks at changes in LOLE in reliability modeling. In certain time periods you can get different results. For example, solar at noon makes a large contribution to meet load but its LOLE value is zero under ELCC. Which should SoD address? CLECA also pointed out that the CEC RA working group is not looking at an SoD framework.

SEIA said that in the past there were differences between the results of exceedance when addressing individual projects compared to a total portfolio. This is especially problematic as the exceedance value used rises much above 50%. SEIA will present on this next time. When choosing the exceedance percentage, this should be considered.

There were questions about treatment of 6-hour storage if it fits into more than one slice. Does this affect its must offer obligation (MOO)? PG&E said no. The limits on storage are the amount of energy that can be provided for a full slice. There could be different amounts of energy for different slices. If MOO is 24/7, can manage charge and discharge through bidding.

PG&E confirmed that exceedance for wind and solar should include location, which is particularly important for wind due to greater geographic variability in the production profile.

MRP suggested that different counting rules might be appropriate for different sizes of slices. PG&E responded that it wanted to use resource counting rules to inform the design. MRP asked which was more important and PG&E said they have to be developed in parallel.

CalCCA asked what could be done with energy in excess of what is needed for storage and could this be transacted? PG&E indicated it has not addressed transactability yet.

The CAISO next presented on the unforced capacity (UCAP) approach. (Please refer to its slides.) It has changed from EFORd to a seasonal availability factor but is not sure it will work for resources other than thermal units. It will present on non-thermal units next time. A non-availability factor is applied to deliverable QC to get NQC but MOO is in terms of deliverable QC. UCAP would be in place of the exceedance methodology. The CAISO has not considered UCAP for wind and solar because the ELCC values were so low and thus did not consider forced outages either. UCAP will capture use limitations reached but not long start that is not committed day ahead. Calculating outage rates for high load periods should capture usage correlation with high temperatures but not necessarily weather-related outages like for high clouds and solar.

The CAISO said there could be a higher PRM or use of 1-in-5 weather to address risk tolerances.

NRDC asked about the differences between exceedance and UCAP and how they interact with the PRM. CAISO responded that under UCAP the PRM would be lower because UCAP already accounts for forced outages.

The issue arose of whether historical performance is a good predictor of future conditions due to climate change. CAISO felt that since UCAP only relies on the last three years of generation data, the information is current enough to reflect climate impacts on performance. There was also discussion of substitutions for planned outages that were cancelled. Use-limit reached outage cards can be used for UCAP.

Concerns were expressed about the use of the top 15-20% of hours to establish the RA cushion and whether a set MW amount could be used. The CAISO responded that there could be too few hours below the threshold or none. There would not be different UCAP values for each slice of day but only one, at least for thermal units.

CalCCA said it wondered if basing UCAP on all 24 hours of a day and not a subset (if there are more likely going to be outages in some hours than others) would be more appropriate if moving to an RA structure in which the need for resources in each hour (e.g. to oversupply in order to charge batteries for later delivery) was more appropriate. CAISO responded that it could calculate an average on all hours or could lower the NQC value if there were availability limits or could weight hours differently. The focus has been on thermal units which are generally 24/7.

After lunch, Nick Pappas presented on behalf of NRDC on resource counting for preferred resources. (See his slides.)Nick thinks a one-hour slice and use of exceedance represent the best approach and that hourly slices will reduce compliance costs. His showed that one-hour accounting would reduce LSE procurement requirements given the same amount of solar, wind, and storage. He proposed resource-specific exceedance.

There was considerable discussion in the Q&A. Calpine said if you do not use ELCC, a more complex compliance framework would be required. There are 3 degrees of freedom – slices/seasons, resource counting, and PRM. These 3 need to assure reliability. How do we define the PRMs and resource counting rules to be sure the entire system is reliable? Should the PRM be the same with differently sized slices?

Nick responded that he struggles with the 3 degrees of freedom. If you fix the PRM and exceedance and vary width you lose precision. Need to determine exceedance parameter and PRM. Calpine responded that Nick had not demonstrated that the various portfolios he presented are equally reliable. Nick said the 4 portfolios have the same resources. Others felt finer slices give more predictability of what is needed. Vistra said it prefers ELCC over exceedance, especially marginal ELCC. There was a long discussion about what hourly ELCC means. Vistra clarified that it did not intend to suggest that each hour would have its own ELCC value.

CESA said ELCC is a measure of overlap with moments of highest LOLE and focuses on hours when LOLE is not zero but does not indicate when the resource is producing. The biggest risk of under- or over-counting is granularity. ELCC can't do this, but exceedance can. There is a correlation between load and output of RPS resources via weather. Should we assume a similar correlation for load and output, e.g., 1 in 2 load and 50% exceedance and PRM?

Nick said there are two limits on exceedance. The first is co-variance of load and solar or wind. If a 75% exceedance is used, what are the consequences of the other 25% of hours? How do we not overly devalue if the tail hours do not matter? Hourly exceedance might produce a different value compared to cumulative. All this needs to be taken together to be sure the PRM provides reliability.

CalAdvocates discussed the potential portfolio benefits of exceedance; if look at one LSE, what about separate portfolio benefits? Would you allocate back to all LSEs?

Nick said there is a question of exceedance for individual LSEs vs. the entire portfolio. PG&E did its exceedance analysis for the entire wind and solar fleets. If you go to resource-specific calculations, you get more unique tails that apply. What is the co-variance? What is the right exceedance value and how does it capture co-variance?

Carrie (Gridwell) said Nick's approach understates complexity. Each LSE has to procure for its own peak and there are transaction costs. She likes the idea of supporting reliability in each hour but is not sure it is transactable. If each LSE procures to its own load, there will be over-procurement on a system level due to the non-coincident nature of peak and diversity on the resource side. Nick said the PRM addresses this.

MRP asked whether each hourly slice would have its own UCAP value. CAISO responded that since thermal resources are dispatchable, there would only be a single UCAP value for each resource.

CalCCA said transactability is an issue. Thinks transacting the obligation is key. Generators need to recover revenue. Sees similarities between Nick's proposal and SCE option. What is different? It appears only hourly output for renewables.

SEIA discussed ELCC vs. exceedance. ELCC only looks at hour so risk (non-zero LOLE) which is relatively few hours. Exceedance looks at an entire day. Solar value is to charge storage and has value mid-day. This is a reason to move away from ELCC. Also, there is the issue of deciding which exceedance value to use. PG&E looked at 75% and 50%. For solar the two are close mid-day in summer and there is a good correlation between solar and load. It is different in the winter, early morning and late afternoon with clouds or smoke. SEIA is convinced we should move to hourly slices and then address exceedance and then PRM.

PCE said each resource has one product, its profile. PCE is already trying to meet its own load each hour with renewable energy, which is comparable to IRP compliance. PCE mentioned that the IRP Clean System Power Tool already fills out hourly generation profiles for different resource types, which is similar to what LSEs would need to show compliance with an hourly slice RA framework. It questions why bottom-up is a problem at the system level. Top-down is hard for coastal LSEs – they have to do their own procurement and also procure a share of system RA needed.

Nick agreed a resource's product is its profile, but there are issues re non-coincident peak vs. coincident peak in top-down vs. bottoms-up.

MRP asked if the product had a minimum duration of one hour if use hourly slices? Nick said if product is 100 MW of solar, Excel populates the output profile of the solar and allows the resources to be optimized over a number of hours. You can post-check the allocation. MRP said this was an after-the-fact check and cannot be done via procurement. Nick said this is de-linked from operations and represents planning.

CLECA asked what is being measured, serving load or reliability contributions? If the latter, it is more complex. If have LOLE in 100 hours in year, and there are months with no LOLE, ELCC studies eliminate resources to get to a non-zero LOLE. There needs to be a schedule to narrow what we are trying to measure because you cannot get hourly granularity for ELCC. Nick said he agreed that it is hard to use ELCC as a granular approach. CLECA was concerned that ELCC produces a single value across multiple hours and does not reflect variation.

The CEC said it is possible to do coincidence adjustments so the sum of each LSE's procurement does not exceed the need. CEC has LSE-based coincidence adjustments but would have to do them hourly. It gets each LSEs' hourly loads every year.

The CAISO raised questions: 1) How does SCE hourly slice account for energy limitations across the month like the DR 24-hour energy limit? 2) Do we assume everyone has to have so much energy? Is there any reliability risk if the entire portfolio is DR? Are there any other checks needed for inter-month energy limits? What about minimum down times? Hydro, DR have different limitations from wind and solar.

CESA raised the issue of multi-day reliability like the impact of wildfires on solar output. Should the PRM be greater in some hours/months?

CalCCA asked PG&E whether MOO was installed capacity or exceedance value. PG&E said MOO is still separate and subject to CAISO rules. PG&E was asked about hydro and use-limited thermal. PG&E responded that hydro is subject to exceedance. If thermal is use-limited, you can show it in the relevant hours. If you fit it in a slice, you might lose an hour of two of usable capacity. CalCCA asked if we need a quantification from the CAISO as to how much thermal generation is use-limited. The CAISO indicated that they would be willing to research the number of use-limited resources on the grid. Gridwell offered to confer with the CAISO as the use limit flag may not be a sufficient indicator. Re hydro, the current method is based on peak load need; there is an issue of how much energy is behind the hydro which would be an issue for hourly.

Calpine said the PRM will not necessarily solve the multi-day issue. We may have to look at a worst week or series of days to ensure sufficient resources across multiple days, but that would complicate the framework. CESA felt that a higher PRM might resolve this issue.

Nick summed up issues of precision, weighting values, looking at the tails, PRM is not just how to do clean up after everything else; need alignment in critically reviewing different types of resources and loads. He also noted that the CEC would be able to produce hourly load forecasts for each LSE in order to implement the hourly framework.

Notes from 11/3/21 RA Reform (Track 3B.2) Workshop

Informal comments are due 11/10/21 on structural elements and counting rules. Serve but do not file.

PG&E will put together a comprehensive proposal for the next meeting. PG&E said ELCC is good for long term planning, not necessarily for RA which is shorter term. ELCC does not reflect time of day or monthly energy availability.

PG&E's presentation covers its main proposals. Please refer to it.

Gridwell asked for clarification about slide 9 saying LSEs need to show sufficient capacity to charge. PG&E said you need to be sure there is enough energy in the system in excess of that needed to meet RA needs. Gridwell said PG&E seemed to confuse energy and capacity or to use them interchangeably. It thinks energy sufficiency is an unnecessary constraint unless you limit it to renewables. PG&E responded it may be a constraint if there is less gas capacity in the future. Gridwell said that if there is less gas, it will be too late to replace it.

CalWEA discussed the need to look at the correlation between load and output of wind and solar. If you have wind and solar instantaneous production and instantaneous load, you can net. It suggested focusing on historical net load. PG&E said the RA program is based on forecasts and asked how to forecast net load since load, wind and solar are stochastic. CalWEA said one could us history to forecast load, net load, and wind and solar separately. PG&E asked at what level would one forecast wind and solar since output in the future will be different from history.

PG&E proposes to have an exceedance % calculated for each hour.

SEIA/LSA/Vote Solar (SEIA) asked about PG&E's data set. PG&E said it used 2015-2020. SEIA said the amount of solar grew over that period and asked if PG&E normalized for growth in the fleet and, if so, how? PG&E said it did an exceedance calculation for each year for the worst day of each year which is the same as normalizing. It did not average across all years. SEIA asked for the underlying data.

Customized Energy Solutions (CES) said the IRP ELCC values show declining values over time and suggested you could forecast net. PG&E responded asking at what level of uncertainty. CES said you could use net and use LOLE to set slices up, recognizing that if there is no LOLE, there is no RA value, but this is premature since don't know the slices. PG&E said it will address this at the next meeting.

CalCCA asked about use of net vs. gross load in PG&E's exceedance. PG&E responded that whether gross load or netting was done for wind and solar there should be consistent treatment of them. CalCCA asked if supply side, would it be the worst load in the slice, so wind and solar vary by season and slice? PG&E said yes, there would be a different value for each slice based on the worst hour in the slice.

NRDC said this is critical for any method; the exceedance method is a proxy; what about using the worst day or 3 days? PG&E said it is trying to be more accurate using as much data as possible and you may over-procure if you use the worst day. NRDC said depends on the correlation between resource output and load. PG&E said you need to study the correlation as part of exceedance. The "worst" day is the peak day of the month.

Because time was up, many questions went into chat.

SCE presented next. Please see presentation. It recapped its previous proposal. It has not defined "worst day". The load shape it proposes using should be reasonably representative of an LSE load shape, either individual or grouped. One does not have to take the worst slice in an hour. Each hour is independent. RA resources cannot be unbundled but a resource can sell partial capacity to different LSEs. The RA has to be deliverable. SCE thinks a use-limited dispatchable resource could be used in non-consecutive hours. Solar/wind do not require a single monthly QC. There could be hourly ELCC. Hourly slices give solar and wind the best chance to show contribution to reliability. One should not create a custom profile for each resource.

CLECA said it is struggling with hourly ELCC. Historically ELCC is an annual concept. Energy Division creates monthly ELCC by removing resources to generate non-zero LOLE. If hourly, doesn't SCE have to pull out a lot of resources? SCE responded that it agrees. The current ELCC makes no sense in the slice of day (SoD) world. Reformed ELCC would be completely different. Unless state law is changed, you could call something ELCC but it could be based on exceedance. There was some discussion about how important it would be to get the statutory ELCC mandate changed.

PCE asked about Pmax vs. UCAP. Why wouldn't one use UCAP? How many years of forced outages would be used? SCE replied It supports UCAP. Either works with 24 slices a cay.

MRP asked about transactions. SCE responded that an LSE would buy an hourly normalized profile shape, normalized by the number of MW. 25 MW could be 8 MW in HE 7.

SCE raised questions about storage hybrids. It thinks there should be default shapes for renewables and storage based on configuration, including interconnection and source of charging power.

Vistra said modeling should not limit standalone storage to one cycle. In NGR[1], it is modeled as being available continuously and bid insertion will happen. Restrictions would have commercial consequences.

[1] Non-generator resource.

SCE said it was not restricting operations. It wants to be consistent with showings and is not trying to impact commercial value. Dispatches would still be determined by the CAISO market based on actual conditions.

Vistra said it wants alignment among contracting, showing and operations. The seller can provide hours of availability in an offer, like a profile. SCE agreed.

CES said it agrees there is a need to consider the size of a hybrid resource. It doesn't have to be deliverable beyond the interconnection; the excess can be used to charge the storage; the CPUC is too conservative. Re deliverability, do not do studies across all hours of the day; use CAISO studies. SCE agreed more studies were not needed.

Calpine asked how the SCE proposal was consistent with the CAISO backstop process. Would the CAISO validate a particular hour? SCE said backstop occurs if an LSE has failed to meet procurement requirements. Calpine said the CPUC determines but the CAISO backstops. SCE said, if the current process is used, LRAs have to meet RA requirements but all resources are turned over to the CAISO so it can determine if there are sufficient resources in one or more hours. Thus, the CAISO has to have a "failure" definition.

SCE would like the MCC buckets to go away.

CESA said an hourly approach makes it less likely to undercount resources. SCE said it considers downtime to recharge and assumes charging fully. SCE responded that it will allow showing partial use and partial discharging but it does not know how to model on a forecast basis for RA showings and is using stacking rather than optimization. There is a need for a larger discussion of the one-cycle approach, perhaps like a default shape. CESA noted that PG&E would allow storage to be shown in non-consecutive slices. No need to limit under SCE's framework.

GridLABS for CEERT discussed the importance of looking at hybrids and said it wanted to present a real LOLE analysis and compare the results to exceedance.

After lunch, Gridwell presented a "different" option. It said it is important to make sure the counting rules are accurate and to capture portfolio effects from resource diversity. It prefers seasonal showings for all RA products with local still annual and seasonal for flexible RA until it is sunsetted. Both peak and net peak load requirements must be met. Gridwell likes ELCC for wind, solar, hybrids and operationally-limited resources. If ELCC doesn't capture all contributions to reliability, the sum of all showings would have to validated. Gridwell takes out solar in assessment to do a net peak load validation.

SCE asked how this is consistent with the CPUC preference for SoD. Gridwell responded that it is a two-slice proposal, one being peak load and one net peak load. It repeated that the counting rules should be pinned down first and then sufficiency can be determined. It said counting rules should be coordinated across proceedings and that IRP uses incremental ELCC which buckets groups of resources by COD, thus naturally allocating diversity benefits. It thinks ELCC should be used for use-limited CTs and that an ambient derate should be used for non-use-limited thermal units. Gridwell said it could not find any correlation between past and future forced outages.

PG&E asked if ELCC would be done on individual resources. Gridwell replied this would be done in buckets by location and technology.

CLECA asked if the peak and net peak were monthly or annual. Gridwell replied seasonal. There would be one ELCC value per resource per season. Net peak is only a validation. You would use Energy Division calculations for ELCC. You would use the CAISO net peak load to validate that if solar is removed, the remaining resources can meet the net peak load.

CLECA said the current LOLE is based on net peak. If you take that ELCC and apply it to earlier time periods, this would underestimate solar's contribution at peak. Gridwell responded that average ELCC overestimated solar's contribution to net peak in August 2020.

CLECA asked if use of incremental ELCC could eventually drive solar's NQC to zero. Gridwell responded that if you cannot use solar to meet reliability in the IRP, why would this not be the case for RA. CLECA said RA deals with the entire resource stack. Gridwell responded the mid-term IRP doesn't make all solar zero. Existing assets use average ELCC, only new ones use incremental.

Gridwell said seasonal slice validation at net peak load is done in the aggregate. Battery charging energy sufficiency is not a binding constraint for roughly 8 years and that storage should not be built that can be charged from fossil resources. You should address hourly reliability through counting rules and validation.

PCE asked if this was like the current RA process with extra validation for net peak. Gridwell responded that it thought this was an improvement without changing too much. PCE said it does not think existing RA works and that NQC over-estimates the value of gas-fired generation. Gridwell responded this can be addressed with an ambient derate and use of ELCC for more resources.

American Clean Power (ACP) expressed concern about the complexity of SoD.

Vistra agreed that RA and IRP rules need aligned counting rules. It said RA rules (because of multi-year contracts) are starting to lead to new resources and that new rules should allow rational exit. It supports diversity benefits for system RA and likes the validation.

CalCCA said coordination with IRP is a good idea but using similar methodologies is not. ELCC is not going to work. Where does the diversity benefit go? Gridwell defended ELCC.

CES likes the idea of keeping counting rules similar for RA and IRP but was unsure how planned outages would be addressed.

Gridwell said most solar and wind contracts are not for RA although some wind contracts provide RA depending on location.

The next presentation was on behalf of SEIA/LSA/Vote Solar. The summary will refer to them as SEIA. Please refer to the presentation.

SEIA used September 2021 RA hourly market slices. It said that solar's RA value is not captured in marginal ELCC. Average ELCC better values the reliability contribution of the entire solar portfolio. The net load peak is lower than the gross load peak due to solar. The peak is 5-9 pm based on E3's ELCC LOLE hours rather than 4-9 pm. Using a 50% exceedance eliminates any diversity benefit issues. There is sufficient solar energy to charge storage for about a decade.

Calpine said re slide 5 that we have not worked through whether solar counting might require an increased PRM. Calpine asked if SEIA proposed to benchmark exceedance to average ELCC, would this be updated regularly. SEIA said yes but there is a need to look at the entire portfolio. SEIA also said that as solar is added in the future with storage, this would change the ELCC results. Energy Division would have to calculate ELCC so that it can be a benchmark in the future, but it would do this for the IRP anyway.

Vistra said some of the slides appeared to conflate energy and capacity.

CalWEA made a presentation on deliverability. Please see the presentation. It wants to drop the N-2 contingency for highest system need and eliminate the secondary system need test for deliverability and not use curtailment as a criterion. It also says that resources in local capacity areas should not have to provide system RA.

ACP said it agreed with CalWEA but also asked what the CPUC could do about the CAISO policies.

CalWEA said each slice should have its own deliverability study. CES responded that if there are multiple deliverability studies across the day, this will create contracting problems.

CalWEA doesn't see this as an issue. It thought each slice would have its own market. In some slices RA value would vary and demand would vary. Gridwell said the MOO is still 24/7 even if you procure a one-hour slice and asked if there would be benefits to doing a seasonal deliverability study. CalWEA thought there might be.

Wrap-up

PG&E asked for feedback on the definition of worst day.

PCE 1) asked which proposals would interact with the IRP best and 2) said the issue of complexity is not straightforward. LSEs are transacting a portfolio of resources to meet a portfolio of load. There is an Excel spreadsheet to present this for each LSE in the IRP.

SCE, Gridwell and SCE had an extensive discussion in the Chat, which is separately posted. CESA summarized that if one uses ELCC for storage, there is a need to look more accurately at several variables now overlooked including location, duration, and technology. This will make ELCC more complex. CESA has some reservations about using ELCC for dispatchable resources. It supports deliverability revisions although it is not sure what the CPUC can do about this. Gridwell agreed with CESA that ELCC would need to be augmented. It does not think storage should be valued at Pmax. CESA said it was not clear than storage should count at Pmax and the UCAP offers ex post verification. Gridwell said it struggles with the lack of analysis around UCAP; data are needed to see whether history is representative of future forced outages. Historical forced outages may not be a good indicator of likelihood of future outages because a gas plant or storage facility that is repaired/refurbished may be **more** reliable going forward.

CalWEA said it filed detailed testimony on its concerns on 9/1/21 in R2011003.

Vistra said it doesn't know how incremental ELCC would compare to UCAP. UCAP would include forced outages. However, batteries use forced outages to manage their dispatch so these are not the same type of forced outages. It thinks a robust ELCC would better capture complementarity among classes of resources. There are performance adjustments in ELCC in other ISO/RTOs to capture variation.

CAISO said it will provide data in a January UCAP workshop about outages but is not sure how much can be released. Substitute capacity is built into UCAP. MOO is at full capacity even if only 90% is available. 90% of full capacity is designed to have a pool of excess capacity. Preliminary outage data shows current forced outages higher than in PRM. Some outages are consistent like ambient temperature but others are random.

Notes from November 17, 2021, RA Reform Workshop

PG&E was the sole presenter. (Please see slides.)

The informal comments due November 10 were about 50-50 between the PG&E and SCE proposals with those who pay preferring SCE's proposal and merchant generators preferring PG&E's initial proposal.

PG&E presented on Need Determination and Allocation. Its key objectives were over/under-procurement risk, administrative complexity, fair cost attribution, and alignment across proceedings including IRP and RPS. It said the key elements for the final framework are Season and Slice Structure, Resource Counting, Setting Requirements and LSE Allocation, and Planning Reserve Margin (PRM).

In response to a discussion about an early discussion of the components of the PRM, i.e., operating reserves, outages and demand variability, the CAISO stated that it prefers UCAP for forced outages but that, if it is not adopted, one could look at actual outage rates and include these in the PRM calculation. PG&E agreed that, if UCAP is not adopted, we need to consider the impact on the PRM of forced outages. The PRM will be determined later, not now. GPI said the PRM is related to the load forecast since the PRM addresses unpredictability in load and resource output. It should reflect any changes in CEC load forecasting methodologies. PG&E said we may want to adjust some factors more often than others, like PRM, but not adjust the RA structure or counting rules. It hopes the CEC will reflect changing loads in its forecasting. The PRM allows changes in procurement up and down more regularly based on periodic LOLE analysis.

MW Storage Farms said the modeling would be complex and should look at the cross-correlations between inputs, requiring statistical expertise. It said the cost of the modeling would likely be less than the cost of avoided over-procurement. PG&E agreed but asked who would do the analysis, who will pay for it, and how will it affect public policy? All parties have vested interests and it is not clear the CPUC has the resources or ability to get the analysis done. The study cannot be biased.

Gridwell asked if PG&E intended upfront LOLE analysis. PG&E replied there should be some LOLE analysis. Gridwell asked which parameters would be fixed. Would others be fixed and the PRM then developed? PG&E said either way. You could determine some factors and then figure out how the other factors need to be adjusted. You would need agreement on the factors to determine, e.g., slices, counting rules, and load forecasting. Stakeholder input would be used to develop a proposal.

CESA asked about the effect of transitions between slices. PG&E said if you put more hours together, this will affect the amount of excess procurement; the current structure over-procures based on 115% of highest demand in the month.

PG&E said the PRM may be the most flexible parameter to adjust. The RA structure and counting rules should not change often.

Vistra asked PG&E about Gridwell's two-slice proposal. PG&E was unsure about the size of the slices and whether there were seasons. Gridwell said there would be a stack at the gross peak and a stack at the net peak that did not count any solar. Gridwell and Vista will present at the next meeting.

NRDC said we need durability of resource counting rules over time. Which approach would assure that so there can be multi-year contracts? PG&E said resource counting needs to assure resources provide energy when they are expected to. PG&E reiterated its principle that the structure should be static because changing it will be much more destabilizing to a portfolio than the particular counting methodology that is closen. If 24 slices, performance over time is caught by exceedance method; UCAP can catch some of that. NRDC said with solar and wind you are less likely to get massive swings but when you add storage, there could be longer peaks if there are 4-hour slices and how would you address this? PG&E replied that for resources that can count for more than one slice, can still dispatch less capacity to cover more slices with the energy. As such, PG&E noted those resources should be counted at the maximum capacity they can provide over the number of hours shown, subject to interconnection limitations.

There followed a long discussion about how to deal with longer duration storage, whether slices had to be the same length, what happens when requirements change and load is moving between slices, what happens when net peak load changes in the two-slice proposal, and the certainty with which we know the peak demand will occur within a 4-hour period.

Cal-CCA initiated an extended discussion of how to ensure storage is charged in prior periods so that it can discharge when needed, whether this was an operational issue, and whether this was a capacity or an energy market issue. Does the CPUC need to set up RA so CAISO can dispatch when needed? PG&E said if an LSE wants to show charging in the net load peak it will have to show capacity to allow it to charge. CESA said the RA program should reflect some but not all aspects of operations. Focusing on daily energy sufficiency does not address long duration storage which may be charged months in advance. MW Storage said we are moving towards a storage forward grid, moving away from the "just in time" grid that we have had up until now, and that the shoulders on the grid are a major factor in over-procurement. PG&E asked to what extent the PRM can address the uncertainty. There was a general sense that more time needs to be devoted to the many storage issues.

PG&E said any LOLE analysis includes many assumptions and these should link to both RA and IRP and consider the future distribution of loads. There should be coordination between RA and IRP including the target level of reliability.

Cal Advocates asked if PG&E expected the IRP to initiate common assumptions like LOLE. It thinks RA should do it; IRP develop RSP and PSP; if LSEs develop portfolios based on RA requirements, IRP will combine them, but they are not sure how the diversity benefits should be allocated. Portfolio-level exceedance could be different. IRP-level LOLE might capture the diversity but RA should drive the individual IRPs which drive the RSP.

PG&E said the Commission needs to decide what the appropriate level of reliability is via the LOLE.

PCE said as an LSE, it makes sense for the RA requirement to make it more likely to have overall long system capacity to reduce market power for marginal resources.

ACP-CA said consider the commercial context; contracts right now cover many regulatory requirements; they fear changes in the RA program will hurt the contracting process since there is uncertainty about the exceedance values for wind, for example.

CAISO supports coordination between RA and IRP and use of common inputs. Vistra wants consistency between CPUC and CAISO and a probabilisticly-determined LOLE reliability target of at least 1-in-10. PG&E said the Commission needs to decide that. Vistra said the working group should provide a recommendation.

After lunch, PG&E presented on Forecast/Need Determination. One option is using maximum hourly values in a month or season from the IEPR, but this could lead to reliability problems. An alternative would be to use the highest value in a season or slice.

Next there was a discussion of the PRM. Right now, it covers operating reserves, outages, and demand variability. There are proposals to change the percentages for outage rate and demand variability and add resource variability. PG&E leans toward not varying the PRM by season or slice.

MRP asked if these were components of the PRM or could they be used as inputs to an LOLE study which could provide a different result. PG&E said you could determine some in advance, e.g., if you adopted UCAP. Some are fixed like operating reserves and ancillary services. How to account for demand variability, e.g., due to climate? Do we want to add resource variability? This relates to counting rules for variable resources and exceedance. PG&E proposes we decide in advance what will not change and look at the interdependence of the result and whether to use UCAP. The resulting LOLE will determine how to adjust the PRM.

SCE asked if PG&E proposed to set a reliability plan standard, do a LOLE study, and base the PRM on the LOLE results. PG&E said yes. SCE supports this but thought both should be done in the IRP. CES agreed they should be addressed in the IRP and that other RTOs do this. PCE said the PRM will depend on exceedance values and the resource mix.

Cal Advocates raised the issue that production cost modeling is tied to past normalized weather years and tends to underestimate climate trends. It said the IRP rulings proposed a 1.8% climate adjustment which looks reasonable but might vary across TAC areas. The current PRM does not relate to an LOLE reliability target. PG&E agreed and said you must pay attention to the inputs to the LOLE analysis.

CalWEA asked if all slices necessarily had to be of the same length and if you had to have the same PRM for each slice and mentioned a CPUC study where the PRM was higher in the winter. PG&E said a variable PRM could create compliance and administrative challenges. The CAISO said you cannot decide this yet. It is looking at outage data. It said it might not support a variable PRM across slices but might by season. It raised the issue again of planned outages and the possible need for excess RA capacity for maintenance.

The CEC said there are some limited climate effects in the IEPR and in the next 1-2 years it will have improved climate modeling.

Vistra said part of its proposal is addressing substitution risk.

Cal Advocates said if you tie RA and IRP together, it might create tight markets and high costs due to market power. The IRP might have a higher PRM for planning to allow for retirements greater than the baseline. MRP asked if Cal Advocates was suggesting more LOLE in the IRP vs. RA if all else were equal. CalAdvocates said to consider how to look at the RSP and PSP and enforce without creating market power impacts. PCE said to consider same PRM in each with a market liquidity adder in IRP above the PRM to make the RA market liquid.

PG&E next presented on Allocation (see slides)

It is currently top-down. Under SoD, you would have to reconcile the CEC and LSE load forecast more often, i.e., for the various slices. You would use coincident peak for gross load; if net load, would need parallel accounting process for wind and solar; net load would require earlier showing of renewable resources by LSEs so the gross load could be adjusted by wind and solar. Wind and solar also affect the load forecast so if trade RA, this is an issue.

DACC pointed out that in the CEC process to determine LSE-specific RA requirements, each LSE provides hourly loads to the CEC and the CEC does a plausibility check for each LSE and then does a coincidence adjustment to ensure that LSEs with different load shapes are not unfairly burdened. SoD would have CEC doing the same thing. PG&E agreed and wanted the CEC to provide feasibility input. The CEC said it would have to make LSE-specific coincidence adjustments so it would be more complex but similar. It already gets individual load forecasts from the LSEs.

CalCCA asked if the individual load curves and individual LSE wind and solar shapes would be used. PG&E said this would occur for the net load approach only.

ACP-CA was concerned that shifting from ELCC to netting could disrupt contracting. If an LSE contracts with a resource and the LSE has already adjusted its load curve but bought the renewable power for RPS, not RA, it wouldn't be contracted on the basis of RA value.

PG&E said this was a good point on tradability on a net load basis.

ACP-CA asked how the RA value would be known using exceedance. PG&E said it will be able to know what the RA value will be on an ex ante basis using exceedance. If choose net load approach, need to net wind and solar procured by an LSE against its load; each LSE has to report its contracted renewables in advance so the CPUC can net; not sure this is possible. How to use renewable resources not yet contracted to meet that need. This is a complication of the net load approach. ACP-CA asked that this be included in the Working Group Report. MRP asked if PG&E had a preference. PG&E said there are tradeoffs but net load is more complicated.

PCE said LSEs procure resource to meet their own load profiles. If procure resources to meet energy needs for all hours, would have to buy more RA for other peoples' customers which could lead to a cost shift.

PG&E says if do bottom-up, you have to credit to the LSE the resources it has contracted; this is why easier to do on gross basis and allocate to LSEs on a slice-by-slice basis.

The CAISO asked if we would continue to use ELCC to calculate the capacity value of resources. PG&E said we need to think more about the showing process at the CPUC and the CAISO.

Vistra asked how the CAISO is looking at the net load peak for local reliability and is not sure how the CAISO would use this for system. PG&E said we need a description of how revised RA will line up with CAISO for system and local RA. Vistra said if it were done differently from CAISO, it could have CPM implications.

There followed a process discussion about what should happen in the remaining workshops and how it might be possible to come to consensus. PG&E intends to put forth a complete proposal and thinks other should as well at the 12/15/21 workshop. There was a discussion of the use of polls and matrixes to attempt convergence and whether more time would be needed and, if so, when to ask for it.

Notes from December 1, 2021, RA Reform Workshop

Informal comments on need determination, allocation and the recap of proposals are due 12/22/21. There will be workshops on 12/15/21 (recap) and 12/17/21 (storage issues). There will be a survey this week on elements of the proposals and a second survey on the proposals after the recap workshop.

CalWEA presented on the concept of a net load reduction (NLR) QC for wind and solar. (See sides.). It supports the use of gross load but would use net load to calculate the QC for wind and solar. It said a single QC value for an entire month does not correctly predict the capacity of VERs in critical hours. ELCC is a single number for all hours in a slice, which does not necessarily represent output in a critical hour and ELCC is hard to calculate for SoD. Exceedance is calculated separately from load. NLR correlates load with wind and solar output and can be calculated for each hour in a slice and then averaged. NLR would be based on historical data and could be differentiated by location or technology. System need would be developed at the CAISO level but allocated to LSEs on an LSE-specific basis.

ACP asked whether NLR would be contractable. CalWEA replied that it would only be used for QC for wind and solar for each slice and the rest would be done on a gross load basis.

The CAISO said the correlation with load is indirect because the direct correlation is with weather and so could not be used to predict the future. CAISO thinks ELCC is better because of stochastic draws. CalWEA agreed that the correlation is with weather but that there is a need to establish a relationship with gross load which determines need. Exceedance takes a percentage without looking at the relationship to load.

MRP asked if CalWEA thought NLR would be different for different sized slices (24 hours vs. 4 hours vs. 2 hours a day). It replied the wider the slice, the bigger the requirement but they should be the same length. The bigger the slice, the more over-procurement. Slices should not be too wide. Critical capacity could move from one slice in the summer to a different slice in the winter. During a 4-hour slice, if there are 4 seasons, a slice would cover 480 hours. It depends on how you determine system need during the 480 hours in summer. If you pick the worst hour in the slice with the highest net load, you can forget about the other 479 hours. You can calculate NLR for each of the 480 hours and average or take the average of the 1 critical hour over 120 days. Each slice will have its own NLR QC for wind and solar.

NRDC said it agrees with CalWEA's problem statement but feels the approach is similar to exceedance but tied to the worst day. CalWEA disagreed because it said exceedance does not look at the relationship to load. If you first match load to wind and solar and take the difference, you could apply exceedance to the resulting difference and it might work.

Calpine asked if what CalWEA calls a resource contribution its output. CalWEA said in the simple case it is output but there are nuances based on zone or technology. Load and output vary, i.e., are not the same over the entire 480 hours, and the relationship between load and output is not linear.

SCE presented next. (See slides.) SCE said there is a need to focus on load shapes for all 24 hours for each LSE and not a single point. CEC support would be needed to validate each load shape. One option would be that every LSE gets a gross peak share of the CAISO worst day load shape but this raises fairness issues. Another option is fully customized load shapes for each LSE based on its own worst day. The middle ground would be semi-customized load shapes based on each LSE's mix of customer classes.

Vistra said this does not account for diversity effects. SCE said there would have to be an adjustment to scale to the system load shape. CLECA said rate schedules combine customer classes with different load shapes so the middle ground would be hard to do. PCE said weather affects load shapes and there are differences between summer- and winter-peaking LSEs.

MRP asked if the proposal was for the worst day for each LSE or the worst day overall? SCE replied that the final check is the CEC's 24-hour worst day and it was not sure how often a LSE's worst day differs from the grid's worst day. Each LSE would submit a single gross load and would get a 24-hour profile from the CEC. The CAISO would not do a 24-hour check, only 1 hour. The CPUC could do the 24-hour check.

NRDC asked if the end goal was LSE-based load shapes and whether one could transition from system-wide to LSE-specific. SCE said yes, but it doesn't like using the system-wide load shape for each LSE as a starting point. An interim could be having several transitional load shapes and LSEs could pick. CalWEA said it thinks SoD will capture load profiles well for procurement of RA capacity in the new framework.

SCE said it does not supports selling off resources for different slices; they should be kept bundled and not traded or sold. If an LSE buys a share of a resources, it would get that share of its entire output profile. This will allow the end of MCC buckets.

AReM pointed out that the CEC said most LSEs are providing LSE-specific load information and questioned the need for a transition. NRDC responded that there is a lot of detail still to be developed and all LSEs may not be providing this information. AReM said the CEC should say whether it needs a transition. NRDC agreed on the load forecasts but said the results need to be calibrated with the PRM to get the right level of aggregate procurement.

In response to Vistra, SCE said is does not proposing load obligation trading. Vistra said this has a commercial impact.

PCE is interested in obligation trading because it is not clear there is any combination of 24-hour strips that can meet its load and asked why SCE objected. SCE replied that its modeling showed that if an LSE is long in most hours and short a few hours a battery would solve the problem. It also said that obligation trading requires a new infrastructure and someone would have to demonstrate that this is necessary.

The CEC presented next. (Please see details on slides.). It discussed its current load forecast method and how to disaggregate hourly as opposed to peak day. It said there is a need for an hourly energy sufficiency check. There is a lot of heterogeneity among LSE load shapes. The CEC could have LSEs provide a 24-hour forecast for their peak days. For hourly energy buckets, LSEs can reflect their load-modifying activities. Weather normalization has a big effect. Best estimates of an LSE's hourly load next year are based on last year and load migration. You must account for load modifiers because electrification, etc. will create changes in load profiles.

The CEC's final concern is the tight time schedules and suggested it might be good to do a dry run in 2022 to evaluate the forecast and check the results. The CEC would like LSE perspectives on how easy it is to develop a 24-hour load profile.

NRDC supported a dry run not just for load forecasts. The end goal is LSE-specific load forecasts but they may have to be phased in. The CEC responded that it already does LSE-specific coincident peak forecasts. Off-peak hours are more challenging but not as critical. The CEC could explore downscaling its current 8760 forecast. What weather stations and PV installation forecasts would it use? The task is harder for some ESPs and new CCAs.

Lunch break

Gridwell/Vistra presented their two-slice approach (see slides), which had been modified since the last meeting. It involves two slices based on the gross peak and the net peak with a buffer to account for potential suboptimal battery dispatch. It would be a monthly requirement with more specific counting rules, which will partly depend on the future of the CAISO's UCAP proposal. They mentioned the importance of the relationship to the CAISO's local RA requirements since 2/3 of all RA capacity is local. The net peak requirement assumes there is no solar output. If there is inefficient battery dispatch or insufficient energy, this should be incorporated into RA requirements for all LSEs.

They anticipate that in 2030 batteries will be used when the sun goes down and there must be enough renewable energy to charges the batteries; for battery capacity they propose to use incremental ELCC. RA reform should allow for efficient procurement and allow retirement. You need load and supply diversity benefits to be reflected to avoid over-procurement.

SCE asked what would happen to MCC buckets. They replied that they should be retained for one year and there can then be a determination as to whether they are needed. SCE asked if they assume every resource expected in the draft Preferred System Plan (PSP) will count for RA. They replied if there is assurance that resources will meet the peak and (non-solar) net load peak, the MOO would cover all other hours.

The counting rules should be explicit about how to count wind and solar through ELCC and UCAP. You can get to hourly reliability on the requirement side (covering 24 hour) or via the counting rules.

They support bundling of a single RA requirement and no trading of individual slices. They mentioned a recent WECC study of California and Mexico with a maximum PRM that varied greatly across the year and a similar ED report. (See slides for citations.). They proposed to use probabilistic LOLE to set monthly gross peak requirements, to model generation capacity expected to be online in the target year, to use an hourly load forecast and to do an hourly LOLE calculation, reflecting various uncertainties. The goal is a 1 in 10 reliability standard.

PCE asked about the use of ELCC to discount capacity resulting in more storage. They replied that ELCC would be used to measure resource contribution to reliability in the net peak. You would use the minimum of the ELCC value vs. historical output. PCE said ELCC covers multiple hours, not any particular hour. They replied that if you use a heat map to determine hours with LOLE, you can use it for counting too. They are trying to match the hours of greatest need with capacity contribution in those hours. PCA asked if we can meet peak and net peak using storage, how does the proposal assure we don't run out of energy when we need to charge batteries? They replied one would use the dispatch assumptions in the LOLE studies. [DID I GET THIS RIGHT?]

NRDC asked about PRM calibration. RA is about finding reliability constraints and then procuring a portfolio of resources to achieve that reliability. It does not understand how this proposal fits with the CPUC's other goals like no leaning, having LSEs procurement for their own loads, etc. In the July RA decision. Gridwell/Vistra said its proposal does fit. They said if there is a future need for more slices, they can be added.

SCE asked if each LSE was given two numbers, a capacity quantity for gross and one for net. They said yes for wind and solar. SCE asked if you have a 4-hour use-limited resource, can you show it for both gross and net peak. They said yes if the NQC is based on ELCC. SCE said this was not efficient.

CAISO said it was still discussing whether their proposal is a durable framework for the long term. It had proposed a net peak requirement for 2022 and 2023 only. If you rely on ELCC, you have ELCC calculations that have non-zero ELCC for solar. You could be undercounting capacity at gross load. The CAISO's net load check covers the net load. They replied that ELCC going forward will capture contribution to reliability including at peak because there is increased capacity value from charging storage. The CAISO said having more storage would increase the ELCC value but there is an issue of the distribution of benefits between solar and storage.

PG&E presented next (see slides). It discussed use of a 1 in 2 vs. a 1 in 5 load forecast. Using the latter would capture more load variation but would affect other proceedings. It proposed that the maximum demand in a slice would set the need requirement and that it would be the maximum for the system, not for the LSE. For long-term contracting you need certainty on the

RA structure and the counting rules. Allocation should be performed on the basis of LSE load shapes and should sum to the CEC forecast. It should be done on a gross load basis because net requires more reporting by LSEs.

UCS asked why PG&E proposed to divide up the PRM into different categories. PG&E replied that it is necessary to be explicit about the uncertainty that the PRM addresses.

CLECA asked if using a 1 in 5 load forecast would affect the PRM and PG&E said yes; once you decide the inputs, then you determine the right PRM. You iterate to get the desired level of LOLE.

NRDC presented on the relationship between RA and the IRP. (See slides for the many details.). It said there is confusion among LSEs about how to show that a portfolio is reliable. RA reform includes developing a tool or metric that LSEs can use for IRP to be sure they have a reliable portfolio. This requires a focus on the near-term in the IRP and updates every year or two. Diversity among LSE procurement can be inefficient and lead to over-procurement.

Calpine said it was not sure SoD allows elimination of the MCC buckets. It likes leveraging the IRP LOLE analysis to get the RA PRM. This may be easy to do from peak/net peak hours and summer months but what about backing into PRM for other hours/months, e.g., LOLE mid-morning in non-peak months? It also said that one issue not captured is dispatch limitations for DR. NRDC agreed re DR; it thinks there should be the same PRM for all hours within a month to drive compliance showings; do you need to calibrate for each month or can you focus on the peak month and spread it to other months? Calpine said there is an existing analysis of monthly PRMs to meet a reliability standard; reliability may very monthly with one PRM.

Gridwell asked how NRDC would connect the PRM with a resource's capacity value? NRDC said you would develop counting rules before doing the PRM. An LOLE study could be used to adjust the PRM. PRM is just a number and is a function of the counting rules; you use it to determine the portfolio to calibrate to get LOLE. [MY NOTES ARE SKETCHLY HERE. DOES ANYONE HAVE CLEARER ONES?]. Gridwell commented on leaning vs. no leaning, saying some LSEs are short and some are long and different LRAs have different PRM standards. It said NRDC's definition seems not to account for natural diversity. NRDC said historically this was a quantitative issue. More recently, with the emergence of preferred resources, the mix has become more important. This is why solar and wind were moved out of the dispatchable resource MCC bucket. Gridwell said there was no clear definition of leaning.

CLECA asked if the use of UCAP and a 1 in 5 load forecast would affect the PRM and would calibration resolve them? NRDC says yes, if we move to derate, would probably include UCAP; still have to develop counting rules; load forecast is an open issue; use of 1 in 5 or 1 in 10 might change the shape.

SCE supports this approach to PRM. It should be based on LOLE in the IRP.

Vistra said it heard agreement re use of LOLE. If you calculate PRM, it could vary by month. We thought you would need to do another LOLE with planned resources with executed contracts which we think is similar to NRDC. NRDC agrees; the IRP needs more near-term analysis, over 1-3 years; need to consider delay/interconnection risk and other elements to keep updating the IRP analysis. Vistra thinks RA LOLE is still necessary. NRDC might do IRP study showing different needed resources in 2026 – are these resources that might need to be retained?

MRP asked how to do showings. NRDC replied you try to get a standard MW. You know contracted wind, solar and storage will be shown. The issue is resources to fill out the net position. These are more likely to be firmer resources. MRP asked how to get perfect PRM in April when you have excess supply. NRDC said you would do a monthly PRM and think through how PRM works across the months.

SCE said the IRP is still in process; we haven't gone through a fully successful cycle; no procurement yet is based on LOLE. IRP is hourly capacity to produce energy; need to link modeling generation capacity to meet 0.1 LOLE and translate to RA.

MRP said IRP has 11 GW procurement requirement with incremental ELCC values which are different from RA counting method. SCE said IRP procurement is not directly related to LOLE and using incremental ELCC is brand new – each resource will have an expected hourly contribution. MRP asked about the difference between IRP PRM and RA PRM and that calculations were needed. SCE agreed.

PCE asked how you would allocate a 0.1 LOLE across the months and said the monthly grid stress depends on the mix of resources.   NRDC said SoD is an approximation to address capacity and energy sufficiency; the expensive procurement is new capacity; the rest is about maintaining the existing resource fleet.

Vistra cited the WECC assessment and the ED one and said there are months with no risk of LOLE. They may need less capacity.

Notes from December 15, 2021, RA Reform Workshop

CAISO and LDSA presented the results of the Elements Survey. This survey was designed to get feedback on the various components of the proposed RA Reform Frameworks. It was designed to show directionally where party positions are now and not as an ultimate product to show the CPUC. The CCAs have not yet filled it out and they are still considering the various proposals.

SCE presented an update on its proposal. (See slide deck.) It indicated that several matters would need to be further addressed after a basic framework is decided, such as solar and wind counting and load forecasting. SCE also dropped its proposal for using load shapes based on the mix of customer classes an LSE serves.

SCE raised concerns about Gridwell's proposal's ability to demonstrate meeting load in every hour or addressing charging for batteries.

CESA and SCE discussed SCE's proposal for a minimum 4-hour requirement for storage. SCE said this was based on the CPUC's current policy and was not a technical requirement. Storage can be shown in all hours it is available.

AReM asked if SCE was supporting the CEC's load forecasting proposal. SCE said it is largely consistent but that it proposed to use historical load shapes. AReM said it supported whatever the CEC proposes.

SCE continued its presentation. It provided a format for the RA showing requirement with an illustrative compliance showing. The CPUC would validate the showing to meet load shape plus PRM for all 24 hours along with sufficient energy to charge storage. It said that if parties want to be able to trade resources there will have to be a single public data base of resources with their attributes as well as NQC, which would be new. Capacity values would include gross peak checked by the CAISO and all 24 hours checked by CPUC review. Failing to meet the CPUC requirements could lead to penalties and possibly CAISO CPM costs. At least initially, the CAISO will only look at 1 or 2 points (gross peak and perhaps net peak). CAM resources would be credited to LSEs by CPUC staff. MRP asked if LSEs could then determine how to apply the credits? This was not clear.

CAISO asked if storage counting could include multiple cycles in a day and enough time to charge, how would this be evaluated? SCE suggested just checking across the day and respecting downtime and recharging needs. It did not want the effort to turn into a dispatch model. The CAISO expressed a concern about multiple cycles a day and its ability to track them.

WPTF asked if SCE had shared its proposal with the CPUC ED and SCE said it had talked to staff but staff would have to speak for itself. WPTF asked why there was no procurement by slice and SCE responded that this would increase administrative complexity and that there is a 24-hour MOO. WPTF asked if LSEs could swap load to help address lumpy resources SCE said it was not proposing this.

Gridwell presented next (see slides). It wants consistent RA rules for both CPUC and CAISO and emphasized the importance of local RA. It expressed concern about the commercial consequences of SCE's proposal and said PRM would have to vary hourly. It distinguished capacity as value to grid reliability over longer periods of time like a month from hourly energy.

The focus of the Gridwell presentation was capturing the diversity benefits of loads and resources and said these were best captured through the use of ELCC. Gridwell said it does not read the CPUC decision as mentioning LSE-specific load shapes and does not like the idea because it reduces diversity benefits. Gridwell proposes to discount the capacity value of use-limited resources. In response to a question from PG&E, Gridwell said ELCC would be calculated on a monthly basis as for wind and solar. Longer duration would be derated by less than longer duration storage. Storage could count to meet both the gross peak and the net load peak using ELCC.

PG&E presented next (see slides). It said more analysis is needed before exceedance values are determined for wind and solar. It recommended looking to the results of the CEC process for determining QC for DR although it agreed that calculating ELCC values for shorter periods of time like hourly is problematic and works better for long time frames like the IRP. Storage capacity would be based on the maximum discharge rate or limited by the interconnection. Additional storage will be able to use surplus energy and reduce the usefulness of unbundling and trading.

IEPA asked about monthly showings vs. seasonal showings. Seasonal showings assume resources have been contracted for multiple months and are likely to be less accurate as to when new resources come online. In response to IEPA, PG&E said that exceedance cannot capture resource interactions except for hybrid resources but also questioned whether one should rely on synergy among resources. Later SDG&E said monthly showing were preferable because 1) they reduce the risk of over-procurement compared to seasons and 2) seasonal showing would require forecasting load farther away from when the load would occur.

CEDMC asked about PG&E's proposal to cap the amount of DR and was told the details have not been worked out yet. CEDMC also said that DR backed by storage will not be subject to customer fatigue. CLECA and PG&E discussed possible overlaps between PRM determination and load forecasting methods and uncertainty. MW Storage Farms said it was not clear if use of a single load profile would capture the worst-case charging scenario for storage and asked if PG&E had analyzed scenarios for worst case charging and worst-case load. PG&E said this was like asking to what extend the CEC's load forecasting is addressing charging need.

NRDC presented for a group called the Slice of Day Coalition and put forth the group's principles for RA Reform. (See slides.). The CAISO asked if there would be a separate CPUC 24-hour check and one CAISO check and NDRDC said yes, like MCC buckets now.

CAISO sad it wanted to harmonize CAISO and CPUC processes and asked if SCE was suggesting assigning backstop to LSEs based on deficiencies determined by the CPUC or by CAISO. SCE said CAISO could get deficiency information from the CPUC or do its own check.

General Q&A followed.

SCE said it is not proposing use of ELCC and NRDC said it is not endorsing the use of ELCC and that it was better to look at all 24 hours. For charging storage, you would need exceedance or some other method.

MRP asked where and when the CPUC would make a decision on PRM and the general reaction was after the input parameters are set; Gridwell agreed but said the proposal needed further advancing.

There was extensive discussion of diversity benefit with Gridwell saying having LSEs procure to meet their load shapes would reduce diversity benefit and PG&E and SCE disagreed since the sum of LSE load would have to add to the system load. PG&E said that each LSE can use storage when it wants to meet its load which would provide a diversity benefit. Gridwell raised concerns about small LSEs not being able to manage this and possibly incurring higher costs as a result.

PCE discussed moving toward 100% renewables and storage and that declining capacity value for storage and wind will require it to buy gas resources to get sufficient RA value, resulting in over-procurement to meet its needs. Gridwell said PCE should think about capacity and energy separately and that 100% clean energy is not equivalent to RA capacity required for reliability.

IEPA said if you use a 24-hour shape and exceedance for wind and solar for different locations there should be no need to calculate a diversity benefit. Average ELCC would change and maybe ELCC should be vintaged.

NRDC asked how diversity benefits from LSE procurement diversity relates to leaning and that MCC buckets avoid leaning. Gridwell replied that it saw no definition of leaning and it should not occur if you take advantage of natural diversity benefits.

CESA asked Gridwell about the term “deliverable nameplate” and Gridwell replied it referred to CAAISO deliverability studies. CESA also asked if 2 slices created a risk of over-procurement since it this approach less granular. Gridwell said it thought 2 slices would be more transactable. SCE said it did not think that Gridwell’s proposal met CPUC guidance for assuring coverage of all hours and showing energy sufficiency. Gridwell replied that hourly energy sufficiency only applies when there is a risk of LOLE.

There followed a discussion of next steps, of whether there could be convergence, and whether to ask for more time. CLECA recommended asking the CPUC what it wanted in terms of the report and timing and IEPA said the workshop report can reflect convergence of divergence of views. The facilitators will talk again. It is important for the final proposal(s) to be workable for LSEs.

Notes from December 17, 2021, RA Reform Workshop on Storage

Vistra presented first (see slides). It said it did not think there is a risk of being unable to charge the storage fleet for the foreseeable future. The PRM can address this risk if it occurs. We should expect multiple possible charges and discharges in a day as well as at least 2 possible full charges and discharges. Vistra believes storage RA resources are accurately being valued for their reliability contributions accounting for their physical limits.

Vistra went on to say that the CEC mid-term reliability analysis tested the ability of the system to charge in a limited energy scenario and found minimal impact on reliability through 2026.

PCE said it was unclear what RA and IRP do. RA needs to guarantee that CAISO has enough resources to run the grid only with RA resources. IRP shows enough resources to charge batteries. They asked if Vistra did not care if charging capacity is under RA. Vistra responded that the IRP procurement directive is for new resources which then get RA contracts and that RA will create a fleet with incentives for providing RA after the initial contracts.

CalCCA said it was still not sure this is what RA is designed to do. It has a concern that ELCC will not necessarily take care of charging if ELCC is based on RA resources compared to all resources.

Vistra said Gridwell's two-slice proposal would incorporate this risk into LOLE along with other risks including operational uncertainty and that CAISO and the CPUC must determine operational uncertainty. LOLE should be studied with installed and planned capacity.

WPTF asked if the LOLE study is to be sure there is enough capacity to meet a standard of one outage in 10 years, why not just make it an explicit requirement as parties have proposed? Vistra responded there is downside energy risk with multiple drivers. If you choose only one like solar, you don't capture the other risks. Insufficient energy in real time operations would raise energy costs. The result is paying capacity costs for energy needs which it considers unfair.

Vistra said showings should reflect resource-specific attributes and include use limitations. CAISO's Today's Outlook shows more than one charge and discharge per day.

Vistra said ELCC study should be performed after the LOLE study with stakeholder input. For longer duration storage, it would assign a higher ELCC.

LDESAC discussed the need for multi-day analysis for charging if resources can provide output for more than 12 hours. Vistra said the CAISO looks at 48 hours for RUC runs and operators know this.

CES asked why Vistra proposes to do LOLE before ELCC. Vistra replied that for LOLE, you need to be confident about NQC values; the first year you do the LOLE study so you know the hours of LOLE; then you can determine ELCC. This would ideally be done every year or two in the RA proceedings. CES supports an open stakeholder process like MISO's wind process with resource-specific adjustments to NQC.

PG&E asked if ELCC would be calculated on an individual resource or class basis and whether this is for monthly showings or seasonal showings. Vistra replied LOLE would be calculated for 8760 hours and tuned to produce monthly values with a single ELCC for each month; the buckets would be based on duration. PG&E asked if the class is defined only by duration? Vistra said yes, based on maximum discharge hours after real time and different buckets for solar, wind and hydro. Gridwell said there is a need to propose an exact process for stakeholder input. Vistra said the RA value would be only up to the NQC for all RA products and the NQC for storage should be a reasonable estimate of its ability to discharge. The economic impact of operations should be included in market offers.

The CAISO said if there were multiple cycles for storage, there needs to be an attestation that the contract or warranty allows more than one cycle per day. Vistra said this was inconsistent with the CAISO CCE 3 stakeholder process where the CAISO decided not to respect contractual factors.

CESA presented next. It said its members were not ready to respond to SoD proposals so it was presenting CESA staff's thinking. RA is a critical value stream for storage so CESA staff do not like multiple-hour slices or fewer seasons. They like the 24x1 monthly proposal. They would like unbundling to be considered with slice-specific transactability.

CES said it is difficult to validate if there is trading and would like to see an example. SDG&E said the IOUs will not support load transactability. The CCAs should be responsible for their own load. CESA said that an LSE that wants to sell part of its requirement would have to compensate the taker. PCE said if it has RA need, it can buy RA only from an IOU and this is important for smaller LSEs. It asked about transacting for supply vs. load; if on the load side, it cuts out suppliers but load trading is easier.

CESA said you should be able to trade system RA and meet requirements, not local. It said the CPUC principles included transactability. CAISO said to keep in mind who will have the MOO and backstop risk. WPTF said this could be handled contractually. Vistra said transactability should be commercially viable and not too complex; this is a reason for a two slices. SCE said it disagrees with Vistra and does not support unbundling; LSEs can swap by trading units, not slices,and this would require a master data base.

CESA then addressed storage-specific issues. It likes 24x1, monthly and says MCC buckets can be eliminated. It does not support a minim 4-hour output requirement for RA. It said neither ELCC nor exceedance was appropriate for storage, that there is a correlation between storage output and LOLE and that storage is arbitrage. ELCC depends on availability and cost of charging energy and would require annual incremental ELCC studies by technology and the results would vary every year. Exceedance is based on history which may not predict future adequacy. CESA staff is not clear on how UCAP could value the different durations of storage.

It prefers to value storage based on Pmax over the number of hours but needs to determine how to capture incremental duration and how to reflect contractual obligations.

Calpine disagrees on ELCC. In ELCC modeling, it said storage is modeled to minimize LOLE and may be overly optimal; there is a change in ELCC over time; supply and demand balance can change over time and there are saturation effects. CESA staff replied ELCC is usually used for resources whose output cannot be matched to LOLE. Calpine said most ELCC modeling dispatches storage based on LOLE. Energy Division said it had the same questions as Calpine, that ELCC studies are not just used for VERs and can apply to dispatchable resources as it addresses all limitations of generators. Vistra agreed and said you need frequent updates of LOLE and ELCC. It said under the Gridwell proposal, ELCC would be vintaged for the term of a contract.

CAISO said UCAP requires tweaking for SoD; for the SCE proposal, you need similar QC plus deliverability to get NQC. The availability factor is a percentage of QC; it thinks this could be used for storage.

CESA discussed the issue of sufficiency verification. If it is required, real time efficiency should be considered on an asset or technology basis; multiple cycles should be allowed and there should be no downtime verification. Any excess energy should be available to charge storage. It supports use of gross load to set requirements. Multi-day reliability should be addressed through sensitivity analysis in the IRP.

LDEASAC presented next (see slides). It reviewed the various technologies and said the RA framework must be transactable and financeable for LDES. You need to figure out how to get RA credit for multi-day resources. The NWPP Regional RA program has ideas for LDES.

Vistra said in the mid-term IRP some tranches require procurement of LDES and asked if 2026 was a reasonable commercial date. LDESAC said yes, there are supply chain issues to get to one GW. Vistra asked if the long-term contracts were for 10 years ending in 2036 and LDESAC said companies would prefer 20-30 year contracts given the duration of the assets; also the RA attributes need to be known up front. Vistra asked if what was developed for RA would apply to IRP and LDESAC said yes.

Barbara Barkovich reviewed the schedule for the CEC DR NQC process and said that SoD issues were not expected to be addressed until after June 2022 when SoD was expected to be adopted by the CPUC. There were concerns about an interim proposal to use LIP-informed ELCC and how it could be compatible with SoD.

WPTF said the RA Reform report would probably present several options and that it expected there to be comments at the CPUC and perhaps a workshop. It expected further process to work out details. It asked CPUC staff for a reaction and staff said it did not have the right representatives to do that. It was willing to meet with the facilitators in January.

Notes from January 5, 2022, RA Reform Workshop

This workshop addressed hedging and transactability. The last workshop, on 1/19/22, will address UCAP and multi-year RA contracts. Parties wishing to present must inform the facilitators by 1/7/22.

PG&E presented first on hedging (see slides). It cited D. 21-07-014 at pages 27 and 38 regarding the CPUC's direction to look at linking RA to a resource's energy bidding behavior and to address the energy component of RA contracts. PG&E said that ED's proposals would enforce any hedging requirements through the LSEs.

PG&E summarized its two proposals and how they would be implemented without discussing their merits. These are the variable cost hedge and the price cap rebate. These are intended to provide incentives for behavior in the energy market in RA contracts rather than imposing requirements. PG&E said it had included hedging in some recent contracts and in a CPE solicitation.

REV Renewables asked if the rebate in slide 12 was based on the entire spread between the cost of charging and discharging and was told yes by PG&E. REV then said that this proposal would take a lot of revenue from storage resources. PG&E replied that this proposal would tap into energy margins as would the variable cap; it would be less so for its proposed hedge cap. It acknowledged that if a seller gave away some energy margin it could increase the RA capacity price. REV asked if this would apply only to contracts going forward or to revising existing contracts. PG&E said this only makes sense for new contracts and would reflect the degree the LSE wanted to eliminate price risk.

Shell asked for a definition of the "index price". PG&E said it would be whatever the LSE and the seller agree to. It would be a fixed reference price. The locational price would be up to the buyer and seller.

MRP asked if the inclusion of energy hedging would tend to increase capacity prices. PG&E said it did not know but that it makes sense to an economist.

Vistra said an energy hedge was an option today. A seller can submit multiple types of bids. PG&E said the issue here is whether then CPUC would mandate such hedges.

Constellation asked if the existence of RA contracts with and without hedges would affect the determination of LMP and if there would be different types of bidding behaviors in the energy market. PG&E said there are different types of RA contracts now, including RA-only and tolling. PG&E said it thinks bidding behavior depends on the amount of competition. If there is enough competition, do we need hedges? If the market is less competitive, what are the incentives for a resource to bid?

CLECA asked if the hedge issue is separable from SoD. PG&E said yes. CLECA agreed. It said hedges are not free and 100% hedging is not cost-effective. It asked how one would determine the optimal level of hedging. PG&E replied that the CPUC is interested in hedging by IOUs and its impact on customers. It did not know about other LSEs. PG&E said it believed that the CPUC can avoid a mandate that would be FERC-jurisdictional by creating an incentive structure so it would not dictate bidding behavior.

Calpine asked if an LSE could put together a hedging plan with different instruments like energy contracts separate from RA contracts and would this be the best mechanism. PG&E said it depends on how much oversight the CPUC has over LSE procurement and whether it has jurisdiction to require review of non-IOU LSE hedging plans. Calpine said it was not sure the CPUC has such jurisdiction. PG&E noted that the CAISO only has market power mitigation at the local level, not the system level.

Vistra presented next on hedging and transactability (see slides). It also cited D. 21-07-014. It asked what type of risk the CPUC is concerned about and who is at risk. It believed the CPUC was concerned about financial exposure. It said that the risk to end use consumers depends on the type of retail product the consumer is buying and that this was a retail issue, not an RA issue. If the concern is the effectiveness of CAISO market power mitigation, this is a CAISO issue. It proposed to move the hedging issue into a retail or DA docket and not keep it in RA. Vista also said the CPUC should not require hedging but could allow it as an option.

In the Q&A, NRDC asked Vistra how this was different from the status quo. Vistra said hedging should be an option subject to some standards. CalCCA said this is status quo. LSEs can buy energy and capacity today and hedging is optional. It is not clear what is most cost-effective. CalCCA thought the concern was mainly about imports biding at the cost cap. Vistra said the CAISO will take up the issue of system market power this year. Shell agreed with CalCCA and Vistra.

SJCE said it did not have a position but was concerned about market power in the RA market. Vistra said someone should analyze data to see if there are issues with market power mitigation and questioned if ED thought there was such an ongoing concern. ED said it did.

ACP said it thought a hedging requirement might disrupt the timing for getting IRP procurement online. Vistra said a requirement would increase risk of providing RA, even with long term contracts for IRP because these will roll off. A greater concern would be a hedging requirement in the IRP.

Wellhead said it has many local RA contracts and they are mitigated 15-20% of hours.

CalPA said variable cost hedging helps with least cost dispatch but there is a potential for increasing RA capacity costs. It would like to look at data on hedged contracts and hedging should be kept as an option, not a requirement. It also agreed it was separable from SoD.

MRP asked how CalPA would do the analysis. CalPA said it could look at the impact on RA prices. ED said it would like a clear picture of the magnitude of the problem. It wanted to issue a data request to all LSEs on the strength of their hedging but was not sure how to ask for the right data.

Vistra then presented on transactability. It said it wanted to minimize changes to contracting and limit granularity. It said increasing the number of slices would harm liquidity and make contracting more complex. It said there is a need for a standard capacity contract that is fungible. RA resources must be allowed to take planned outages.

IEPA asked the CCAs whether they think there is a problem with the hedging proposals and whether they need additional tools. There was no response.

CESA clarified that it does not propose to unbundle RA but to allow load requirement trading.

CalWEA presented next (see slides). It does not like the exceedance methodology and said it does not focus on VER output at times of higher load. It provided more information on its effective net load reduction (ENLR) proposal for determining the QC for wind and solar based on the correlation between wind and solar generation and load. It raised concerns about the limited sample for calculating QC for a VER for a particular hour, saying it could only get data for 3 years on an hourly basis from OASIS.

CalWEA presented two options. One is using a weighted average of historical VER output by hour. The other is a simple average based on hours of higher load. It likes ELCC because it reflects load need and says its averaged approach is a simplified version.

CalPA asked what the term “maximum” meant in the approach. CalWEA replied it is the maximum of the load or output for that hour and month in the 3 years of data.

Vote Solar asked if ELNR was compatible with 24 slices or two slices and was told both. Vote Solar asked if it would be possible to use multiple years of NREL data to simulate output for more years. It also asked if there should be different approaches for wind and solar. CalWEA replied that you could use future production if you could agree on weights and that one should consider target sampling in the future. Vote Solar said multiple LSEs will have to file RA at the CPUC and will have different load profiles; thus, to correlate historical production with each load profile would be complex. CalWEA said its proposal can be used for individual resources, LSEs and locations but you have to tie back to system load need, not individual LSE load need. The QC for VERs should be based on aggregate system needs. Bottoms up is OK for the allocation but top down should be used to determine system capacity. Vote Solar asked how to determine QC for resources without historical information. CalWEA said this was a problem for any approach.

SDG&E asked about the left column on slide 5. CalWEA said this was the peak load you are measuring against. SDG&E asked if you look at 95% of peak load, what are the columns?

CalWEA said samples; if the load threshold is 80%, you only look at samples where load exceeds 80% of peak.

SDG&E asked how this would work for two slices. Would you forecast gross and net peak hours for the next month? Vistra replied that it would do LOLE for gross peak and for net peak and identify the hour of largest LOLE that does not occur at the gross peak. It would use that hour to test sufficiency. More workshops would be needed to refine this approach.

GridLabs said since you are looking at performance against the maximum load, wouldn't ELNR double count load? CalWEA replied that you would use actual OASIS data from 2019-2021. Gross load varies a lot for a given hour in a given month, but you would focus on the high load hours/days.

Vistra asked if CalWEA was coming up with QC to subtract from gross load to reduce need. CalWEA said its position had changed and that it is only using load as it is and generation as it is. Either would be adjusted by the ratio of load for the time period divided by the generation in the time period for periods when load is greater than a threshold.

Vistra said it did not see a strong causal relationship among loads, wind and solar. CalWEA responded there is a correlation among them. Hot sunny days have higher gross load and more solar output and less wind. Vistra said there should be a correlation coefficient. It would be better to use LOLE. CalWEA said you should use LOLE to determine the capacity need but this approach is for QC for VERs. Vistra said you should use LOLE hours. CAISO said there was no direct correlation between load and solar and that both correlate with weather. It suggested getting variances in the samples. CAISO also said energy is needed to charge storage. CalWEA said that with a lot of storage the capacity values of wind and solar are less important. It reiterated its concerns about the use of exceedance with limited data, especially for wind.

Notes from 1/19/22 RA Reform Working Group Meeting

The workshop started with informing participants that the last informal comments are due 2/4/22 and will be presented in the form of a position matrix covering all matters discussed in the working group meetings.

Next the CAISO presented its proposals on UCAP and use-limited thermal resources (see slides). The latter only include internal resources and some CHP. Most thermal resources are use-limited due to air permits. Over the last three years, there were higher outage rates in the summer and higher outage rates in 2021 compared to the two previous years. Higher outages in summer may be due to higher ambient temperature derates and more maintenance/trouble outages. The CAISO proposed two periods, peak (May to October) and off-peak (November to April). Some outages exceeded the 15% PRM.

Gridwell asked if both forced and planned outages were included and CAISO said just forced.

CalAdvocates asked if CAISO could provide insight as to the impact of the OTC units on forced outages compared to other resources. CAISO said OTC plants are included in a section at the end of the slides which shows outages by technology type. The OTC units had 85-90% availability.

MRP said the forced outage rate was lower for 2020 than in the CAISO RAAIM report. The CAISO responded that these data were in relation to Pmax and not what was sold for RA. There are resources that don't sell their full availability. Also, these data include all hours whereas RAAIM only looks at a subset of hours. There could be more overnight outages for air emission restrictions. Forced outages that are RAAIM-exempt are also included. MRP asked if CAISO could look at RAAIM only to see if RAAIM is doing its job. It also asked if changing to UCAP would lead to a one for one effect on the PRM, i.e., if you could take out 7.5% for outages from the PRM. CAISO said this could be discussed. Not all resources are covered by UCAP so it thought the reduction would be smaller.

Vistra said it treated forced outages separately from substitution risk for planned outages and that the rules changed in June 2021 when extensions of planned outages without substitution were disallowed. CAISO said there are two separate categories of outage rates to separate major plant maintenance outages from forced.

Energy Division said the outages rates for CTs and CCGTs were very different. CAISO said this was at the end of its presentation but not broken out in the presentation.

Gridwell asked if CAISO broke down outages by major work category and whether it addressed ambient derates due to temperature compared to UCAP. CAISO it had looked at it by nature of work card but there were some errors in the denominators and it did not have enough time to update the data. Plant trouble/maintenance outages were a little over 3% and thermal derates were around 3%. Gridwell asked if plant maintenance were the same as planned to forced. CAISO said it had plant maintenance data, but it was difficult to parse out planned to forced.

CalAdvocates asked about maximum outages over 15% and CAISO replied that thermal units are a large percentage of the total PRM.

CAISO continued to discuss its unforced capacity evaluation methodology. PRM, forced outages rules and RAAIM are inadequate to replace capacity on forced outage. With UCAP, the PRM would only need to cover operating reserves and forecast error for the thermal fleet. CAISO said UCAP would only be applied to thermal and storage resources. Resource availability would be measured during tight RA supply cushions without looking at non-RA resources. Wind and solar would not be included.

CAISO said seasonal UCAP is compatible with SoD. There are RAAIM-exempt outages that are included in UCAP. UCAP would be based on historical availability but new storage would not have any history yet so CAISO proposes an alternative. CAISO assesses deliverability and would then apply an availability factor. In the past CAISO recommended looking at the top 20% of RA supply cushion hours. Continuing to use 20% would capture possible issues in the morning ramp and cover 84% of days. CAISO said UCAP would provide information on the availability of resources and inform which resources to contract and which to retire.

Gridwell said it was concerned that history might not predict future performance well. The CAISO disagreed. Gridwell said it was not appropriate to penalize a resource if history is not a good predictor but that it did support ambient derates.

CalAdvocates asked if the CAISO accounted for deliverability across all hours like UCAP accounts for availability across all hour. CAISO said no, it only considers deliverability at the peak and did not think it was appropriate to assess it across all hours. UCAP assumes that if the resource is deliverable at peak, it will be so in all hours.

CLECA asked if resources had use limitations for noise or air quality, would this affect UCAP. CAISO said no referring to slide 36. There are few UCAP hours 2-5 am. The impact of these outages is not significant in tight RA hours. In the 24-slice proposal, you might reflect this if resources were never available in those hours.

CLECA asked if a unit had a planned major overhaul would that affect its future UCAP? The CAISO said you would have to define such an overhaul and that its improved performance would be captured over time. CLECA said its reflection might influence a decision to do the overhaul.

Vistra supported use of LOLE and ELCC. CAISO said ambient derates are predictable and ELCC would have to be done by technology type. Vistra said there is a performance adjustment for ELCC classes but that it is not necessarily recommending ELCC for thermal plants. It said to use UCAP it would be necessary to get rid of POSO rules and include all hours and use EFORd.

On slide 34, the CAISO summarized the changes in its systems and processes that would be needed to implement SoD, including MOO, bid insertion, CPM and interconnection, and requested feedback for its upcoming stakeholder process.

ED presented on SERVM modeling results for unit outage rates from 2024 RA modeling (see slides). They are based on EFOR or EFORd and are class averages by technology type. They are not broken out by month. They do not include ambient derates, only equipment failure. ED would use these data if UCAP were adopted for generation. SERVM data are based on class averages. ED is not opposed to using unit-specific data.

CES asked about the different results between EFOR and EFORd and why the latter was zero for storage. ED said it would consider this. These are calculated using industry standards.

After lunch SCE presented on SoD resource counting and penalties (see slides). If an LSE is short and the CAISO backstops, the LSE should be first in line to pay for its share of backstop and should pay CPUC penalties based on the hour of greatest deficiency.

Gridwell asked about the MOO if there is hourly UCAP with different QC in different hours. SCE said if there is a UCAP derate, the MOO would be for the amount before derating and that SCE is not proposing hourly UCAP and not proposing resource counting rules for thermal plants. Penalties would be the same as today and applied based on the hour with the greatest deficiency.

Calpine asked if CAISO validates a slice, what if the CPUC deficiencies are in different hours? How would the CPM allocation work? If the CPM was allocated to the CPUC and then to LSEs, would tariff changes be required?

SCE said the idea is not to allow an LSE to shift its deficiency to an hour that is not validated so a mismatch in the hour validated by the CAISO and the hour of greatest deficiency would not matter. There might be an issue with non-CPUC-jurisdictional LSEs.

CESA asked about multiple storage discharge scenarios. SCE said they could be included as long as the energy for charging is accounted for.

Gridwell said a deficiency for one LSE could be offset by excess RA for another.

CAISO said Calpine and SCE were addressing the right questions. In the future, there might be a different process for the CPUC compared to other LRAs.

SCE continued its presentation. There would be hourly profiles for wind and solar so there would be no single NQC value; it would vary by hour. If the CAISO validates for a given hour, that will not be the value for all hours. The value of capacity must track the value for system load in the same hour.

In response to a question by CalAdvocates, SCE said it will not allow energy-only resources to be part of an RA showing, nor is it proposing changes to the CAISO deliverability studies. All showings should sum to CAISO system load. It is not proposing changes to the PRM until a policy decision is made on the preferred reliability target. It is not proposing changes to CAISO's local RA process. SCE and CAISO agreed that the MOO would be for the full capacity value before UCAP derates.

SCE said ELCC is currently used but that in the future load and resource profiles would be used to determine qualifying capacity values. CAISO uses a single NQC by resource for MOO for a deficiency test. The numbers will change if we use profiles. CAISO will need to be clear about what hour it will test and the amount of MOO by unit will be part of the showing.

CES expressed concern about use of exceedance over 24 hours.

Calpine noted that the reliability modeling in the IRP is based on a different structure from SoD so the PRM from one cannot be used in the other.

Calpine presented on penalties and backstop as well (see slides). It supports SCE's general approach and the concept that penalties should assure procurement for the hardest periods to meet requirements and should be based on the maximum deficiency. Ideally CAISO should validate all slices like the CPUC and allocated CPM costs like CPUC penalties.

PG&E said penalties should not be imposed by slice.

WPTF/IEP presented on multi-year RA requirements (MYR) (see slides). WPTF discussed the history of MYR proposals and the fact that they have only been adopted for local RA. MYR would support retention of needed units and appropriate retirement decisions. PG&E questioned whether it was appropriate to lock in RA values for multiple years and only for non-CPUC-jurisdictional LSEs.

IEP presented next. NQC values should be refreshed annually. There is 5-year-ahead procurement in IRP. IEP discussed MYR for PJM and NE-ISO. Vistra said MYR would better balance reliability and minimizing costs.

CLECA presented on a QC methodology for DR that varies hourly to reflect temperature-sensitive DR capacity using LOLE-based weighting of Load Impact Protocol (LIP) results. It expressed concern that the CEC DR QC process has so far only looked at an interim methodology for RA compliance year 2023.

Then there was a discussion of the process to complete the report. An informal comment matrix will go out shortly and parties should return it, along with any proposals that have not been written up, by 2/4. The sections of the report on specific proposals will be written by the proponents. The report is due to the CPUC on 2/28/22.

Appendix – B

Informal Comments and Party Position Matrices

The Co-Facilitators asked parties to provide a final set of informal comments and to fill out a party position matrix, to be included in this report. Included in Appendix B are the informal comments and/or filled position matrices provided by parties.

American Clean Power – California Informal Comments on Resource Adequacy Long Term Reform Workshops (R.19-11-009 and R.21-10-002)

February 7, 2022

I. Introduction

American Clean Power – California ("ACP-California") offers the following comments on the Resource Adequacy ("RA") workshops on long-term reform.[1] These comments focus on the recap of the two primary proposals offered by Southern California Edison ("SCE") and Gridwell Consulting.

ACP-California encourages all parties to consider transactability in terms of both transacting RA products in the short term and in terms of the longer-term needs of contracting and financing new, carbon-free Integrated Resource Plan ("IRP")-capacity that will be used in RA supply plans. The RA program should strive to provide certainty and stability in the development and financing of new carbon-free capacity by removing barriers such as sudden changes in capacity counting conventions or disruptions to existing contracts. Suppliers and their financing parties should have confidence that the projects providing the most value to the environment, ratepayers and grid operators will be appropriately valued over the life of their contracts. In the long-term, qualifying capacity values should be known well in advance and not subject to a high degree of variability. The proposals should help facilitate and de-risk the

[1] ACP-California's members develop utility-scale solar, storage and wind resources. Our wind developers are focused on high-capacity factor regions like New Mexico and offshore. Our primary interest in the Resource Adequacy proceeding is to ensure that Californians have timely access to reliable, cost-effective, and clean capacity and the RA program design works in concert with other CPUC policy objectives.

current development cycle of clean capacity that provides the best value to both grid operators and ratepayers.

II. Discussion

A. An Abrupt Change in the RA Program Design Starting in 2024 Could Disrupt New Capacity Development.

ACP-California has expressed its support for the 24-hourly slice proposal for several reasons. We believe that *in concept*, the granularity of the 24-hour slices best accounts for the needs of different resource production profiles and Load-Serving Entity ("LSE")-specific load profiles. In today's disaggregated market, a more granular approach could enable LSEs to more efficiently transact with the resources that are most effective in supplying energy during the hours of greatest LSE-need. LSEs and suppliers with excess capacity during particular hours should be able to trade that capacity with LSEs who are short in certain hours. In order to ensure a smooth transition, the Workshop Report should address the value of load trading, the need for a test-year, and recommend that the California Independent System Operator ("CAISO") evaluate changes to deliverability requirements.

Load Trading

We also believe there is a need to enable some form of load trading within the 24-hourly slice framework. Load trading would better ensure that the efficiencies of the CAISO's centralized energy markets can be realized by LSEs whose current resource plans may not align well with their hourly needs. Load trading would also provide a tool to LSEs (particularly smaller-LSEs) to be able to transact with large clean capacity resources. The recent Preferred System Plan in the IRP has identified procurement of large resources like out-of-state wind and offshore wind as a key area where a programmatic procurement framework is needed. By enabling a single LSE to procure particular hourly slices from a large resource, the RA framework will better align with the direction of the IRP proceeding and the California Public Utilities Commission's ("CPUC" or "Commission") efforts to encourage resource diversity. The Workshop Report should acknowledge the potential value of load trading and recommend a process for ensuring that load trading concepts can be administered in a way that is both efficient and consistent with the CPUC's need to enforce the supply plan filing requirements of the RA program.

Test Year

ACP-California acknowledges that a more granular, 24-hourly slice system would be more complex than the current RA program design. In light of this complexity, ACP-California does not believe a 24-hours slice proposal can realistically be implemented by 2024 without considerable disruption and uncertainty. We are concerned that an abrupt change in: (1) how LSE loads are reported to the California Energy Commission ("CEC") and obligations are calculated (i.e., bottom-up); (2) new resource counting conventions; (3) CPUC supply plan review process; and (4) CAISO implementation of reforms to the Customer Interface for Resource Adequacy all necessitate ample time to ensure a smooth transition. In particular, the change from the Effective Load-Carrying Capability ("ELCC") model to a new Qualifying Capacity ("QC") accounting methodology could be particularly problematic for wind resources, as noted in ACP-California's November 10^{th} and December 22^{nd} comments on the long-term reform workshop series (also discussed below). ACP-California recommends further consideration of the CEC's hybrid, top-down approach to establish individual LSE-obligations and reduce the complexity of the load forecasting portion of the 24-hourly slice proposal. In addition, there is a need to ensure that LSEs can effectively contract for replacement RA. Replacing particular slice(s) may be more difficult on a short term basis when resource profiles are less fungible. The need to redefine replacement RA may also create an issue for existing contracts providing replacement RA that will need to be transitioned into a new RA framework.

We encourage the Workshop Report to provide discrete recommendations for additional processes that would ensure the final program design is administratively feasible for the CPUC, CEC and CAISO to implement and market participants to transact. The Workshop Report should recommend a delay in implementation by at least a year while the program undergoes a dry-run in 2024 (i.e., existing RA supply plan rules should apply in 2024, while being required to build *hypothetical* 24-hourly slice supply plans for 2024 that are submitted to the CPUC and CAISO for review).

Deliverability Status

The 24 -hourly slice proposal would also require all projects to have full capacity deliverability status. We believe this issue requires further consideration. As discussed during the workshops, energy-only off peak deliverability status can provide a more cost-effective way of aligning transmission development with capacity requirements, and the Workshop Report should address how the 24-hourly slice proposal could be refined to enable more cost-effective transmission planning through the recognition of energy-only off peak deliverability status for certain hourly slices outside of the most stressed hours.

While there are issues that must be worked through, ACP-California is optimistic that the 24 hourly slice proposal can be structured to enable RA products and load obligations to be freely traded among LSEs and suppliers. Allowing bilateral transactions for capacity and load obligations among LSEs and suppliers will enable LSEs and suppliers to adapt to changes in individual LSE load profiles over time. This will be especially important for smaller LSEs to find the right capacity products for particular hours of need. Capacity needs and QC values must be stable. If these objectives can be achieved, a more granular system like that proposed by SCE may achieve greater efficiency in procurement by tailoring capacity development and procurement practices to focus on specific hours of need.

B. The Working Group Should Ensure that Exceedance or Another New Resource Counting Methodology Does Not Inappropriately Discount Resources for Their Aggregate Contribution to Reliability.

Certainty in the RA program design is critical to ensuring the timely achievement of the IRP procurement targets. The RA and IRP proceedings cannot be viewed in silos. The counting conventions used for measuring compliance with IRP procurement targets should be generally consistent with the RA proceeding. While we acknowledge that there may be some checks necessary in the RA program to ensure resource sufficiency in the year-ahead timeframe, as a general matter LSEs should have the confidence that the IRP capacity they buy will be valued in the RA program in both the year-ahead and longer terms.

Currently, the ELCC derate methodology provides certainty insofar as it is generally understood within the marketplace and the future changes to the model can be anticipated. While the ELCC is subject to periodic updates, we have found those updates to be fairly limited and somewhat predictable based on the ongoing ELCC modeling work in the IRP proceeding.

Moreover, in Decision ("D.") 21-06-029, the CPUC recognized the need for geographic granularity in the ELCC methodology and committed to updates in the RA process to account for the geographic granularity in wind production profiles, with the first biennial update to occur in 2022 for the 2023 RA year.[2]

If the Workshop Report ultimately recommends an exceedance approach, it should note that exceedance thresholds should be determined not just by resource type, but also by geographic location, consistent with the direction of D.21-06-029. Moreover, the refinement of an exceedance proposal should allow for differentiation in exceedance thresholds by hour and season, rather than imposing a single exceedance threshold across the entire year. The exceedance methodology used in the past did not properly account for the locational value of wind resources. While a relatively higher exceedance value may be necessary for some regions to account for variability in production, other regions like New Mexico offer more consistent wind output. For regions like New Mexico and offshore, where the wind resources are more consistent, the Workshop Report should analyze these regions in isolation in reaching a recommended exceedance threshold that is unique to the region.

The 24-hourly slice proposal would presumably require a determination of qualifying capacity in each hour (as opposed to monthly values, as provided by ELCC modeling). ACP-California does not believe an ELCC can be calculated on an hourly basis since the ELCC models a resource's contributions to reliability over a sustained period of time. If exceedance is included in the Working Group proposal, in addition to addressing the methodological issues

[2] D.21-06-29 at p. 44.

discussed above, the Workshop Report should acknowledge the statutory requirements for the ELCC and discuss how a statutory change would be necessary to move away from the ELCC. We do not agree with parties who have suggested during the workshops that this issue can be resolved by simply calling exceedance something else. Principles of statutory construction require more than mere changes in semantics. The Commission must first give the statute a plain reading and will need to address the fact that Section 399.26(d) of the Public Utilities Code expressly requires the use of the ELCC. If the meaning of an ELCC is ambiguous, only then may the Commission inquire into the Legislature's intent in adopting the statutory language.

While we do not believe the use of the term 'ELCC' in the Public Utilities Code is ambiguous, parties should be aware of the historical context of when the Legislature adopted this statutory provision (SB 2-1x). The statutory provision was adopted following the Commission's implementation of an exceedance methodology. The Commission originally adopted exceedance methodology in D.09-06-028.[3] Following this 2009 decision (and as discussed during the long-term reform workshops), the exceedance methodology resulted in very low capacity determinations for wind resources. Just six years after adopting an exceedance methodology, the Commission recognized a slew of concerns stemming from exceedance and shifted away from it as a counting methodology in D.15-05-063.[4]

In sum, if the Working Group ultimately recommends an exceedance methodology as a replacement to the ELCC, statutory changes will be needed and a substantial rulemaking process

[3] Proceeding R.08-01-025, D.09-06-028, See https://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/102755.pdf.
[4] Proceeding R.14-10-010, D.15-06-063.

will be needed to refine the QC methodology to properly account for the contributions to reliability made by wind and solar resources across hours and seasons.

III. Conclusion

American Clean Power – California appreciates this opportunity to provide informal comments on these workshops and looks forward to working with interested stakeholders to further refine and improve the Resource Adequacy program, while at the same time achieving other Commission priorities, such as the IRP procurement targets.

Respectfully submitted,

/s/

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AReM
Alliance for Retail Energy Markets

INFORMAL COMMENTS ON RA PROPOSALS AND WORKSHOPS

February 7, 2022

Slice-of-Day Proposals

The Alliance for Retail Energy Markets ("AReM")[1] seeks a slice-of-day reform approach that enhances reliability, is simple, has low customer-cost impact, can be implemented for the 2024 RA year, and minimizes disruptions to current commercial transactions.

Based on the information available today, AReM prefers the Gridwell proposal to PG&E's "slice of day" or SCE's 24-hourly slices because of its relative simplicity, commercial transactability, and consistency with CAISO operations and systems. While PG&E's original approach to define seasons and slices of day for RA showings was the basis for the initial conversations in the workshops, most all stakeholders, including PG&E, abandoned that approach in favor of either SCE's or Gridwell's simpler approach. And while SCE's approach represents a better

[1] AReM is a California non-profit mutual benefit corporation formed by electric service providers that are active in the California's direct access market. This filing represents the position of AReM, but not necessarily that of a particular member or any affiliates of its members with respect to the issues addressed herein.

alternative to PG&E's, Gridwell's approach should provide similar reliability benefits when compared to SCE but in a more efficient manner that takes into account validation constraints. The CAISO has already announced that it will not be validating all 24 hours, a fact that the Gridwell proposal recognizes. AReM thus questions the need for 24-hourly slices when the CAISO will only validate at most two of those hours (gross and net peaks); greater justification would need to be made to demonstrate that 24-hourly slice validations will enhance system reliability given the extra burden on load-serving entities ("LSEs") and regulators to prove and validate showings that the grid operator itself does not plan to validate. Specific analysis to demonstrate the need to impose additional administrative and commercial procurement burdens associated with the 24-hourly slice showings should be done before enacting this type of structure.

Some have criticized Gridwell's proposal because it does not validate charging and discharging by energy storage RA resources. However, Gridwell has argued that sufficient energy exists on the system to ensure all existing and planned energy storage can be charged as needed. To justify this assumption and remove the MCC buckets, AReM recommends that the IRP analysis be run to set a limit as to the maximum storage that can be deployed given the excess energy installed on the grid. This approach would set an analytical limit to the amount of storage that can be accommodated.

<u>Need Determination and Allocation</u>

AReM strongly supports the approach specified by Lynn Marshall of the California Energy Commission ("CEC") in her December 1st workshop presentation. That approach continues the *status quo*, in which the IEPR forecast sets the total requirements for LSEs, LSEs submit their specific load forecasts, and then the CEC applies LSE-specific plausibility and coincident adjustments. Thus, the CEC would conduct the same analysis it does today in compliance with the policy adopted by the Commission in D.12-06-025,[2] but apply the process to whatever slice approach is approved by the Commission. This approach can best be summarized as a top-down, hybrid approach, based on the LSE's hourly forecasts, and applying the coincident adjustment to each LSE's load forecast.

[2] D.12-06-025, pp. 28-29, Finding of Fact 8, Conclusion of Law 7, and Ordering Paragraph 4.

AReM opposes SCE's proposal as outlined in its recap presentation at the December 15th workshop. SCE stated that it supported the CEC approach, but its proposal (slide 3) referred to the CEC approach as "bottoms-up," which is not accurate, as described above. More importantly, in workshop discussions, SCE emphasized that it proposed modifying CEC's proposed approach by relying on historical data, rather than forecasts as the CEC does today, which would mean that an LSE's forecast of its load would no longer be considered. SCE was unable to provide justification for its proposed deviation from the CEC's load forecasting approach. The CEC's approach fairly allocates the obligations to LSEs and should not be modified without substantive evidence justifying the change, and explaining how the change would impact the need determination.

Resource Counting and Resource Need Analysis

AReM supports Pmax or UCAP-light for dispatchable thermal generators. However, as AReM has mentioned in comments during the workshop, if a new NQC approach, such as UCAP or UCAP-light, is adopted, there must be a commensurate change to decrease the Planning Reserve Margin ("PRM") to reflect how the new NQC approach takes into account derates as outlined below.

AReM also supports the proposals made during the workshops to perform a rigorous Loss of Load Expectation ("LOLE") analysis so that the PRM is sufficient, but not excessive, in ensuring reliability. Only after LOLE analysis is performed can a new PRM and NQC approach be adopted as the two are intertwined. For example, if a new LOLE analysis supports a 17 percent PRM that assumes a 6 percent forced outage rate during the peak period (May through October), adopting UCAP in this proceeding should then result in a commensurate downward adjustment of the PRM to 11 percent during peak periods. In addition, if CAISO's proposal is adopted with different UCAP values based on the time period, there would need to be consideration given to having different PRMs for the peak and off-peak periods that align with the different seasonal UCAP values being adopted.

For the preferred Gridwell approach, AReM would need to better understand how ELCC in its current form could be adopted to this structure. Since ELCC is an 8760-hour analysis that compares the value of a resource to a "perfect generator" in a stochastic simulation representing an entire year, it appears to need modifications if the capacity contribution is not during a range of hours, but instead during two very specific hours (gross and net peak). If instead, exceedance is applied to wind and solar, AReM supports the 50% exceedance level. And as mentioned above, changing the RA values of any resource type will require a reevaluation of the PRM and total RA showings since potential fleet derates without changing the PRM will lead to overprocurement and higher costs for customers.

RA Transactions

AReM supports retaining bundled RA attributes. AReM agrees with SCE[3] that this is critical to ensure alignment with existing RA must-offer requirements, retain commercial transactability and support administrative feasibility.

Trading Load Obligations

AReM opposes trading of load obligations, which is unnecessary and would be exceedingly complicated to track for compliance purposes. LSEs should instead sell to other LSEs their excess capacity resources found to be not needed for certain "slices", which would work for any of the proposals being considered. Transacting capacity is already well established and would have the same result as transacting load slices.

Energy Hedging

AReM opposes any mandatory hedging requirement or cap on energy bids within the RA proceeding as a way to address potential market power issues. Rather than impose a hedging requirement as part of RA obligations, AReM agrees with the presentation made by Vistra at Workshop #8 on January 5, 2022 that any concerns regarding market power should be addressed via CAISO initiatives The CAISO will be starting an initiative in the second quarter of 2022 titled "Price Formation Enhancements," which will address issues related to market power and scarcity pricing. In addition, there is no compelling evidence that the "price cap rebate" design proposed by PG&E or the RA energy cap is necessary given recent analysis by the CAISO's

[3] SCE's November 10, 2022 Informal Comments, p. 2.

Department of Market Monitoring that "performance of the day-ahead and real-time markets remain highly competitive".[4]

Today, there exists many pathways for LSEs to enter into energy hedges if they so choose; LSEs should have the freedom to select the energy and procurement options that best fit their needs. Specific energy hedging requirements should not be mandated via the RA program. If the Commission wants to move forward with a hedging proposal in the RA docket, the structure should be optional given the other energy hedging products that exist. This will give LSEs the flexibility to work with counterparties on a structure that works best for their RA portfolio, such as the voluntary hedges PG&E has incorporated into their recent RA contracts as outlined in Workshop #8.[5]

Penalties and Multi-Year Procurement

AReM agrees with SCE's proposal that 1) penalty rates be applied as currently structured, 2) LSEs that are deficient are "first in line" for CAISO CPM costs, and 3) penalties be based on the maximum daily deficiency in any slice.[6]

AReM does not support the proposal from IEP/WPTF[7] to adopt multi-year System RA requirements for all LSEs at this time without commensurate changes to the IRP procurement process. In the IRP proceeding (R.20-05-003), AReM did support a multi-year System RA procurement approach in lieu of separate long-term RA procurement obligations via the IRP proceeding.[8] Having a multi-year System RA procurement requirement would eliminate the need for separate 10-year RA procurement contract obligations and align the needs of the IRP and RA proceedings. However, this recommendation was not adopted in the IRP process[9] in favor of a separate procurement mandate for new 10-year RA resource contracts. Since the intent of longer-term contracting and procurement is to assure that resources have contracts with sufficient revenue to maintain operations and perform necessary maintenance, it is unnecessary

[4] California ISO, Q3 Report on Market Issues and Performance, December 9, 2021, p.1.
[5] PG&E's Presentation, Workshop 8, January 5, 2022, slides 8-11.
[6] SCE's Presentation, Workshop 9, January 19, 2022, slide 4.
[7] IEP/WPTF Presentation, Workshop 9, January 19, 2022, slide 9.
[8] *Comments of the Alliance for Retail Energy Markets on Administrative Law Judge's Ruling Seeking Feedback on Mid-Term Reliability Analysis and Proposed Procurement Requirements,* R.20-05-003, March 26, 2021, p. 22.
[9] D.21-06-035, pp. 78-80.

to complicate procurement even further with a multi-year System RA obligation unless it can be demonstrated that the existing procurement orders, multi-year Local RA contracts, and RA prices are insufficient to keep needed resources operational.

If the Commission believes that multi-year System RA procurement should be considered further, additional discussion should be performed in conjunction with the LOLE analysis done in the Implementation Track of the RA proceeding and the next cycle of the IRP. Only if these proceedings demonstrate that further incentives are needed to support existing resources via multi-year contracts should multi-year procurement be ordered.

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February 7, 2022

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 19-11-009 (Filed November 7, 2019)

INFORMAL COMMENTS ON RESOURCE ADEQUACY FRAMEWORK WORKING GROUP PROCESS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. Introduction

The California Independent System Operator Corporation (CAISO) hereby submits informal comments on the Resource Adequacy Framework Working Group Process (RA Framework). Per the January 20, 2022 email update from the working group co-facilitators, the CAISO submits its completed *RA-Framework-Working-Group_Party-Position_Matrix.xlsx* (Position Matrix) concurrently with these comments.

II. Discussion

A. Rapid Changes to the Resource Mix and Demand Trends Warrant Revisiting the Resource Adequacy Program Structure.

The CAISO balancing authority area resource fleet is rapidly changing to one largely comprised of renewable, storage, and availability-limited resources. Fuel substitution and economy-wide electrification are changing demand profiles, and thus, potentially changing the critical operational periods on the grid. In recent years, the CAISO has experienced challenges managing the system at the net demand peak period when loads remain high and solar generation becomes largely unavailable. As the resource mix and demand trends continue to evolve, resource adequacy program changes will be necessary to ensure reliability.

The Commission should ensure the resource adequacy framework results in load serving entities (LSEs) procuring and showing to the CAISO a resource mix capable of ensuring grid reliability during all hours of the day. To that end, the CAISO proposes attributes the Commission's future resource adequacy program should include to support reliability under rapidly changing supply and demand conditions. These attributes should serve as a guide to help evaluate slice of day proposals. The CAISO's proposed attributes for the Commission's resource adequacy program include the following:

- Ensuring LSEs show and offer to the CAISO sufficient resources with the right capabilities under a 24x7 must-offer obligation.
    - This is necessary for the CAISO to operationalize the resource adequacy fleet effectively and efficiently to maintain reliability around-the clock. If resources are not subject to a 24 x 7 must offer obligation, they may not be available when the CAISO needs them. The increasing number of energy and use-limited resources can create operational challenges during periods of the day other than the peak.
- The ability to ensure a reliable resource adequacy fleet (*e.g.*, a fleet that can meet a 0.1 loss of load expectation (LOLE) or planning reserve margin (PRM) based on a reliability-based assessment). This includes meeting reliability needs across critical operational periods, under multiple day high load conditions, and other climate change driven risks/events.
    - An LOLE analysis and a one-in-ten year planning standard should be used to establish resource adequacy requirements and determine an appropriate PRM. This is a widely accepted practice and standard for determining resource adequacy. LOLE analyses, such as those based on a stochastic production simulation model, can model hundreds of iterations of full-year hourly chronological simulations. Such detailed modeling can test whether the resource adequacy fleet is capable of maintaining reliability in the face of different and extreme weather events, which may last several hours or days.
- Sufficient flexibility to adapt to the rapidly changing demand and resource mix. The unique challenges presented by the changing demand and resource mix are detailed below.
    - Demand – According to the California Energy Commission's (CEC's) January 2021 demand forecast, the gross peak and net peak demand hours will converge by 2023.[1] Expected future fuel substitution and economy-wide electrification will further change the load shape and potentially change the critical operational periods on the grid.
    - Resources – California is shifting to a resource mix increasingly comprised of variable, use-limited, and availability-limited resources.
        - Between summer 2020 and the end of 2021, the battery storage fleet increased from 500 MW to 2,500 MW.
        - Based on the Proposed Decision in the Integrated Resource Planning proceeding, LSEs are expected to add an additional 2,500 MW of

[1] California Energy Commission, CED 2021 Hourly Forecast - CAISO - Mid Baseline - AAEE Scenario 3 - AAFS Scenario 3 (2021 IEPR forecast). The gross peak occurs by 2023 at hour ending 19 Pacific Standard Time (hour ending 8:00 p.m. Pacific Daylight Time).

battery storage in 2022, increasing to a cumulative 11,300 MW by 2025.[2]

        - This same Proposed Decision indicates LSEs will add 1,000 MW of geothermal resources and 1,000 MW of long-duration storage by 2028.
        - Significant dispatchable resource retirements are expected over the next five years as the remaining once-through-cooling gas-fired generation resources reach the end of their compliance extensions.
        - The Diablo Canyon Power Plant, which provides significant baseload capacity, will reach its scheduled retirements in 2024 and 2025.
- Resource counting rules that accurately reflect resource availability, including outage rates and use limitations.
    - Resource counting rules should provide a reasonable expectation of the availability of the resource adequacy fleet. Counting rules that appropriately reflect resource availability and use limitations, while providing incentives for resources to be available, can help the Commission and the CAISO avoid relying on resources that may not actually be available when needed in the operating timeframe.
- Sufficient capability to meet both energy and capacity needs, including resources to meet storage charging demand.
    - A significant amount of dispatchable thermal resources will retire, and storage resources are expected to provide the bulk of capacity needed to maintain reliability in the face of these retirements. The resource adequacy program should consider when storage resources will be charged and discharged and assess whether there will be sufficient capability to meet storage charging requirements.
- Contracting sufficient to meet established resource adequacy capacity requirements and minimize CAISO backstop procurement
    - CAISO procurement mechanisms are intended to serve as back-stops to LRA resource adequacy programs, and they should not be relied upon to front-run the Commission's procurement processes.
- Coordination with CAISO's resource adequacy construct, which the CAISO must administer for all local regulatory authorities (LRAs) within its footprint.
    - The Commission should coordinate closely with the CAISO because changes to the Commission's resource adequacy program may affect the CAISO's overall resource adequacy construct. The CAISO must ensure it has a resource adequacy construct that is workable and just and reasonable across all LRAs.

[2] California Public Utilities Commission, Order Instituting Rulemaking to Continue Electric Integrated Resource Planning and Related Procurement Processes, R.20-05-003, Proposed Decision of ALJ Fitch, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M434/K547/434547053.PDF.

B. Gridwell's Proposal Has Merit, But It May Not Adapt Adequately to Future Demand and Resource Conditions.

Gridwell's resource adequacy proposal would largely maintain the existing framework, while adding an additional compliance check for the net demand peak hour. Gridwell's proposal has merit as it addresses reliability needs in the net demand peak period. In recent years, the CAISO has experienced challenges managing the grid at net peak, which currently occurs around 8:00 pm in summer months, when demand remains high but solar resource production is unavailable or minimal. Gridwell's proposal also appears to be largely compatible with CAISO's existing resource adequacy construct, which would limit implementation challenges and not disrupt the existing process for other LRAs.

Although Gridwell's proposal provides reliability benefits—especially in the short-term—those benefits may not be sustainable in the long-term as the demand and resource mix rapidly change. For example, when the gross peak and net demand peak periods converge in 2023, the separate "net peak" check will be obsolete. Additionally, the impacts of fuel substitution and electrification will further change the load shape and potentially change the critical operational periods on the grid outside of the gross peak/net peak period. Gridwell's proposal does not appear to be flexible enough to capture potential future shifts in critical operating periods and may require a new counting methodology when a new critical operating period is identified in the future

Additionally, Gridwell's proposal does not ensure sufficient capability to meet storage charging demand. Properly accounting for storage charging will be an important resource adequacy framework attribute with the significant expected increase in storage capacity by 2025.

C. SCE's Proposal Has Merit, But the Commission Should Consider Additional Design Elements to Implement a Framework Compatible with the CAISO's Resource Adequacy Program.

SCE proposes a 24-hour slice framework where LSEs show resources to meet demand plus a planning reserve margin across 24 hours of a representative day of the month. SCE's proposal appears capable of securing both capacity and energy needs under changing supply and demand conditions. Under SCE's proposal, showings are not required during only select hours of the day, and variable and limited-energy limited resources are shown in hours they are capable of producing. SCE's proposal also includes storage charging requirements in addition to meeting demand plus a planning reserve margin, ensuring sufficient excess resources will be available to meet storage charging. SCE's proposal provides a more precise energy sufficiency check than the current maximum cumulative capacity (MCC) bucket framework.

Although SCE's proposal has merit, this proposal represents a significant change to the Commission's resource adequacy framework. SCE's proposal likely would not be compatible with the CAISO's existing resource adequacy construct, which is designed to ensure LSEs meet a Commission established demand and reserve margin requirement with sufficient shown capacity. For example, the CAISO may need to modify its systems to include additional hourly validation for each slice of day component. To harmonize the CAISO's processes and systems with SCE's proposal, the CAISO would need to open its own stakeholder process to discuss the relevant tariff changes with other LRAs and market participants. The CAISO anticipates it would have to vet significant changes through its own stakeholder processes to accommodate a slice of day framework like SCE's. The CAISO anticipates it would have to revisit the following CAISO rules and processes, at a minimum, under SCE's proposal:

- Bid insertion rules;
- Outage and substitution rules; and
- Capacity procurement mechanism (CPM) checks, triggers, and cost allocation rules

The CAISO will not be able to complete a stakeholder process and implement resource adequacy tariff and program changes by resource adequacy year 2024. The CAISO, however, recognizes the urgency of resource adequacy reform and commits to working with the Commission and stakeholders to further develop a resource adequacy framework that can be implemented soon after resource adequacy year 2024.

D. Key Slice of Day Design Elements Remain Unresolved.

Stakeholders covered a significant amount of material in the working groups. However, some key design elements to inform a slice of day resource adequacy framework remain unresolved and would benefit from further discussion and development. The CAISO details these unresolved issues below.

1. How the planning reserve margin (PRM) will be set and resource counting methodologies

Resource counting methodologies should be considered in step with determining an appropriate PRM. For example, if wind and solar resources are counted under an exceedance methodology, the level of exceedance affects whether additional uncertainty should be accounted for in the PRM. For thermal resources, the Unforced Capacity (UCAP) approach could be viable for reflecting resource forced outage rates up front in resource counting.[3] Embedding forced outage rates in resource counting would offset the need to assume a forced outage rate for those resources in the Commission's planning reserve margin.

2. Ensuring reliability across multiple days

Under the Commission's resource adequacy program, some MCC buckets (although not binding requirements) capture multi-day availability requirements and account to some extent for multi-day reliability events (Demand response bucket and Bucket 1). However, the SCE and Gridwell proposals do not explicitly account for multi-day reliability needs. Many resource use-limitations exist across a month or a year (*e.g.*, starts per month or year, or run hours per month or year). Several demand response programs also have limited calls across a shorter period of time. Although SCE and Gridwell both mention potentially retaining certain MCC buckets, the CAISO believes this design aspect warrants further thought and discussion.

III. Conclusion

The CAISO appreciates the opportunity to provide these informal comments and looks forward to working with the Commission.

Dated: February 7, 2022

[3] As detailed in CAISO's presentation on UCAP, a UCAP methodology is compatible with both SCE and Gridwell proposals, Slide 23: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-9-ucap-proposal_caiso.pdf.

Informal Comments of the CAISO Department of Market Monitoring on the Track 3B.2 Slice-of-Day Workshops

R.19-11-009 and R.21-10-002

February 7, 2022

I. Summary

The Department of Market Monitoring (DMM) of the California Independent System Operator Corporation (CAISO) appreciates the opportunity to provide informal comments on the topics presented in the Track 3B.2 resource adequacy workshops on a Slice-of-Day framework.

DMM supports the efforts by the Commission to implement a restructured resource adequacy program in line with the principles stated in D.21-07-014.[1] DMM summarizes its comments below:

- DMM continues to support a 24-Hourly Slice framework as proposed by SCE as a viable design to be considered by the Commission. DMM supports the Commission focusing efforts to develop the details of a 24-Hourly Slice framework for implementation by resource adequacy year 2024.
- Counting methodologies for solar should include the ability to capture solar's contribution to charging storage resources. An hourly slice framework would support this better than the 2-slice variation of the proposals.
- A 24-Hourly Slice framework helps ensure that resources procured through IRP will be available to serve California load.
- DMM supports the Commission pursuing further examination of a hedging component within the resource adequacy reform.

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[1] *Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program*, July 15, 2021: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.PDF

II. Discussion

DMM continues to support SCE's 24-Hourly Slice framework as a viable design.

The resource adequacy design that emerges from these workshops for delivery year 2024 must be durable and adaptable to the changes to the electric grid and resource mix that will occur as California transitions to meeting 60% of its retail electricity from renewable generation by 2030. A significant increase in solar and storage capacity will be needed on the system to meet this target.[2] The interactions between these two resource types will be increasingly important to meet load across the day. Solar generation will be critical for serving load midday, but will also be critical for charging storage capacity to meet load at net peak and through the night.

DMM continues to support SCE's variation of PG&E's slice-of-day concept. SCE's 24-Hourly Slice framework should capture the reliability requirements across all hours of the day. Participants appear to have coalesced around two versions of a slice of day proposal—one which considers hourly reliability requirements as proposed by SCE, and one which considers a two-slice requirement based on a gross and net load peak. As discussed in previous comments, DMM believes SCE's 24-Hourly Slice framework is better aligned to meet the reliability needs under a system more heavily comprised of preferred and intermittent resources in the future. We encourage the Commission to develop all details necessary for making the 24-Hourly Slice framework implementable by 2024.

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[2] *2021 SB 100 Joint Agency Report – Achieving 100 Percent Clean Electricity in California: An Initial Assessment*, California Energy Commission/CPUC/CARB, March 2021: https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity

Counting methodologies for solar should include the ability to capture solar's contribution to charging storage resources.

The SCE proposal suggests resources should be counted in hourly slices for load-serving entities' compliance showings. To mitigate concerns of the administrative burden of transacting 24 different requirements and products for each month, the SCE proposal seeks to retain simplicity by keeping resource attributes bundled and allowing load-serving entities to use those attributes to meet their hourly load requirements.

DMM shares the concerns expressed by some participants that slices of day larger than one hour could significantly undercount the contribution of operationally-limited resources – such as solar and demand response– towards meeting load requirements and charging storage resources. DMM also understands the concerns raised by some participants about the administrative burden as the number of slices increase. Therefore, DMM believes that SCE's variation of PG&E's slice-of-day concept has the potential for striking the right balance between these competing concerns, while still requiring each LSE to make sufficient resources available to CAISO to meet its energy and capacity needs across all hours of a month or season.

Solar resource adequacy values should be non-zero to the extent that solar resources' generation is necessary to charge the storage resources relied upon for meeting reliability requirements. In workshops stakeholders discussed the potential for solar ELCC values approaching zero if marginal ELCC values are used to develop solar QC values, particularly under a 2-slice proposal. If solar QC values approach zero, load serving entities may not contract with enough solar resources to provide the energy necessary for meeting demand midday and charging storage resources. If this capacity is not contracted with LSEs, or otherwise not shown to the CAISO as resource adequacy capacity, then these resources will not be bound by must offer obligations to the CAISO and could be eligible for export outside of the CAISO market. Resources without a contract with a CAISO load serving entity, or load serving entities that have contracted resources but have not shown them as resource adequacy capacity, could instead sell the energy or capacity to support high priority exports out of CAISO. DMM believes a 24-Hourly Slice framework could help ensure that solar continues to be contracted and valued for its contribution to reliability in the resource adequacy program.

The 24-Hourly Slice framework helps ensure that resources procured through IRP will be available to serve California load.

Some participants have argued that the resource adequacy design can assume that the integrated resource planning process will result in sufficient clean energy and storage being constructed in California to meet these challenges.[3] However, it is not clear how a resource adequacy framework that only counts resources' contributions to peak gross load and peak net load would ensure that the clean energy and storage capacity necessary for meeting load overnight in 2030 and beyond remain under contract to California load serving entities, and that those resources are ultimately made available to the CAISO markets.

In the absence of a robust resource adequacy program that considers the energy needed to charge storage resources and the storage capacity needed to meet load through the night, there does not appear to be a mechanism to assure that the critical energy and capacity will be made available to CAISO. Resources that were constructed through the IRP process may instead sign contracts, or California load serving entities who have them under contract may instead sell their energy and capacity, to support high priority exports to other balancing areas. Compared to

[3] *Resource Adequacy Seasonal Slice Proposal*, Gridwell Consulting presentation at November 1, 2021 Slice-of-Day workshop, p. 21.

resource adequacy frameworks that only count resources' contributions to peak gross and/or peak net load, SCE's 24-Hourly Slice framework seems to provide much better assurance that load serving entities will contract with resources that could collectively meet energy requirements across all hours of the day and will make these resources available to the CAISO.

Hedging is an important issue in this proceeding but warrants further discussion on how it should be implemented.

In D.21-07-014, the Commission noted concern that resource adequacy reform proposals 'lack a means to ensure that RA is linked with energy bidding behavior in order to balance reliability with minimizing costs to customers' and directed parties to propose a hedging component as part of the final proposed framework.[4] In the second to last working group meeting, PG&E presented two potential hedging approaches: a variable cost hedge and a price cap rebate.[5] DMM believes these two types of hedges could potentially provide benefits for both suppliers and load-serving entities. However, requiring these hedges as a necessary component of a resource adequacy contract warrants further discussion to how it could fit with the hedging strategies already employed by market participants today.

Under PG&E's proposal, a price cap rebate would limit any excess energy revenues received by a generator when spot market prices exceed a fixed price cap. Any excess revenues resulting from the spot market price above the price cap would be returned to the load serving entity counter-party to the contract. A variable cost hedge would function similar to a price cap rebate except the strike price would be based on a cost-based reference price instead of a fixed price.

[4] Ibid. pg. 38
[5] *RA Reform: Hedging,* Pacific Gas & Electric presentation on January 5, 2021 Slice-of-Day workshop

Some participants in the working group expressed concerns that either of these proposed hedging components would result in a price increase of resource adequacy contracts. As other stakeholders have stated in the working group process, hedging is not free. However, DMM notes that high levels of hedging in the overall market can also provide indirect benefits to all LSE's by significantly reducing the potential for the exercise of market power. Therefore, requiring each LSE to acquire a hedge for most or all of its resource adequacy obligation may be cost-effective because it would reduce each LSE's exposure to risky spot market price spikes and also mitigate the potential exercise of market power in CAISO spot markets. A carefully designed hedging requirement could also potentially create sufficient incentive for importers to support resource adequacy imports with dedicated physical capacity. This may allow the CPUC to relax the requirement that import resource adequacy must bid at or below $0/MWh in CAISO markets.

While DMM continues to support the possibility of the Commission requiring some form of energy hedge for resource adequacy capacity, the details of the requirement should be carefully worked out with stakeholders in order to avoid unintended detrimental consequences. For example, a simple price-cap rebate on its own may undermine incentives for generators to sell fixed price energy contracts. The design of an energy hedging component for resource adequacy warrants further discussion going forward.

Respectfully submitted,

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Dated February 07, 2022

Informal Comments of Calpine Corporation on the Implementation of the Slice-of-Day System RA Proposal and Other Reform Track Topics

R.21-10-002

February 4, 2022

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Calpine Corporation ("Calpine") appreciates the opportunity to offer these additional comments on the workshops to implement the Slice-of-Day ("SOD") system resource adequacy ("RA") proposal. D.20-07-014 adopted SOD and directed parties to hold a series of implementation workshops. With the collaboration of other parties, Pacific Gas and Electric Company ("PG&E") took the lead in organizing the workshops, including establishing a schedule for the workshops and comment opportunities. These comments are the last scheduled opportunity to provide feedback on the workshops before the publication of the workshop report.

In these comments, Calpine reiterates its support for the proposal set forth by Gridwell Consulting ("Gridwell") and Vistra Corp. ("Vistra") (the "Gridwell/Vistra proposal"). In addition, Calpine addresses the topics of energy hedging, penalties and backstop procurement, UCAP, and multi-year forward system RA requirements, which were the focus of workshops 8 and 9.

The workshops narrowed the proposals under consideration to two: (1) a Southern California Edison Company ("SCE")/PG&E proposal that entails 24 separate hourly compliance requirements for each compliance period, with distinct resource counting for each hour and explicit storage charging capacity requirements; and (2) a Gridwell/Vistra proposal that involves a single compliance requirement for each month (with an additional validation that non-solar capacity is sufficient to meet net peak needs) and broader application of the effective load carrying capability ("ELCC") methodology for resource counting. For all of the reasons articulated in its previous comments, Calpine continues to support the Gridwell/Vistra proposal. The Gridwell/Vistra proposal uses ELCC, an established and analytically robust method for determining the reliability contributions of intermittent and/or use-limited resources. In contrast, the SCE/PG&E proposal relies on ad hoc exceedance approaches to resource counting, and it has not been demonstrated to meet objective reliability standards, such as the 1-event-in-10-year standard. In addition, the SCE/PG&E proposal does not explicitly address certain types of reliability challenges, such as multi-day periods of low renewable generation, which are likely to become more significant and could be addressed with ELCC. Finally, the SCE/PG&E proposal entails complicated compliance requirements that would inhibit the trading and increase LSE compliance costs.

Notwithstanding the fact that SCE/PG&E and Gridwell/Vistra now utilize monthly compliance periods, Calpine continues to favor seasonal or annual compliance periods. As Calpine has previously explained, there is a false economy in more temporally granular compliance periods. While they ostensibly allow load serving entities ("LSEs") to procure capacity only for the narrow windows in which they need it, ultimately suppliers must recover the costs of all needed capacity, most of which are fixed over annual or longer periods. Consequently, to the extent that capacity is procured for more limited time windows, its price (per unit of time) will rise accordingly, offsetting any presumed savings.

Calpine does not repeat the arguments articulated in our previous informal comments with respect to why the Gridwell/Vistra proposal better addresses the principles that the Commission articulated in D.20-07-014. However, with respect to principles 1 (reliability) and 4 (timely implementation), Calpine is concerned that the workshops have concluded without the development of a complete SCE/PG&E proposal, including specific counting rules and planning reserve margins ("PRMs") and clear demonstrations that those counting rules and PRMs would satisfy the Commission's reliability objectives. Consequently, to the extent that the Commission adopts the SCE/PG&E proposal, it should allow sufficient time for the development of these details. (Calpine does not have similar concerns about the Gridwell/Vistra proposal because its structure is more similar to the status quo.)

In the rest of these comments, Calpine addresses the topics that were the focus of the most recent workshops.

Energy Hedging

Proposals to mandate energy hedging through RA were considered in workshop 8. As it has consistently maintained since this topic was first introduced in the previous RA proceeding, Calpine opposes mandating energy hedging through RA. While Calpine acknowledges the concerns that energy hedging proposals are intended to address, *i.e.*, that LSEs may be insufficiently hedged and hence their customers may be exposed to volatile spot prices and/or that exposure might precipitate a disorderly return of non-investor-owned utility ("IOU") customers to IOU service, Calpine believes that the topic requires more analysis before a policy determination is made. In particular, as CPUC staff have suggested, Calpine agrees that it would be helpful to gather data on LSE hedging practices to understand the nature of the potential exposure before implementing mandatory hedging through RA. Calpine is also concerned that the specific nature of the hedges that have been proposed may not be cost-effective and that mandating their use may undermine current hedging practices.

Finally, Calpine believes that mandating energy hedging through RA may not actually achieve the proponents' objectives for at least two reasons:

First, the proposals fail to acknowledge the hedges that specific LSEs already have in place, either physical or financial. Consequently, imposing uniform requirements through RA could lead to very different levels of hedging for different LSEs.

Second, even if energy hedges are mandated through RA, it may be difficult or impossible for the Commission to ensure that LSEs maintain those hedges. For example, nothing that has been proposed would limit an LSE from taking an offsetting financial position to an RA-mandated hedge, and imposing such limits would require regular oversight of LSE energy procurement, which, for non-IOUs, may exceed the CPUC's statutory authority.

With respect to specific hedging proposals, PG&E proposed two different call option approaches: the Price Cap Rebate and the Variable Cost Hedge. Both of these approaches are problematic for suppliers. The Price Cap Rebate proposal is particularly problematic.

The Price Cap Rebate proposal would obligate a supplier to refund the buyer any positive difference between the realized spot price and the price cap. Calpine typically hedges by selling fixed price energy. To the extent that a supplier has sold fixed price energy from a specific MW, if it is also required to refund any positive difference between the spot price and the price cap, it would not be able to offset the costs of the option with additional spot market revenues from the same MW. To address this problem, suppliers might not sell fixed price energy backed by the MW in the first place, limiting their ability to lock in prices on a forward basis. Alternatively, suppliers might price the option as if its costs were not offset by spot market revenues for the MW, in which case it might be expensive because it would expose the supplier to potentially large risks that it could not control directly through the provision of energy from its own capacity. (As Eric Little of the California Community Choice Association ("CalCCA") observed, LSEs already have the option to hedge using similar call options and generally choose not to, suggesting that they may not be considered cost-effective).

The Variable Cost Hedge is more palatable in some ways because it resembles a tolling agreement. Under a tolling agreement, suppliers generally convey to LSEs RA capacity as well as the right to dispatch a resource at its variable cost and realize the value of its energy in return for a fixed payment. Consequently, a toll would obviate the need for a supplier to hedge energy because the toll eliminates the supplier's exposure to energy prices. On the other hand, if these tolling arrangements were contracted through RA, they could occur as late as the month-ahead time frame, which is generally far closer to delivery than when suppliers would prefer to hedge. In addition, while tolls can be attractive to suppliers, they typically involve cumbersome negotiations because they are so resource-specific, which might not be suitable for the large numbers of transactions involved in RA compliance.

Further, it is unclear that the Variable Cost Hedge would provide appropriate hedges for LSEs. Because the variable costs of resources are generally different, mandating the hedges in the proposal would leave LSEs with different levels of exposure to spot prices. For example, a variable cost hedge with a high heat rate gas unit might provide less protection than a variable cost hedge with a lower heat rate gas unit. Further, with respect to gas units, variable cost hedges could leave LSEs exposed to gas price volatility unless they separately hedge gas, *e.g.*, if an LSE secures a Variable Cost Hedge with a 7 MMBtu/MWh unit, (ignoring non-fuel variable costs) the strike price of the hedge might be $28/MWh if gas were $4/MMBtu, but $70/MWh if gas is $10/MMBtu. LSEs may not be inclined, and the CPUC may not be able to force LSEs to implement, the complementary gas price hedges required to provide energy price certainty under the Variable Cost Hedge proposal.

While Calpine believes that energy offer caps should be the purview of the CAISO and FERC, Energy Division's RA-specific energy offer cap proposal, which would require RA resources to offer energy to CAISO at prices below CAISO's energy offer cap, would be less problematic than the PG&E call option approaches because it would limit how suppliers offer into CAISO markets but would not involve any explicit energy settlement. Consequently, it wouldn't directly interfere with current hedging practices. In addition, Calpine is open to voluntary RA energy hedging requirements although it is unclear what impact they might have and whether they would be enforceable. For example, it is unclear that the CPUC could mandate that non-IOUs include energy hedges as an option in their RA solicitations.

UCAP

In the ninth workshop, CAISO revived its proposal to use UCAP to determine the Net Qualifying Capacity ("NQC") of primarily thermal units. UCAP is intended to differentiate between more and less reliable units by reflecting unit-specific forced outage rates in RA counting. In addition, the incentive provided by the potential for prospective NQC de-rates due to forced outages may obviate the need for explicit performance incentives, such as the current RAAIM incentives, and the associated substitution rules.

Calpine appreciates certain aspects of the CAISO's proposal, in particular the focus on "tight supply cushion" hours to measure unit performance, but Calpine remains unconvinced that a full transition to UCAP makes sense. In particular, Calpine agrees with Carrie Bentley of Gridwell Consulting that UCAP, which would reflect historical outages, may not provide an accurate measure of the expected performance of a resource prospectively. For example, during major outages, sometimes entire components are replaced and this can lead a resource to be significantly more reliable prospectively. As CAISO indicated, the repairs would eventually improve the generator's UCAP, but only after a multi-year lag during which the generator's actual performance may not be accurately reflected in its UCAP.

While not explicitly addressed by CAISO, a UCAP-lite approach that adjusts NQCs for ambient de-rates might be more accurate to the extent that ambient de-rates are relatively predictable from year to year. If a UCAP-lite approach is implemented, it must provide suppliers with the opportunity to adjust NQCs when they make investments to limit ambient de-rates.

Penalties and Backstop

Also at the ninth workshop, Calpine and SCE presented on how CPUC RA penalties might apply to the SCE/PG&E 24-slice approach. Calpine fully agrees with SCE that penalties should be assessed on the maximum deficiency in any slice in order to encourage LSEs to meet compliance requirements in even the hardest-to-satisfy slices. In addition, this approach would preserve the current relationship between penalties and supplier's costs by encouraging LSEs to pay enough to cover a supplier's costs even for capacity that is only needed in a single slice. Further, by not compounding penalties for deficiencies in multiple slices, the proposal recognizes the potential that multiple deficiencies might be addressed with the same physical capacity.

Calpine's presentation also flagged concerns about alignment between the 24-slice approach and CAISO's Capacity Procurement Mechanism ("CPM") backstop rules. The CAISO can use CPM to cure deficiencies in LSE RA procurement. The combination of exposure to CPUC penalties and CPM costs provides the full incentive for LSEs to satisfy RA procurement requirements. In the near term, it is Calpine's understanding that the CAISO might only be able to validate and determine LSE deficiencies based on a single hourly slice. Consequently, LSEs may not face exposure to CPM costs for deficiencies in slices other than the slice that the CAISO validates. While this might lead to some hiccups, there seemed to be broad agreement among workshop participants that the CPUC and CAISO can solve these issues by aligning how they assess LSE RA deficiencies.

Multi-Year Forward

Calpine has long supported and continues to support multi-year forward RA requirements. The Western Power Trading Forum ("WPTF") and Independent Energy Producers ("IEP") presentation at the ninth workshop aptly summarized the benefits of such requirements including providing more certainty for suppliers, which ultimately reduces costs for load. Regardless of what structure is ultimately adopted, it should be accompanied by multi-year forward requirements.

Relatedly, Calpine believes either of the primary proposals under consideration could obviate the need for flexible RA requirements. Calpine is not convinced that they serve any useful function even under the status quo. Consequently, concerns about the durability of the flexible RA product definition, which have stymied previous attempts to implement multi-year forward requirements, should be moot.

Simplified ELCC

At the eighth workshop, California Wind Energy Association ("CalWEA") presented a "simplified ELCC" proposal to resource counting under the 24-slice approach or similar approaches that do not explicitly rely on ELCC. Rather than relying on exceedance, *i.e.*, some percentile of performance measured over all hours in a slice, the CalWEA approach would measure performance within a slice in the highest load hours as a proxy for performance when system conditions are tightest and capacity is most needed. While Calpine believes that the proposal requires refinement, *e.g.*, net load may be a better proxy for tightness than gross load, Calpine supports further consideration of the proposal in the event that the 24-slice approach is adopted.

California Wind Energy Association (CalWEA)
Final Informal Comments for the Final Working Group Report

R.19-11-009

Nancy Rader, Executive Director
Dariush Shirmohammadi, Technical Director

February 7, 2022

The California Wind Energy Association ("CalWEA") is a 22-year-old trade association representing members of the wind energy industry focused on developing and supporting projects in and directly interconnected to California, including onshore and offshore wind projects with turbine sizes ranging in size from 50 kW to 15 MW. CalWEA was pleased to participate in the Resource Adequacy ("RA") workshops focused on major structural reforms held between September 2021 and January 2022. CalWEA very much appreciates the significant efforts of PG&E and the other workshop co-facilitators, which enabled highly substantive, efficient and professional discussions.

As has characterized the discussions in these workshops generally, CalWEA's views on the various proposals as they have evolved have progressed as well. This final set of informal comments reflects our further consideration of the proposals and consultation with our membership. To summarize:

- CalWEA recommends that the Commission move forward with the Gridwell/Vistra proposal.

- CalWEA is concerned that the SCE/PG&E proposal is still not fully developed, could be disruptive to the market, and therefore risks failing to achieve necessary RA reforms. Should the Commission adopt the SCE/PG&E framework, CalWEA strongly recommends using CalWEA's proposed ENLR counting methodology for wind and solar resources (explained elsewhere in the Final Workshop Report) and would oppose the SCE/PG&E proposal if it relies on an "exceedance" counting approach.

- CalWEA strongly recommends that the Commission encourage the CAISO to revisit its deliverability methodology on a parallel path to the Commission's implementation of its new RA framework.

Position on Framework Proposals and Counting Methodologies

CalWEA was perhaps the last supporter of PG&E's slice-of-day proposal; in fact, had PG&E not dropped its proposal, CalWEA might be supporting it now. Having spent more time to fully understand the Gridwell/Vistra proposal, however, CalWEA is now supportive of it.

Advantages of the Gridwell/Vistra framework

The Gridwell/Vistra framework is technically sound and theoretically elegant, relying on the well-established and widely recognized ELCC modeling methodology that evaluates resource performance in every hour of the RA capacity counting time period (monthly) and based on a stochastic assessment of all parameters that impact the RA capacity of a resource. While developing ELCC values for all resources would require an upfront investment of time and resources, that exercise would simultaneously determine the overall ELCC target to ensure that an objective grid reliability standard is met – avoiding the need to separately establish a planning reserve margin. Once ELCC values of all types of resources (including gas plants, geothermal, storage, various hydro and, of course, wind and solar resources) are established on a monthly basis, the RA market would operate effectively as it does today, with the CAISO performing an added reliability check at the evening net peak (or the most hourly-RA-capacity-constrained) hour to ensure that LSEs have procured sufficient resources for that critical hour each day. CalWEA's proposed ENLR methodology would be appropriate for performing this hourly capacity check.

The Gridwell/Vistra framework thus carries the following benefits:

- Straightforward implementation increases the likelihood of successful RA market reform by 2024 that ensures achievement of an objective reliability standard.
- Maintenance of the current market structure eliminates possible market disruptions, preserves the ability of all LSEs to easily comply and the ability of all market participants (particularly small ones) to participate in a transparent market and obtain fair market values.
- The ELCC approach inherently addresses all system risks, including multi-day periods of constrained resources.

Concerns regarding the SCE/PG&E framework proposal

The proposal supported by SCE and PG&E would create 24 hourly compliance requirements for monthly compliance periods and would impose explicit storage charging requirements. CalWEA does not object to the proposed framework per se. However, the proposal is far from fully formed; many fundamental and critical details would require further development, such as modeling to establish an appropriate PRM for this framework, how multi-day system risks would be addressed, and how LSEs would comply (compliance could be more difficult, especially for smaller LSEs, given the greater complexity).

Because it is a fundamentally new approach, the SCE/PG&E approach carries some risk of bogging down in implementation and therefore risks failing to achieve the Commission's purpose in updating (or timely updating) its RA program to reflect the state's growing reliance on energy-limited resources and its diminishing reliance on dispatchable resources. This inherently more uncertain approach, as compared to the Gridwell/Vistra approach, would also completely reconfigure the RA capacity market. An important characteristic of that reconfiguration would be that the value of RA resources would likely become far less transparent since values will depend on the complex matching of buyers' load profiles and suppliers' resource portfolios. (This would be particularly problematic for sellers that unbundle their product attributes, e.g., selling RECs to corporate buyers and RA separately to LSEs.)

SCE and PG&E have not recommended a specific methodology for counting wind and solar resources within their proposed framework; rather, the proposal states that the methodology – whether "exceedance, hourly ELCC, or other" is "to be determined in subsequent forum." In CalWEA's explanation of our proposed ENLR approach to counting wind and solar capacity value (found in the Final Workshop Report), we explain that the exceedance approach is highly unreliable, especially with limited datasets of largely varying data, and fails to capture wind and solar energy production during the time of actual system need when such production is most valuable and should be counted. Fundamentally, exceedance is disconnected from any reliability targets. On the other hand, calculating ELCCs on a 24-hour basis (288 hours per year) would be very resource-intensive. Therefore, should the Commission move forward with the SCE/PG&E approach, it should select the ENLR methodology for counting wind and solar capacity value.

Positions on Energy Hedging, Penalties and Backstop Procurement, UCAP, and Multi-Year Forward System RA Requirements

CalWEA offers no comments on these elements at this time.

Reform of CAISO's Deliverability Methodology is Needed

A fundamental premise of the Commission's effort to reform its Resource Adequacy program is that the program must evolve to ensure that energy needs are met in all hours. This new focus is at odds with the CAISO's deliverability assessment methodology, which governs whether resources can qualify to provide RA value, because the CAISO's methodology is focused on a very few, highly unlikely hours. This mismatch, and the need to reform CAISO's deliverability methodology, is discussed in CalWEA's October 18, 2021, joint submission with the California Energy Storage Alliance to the CAISO's Policy Initiatives Catalog, which is appended to these comments. CalWEA strongly recommends that the Commission encourage the CAISO to revisit its deliverability methodology on a parallel path to the Commission's implementation of its new RA framework.

California ISO

Policy Initiatives Catalog Submission Form

<table>
<tr><th colspan="4">California ISO Policy Initiatives Catalog Submission Form</th></tr>
<tr><td colspan="4"></td></tr>
<tr><td colspan="4">Date: 10/18/2021</td></tr>
<tr><td colspan="4">Submitter Information</td></tr>
<tr><td>Organization</td><td>Contact Name</td><td>E-mail</td><td>Phone</td></tr>
<tr><td>California Wind Energy Association &
California Energy Storage Alliance</td><td>Nancy Rader

Jin Noh</td><td>nrader@calwea.org

jnoh@storagealliance.org</td><td>510-845-5077 x1

510-665-7811 x 109</td></tr>
<tr><td colspan="4">Please provide a title for the issue.</td></tr>
<tr><td colspan="4">Reform of the Deliverability Assessment Methodology</td></tr>
<tr><td colspan="4">Please provide a summary description of the issue (i.e. 500 words)</td></tr>
<tr><td colspan="4">The CPUC is in the process of considering major structural reforms to its Resource Adequacy program in Rulemaking 19-11-009. A premise of these reforms is that the RA program must evolve to ensure that energy needs are met in all hours, particularly in all evening peak hours, as well as under more extreme conditions. This new focus is at odds with the CAISO's deliverability assessment methodology, which is focused on a very few, highly unlikely hours.
The CAISO's On Peak Deliverability Assessment methodology is designed around two operating scenarios. The first scenario, High System Need (HSN), includes three system conditions that are assumed to be occurring simultaneously: an N-2 condition; system dispatch conditions where all generation in a particular area is operating at near Net Qualifying Capacity (NQC); and a "peak-net-load condition," an operating condition where the system is most likely to experience a generation shortfall. This condition has consistently been occurring during the summer evening hours in the past few years.
The second operating scenario, called Secondary System Need (SSN), represents similar assumptions regarding system outages and generation dispatch but gross load (not peak load) is assumed to be at or near its peak level and energy production from both wind and, particularly, solar resources with FCDS and PCDS status are assumed to be significantly higher than their NQC levels and in the HSN scenario, along with all other resources at full NQC output.
The CAISO and stakeholders should consider whether and how these assumptions could be reasonably relaxed, consistent with the purpose of the structural reforms being pursued by the CPUC. CAISO and stakeholders should consider whether reformed conditions should be used to determine deliverability for all resources for each of the new "RA time periods" (or "slices of day" as they are termed under the Commission's adopted framework). For each slice, the assessment methodology should reflect the expected net peak load in that time period. The rarest and most constrained system operating conditions could be considered for the more critical slices of day (the ones with higher net load) for a planning year. The CAISO can advise the CPUC to raise the PRM raised if deemed necessary for such critical slices of day to ensure that there are sufficient RA resources on the system.</td></tr>
</table>

Reform is also needed for the process of granting resources local RA credit. Currently, a resource located in a Local Reliability Constrained Area (LCRA) is required to qualify as a system RA resource before it is qualified to provide local RA capacity. Qualifying as a system RA resource could require transmission upgrades to deliver energy from, for example, a battery project in SCE's Los Angeles Basin LCRA to PG&E's Bay Area LCRA, preventing it from providing local RA capacity in the Los Angeles LCRA. CAISO and stakeholders should consider whether to eliminate the system-RA requirement for resources providing local RA capacity.

The goal should be to implement these reforms simultaneously with the CPUC's RA reforms, which are being targeted for the 2023 RA-year.

Please provide any data/information available that would characterize the importance or magnitude of the issue.

The CAISO's conservative deliverability assumptions are causing substantial and unnecessary roadblocks in building the evolving system that will be dominated by widely dispersed, relatively small, variable energy and storage resources, preventing resources that could provide RA capacity during most hours, including during the critical evening net-peak-load period from interconnecting to the system and providing the needed RA capacity that they could readily provide even under contingent system conditions.

We believe that all or a portion of the more than 1,700 MW currently in the CAISO queue with Energy-Only status, and more than 3,000 MW with PCDS that have commercial operation dates prior to Summer of 2023 could become deliverable under these reasonable reforms. In addition, there are approximately 120 operating projects that have Energy-Only status and eight operating projects that have PCDS that total well over 1 GW. Those could obtain additional deliverability status, which could immediately count towards California's RA capacity requirements.

In addition to these reliability benefits, major economic benefits would accrue by making more efficient use of existing transmission assets, enabling a large volume of resources to interconnect and provide RA capacity without network upgrades. Greater supply would foster more competition that would lower the cost of RA and benefit ratepayers and would facilitate load-serving entities in meeting their RA requirements.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION
INFORMAL COMMENTS ON THE TRACK 3B.2 WORKSHOPS

I. INTRODUCTION

The California Community Choice Association[1] (CalCCA) submits these informal comments on the Track 3B.2 workshops. Through the workshop process, parties have generally converged around two proposed structural frameworks. The first proposal is a 24-hourly slice proposal in which each load-serving entity (LSE) must demonstrate it has enough capacity to meet its load profile plus a planning reserve margin (PRM) in all 24 hours on the "worst day" of the month. The second proposal is a two-slice proposal in which each LSE must demonstrate it has enough capacity to meet its load ratio share of California Independent System Operator (CAISO) gross peak plus a PRM and net peak plus a PRM.

In these comments, CalCCA does not yet take a position on either of the structural frameworks proposed. Instead, these comments discuss the principles defined by CalCCA to use when evaluating each option. In many cases, CalCCA's principles align with those defined by the California Public Utilities Commission (Commission) in Decision (D.) 21-07-014[2]. A proposal for Resource Adequacy (RA) structural reform should meet these principles to ensure the approach ultimately adopted will result in a reliable, durable, and cost-effective RA program.

II. CALCCA DEFINED PRINCIPLES

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[1] California Community Choice Association represents the interests of 22 community choice electricity providers in California: Apple Valley Choice Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

[2] *Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program*, July 16, 2021 (D.21-07-014) at 26.

A. CalCCA Principle 1: A Structural Framework Should Adapt to Current and Future Peak and Net-Peak Needs

Any structural framework adopted must be durable enough to address both current and future reliability needs. A durable program will meet reliability needs each year without time- and resource-intensive work in RA proceedings to make significant RA program modifications year after year. A program that is not durable will result in the RA program falling behind evolving reliability needs and create regulatory uncertainty for parties contracting under uncertain RA rules. A new structural framework should be durable enough to adapt to changing reliability needs and bring stability to the RA program's design.

This principle is aligned with Commission Principle 5: To be durable and adaptable to a changing electric grid.

B. CalCCA Principle 2: A Structural Framework Should Maintain a Capacity-Based Approach While Also Accounting for Energy Needs

California is continuing to make progress on its important mission to decarbonize the grid. In doing so, the resource mix is evolving to be increasingly use- or energy-limited. This evolution necessitates a change in the RA program to account for both capacity and energy needs. The RA program was originally designed to ensure sufficient *capacity* to meet the system-wide *gross* peak. If this requirement was met, coupled with the Maximum Cumulative Capacity (MCC) process, it was assumed there would be sufficient energy available in all other hours to maintain reliability to the pre-determined planning standard. As the grid evolves, energy sufficiency can no longer be assumed as it once was given the increase in the number of use-limited and energy-limited resources that do not necessarily align with the MCC concept. Instead, a new RA structural framework should evolve to account for energy needs in addition to capacity needs to ensure the RA fleet provides sufficient energy to serve load in all hours, not just the peak hour.

This principle aligns with Commission Principle 2: To balance addressing hourly energy sufficiency for reliable operations with advancing California's environmental goals.

C. CalCCA Principle 3: A Structural Framework Should Recognize the Full Value of Renewable and Energy Storage Resources to Meet Reliability Needs in a Capacity-Based Framework

As the resource mix transitions to one of increasing amounts of solar, wind, and storage, the RA program must ensure the full value of renewable and energy storage resources is accounted for to meet reliability needs. Under the current framework, the capacity value of renewable resources is fixed. However, the contribution to reliability provided by renewable resources varies throughout the compliance period depending on the time of day and weather conditions. A new structural framework should reflect this variability in the qualifying capacity methodology. The full capability and flexibility of storage resources should also be reflected in its qualifying capacity methodology. An RA structural framework proposal should ensure renewable and energy storage resources are fully valued for their contribution to reliability.

D. CalCCA Principle 4: A Structural Framework Should Not Require Abrogation or Unwinding of Existing Resource Contracts

To ensure ease of implementation and maintain the sanctity of contracts already executed by LSEs, a new RA structural framework should ensure existing contracts can continue to be used to meet compliance obligations and are not devalued. This will allow the market to transition to the new structural framework quickly and efficiently.

E. CalCCA Principle 5: A Structural Framework Should Allow for Readily Transactable Products

Transactability is a key component of any RA program. If RA products are not easily transactable, LSEs may be unable to closely shape their resources to their obligation, resulting in over-procurement and increased customer costs or the potential to fail to meet obligations. Any new structural framework should ensure LSEs can easily transact RA products to meet their obligations without unnecessary complexity or over-procurement. Likewise, the framework should place all LSEs on equal footing in transacting to meet their requirements considering all viable trading options that could be implemented.

This principle aligns with Commission Principle 3: To balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity and transactability.

F. CalCCA Principle 6: A Structural Framework Should Support a Reliable Grid While Minimizing Cost

One of the Commission's top priorities is affordable electric service, a topic currently being addressed in Rulemaking (R.) 18-07-006. A cost-effective RA program must balance meeting planning standards that achieve a targeted level of reliability and minimizing costs to customers resulting from RA procurement. Any structural proposal should be evaluated with affordability in mind to ensure reliable operations while minimizing customer costs.

This principle is aligned with Commission Principle 1: To balance ensuring a reliable electrical grid with minimizing costs to customers.

III. COMMISSION DEFINED PRINCIPLES

As discussed above, CalCCA's principles generally align with the Commission's principles established in D.21-07-014, which include:

- Commission Principle 1: To balance ensuring a reliable electrical grid with minimizing costs to customers;
- Commission Principle 2: To balance addressing hourly energy sufficiency for reliable operations with advancing California's environmental goals;
- Commission Principle 3: To balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity and transactability;
- Commission Principle 4: To be implementable in the near-term (e.g., 2024); and,

- Commission Principle 5: To be durable and adaptable to a changing electric grid.

With regards to Commission Principle 4 regarding implementing the new structural framework in 2024, CalCCA understands the need to implement a solution quickly to address near-term gaps in the existing RA framework. However, each of the proposals will require significant additional work before implementing a robust and durable framework. For example, the 2-slice framework will require vetting and calculating a new Effective Load Carrying Capability (ELCC) methodology and associated values. Alternatively, a 24-hourly slice framework will require defining "worst day," calculating exceedance values, and ensuring transactability. Both frameworks will require a new LOLE study to inform the PRM needed to meet planning targets under the new framework. The Commission should take additional time if needed to develop a robust framework that addresses these implementation details to ensure any framework adopted meets the principles outlined above.

IV. CONCLUSION

CalCCA is continuing to evaluate both proposals using the principles discussed in these comments and may take a position on the structural frameworks proposed in comments to the working group report. CalCCA looks forward to continuing to collaborate with parties to develop an implementable proposal that supports the reliability, durability, and cost-effectiveness of the RA program.

Date: February 7, 2022

(*Original signed by*)

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COLLECTIVE CCA INFORMAL COMMENTS ON THE TRACK 3B.2 WORKSHOPS

February 4, 2022

I. Introduction

Clean Power Alliance of Southern California (CPA), East Bay Community Energy (EBCE), Marin Clean Energy (MCE), Peninsula Clean Energy (PCE), Pioneer Community Energy (Pioneer), San Jose Clean Energy (SJCE), and Sonoma Clean Power (SCP) (the Collective CCAs) submit these informal comments on the Track 3B.2 workshops. The Collective CCAs understand that parties have generally coalesced around two proposals—one put forth by the Southern California Edison Company (SCE) and supported by the Pacific Gas and Electric Company (PG&E) that would require load serving entities (LSEs) to meet a monthly 24-hour capacity requirement; and the other proposal put forth by Gridwell, where LSEs would demonstrate their portfolios' ability to meet a gross peak and a net peak requirement.

As demonstrated throughout the workshops, implementing a new reliability compliance framework will be a complex undertaking, and transitioning to a newly adopted framework will likely need further fine-tuning of the framework and implementation details to ensure minimal market disruptions. As such, the Collective CCAs make the below recommendations:

a. SCE's 24-hour slice proposal should be pursued but compliance using the new framework should be pushed back to 2024 for the 2025 compliance year, at the earliest, to allow sufficient time to make further critical refinements to the adopted compliance framework through a public and transparent workshop process. The additional year before implementation should be used to develop critical refinements, test aspects of the 24-hour slice proposal, and refine procedures while trying to minimize undue burdens on LSEs. The results of the tests can be used to adjust the 24-hour slice framework to ensure a smooth transition between compliance frameworks. The CPUC can also conduct additional assessment of RA cost and pricing trends.

b. If the SCE 24-hour proposal is adopted, prior to its implementation it is critical to pursue a method of hourly trading to enable LSEs to optimize their portfolios and meet the new compliance requirements in the most cost-effective and efficient manner. This could be accomplished by allowing hourly resource trading, although this approach may require the California Independent System Operator (CAISO) to ultimately oversee the required compliance process. Additionally, the Commission could adopt a system to allow LSEs to trade hourly compliance obligations. The latter could be fully under the control of the Commission and any trades would be reported by the Commission and the CAISO as obligations of the LSE agreeing to accept the obligations.

II. Delaying the Implementation Would Provide Room for a Methodical Process to Further Develop Refinements to the New Framework and Minimize Market Disruptions

Decision (D.) 21-07-014 directs parties to develop a framework that can be implemented for the 2024 compliance year,[1] based on PG&E's Slice of Day proposal. The Commission adopted the Slice of Day Framework based on the below principles:

1. To balance ensuring a reliable electrical grid with minimizing costs to customers.
2. To balance addressing hourly energy sufficiency for reliable operations with advancing California's environmental goals.
3. To balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity and transactability.
4. To be implementable in the near-term.
5. To be durable and adaptable to a changing electric grid.

These principles present complex issues that have not been sufficiently addressed in the workshops thus far. Notably, the Collective CCAs echo the concerns expressed in informal comments by other parties that the SCE proposal contains significant outstanding questions that must be resolved before the new framework is used for compliance. Similarly, although the Gridwell proposal seems more easily implementable in the near-term, structural elements and critical enhancements may need to be added to meet the principles to address hourly energy sufficiency and meet hourly RA needs. This demonstrates that neither proposal is ready to be made the new compliance framework next year, and rushing the transition to a partially formed and untested RA framework would likely cause more market uncertainty and disruption, increase procurement and ratepayer costs unnecessarily, and jeopardize the state's goal of ensuring reliability and emission reductions.

Therefore, the Collective CCAs recommend that the Commission delay use of the new framework for compliance by at least one year to allow parties more time to further refine aspects of the new framework, and to potentially test out the compliance process for the 24-hour slice framework. For example, in 2023, LSEs could report on resources procured for 2024, using the current compliance reporting template for compliance, and the 24-hour slice template for information gathering to inform future implementation. This could give the Commission staff the time to collect the data using the 24-hour slice template and methodology, including RA cost and availability, and address any loose ends before launching the new methodology for compliance. Thus, 2023 and 2024 should be used to refine the new framework and compliance procedures, and to test implementation of aspects of the 24-hour slice proposal while trying to minimize administrative burdens on LSEs.

The delay is unlikely to cause reliability issues to the electricity system, especially since a large number of new resources will have achieved commercial operation by August 1, 2024, pursuant

[1] *See* D. 21-07-014 at page 38. PG&E's Slice of Day framework was selected because it "is best positioned to be implemented in 2023 for the 2024 compliance year."

to D. 19-11-016 and D. 21-06-035. Rather, delaying the implementation will give the Commission and LSEs time to better understand how the anticipated changes to the resource fleet in the near- and mid-term will perform, and how that demonstrated performance might inform what a durable RA framework will require. Delaying the implementation would give the Commission and parties more time to finalize implementation details, evaluate RA costs and structural RA market power concerns pursuant to D. 04-10-035,[2] and would minimize market disruptions when the 24-hour slice framework is implemented for the 2025 compliance year and beyond. In the interim, to address immediate reliability concerns, the CAISO could perform a simple check of resources expected to be available at the net peak and publish the results, similar to what is done today. If that analysis indicates potential reliability issues, LSEs could have an opportunity to provide additional resources to resolve the issues. Failing that, the CAISO could use its significant event Capacity Procurement Mechanism designation to ensure sufficient resources are available.

III. If the Commission Adopts SCE's 24-Hour Proposal, Hourly Resource Trading, and Other Identified Transactability Measures Must Be Integral Parts of the Finalized Framework

While the Collective CCAs support pursuing SCE's 24-hour proposal, the Collective CCAs' support is conditional upon the inclusion of the ability to adjust resources and RA obligations on an hourly basis. This could be achieved by evaluating and implementing methods whereby LSEs could trade resources and compliance requirements on an hourly basis. Without the ability to trade resources and compliance requirements at that granular level, the 24-hour slice framework could be unworkable. The Collective CCAs understand that there are many operational challenges associated with hourly trading, and are committed to working with stakeholders in future workshops and working groups to develop rules and regulations that would overcome these challenges.

The SCE proposal currently does not allow LSEs to trade resources by the hour to meet their hourly requirements, nor does it explicitly allow trading of hourly compliance requirements. This goes against Principle 3 that was contemplated in D. 21-07-014—the proposal should balance meeting hourly RA needs with a reasonable level of simplicity and transactability.

From a practical standpoint, as LSEs, the Collective CCAs are concerned that without the ability to trade resources and compliance obligations on an hourly basis, there could be costly unintended consequences to ratepayers. For example, if an LSE needs 2-3 hours of resources, outside of the gross peak and net peak, during their worst day of the month, that LSE might have to purchase capacity outside of the 2-3 hours of need depending upon what resources are available in the market, and in some cases, it might end up buying capacity for an entire 24-hour strip. In this example, because many LSEs are also forced to hold on to their 24-hour slice requirements, the market supply is falsely constrained, creating market inefficiency and cost increases. This inefficiency would be especially inconsistent with California's environmental

[2] *See* D. 04-10-035 at page 15. The Commission established it did not expect LSEs to "pay any price" or require utilities to sign contracts to meet RA requirements "at any cost."

policy goals in the context of natural gas, where efficient utilization of existing natural gas capacity is crucial in the transition to a low- and zero-carbon emitting electricity grid.

The lack of transactability would also create further incentives for the market to be artificially constrained. D.21-05-030 determined that no allocations of RA from investor owned utilities' (IOUs) portfolios would take place, thus IOUs retain the RA attributes for resources in their portfolio. Departed load receives a financial credit in lieu of the RA resource. This creates a scenario wherein the IOUs are systematically long on RA in certain hours. Essentially, as long as the IOU is short in the highest peak hour, they will likely continue to accumulate length in all other hours. As load continues to depart, the IOUs will have more and more capacity than they need to serve their load in these non-peak hours. Without allocations of RA capacity with the corresponding slice-of-day properties, the ability for non-IOU LSEs to transact and purchase the hours they need is critical. Without either, the Commission would create a scenario where the IOUs are required to be long in almost all hours, and others will have to compete for remaining supply in the market. This will drive up costs for all customers (including IOU bundled customers), would not aid in system reliability, would contribute to excess greenhouse gas emissions, and would only increase the risk of noncompliance.

The Collective CCAs raise these concerns and urge the Commission and stakeholders to consider hourly resource and compliance trading and other transactability issues in future workshops, including the consideration of potential market power without ability of LSEs to trade resources, should the SCE 24-hour slice proposal be adopted. Without attempting to consider this complex issue and create potential solutions, the 24-hour slice framework would risk creating an inefficient market at a high cost to ratepayers.

IV. Conclusion

The Collective CCAs appreciate the opportunity to provide these comments, and thank the stakeholders and Commission staff for their consideration.

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Informal Comments of Coast Community Energy, San Diego Community Power, and Silicon Valley Clean Energy Authority on the Implementation of the Slice-of-Day System RA Workshops

R.21-10-002

February 7, 2022

I. Introduction

Central Coast Community Energy, San Diego Community Power and Silicon Valley Clean Energy Authority, collectively the "Joint CCAs," appreciate the opportunity to provide joint informal comments on the Resource Adequacy ("RA") Frameworks Working Group Process. The Joint CCAs applaud the efforts of the many presenters and participants who have taken part in the workshops to explore these complex issues over the past five months. As the workshops conclude, the Joint CCAs offer the following comments regarding foundational issues related to the CPUC's original RA Reform Principles including reliability, meeting environmental goals, transactability and implementation, all of which have important implications for affordability. In summary:

- The current and mid-term reliability challenges of the grid can be met by both the Gridwell and the 24-hour slice proposals.[1]
- The Gridwell proposal does a better job of ensuring reliability while facilitating decarbonization, primarily because the 24-hour proposal incentivizes gas procurement.
- The transactability challenges of the 24-hour proposal must be addressed if it is to be implemented
- The Gridwell proposal is readily implementable, while the 24-hour proposal requires structural changes and additional analysis.
- The Joint CCAs are open to further updates to the RA framework as grid needs change, including eventual creation of a 24-hour obligation.

II. The current and mid-term reliability challenges of the grid can be met by both the Gridwell and the 24-hour slice proposals

The RA structure in California has not kept pace with the evolving needs of the grid, as evidenced by the CAISO August 2020 rotating outages. In its Final Root Cause Analysis report,

[1] For the purposes of these comments the Joint CCAs refer collectively to both the PG&E and SCE proposals as the "24-hour slice proposal". The Joint CCAs acknowledge the two proposals had minor differences, however, for the purpose of these comments these differences did not seem consequential.

the joint agencies cite increases in extreme weather events, insufficient planning reserve margin ("PRM"), and out-of-date resource counting methods, particularly for the net peak, as key causes of the 2020 rolling blackouts[2].

Both the Gridwell and the 24-hour slice proposals address these problems. First, regardless of the adopted proposal, a first step toward implementation of a new RA framework is for the CPUC to work with stakeholders to establish an updated PRM. While details, inputs, and assumptions for the PRM update need to be determined, workshop participants widely acknowledged the need to consider extreme weather events as part of the PRM analysis. Secondly, both proposals suggest updating resource counting, albeit using differing methodologies. The Joint CCAs believe either counting methodology is capable of accurately capturing a resource's reliability contribution but, note that neither proposal includes clear resource accounting standards or rules.[3] Combined, updates to the PRM and accounting rules should address California's current reliability challenges.

Further, both proposals appear to address reliability through at least the mid-term. Reliability studies within the Integrated Resource Planning proceeding show that at least through 2030 reliability events occur almost exclusively during the summer peak and net peak hours[4] – hours which both proposals distinctly address. This implies that both the Gridwell and 24-slice proposals should be functional until at least that year. The Joint CCAs are not aware of any modeling that exists to show when reliability events are expected to occur largely outside of the peak and net peak hours, suggesting both proposals may be viable beyond 2030.

Until such a time when reliability events are dispersed across more hours of the day, there is no reliability benefit to instituting a 24-hour requirement. Thus, *any* added costs introduced as a result of introducing new obligations outside the peak and net peak hour do not have corresponding reliability benefits to justify them. Given a foundational principle of the RA reform work is to balance a reliable electrical grid while minimizing costs to customers, it is unclear how the 24-hour proposal can meet this principle.

The Joint CCAs caution the Commission against introducing additional obligations without a corresponding reliability benefit, especially given new obligations may slow decarbonization while creating transactability challenges and market power issues. The Joint CCAs discuss each of these concerns in more detail below.

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[2] See Final Root Cause Analysis, Mid-August 2020 Extreme Heat Wave. January 13, 2021. Prepared by California ISO, California Public Utilities Commission and California Energy Commission. http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

[3] For instance, for the 24-hour slice proposal exceedance levels for renewables have not been determined. For the Gridwell proposal, exact ELCC methodology is not finalized.

[4] See Integrated Resource Planning (IRP) Proposed Preferred System Plan Analysis Workshop slides from September 1, 2021. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/psp-workshop-slides.pdf

III. The Gridwell proposal does a better job of ensuring reliability while facilitating decarbonization, primarily because the 24-hour proposal incentivizes gas procurement.

In addition to ensuring reliability, the new RA program will have a significant impact on California's decarbonization effort. California has set aggressive, necessary GHG reduction goals that can only be met through a major transition in the state's resource fleet over the next eight years. Fossil resources and the retiring Diablo Canyon Power Plant must be replaced with renewables paired with storage, with the most urgent component being the buildout of storage. Storage is currently the only viable alternative to natural gas for ramping up energy output quickly in the evening when solar drops off. Retiring natural gas plants that are currently critical to meeting net peak demand will thus only become possible once enough storage has been built to replace them.

The new RA framework will either work with or against California's decarbonization effort depending on which resources it incentivizes LSEs to procure for RA compliance. The relative competitiveness of different resources, and particularly gas versus currently available battery storage technology, will determine whether the RA program accelerates decarbonization or delays it. The Joint CCAs propose that under the Commission's timeframe (2023 implementation for the 2024 compliance year), a two-slice model is the better choice for ensuring reliability without penalizing resources that are critical to decarbonization.

The most widely available storage technology on the market today is four-hour battery storage. Four-hour storage may eventually become less dominant as longer-duration storage, offshore wind, and other renewable and carbon-free resources mature. But for now, it is critical to the decarbonization effort since it is the only resource that can effectively replace gas in the net peak period. Given that, as discussed above, either a 2-slice or 24-slice model can ensure reliability, the relative viability of four-hour storage under each becomes important. An RA program where currently available storage technology is a competitive resource with gas for compliance will help facilitate decarbonization without reducing reliability.[5]

Under the Gridwell proposal, four-hour storage is a viable RA compliance resource. Though it will be derated by the introduction of the effective load carrying capacity ("ELCC") accounting for storage, its availability in the net peak period still makes it fundamentally competitive. Under this framework, load serving entities ("LSEs") that have been planning to build storage for decarbonization reasons will continue to be able to count on RA capacity value as one of its value streams, creating synergy between California's reliability and decarbonization efforts.

By contrast, moving to a 24-hour model now would push LSEs back onto gas and work against decarbonization. A 24-hour obligation incentivizes market participants to contract with resources that have 24-hour availability. On the timeline the Commission is proposing, no other resource

[5] The Joint CCAs acknowledge that "four-hour storage" is a naming convention and that the actual discharge time of any storage technology can be lengthened by discharging at less than the maximum discharge rate. The point is that with a full charge, most currently available storage technology can discharge at maximum output through most or all of the net peak period but not all night. This gives it immediate value in displacing gas needed to meet the net peak that will be obscured by a 24-hour model that rewards 24-hour resources.

besides gas is widely available for meeting overnight capacity obligations.[6] Even though four-hour storage can significantly address the net peak demand challenge, LSEs will be incentivized to procure 24-hour products which can fill all hours, giving them effectively six times the capacity contribution of a 4-hour battery. This will push LSEs into continuing to sign RA contracts with natural gas facilities, even though in the most constrained hour, the net peak, storage has become a viable alternative. And once those contracts are locked in, California's reliance on natural gas is further extended. Facing this push to contract with gas, investment in storage will potentially be dampened and decarbonization slowed.

The Joint CCAs acknowledge that some stakeholders feel the 24-hour model will provide better value for renewables and storage and therefore better promote decarbonization. However, the Joint CCAs encourage stakeholders and the CPUC to consider the net impact that a 24-hour model will have on resource procurement across the entire day. While the exceedance methodology associated with the 24-hour proposal may provide greater hourly value for some renewables during the daytime hours than current ELCC values do, the 24-hour model also introduces an entire new set of RA obligations overnight.

In these overnight hours, gas is still the predominantly available resource. Regardless of how renewable output is valued when it is generating during the day, the only way to avoid procurement of gas capacity to meet the nighttime obligations is to have enough storage to transfer that renewable output into the nighttime hours. There is not time for LSEs to build enough storage to replace gas on the Commission's current timeline for implementing this RA reform. So higher valuation of renewables during the daylight hours does not address the Joint CCAs' concern about pushing LSEs into gas contracts to meet RA obligations in hours where there is no current reliability constraint. If anything, the incentive to contract with gas capacity in 24-hour strips has the potential to dampen storage investment and delay the move away from reliance on gas overnight.

The Joint CCAs also note that this push towards gas contracting would be more appropriate if the grid were currently constrained in both net peak and off-peak hours. In that scenario, the RA framework would be sending an accurate signal that California was not yet ready to move away from gas. But as discussed in Section II, the grid is not currently constrained overnight and is not predicted to be until at least the end of the decade. In the meantime, adopting an RA framework for which gas is the most viable compliance resource when carbon-free alternatives to gas in the constrained hour already exist unnecessarily delays decarbonization without adding any reliability benefit.

IV. The transactability challenges of the 24-hour proposal must be addressed if it is to be implemented

[6] The Joint CCAs recognize that geothermal and biomass resources can provide overnight generation and that some LSEs will be able to obtain a portion of their overnight capacity needs from these sources. However, these resources are not available in sufficient quantities to prevent the net push onto gas that the Joint CCAs are concerned about.

The 24-hour proposal introduces several important market and transaction problems to the RA structure which the Commission must address as it considers adoption of the proposal. Failure to do so risks over procurement, market power issues and the addition of undue administrative burden to stakeholders. All of these, if unaddressed, are likely to increase ratepayer costs without corresponding benefits.

First, a 24-hour structure which does not allow hourly trading of resources will result in over procurement, especially for smaller LSEs. Restricting the unbundling of hourly slices could lead to stranding of hourly length that could be otherwise utilized to meet compliance requirements. Restricting transactions to only 24-hour strips will set each LSE's procurement target at its largest hourly net short position, which will cause over procurement. This problem is particularly pronounced for smaller LSEs who may be less able to shape their load to specific products in the market. During the workshops, opponents of hourly trading seem to have found implementing it to be too challenging. While unbundling the hours may add complexity, failure to allow hourly trading in an hourly compliance structure introduces fundamental market inefficiencies and increased opportunity for exercise of market power, both at the cost of ratepayers. It is the view of the Joint CCAs that, at a minimum, unbundling of products must be allowed in any 24-hour structure.

The 24-hour proposal may create market power for owners of some resource classes, especially natural gas. Unlike the Gridwell proposal where ELCC calculations create a single measure of capacity regardless of resource type, the 24-hour proposal creates product differentiation by shaping resource types to expected output. The result of this is that resources which can produce when others cannot, will be able to demand a higher price in the market. As noted above, it is the view of the Joint CCAs that overnight obligations incentivize natural gas contracting. Given most natural gas resources are under long-term contract or owned by the IOUs, this would provide them an increased market advantage and opportunity for exertion of market power in an already tight RA market. Since there is no reliability benefit to off-peak RA obligations at present, the 24-hour proposal provides an opportunity for market power exertion with no benefit to ratepayers. The issue is further compounded by the fact that CCA customers pay for RA resources as bundled customers but do not currently receive the corresponding benefit through an allocation of RA attributes.

The Commission must also consider how this RA framework aligns with the local RA CPE structure and how CAM allocations are assigned to hourly slices. If LSEs are not able to assign these allocations to meet their hourly requirements, inefficiencies and underutilization of capacity will occur. We request that the Commission direct the CPE to manage its excess length in the 24-hour framework should unbundling be permitted and to begin outlining a process for LSEs to fairly allocate their share of CAM.

Finally, one of the key features of the original seasonal 6-hour slice proposal was that it was less administratively burdensome. Now that the focus has shifted to a monthly 24-hour proposal, consideration should be given to the enormous effort that will be required for market participants, the CAISO, and the Commission to administer this RA structure. Transacting and tracking at this granularity will introduce liquidity problems if systems and tools are not able to adapt to this changing need.

Combined, these issues jeopardize the viability of the 24-hour proposal and create substantial challenges for many stakeholders. Without further consideration and vetting of the proposal, some of these risks may not be fully realized until implementation is underway. As identified in the CAISO's reply comments, the 24-hour proposal might be incompatible amongst Local Regulatory Authorities administering drastically different RA programs. Publicly Owned Utilities RA will not be shown at a 24-hour level and should an hourly backstop procurement mechanism be implemented it will be unclear which entities were the cause of the deficiency and for what volume.

The Joint CCAs encourage the Commission to be mindful that even with a good faith effort LSEs may be unable to meet their compliance obligations due to market constraints and market power issues. If the 24-hour model is adopted, the Joint CCAs urge the Commission to delay the implementation of any penalties for LSEs that show good faith efforts to meet the requirements of a 24-hour structure, given the radical change it represents as well as the potential for unforeseen issues and barriers to compliance.

In contrast, Gridwell's proposal is largely compatible with existing contract structures and would not require significant market changes to implement. While minor renegotiations may be required as some resources will lose effectiveness in meeting the net peak requirement, these challenges are significantly less complicated than those presented by a 24-hour proposal. More important, the Gridwell proposal avoids key market power and transactability issues that arise from the 24-hour proposal.

V. The Gridwell proposal is readily implementable, while the 24-hour proposal requires structural changes and additional analysis

A key benefit of the Gridwell proposal is that it addresses the foreseeable challenges of the grid while not making substantial structural changes to the RA paradigm. Under the Gridwell proposal the core components of the systems for contracting and compliance will remain largely unchanged, easing implementation and reducing risks. While new ELCCs will need to be established to determine resource values, ELCC studies are regularly being conducted for the CAISO, so this does not appear to be a significant hurdle to adoption. Simply put, the 2-slice implementation process appears to be relatively straightforward, with few implementation risks and less market disruption.

The 24-hour proposal has several implementation challenges. First, the 24-hour proposal significantly alters Resource Adequacy methodologies including for resource counting and allocation, each which deserve further consideration. Second, its implementation requires material changes to compliance tools and methodologies. This is especially true given the need to address transactability and market power issues created by the 24-hour structure. Once assumptions and compliance tools are finalized LSEs still must work with developers to create viable contracts and complete procurement for this framework.

The 24-hour proposal fundamentally alters the RA paradigm. Simultaneously, the proposal still does not fully define methodologies for key elements such as what exceedance level should be used for renewables. The PG&E and SCE proposals differ in need determination and allocation. These issues are consequential to achieving reliability and deserve thoughtful analysis which considers the complex interaction the various assumptions have on one another[7].

The Joint CCAs believe the transactability and market issues outlined in section IV must be addressed before implementing any 24-hour slice RA structure. Unless there is an ability to unbundle and trade resources between LSEs, the market power that the IOUs hold will result in a disadvantage to ratepayers that are not a part of the bundled IOU portfolio. Developing this process will take time as it not only requires a substantial change to the compliance instruments, but also changes to contract structure. Such changes bring with them risks and unforeseen challenges which may cause further delays.

Should the Commission approve a fair and equitable 24-hour proposal that addresses market power and includes unbundled resource trading, the next task will be to upgrade existing systems and compliance filings. The CAISO has indicated that they will be unable to upgrade their Customer Interface for Resource Adequacy ("CIRA") application to check each 24-hour slice by 2024. Currently CIRA only registers one RA value for the month per LSE. Moving to an hourly framework would require that the CAISO has the ability to track across each hour and identify hourly backstop costs to the deficient LSE. Additionally, a modern, efficient software solution will be required to enable efficient transactions and filings; excel will not be sufficient for implementation of a 24-hour structure.

Provided that we work through the complexities of upgrading systems, there is still the need to successfully procure capacity to meet each of the hourly slices. This effort should not be overlooked as LSEs will be dedicating significant amounts of time to fulfill these obligations and for hours in which there are presently no reliability issues. Consideration and adequate time should be given so that LSEs can renegotiate contracts should it be in their best interest to do so.

While on its face the 24-hour proposal may seem elegant, it may be an over engineered solution to problems we don't have which will only act to create a new set of challenges for the system and stakeholders. We caution the Commission from rushing into the 24-hour framework before we have greater certainty the structures are in place for a smooth transition to a new paradigm. Attempting to make corrections to the framework after implementation may cause significant market disruption. A solution that requires additional iterations is not durable or worth the significant problems that may arise in the near-term.

[7] For instance, the PRM model should account for the final exceedance level assumed for variable energy resources (VERs) to ensure there is no "double counting" of reliability need in the PRM and VER resource accounting.

VI. The Joint CCAs are open to further updates to the RA framework as grid needs change, including eventual creation of a 24-hour obligation.

The Joint CCAs are open to further reevaluation of the RA program as grid needs and generation technologies evolve. By the time the grid becomes constrained in off-peak hours and the Gridwell model requires updates, there will likely be more renewable and carbon-free technologies capable of replacing gas in the overnight hours. Availability of those alternatives may lessen some of the current problems with a 24-hour obligation, including market power and contravening decarbonization. The Joint CCAs are open to consideration of other frameworks, including a 24-hour obligation, if they best serve grid and ratepayer needs in the future.

In the meantime, the timing of RA reform is critical to co-optimizing between reliability, affordability, and decarbonization. With current reliability risk concentrated around the net peak, there is no immediate reliability need for a 24-hour regime. If we want to move towards a 24-hour clean grid we cannot create a 24-hour RA requirement before there are clean resources to meet it. Doing so will only push LSEs back onto gas, unnecessarily prolonging the status quo and potentially dampening storage development. By incrementally evolving the RA framework alongside the development and maturation of clean technologies, regulators can address reliability challenges as they arise while complementing decarbonization efforts and minimizing ratepayer costs. Of the two models at hand, Gridwell's is the best choice for ensuring a clean, affordable, and reliable electricity system for California.

VII. Conclusion

The Joint CCAs appreciate the opportunity to provide these comments and thank the parties and Commission staff for their consideration.

Respectfully submitted,

February 7, 2022

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Joint Informal Comments on the RA Reform Workshops
R. 21-10-002 and R.19-11-009

February 7, 2022

The California Energy Storage Alliance ("CESA"), Peninsula Clean Energy ("PCE") and San Jose Clean Energy ("SJCE") ("Joint Parties") appreciate the opportunity to provide informal comments following the RA program restructuring workshops. The Joint Parties submit these comments to present a simple approach to enhance the slice of day (SOD) RA framework by providing for trading of the load obligation. The Joint Parties have a strong view that effective transactability is a critical feature for any RA framework. While the SOD has some important features, such as properly valuing renewables and storage, it requires enhancements to improve transactability. The proposal described in these comments is one simple enhancement that could improve transactability in a manner that the Joint Parties believes could be acceptable to a large number of stakeholders. The Joint Parties are open to working with other parties to ensure this proposal is adequately developed and incorporated in the SOD framework.

I. Summary

The slice of day (SOD) framework would require load-serving entities (LSEs) to show their resources in a manner that matches their load profile. Since, in many cases, an LSE might not have a portfolio that allows it to match its load profile precisely, efficient mechanisms allow LSEs to shape their RA portfolio profiles to their load shapes are essential to market efficiency. Mechanisms to allow LSEs to shape their portfolios would

1) provide for better utilization of the RA fleet and minimize costs to consumers;
2) allow the benefits of integrated system portfolios to be realized; and

3) mitigate market power that could otherwise be exercised by RA suppliers in tight RA markets.

Three options could provide such a shaping function:

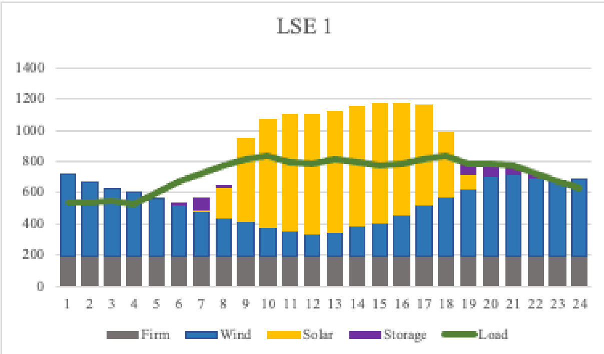
1) **Option 1:** LSEs with open positions in some hours could trade those obligations to other LSEs with long positions in those hours. ("obligation trading")
2) **Option 2:** LSEs could procure hourly capacity without contracting for the entire resource profile across all 24 hours. ("hourly resource trading")
3) **Option 3:** LSEs procure storage with charging capacity that can be used to discharge in any open hour to shape small positions.

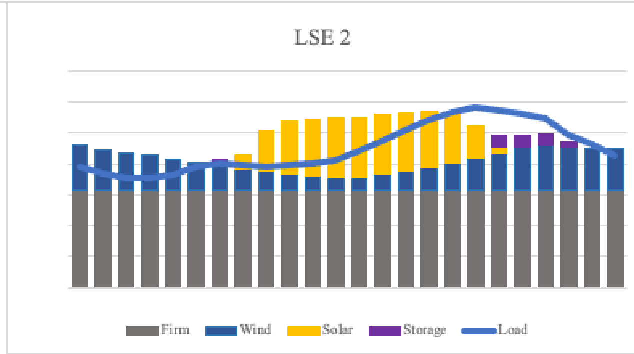
These comments present a simple proposal for Option 1. The proposal allows an LSE A that is deficient in one or more hours during one showing month to trade its obligation in the deficient hours with an LSE B that has excess resources in those hours. After the trade, LSE A would have a reduced obligation in the hours in which the obligation is traded, and LSE B would have an increased obligation in the hours in which the obligation is traded that matches the reduction in the obligation of LSE A during those hours. Since the showing would consist of set of obligation reductions and a corresponding set of obligation increases that sum to zero, this approach would be simple for the CPUC and LSEs to implement.

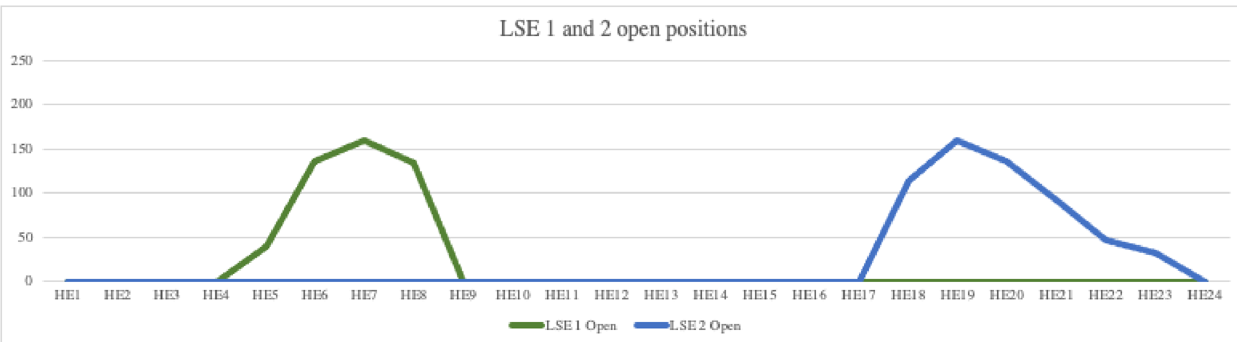
II. Illustration of the need for the hourly resource or trading construct

To understand why such a construct is needed, consider two LSEs that have different load shapes and different profiles. The two LSEs will have different open positions, once their generation portfolios are incorporated.

Figure 1 – Example of load diversity benefits from non-coincident open positions







If all or nearly all storage is under contract to LSEs, such that there is nearly no merchant storage supply, then the dominant available resource will be firm 24-hour resources, primarily gas. Without load trading or hourly resource trading, each LSE would need to procure a separate RA contract with a separate resource, with LSE 1 contacting with 160MW for its morning open position and LSE 2 contracting with 160 MW for its evening open position, for a total of 320 MW. This increases the cost for both and increases the tightness of the RA market, driving up prices.

In addition, SOD will create a market where most suppliers with RA will seek to sell a 24-hour offering to monetize the most value from the resource. Experience with the current RA market suggests that it may be difficult for LSEs to find reasonably priced offerings to meet specific hours as suppliers will likely try to increase their prices for slices for particularly critical hours in order to offset the risk of being unable to monetize RA in less critical hours (as is the case today with particularly critical months).

In contrast, with load trading and hourly resource trading, the two LSEs can share a firm RA resource, such that 160 MW is used to meet both open positions. (Either the generator could sell RA capacity for the needed hours to each LSE separately, or one LSE could contract with the resource and then contract with the other LSE to meet its open position.) This saves ratepayer costs since each LSE could be expected to pick up half the cost of the resource. In a real sense, a system that includes load trading and hourly resource trading alongside full resource trading would generate market efficiencies in a mode analogous to cap-and-trade systems. Since such systems allow participants to compare the costs of compliance internally to the cost of trading obligations to other participants that may have a lower compliance cost, total costs are optimized to the lowest level. In addition, this would serve to dampen RA prices for all other LSEs, by reducing overall demand for RA projects.

In addition, a mechanism is needed to capture the full diversity benefit of resources that may reside in different LSE portfolios. Under the current proposed system, the diversity benefit of the combination of generation and storage is difficult to realize if the generation and storage are under contract to different LSEs. Currently, a LSE seeking excess capacity to charge storage could contract with a slice of generation with another LSE, but since the two LSEs can only transact in full strips, if the LSE with excess needs even one hour's worth of capacity from the full resource, it would be unable to trade any portion of the resource without leaving itself short, even if it is long in all other hours. However, if the LSE can trade only certain hours, while retaining those hours in which is needs the resource, or the LSE can take load obligations in hours when it is long to free up capacity in the counter party LSE, then the LSE would be able to arrange to show its excess capacity to charge storage in another LSE's portfolio. At a system level, this would allow resource diversity benefits to be recognized that are otherwise difficult or impossible to realize in a 24 hourly construct without hourly flexibility.

Together, any system that forces duplicative procurement or ignores resource diversity benefits would create greater requirements to retain more of the gas fleet and prevent the retirement of gas resources that are not needed for reliability at a system level, but would be needed solely to ensure all LSEs can make their regulatory RA showings. This result would hamper California's decarbonization and environmental justice goals.

III. Discussion of the Three Transactability Options:

Option 1: Obligation Trading

Option 1 is intended to prevent LSEs having to procure full-day strips from resources to cover small open positions of a few hours, resulting in duplicative procurement across LSEs and tightening the RA market and prices. Conversely, if LSEs with complementary load profiles could share resources by trading load obligations, LSE RA obligations can be met with fewer resources overall, alleviating tightness in the RA market and helping moderate prices. This proposal for load obligation trading is simple from a CPUC compliance standpoint, since other than tracking RA showings, no other rules need be changed. The proposal would have the receiving LSE take on the full obligation of the granting LSE for the obligation hours traded. Both LSEs would show corresponding credits and debits in their RA showings to ensure that there is no overcounting or duplication.

Option 2: Hourly Resource Transactions

When Pacific Gas & Electric (PG&E) initially introduced the slice of day (SOD) proposal it noted that this framework could allow load-serving entities (LSEs) to transact resources by slice in order to promote more efficient use of existing RA resources. This would enable an LSE that is long in particular slices or hours, for example, to trade with another LSE that is short in those hours. Several parties were enthusiastic about this prospect since it would enhance utilization of the RA fleet and potentially reduce ratepayer costs. Since the introduction of the SOD proposal, however, some parties contend that this sort of trading could be complex to achieve due to two constraints: the current bundling of all RA characteristics (*i.e.* System, Local, and Flex) and the 24 by 7 must-offer obligation (MOO).

Since there is at least some opposition to hourly resource trading as too complex to warrant development, despite the potentially significant market benefits of hourly resource trading, the Joint Parties do not take a joint position on whether and how hourly resource trading should be implemented (this topic is discussed in other informal comments), but they do stress that pursuing load obligation trading is both simple and critical.

<u>Option 3: Storage resources for shaping small open positions</u>

The use of storage to perform shaping functions is already considered within the 24-hourly SOD proposal developed by Southern California Edison (SCE) and backed by other parties such as PG&E. Under this framework, an LSE will be able to shape its RA storage flexibly in order to adequately match its load shape. Nevertheless, LSEs will be limited in their use storage for RA purposes by the excess capacity shown in compliance filings needed to support storage charging, accounting for round-trip efficiency. This step provides some assurances to the Commission regarding energy sufficiency to charge of RA storage. However, the fact that this charging sufficiency verification must be done on an LSE by LSE basis does not recognize potential capacity excess on a system basis and could hinder appropriate storage deployment if LSEs are unable to access existing excess capacity that may exist in other LSEs' portfolios to use for battery charging. For example, LSE A may have significant excess capacity due to an abundance of solar generation, that could be used to charge storage in LSE B's portfolio, but without some trading option, LSE B would need to procure separate RA resources and the system would not be able to capture resource diversity benefits across LSE portfolios.

Additionally, storage procurement isn't likely to become a viable option for LSEs to meet hourly needs in the short-term (i.e., for one month-ahead showing) because it is unlikely for an LSE to contract with a storage resource for a term of one month or even a few months in a year. Typically, storage is procured under a long-term contract with developers directly, so unless another LSE can sell RA from its storage asset for specific months to help another LSE satisfy hourly needs, the use of storage will not be a common short-term option to meet particular hourly slice needs. Finally, while storage may be theoretically useful, for the next several years, the supply of storage available for RA contracts will be very limited as most storage coming online will already be under contract to LSEs under long term contracts. While D.21-06-035 would require some long duration storage to be online by 2026, D.19-11-09 has no storage requirement. Thus, IRP related procurement cannot be relied upon to fill this need.

IV. Proposal for Obligation trading

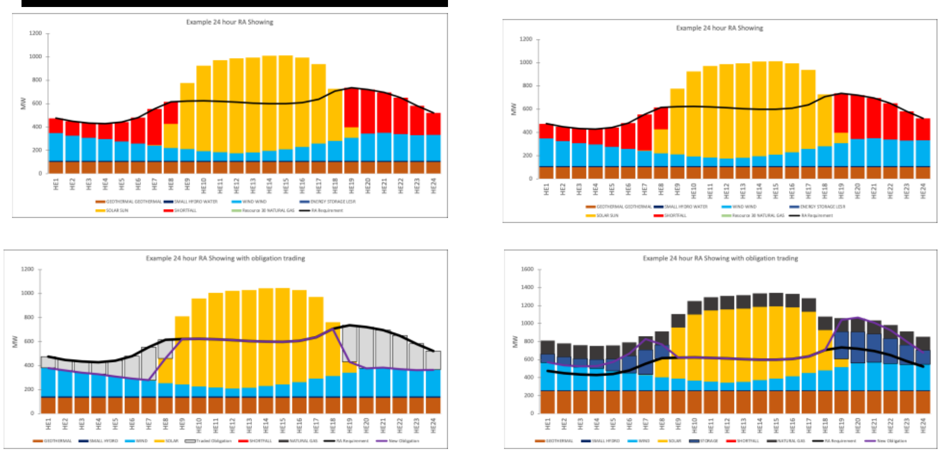
Trade concept

LSEs with short positions in some hours would be allowed to trade with others with long positions in those hours to allow resource sharing between the two LSEs with different loads and RA portfolios. For an illustration of how this would work, consider an example of two identical

LSEs. Both have the same load requirement profile and the same portfolio. Their open positions are shown in red below.

After the trade, LSE A would trade away part of its obligation in the evening and overnight hours, reducing its load obligation to what its portfolio can cover (purple line, lower left). LSE B would take on that obligation, increasing its obligation during those hours, and would need to procure a combination of resources to cover that obligation (purple line, plus resources in lower right panel.)

[redacted]



Note, this approach would also work to free up excess capacity to be used to qualify as charging capacity. For example, an LSE that had enough capacity for each hour, but not enough charging energy for the storage used, could trade its obligation to an LSE long in some hours, particularly during the day when most LSEs will be long with solar generation. This would reduce the obligation during these hours, creating excess capacity which could then be shown as charging capacity for the storage. This would allow LSEs to take advantage of diversity benefits across their portfolios by charging storage with generation in other LSEs' portfolios.

Showing

1) Both LSEs involved in the trade would show the trade on their RA showings spreadsheet. The LSE trading their load away (or "selling") would show a reduction of their obligation for the load in which they sold, and the LSE receiving the load obligation (or "purchasing") would show a corresponding increase in their obligation in the same hours and quantities. The sum of these showings would equal zero in all hours.
    a. Trades would specify the list of hour-specific showings and the MW of capacity showing in each hour traded.
    b. The LSE trading away its obligation would show the trade in its RA showing as an hour specific list of reductions against its hourly obligation profile

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	etc
MW	-15	-12	-21	-23	-27	-5	0	0	0	0	0	0	0	0	0	

    c. The LSE receiving the obligation would show the trade on its RA showing as an hour-specific list of increases to its RA portfolio.

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	etc
MW	15	12	21	23	27	5	0	0	0	0	0	0	0	0	0	

2) The LSE receiving the obligation would accept all responsibilities as would apply to its organic obligation.

a. LSEs can contract for indemnification of any costs arising from the deal, to provide for the two LSEs to share compliance risks, should they desire.

3) CPUC would confirm:

a. Both LSEs show corresponding debits and credits, such that sum of both showings would be zero in each hour.

b. ALL trades combined sum to zero.

c. This should ensure there is no double counting or any loss of total RA obligation across all hours.

Conclusion

The SOD proposal has some advantages but requires enhancements to provide for better transactability to reduce costs by improving market efficiency. Load obligation trading construct is a simple a mechanism that fits easily within the SOD construct and should be adopted. It would result in only a very minor increase in complexity while providing key functionality to ensure RA obligations can be met cost effectively, while reducing upward pressure on RA prices.

February 7, 2022

Re: Final and Summary Informal Comments of the California Energy Storage Alliance Regarding the Resource Adequacy Slice-of-Day Reform Workshops

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The California Energy Storage Alliance ("CESA") is a 501(c)(6) organization involved in a number of proceedings and initiatives in which energy storage is positioned to support a more reliable, cleaner, and more efficient electric grid. CESA represents over 100 member companies across the energy storage industry. CESA appreciates the opportunity to provide informal comments on the series of Resource Adequacy ("RA") Slice-of-Day ("SOD") Workshops held September 2021 through January 2022. CESA recognizes the dedication and efforts of parties to this proceeding in assembling these meetings and fostering an environment of creative policymaking.

To support the development of the final workshop report, CESA includes Sections I and II below that were submitted in previous opportunities for informal comments, with minor modifications, in order to comprehensively present and summarize CESA's positions on the SOD proposals and workshops. Section III of these comments are being submitted for the first time for consideration by the Commission and stakeholders.

I. CESA's Position Regarding the SOD Proposals and Resource Counting

A. CESA favors an SOD structural approach with monthly showings and 24-hourly slices, aligned with Southern California Edison's ("SCE") proposal.

When Pacific Gas & Electric ("PG&E") first proposed to establish RA requirements based on a SOD framework, they noted that this approach would ensure load will be met in all hours of the day, not just during gross peak demand hours. This would be achieved by: (1) setting requirements by slice; and (2) reducing compliance showings, from monthly to seasonal. During the workshops, several parties noted that longer slice durations and seasonal compliance have the potential to induce overprocurement, undercount resources, and generally increase ratepayer costs. SCE underscored that PG&E's proposal to have multiple-hour slices creates major inefficiencies and additional cost to ratepayers since use- and energy-limited resources cannot be allocated hourly and the hour with the highest load per slice will set the requirements for the entire slice. As a result, an SOD framework with multiple-hour slices is likely to overestimate the capacity necessary to meet the same planning reserve margin ("PRM"), relative to an approach with more granular hour-long slices.

CESA agrees with SCE. Slices and seasons are created to address hourly needs while managing showing requirements and other administrative costs. Considering that longer slice durations have the potential to induce overprocurement and undercount the value of preferred resources, CESA believes that higher granularity (*i.e.*, more seasons and slices) is consistent with the Commission's mission to retain reliability and minimize ratepayer costs.

In addition, when considering the SOD variations from PG&E, SCE, and Gridwell, SCE's month-hour SOD approach is the most consistent with the Commission's guidance regarding RA Reform. In Decision ("D.") 21-07-014 the Commission offered the following principles for the evaluation of reform alternatives (emphasis added):

- To balance ensuring a reliable electrical grid with ***minimizing cost to customers***.
- To balance addressing ***hourly energy sufficiency*** for reliable operations with ***advancing California's environmental goals.***
- To balance granularity and precision in ***meeting hourly RA needs*** with a reasonable level of simplicity and transactability.
- To be implementable in the near-term (*i.e.*, 2023).
- To be durable and adaptable to a changing electric grid.

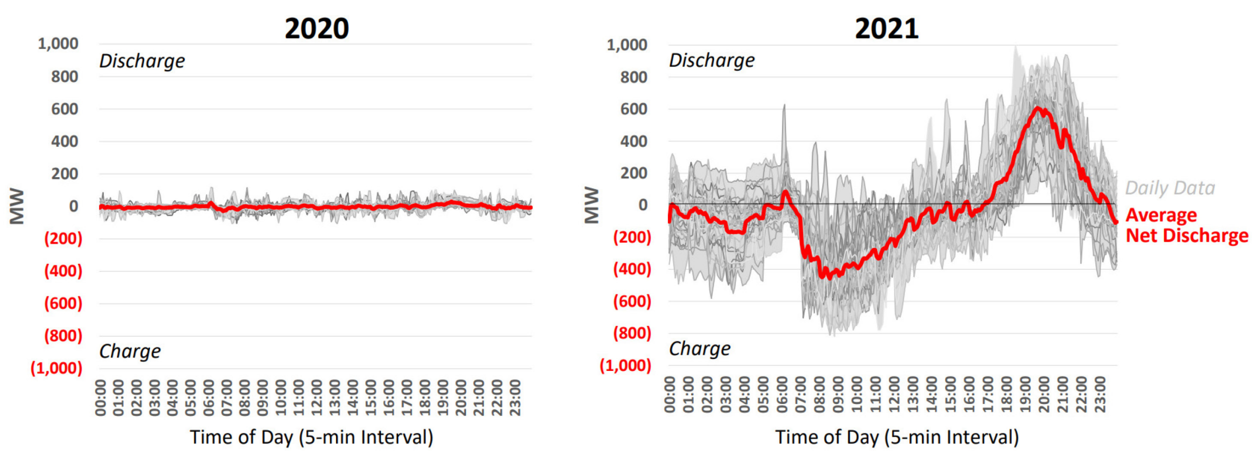
As noted in the above principles, the Commission seeks an RA framework that minimizes cost to customers, addresses hourly energy sufficiency, and advances California's environmental goals. SCE's 24-hourly SOD framework is well-positioned to meet these principles as it allows for the flexible utilization of use- and energy-limited assets, the accurate counting of variable energy resources ("VERs") and the minimization of procurement costs through the establishment of precise requirements. As such, CESA favors 12 seasons (monthly showings) and 24 hourly slices, aligned with SCE's proposal.

B. Storage counting should recognize the flexibility of these assets and the incremental value of assets with longer durations.

Today, the net qualifying capacity ("NQC") value of storage assets is determined by the maximum power output ("Pmax") it can sustain for 4 or more hours, colloquially known as the "*4-hour rule*". As such, the value of a 100 MW, 4-hour asset is identical to that of a 100 MW, 6-hour asset. During the workshops, parties have noted there are several methodologies to estimate the reliability contribution of energy storage resources and capture the incremental value of resources with durations above 4-hours. Overall, there are four proposals to assess the value of energy storage resources: exceedance; Pmax over a period of time (duration); some form of effective load carrying capability ("ELCC"); and/or some type of unforced capacity ("UCAP") evaluation.

First, counting methodologies that have been historically applied to VERs (*e.g.*, exceedance and ELCC) are not good fits for energy storage assets by virtue of their dispatchability and their responsiveness to periods of grid stress. Under an exceedance methodology the qualifying capacity ("QC") of a storage resource would be equal to the minimum output achieved by the resource for at least N% of the hours in the data set of historical generation for each period (season and slice). This may not be adequate for energy storage since dispatchable resources are able to shape their output in response to grid conditions (prices) that change across many different time horizons (*e.g.*, within a day, month by month, over years). As it can be seen in Figure 1, the aggregate output of storage assets has changed dramatically in a single year (2020-2021). To support forward determinations of capacity count, a methodology focused on a historical lookback for a resource class that can change its dispatch over time is limited. As such, QC estimates based on historic performance do not seem readily applicable for these assets.

Figure 1: CAISO Aggregate Battery Output (June 10 – July 10)[1]



Similarly, under an ELCC approach, a single monthly value (percentage) approximates the degree of coincidence between output of the storage asset and the loss-of-load probability ("LOLP"). Despite arguments to the contrary by some stakeholders, CESA is not convinced ELCC is a methodologically sound counting metric for dispatchable resources as they can maximize the degree of overlap between their output and LOLP (*i.e.*, these are not independent events). By virtue of their dispatchability, storage assets should not be evaluated in a manner that assumes their output is disconnected from the periods of grid stress (*i.e.*, LOLP). In fact, as storage resources are in essence pure arbitrage products, their response to price signals positions them quite well to align their output with LOLP.

Furthermore, when considering either exceedance or ELCC as alternative storage counting conventions, the Commission and other stakeholders should also consider the practical implementability of the methodology and take into account commercial perspectives regarding whether the counting conventions are not only reasonably accurate but also whether it is durable and provides certainty for the contracting of RA resources. After all, one of the key purposes of the RA Program is to ensure that load-serving entities ("LSEs") have contracted for not only the right resources but also sufficient resources to meet their RA obligations. Under an ELCC approach, the RA Program would be providing greater certainty of the reliability contributions of energy storage

[1] Lumen Energy Strategy, AB 2514 Evaluation Report, 2021.

resources as a portfolio and asset class, with greater certainty in the immediate and near term and much less uncertainty in the long term. However, for any new resource procurement requiring long-term contracts, many stakeholders are aware that RA counting values must have some degree of certainty to be financeable from the supplier/developer side and for portfolio management certainty on the buyer/LSE side. This will naturally entail ELCC approaches in practice requiring the use of ELCC vintages to specific years, or the use of average ELCC values, which would lead us to the very same problem we have today: solar resources have some non-zero average ELCC value today that can be "counted" or "stacked" across all hours, but we know that their capacity contributions are minimal, if not zero, at the critical summer net load peak hour at 8pm. If proponents of ELCC approaches are instead advocating for marginal ELCC to be used for RA counting purposes, then new procurement for resources like energy storage will be challenging to contract, especially when RA values fluctuate on a year-by-year basis. These questions are on top of the ones CESA has about the ability for ELCC models to capture granular traits (*e.g.*, location, technology type), be updated frequently (*e.g.*, due to computational power required), and ensure the appropriate and most accurate inputs and assumptions (*i.e.*, a robust and complex model is only as good as its inputs and assumptions). In essence, while ELCC proponents state that the model is robust and more accurately captures resources' QC contributions, it may not be accurate in practice.

In this context, CESA is left considering either the Pmax approach (subject to the number of hours shown and interconnection limits) or the UCAP methodology. Critically, the UCAP methodology implies the estimation of a seasonal availability factor to be applied to a predetermined NQC value, which would be based on the 4-hour rule.[2] It is unclear how UCAP could value the different durations of storage without resorting once more to an N-hour rule (*e.g.*, a 6- or 8-hour rule). Thus, given its inherent recognition that storage can be shown and operated in any manner an LSE decides to show it, subject to interconnection limits, CESA favors valuing storage based on the Pmax over number of hours shown, subject to interconnection limits. Such an approach recognizes the flexibility of storage assets, is compatible with the 24-by-7 MOO, enables cost-effective usage of assets, and provides clear and certain resource counting rules.

C. Hybrid and co-located resource counting requires some clarification, but they appear to fit well with the 24-hourly slice framework against gross load requirements.

To date, there has been little clarity on how to count hybrid and co-located resources. Parties have discussed the potential to use the same counting method for both these types of resources. Currently, hybrid and co-located resources may merit separate methodologies due to the way in which they are designed, metered, and operationalized by the CAISO. For hybrid resources, we consider that exceedance-based approaches should be preferred over ELCC approaches as they better account for an asset's output at specific slices or hours. For co-located resources, separate counting may be desirable given the fact that the CAISO will operate the underlaying resources as separate assets.

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[2] The formula for UCAP, as last presented by the California Independent System Operator ("CAISO") is defined as *UCAP value (or deliverable qualifying capacity ["DQC"]) = NQC * Weighted Seasonal Average Availability Factor.*

Regardless of the approach or the specific exceedance level, it is important that load requirements be set using gross load instead of net load. In doing so, existing contracts retain their RA value, and it incentivizes hybrid and co-located resources to be designed and developed in a way that co-optimizes for RA capacity as well as other revenue streams and policy drivers. In addition, it provides greater certainty of the capacity value of hybrid and co-located resources when any excess energy and charging requirements, if established, are within the developer's control of the resource, rather than it being required of the LSE to ensure sufficient excess energy in its portfolio, or trading for sufficient excess energy.

II. CESA's Specific Recommendations Regarding Energy Storage

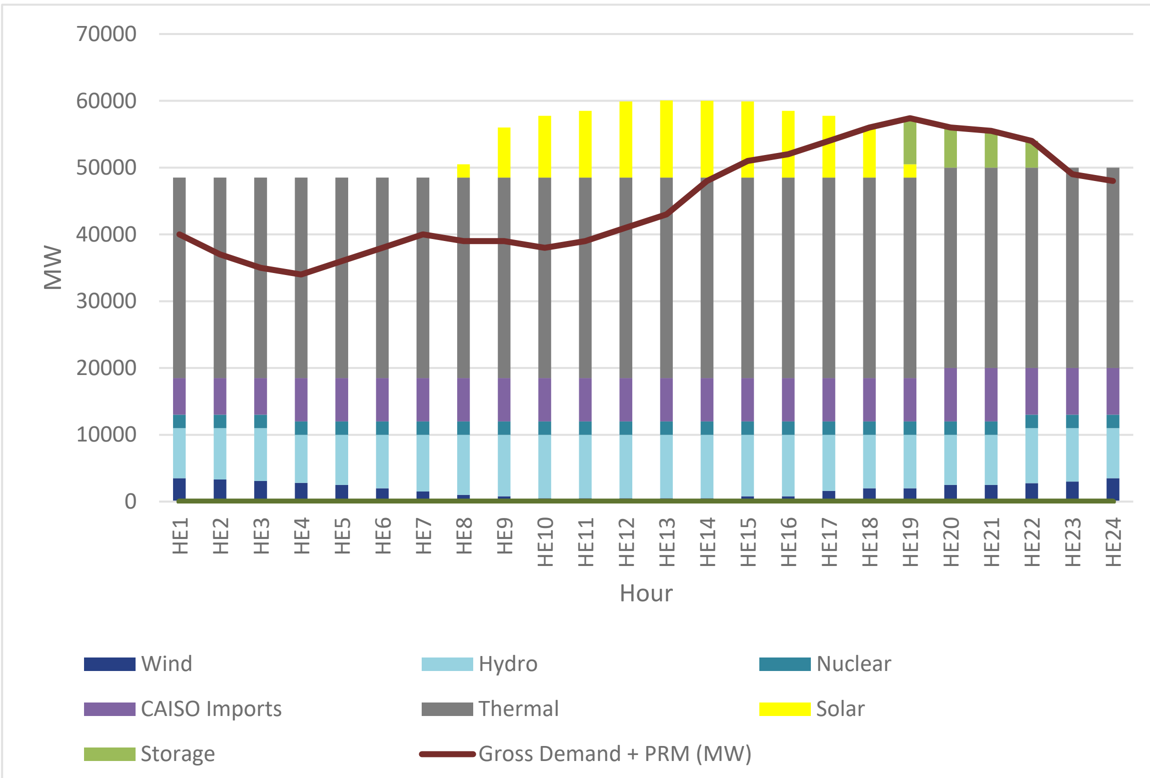
A. If charging sufficiency verification is required under the RA SOD framework, it should recognize resource-specific operational characteristics.

The SCE SOD proposal includes consideration of some form of charging sufficiency verification by LSEs that utilize storage assets to comply with their RA requirements. Importantly, this onus would be placed on the LSE using storage to comply with their RA requirements. This requirement would imply that LSEs would need to show storage resources as "positive" RA assets when expected to discharge and "negative" RA assets when expected to charge. Notably, this proposal would not require that storage be charged when shown as charging since such showing is only done as an accounting exercise and for compliance purposes. As such, this proposal assumes that, in the actual day of operations, storage will be charged and discharged based on its bids, as optimized by the CAISO market.

SCE proposes that charging sufficiency account for round-trip efficiency ("RTE"). For example, if an LSE uses 20 GWh to meet RA requirements in evening hours, it should show 25 GWh of capacity to charge the storage in hours prior, assuming 80% RTE. Significantly, this proposal would include no limitations for storage to be shown in excess of one cycle per day, provided the LSE has sufficient energy to charge it.

CESA does not have a position at this time on the inclusion of charging sufficiency verification. Nevertheless, if charging sufficiency is to be verified, resource-specific characteristics should be considered. First, RTE should not be considered on average terms, but on a per-asset or, *ad minimum,* per-technology basis. This will limit the potential for resources with significantly distinct RTEs to overestimate the amount of excess energy needed, affecting other storage assets. Second, storage resources should be allowed to be shown as cycling multiple times, with no consideration of "downtime". This allows resources that can cycle more than once to be shown incrementally, consistent with their capabilities and bidding strategies. Moreover, "downtime" verification goes beyond the accounting purposes of RA compliance showings, stepping into CAISO dispatch optimization. Multi-cycle charging sufficiency verification could be accomplished by simply estimating the amount of excess energy required to support one or more cycles of the storage shown, as presented during the December 17, 2021 workshop and illustrated below in Figure 2. This check would not require excess energy to come from specific sources or be shown in intervals prior to the storage being shown since those issues relate to dispatch, not capacity sufficiency. Finally, compliance of this check should be eased through obligation transactability, as explained below, in Section III, Subsection A.

Figure 2: Illustrative Compliance Showing with Multi-Cycle Sufficiency Verification



Storage RTE	Storage Shown (MWh)	Excess Energy Shown (MWh)	Energy Needed for One Cycle (MWh)	One-cycle Check	Energy Needed for Two Cycles (MWh)	Two-cycle Check
80%	22,440	214,351	28,050	PASS	56,100	PASS

B. The RA SOD framework must include a mechanism to show resources with operational timeframes that exceed 24 hours.

The SOD framework rests on the critical assumption that the interactions between demand and supply can be simplified to a 24-hour timeframe with significant certainty. While this approach might be adequate for a grid largely reliant on conventional fossil-fueled assets, CESA and other parties have expressed concerns regarding the durability of this methodology considering the potential for multi-day reliability events triggered by low solar conditions, drought, or other outlier events.

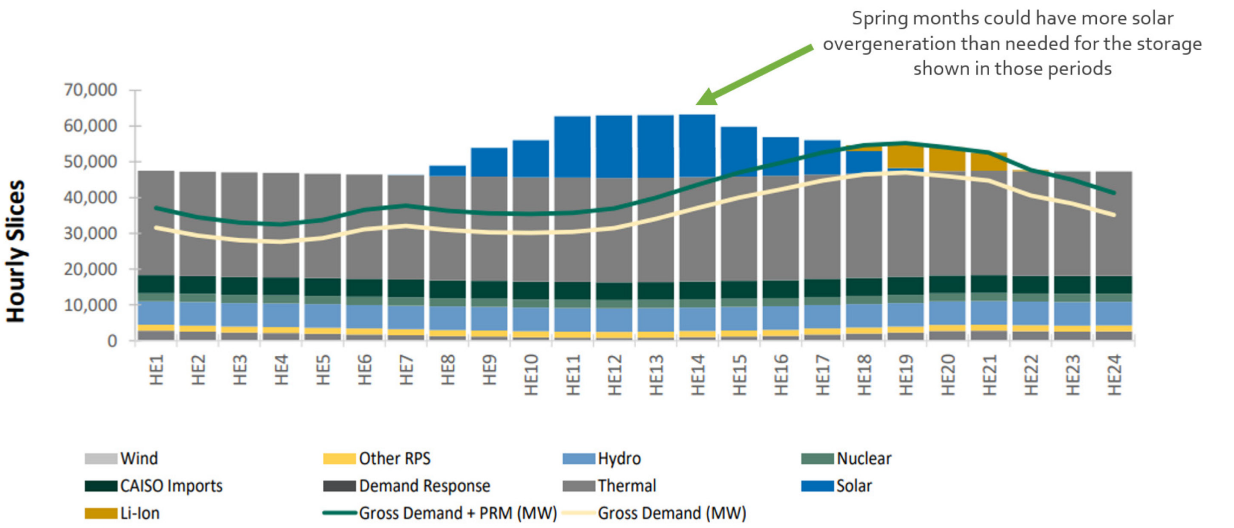
In a system that relies heavily on VERs and energy-limited assets, the interactions between weather, load, and supply are more impactful for reliability purposes. According to the Commission's IRP proceeding's modeling, the 2021 Senate Bill ("SB") 100 Joint Agency Report ("2021 SB 100 JAR"), and Strategen's *Long Duration Energy Storage for California's Clean, Reliable Grid*, California will require between 140-200 GW of incremental installed capacity (total of all resource types) to meet its 2045 emissions targets. Crucially, given California's outstanding solar resources and rapidly declining technology costs, the large majority of these capacity will come from solar PV and storage assets: between 70-100 GW of solar PV generation and 40-60 GW of energy storage by 2045. As a result, California's electric grid will largely depend on daily energy arbitrage to meet evening demand, particularly in the net load peak period when the sun has set yet load remains substantial.

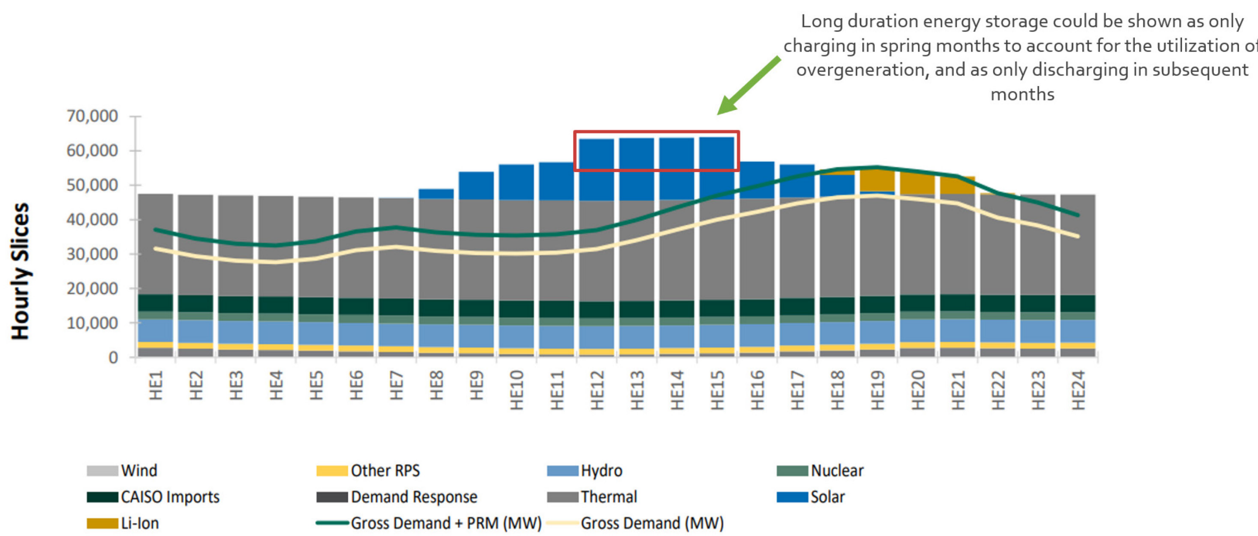
While the daily reliability needs could be easily addressed by refining the SOD framework, the same cannot be said about multi-day interactions. CESA has noted that the currently proposed 24-hour compliance framework might overlook multi-day reliability needs. Moreover, this 24-hour framework is not well-equipped to recognize the value provided by resources with operational timeframes that extend beyond a single day, such as some long duration energy storage ("LDES") technologies, which may focus on weekly or even seasonal arbitrage. A daily snapshot of RA slice requirements would not capture how excess energy to charge storage resources beyond the daily RA needs could be used to support multi-day reliability events.

However, at this time, the potential for outlier conditions that may induce multi-day reliability events may be better addressed through sensitivity modeling in the IRP proceeding, which is also better positioned to address the procurement of resources for these events and needs in a cost-effective manner. While the potential for these events can be modeled for in IRP, the RA SOD framework will still require a means to represent LDES assets with operational timeframes that exceed 24 hours and have a means to count their attributes for RA compliance purposes. To this end, CESA staff recommends the consideration of a "seasonal charge scheme".

The seasonal charge scheme is a mechanism that would allow LSEs to take excess spring-month overgeneration to provide charging sufficiency for energy storage assets shown in summer or winter months. This approach recognizes that there may be particular value in taking shoulder-month solar overgeneration to not serve spring month loads but to serve summer and winter loads. This solution would allow for carryover excess energy to be used in future seasons (showings) for storage charging. In essence, this would not set a "use it or lose it" approach for excess generation and allow for "banking" of these RA attributes across different showing periods. This way, the charging of LDES can be represented and accounted for as presented during the December 17, 2021 workshop and illustrated in Figure 3 below.

Figure 3: Illustrative Compliance Showing with Seasonal Charge Scheme





C. The RA SOD framework should incorporate proposed behind-the-meter energy storage capacity counting rules as submitted in the Phase 2 proposals from joint parties.

Each of the SOD variations would require LSEs to show RA resources in one or more slices of the day for a particular showing period, with a resource's ability to produce during that particular slice of day determining how much RA capacity would count for that slice. As proposed in a Phase 2 proposal submitted by CESA, Sunrun, Enel X, and CALSSA ("Joint DER Parties") on January 21, 2022 in R.21-10-002, the QC methods for IFOM and BTM hybrid and energy storage resources can be the same, with their showing to particular slices also done in the same way. As dispatchable resources, IFOM and BTM hybrid and energy storage resources can be shown in the particular slice as needed to meet an LSE's RA obligations and as contracted. In addition to a discharging obligation for the particular slice in which it can be "counted" for capacity, energy storage resources would also count "negatively" toward the slice for which it has a charging obligation using any shown "excess capacity." Similar to its IFOM counterparts, BTM hybrid resources should account for onsite charging availability from its paired generation resource before determining and accounting for any additional excess energy needs (if any) from the grid, while BTM standalone energy storage resources must demonstrate excess energy is available in other non-shown slices to fully charge the resource and ensure its QC.

III. CESA's Comments on Transactability, Hedging, Multi-Year Requirements, and Deliverability

A. Transactability of load requirements should be further explored in order to ease compliance with the 24-hourly SOD framework and the potential storage charging sufficiency requirement.

The SOD framework would require LSEs to show their resources in a manner that matches their load profile. Since, in many cases, an LSE might not have a portfolio that allows it to match its load profile precisely, efficient mechanisms allow LSEs to shape their RA portfolio profiles to their load shapes are essential to market efficiency. While recognizing the potential for energy storage and BTM resources to right-size LSE portfolios, we still recommend the need to incorporate transactability into the framework to account for timelines to procure new-build resources and to provide flexibility to, for example, meet the charging sufficiency requirement, if implemented.

Mechanisms to allow LSEs to shape their portfolios would:

- provide for better utilization of the RA fleet and minimize costs to consumers;
- allow the benefits of integrated system portfolios to be realized; and
- mitigate market power that could otherwise be exercised by RA suppliers in tight RA markets.

Three options could provide such a shaping function:

1) **Option 1:** LSEs with open positions in some hours could trade those obligations to other LSEs with long positions in those hours. ("obligation trading")

2) **Option 2:** LSEs could procure hourly capacity without contracting for the entire resource profile across all 24 hours. ("hourly resource trading")

3) **Option 3:** LSEs procure storage with charging capacity that can be used to discharge in any open hour to shape small positions.

These comments present a simple proposal for Option 1. The proposal allows an LSE A that is deficient in one or more hours during one showing month to trade its obligation in the deficient hours with an LSE B that has excess resources in those hours. After the trade, LSE A would have a reduced obligation in the hours in which the obligation is traded, and LSE B would have an increased obligation in the hours in which the obligation is traded that matches the reduction in the obligation of LSE A during those hours. Since the showing would consist of set of obligation reductions and a corresponding set of obligation increases that sum to zero, this approach would be simple for the Commission and LSEs to implement.

Option 1 is intended to prevent LSEs having to procure full-day strips from resources to cover small open positions of a few hours, resulting in duplicative procurement across LSEs and tightening the RA market and prices. Conversely, if LSEs with complementary load profiles could share resources by trading load obligations, LSE RA obligations can be met with fewer resources overall, alleviating tightness in the RA market and helping moderate prices. This proposal for load obligation trading is simple from a Commission compliance standpoint, since other than tracking RA showings, no other rules need be changed. The proposal would have the receiving LSE take on the full obligation of the granting LSE for the obligation hours traded. Both LSEs would show corresponding credits and debits in their RA showings to ensure that there is no overcounting or duplication.

When initially introducing the SOD proposal, PG&E noted that this framework could allow LSEs to transact resources by slice in order to promote more efficient use of existing RA resources. This would enable an LSE that is long in particular slices or hours, for example, to trade with another LSE that is short in those hours. Several parties were enthusiastic about this prospect since it would enhance utilization of the RA fleet and potentially reduce ratepayer costs. Since the introduction of the SOD proposal, however, some parties contend that this sort of trading could be complex to achieve due to two constraints: the current bundling of all RA characteristics (*i.e.* System, Local, and Flex) and the 24-by-7 must-offer obligation ("MOO").

Since there is at least some opposition to hourly resource trading as too complex to warrant development, despite the potentially significant market benefits of hourly resource trading, the Joint Parties do not take a joint position on whether and how hourly resource trading should be implemented (this topic is discussed in other informal comments), but they do stress that pursuing load obligation trading is both simple and critical.

The use of storage to perform shaping functions is already considered within the 24-hourly SOD proposal developed by SCE and backed by other parties such as PG&E. Under this framework, an LSE will be able to shape its RA storage flexibly in order to adequately match its load shape. Nevertheless, LSEs will be limited in their use storage for RA purposes by the excess capacity shown in compliance filings needed to support storage charging, accounting for round-trip efficiency. This step provides some assurances to the Commission regarding energy sufficiency to charge of RA storage. However, the fact that this charging sufficiency verification must be done on an LSE-by-LSE basis does not recognize potential capacity excess on a system basis and could hinder appropriate storage deployment if LSEs are unable to access existing excess capacity that may exist in other LSEs' portfolios to use for battery charging. For example, LSE A may have significant excess capacity due to an abundance of solar generation, that could be used to charge storage in LSE B's portfolio, but without some trading option, LSE B would need to procure separate RA resources and the system would not be able to capture resource diversity benefits across LSE portfolios.

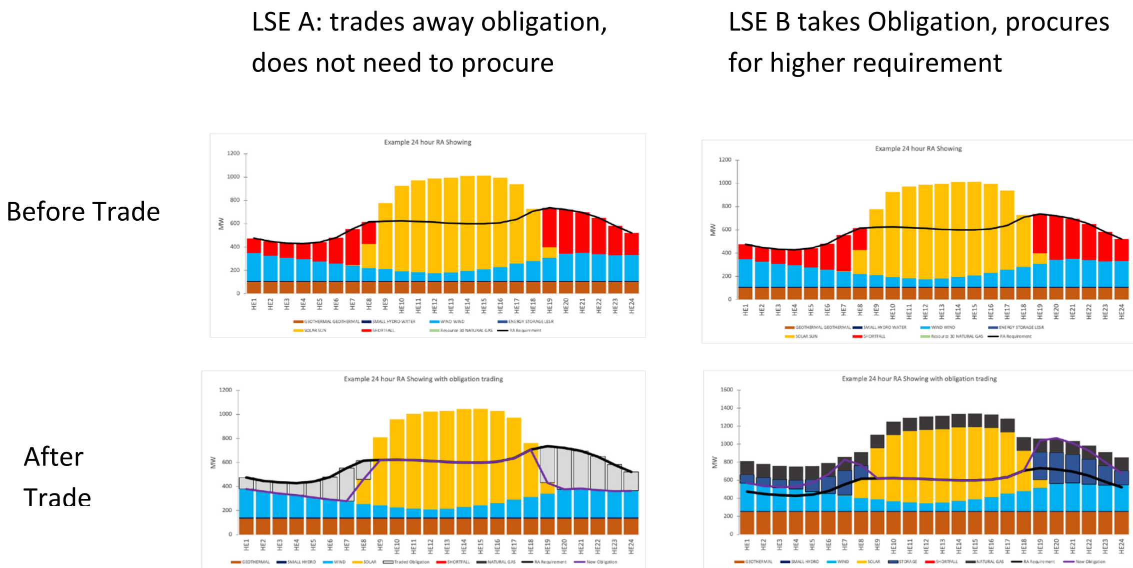
Additionally, storage procurement isn't likely to become a viable option for LSEs to meet hourly needs in the short-term (i.e., for one month-ahead showing) because it is unlikely for an LSE to contract with a storage resource for a term of one month or even a few months in a year. Typically, storage is procured under a long-term contract with developers directly, so unless another LSE can sell RA from its storage asset for specific months to help another LSE satisfy hourly needs, the use of storage will not be a common short-term option to meet particular hourly slice needs. Finally, while storage may be theoretically useful, for the next several years, the supply of storage available for RA contracts will be very limited as most storage coming online will already be under contract to LSEs under long term contracts. While D.21-06-035 would require some long duration storage to be online by 2026, D.19-11-09 has no storage requirement. Thus, IRP related procurement cannot be relied upon to fill this need.

Under the proposal for obligation trading, LSEs with short positions in some hours would be allowed to trade with others with long positions in those hours to allow resource sharing between the two LSEs with different loads and RA portfolios. For an illustration of how this would work, consider an example of two identical LSEs. Both have the same load requirement profile and the same portfolio. Their open positions are shown in red below.

After the trade, LSE A would trade away part of its obligation in the evening and overnight hours, reducing its load obligation to what its portfolio can cover (purple line, lower left). LSE B would take on that obligation, increasing its obligation during those hours, and would need to procure a combination of resources to cover that obligation (purple line, plus resources in lower right panel.)

Note, this approach would also work to free up excess capacity to be used to qualify as charging capacity. For example, an LSE that had enough capacity for each hour, but not enough charging energy for the storage used, could trade its obligation to an LSE long in some hours, particularly during the day when most LSEs will be long with solar generation. This would reduce the obligation during these hours, creating excess capacity which could then be shown as charging capacity for the storage. This would allow LSEs to take advantage of diversity benefits across their portfolios by charging storage with generation in other LSEs' portfolios.

Figure 4: Illustrative Example of Load Obligation Trading



Both LSEs involved in the trade would show the trade on their RA showings spreadsheet. The granting LSE would show a credit for the load traded away, and the LSE receiving would show a corresponding debit in the same hours and quantities. The sum of these showings should equal zero in all hours. Trades would specify the list of hour-specific showings and the MW of capacity showing in each hour traded. The LSE trading its obligation would show the trade in its RA showing as an hour specific list of credits against its hourly obligation profile, as shown in Table 1. The LSE receiving the obligation would show the trade on its RA showing as an hour-specific list of debits against its RA portfolio, as shown in Table 2.

Table 1: Illustrative Example of Load Obligation Trading – LSE A Showing

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	…
MW	15	12	21	23	27	5	0	0	0	0	0	0	0	0	…

Table 2: Illustrative Example of Load Obligation Trading – LSE B Showing

HE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	…
MW	-15	-12	-21	-23	-27	-5	0	0	0	0	0	0	0	0	…

Under this proposal, the Commission would confirm that both LSEs show corresponding debits and credits, such that sum of both showings would be zero in each hour. The Commission would only need to ensure that *all* trades combine and result in zero. This should ensure there is no double counting or any loss of total RA obligation across all hours without substantially increasing administrative burdens.

B. The Commission should not include a hedging requirement in the scope of the RA SOD Reform as it may be a less cost-effective outcome for consumers.

CESA does not support the inclusion of a hedging *requirement* as part of the SOD RA Reform process. Instituting a hedging component does not significantly affect reliability as both sellers and buyers of RA today can willingly enter into hedging agreements as an *option*. Moreover, the requirement of a hedging component will not reduce costs for consumers, as sellers of RA would be incented to replace one potential revenue stream (high energy prices) with another (higher RA contract prices) in order to retain financial viability. As such, the implementation of a hedging requirement could in fact increase RA costs, resulting in a less cost-effective outcome for consumers. Consequently, since the inclusion of a hedging requirement would almost certainly increase the costs of RA capacity, negatively affecting consumers with higher rates for the same level of reliability, CESA does not see merit in adopting a hedging requirement at this time.

C. Multi-year requirements for System RA should, at most, align with currently applicable requirements for Local RA resources.

Today, the CPUC already requires multi-year contracts for Local RA. Three-year forward requirements are in place as follows: 100% for Years 1 and 2, and 50% for Year 3. This multi-year requirement is reasonable for Local RA resources due to the limited number and locations for Local RA resources that may not be currently supported in the development and/or retention of incremental capacity.

During the workshop regarding this issue, parties noted that an approach similar to that applied to Local RA could be explored for System RA, highlighting that Year 3 requirements could be superior to 50%. In order to align market signals, CESA recommends that, if the Commission decides to adopt multi-year forward requirements for the System RA market, they should be aligned with Local RA requirements. Namely, these should be 100% for Years 1 and 2, and no more than 50% for Year 3. CESA considers that this approach provides the necessary assurances to retain critical facilities and incent the development of new resources while managing the risks of technology or resource lock-in.

D. The Commission should encourage the CAISO to reconsider its deliverability requirements for RA resources.

The major structural reforms the Commission is considering for the RA program would transform this paradigm from one designed around a single peak hour to one that can ensure that energy needs are met in all hours, particularly in all evening peak hours, as well as under more extreme conditions. While this focus is aligned with the principles outlined by the Commission in D.21-07-014, this new focus is at odds with the CAISO's deliverability assessment methodology.

Currently, the CAISO's deliverability assessment focuses on a very limited set of hours with unlikely, outlier conditions. The On Peak Deliverability Assessment methodology is designed around two operating scenarios. The first scenario, High System Need ("HSN"), includes three system conditions that are assumed to be occurring simultaneously: an N-2 condition;[3] system dispatch conditions where all generation in a particular area is operating almost at NQC; and a "peak-net-load condition" where the system is most likely to experience a generation shortfall. The second operating scenario, called Secondary System Need ("SSN"), represents similar assumptions regarding system outages and generation dispatch but gross load (not peak load) is assumed to be at or near its peak level and energy production from both wind and, particularly, solar resources with FCDS and PCDS status are assumed to be significantly higher than their NQC levels and in the HSN scenario, along with all other resources at full NQC output.

In a grid run by a significant penetration of energy-limited resources, the underlying assumptions and basis for the current On Peak Deliverability Assessment methodology warrants reassessment. It is, for example, highly unlikely for all energy-limited resources to be dispatched simultaneously in the way that the current methodology assumes since this is not economically rational and could be physically impossible.[4] The Commission should coordinate with the CAISO and stakeholders to evaluate whether and how these assumptions could be reasonably relaxed, consistent with the purpose of the structural reforms being pursued by the Commission through the RA Reform Track, specifically considering SCE's 24-hourly SOD framework. The anticipated modifications to the RA structure merit consideration of whether reformed conditions should be used to determine deliverability for all resources for each of the new "slices of day". This outstanding topic is crucial as it will greatly influence the resources that can contribute to RA as well as the costs to customers. As such, the CAISO's current conservative deliverability assumptions may cause substantial and unnecessary roadblocks (*e.g.*, overbuilding upgrades to support deliverability, timelines associated with building of such upgrades) in building the evolving system that will be dominated by widely dispersed, relatively small, variable energy and storage resources, as outlined in SCE's SOD proposal.

IV. <u>Conclusion</u>

CESA appreciates the opportunity to provide these informal comments on the workshops. We look forward to collaborating with the parties to this proceeding.

Respectfully submitted,

[3] N-2 refers to nominal minus two crucial elements (generation and/or transmission).

[4] For example, it is likely impossible for a portfolio of four-hour energy storage resources to all be simultaneously dispatched in peak or net peak conditions given their energy-limited nature.

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	**Rulemaking 19-11-009** **(Filed November 7, 2019)**

NOT CONSOLIDATED

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	**Rulemaking 21-10-002** **(Filed October 7, 2021)**

INFORMAL COMMENTS OF THE
CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION
ON RA SLICE-OF-DAY WORKSHOPS

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February 7, 2022

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INFORMAL COMMENTS OF THE
CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION
ON RA SLICE-OF-DAY WORKSHOPS

The California Large Energy Consumers Association (CLECA)[1] appreciates the enormous effort since September of stakeholders to develop and present proposals to implement the Slice of Day framework that was adopted by the CPUC in D.21-07-014. CLECA offers this feedback on its current preferences based upon the work presented in the workshops ending

[1] CLECA is an organization of large, high load factor industrial customers located throughout the state; the members are in the cement, steel, industrial gas, pipeline, beverage, cold storage, and minerals processing industries, and share the fact that electricity costs comprise a significant portion of their costs of production. Some members are bundled customers, others are Direct Access (DA) customers, and some are served by Community Choice Aggregators (CCAs); a few members have onsite renewable generation. CLECA has been an active participant in Commission regulatory proceedings since the mid-1980s, and all CLECA members engage in Demand Response (DR) programs to both promote grid reliability and help mitigate the impact of the high cost of electricity in California on the competitiveness of manufacturing. CLECA members have participated in the Base Interruptible Program (BIP) and its predecessor interruptible and non-firm programs since the early 1980s.

January 19, 2022. These comments summarize CLECA's position on the various Slice of Day proposals addressed in these workshops and suggest a way forward for a more permanent treatment for demand response following the interim proposal(s) that will be presented in the California Energy Commission's (CEC's) report to the Commission on qualifying capacity for demand response for the resource adequacy compliance year 2023. CLECA is also joining in the Joint Informal Comments separately being submitted by the Natural Resources Defense Council (NRDC) and others.

1. The 24-hour Slice of Day proposal best meets the objectives in the CPUC Decision on RA reform

By the end of these workshops, two competing proposals for the number of slices and seasons had emerged, with several additional proposals for counting rules for subsets of resources. We start with the proposals for the number of slices per day and months or seasons in a year.

The first proposal is for 24 hours per day for each of the 12 months in a year developed by Southern California Edison Company (SCE) and later supported by Pacific Gas and Electric Company (PG&E) and other parties who are separately filing jointly in support of this proposal referred to above. The alternative is a proposal for two slices a day determined by the peak and net peak, grouped by 12 months, as proposed by Gridwell and Vistra. The Commission was clear in adopting the Slice of Day framework that storage resources and the resources providing the energy to charge them must be shown for resource adequacy. On a peak day there must be sufficient resources to meet the daytime retail customer load requirement PLUS the load needed to charge storage, as well as sufficient storage for discharge to meet evening peaks after sunset. The 24-hour proposal meets that objective. A shortcoming of the two-slice proposal is that is does not formally account for the resources providing energy to charge the storage. If resource adequacy (RA) reform is to be durable, that shortcoming must be resolved. The assumption that there is sufficient excess solar energy during the day to charge storage is not adequate.

The 24-slice proposal also mitigates the difficulty of attempting to group similar hours into a slice. The slice definition will impact the qualifying capacity of a resource. Since different resources have different potential durations and shapes, the more slices there are, the better those characteristics are captured. The 24-slice per day proposal mitigates the concern that a resource that partially fits into more than one slice will not be able to be fully counted if hours are grouped into multi-hour slices. While this makes for a more detailed showing requirement, it will better capture the full capability of each resource to meet load in each hour. Accordingly, CLECA supports the 24-hour slice proposal.

The following responses assumes a 24-hour slice proposal as opposed to a 2-slice proposal.

2. Load Forecast Issues

The load forecast should be based upon the worst day

Selecting the worst day of the month for the 24-hour monthly forecast is the most logical option. It will reflect the underlying impact of weather on the load forecast. The use of maximum monthly values for each hour (or worst hour) approach to generate a synthetic load shape breaks the relationship between the weather of the worst day and the load forecast. A load shape based upon a combination of worst hours from different days to create a synthetic load shape is artificial and unlikely to reflect any plausible weather pattern. The use of the planning reserve margin will also reflect load uncertainty, so it is not clear the worst hour approach is warranted. In addition, the use of the worst hour approach would create difficulties in the adjustments the CEC will perform to calibrate the sum of load serving entity load forecasts to match the CEC's system peak forecast.

Load Forecast

The CEC proposes to use a hybrid of the current top-down approach to determine a system-wide load forecast for each hour from the Integrated Energy Policy Report (IEPR), but then allocate the load to each slice using each Load serving Entity's (LSE's) hourly load forecast (a bottoms up approach) to determine LSE shares of each slice; this CEC proposal will address both the overall system need and each LSE's contribution to it. Since the CEC has indicated it can perform such hourly analysis, it appears that this is a viable approach. It captures each LSE's contribution to each slice while meeting the CEC's load forecast.

Once each LSE's share is determined, each LSE can develop a portfolio of resources that best meets its respective needs and policy goals.

The Load Forecast Severity and PRM are Linked Together

Currently, for the annual peak, a 1 in 2 load is used and is grossed up for the planning reserve margin (PRM) to account for weather variation. If a 1 in 5 or 1 in 10 load forecast is used, the PRM would need adjustment. Unless that adjustment can be made, the 1 in 2 load forecast should be used.

Gross Load Should be Used as the Target

The CEC would need to adjust each LSE's load forecast to apply a California Independent System Operator (CAISO)-wide coincident load adjustment. Excess complexity would be introduced by forecasting wind and solar output for each LSE to create a net load forecast by LSE. We conclude that the use of a net load forecast for each LSE is not worthwhile and that a gross load should be used.

Resource RA Should Not be Unbundled

The ability to buy particular hourly segments of a resource's output and the need to keep track of such segments add a degree of complexity that would impose a substantial burden on the early stages of RA Reform. We agree with SCE that resource RA should not be unbundled, and that any LSE should be able to buy a share of a full day's output of each resource. While increased transactability may be appealing to allow LSEs to meet their individual load shapes, we are concerned that tracking such transactions may be quite burdensome for the Energy Division. Cal Advocates also raised concerns about the implications for calculation of the Power Charge Indifference Adjustment (PCIA). We note that some Community Choice Aggregators (CCAs) are procuring resources as a group that can conform to their collective load shapes, and this may be a test case of procurement at a finer level of granularity. Once RA Reform is implemented, refinements to address transactability should be considered as needed.

No Trading of RA Load Obligations

While the trading of RA load obligations might offer some market efficiency benefits, at this time it adds a complexity that has not been demonstrated to be necessary. CLECA is not even sure how this would be accomplished.

3. Resource counting should reflect the resources' expected ability to meet the load for the defined slice

The Slice of Day framework is to show a stack of resources to meet the load requirements throughout the year, and not just the peak, net peak, or summer. This recognizes that much of the future fleet of resources cannot provide output continuously during the day. Therefore, the counting of a resource should reflect its ability to meet the load forecast in a given slice. We do have some concern about the uncertainty of assigning a capacity value to wind and solar in developing the stacks. This will be a function of the methodology used, and, if exceedance is the methodology chosen, the percentage exceedance value chosen. The exact methodology to determine capacity values for wind and solar was insufficiently developed in the workshops, and further analysis is needed before the resource counting methodology for wind and solar is finalized.

Thermal

At a minimum, the net qualifying capacity (NQC) for a thermal resource should reflect its availability after accounting for the impact of ambient temperatures, because the output of a combustion turbine declines when it gets hotter. The CAISO's revised Unforced Capacity (UCAP) proposal presented January 19 focused on using historical performance to derate nameplate for counting QC. There was a legitimate debate in the last workshop over whether historical performance is the best estimator of future performance. One concern CLECA has is whether such a metric would discourage investments in improved performance if that improvement would take years to be reflected in the QC. If a UCAP incorporating forced outage rates is to be used in the future, the PRM should be adjusted, since it also accounts for forced outages. CLECA recommends more discussion on how the PRM would be adjusted if UCAP is utilized.

Solar and Wind

The continued use of Effective Load Carrying Capability (ELCC) is not appropriate for the Slice of Day framework for either the 2- or 24-hour proposal. The current solar ELCC is a single monthly value that undervalues solar's contribution to serve load during the gross peak and overvalues solar's contribution at the net peak, when the sun has set. The same would be true for wind or demand response. Wind ELCC values are similarly problematic. The current ELCC's monthly nature would not work for 24 hourly slices in a day, because it would capture none of the hourly output variation of solar or wind resources (or demand response).

The use of exceedance for solar and wind appears to have an advantage, in that it would reflect a resource's hourly contribution and not a monthly average. However, as noted above, more work is needed to develop an alternative to ELCC and test it against exceedance. The difficulty is selecting an exceedance percentage, and the values for wind and solar may be different.

PG&E's proposal to use wind and solar generation data during the highest load days to develop an average for each hour also has merit. The remaining question is determining the threshold (5%, 10%, other) of the highest load days to use as the basis for calculating the average generation.

CLECA recommends further analysis using reliability modeling to refine a methodology for developing QC values for wind and solar on an hourly basis.

Demand response and other resources

For demand response to be compatible with the Slice of Day framework, an hourly profile of load reduction is required based upon an assumed demand response event. Some demand response programs' load reductions are not uniform over the utilization event; the reductions can vary by hour due to changes in the underlying participant load or changes in weather. The load reduction forecast should use the weather forecast consistent with the load forecast under Slice of Day. In other words, if the load forecast is based upon a 1 in 2 peak event, then the demand response should also be based upon the same forecast. In addition, the forecast should include expected participation in the demand response event based upon event and test data. The existing Load Impact Protocols (LIP) already produce hourly load reductions for a 1 in 2 weather event which can be utilized for Slice of Day.

The existing monthly qualifying capacity values, which represent the average of the hourly load impacts from an assumed 4-9 pm call, do not work for the Slice of Day framework. In either the 2 or 24 Slice of Day proposal, the load impact must be matched to a specific hour. Using a single value for all hours in a slice will either over- or underestimate demand response's ability to meet load in that particular slice; this would send the wrong signal for resource procurement.

At this point CLECA does not have a position on hydro, storage, hybrid, or co-located resources.

Hedging

The issue of hedging is not a reliability issue but a cost issue, and it does not appear they need to be linked together for implementation. The issue of hedging should be separated into a different track. CLECA shares the Energy Division's concerns over the observation of higher bidding prices when tolling agreements no longer are a significant portion of resource mix. Hedging is not free, so an excessive requirement would lead to higher costs to the customer.

Additional work is needed to develop the hedging framework and to determine the appropriate quantity of hedging.

Multi-Year System RA

Multi-year system RA requirements have been proposed to allow for retention of gas-fired generation needed for reliability. CLECA supports the retention of such gas-fired generation as needed in the future for reliability. However, we have two concerns with proposals for multi-year system RA. The first is load migration, which could result in some LSEs having over-procured if load departs. The second is that some LSEs may not want to sign multi-year RA contracts with gas-fired generation for policy reasons, requiring customers of other LSEs to pay for the additional reliability burden. These two issues should be addressed before multi-year system RA is required. In addition, load migration concerns make multi-year contracts longer than 3 years for existing resources highly questionable.

Respectfully submitted,

Buchalter, A Professional Corporation

By:

Nora Sheriff

Nora Sheriff
Counsel for the California Large Energy Consumers Association

CLECA CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

February 7, 2022

Informal Comments of Form Energy, Inc. Regarding the Resource Adequacy Slice-of-Day Reform Workshops

February 7, 2022

Form Energy, Inc. ("Form") is developing a new class of multi-day energy storage systems to enable a clean electric grid that is reliable and cost-effective year-round, even in the face of multi-day weather events. Our first commercial product is a rechargeable iron-air battery capable of continuously discharging electricity for 100 hours at system costs competitive with conventional power plants and at less than 1/10th the cost of lithium-ion battery storage. Form is headquartered in Somerville, MA, with offices in the San Francisco Bay Area and the Greater Pittsburgh area.

Form appreciates the opportunity to provide informal comments on the series of Resource Adequacy ("RA") Slice-of-Day Workshops held September 2021 through February 2022 ("Slice-of-Day Workshops"). We do not attempt here to address all issues that the Slice-of-Day Workshops have covered, focusing instead on two areas where we believe additional consideration is needed. First, the Slice-of-Day framework, as currently proposed, does not adequately address multi-day reliability risks. Form recommends that the Commission refrain from adopting the Slice-of-Day proposal and instead commit to developing a framework that sufficiently addresses emerging reliability risks. Second, the proposed charging sufficiency verification methodology for energy storage resources is incompatible with and prejudicial against many long duration energy storage ("LDES") and multi-day energy storage ("MDS") technologies. Form recommends that, if the Commission adopts the Slice-of-Day proposal on an interim basis, LDES and MDS technologies should be exempted from any diurnal charging sufficiency verification requirement.

I. The Slice-of-Day framework is deficient because it fails to ensure energy sufficiency over consecutive days of grid stress

In Opening Comments on the Proposed Decision ("PD") on Track 3B.2 of Rulemaking (R.)19-11-009,[1] Form raised concerns about the ability of the Slice-of-Day framework to

[1] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M390/K483/390483331.PDF

appropriately address multi-day reliability risks. We urged the California Public Utilities Commission ("Commission") to commit to adopting an RA framework that could ensure reliability during sequential day periods of high net load caused by extreme weather, low renewable generation, and correlations between these events and other contingencies. To this end, we requested that the Commission conduct foundational analytical work to define California's mid and long-term reliability risks, including by assessing 1) the conditions of highest reliability risk across all seasons and how these conditions are likely to change over time, 2) appropriate reliability metrics, and 3) appropriate reliability planning standards.

Decision (D.)21-07-014 directed parties to undertake the Slice-of-Day Workshops and required that the workshops should also cover multi-day reliability event concerns. Discussion of these topics has been cursory. More importantly, the Slice-of-Day framework is poorly suited to addressing multi-day reliability risks by virtue of its sole focus on single representative days and lack of consideration of energy sufficiency requirements over consecutive days. Multiple long-term reliability studies indicate that the nature of reliability risks is shifting and that resource adequacy frameworks will be increasingly called upon to ensure reliability not only during average-year summer peaks but also during the winter and traditional "shoulder" seasons and across sequential-day periods of atypical weather. Hence, the failure of the Slice-of-Day framework to address long-term reliability risks and resource trends renders it out of compliance with D.21-07-014's Principle 5: that the future RA framework be durable and adaptable to a changing electric grid.

Form conducted analysis of 35 years (1980-2014) of intermittent renewable generation in order to estimate typical durations of renewable energy generation lulls, defined as periods during which actual renewable energy output was at least 25 percent below the 35-year average for consecutive hours. We found that California experiences 50-hour renewable energy generation lulls, on average, annually, and 100-hour renewable energy lulls, on average, once in ten years.[2] Any reliability assessment focused on a single 24-hour period will fail to assess the magnitude of the cumulative energy shortfall that would arise as a result of such a renewable energy generation lull or any other multi-day period of grid stress, such as that caused by a heat-wave-induced period of elevated load, fossil fuel shortages, or other infrastructure outages.

Neither the use of an increased production reserve margin ("PRM") nor of a more conservative assessment of the qualifying capacity of intermittent renewables can adequately address the shortcomings of a reliability assessment that focuses solely on 24-hour periods and ensure that the Commission is planning prudently.

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[2] *See* R.20-05-003, Opening Comments of Form Energy, Inc. on Administrative Law Judge's Ruling Seeking Feedback on Mid-Term Reliability Analysis and Proposed Procurement Requirements, March 26, 2021, p. 3-5.

A. Commission should not adopt the Slice-of-Day framework, which is not durable to long-term reliability risks, and instead commit to the development of a framework that centers multi-day energy sufficiency

While the Slice-of-Day framework represents an incremental improvement over the current RA framework, it is not well-suited to address multi-day reliability risks and hence is not durable enough to ensure reliability over the long term. Form recommends that the Commission refrain from adopting the Slice-of-Day proposal and instead commit to the development of a framework that centers the assessment of energy sufficiency over multiple days. Should the Commission adopt the Slice-of-Day framework, it must only serve as an interim solution. However, the implementation of a new RA framework entails significant administrative complexity and potential cost. Given that the procurement ordered by the Commission in the Emergency Reliability proceeding and the Integrated Resource Plan (IRP) proceeding significantly reduces the likelihood of a capacity shortfall in the near and mid-term, it is unnecessary and imprudent to rush to develop an interim framework that is not durable.

B. The Commission and LSEs should carry out analysis to assess multi-day reliability risks and develop appropriate reliability metrics and planning standards before adopting a new resource adequacy framework

In order to design a durable RA program, consistent with D.21-07-014's Principle 5, the Commission must first conduct analysis to characterize multiple emerging and long-term reliability risks and develop planning standards and reliability metrics appropriate to enable a reliable, low carbon grid. We outlined necessary analysis in both our Opening Comments on the R.21-10-002 Order Instituting Rulemaking ("OIR"),[3] and our Opening Comments on the proposed Decision Adopting 2021 Preferred System Plan in the IRP proceeding.[4] We've included key recommendations below.

The Commission should characterize emerging reliability risks including, at minimum, multi-day renewable energy lulls, multi-day periods of high demand and extreme temperature, and planned or unplanned fossil outages and their coincidence with other grid events, including renewable energy lulls and atypical weather. In assessing these risks, it is essential that the Commission consider multiple years of weather data, not only typical or average years. Form recommends that the Commission utilize 1-in-10 or 1-in-20 demand and generation profiles. The Commission should leverage an improved understanding of emerging reliability risks to assess 1) the appropriateness of various target reliability standards (e.g. loss of load hours or unserved energy) for assessing portfolio and system-level reliability and accurately capturing the impacts of

[3] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M420/K127/420127567.PDF
[4] https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M441/K160/441160042.PDF

multi-day reliability events and 2) the aggregate resource needs, both in terms of gigawatts (GW) of capacity and gigawatt hours (GWh) of energy, and reserve margins necessary to achieve a sufficient level of reliability.

While it may be more appropriate to conduct necessary analysis in the IRP proceeding, given that significant data is already in the record of that proceeding, it should be jointly noticed to this the RA proceeding and any RA framework should be designed to address the energy sufficiency risks identified therein.

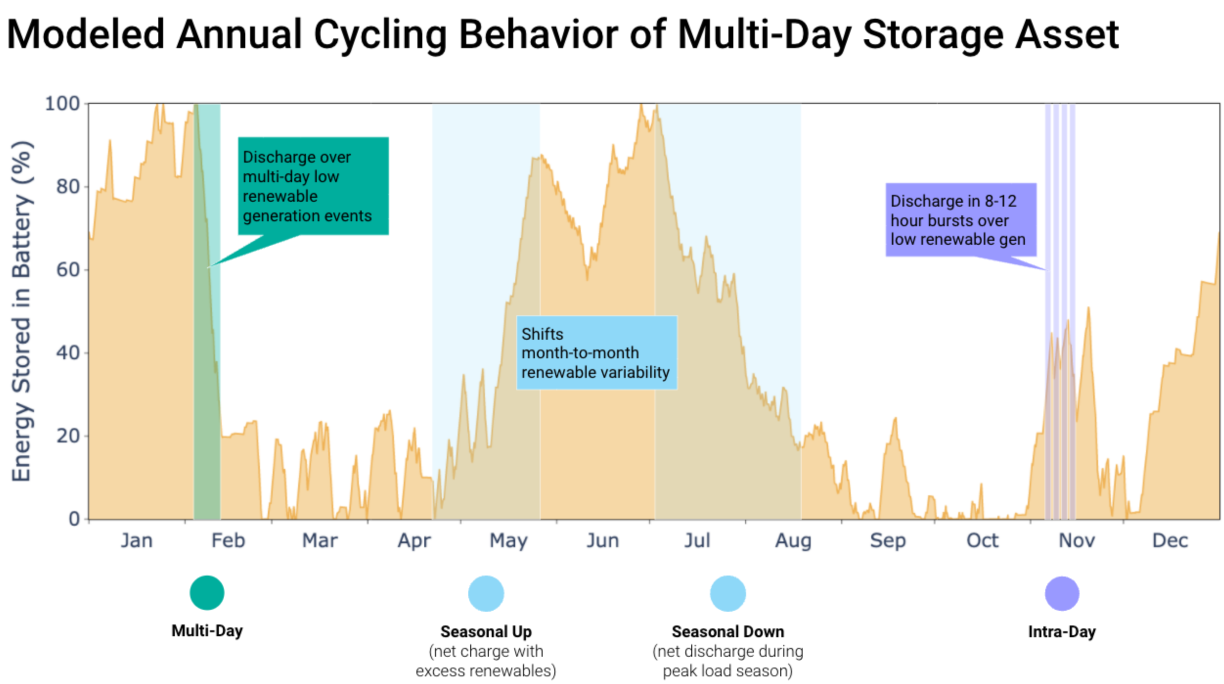
II. The proposed charging sufficiency verification methodology is incompatible with energy storage technologies with durations significantly beyond 8 hours

The Southern California Edison ("SCE") Slice-of-Day proposal, which has received support from a number of parties, would require that load-serving entities ("LSEs") demonstrate that they have sufficient excess generation capacity within a single day to fully charge energy storage systems used to meet RA requirements. This requirement is inapplicable and prejudicial to MDSsystems that can discharge at rated capacity over sequential days without having to recharge, such as Form Energy's 100-hour iron-air battery and other forms of MDS like green hydrogen. Additionally, LDES technologies with durations as short as 10-12 hours could likewise face unreasonable barriers to providing RA value if they are forced to demonstrate the ability to fully charge each day, which may not be physically possible or economically optimal.

We acknowledge and agree with SCE's underlying concern, which is to ensure that LSE portfolios can maintain energy sufficiency across multiple days, a primary value proposition of LDES and MDS. However, it is misguided to require that energy storage must be able to fully charge every day. It presupposes that the grid will only depend on short duration storage (i.e. <8-hr storage) in the mid and long-term and not LDES or MDS. It would arbitrarily create barriers to market for LDES and MDS resources that have durations far longer than 8 hours. Moreover, such an approach would lead to the uneconomic overbuilding of generating resources and, as a result, the inefficient allocation of ratepayer dollars. Hence, a single-day charging sufficiency requirement is not only fundamentally unsuited to account for the grid benefits provided by LDES and MDS–it is incompatible with RA framework Principles 1, 2, and 5 that the Commission established in D.21-07-014.

A seasonal charging scheme, as has been proposed by California Energy Storage Association ("CESA"), is a step in the right direction because it acknowledges the inappropriateness of applying a diurnal charging sufficiency requirement to LDES and MDS. However, a seasonal charging scheme also has significant limitations and represents an oversimplification of the capabilities of MDS assets.

MDS technologies like Form's 100-hour battery can operate year-round to balance seasonal, multi-day, and intra-day variability in renewables. The graph below illustrates the optimal cycling behavior of a portfolio of 100-hour batteries to minimize costs and meet reliability standards in a representative grid with high levels of renewables, as modeled by Formware™, Form's proprietary capacity expansion modeling tool.



III. Summary of Recommendations

Form does not recommend that the Commission adopt the Slice-of-Day framework in its current form, because the framework does not account for or ensure reliability over sequential multi-day periods, and thus is neither durable nor cost-minimizing. We are especially opposed to proposals that would impose a blanket diurnal charging sufficiency requirement to all energy storage assets, which would arbitrarily preclude most LDES and all MDS technologies from participating in the RA program and hence be unreasonably discriminatory. While a seasonal charging sufficiency scheme would be more appropriate than the blanket application of a 24-hour changing sufficiency requirement to all technologies, such a proposal needs further development before we can assess its reasonableness, and it should be based on an assessment of multi-day or seasonal reliability risks. If the Commission were to adopt the charging sufficiency requirement that LSEs have proposed, we recommend that energy storage technologies with duration in excess of 12 hours should be exempt.

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February 7, 2022

Green Power Institute Informal Comments on RA Slice-of-Day Workshops

The Green Power Institute (GPI) continues to support in principle the PG&E slice-of-day proposal as it is being developed in the working group process, with the proviso that it incorporates SCE's approach of using hourly profiling of monthly supply and demand curves. GPI has been a strong proponent of hourly profiling of supply and demand curves since the beginning of the Commission's RPS program. We have consistently urged the Commission to change the time-of-delivery SRAC profiling from multi-hour blocks to hourly profiling, and we apply the same reasoning here. During the hours of greatest interest from the grid reliability perspective both supply and demand are in considerable flux, and multi-hour slices cannot accurately represent either one.

Slices, Seasons, Showings

GPI has been a strong proponent of hourly profiling of supply and demand curves throughout our participation in the Commission's RA program. We are pleased to see that at this point the majority of the parties, including both SCE and PG&E, are endorsing adopting an hourly slice-of-day structure. Hourly profiling provides a sound basis upon which to move forward in the development of the slice-of-day RA framework.

In PG&E's useful Menu of Framework Options (page 3 of their 12/15/21 workshop presentation), they list four options for the number of seasons: 2, 3, 4, and 12. These are the choices that are included in the matrix of options spreadsheet, a filled-out copy of which we are attaching to these informal comments. In our November 12, 2021, informal comments, we introduced an additional option – 6 seasons. In the opinion of the GPI the proper pairing for a six-season framework would begin with January and February, and continue from there. We acknowledge that, similar to the situation with moving from hourly to multi-hour slices, going to bimonthly from monthly reporting will lose some amount of accuracy. However, we have a notion that the diminution of accuracy in going from monthly to bimonthly compliance periods is likely to be considerably less than going from hourly to block-hour profiling.

There is an insufficient record to recommend adopting bimonthly reporting at the present time. The GPI is suggesting that studying bimonthly compliance in order to quantify the loss of accuracy vs. the gain in simplicity would be a worthwhile exercise to conduct for purposes of continuing to develop the overall Slice-of-Day concept. We are certainly comfortable with moving forward with monthly compliance periods, if that is the preference of the working group. We certainly do not endorse using fewer than six compliance periods.

Going to monthly or bimonthly seasonal groupings does not preclude reducing the frequency of the requirement for making RA showings. The GPI recommends considering quarterly RA showing filings if monthly or bimonthly compliance periods are adopted. Projecting a couple of months ahead should not represent an impediment to the rapid penetration of new technologies into the system.

One of the most compelling reasons for incorporating hourly profiling into the slice-of-day framework is because of its superior treatment of storage and hybrid resources. Storage resources are fundamentally different than generating resources. In the current RA paradigm storage is required to have a four-hour discharge time in order to count as an RA resource. In a slice-of-day framework with hourly profiling storage resources of almost any discharge time could be able to contribute to an LSE's showing, as long as both their charge cycles and discharge cycles are accurately represented in an LSE's system showing. Similarly, hourly profiling provides a superior platform for hybrid resources that include intermittent renewables coupled to storage on the same side of the meter. We note that SCE's presentations to the working group on storage resources gave short shrift to hybrid resources. In the opinion of the GPI hybrid resources should be handled as an integrated unit based on the net 24-hour output profile from the integrated hybrid system through a single meter to the grid.

Load Forecasts and Planning Reserve Margins

The topics of load forecasting and Planning Reserve Margins (PRMs) have been treated as largely separate matters in the workshops, but in the opinion of the GPI the two topics are intrinsically linked and should be treated as such. The weather event that triggered the California grid emergency in the summer of 2020 has been characterized as a 1-in-35 event, which is well outside of the worst-case planning conditions that the Commission uses or is considering using in setting annual RA requirements. In a sense, the 2020 summer event, which fell well outside of the planning standards, should have been expected to cause outages. It was, in fact, beyond what the planning standards were designed to handle.

Many parties have pointed out that for purposes of ensuring greater system reliability, the PRM is easier and quicker to manipulate than the load forecast. As a result, several proceedings, including the IRP, the severe weather reliability proceeding, as well as this proceeding have gone to various lengths to increase the PRM beyond the currently official 15 percent. We acknowledge that for purposes of increasing system reliability, the PRM is easier to manipulate for making short-term adjustments than the underlying load forecast. Nevertheless, it is our opinion that the real problem with respect to our preparedness for grid emergencies is not that the PRM is too low. Rather, it is a result of using an underlying planning load forecast that is too low. In future years we suggest using a more stringent planning standard to determine the load forecast that will form the basis for RA requirements, and reserve using the PRM for short-term fluctuations of all kinds on the grid. We note that the underlying load forecast also has to be adjusted to take into account changing weather conditions due to ongoing climate change.

Top Down vs. Bottom Up Supply and Demand Forecasting

SCE's presentation to the December 1, 2021, slice-of-day workshop looks for a "middle ground" between a purely top-down allocation of RA requirements based on the total system load profile, and a bottom-up allocation based on aggregating from the LSE-specific profiles to produce a system-level profile. The CEC hybrid proposal also seeks a middle ground that combines both top-down and bottom-up information. The GPI agrees with the CEC that both approaches, top-down and bottom-up, should be used in the RA needs determination and allocation of obligations.

We note that the IRP proceeding, R.20-05-003, has initiated each of the first two IRP cycles by performing top-down modeling of the CAISO control area to generate control-area reference portfolios. This has been followed by having each IOU construct an LSE-specific portfolio, the complete collection of which are then aggregated and adjusted to determine a final Preferred System Portfolio. In the opinion of the GPI, this sequencing of supply and demand forecasting provides a useful model for the needs determination and obligation allocation that needs to be conducted as part of the slice-of-day framework implementation.

With respect to the proposals that are currently on the table, GPI thinks that there is an easier way to incorporate the kind of LSE-specific information that a bottom-up allocation affords than the one proposed by SCE. In our envisioned framework, which, as far as we can see is compatible with the approach suggested by the CEC, each LSE should submit their projected monthly load shapes and sizes to a responsible analyst, who would construct a composite systemwide load curve for each month. The system load specifications and PRM would then be imposed, and the final RA obligation allocations would then be made according to the adjusted modeled composite load profiles of the individual LSEs.

Resource Counting

Resource counting rules for schedulable resources, including baseload renewables, is a relatively straightforward matter. The counting rules to be applied to intermittent resources engender considerable disagreement. The working group has been presented with several different methodologies for counting the RA contributions of intermittent resources, including exceedance, average or incremental ELCC, and other alternatives. We have attempted to evaluate the alternatives, and while it is our opinion that it is still premature to make a final determination on methodologies to use for intermittent resources, we are intrigued by the effective net load reduction approach advanced by CalWEA. In the opinion of GPI, resource counting for intermittent resources is one of the issues that needs continuing development beyond the completion of this phase of the working group process.

Conclusion

There are many aspects of the PG&E slice-of-day proposal that appear to be attracting widespread group agreement, including using hourly profiling of load curves and monthly (or bimonthly) seasons, inclusion in the profiles of consideration of charging requirements for storage, and use of gross vs. net demand curves. Other aspects of the proposal still need additional development

This completes our informal comments on the nine workshops in the RA proceeding to explore further development of PG&E's slice-of-day proposal. We look forward to the ongoing progress of the process.

Gregg Morris

Gregg Morris
Director, GPI

Informal Comment on all topics from the RA Framework Working Group Process
R.19-11-009 and R.21-10-002
February 7, 2022

Golden State Clean Energy ("GSCE") appreciates the effort of all the parties involved in the Resource Adequacy Framework Working Group Process and their attention to the urgent need to evolve the RA program. GSCE offers a limited comment for this final informal comment opportunity in support of the inclusion of an energy sufficiency requirement within the RA program to demonstrate that storage has sufficient energy supporting it.

GSCE supports an energy sufficiency requirement for storage for the following reasons:

- An energy sufficiency requirement creates a more durable framework.
  - Durability was one of the five principles the Commission considered when it evaluated RA restructuring in the June decision.
  - One of the primary reasons for not including energy sufficiency in the RA program is that there is currently sufficient energy in the system and energy insufficiency is not expected in nearer-term planning horizons.
  - However, it is not a sustainable approach to RA to exclude energy sufficiency simply because California does not expect energy sufficiency issues in the near-term.
  - Considering that an unprecedented amount of storage is expected to be deployed in California and that storage will play a crucial role in the future of RA, a more durable RA program design would ensure storage has sufficient energy supporting it and not take energy sufficiency for granted.
- RA requires resources to be under contract, and this requirement should extend to resources providing the energy supporting non-generator RA resources.
  - Some arguments against an energy sufficiency requirement rely on there being sufficient energy in the system, regardless of the generating resources' contract status or performance obligations. However, RA has historically ensured reliability by contractually obligating sufficient resources to bid into CAISO markets, ignoring the potential for economy energy to serve load even when there is a high probability that such energy will be available.
  - By not including energy sufficiency as an RA program feature, storage can rely on the market to provide the energy that is stored to eventually serve load.
  - It seems incongruent with the history of RA to design a program that allows storage resources to provide RA while storage is reliant on charging from resources without an RA obligation.

    - Storage's energy needs should be viewed as an extension of RA storage resources. Without energy backing storage, storage cannot support reliability.
    - If energy sufficiency was required, there are still questions as to whether a must offer obligation would be required for resources providing energy sufficiency. Nonetheless, RA should at least plan for sufficient energy to ensure it is procured. This can be roughly compared to the current MCC buckets, which are not binding and yet still provide an important check on the RA program.
    - Other planning exercises like the IRP should also help ensure energy sufficiency, but relying on this still seems to miss the operational aspect of a must offer obligation and be incongruent with the history of RA.
- Solar will continue to play an important role in the future of RA despite declining marginal ELCC values, and this role should be accurately reflected.
    - Some concerns with energy sufficiency seem to be that such a requirement will create an incentive for solar in the RA market, and that this signal is inappropriate because of solar's declining marginal ELCC value.
    - This argument seems to unfairly target solar and prevent it from being properly valued.
    - Solar's energy production is still expected to support non-generator RA resources by providing the affordable energy that storage will store and discharge during hours with a greater risk to reliability. This is irrespective of the fact that solar's capacity may be decreasingly supporting net peak demand.
- Allowing batteries to cycle twice in a day furthers the need to have sufficient energy.
    - There are a number of questions surrounding the proposal to allow batteries to count for two cycles in one day. GSCE does not comment on cycling broadly.
    - We do see an issue with allowing batteries to count for two cycles in one day if the RA program does not consider when storage plans to charge and from what resources. An energy sufficiency requirement would provide an important check on the ability for storage to fully discharge twice in a day.

Again, we thank the parties that have taken the time to present during the working groups and appreciate those that have led administratively in managing this process.

Dated: February 7, 2022
Respectfully submitted,

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INDEPENDENT ENERGY PRODUCERS

Informal Comments on RA Reform Workshops

February 7, 2021

INTRODUCTION

In these comments, the Independent Energy Producers Association (IEP) provides a comprehensive overview of our positions on all topics that have been discussed during the resource adequacy (RA) reform workshops. While our positions on the topics covered in workshops 1-7 remain unchanged from our previous rounds of informal comments, following the guidance provided by the workshop co-facilitators, we first provide a summary of our positions on all issues and then discuss the issues raised in workshops 8 and 9 (hedging, Unforced Capacity (UCAP), and multiyear forward requirements) in more detail in a subsequent section.

OVERVIEW OF POSITIONS ON ALL TOPICS

Number of Compliance Slices

IEP supports the framework presented by Gridwell, which focuses RA procurement and compliance showings on the only hours that are expected to have a high loss of load expectation (LOLE) for the foreseeable future: the gross peak and net peak. While production cost modeling results presented at the September 1, 2021 Integrated Resources Planning (IRP) workshop showed small quantities of expected unserved energy in winter mornings in 2030 (a 7 MWh shortfall across the entire CAISO territory),[1] it is unknown whether that shortfall persists after improvements in the storage dispatch algorithm were found to reduce the LOLE of the 2030

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[1] "Integrated Resource Planning (IRP) Proposed Preferred System Plan Analysis," slide 56. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2019-2020-irp-events-and-materials/psp-workshop-slides.pdf

portfolio by nearly a factor of 100.[2] Limiting compliance activity to the hours of concern aovids the need for LSEs to demonstrate adequate capacity during the large majority of hours that have zero LOLE.

The main objection that has been raised to a two-slice compliance obligation is that it fails to address energy sufficiency for charging energy storage systems. IEP disagrees with that assessment of Gridwell's proposal. As we discuss in the resource counting section below, the framework advocated by Gridwell accounts for energy sufficiency by the use of Effective Load Carrying Capacity (ELCC) as the net qualifying capacity methodology for variable energy resources and storage.

Seasonal vs Monthly Compliance Obligations

IEP supports Gridwell's original proposal to shift from monthly RA obligations to a two-season obligation, which would reduce the administrative burden on Commission, CAISO, load-serving entity (LSE), and California Energy Commission (CEC) staff, particularly when paired with the two-slice approach. A two-slice/two-season framework results in only four hours per year that require LSE-specific load forecasts, preparation of compliance documentation, and verification by the Commission and CAISO. If long-term modeling indicates that other times of day face an impending reliability challenge, additional slices or seasons can be added to the framework.

The primary reason that some parties have offered in support of retaining monthly compliance periods is that they allegedly save ratepayers money by allowing LSEs to procure marginal capacity only for the months when it is needed. However, as stated in IEP's previous informal comments:

> IEP doubts that monthly compliance actually yields significant, if any, savings. In theory, generation and storage facilities will price their *annual* fixed costs into their capacity bids, with the expectation that they will recover variable costs in energy markets. Compressing the duration of a capacity contract simply forces generators to increase their kW/month bids to recover their costs over a shorter timeframe. Generators do not avoid fixed costs during the months they lack RA contracts.[3]

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[2] Proposed Decision Adopting 2021 Preferred System Plan, p. 102.

[3] IEP. Informal Comments on RA Reform Workshops 1-7, p. 3.

For this reason, IEP questions whether the administrative burden of monthly compliance obligations yields a countervailing benefit.

Resource Counting

IEP favors the Gridwell framework largely because it allows for the continued use of ELCC to attribute capacity value to variable energy resources, storage and other use-limited resources.[4] ELCC makes sense under the two-slice proposal because the framework measures sufficiency during single points in time with a critical need, gross load peak and net load peak, and works in conjunction with the appropriate planning reserve margin (PRM) to maintain a 0.1 LOLE. Compared to exceedance and Pmax value approaches, ELCC is a more sophisticated, probabilistic method for attributing capacity value to variable and use-limited resources that captures their contributions to reliability throughout the year. Moreover, deriving capacity values from the production cost models used to calculate the reliability metrics of the total LSE portfolios better reflects variable and use-limited resources' contributions to reliability under a wide range of conditions and aligns the capacity values with the model results for the entire portfolios.

Gridwell's proposal has been criticized for not including a specific check to verify energy sufficiency for charging storage. However, the lack of an explicit charging sufficiency check is not tantamount to simply assuming that there will always be sufficient energy for charging. Although no analysis has been presented demonstrating a foreseeable shortage of charging energy, to the extent this ever emerges as a reliability constraint, the ELCC for storage will decline and the ELCC for solar and other resources that can provide charging energy will increase. These tendencies will appear in long term analysis of the integrated resources planning (IRP) proceedings and additional new procurement will be directed to ensure such shortages do

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[4] IEP supports transitioning from an average ELCC framework to either a vintaged marginal or delta ELCC. Both methodologies are described in N. Schlag et al., "Capacity and Reliability Planning in the Era of Decarbonization: Practical Application of Effective Load Carrying Capability in Resource Adequacy," Energy and Environmental Economics, Inc., 2020. https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf Analysis of the capacity value of the resources LSEs were ordered to procure in the IRP Mid-Term Reliability decision relied on the delta ELCC method. See https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20211022_irp_e3_astrape_incremental_elcc_study_updated.pdf

not occur. The Gridwell proposal works in concert with those incremental ELCC values of new resources to ensure reliability for all hours of the year.

For dispatchable thermal resources, IEP supports the use of a UCAP-light methodology that derates facilities' summer month capacity ratings for ambient temperature effects but not for other categories of forced outages. IEP has significant concerns about the impact of forced outage derates on facilities that invest in measures to improve availability, which we elaborate on in the section below with our detailed comments on workshop 8 and 9 topics.

Regardless of the relative advantages or disadvantages of ELCC or exceedance/Pmax resource counting methodologies, the Commission has two other regulatory tools to ensure sufficiency of energy resources for storage charging. The Renewable Portfolio Standard creates a floor for the amount of additional wind, solar, and other renewable resources that all LSEs will be required to procure through 2030. Additionally, under the IRP framework, the Commission can order LSEs to procure specific quantities of solar, baseload, or dispatchable renewables that long-term analysis demonstrates are necessary for energy sufficiency.

If the Commission ultimately adopts the 24-hourly slice framework for RA, ELCC-based resource counting methodologies are incompatible because they return a single value that represents a generalized estimate of a resource's capacity value during all hours of the time period in question (month, season, or year). For a 24-hourly slice framework, variable and daily use-limited resources require capacity valuations at an hourly level of granularity. For variable resources, an exceedance approach, or similar methodology, is an appropriate choice. The methodology described by Pacific Gas and Electric Company (PG&E) is a good starting point, but IEP is concerned that looking only at five days (one peak day per month over the last five years) of historical production data to calculate the hourly exceedance values for each month provides an insufficient sample size. IEP suggests using the top three to five peak demand days for each month to yield a more robust sample size. Given the lack of details necessary to implement an exceedance methodology for the 24-hourly slice framework, IEP agrees with SCE that another implementation phase of the RA proceeding may be required if the 24-silce approach is adopted, which would delay implementation of a new RA framework until 2025, thereby not meeting the Commission's goal of timely implementation.

Under SCE's framework, resource counting for energy storage should allow LSEs to count the storage up to Pmax in any hour, subject to the energy capacity of the storage system and the facility's interconnection limits. Similarly, the capacity value of hybrid and co-located resources should use the same methodology for the storage component with any excess capacity above the level needed to charge the storage system converted to its own capacity value by applying an exceedance profile to the excess capacity.

Hedging

IEP opposes hedging *requirements* as a condition for a generator or storage facility to receive an RA contract. Vistra Corp's (Vistra's) presentation at the hedging workshop reflects IEP's view that concerns about market power should be addressed through CAISO's market power mitigation process.[5] Moreover, as PG&E noted in its presentation on hedging, it has already executed two contracts with the quasi-tolling arrangement it refers to as the "variable price hedge."[6] If PG&E has executed such contracts, other LSEs are free to do so as well, if they find that the variable price hedges (or price cap rebates) are the most effective strategies for reducing their exposure to wholesale energy price risk. Before the Commission makes any decision regarding hedging requirements, Energy Division should gather more data to determine if a problem exists, and if so, the magnitude of the problem, and the strategies that various LSEs are already employing to hedge their exposure to high wholesale energy prices.

Multiyear Forward RA Requirements

Multiple analyses of long-run low-GHG portfolios conducted by the Commission and sister agencies have recognized the need to retain existing thermal capacity to ensure reliability over the next 20 to 30 years, even in a highly decarbonized future. However, with only a one-year forward requirement for system RA, generators outside of Local Reliability Areas lack the financial certainty to make the substantial investments that may be needed to keep plants running over the longer-term. IEP and the Western Power Trading Forum propose a minimum three-year forward requirement for system RA that aligns with the three-year forward requirement the Commission has already adopted for local RA. A three-year forward requirement will lead to

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[5] Vistra. Slice of Day Workshops: Hedging Component, slide 9. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-8-vistrar1911009-r2110002vistra3b2-workshop-hedging.pdf

[6] PG&E. RA Reform: Hedging, slide 9. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-8-pge_ra-reform---hedging-workshop.pdf

longer-term contracting, which will provide greater certainty for RA market participants, which in turn will lead to lower, more stable prices for RA capacity. A three-year forward requirement also allows for more orderly retirement of resources by sending earlier signals to marginal generators whose capacity is no longer needed. Under the CAISO tariff, RA resources may submit a notice of intent to mothball or retire a unit the following year as long as the notice is submitted in the first quarter of the current year.[7] Such notice triggers a reliability assessment by CAISO, which may lead to a Reliability Must Run designation for the facility. Incentivizing generators to submit notices earlier would give LSEs more time to secure alternative sources of RA capacity and could reduce reliance on RMR designations.

DETAILED COMMENTS ON ISSUES RAISED IN WORKSHOPS 8 AND 9

Hedging

During workshop 8, PG&E presented two hedging options: Price Cap Rebate and the Variable Cost Hedge. In essence, the Variable Cost Hedge is a quasi-tolling arrangement that requires facilities with an RA contract to rebate all earnings from the energy markets in excess of plant-specific variable operations and maintenance costs. The Price Cap Rebate is a similar, but simpler, version that requires generators with RA contracts to rebate energy market earnings that exceed a predetermined threshold in any given hour. For illustrative purposes, PG&E suggested a threshold of $400/MWh.[8]

IEP objects to requiring hedging provisions in RA contracts for several reasons. First, market reforms and the creation of CAISO's Department of Market Monitoring (DMM) have resulted in highly competitive energy markets where there is no evidence of market manipulation, even when markets are tight. The DMM, whose mission is to monitor the competitiveness of the wholesale energy market and recommend market power mitigation mechanisms, stated in its most recent annual report that "The performance of California's

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[7] CAISO Fifth Replacement FERC Electric Tariff, Section 41, p. 4. http://www.caiso.com/Documents/Section41-Procurement-RMRResources-asof-Sep28-2019.pdf

[8] PG&E. RA Reform: Hedging, slides 7, 10, and 11.

wholesale energy markets remained competitive, with prices during most hours at or near the marginal cost of generation."[9] DMM further explained that:

> Actual market prices were very close to these [DMM's] estimated competitive baseline prices, even during the heat wave period of August 14 to 19, indicating that replacing high-priced energy bids with cost-based bids did not lower prices. Resources that may be subject to mitigation, such as gas-fired and other resources, were generally infra-marginal during high-priced hours. When performing day-ahead market reruns using cost-based bids, high prices were set by demand response and other resources not subject to mitigation. System-wide mitigation of imports and gas-fired resources during this period would not have lowered prices.[10]

Based on the DMM's analysis, and no finding by the Commission to the contrary, IEP is not convinced that a problem has been identified that would be resolved by mandatory hedging mechanisms in the RA program.

Second, LSEs already have a variety means at their disposal to hedge their exposure to high market prices. As PG&E stated in its presentation, it has already negotiated some contracts with a Variable Cost Hedge, which indicates that other LSEs are capable of negotiating similar contracts with willing generators. The hedging proposals described by PG&E aren't necessarily the only, or best, hedging strategies for all LSEs. No evidence or analysis has been provided that LSEs are generally failing to hedge their wholesale price risks, and requiring the use of one specific mechanism would crowd out other strategies that some LSEs may prefer. Third, the Energy Division acknowledged during the hedging workshop that it had not yet requested data on LSEs' hedging practices, which indicates that more information gathering and analysis are needed before a determination can be reached that any specific hedging requirement is necessary or desirable.

IEP strongly recommends that Energy Division's analysis consider offsetting effects of mechanisms that require generators and storage operators to transfer energy market earnings to their LSE counterparties. If market participants earn less from energy markets, they will likely compensate for this loss by increasing capacity bids. An analogous phenomenon occurs in the

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[9] DMM. 2020 Annual Report on Market Issues and Performance, p. 90. http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

[10] DMM. 2020 Annual Report on Market Issues and Performance, p. 90.

health care market, in which lower insurance deductibles are generally associated with higher insurance premiums. Simply looking at the decrease in deductibles cannot guarantee that overall costs would go down.

Unless detailed analysis can be provided, and workshops scheduled, quickly enough to allow more informed hedging deliberations to occur in parallel with the implementation of broader RA reform, IEP supports SCE's recommendation to consider hedging in a separate phase of RA reform implementation. As SCE argued in comments on the proposed decision on Track 3B2: "the issues mentioned in the PD may conflate LSE hedging and market power mitigation, which raise separate concerns and potential solutions, and that these are complicated topics that will take significant time to resolve and may distract from developing the other implementation details of the final proposed RA framework."[11] IEP concurs with SCE's sentiment that deferring consideration of hedging requirements "would also allow the discussion to benefit from the information collected by Energy Division on LSE hedging…"[12]

Multiyear Forward Requirements

During Workshop 9, IEP and WPTF presented our joint proposal for multiyear forward requirements. We suggest that the RA rules require LSEs to contract for 100% of their system RA requirements for one and two years forward, with an indeterminate level set for the third year forward. While we did not offer a specific percentage, we noted that the requirement would need to be relatively close to 100% to have any material impact on sending either retirement or investment signals to generators.

IEP and WPTF note several advantages to longer forward requirements. First, three-year contracts allow facilities to amortize major investments over a longer timeframe and provide plant operators more certainty about recouping those investments. The greater certainty afforded by multiyear requirements will help to avoid premature retirements of facilities needed for reliability when confronted with the need for such investments. Stimulating investments in plant availability may also help to avoid RMR designations from CAISO for facilities deemed critical for reliability. Second, multiyear requirements can incentivize LSEs to invest in incremental new

[11] SCE Opening Comments on Track 3B.2 PD, p. 8.

[12] SCE Opening Comments on Track 3B.2 PD, p. 9.

capacity at a steady cadence, rather than relying on sporadic procurement orders from the IRP process. Third, while multiyear forward requirements may help to retain existing capacity that has rolled off long-term contracts, it may also help to facilitate more orderly retirement of assets that are no longer needed. Facilities that fail to secure a contract two and three years ahead may decide that the facilities are no longer competitive and file notices of intent to retire or mothball the facilities with longer lead time than they would have otherwise. Finally, multiyear requirements will ensure that California LSEs secure sufficient capacity further into the future as supply conditions tighten across the West.

IEP and WPTF noted that other jurisdictions, such as PJM and ISO-New England (ISO-NE), have three-year forward requirements. Since those regions use centralized capacity markets, PJM and ISO-NE are the counterparties. Even though contracts are procured three years ahead, costs are allocated to LSEs based on prior year contributions to peak load. Because LSEs do not contract directly with generators, they do not face an overprocurement risk as load shapes or markets shares change. In California, LSEs may be significantly long or short on capacity due to load migration between the time forward contracts are executed and the RA compliance year. The Commission and stakeholders may consider mechanisms to facilitate assignment of contracts to other parties or consider allowing LSEs to swap load obligations on a bundled monthly or annual basis, not disaggregated by hour or slice. IEP also observes that over- or underprocurement risk is not completely absent under the current RA and IRP constructs. In D.21-06-035, the Commission ordered all LSEs to procure incremental capacity up to five years forward on the basis of their anticipated future load shares.

Unforced Capacity (UCAP) for Thermal Resources

IEP does not support the use of UCAP to establish the qualifying capacity of thermal generators. Although IEP understands the impetus to motivate plant operators to achieve high availability rates by adjusting plant-specific qualifying capacity to reflect plant-level performance data, IEP has strong reservations that implementing UCAP as proposed would punish plants that have made significant investments to improve performance. CAISO proposes that the Commission base thermal generators' qualifying capacity for a given year on plant performance data during tight supply conditions in the three prior years. Specifically, CAISO would base the qualifying capacity on an average of prior years' availability factors with weightings of 45% for Year -1, 35% for Year -2, and 20% for Year -3.[13] If UCAP were adopted as CAISO proposes, a plant that experiences a major failure and then makes substantial investments in plant maintenance to improve performance would suffer a diminished capacity value for three following years after coming back online.

During the workshop, one participant suggested that in order to avoid this perverse outcome, certain types of investments could allow a plant to reset its UCAP baseline as if it were a new plant. CAISO suggested that new facilities would be rated at their full deliverable capacity in their first year of operation. In the second year of operation, UCAP capacity would be weighted at 70% of first year availability and 30% of deliverable capacity. By the fourth year of operation, a new facility's qualifying capacity would be based on the three prior years' performance, the same as any other plant.[14] If the Commission ultimately decides to adopt UCAP, the methodology must recognize major plant investments to improve availability. It will also be important to exempt certain outages due to factors beyond operators' control. CAISO listed several factors that would and would not be included in the UCAP calculations, but other factors, such as curtailments of gas delivery, may need to be added.[15]

CONCLUSION

Both of the broad frameworks that have emerged as the primary contenders for a new RA regime are feasible and can adequately address California's system-level reliability challenge as the primary hours of concern shift to the net peak. However, IEP has highlighted several advantages to Gridwell's two-slice approach: the use of more sophisticated resource counting methodologies, administrative efficiencies, and superior transactability. In addition to adopting substantive reforms to the RA framework, implementation of a multiyear forward requirement would further enhance the ability of the RA program to ensure the continued reliability of California's electric system.

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[13] CAISO. Unforced Capacity Evaluation Proposal, slide 24. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-9-ucap-proposal_caiso.pdf

[14] CAISO. Unforced Capacity Evaluation Proposal, slide 26.

[15] CAISO. Unforced Capacity Evaluation Proposal, slide 21.

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Joint Informal Comments on the Resource Adequacy Frameworks Working Group Process of the Natural Resources Defense Council, the Center for Energy Efficiency and Renewable Technologies, the California Energy Storage Alliance, the Solar Energy Industries Association, the Large-scale Solar Association, American Clean Power – California, the California Efficiency + Demand Management Council, the California Large Energy Consumers Association, Southern California Edison, and Pacific Gas and Electric

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Resource Adequacy Proceedings R. 21-10-002 and R.19-11-009, February 7, 2022

The Natural Resources Defense Council ("NRDC"), the Center for Energy Efficiency and Renewable Technologies ("CEERT"), the California Energy Storage Alliance ("CESA"), the Solar Energy Industries Association ("SEIA"), the Large-scale Solar Association ("LSA"), American Clean Power – California ("ACP-CA"), the California Efficiency + Demand Management Council ("CEDMC"), the California Large Energy Consumers Association ("CLECA"), Southern California Edison ("SCE"), and Pacific Gas and Electric ("PG&E"), collectively the "Joint Parties," appreciate the opportunity to provide joint informal comments on the Resource Adequacy ("RA") Frameworks Working Group Process.

In these comments, Joint Parties reiterate their support for the 24-slice, 12-month Slice of Day framework ("Hourly Framework") originally presented by Southern California Edison,[1]

[1] 24-Hourly Slices Presentation, Southern California Edison, October 6, 2021. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-2-sce_ra-framework-presentation-final.pdf

supported by Pacific Gas & Electric, and refined through stakeholder input through the workshop process. The Joint Parties represent a broad set of market participants and stakeholders, including the state's two largest Load Serving Entities (LSEs), trade associations representing the renewables, storage, and demand response industries, and environmental advocacy groups. The Joint Parties represent a diversity of market and policy interests, and bring extensive expertise related to reliability and resource planning, market design, commercial transactions, and legal and regulatory policy relevant to RA structural reform.

While individual parties have unique perspectives on implementation details, Joint Parties are aligned in their support for the core tenets of the Hourly Framework as the best path forward for the evolution of the RA program. The Hourly Framework is a refined evolution of the Slice of Day framework directionally adopted in D.21-07-014, which would:

- Provide a more robust and adaptable reliability structure that can address a wide range of future grid conditions and emerging reliability needs;
- Be iteratively calibrated and managed using industry standard reliability analysis to mitigate both reliability and overprocurement risk;
- Facilitate more effective participation of preferred resources through the explicit representation of hourly dynamics and storage charging requirements;
- Reduce barriers to demand-side management and distributed resource participation in the RA program through the use of LSE-specific load shapes;
- Support near- and long-term resource planning by individual LSEs as a linkage between the RA and Integrated Resource Planning processes; and
- Retain many key elements of the current program, including a bilateral marketplace, resource transactability, and existing CAISO market participation rules.

The Joint Parties support a managed, thoughtful transition to the new RA framework, with an emphasis on minimizing disruption to existing contracts and on-going procurement, and a strong emphasis on the role of probabilistic reliability modeling as a key input to program calibration and robustness. The Joint Parties look forward to working with Energy Division and parties on continued calibration of the final RA framework, and submit the attached consensus principles to guide program implementation.

RA Slice of Day Coalition Principles[2]

Summary Position: Support the 24-slice, 12-month Slice of Day Framework ("Hourly Framework") approach as the best path forward to ensure reliability, maximize the ability of preferred resources to provide RA capacity commensurate with their operational capabilities, and properly align reliability incentives for LSEs.

1. **Structural Elements:**
   a. **Framework:** Adopt the Hourly Framework with hourly capacity and storage charging sufficiency checks
   b. Showing: Single monthly showing of resources (not 24 hourly showings)
   c. Must Offer: Maintain compatibility with CAISO market operations and CAISO Must Offer Obligation rules
2. **Resource Counting:**
   a. **Variable Energy Resources:** Assign variable renewable resources a month-hour profile in a manner:
      i. Commensurate with expected availability
      ii. Transparent and accessible to stakeholders
      iii. Inclusive of technology and geographic diversity
      iv. Which recognizes the unique characteristics of hybrid resources
   b. **Storage and DR:** Assign storage and DR efficiently across hours consistent with their capabilities
   c. **Conventional Resources:** Assign conventional resources counting characteristics commensurate with their operational characteristics
   d. **Transition:** Minimize disruptions when transitioning resources to new counting methodologies
3. **Need Determination and Allocation:**
   a. Load: Use LSE-specific load shapes
      i. Establish avenues for greater participation of BTM / DSM load modification technologies and approaches
   b. **PRM:** Determine PRM annually / biennially informed by LOLE analysis through the IRP
4. **IRP Integration:**
   a. Incorporate RA test into LSE IRP filings
   b. Use IRP submissions for annual or biennial calibration

5. **Transactability:**
   a. Each RA resource will have all relevant slices bundled with the resource
   b. Maintain the ability to trade RA capacity, including a pro-rata share of an RA resource
   c. Respect the terms of existing PPAs between power suppliers and LSEs

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[2] The coalition principles were presented at the 12/15/21 stakeholder workshop on behalf of: The Natural Resources Defense Council, the Center for Energy Efficiency & Renewable Technologies, Vote Solar, the Solar Energy Industries Association, the American Clean Power Association, the California Efficiency + Demand Management Council, and Southern California Edison.

Respectfully submitted,

Dated: February 7, 2022

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February 7, 2022

The Long Duration Energy Storage Association of California Informal Comments on the Resource Adequacy Framework Workshops

Introduction:

The Long Duration Energy Storage Association of California (the LDESAC) respectfully submits these informal written comments on the Resource Adequacy (RA) Framework Workshops. These informal comments are submitted pursuant to instructions from the RA Framework Working Group. In addition, the LDESAC has completed the Party Position Matrix which is being served concurrently with these Informal Comments.

Background:

The LDESAC represents a diverse mix of long-duration energy storage (LDES) technologies, and its members offer products and services along every stage of the value chain, from invention to design, engineering, manufacturing, project development, and full-scale renewables integration.[1]

The LDESAC storage technologies currently include pumped hydro, compressed air, liquid air, zinc-air batteries, flow batteries, flywheels, thermal batteries, concentrating solar thermal power, electrolytic hydrogen, and repurposed gravity wells. These technologies can be deployed in projects ranging from a few hundred kilowatts to several gigawatts. Some involve site-specific applications, while others can be deployed virtually anywhere. Some, such as pumped storage and concentrating solar thermal, are fully mature and have been commercially deployed around the world for decades, while others like liquid air and zinc, are only now becoming commercially available and require strong public support to advance their deployment.

Informal Written Comments on the RA Framework Workshops:

Over the last several months, the RA Framework Working Group has held Working Group Meetings and will be submitting a Final Working Group Report in February 2022. On December 17, 2021, the RA Framework Workshop focused on energy storage counting. The LDESAC presented at

[1] Our membership includes 247Solar, 7Skyline, Cat Creek Energy, Cupertino Electric, E-Zinc, GE Renewables North America, GreenGen Storage, Highview Power, Hydrostor, H2B2 USA, McMillen Jacobs Associates, Morse Associates, NextEra Energy Resources, RedoxBlox, Renewell Energy, Stantec and Zinc8 Energy Solutions.

the Energy Storage Counting Workshop and submitted Informal Comments on that Workshop on December 21, 2021.

The LDESAC reiterates its position taken in the December 21, 2021 Informal Comments and urges the current RA framework to be modified to provide full capacity accreditation for LDES which is already being provided for four-hour storage resources. The LDESAC recommends that the Working Group Final Report include this recommendation.

The RA metrics must be amended to include and account for the capacity benefits provided by LDES. LDES provides numerous benefits which include that these resources have a long-lasting state of charge, provide grid flexibility, and provide clean firm power. There are also a diverse set of technologies that can meet local and system wide needs. Furthermore, LDES bridges the gap from four-hour battery storage to eight-hour storage technologies and LDES can meet value during multiple hours and days, as well as seasonally.

The current RA framework does not provide additional capacity credits for increased dispatch capability for storage resources that can dispatch at maximum capacity for greater than four hours. As a result, load-serving entities (LSEs) lack incentives to procure resources with durations above four hours. In order for LDES to be deployed at scale and participate in the transition to a carbon-free grid, there must be a reform to the current RA construct.

As such, the LDESAC recommends that the RA framework be modified to do the following:

- Provide an attribute-based definition of LDES and inclusion in resource counting.
- Be transactable and financeable for LDES and provide certainty.
- Transition to reflect the hours of grid constraint to fully value resources that can significantly contribute to reliability despite energy- or use-limitations.
- Value energy storage as a function of the "size of the tank" (i.e., MWh) and the asset's cycling capability.

The LDESAC is committed to continue to work with other stakeholders to advance this important resource.

February 7, 2022

Sincerely,

/s/ Julia Prochnik
Julia Prochnik
Executive Director
Long Duration Energy Storage Association of California

cc: Service Lists in R.19-11-009 and R.21-10-002

MegaWatt
Storage Farms

Informal Comments of MegaWatt Storage Farms, Inc. on RA Slice-of-Day Workshops

These are the informal comments of MegaWatt Storage Farms, Inc. for the final round of the series of Resource Adequacy (RA) Reform workshops discussing the slice-of-day proposal and held under CPUC **R.19-11.009** and **R.21.10.002**, in accordance with decision **D.21-07-014**.

The workshops provided an excellent opportunity for detailed discussion regarding the slice-of-day proposal for RA. We believe there are a number of issues that still need to be addressed. In Part 1, we discuss general issues. In Part 2, we discuss certain storage specific issues.

1. Reforming RA for a High Intermittent Renewables, High Storage Grid

To achieve zero carbon, CA is transforming its grid from a fully-dispatchable, large-centralized-generation grid, to a grid with large amounts of locally distributed intermittent renewables and large amounts of storage. This profound transformation needs to be done while maintaining 1-in-10 reliability.

We are at a key point in this transition because of the rapidly growing use of storage. The August 2020 grid problems occurred with only 200 MW of RA storage on the CAISO grid[1]. Current procurement orders could result in over 10 GW of additional storage on the grid.[2] Over the next few years, the role of storage will change from being an insignificant factor to being a massive, highly influential resource on the grid.

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[1] Final Root Cause Analysis – Mid-August 2020 Extreme Heat Wave, CAISO, CPUC and CEC, January 13, 2021. Available at http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

[2] Midterm Reliability Analysis, CEC, September 2021. CEC-200-2021-009 Available at: https://www.energy.ca.gov/sites/default/files/2021-09/CEC-200-2021-009.pdf

To ensure this new grid will reliably deliver power, the RA process must change to reflect the very different characteristics of the new grid, including addressing the issues discussed below. We do not believe the current RA slice-of-day proposals adequately address the issues that arise in reliably providing power from this profound grid transformation.

Path-Dependency - Due to the timeshifting of energy enabled by large amounts of storage, the determination of reliability risks becomes path-dependent. In other words, the decisions made in one hour, such as whether to charge or discharge storage, affects the resources available to solve reliability issues in a later time period. One can no longer consider each hour standalone, as has historically been done in RA. Once there is timeshifting of significant energy, the actions in each hour become linked together, and the choices made across a sequence of hours or days determine a specific path taken.

Multiple Risks, Not Just High Load - Because of this path dependence, there may be a variety of paths (multiple scenarios) that can lead to loss of load in any given hour. Some of those issues may not be because of a historically high load. Some of the time sequenced events that collectively lead to loss of load may be difficult to see without detailed analysis, but this analysis must be done to achieve 1-in-10 reliability.

For example, to illustrate the concept, multiple cloudy, winter days could result in insufficient energy to fully recharge storage. Over the course of a week, the storage is cycled, but the peak charge drifts down from day to day, until after a number of days there is not enough stored energy to meet the load. This could be during a period when the load is far from a historical peak. In this example, it was cloudy winter weather, short days and long nights that resulted in the shortfall of solar and hence depletion of stored energy, not a historically high load. This analysis requires consideration of worst case renewables output as a primary factor affecting reliability, rather than maximum load.

Statistical Modeling Needed for RA Deployment Plans – With each hour potentially having multiple reliability risks and with path dependent reliability, a statistical modeling framework that runs scenarios over extended timeframes is needed to accurately identify reliability issues and actually achieve 1-in-10 LOLE (loss of load estimate). The slice-of-day proposal is a step in the right direction but it oversimplifies by considering only a few days. Given the profound grid changes occurring and our limited knowledge of how to best procure and operate resources on this grid, it is far more appropriate to run full year scenarios with hourly or finer grained resolution.

These models need to be run under various RA deployment models, using statistically valid input data, including cross-correlations, in order to accurately predict LOLE risk levels for the actual expected RA deployments.

Modeling Cross-Correlations is Important – There are cross correlations between weather, generation (solar, wind) and load (heating, air conditioning, DR activation and compliance, etc.) that must be included in a reliability analysis to accurately predict LOLE. Considering each element (wind, solar, load, DR) by itself will not provide an accurate LOLE if there are cross correlations that boost the likelihood of multiple rare events occurring together. Similarly, with retail transactional energy, pricing becomes an important coupling between generation and load response and needs to be considered in a LOLE. These models need to be run under various RA deployment models, using statistically valid input data, including weather and cross-correlations, in order to accurately predict LOLE risk levels.

Problems with Current Siloed Approach – RA is currently done in a siloed manner. A LOLE analysis is performed using stochastic modeling approaches. However, this is then reduced to the RA capacity that needs to be procured. In the next step, elaborate counting rules are employed by the CPUC to procure widely disparate resources to meet the RA requirement, so as to ensure system RA. Once that is achieved, a separate set of analysis is done by CAISO to ensure local RA and flex RA.

The reduction of the stochastic LOLE analysis to a capacity requirement discards rich information from the model about the different benefits that various types of resources can provide in each hour, including the cross-correlated benefits arising from interactions between additional capacity of each type. It also discards information about path dependencies and in doing so also discards information about multiple risks that can occur in each hour.

That siloed approach may have been suitable when each hour could be independently analyzed because all generation resources were dispatchable to meet the independent needs of each hour, and no storage timeshifting occurred. However, that special set of circumstances no longer exists in a high intermittent renewables, high storage grid.

Accurate LOLE and RA planning now requires tight coupling between the addition of resources and the statistical modeling to analyze the path dependencies and identify multiple risk scenarios. When additional resources are to be added to the grid, the scenarios need to be re-run to get accurate assessment of the LOLE with those new reeources.

As one example of where cross-correlated effects are currently masked, the Astrape – E3 ELCC report[3] discusses the complex ELCC adjustments they needed to make to tuck the cross-correlated factors (aka diversity factors) into the traditional RA capacity requirement. They also use "removal of perfect capacity" over "addition of perfect load" in estimating incremental ELCC in order to be consistent with the CPUC approach, but they note the result is that it hides some of the impact of the cross-correlations.

Similarly, the CEC's Summer Stack Analysis Update[4] increased the planning reserve margin from 15% to 22.5% rather than model the direct impact of extreme weather on the grid. This presupposes that one knows that extreme weather causes a 7.5% impact. We contend that the complex interplay of weather with the grid requires use of statistical models and scenario analysis to best capture its impact, including cross-correlations that reflect the impact of the extreme weather on load and generation.

Local RA, then System RA - Transmission is difficult and time consuming to construct - a decade for a major new line is not unreasonable. Currently, the RA process addresses system-level RA, and then Local RA and Flex RA. This can require construction of transmission lines or addition of further resources to solve local RA problems, if RA generation or RA storage is adequately placed for system RA, but poorly placed for Local RA. It can also force the repowering or postponement of retiring gas plants to solve local RA needs, undermining

[3] Incremental ELCC Study for Mid-Term Reliability Procurement, prepared for the CPUC by Astrape Consulting and Energy + Environmental Economics (E3), September 31, 2021

[4] 2022 Summer Stack Analysis Update, California Energy Commission, January 2022. CEC-200-2021-0006-UPDT

achievement of a zero carbon grid. By starting with a Local RA analysis and solution, rather than a System RA analysis and solution, resources such as storage can be right-placed for both Local RA and System RA needs, including:

> * to enable microgrids, thereby protecting against reliability issues of wildfires and other events that isolate communities from the main grid;
>
> * to most cost-effectively address the needs of LSEs by locating resources in their service areas and avoid the need for new transmission;
>
> * to increase utilization of existing transmission lines through appropriately located storage.

2. Storage Specific Issues

2.1. The RA Requirement for Storage Should Be Stated in MW and MWh, for Both Charging and Discharging

For a grid based on dispatchable resources, RA can be calculated considering only the MW rating of resources. That is because every hour can be viewed by itself and only the MW rating needs be measured. A dispatchable fossil resource can be turned on or off as needed, and for every MW of output delivered for an hour, a MWh of energy is delivered.

Now consider a grid with substantial amounts of storage. Specifically, for discharging, if there is a 2 hour period that needs storage to provide 5 GW to the load, then the storage must have both a 5 GW or larger power rating, and a 10 GWh or larger energy rating. A 3 GW/20GWh storage project could not do this. Neither could a 10 GW/5 GWh storage project. Both the GW and GWh need of the load are relevant and both discharge specifications (GW and GWh) must be met by the storage resource. In addition, the state of charge must be adequate to meet the discharge needs – this is the path dependent issue.

Furthermore, the storage charging need must also be met in both GW and GWh metrics. And the round trip efficiency must be accounted for. If the storage is a 5 GW (in or out) / 10GWh (output) system with 80% round trip efficiency, then to fully charge it, there needs to be 12.5 GWh of energy absorbed, and the rate of delivery is limited to 5 GW maximum at any time. If charging energy (e.g. excess solar) of 10 GW is available but only for 1 hour, then the storage would only be able to charge to 80% * 5 GW * 1 hour = 4 GWh, because the storage is rated at just 5 GW and the round trip efficiency is 80%.

As a result of the above, the RA metrics for storage should be clearly stated in both GW and GWh metrics. The round trip efficiency is also relevant and can be separately stated or incorporated by using different GW/GWh figures for charging and discharging.

2.2. The 4 Hour Rule Should be Removed for Storage

Previous RA metrics have been based on a 4 hour availability rule. Many procurements have failed to compensate storage that is able to provide longer durations than 4 hours.

It is clear that storage of longer duration than 4 hours provides enhanced value, as analyzed in CESA's Long Duration Energy Storage study[5] and as reflected by CPUC's carveout for long duration storage in D.21-06-035. Similarly, the Astrape-E3 study[3] showed longer duration storage consistently provided higher value ELCC values than 4 hour storage, and the gap favoring longer duration storage over 4 hour storage increased as more storage was placed on the grid. In the chat for workshop #3 held October 20, 2021, Matthew Barmack (Calpine, VP Market and Regulatory Policy) stated "in our own work on nearly completely decarbonized systems, we found that longer and longer duration storage was required to get through multi-day events and that the ELCC of shorter duration storage went to zero."[6]

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[5] Long Duration Energy Storage for California's Clean, Reliable Grid, December 8, 2020. Available at: https://www.storagealliance.org/longduration

[6] Available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-history and a direct link is https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-3_chat.pdf

The need for longer duration storage to achieve a zero carbon grid is compelling. To ensure that CA procures resources that can best carry it to zero carbon, long duration storage should receive full value in all RA targets, RA contracts and RA procurements.

2.3. Storage Requires Long Term Certain Revenue

Storage is a fairly expensive resource. Long term contracts with certain revenue streams enables storage to obtain financing at the most attractive rates. This helps keep costs low for ratepayers. When storage is used for timeshifting, it is arbitraging and can benefit from pricing differences. However, the very presence of the storage causes the pricing gap to close. For this reason, storage facilities relying on spot pricing for their economic viability are at high financial risk.

In revising RA, given the major role storage will play on the future grid, it is important that the procurement policies chosen enable storage to secure low cost financing from traditional infrastructure funding sources.

Any unbundling of the RA resources provided by storage that fragments the definite revenue stream for the storage, or causes that revenue stream to be provided by multiple parties rather than one, is likely to result in a storage project being far more difficult to finance and build. The situation is even worse if the multiple definite revenue streams have different timeframes or are obtained through different procurements.

If unbundling of RA resources is allowed, care must be taken that it does not make storage financing more difficult.

3. Summary

California is transitioning to a high renewables, high storage grid. As part of this transition, the grid is changing from a giant just-in-time delivery system to more of a store-and-forward system architecture.

We are at the cusp of this transition, as storage deployments grows from an insignificant 200 MW to a colossal 10 GW. This profound grid transformation changes reliability into path-dependent problem. The RA process needs to change to reflect the different reliability issues of this new grid.

The workshops have been helpful, but there are significant remaining issues that require further attention, as described herein.

/s/ David MacMillan
President
MegaWatt Storage Farms, Inc.
February 7, 2022

Informal Comments of Middle River Power
Following Resource Adequacy Track 3B.2 Workshops

R.21-10-002 and R.19-11-009

February 7, 2022

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In accordance with Mia Berros' January 28, 2022 and February 3, 2022 e-mails requesting parties to (1) provide a succinct overview of their positions on all issues and (2) provide detailed comments on the topics for the last workshops (the CAISO's Unforced Capacity ("UCAP") proposal, hedging, and multi-year forward Resource Adequacy ("RA") requirements), Middle River Power ("MRP") hereby provides these informal comments.

MRP's positions on the topics of the January 2022 workshops follow.

- **Hedging.** While MRP understands the Commission requested parties to consider hedging components in the RA workshops, it is unclear what problem parties are supposed to solve. It is unclear whether the problem is the level at which non-IOU LSEs hedge energy prices for their load or decrease the infrequent energy market price spikes that occur in the market. MRP agrees with Vistra that issues about wholesale market energy prices and energy market power mitigation should be addressed through initiatives facilitated by the entity that has the jurisdiction over those markets – the CAISO. If LSEs desire the rights to offer energy and ancillary service capacity to the CAISO's markets through tolling agreements, that should be an option decided by the LSE. As noted by PG&E's presentation, regardless of whether the Commission decides to adopt hedging components in the RA program, PG&E will continue to use energy settlements in its RA contracts. MRP strongly opposes trying to force "hedging" through artificial price caps or rebate levels in RA contracts; such provisions are more appropriately characterized as wholesale market energy price suppression, not hedging, tools. MRP strongly urges the Commission to clearly state the problem and provide data that verifies and quantifies the problem.

- **UCAP.** MRP understands that the CAISO's UCAP proposal would update the NQC values only for thermal and energy storage resources. It is unclear whether the CAISO's UCAP methodology is a more appropriate methodology for establishing NQC values than an ELCC methodology for such resources.

  MRP's concerns about CAISO's UCAP proposal are as follows. *First,* MRP questions the underlying premise of UCAP, that past availability performance will be a reliable indicator of future availability performance. *Second,* MRP does not support the CAISO's proposal to calculate UCAP based on a 20% sample of hours because that sample is arbitrary and includes many hours in which the CAISO has more than sufficient capacity to meet its operational needs. *Third,* MRP is concerned that the CAISO is discriminatorily applying UCAP concepts to a select, limited portion of the overall RA fleet and not to any other resources, effectively allowing the CAISO's proposed methodology to pick winners and losers, while MRP also believes an Effective Load Carrying Capability ("ELCC") methodology could appropriately calculate the NQC values of many resources including thermal and energy storage resources. *Finally, w*hile CAISO proposes that adopting UCAP can decrease the forced outage rate component of the planning reserve margin, MRP submits that this does not provide a complete picture because the Loss-of-Load Expectation ("LOLE") study that will be used to calculate the PRM will include forced outage rates for other resources. Removing outage inputs from the LOLE analysis does not automatically yield a similar reduction in the PRM. Setting a proper PRM that works with resource counting rules to achieve 0.1 LOLE will be crucial to ensure the CAISO has the right set of resources needed to maintain reliability.

- **Multi-year Forward RA Requirements.** MRP strongly supports three-year forward system and flexible RA requirements. Given tight conditions in the west, such requirements will provide greater certainty, both for internal resources and for California consumers, and should lower RA prices. To confirm this, it would be helpful for Energy Division to provide aggregated price data regarding multi-year forward RA contracts it has collected from LSEs for its quarterly or annual reports.

The overview of MRP's position on other RA issues follows.

- **Problem Statement.** Over the course of the workshops, MRP has noticed that parties have offered solutions to what appear to be very different problems, and that there has been no effort to establish a common problem statement to guide RA program redesign. MRP offers its view of the reliability problem warranting RA program redesign: Resource counting rules do not accurately represent a resource's reliability contribution to serve demand in certain hours and the initially adopted planning reserve margin ("PRM") has neither been validated nor updated, resulting in involuntary load shedding in 2020 not at the time of the gross load peak but at the time of the net load peak. Therefore, to ensure a reliability of 0.1 LOLE, the RA program must update its NQC counting methodologies and PRM and establish both gross and net load peak requirements while retaining transactability of the RA capacity product and minimizing administrative complexity.

- **Planning Reserve Margin**. Though this topic was not listed among the elements in the position matrix that parties were requested to fill out, MRP believes it is an important, if not *the* most important issue, in restructuring the RA program. Several parties have proposed that the PRM must be recalibrated/recalculated based on the QC counting methodologies adopted within the new RA framework. Parties have also proposed that the most important implementation step in RA program redesign is to determine the appropriate PRM for the adopted design through a LOLE analysis once the Commission adopts a framework. The PRM and the RA resource counting rules must be coordinated to ensure that the RA program secures the amount and mix of generation that the LOLE analysis says is required to achieve the desired level of reliability (which MRP assumes will be a 0.1 LOLE).

MRP also reiterates that it is also critical to align the PRMs and resource counting rules used in the Integrated Resource Planning ("IRP") process and the RA program. If the IRP process establishes procurement – and, critically, resource retention – targets using one set of capacity rules to a given LOLE/PRM, and the RA program uses a different set of counting rules and a different PRM, there can be no assurance that the two procurement programs will work in concert to achieve the desired level of reliability at the least cost.

- **Implementation Timelines**. Based on the two proposals presented during the workshops, MRP understands that the 24-slice proposal requires an additional implementation phase of the RA proceeding to discuss additional implementation details, particularly with how exceedance methodology for variable energy resources would be calculated, the profiles of different resources, and the PRM. This would defer implementation of the new RA framework to 2025. MRP understands that the two-slice proposal does not require additional implementation phase of the RA proceeding because it utilizes existing ELCC methodology calculations for most resources and would require additional calculations for PRM and be able to implement the framework by 2024, meeting the Commission's original target date. Given the shorter timeline as well as the reduced administrative complexity and better transactability of the two-slice proposal, MRP submits that the 2-slice proposal best meets the Commission's principles for a new RA framework.

Additional structural elements discussed in previous informal comments as well as requested by the matrix.

- **Load (gross or net)**. MRP supports the use of gross load to determine RA requirements.

- **Compliance periods.** MRP supports a smaller number (i.e., one or two) of compliance periods as opposed to a larger number (i.e., 12) of compliance periods. While parties assert that using a larger number of compliance periods will reduce "over-procurement" and therefore reduce cost, MRP believes this assertion to be a fallacy. A resource that is needed to meet the peak demand in one month of the year will have to recover all its annual costs whether it is contracted for one month or for all twelve. A larger number of compliance periods increases the number of required RA showings but does not reduce the costs of being resource adequate in all months of the year.

- **Number of slices.** MRP supports two slices instead of 24 slices. While MRP believes that a two-slice approach could be implemented by 2024, MRP believes parties would need to spend another year working through the yet-to-be specified details of implementing a 24-

slice approach, which makes it unlikely that such an approach could be implemented for the 2024 RA compliance year.

MRP also believes that a primary appeal of the 24-slice framework – the desired ability to "shape" four-hour storage resources to count towards RA requirements in more than four hours – is not yet workable in a paradigm in which RA resources have a 24-hour must-offer obligation.

MRP also believes that a second proposed appeal of the 24-slice approach – that RA capacity will continue to transact via a single value – is illusory. Because, under the 24-slice approach, resources' capabilities will be profiled across all 24 hours, and because those profiles will be different depending on the resource type, a MW of one type of resource will not and cannot functionally equal a MW of another type of resource. Because a 24-slice framework cannot guarantee RA "fungibility" among disparate resources using a single capacity value, adopting a 24-slice framework will greatly complicate the transactability of RA capacity.

- **Determining and allocating RA requirements.** MRP supports the current approach for setting and allocating RA requirements to LSEs that is employed by the CEC.

- **Resource counting.** Resource counting is a topic that cannot be discussed as a stand-alone element of the RA program. It is integrally linked with other aspects of the RA program, notably, the PRM. An RA program that adopts resource counting rules that overcount the reliability contribution of resources can maintain reliability if the PRM is sufficiently high, while an RA program that undercounts the reliability contribution of resources can still be cost-effective if the PRM is set appropriately.

  For years, assigning capacity values through ELCC analysis was the "gold standard" for setting capacity values that applied over an extended, contiguous period. Assigning ELCC-based capacity values to wind and solar resources in a program that only enforced RA requirements at a single point across the day helped ensure that those resources were not overcounted at that single point at which resource adequacy was assessed; however, when the critical, constraining operating period of the day shifted from the gross load peak to the net load peak, those single ELCC-based capacity values became overstated for some resources and likely somewhat understated for others.

  MRP's positions on resource counting for individual resource types follow.

  - **Variable energy resources.** As noted above, setting VER capacity values through ELCC analysis worked until the penetration of solar resources increased to the point that it didn't – when the net load peak became the operationally constraining time. While MRP believes that assigning an ELCC-based value to solar no longer ensures reliability across the net load peak hour, MRP is skeptical that using the exceedance method to set capacity values for wind and solar will work – absent corresponding and appropriate changes to the PRM – because there will be intense pressure to adopt favorable (e.g., 50%) exceedance values for those resources. MRP believes the proposed two-slice approach – which would not allow solar resources to count towards meeting the net load peak slice and would assign an ELCC-based capacity value to wind resources – would help ensure reliability. In any case, whatever VER counting rules the Commission adopts, it is critical that the Commission then plug those rules into a LOLE analysis to set the proper PRM.

- **Thermal resources:** MRP supports consideration of a "UCAP light" (accounting for thermal ambient derates) to setting capacity values for thermal resources. MRP also supports consideration of average ELCC for thermal resources.

- **Hydro:** MRP supports retaining the current approach, which appropriately weights dry years.

- **Storage.** MRP supports ELCC to set the capacity value for storage. MRP supports an "incremental" approach which would grandfather capacity values for existing storage and assign lower incremental values to new storage.

- **Hybrid resources.** MRP supports the current approach adjusted to account for the round-trip efficiency of the battery energy storage system.

- **Co-located resources.** MRP supports the current approach.

- **Demand response.** While this topic is still under discussion in the working groups facilitated by the CEC, MRP sees value in a LIP-informed ELCC approach.

- **Transactability.** While transactability was not a key topic discussed during the workshops (except by Vistra), MRP believes that the Commission and parties ignore this issue at their peril. In the more than fifteen years since the RA program was implemented, a robust bilateral procurement market has grown up around this program. Undue disruptions to this paradigm could have significant implications for the transition from the current program to the future new program. Under the 24-slice framework, RA capacity will be less fungible due to the inability of one resource to be equivalent to another resource because one resource's profile may and likely will be different from that of another resource. For example, a wind resource cannot be replaced by a solar resource because the solar profile is significantly different from the wind profile. Under the 2-slice framework, transactability is retained because all resources are treated comparably because of the ELCC methodologies and the single NQC values.

- **Energy sufficiency for charging storage.** MRP agrees that, as storage penetration increases to a critical level, the RA framework must account for the capacity and energy needed to charge the storage. However, MRP expects that the energy to charge the storage resources will come from new resource buildouts as part of the IRP. While MRP does not propose to change the enforcement of RA program requirements from its current design of doing so on an individual LSE-specific basis, MRP agrees that enforcing charging requirements on an individual LSE-specific basis will create additional administrative complexity and costs of RA compliance. MRP recommends that the Commission either allocate the charging requirement *pro rata* to all LSEs or defer this charging requirement until after the new RA framework is implemented. A framework that does not evolve with an evolving resource mix is not durable because it will remain locked to the decade it was born and not the decade in which it resides.

MRP notes that this topic is significantly complicated by assuming that energy storage resources can charge and discharge over more than one cycle per day.

- **Penalties.** MRP agrees with parties (e.g., SCE and Calpine) who recommend that, if a multi-slice approach (either two or 24) is adopted, penalties must continue to be based on the maximum deficiency in any shown slice.

MRP appreciates the opportunity to provide these informal comments and looks forward to commenting on the workshop report.

Resource Adequacy Framework Workshops

Pacific Gas & Electric Company – Informal Comments #3

I. Introduction

PG&E provides the following comments on the slice-of-day frameworks and hedging and multi-year proposals that have been discussed to date in ten workshops held between September 2021 and January 2022. PG&E's comments are organized as follows:

- PG&E's Position on the Slice-of-Day Framework and Scoring Relative to the CPUC Principles
- Implementation for 2024 Compliance Year
- Implementation Actions
- Comments on Hedging and Multi-Year

II. PG&E's Position on Slice-of-Day Framework and Scoring Relative to the CPUC Principles

PG&E supports SCE's proposal for a 24-slice, 12-month slice-of-day framework. PG&E believes a 24-slice, 12-month structure is best positioned to meet the CPUC principles outlined in D.21-07-014. We'll look at each of these principles in turn:

- Balance a Reliable Electrical Grid with Minimizing Costs to Customers

The 24-slice, 12-month framework ensures reliability by requiring that system needs be met in all hours. It minimizes costs by using an hourly framework, whereas a framework with larger slices would result in excess procurement in many hours, without that excess procurement necessarily resulting in a greater level of reliability.

- Balance Addressing Hourly Energy Sufficiency with Advancing Environmental Goals

The 24-slice, 12-month framework addresses hourly energy sufficiency by requiring that LSEs show sufficient capacity to charge any storage that they are showing. It also advances environmental goals by enabling a system that will increasingly be based on GHG-free resources.

- Balance Granularity in Meeting Hourly Needs with Simplicity and Transactability

The 24-slice, 12-month framework meets hourly needs but does so in a way that keeps things simple. The showings are still essentially one showing per month, but with greater detail at the hourly level, which keeps the framework manageable in terms of showing burden. The framework, if coupled with resource bundling by month (i.e. resources cannot be sold for individual hour slices), which PG&E supports, also minimizes transaction complexity, as a resource needs to be transacted for all 24 hours (although it could still sell portions of its capacity).

- Implementable in the Near-Term (2024)

The 24-slice, 12-month framework is also implementable by the 2024 RA compliance year. If the 24-slice, 12-month framework were adopted, the Commission could turn its attention during 2022 to implementing the changes. PG&E sees the big tasks to be completed during implementation to be: 1) a showing tool (SCE's looks to be a viable initial tool), 2) resource counting changes, 3) requirements allocation tests with the CEC, and 4) loss of load analysis to establish a PRM. PG&E believes the recommendations outlined form the basis for a viable initial launch, with further refinements coming as part of the regular RA program updates that occur every year. The Commission should not make the perfect the enemy of the good and delay adoption of the new framework beyond 2024, as PG&E's proposed changes would significantly improve the RA program resulting in a more reliable system.

- To be durable and adaptable to a changing electric grid

The 24-slice, 12-month framework is also the most durable proposed framework. Since the framework is hourly, slices and resource counting rules do not have to be updated based on changes in the resource mix or load forecast. And this framework covers not only the gross and net load peaks, but all other hours, in the event problems arise in unexpected hours in the future.

III. The Commission Should Implement the 24-Slice Framework in Time for the 2024 RA Compliance Year

"Implementable in the near-term (e.g. 2024)" is one of the principles in D.21-07-014 for the development of the slice-of-day framework. PG&E urges the Commission to maintain the 2024 timeline. The existing framework lacks the ability to ensure reliability in all hours, which speaks to the urgency of adopting a revised framework and moving forward with implementation of that structure. The RA program is also not a static program; incremental improvements are made to the program every year, and the new framework will not be static either. Improvements to the revised framework can be scoped into the regular RA cadence and can include issues that stakeholders are still discussing in the slice-of-day stakeholder process. Delaying implementation beyond 2024 would perpetuate inadequacies with the existing system, create uncertainty as transactors contract for the IRP-directed procurement, and not necessarily result in greater alignment among parties on key issues. PG&E urges the Commission to act expeditiously and issue a decision on direction and structure no later than June 2022 to keep the existing timeline for implementation of the new RA framework for RA year 2024. While there will still be implementation steps that need to be taken prior to 2024, these steps can be addressed in 2022, while still preserving the 2024 implementation timeline.

IV. Implementation Actions

The Commission should have sufficient information following the publication of the workshop report to decide on all key structural elements. To keep a 2024 implementation timeline, it is important that the Commission signal direction on all elements so that efforts can move to implementation. Key issues that the Commission should indicate direction on in the Summer 2022 decision include the following:

- Slice structure
- Season structure
- Showing structure and tool
- Resource counting (solar, wind, dispatchable, storage, hybrids, hydro, DR, imports, non-dispatchable)
- Charging requirements
- MCC buckets (and any caps on use-limited resources)
- Load forecasting and requirements issues (max hourly values v. worst day, gross v. net load)

- LSE allocation
- Bundling / unbundling
- Penalties

Note that this list does not include the PRM. The PRM will need to be studied as part of a loss of load analysis, ideally after all structural elements have been determined. The PRM therefore should be studied following the Summer 2022 decision and completed in time for a 2024 compliance year launch.

If the Commission does not provide direction on all of these elements, a stakeholder process should be outlined with deliverables in 2022 to ensure a finalized framework can be included in a decision in the first half of 2023, in time for 2024 implementation.

V. PG&E's Positions on Hedging and Multi-Year

a. Hedging

At the January 5th workshop on hedging, PG&E presented on the hedging proposals that had been introduced into the proceeding. PG&E's presentation summarized the four different proposals that had been made previously:

- Energy Division's Standard Fixed-Price Forward Energy Contract (SFPFC) proposal would make forward energy contracting mandatory.
- Energy Division's Bid Cap proposal would impose a bid cap for all RA capacity at the greater of $300/MWh or the resource-specific default bid.
- PG&E's variable cost hedge, which was reviewed at the workshop; and
- PG&E's price cap rebate which was also reviewed at the workshop.

PG&E walked through each of its proposals and discussed how each might be implemented.

PG&E walked through both of the PG&E proposals and provided more in-depth examples about how each would work. PG&E also discussed its experience with these types of mechanisms as PG&E has implemented them on a voluntary basis in storage procurement as well as an option for the procurement of dispatch rights associated with procurement of local capacity by the CPE.

The discussion at the workshop yielded questions that should be addressed by the commission before adopting any of these mechanisms:

- What is the purpose of the Commission adopting requirements for this type of mechanism?
- What is the appropriate level for a bid cap or energy market rebate?
- Should LSEs be allowed to set the level for the cap for their own contracts? Or should it be uniform across all LSEs?
- What percentage of an LSE's portfolio should be required to have these types of mechanisms?
- How much hedging are LSEs already doing and is additional hedging warranted?

Some parties observed that both LSEs and suppliers have the incentive to hedge their energy positions, and that any action by the Commission should recognize existing efforts and count those towards any requirement.

The POLR provider for its service territory has an incentive to help assure LSEs in its service territory do not fail unexpectedly. However, evidence hasn't been presented on the level of hedging LSEs are currently undertaking and whether it is sufficient to avoid failure. Consequently, the Commission should gather more information on current hedging levels to inform any actions in this area.

b. Multi-Year Forward RA Requirements

At the January 19 workshop, WPTF and IEPA presented on multi-year forward RA requirements. In August of 2020, both WPTF and IEPA proposed the Commission adopt three-year forward RA requirements for both system and flexible RA for all its jurisdictional LSEs. In addition, the CAISO also urged the Commission to adopt three-year forward requirements for system RA in December 2020.

At the workshop, WPTF and IEPA advocated that implementation details regarding multi-year requirements be worked out after the Commission has adopted multi-year requirements. PG&E believes greater details of how the multi-year requirements would address previously identified issues be worked out prior to the Commission adopting such requirements. These issues include: load migration, changing counting rules, changing requirements, backstop provisions, and jurisdictional differences in RA requirements.

The Public Advocates Office's Informal Comments on Structural Elements and Resource Counting Workshops of the Slice of Day RA Framework Process

Resource Adequacy: R.19-11-009 and R.21-10-002
February 7, 2022

Submitted by	**Organization**	**Date Submitted**
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I. INTRODUCTION

Decision (D.) 21-07-014, issued in the California Public Utilities Commission's (Commission) predecessor Resource Adequacy (RA) proceeding, Rulemaking (R.) 19-11-009, directed parties to undertake a series of workshops to develop implementation details for Pacific Gas and Electric Company's (PG&E) Slice-Of-Day proposal.[1] Consistent with this directive, PG&E provided a schedule for stakeholder participation in workshops and scheduled three sets of informal comments following an initial stakeholder meeting.[2] The Public Advocates Office at

[1] D.21-07-014, *Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program*, July 15, 2021, pp. 51-52, Ordering Paragraph (OP) 1.

[2] E-mail served by PG&E to service list for R.19-11-009, *Additional Logistic Details for RA Framework Workshops, per D.21-07-014,* September 8, 2021.

the California Public Utilities Commission (Cal Advocates) submits the following informal comments responding to the third set of two workshops, which focused on hedging, multi-year requirements, and Unforced Capacity (UCAP) counting rules of the Slice-Of-Day framework. Cal Advocates also takes this opportunity to comment on previously discussed framework topics and issues, as requested by the workshop facilitators.[3] Lastly, as requested by the working group facilitators,[4] Cal Advocates provides general position statements, in Appendix A, on various aspects of Slice-of-Day proposals.

II. BACKGROUND

Track 3B.2 of R.19-11-009 considered an "[e]xamination of the broader RA capacity structure to address energy attributes and hourly capacity requirements…."[5] Stakeholders and Energy Division staff submitted RA restructuring proposals for Commission and stakeholder consideration in the Rulemaking.[6] The Commission ultimately found PG&E's Slice-Of-Day proposal to best meet a set of five principles established by the Commission:

- Principle 1: To balance ensuring a reliable electrical grid with minimizing costs to customers.
- Principle 2: To balance addressing hourly energy sufficiency for reliable operations with advancing California's environmental goals.
- Principle 3: To balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity, and transactability.
- Principle 4: To be implementable in the near-term (*e.g.,* 2024).
- Principle 5: To be durable and adaptable to a changing electric grid.[7]

The Commission ordered stakeholders to conduct a series of workshops to develop an

[3] E-mail served by PG&E to service list for R.19-11-009, *Presentations and Agendas: RA Framework Workshops, Hedging Component,* January 18, 2022.

[4] PG&E E-mail, *RE: [EXTERNAL] [R.19-11-009 & R.21-10-002] REMINDER: RA Framework Workshop - Informal Comments and Position Matrix due Friday 2/4*, sent by PG&E to the RA service lists on January 28, 2022.

[5] D.21-07-014, p. 5.

[6] D.21-07-014, p. 7.

[7] D.21-07-014, pp. 37-38, OP 2.

implementable RA framework based on PG&E's Slice-Of-Day proposal.[8] A workshop was held on January 5, 2022 to discuss energy price hedging proposals, and another workshop was held on January 19, 2022 to discuss the unforced capacity (UCAP) counting methodology and multi-year proposals. The workshop facilitators set a date of February 4, 2022 to submit informal comments responding to those two workshops and to address any remaining Slice-Of-Day implementation issues in general.[9]

III. DISCUSSION

A. Proponents of 24-Slice Showings Should Clarify the Interaction of 24-Slice Showings with Resource Deliverability

A 24-slice design would establish hourly generation values for resources that may be above the resources' current net qualifying capacity (NQC) value. As proposed by Southern California Edison Company (SCE), solar and wind resources in particular would have an "Hourly Profile," or a number of geographic Hourly Profiles, that maps hourly variation in the resources' NQCs to the resources' hourly generation capability.[10] According to SCE, the California Independent System Operator Corporation (CAISO) would simply accept these hourly NQCs.[11] This is a marked departure from the CAISO's current practice of obtaining NQCs for RA purposes by assessing resources' on-peak deliverability.

The CAISO pointed out that the hourly availability of resources studied for hourly slices "differs from the deliverability assessment and allocation performed by the CAISO."[12] Significant differences between resources' availability assumptions and the CAISO's deliverability assessment assumptions, which are based upon specified operational scenarios, risk undermining the integrity of the RA program. Proponents of 24-slice showings should clarify how their proposals' availability assumptions will interact with the deliverability assumptions of

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[8] D.21-07-014, Findings of Fact (FoF) 1 and OP 1.

[9] E-mail served by PG&E to service list for R.19-11-009, *Presentations and Agendas: RA Framework Workshops, Hedging Component,* January 18, 2022.

[10] SCE, *Slice of Day Resource Counting & Penalty Process*, Presentation: RA Slice of Day Workshop, January 19, 2022, pp. 5, 7.

[11] SCE, *Slice of Day Resource Counting & Penalty Process*, Presentation: RA Slice of Day Workshop, January 19, 2022, p. 7.

[12] *Informal Comments of the CAISO,* November 10, 2021 (CAISO Informal Comments 1), p. 6.

the CAISO's generator interconnection and deliverability allocation process.

a. Background

Deliverability is a fundamental constraint on the eligibility of generation resources to count for RA. The Commission currently accounts for deliverability in conjunction with the CAISO: the Commission first discounts a resource's nameplate capacity to a "qualifying capacity" that reflects certain attributes of the resource, and then the CAISO assesses whether the grid can actually transmit energy from that qualifying capacity under system peak operating conditions.[13] As the CAISO states,

> A generating resource must pass the CAISO's deliverability test under system summer peak load conditions for its Qualifying Capacity (QC) as determined by the [Commission], and the amount that meets the test requirements, which may be less than the full Qualifying Capacity initially assigned by the CPUC, is the [NQC] that can be counted to meet RA requirements.[14]

Currently, the CAISO conducts deliverability studies for larger resources that request interconnection to the grid.[15] Larger resources that seek RA eligibility require full or partial capacity deliverability status (FCDS/PCDS) for the level, if any, of their capacity that is eligible for RA. The CAISO studies such resources to determine their on-peak deliverability, based on specific scenarios designed to represent summer system conditions. The CAISO recently updated the on-peak deliverability assessment methodology to study resources under two different on-peak scenarios, a "highest system need" (HSN) scenario, defined as hours ending 18 through 22 in the summer months, and a "secondary system need" (SSN) scenario, defined as hours ending 15 through 17 in the summer months.[16] The results reduce the QC value to a lower

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[13] CAISO, *Deliverability Assessment Methodology: Issue Paper,* April 24, 2019, p. 4. Available at https://www.caiso.com/Documents/IssuePaper-GenerationDeliverabilityAssessment.pdf.

[14] CAISO, *Deliverability Assessment Methodology: Issue Paper,* April 24, 2019, p. 4. Available at https://www.caiso.com/Documents/IssuePaper-GenerationDeliverabilityAssessment.pdf.

[15] Larger generators are those that exceed 20 MW. Such generators are subject to the CAISO's Generator Interconnection Procedures. See CAISO, *Business Practice Manual For Generator Interconnection Procedures (GIP BPM)*, Version 11, February 20, 2020, p. 14. Available at https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Generator%20Interconnection%20Procedures.

[16] CAISO, *On-Peak Deliverability Assessment Methodology (for Resource Adequacy Purposes),* March 2020, p. 3 et seq. Available at http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf.

NQC, if transmission congestion or other issues impose constraints.[17]

Resources that do not seek to qualify for RA may request alternative energy-only deliverability status (EODS) as interconnection customers. The CAISO also recently developed an off-peak deliverability assessment methodology.[18] This new assessment methodology enables the CAISO to offer interconnection customers a new service – off-peak deliverability status (OPDS) – that is meant to provide renewable developers an opportunity to mitigate the curtailment risk of certain potential development sites[19] that would otherwise face "potentially unlimited curtailment" absent local network upgrades.[20] The assumptions for the CAISO's off-peak deliverability assessments include CAISO system-wide dispatch levels of 30% for hydro, 15% for thermal, and 0% for storage, representing shoulder season conditions rather than summer peak conditions.[21] The current interconnection queue indicates widespread preference for OPDS over off-peak EODS.[22]

b. Discussion

Since current deliverability studies do not consider all hours of a resource's generation and associated hourly grid conditions, the resource availability assumptions of a 24-slice counting system may be inconsistent with the assumptions that underpin the CAISO's deliverability assessments, as well as the status choices of current and queued interconnection

[17] CAISO Informal Comments 1, pp. 5-6. For additional information, see: *IR Application Generator Facility Data From Overview,* March 11, 2020, pp. 20-21, available at: http://www.caiso.com/Documents/Presentation-2-Studies-StudyResults-ProjectResponsibility.pdf

[18] CAISO, *Off-Peak Deliverability Assessment Methodology,* March 2020, p. 1. Available at http://www.caiso.com/Documents/Off-PeakDeliverabilityAssessmentMethodology.pdf.

[19] The sites in question are ones that face local transmission bottlenecks, rather than larger, regional transmission constraints that would be addressed in the CAISO's Transmission Planning Process. See the discussion of "Location Constrained Resource Interconnection Generators" at p. 70 of the CAISO's Business Practice Manual for Generator Interconnection and Deliverability Allocation Process, Version 28, January 21, 2022. Available at https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Generator%20Interconnection%20and%20Deliverability%20Allocation%20Procedures.

[20] CAISO, *Off-Peak Deliverability Assessment Methodology*, March 2020, p. 1. Available at http://www.caiso.com/Documents/Off-PeakDeliverabilityAssessmentMethodology.pdf.

[21] CAISO, *Off-Peak Deliverability Assessment Methodology,* March 2020, p. 3. Available at http://www.caiso.com/Documents/Off-PeakDeliverabilityAssessmentMethodology.pdf.

[22] This statement is based on Cal Advocates' review of the CAISO interconnection queue, which is available at https://rimspub.caiso.com/rimsui/logon.do.

customers. As a threshold concern, this matter is integral to the RA reform process, so the 24-slice proponents should address these deliverability issues in this proceeding. While the CAISO may adopt conforming changes once RA reform is complete, at this time the CAISO states that further deliverability specification (i.e., on an hourly basis) is not feasible or desirable.[23] And while the CAISO also asserts that any modifications to deliverability should be discussed in a CAISO-led process,[24] the Commission is responsible for RA reform; thus, the Commission should proactively take steps to align its RA program restructuring with the CAISO's deliverability practices.

SCE is the leading proponent of a 24-slice showing. SCE's latest proposal materials clarified that the 24-slice proposal would count most resource types at their single NQCs,[25] and that those NQCs would be shown at the same level across the different hourly slices.[26] Such a showing relies on an implicit assumption that those NQCs could be deliverable at the same NQC level in off-peak hours, even as the NQC levels reflect FCDS testing under on-peak assumptions. SCE argued that the assumption of off-peak deliverability of NQCs would lead to actual reliability in the CAISO's market operations, because CAISO market operations would simply displace off-peak generation from non-RA capacity if necessary.[27]

SCE's proposal also relies upon load-serving entities' (LSEs') showing of shaped hourly generation from variable resources, such as solar and wind. The shaped profiles raised an important question that SCE did not explicitly address in its written workshop presentation materials: What interconnection status(es) would render a resource eligible for the proposed 24-slice RA showing? SCE's materials show that SCE proposes that solar and wind resources

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[23] CAISO Informal Comments 1, p. 6. See also *Informal Comments on RA Reform Workshops of the CAISO,* December 22, 2021 (CAISO Informal Comments 2), p. 4.

[24] CAISO Informal Comments 1, p. 5.

[25] Excluding solar, wind, batteries, use-limited resources, and contracted energy imports. See SCE, *Slice of Day Resource Counting & Penalty Process*, Presentation: RA Slice of Day Workshop, January 19, 2022, p. 3.

[26] SCE, *Slice of Day Resource Counting & Penalty Process*, Presentation: RA Slice of Day Workshop, January 19, 2022, p. 5.

[27] Discussions during Slice of Day Workshop 9: *UCAP and Multi-year*, January 19, 2022. Recordings of workshop discussions are available on the Commission's RA History website, under R.19-11-009 here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-history

"must be fully deliverable."[28] In addition, at the January 19, 2022 workshop, SCE verbally clarified its expectation that resources must continue to obtain FCDS,[29] including renewables. However, SCE also provided the following example:[30]

> The Hourly Profile may be significantly different from NQC depending on the hour considered
>
> – Example, consider a 100MW solar facility with a current NQC of 15 MW
> – However, assume the Hourly Profile for HE18 is 41MW
> – If the CAISO decides to test HE18 for deficiencies, they must count this solar based on its Hourly Profile value of 41MW, not the NQC of 15MW
>   • Otherwise the CAISO may incorrectly conclude there is a 41MW-15MW = 26MW deficiency

SCE's example of how the 100 MW resource mentioned above should be verified at its hourly profile availability appears to sidestep the fundamental question of whether or not those hourly NQCs are actually deliverable. SCE must provide further explanation of how its 24-slice proposal reconciles deliverability in order for the Commission and parties to vet the proposal.

Ultimately, a resource's NQC relates to the CAISO's discounting of the Commission's QC to recognize deliverability limitations.[31] The CAISO-determined NQC is used by both the CAISO and the Commission to represent the RA value of each resource.[32] As noted above, the resource's QC is the Commission's effective statement of the maximum amount of capacity that a resource could count as eligible for RA, without any consideration of grid deliverability. For wind and solar, the Commission's QC values are based on a monthly effective load-carrying capability (ELCC) methodology that discounts a resource's nameplate capacity.[33] The Commission produces monthly ELCC values by comparing the reliability impacts of wind and

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[28] SCE, *Slice of Day Resource Counting & Penalty Process*, Presentation: RA Slice of Day Workshop, January 19, 2022, p. 3.

[29] Discussions during Slice of Day Workshop 9: *UCAP and Multi-year*, January 19, 2022.

[30] SCE, *Slice of Day Resource Counting & Penalty Process*, Presentation: RA Slice of Day Workshop, January 19, 2022, p. 7.

[31] CAISO Informal Comments 1, pp. 5-6. For additional information, see: *IR Application Generator Facility Data From Overview,* March 11, 2020, pp. 20-21, available at: http://www.caiso.com/Documents/Presentation-2-Studies-StudyResults-ProjectResponsibility.pdf.

[32] Commission, *2020 RA Report,* December 2021, pp. 41-42.

[33] Commission, *2020 Qualifying Capacity Methodology Manual,* November 2020, pp. 7-9, 13-14. Available at https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/q/6442466773-qc-manual-2020.pdf.

solar resources' hourly production profiles to the reliability attributes of a theoretical perfect generator. Because the ELCC results are monthly values that represent the full hourly profiles of the wind and solar resources, the wind and solar resources' hourly production necessarily must vary from the ELCC-based QC in order to achieve the reliability attributes of that QC on an overall basis. As a result, the CAISO's on-peak deliverability assessment methodology tests solar and wind at 20% exceedance in the HSN scenario and 50% exceedance in the SSN scenario, rather than at wind and solar resources' ELCC levels.[34] The CAISO grid can deliver up to these specifically tested exceedance levels of wind and solar resources' generation concurrently with the rest of FCDS/PCDS resources' NQCs, even if such conditions were to manifest in off-peak hours – indeed, the point of SCE's 24-slice pass/fail example.[35]

SCE's proposal fails to address these interrelated resource counting and deliverability concerns insofar as SCE's proposal requires the Commission and the CAISO to presume that some significant level of wind and solar generation can be delivered simultaneously with the RA fleet, above and beyond the specifically tested exceedance levels. Specifically, SCE's pass/fail example indicates an LSE that shows a solar resource in 12 hourly slices, with at least 5 different hourly NQC values.[36] This is because SCE specifically envisions that the Commission will adopt an Hourly Profile (or various geographic profiles) for solar and wind resources, in which NQC values vary by hour, and that the CAISO will test for reliability deficiencies against this (these) Hourly Profile(s).[37] If any of these hourly NQCs exceed the relevant tested exceedance level – as is apparently the case – then SCE's proposal involves LSEs showing a portion of wind and solar generation that has not been sufficiently tested for deliverability.

In response to a question from Cal Advocates during the January 19, 2022 workshop, SCE explained that the 15 MW of NQC for its 100 MW example resource (see above) simply reflects the *current* ELCC methodology. Yet this explanation raises serious questions about

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[34] CAISO, *Deliverability Assessment Methodology Revisions: Draft Final Proposal*, October 30, 2019, pp. 5-6. Available at http://www.caiso.com/InitiativeDocuments/RevisedDraftFinalProposal-GenerationDeliverabilityAssessment.pdf.

[35] SCE, *Slice of Day Resource Counting & Penalty Process*, Presentation: RA Slice of Day Workshop, January 19, 2022, p. 5.

[36] SCE, *Slice of Day Resource Counting & Penalty Process*, Presentation: RA Slice of Day Workshop, January 19, 2022, p. 5.

[37] SCE, *Slice of Day Resource Counting & Penalty Process*, Presentation: RA Slice of Day Workshop, January 19, 2022, p. 7.

whether the realities of hourly resource availability, deliverability status, and LSEs' existing contracts can support SCE's 24-slice proposal. If an existing solar resource with a nameplate capacity of 100 MW is under contract with a CAISO LSE to provide 15 MW of NQC for system RA, then the most applicable examples would be a resource with either FCDS or PCDS, sufficient to support 15 MW of NQC. Such a resource would have been tested for on-peak deliverability at alternative exceedance levels – 20% for HSN and 50% for SSN. But rather than map these specifically tested levels to the 24-slice showings, SCE instead presents a pass/fail example with a solar resource that has at least 5, and as many as 12, different hourly NQC values.[38]

The figures that SCE provides as an example for how the CAISO might test for deficiencies are also misaligned with the deliverability testing that earns a solar resource FCDS. SCE's 100 MW solar resource example clearly states that the Commission and the CAISO should assign at least one hourly value of 41 MW to this resource – 26 MW more than the current NQC of 15 MW.[39] In SCE's example, it is possible that the solar resource could produce as much as 100 MW in any given hour, if consistent with the Hourly Profile. This level would include 15 MW of current NQC and up to 85 MW of additional solar capacity that is not currently eligible for RA counting. Depending on the relation of the 15 MW level to the unknown 20% and 50% HSN and SSN exceedance levels, the CAISO may not have studied much of the non-RA capacity level of this resource for on-peak deliverability. And for a corresponding PCDS resource, the CAISO may have determined that some portion of the non-RA capacity level could not be delivered under on-peak conditions. Alternatively, if SCE intended for the 41 MW value to represent some proxy on-peak exceedance of the example 100 MW resource, as the CAISO would test, then SCE should be explicit about this assumption to enable the Commission to understand if and how the 24-slice showing interacts with the HSN and SSN deliverability scenarios.

SCE would face serious and likely insurmountable challenges if SCE intends for its proposal to implicate CAISO testing of wind and solar resources at higher on-peak levels. This

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[38] SCE, *Slice of Day Resource Counting & Penalty Process*, Presentation: RA Slice of Day Workshop, January 19, 2022, p. 5.

[39] SCE, *Slice of Day Resource Counting & Penalty Process*, Presentation: RA Slice of Day Workshop, January 19, 2022, p. 7.

would be the case, for example, if the highest hourly NQC – which, in SCE's pass/fail example, is obtained by solar resources in the mid-day, off-peak hours[40] is meant as a proxy for the specifically tested on-peak exceedance levels. The CAISO would face the prospect of allocating critical but scarce on-peak deliverability to enable LSEs' slice-of-day showings to demonstrate deliverable energy sufficiency during off-peak hourly slices.

Any such deliverability allocations would be extremely costly for ratepayers because the Commission's hypothetical Hourly Profile NQCs will wane as solar production falls in the late afternoon and evening, which is the actual on-peak period. This is evident even in SCE's pass/fail example, which includes a solar Hourly Profile that wanes into the on-peak hours.[41] To state the obvious, solar resources in particular do not need any additional on-peak deliverability, for want of availability in the actual on-peak period. Furthermore, SCE would need to explain how the CAISO could accommodate the potentially large level of re-testing that would be required in order for existing and queued interconnection customers to convert from EO status or to upgrade their PCDS levels. SCE would also need to explain how the Commission and LSEs should transition their large body of existing wind and solar contracts into the new RA paradigm.

Finally, the relatively low amount of solar in SCE's pass/fail example may give the false impression that these deliverability issues are not significant. For example, Gridwell Consulting argued that market operations will determine which resources produce and deliver.[42] While such logic can apply to the vast majority of hours that exhibit no resource adequacy problem, such comments miss the mark when applied to the few constrained hours that are the very target of the RA program. In such conditions, any curtailment of solar or wind generation that was included in the LSEs' collective RA showing could amount to a resource adequacy deficiency. Moreover, this challenge will only grow; with the state on its way to a 60% Renewables Portfolio Standard by 2030,[43] the CAISO's Interconnection Queue continues to exhibit high interconnection

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[40] SCE, *Slice of Day Resource Counting & Penalty Process*, Presentation: RA Slice of Day Workshop, January 19, 2022, p. 5.

[41] SCE, *Slice of Day Resource Counting & Penalty Process*, Presentation: RA Slice of Day Workshop, January 19, 2022, p. 5.

[42] Discussions during Slice of Day Workshop 9: *UCAP and Multi-year*, January 19, 2022.

[43] PU Code Section 399.11-399.33.

demand for new FCDS solar and solar hybrid resources.[44]

SCE and other 24-slice proponents must ensure that their proposal does not enable resources to count generation that has not been tested for simultaneous delivery with the rest of the RA fleet NQCs. SCE's proposal is ultimately predicated on the Commission's adoption of Hourly Profiles that conflate a resource's hourly QCs with the resource's NQCs, even as SCE makes no allowance for any CAISO deliverability testing of those Hourly Profiles. It is imprudent to assume away the deliverability issues of SCE's proposal. Whatever alignment[45] of the Commission's QC methodology and the CAISO's deliverability practices that the status quo may exhibit is the deliberate result of coordination between the Commission and the CAISO. Future alignment is not guaranteed, and the CAISO's current deliverability practices provide no assurance that any above-RA portion of a resource's capacity will be deliverable at the same time as the rest of the collective RA fleet is producing at NQC. To address these fundamental concerns, SCE and other 24-slice proponents must address the interaction of a 24-slice paradigm with the CAISO's deliverability practices.

B. Transaction of Requirements May Introduce Complexities

Cal Advocates described how obligation transactability (henceforth, load trading) could work in the second round of informal comments and suggested that the Energy Division would be the best entity to host or oversee such a market.[46] In the intervening period, Cal Advocates has identified additional concerns about load trading.

First, load trading may violate the Public Utilities Code (PU Code) governing Commission-jurisdictional LSEs. LSEs are subject to certain responsibilities under the Public Utilities Code (PU Code), including serving their customers' load. PU Code-defined LSEs

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[44] This statement is based on Cal Advocates' review of the CAISO interconnection queue, which is available at https://rimspub.caiso.com/rimsui/logon.do.

[45] The status quo does afford many resources a QC value that is close or identical to the final NQC that reflects the resource's deliverability. See Commission, *2020 Qualifying Capacity Methodology Manual,* November 2020, p. 7. Available at https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/q/6442466773-qc-manual-2020.pdf.

[46] Cal Advocates defined load trading "as one LSE paying another LSE to assume a portion of the former's RA requirements." Note that this section is focused entirely on load trading in the context of SCE's 24-hourly framework. *The Public Advocates Office's Informal Comments on Structural Elements and Resource Counting Workshops of the Slice of Day RA Framework Process*, December 22, 2021, pp. 6-7.

deliver a defined service or product to end-use customers.[47] One example of an LSE product is an energy mix that specifies some level of carbon-free electricity. If a customer enrolls with an LSE because they expect to receive a specific amount of carbon-free electricity, but the LSE has sold off some portion of its load obligation to another LSE, the portion of that customer's demand is no longer served by the LSE the customer directly pays. Thus, the customer can no longer be assured of the energy mix of the electricity they receive.[48]

It is unclear whether Community Choice Aggregators (CCAs) could engage in load trading without a change to the PU Code to enable the transaction of load obligations (RA requirements) between LSEs. The PU Code specifies that a CCA "shall be solely responsible for all generation procurement activities on behalf of the [CCA's] customers, except where other generation procurement arrangements are expressly authorized by statute."[49] This language suggests that load trading would require the adoption of a specific authorizing statute. The PU Code authorizes CCAs to aggregate load for the purposes of procurement but does not discuss aggregating load for the purposes of selling load.[50] Likewise, the PU Code provides:

> A community choice aggregator may group retail electricity customers to solicit bids, broker, and contract for electricity and energy services for those customers. The community choice aggregator may enter into agreements for services to facilitate the sale and purchase of electricity and other related services.[51]

This authorization allows CCAs to serve *their* customers and does not provide recourse for a CCA to shift customer load to another LSE. The PU Code provides clear recourse for customers to opt out of CCA service but does not allow CCAs to opt customers out for procurement purposes.[52] These issues require clarification prior to considering approval of load trading.

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[47] The PU Code defines an LSE as an "electrical corporation, electric service provider, or community choice aggregator serving end-use customers in the state." (PU Code Section 8340(e)). The PU Code definition of electric corporation "includes every corporation or person owning, controlling, operating, or managing any electric plant for compensation within this state…" (PU Code Section 218(a)), and an electric service provider is "an entity that offers electrical service to customers within the service territory of an electrical corporation." (PU Code Section 218.3(a)).

[48] As a related concern, the Commission would need to resolve how LSEs' power content labels are calculated if load trading is adopted to prevent gaming.

[49] PU Code Section 366.2(a)(5).

[50] PU Code Sections 366.2(a)(1) and 366.2(a)(2).

[51] PU Code Section 366.2(c)(1).

[52] PU Code Section 366.2(a)(3).

On the policy side of the equation, Cal Advocates noted that load trading would make it difficult to track how much load an LSE is responsible for, which could weaken system reliability.[53] Currently, many LSEs sell their excess RA on a regular basis through general solicitations and bilateral/brokered transactions. Implementing a load trading scheme in addition to the excess RA capacity market would require clearly defined sequencing and timing to avoid threatening system reliability. Month-ahead RA showings are due 45 days before serving load, which is effectively the current deadline for the excess RA capacity market. Adding load trading to this dynamic may be administratively unfeasible on the same timeline, so an earlier deadline for load trading would need to be imposed, perhaps 75 days ahead of serving load. The additional 30 days before month-ahead RA showings are due would be needed so that LSEs are able to then transact on the RA excess capacity market to fulfill finalized RA requirements.

As Cal Advocates discussed in the previous round of informal comments, load trading could offer benefits that include optimizing under-utilized IOU RA capacity and potentially fewer RA deficiency penalties.[54] While the challenges described above are not insurmountable, it is not clear that the added complexity associated with load trading would be beneficial for system reliability or ratepayers in the 24-hourly Slice-of-Day framework. Although load trading and the RA capacity excess market may seem like two sides of the same coin, load trading adds additional complexity compared to operating the excess market. To prevent load trading from weakening system reliability, transacting LSEs would have to report the changes in their respective RA obligations to the Commission. Additionally, the load trading market product would be specific *hourly* slices on a monthly granularity, which adds a second dimension of complexity to the reporting.[55] A single or multiple slice RA obligation product is more complex than the existing RA capacity market product, which is a pro rata share of an RA resource's capacity across all hours it is available. After transacting in the RA capacity excess market, LSEs only need to show adequate capacity to the Commission to comply with their respective

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[53] Tracking LSE load obligations would be even more challenging if the Energy Division is uninterested in hosting a load trading market.

[54] *The Public Advocates Office's Informal Comments on Structural Elements and Resource Counting Workshops of the Slice of Day RA Framework Process*, December 22, 2021, p. 6.

[55] SCE's 24-hourly framework also proposes that RA resources may not be procured by slices; only the full all-hour attributes, aligned with CAISO must offer obligations, could be procured. SCE, *Slice of Day Resource Counting & Penalty Process*, Presentation: RA Slice of Day Workshop, January 19, 2022, p. 3.

RA obligations.[56] There is no additional reporting required, nor clarification of the temporal dimension. Load trading would require more complexity than the existing RA capacity excess market.

Finally, during workshops, CCAs expressed a preference for procuring capacity to meet their own load profiles and suggested that load trading would ease the mismatch between the current load allocation and LSEs' individual load shapes.[57] The California Energy Commission (CEC) indicated a willingness to generate LSE hourly-monthly load profiles.[58] This "bottom-up" need allocation approach adds complexity to the 24-hourly Slice-of-Day framework. Therefore, Cal Advocates recommends that if the bottom-up need allocation approach is used, there should be no need for load trading because LSEs will procure to meet the needs of their unique load shapes.

C. Energy Storage Concerns

a. Multi-Cycle Showings Must Reflect Resource Limitations

CESA proposes that storage resources should be allowed to be shown for multiple cycles per day, with no consideration of the time required to charge the storage resources between cycles.[59] CESA further proposes that verification of charging sufficiency should be based only on the total excess energy available to charge the storage for the number of shown cycles, with no consideration of when the excess energy is available relative to when the storage capacity is shown. CESA argues that the RA framework is only an accounting mechanism, while actual storage dispatch is managed through CAISO market processes.

CESA's proposal would allow a battery with 4-hour maximum discharge capacity, such as a lithium-ion battery, to be shown for more than 4 consecutive hours or longer at full NQC value if the battery can support multiple discharge cycles per day. However, the CAISO cannot count on more than 4 consecutive hours of full capacity discharge because of the battery's

[56] The single capacity showing requirement is true of both the existing RA excess market and its incarnation under a 24-hourly framework.

[57] Discussion at the November 17, 2021 and December 1, 2021 Slice of Day Workshops.

[58] CEC, *Resource Adequacy Framework Demand Forecast Considerations*, presented at the December 1, 2021 Slice of Day Workshop.

[59] *Informal Comments of the California Energy Storage Alliance Regarding the Resource Adequacy Slice of Day Reform Workshops*, December 22, 2021, p. 5.

physical limitations; namely the need to charge the storage after a full discharge cycle.

Showings for energy storage RA capacity should reasonably correspond to the operational limitations of the resource and account for sufficient charging energy ahead of the discharge of the battery. An energy storage resource with 4 hours of maximum capacity discharge should be shown at most for 4 consecutive hours at its maximum capacity, with recognition that actual timing of CAISO dispatch of the 4 hours of capacity will differ based upon market conditions and bids. If storage is shown for multiple cycles, the Slice-of-Day showing requirement should include a showing of both sufficient excess energy and time between discharge cycles to charge the battery. Because the CAISO will not be able to dispatch a 4-hour battery at full capacity longer than 4 consecutive hours, the RA showing for the resource should reflect the physical limitations that constrain CAISO dispatch. Otherwise, the RA showing may overstate the capacity that is available to the CAISO for dispatch over a given time interval.

b. Allowing Multi-Cycle Showings May Harm Cost-Effectiveness of the RA Program

More frequent cycling of energy storage results in accelerated storage capacity degradation. To reflect the marginal degradation costs due to multiple cycles, storage resources will likely submit higher energy bids for the second or third cycle over a given period. To the extent that multiple cycle RA showings for energy storage leads to greater CAISO reliance on the second and third cycles, there may be a corresponding impact on market prices. This is particularly the case under stressed grid conditions.

D.21-07-014 requires that a future RA framework link RA value to a resource's bidding behavior, to increase the cost-effectiveness of RA.[60] A storage resource's bidding behavior over multiple cycles will have an impact on storage cost-effectiveness and should be linked to RA value.

The RA reform effort should be cognizant of any unintended consequences of allowing for RA showings to include multiple storage discharge cycles per day on RA cost-effectiveness and CAISO market outcomes.

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[60] D.21-07-014, p. 27.

c. The Counting Methodology for Co-Located and Hybrid Resources Must Correspond to Market Operations

Counting rules for hybrid and co-located resources should reasonably correspond to how the resources operate in the CAISO market. If either hybrid resources or co-located resources have grid charging constraints that are managed by the resource owner or operationalized by the CAISO,[61] the counting rules should account for the energy available to charge the resources from on-site generation. Such accounting is similar to how QC value is currently determined for co-located and hybrid resources that have Investment Tax Credit charging limitations.[62] If the CAISO is able to issue dispatch instructions to hybrid or co-located resources to charge from the grid to ensure that the required capacity of the storage resource is available when called upon, it is reasonable to use the Pmax value of the storage resource.

IV. CONCLUSION

Cal Advocates looks forward to participating in continued development of Slice-Of-Day workshops and formal development through the current RA proceeding (R.21-10-002).

Please contact Kyle Navis and Patrick Cunningham at Kyle.Navis@cpuc.ca.gov or 415-703-2840 with any questions regarding these comments.

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[61] For example see the *CAISO Energy Storage Enhancements Initiative Straw Proposal*, December 9, 2021, Section 3.3, Co-Located Enhancements, p. 15.

[62] D.20-06-031, Ordering Paragraph 11, p. 90.

Appendix A: Statement of Slice-of-Day Positions

Slice-of-Day working group facilitators requested[63] that stakeholders provide a summary of positions and respond to a Position Matrix Excel worksheet. Using the Position Matrix as a guide for issues and position terminology, the list below includes Cal Advocates' current Slice-of-Day design positions and in many instances includes brief statements to support those positions. Cal Advocates also submitted responses to the Position Matrix in the Excel worksheet file itself and provided the completed Position Matrix to working group facilitators simultaneously with these informal comments. Cal Advocates notes that these positions may change as additional analysis and Commission decision-making occurs.

Load: Gross load-based requirements. Using net load would complicate the resource counting of variable energy resources and could create challenges for setting the Planning Reserve Margin.[64]

Compliance periods: Monthly. Seasonal showings would reduce regulatory visibility, ignore benefits from LSEs' changing monthly coincidence factors, and lead to complications for counting use-limited resources that may inaccurately show adequate supply across a seasonal showing, when a monthly breakdown might show scarcity conditions more accurately.[65]

Number of slices: 24 slices. A 24-slice structure is most consistent with Commission direction to examine hourly energy sufficiency.[66]

Type of load forecast: Maximum value for each slice. Using the maximum load value forecasted for each slice within a month ensures Slice-of-Day requirements account for the highest forecasted load within that month. If instead the hourly load profile for the single most severe forecasted day in a month set all hourly slice requirements, other days in the month may have energy needs forecasted above the requirements for some slices.[67]

Resource counting:

- NQC value granularity: Multiple (slice-specific NQC values). This methodology is preferred, however a 24-slice framework must account for deliverability of resources able

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[63] PG&E E-mail, *FW: [EXTERNAL] [R.19-11-009 & R.21-10-002] CLARIFICATION AND UPDATE: RA Framework Workshop - Informal Comments and Position Matrix due Friday 2/4*, sent by PG&E to the RA service lists on February 2, 2022.

[64] *The Public Advocates Office's Informal Comments on Structural Elements and Resource Counting Workshops of the Slice of Day RA Framework Process,* November 10, 2021 (Cal Advocates Informal Comments 1), pp. 6-7.

[65] Cal Advocates Informal Comments 1, pp. 10-11.

[66] Cal Advocates Informal Comments 1, pp. 3-6.

[67] Cal Advocates has previously supported use of a maximum value for each slice using a sample of the previous five years, though the use of LSE forecast data may also be prudent depending on the ultimate Slice-of-Day design implemented. Cal Advocates Informal Comments 1, pp. 11-12.

to generate beyond their NQC.

- Wind and Solar: Exceedance.
- 24-hour available dispatchable thermal: UCAP-light. Cal Advocates does not support the full implementation of a UCAP system but does support consideration of ambient derates.
    - Cal Advocates continues to oppose UCAP. The CAISO should also remove the retiring Once-through Cooling (OTC) units from the forced outage data in its UCAP workshop materials,[68] so that the Commission can see the going-forward forced outage rate of the generation fleet.
- Daily energy-limited dispatchable thermal: UCAP-light.
- Dispatchable hydro: Current 10-year exceedance methodology. Cal Advocates supports use of the methodology option approved in D.20-06-031 which applies a higher weight to the most severe drought year.
- Storage: PMax over number of hours shown, subject to interconnection limits.
- Long-duration storage: No position. Requires substantial additional development and definition of long-duration storage. Different methodologies may be appropriate for different technologies.
- Hybrid and co-located resources: Counting must reflect their market operational characteristics.
    - Resources claiming ITC: Use the counting method adopted in D.20-06-031 for resourcing planning to access the ITC.[69] Grid-charging Hybrid and Co-located resources not claiming or eligible for the ITC: Treat components separately and apply application QC for each.
- Demand Response: No position.
- Methodology preference for exceedance values: No position. Methodology selection requires additional development.
- In general, resource counting needs more attention before the Commission can implement a Slice-of-Day framework. The workshops did not get into sufficient detail to resolve resource counting issues and resulting impacts on the Planning Reserve Margin.

<u>Whether there remains a need for Maximum Cumulative Capacity (MCC) buckets or Caps on certain use-limited resources</u>: Yes. Due to limited calls per month and year for demand response programs, MCC buckets may be necessary to ensure the grid has access to available reliable resources.

<u>RA resource transactions</u>: Bundled (LSE purchases all of resource's RA attributes for all slices). Cal Advocates is not convinced that load trading delivers adequate ratepayer benefits, as load

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[68] During workshops, the CAISO clarified that OTC units were used in its outage dataset and that the a "Steamer" unit likely represents an OTC resource. CAISO, *Unforced Capacity Evaluation Proposal,* January 19, 2021, p. 32.

[69] D.20-06-031, *Decision Adopting Local Capacity Obligations for 2021-2023, Adopting Flexible Capacity Obligations for 2021, and Refining the Resource Adequacy Program,* June 25, 2020, pp. 25-31.

trading introduces unnecessary complications and may violate load-serving entities' statutory obligations for procurement.[70]

Need determination and allocation: CEC's proposed method (a hybrid of top down and LSE-specific based on LSE forecasts and recorded loads).

Energy sufficiency for charging storage: Explicit requirement to demonstrate energy sufficiency by slice. LSEs must also demonstrate sufficiency for storage efficiency losses. Multi-cycle showings must account for the physical limitations of storage resources, such as charging requirements. The RA program should also consider if capacity degradation due to multi-cycle charging profiles will unintentionally reduce the cost-effectiveness of the RA program.[71]

Hedging: Hedging mechanisms should be developed. However, more analysis into proposed hedging options should be conducted and implementation of hedging tools may be pursued separately from Slice-of-Day development in the RA Rulemaking. Cal Advocates continues to support Energy Division's Bid Cap proposal, presented previously in the RA Rulemaking,[72] which would increase market access to RA resources at more reasonable prices, ensuring ratepayers receive capacity and energy benefits they pay for.[73] RA restructuring should explore other hedging matters in more detail rather than move forward with any proposals, such as forward requirements or requirements to procure other hedging instruments. Hedging concerns should also be considered in coordination with wider Commission decision-making (e.g., Provider of Last Resort, Long-Term Gas Planning, and Aliso Canyon proceedings).

Multi-year Forward RA Requirements: 1 year (status quo). Maintaining a one-year-forward system and flexible RA requirement avoids unintentional overprocurement due to regulatory and forecast load uncertainties and maintains existing access to imports. Additionally, LSEs and the Central Procurement Entities are already authorized to enter into RA contracts of any term which provides LSEs with flexibility to design their RA portfolios and procurement strategies. Multi-year RA requirements would remove that flexibility, reducing the procurement options of LSEs.[74]

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[70] See Section B of these Informal Comments 3 for Cal Advocates' analysis on transactions.

[71] See Section C of these Informal Comments 3 for Cal Advocates' analysis on transactions.

[72] R.19-11-009, *Energy Division Issue Paper and Draft Straw Proposal for Consideration in Proceeding R.19-11-009, Track 3B (Administrative Law Judge's Ruling on Energy Division's Track 3.B Proposal, Appendix A),* August 7, 2020, pp. 34-39.

[73] R.19-11-009, *Comments of the Public Advocates Office on Track 3B.2 Proposals,* January 15, 2021, pp. 1-2.

[74] See also Cal Advocates' previously stated concerns of the adoption of multi-year requirements at: R.19-11-009, *Comments of the Public Advocates Office on Track 3B.2 Proposals,* January 15, 2021, pp. 5-7.

REV RENEWABLES

Final and Summary Informal Comments on Resource Adequacy Long Term Reform Workshops (R.19-11-009 and R.21-10-002)

I. Introduction

REV Renewables ("REV") offers these informal comments on the workshops to date on Resource Adequacy (RA) long-term reforms. REV's comments are summarized as follows:

- REV supports the 24-hourly slices framework but would not oppose a two slice framework that includes a net peak showing.
- Energy hedging should not be required as there is insufficient evidence they are needed or would produce cost effective results for consumers.
- Energy sufficiency requirements should be designed to avoid artificially limiting energy storage capacity at the Load Serving Entity (LSE) level when there is sufficient system level energy.
- Storage resources should count at Pmax over the number of hours shown subject to interconnection limits to recognize their flexibility to dispatch during hours of need on the grid. The Commission should also work on deliverability assessment methodology reforms.

II. Discussion

A. REV supports the 24-hourly slices framework for the RA program

REV supports reforming the RA program into the 24-hourly slices framework, as presented by Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) in the December 15, 2021, meetings. This framework can help ensure reliable electricity throughout the day while accommodating California's increased penetration of renewables and batteries and meets the Commission's Guiding Principles set in Decision ("D.") 21-07-014. This 24-hourly slices framework would align well with the California Independent System Operator (CAISO)'s 24-hour must offer obligation and would eliminate the need for Maximum Cumulative Capacity (MCC) buckets. REV supports monthly showings as is currently done by LSEs.

REV is not opposed to the Gridwell/Vistra proposal for a two-slice framework that evaluates needs at the gross load peak and net load peak. This proposal maintains much of the current RA structure and focuses improvements in on the net load peak hours that are of most concern for grid reliability. If this proposal is adopted, REV recommends that LSEs be required to do a showing for both peak periods to ensure sufficient capacity is available during the net load peak hours.

B. Energy hedges should not be required as there is insufficient evidence they are needed or would produce cost effective results for consumers.

REV opposes requiring a price cap rebate and/or energy hedge in the RA framework and supports Vistra's proposal to explicitly allow LSEs to include an energy hedge option in RA contracts. As discussed in the January 5, 2022, workshop, many LSEs can and do enter into energy hedge agreements, and there is no evidence to suggest that bundling this hedge into an RA contract is more cost-effective for consumers. In fact, including an energy hedge or price cap rebate may increase the cost of RA because it would embed that energy market risk into the RA program. While bundling these products may be the most efficient outcome for some LSEs, it may not be for others.

Further, as discussed by Vistra, if the Commission decides to pursue this topic it should refine what problem it is trying to solve, is it market power concerns? Financial exposure?

Physical exposure? Is it for a specific type of resource or all resources? The CAISO energy market already incentivizes resources to bid their marginal cost in order to participate, otherwise they will not get chosen, and the must offer obligations ensure that RA resources are available or subject to penalty. Energy Division has not presented evidence that the exercise of market power by RA resources is so pervasive that it requires a wholesale modification of the RA requirements. Further, the price cap as presented does not take into account variable energy costs and could create significant market inefficiency. For example, during extreme weather events such as the recent February 2021 cold weather event in other parts of the country, California energy prices were significantly above $300/MWh due to nationwide energy shortages. If an RA storage resource, for example, could only bid at $300/MWh but had to charge at $700/MWh it would have led to significant financial loss. If some of these resources decide to not participate in the market due to artificial bid cap requirements, this can lead to serious reliability issues for the grid and could lead to load shedding events.

CAISO and the Department of Market Monitoring have protocols in place that test market power and take corrective actions if needed; the Commission could work with CAISO to investigate concerns and develop solutions if a problem is identified.

If a requirement is imposed, it should be done on future contracts only so as not to conflict with current contractual obligations. Developers are investing billions into California's energy market based on the current structure, and any changes that disrupt current contracts and financial obligations should be done with caution.

C. Energy sufficiency requirements should be designed to avoid artificially limiting energy storage capacity at the LSE level when there is sufficient system level energy.

REV is not opposed to an energy sufficiency verification for charging energy storage resources; however this requirement should be designed such that it does not lead to artificial limits for energy storage. For example, an individual LSE may not have sufficient energy in its portfolio to support procuring additional storage capacity even though at the system level there is sufficient energy. Storage RA resources operate in a connected CAISO grid and are not limited by LSE boundaries; limiting charging sufficiency requirements to this smaller level could lead to under procuring storage resources or over procuring additional resources (which is a burden to ratepayers) when there is actually sufficient system level energy available. Additionally, as shown by Vistra in the December 17, 2021, presentation, there is limited risks of limited energy for charging storage in the near- and mid-term.

If the Commission and LSEs are concerned about charging sufficiency in the future, REV recommends implementing a mechanism to allow LSEs to trade obligations to achieve a more efficient market outcome. For example, an LSE with excess capacity in the middle of the day could trade load obligation with an LSE that is short of meeting its charging sufficiency requirement. This type of trading recognizes system level operations, avoids LSEs leaning on the others at no cost, and reduces artificial limits on energy storage for a specific LSE. Local Capacity Requirements are done separately and would be a check on local constraints (if applicable) that may impact energy storage capabilities. While REV supports LSEs procuring a bundled product that is the resource's profile (a megawatt amount over the 24-hours) rather than buying a specific hour slice from a resource, this limited unbundling can improve transactability of RA and enhance market outcomes. REV understands some parties are discussing options to improve transactability and does not endorse a specific option at this time but suggests proposals to this effect be evaluated.

D. Storage resources should count at Pmax over the number of hours shown subject to interconnection limits, and the Commission should also work with CAISO on deliverability assessment methodology reforms.

REV agrees with SCE and PG&E's proposal to count stand-alone energy storage at Pmax over the number of hours shown subject to interconnection limits. In the 24-hourly slice framework this method works particularly well for storage given that it is a flexible resource that can tailor its dispatch to any number of hours in the day and is only shown for those hours, therefore is already discounted for its limited use. If a two-slice framework is chosen, REV is open to an average ELCC methodology but suggests that the Commission provide an opportunity for stakeholder feedback on any analysis that determines the ELCC level. REV does not support a UCAP or UCAP-lite methodology at this time because it is unclear exactly what this would entail since CAISO's proposal currently focuses on thermal resources. The Commission could also consider a Pmin value that recognizes a storage resource's ability to absorb excess solar during the middle of the day, which is currently recognized as effective flexible capacity.

REV also agrees with California Wind Energy Association (CalWEA) that the Commission should work with CAISO on reforming the deliverability assessment methodology (as presented in the November 3, 2021, workshop). REV recommends CAISO consider providing a deliverability status for high system need (HSN) period. California's need for resources during the HSN is growing. Resources such as energy storage that could generally charge during off-peak and discharge during highest system are adequately poised to meet these system needs. REV suggests that CAISO's deliverability constructs should capture this and, for example, assign more weight on the HSN scenario for the deliverability. These changes could help align LSE procurement needs with grid system needs for resources in the net peak demand period. The Commission should also investigate whether two NQCs are needed for a resource, one for the gross load peak and one for the net load peak to account for a resource's contribution to reliability during the net load peak hours. These two NQCs could align with the two-slice framework in particular but could also be useful in the 24-hourly slice framework.

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February 7, 2022

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In its Decision (D.) 21-07-014 (Decision), the California Public Utilities Commission (CPUC) found Pacific Gas and Electric's (PG&E) slice-of-day proposal best addresses the Resource Adequacy (RA) reform principles identified during the proceeding, as well as the concerns with the current RA framework, and if further developed, are best positioned to be implemented in 2023 for the 2024 compliance year. The CPUC also concluded the parties should engage in a series of workshops to further develop PG&E's slice-of-day proposal for a final proposed framework. Southern California Edison (SCE) respectfully submits the following final informal comments on SCE's position at the conclusion of the RA reform workshops.

The Commission should adopt the 24-hourly slices framework

The current RA framework requires major revisions to ensure grid reliability in both the near-term and as the grid continues to evolve through at least 2045. Minor changes to the existing RA program are likely to prove unsuccessful in the near-term, and inadequate to serve as a durable reliability framework for the years to come. In contrast, SCE's 24-hourly slice proposal directly addresses the dramatic change in grid technologies, the crucial role and unique attributes of renewable resources and storage, and the need to maintain reliability in all hours of the day, rather than simply in hours that proved challenging in the past. SCE's proposal is durable and addresses both gross and net load peaks, regardless of where they fall, their durations, and how they evolve over time.

SCE recommends the CPUC adopt the 24-hourly slices framework, provide guidance on specific details, and establish a process to resolve any remaining issues. To allow the implementation of this new framework for the 2024 compliance year, the CPUC should render its decision adopting this framework and outlining next steps as early as possible, and SCE recommends an initial decision prior to summer 2022. Remaining open items that must be addressed for 2024 compliance year implementation should be determined in a narrowly focused forum after the CPUC has established the specific slice-of-day framework.

The Gridwell/Vistra Proposal is not a slice-of-day proposal and should not be adopted

The Commission should not adopt Gridwell/Vistra's proposal because it does not meet the Decision's basic requirements and principles. In D.21-07-014, parties were ordered to engage in workshops "to develop implementation details based on the Pacific Gas and Electric Company's slice-of-day proposal."[1] The Gridwell/Vistra proposal is not a "slice"-based proposal; it is a two "point" proposal that only marginally improves upon the existing RA program by adding one additional requirement (*i.e.,* the net peak or "non-solar hour"[2]). The CPUC should reject the Gridwell/Vistra proposal because it fails to ensure hourly requirements are satisfied, cannot meet

[1] *See* D.21-07-014, OP 1, at p.52
[2] *See* Gridwell December 1 Presentation, p. 12

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the CPUC criteria for durability, and is generally not aligned with the direction established in D.21-07-014. [3]

First, by definition, the Gridwell/Vistra proposal only tests two points for resource sufficiency—the peak and net-peak load requirements. There is no check to confirm there is resource sufficiency for any of the remaining hours of the day. Ensuring temporal resource sufficiency for all hours of the day is a necessary component for any RA design given the increasing penetration of renewable, energy storage, and use-limited resources.[4] Moreover, the Gridwell/Vistra proposal continues to rely on the existing single-point effective load carrying capability (ELCC) values to count solar and wind resources' contribution to reliability, even though those ELCC values fail to reflect their expected capacity contributions during the peak and net-peak hours. 8That means the Gridwell/Vistra proposal cannot even ensure reliability during the two single points that it purports to address.

Second, the Gridwell/Vistra Proposal does not address the charging of energy storage resources because it claims "[t]here is sufficient energy to charge batteries in aggregate as far out as we have reliable data, so this is not a reliability issue that needs to be addressed in this proceeding."[5] This claim is unsupported by analysis and inconsistent with D.21-07-014. D.21-07-014 already acknowledges that the lack of an energy storage charging check is a gap that must be addressed.[6] Indeed, the need to incorporate energy storage charging sufficiency in the RA reform framework is urgent given the draft Preferred System Plan's (PSP) estimate that over 10,000 MW of new battery storage will be installed by 2024.[7] The CPUC should reject any proposal that fails to address this core issue.

Third, the Gridwell/Vistra Proposal does nothing to require LSEs procure and show an RA portfolio that demonstrates their ability to meet the requirements of their specific load profiles. The Gridwell/Vistra proposal will allow LSEs to rely heavily on use-limited resources, irrespective of whether those use-limited resources are available to meet the LSEs' actual load. This would shift costs from LSEs that rely heavily on use-limited resources to other LSEs with diverse portfolios that provide capacity in all hours. Reliability could be compromised if all LSEs took advantage of this weakness in the Gridwell/Vistra proposal. For example, if the peak period lasted 4-hours, an LSE might discharge all of the energy from 4-hours batteries to meet the peak. As a result, they might not have any battery energy available for the net-peak. However, since the Gridwell/Vistra proposal only looks at two points, rather than all the hours within all slices, it would allow these batteries to count as serving both the peak period and the net-peak period, fallaciously indicating that reliability had been met. Moreover, the proposal eliminates Maximum Cumulative Capacity (MCC) buckets and provides, ultimately, no assurance that reliability can even be met in the two points it tests. As noted in D.21-07-014,

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[3] Specifically, the Gridwell/Vistra proposal fails to satisfy principle 1, which is "[t]o balance ensuring a reliable electrical grid with minimizing costs to customers," principle 2, which is, [t]o balance addressing hourly energy sufficiency for reliable operations with advancing California's environmental goals," and principle 5, which is "[t]o be durable and adaptable to a changing electric grid." *See* D.21-07-014 at Ordering Paragraph 2.
[4] D.21-07-014 at p. 30.
[5] *See* Gridwell December 1 Presentation "Resource Adequacy Two-Slice Proposal", p.10
[6] *See* D.21-07-014 at p. 27.
[7] *See* December 22, 2021 Proposed Decision in R.20-05-003, at p. 87. The draft PSP estimates an additional 4,000 MW of energy storage (incremental to the 10,000 MW by 2024) will be installed by 2032.

“[w]ith the growing penetration of renewable resources, the Commission seeks a framework that can better manage reliance on use-limited resources to meet reliability needs.” Gridwell/Vistra’s proposal fails to accomplish this goal.

Finally, the Gridwell/Vistra Proposal is not durable, but would require frequent adjustments as the generation fleet and load shapes change over time. Indeed, as discussed above, the Gridwell/Vistra proposal is already ill-suited to address the influx of energy storage expected by 2024. In recent workshops, Gridwell has noted that they might need to add additional “points” to the proposal in the future. It would be shortsighted and counterproductive to spend time implementing a framework that on its face is both ineffective and unable to address evolving reliability needs.

February 4, 2022

INFORMAL COMMENTS OF SAN DIEGO GAS & ELECTRIC COMPANY REGARDING RESOURCE ADEQUACY REFORM TRACK (R.21-10-002)

SDG&E appreciates the opportunity to provide these comments regarding the Slice-of-Day (SOD) framework.

SDG&E's Overall Position

The two competing proposals developed through the workshop process are the 2-slice proposal (gross peak and net peak) and the 24x1-hour slice proposal. SDG&E is currently inclined toward the 2-slice proposal based upon its belief that, if implemented correctly, the 2-slice proposal can adequately ensure reliability while likely being more affordable and more transactable. However, it is critical that a Loss of Load Expectation (LOLE) study be performed for each proposal. An LOLE study is necessary to determine the appropriate PRM to achieve a 0.1 (i.e., 10% chance of loss of load) under each proposal and to estimate the total cost of procurement under each proposal. The proposals differ in two critical areas: (1) how the need determination is performed and (2) how resources are counted towards meeting the need determination. Thus, it is likely that each proposal will produce a different mix of generators, and also a different total amount of procurement. It is therefore likely that one proposal will be less costly to ratepayers. While SDG&E's focus is on a reliable system, total ratepayer cost is also an important element to consider. SDG&E's assessment is that the 2-slice proposal can ensure reliability and will likely be more affordable, and thus favors the 2-slice proposal on this basis. However, a robust procurement simulation under each proposal is necessary to verify this educated guess.

Special Considerations for the 2-Slice Proposal

SDG&E believes that the more robust and reliable proposal is the 24x1-hour slice proposal. It employs a sophisticated test to ensure reliability in every hour of the day and will easily identify any shortfalls. However, SDG&E believes that the 2-slice proposal *can* achieve a level of reliability substantially similar to the 24x1-hour slice proposal assuming the proper rigor is observed.

To ensure reliability for the foreseeable future, it is necessary to ensure adequate capacity to meet both gross and net peak load, to ensure the existence of enough base load resources, and to ensure the availability of sufficient energy to charge battery storage. The most obvious downside of the 2-slice proposal is that it does not explicitly guarantee sufficient energy for battery charging.

Instead, it relies on the Effective Load Carrying Capacity (ELCC) methodology to ensure sufficient energy for battery charging. The ELCC methodology can perform this function, but it is not a durable solution. Broadly speaking, the ELCC methodology for batteries looks at each day of the year, estimates the level of generation for each day, and then uses that information to determine the probability of expected unserved energy. Therefore, baked into the ELCC value are two important assumptions: 1) the total amount of resources available to charge batteries, and 2) the number of batteries expected to be installed over the period being reviewed. Each additional battery potentially takes energy that another battery might have used to charge. Therefore, as the resource mix changes from what was assumed in the ELCC study, and as the number of interconnected batteries changes from what was assumed in the ELCC study, the accuracy of the ELCC value for those batteries degrades.

For this reason, the ELCC value for batteries must be updated regularly to ensure that the ELCC value continues to accurately reflect the batteries' contribution to grid reliability. To this end, SDG&E recommend updating the ELCC once a year as a prudent practice,

Significant portfolio changes affect another key aspect of reliability: the Planning Reserve Margin (PRM). Load-serving entities (LSEs) must procure sufficient resources to meet the California Energy Commission (CEC) forecasted demand including a PRM percentage that ensures adequate capacity to meet a 0.1 (i.e. 10%) loss of load expectation. Ideally, the PRM should be set by a LOLE study that determines the resource capacity needed to ensure that 0.1 loss of load expectation rather than guessing that a certain PRM will result in just enough, but not too much capacity. Therefore, baked into the PRM is an assumption about the number of resources that will be available. Suppose the grid needs 50 MW of reliable capacity to ensure a 0.1 loss of load expectation. If 40 MW of qualifying capacity is expected to be available, then the PRM that achieves a 0.1 loss of load expectation is 25% (40 MW + 25% = 50 MW). This becomes a problem if the ELCC value is not recalibrated often enough. Suppose an extreme example where in Year 1 there is insufficient energy to charge batteries and therefore batteries are assigned an ELCC valuation of 50%. But suppose in Year 2 extra capacity is brought on such that batteries now have an ELCC valuation of 100%. Assuming no change to the PRM, in Year 2 LSEs would only need to procure half the number of batteries as they did in Year 1 to achieve the same level of reliability. If the ELCC was not recalculated for Year 2, LSEs would end up over-procuring since batteries that now contribute 100% ELCC are only valued at 50%. However, as the grid's resource mix changes and resource ELCCs change, the required capacity needed to provide reliability may also increase or decrease depending on how much dispatchable capacity is available in high load hours and how variable that reliable capacity is. A LOLE study would likely determine a different PRM given the large change in the resource mix in Year 2. Since there are complicated resource interactions that can lead to unforeseen changes in ELCC or PRM as the grid's portfolio evolves, the PRM should also be updated regularly along with LOLE to ensure the continued accuracy of both metrics.

Hedging

SDG&E does not believe that the hedging requirement is a necessary component of the RA program.

ENLR

SDG&E would support ENLR if the Commission decides to go with the 24x1-hour slice proposal. But for the 2-slice proposal, ELCC is needed to ensure sufficient energy is available to charge batteries.

UCAP

SDG&E does not support the UCAP counting methodology. The 2-slice proposal requires the ELCC methodology to ensure sufficient energy is available to charge batteries. For the 24x1-hour slice proposal, SDG&E believes the ENLR methodology is superior.

Forward RA

SDG&E does not see a need for a forward RA requirement.

BEFORE THE PUBLIC UTILITIES COMMISISON OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 21-10-002

INFORMAL COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION AND THE LARGE-SCALE SOLAR ASSOCIATION ON RESOURCE ADEQUACY WORKSHOPS

The Solar Energy Industries Association and Large-scale Solar Association (Joint Solar Parties) appreciate the opportunity to submit this final round of informal comments following the conclusion of the workshops on the future of the Resource Adequacy (RA) program. We thank the slice-of-day workshop facilitators, presenters, and participants for the constructive discussions about the many considerations that will go into a reformed RA program. The Joint Solar Parties believe that substantial progress has been made to date in developing a workable proposal for implementing a slice-of-day framework as directed by the Commission in D. 21-07-024. For the convenience of the parties who are assembling the workshop report, a table of contents to these comments is provided below.

1. Support for the Hourly Framework

The Joint Solar Parties continue to support the 24-hour, monthly, slice-of-day proposal (the "Hourly Framework") first put forward by Southern California Edison Company ("SCE") as the best way to move forward in reforming the RA Program. We are among the sponsors of the joint informal comments that a number of parties are submitting today in support of the Hourly Framework and the principles for RA reform that the same coalition presented at the December

15 workshop. We recommend that the workshop report recognize the Hourly Framework as most consistent with the policy guidelines for RA reform adopted in D. 21-07-024.

In the workshops, Gridwell and Vistra presented an alternative to the Hourly Framework that focuses on just two slices of day – the gross load peak in the late afternoon and the net load peak in the evening. Although this proposal centers on the two time slices that are most critical for reliability today, it lacks the granularity and flexibility to adapt to the anticipated changes in the hourly profiles of loads and resources on the CAISO system. If California is to meet its GHG goals through widespread electrification, the state will see rapid growth over the coming decade in off-peak electric demand to charge batteries – both utility-scale storage as well as the batteries in electric vehicles – and to serve new demand from electric heat pumps for space and water heating. The state's reliance on time-varying wind and solar resources will continue to grow, as well. Further, the procurement of RA capacity will be the responsibility of a diverse set of load-serving entities (LSEs) with different load profiles based on the geographic areas they serve. As a result, a reformed RA program must have the granularity and flexibility to be used by multiple LSEs with varying load profiles and different portfolios of time-varying resources. The Hourly Framework fully satisfies this critical design requirement. In contrast, the Gridwell/Vistra proposal, which only measures two points in time over the course of a year, is likely to undervalue more flexible resources like batteries and hybrid resources and overvalue conventional dispatchable resources. Further, the proposal relies heavily on complex and opaque ELCC analyses to establish the RA counting value for wind, solar, storage, and hybrid resources and to compensate for the method's limited temporal granularity. Finally, the Gridwell/Vistra proposal assumes that there will not be constraints on the capacity available to charge storage resources. Although that may be largely true today, it fails to recognize that the new RA program must be designed for the circumstances of 2024 and beyond, including the need to charge the rapidly-growing number of batteries of all types with less expensive midday electricity.

2. Resource Counting for Solar and Wind Resources – Exceedance and ENLR

At the November 3, 2021, workshop, SEIA, LSA, and Vote Solar presented a proposal to use an exceedance methodology as the resource counting rule to use for standalone solar projects in the 24-hour slice-of-day proposal. The presentation recommended that a 50% exceedance value (P50) be used for solar technologies, and showed that the current average effective load carrying capacity (ELCC) value for solar supports the use of a P50 exceedance for solar. This use of ELCC to benchmark the choice of the exceedance value complies with P.U. Code Section 399.26(d), which requires the Commission to use the ELCC values for wind and solar "in establishing the contribution of wind and solar energy resources toward meeting the resource adequacy requirements established pursuant to Section 380." This use of ELCC to benchmark the selected 50% exceedance value for solar should give the Commission additional confidence that the use of the P50 exceedance for solar is justified by more sophisticated reliability analyses such as ELCC. The Joint Solar Parties have not proposed an exceedance value for wind that is consistent with the current ELCC for wind, but the data is readily available to do so.

At the December 1, 2021 workshop, the California Wind Energy Association (CalWEA) presented a similar "Effective Net Load Reduction" (ENLR) method for counting the RA contribution of wind and solar in each hourly slice-of-day. This method takes the recorded output of wind or solar in a particular hour and month, over a historical set of years, and finds the average wind or solar output in those hours in the hour/month set when demand was high (defined as within 20% or 30% of the maximum load in that hour and month). Based on the limited set of hours shown in CalWEA's December 1 presentation (just two hours in August), the results of the CalWEA ENLR method for solar are similar to the use of a 50% exceedance value for solar. While we agree that CalWEA's ENLR method is a feasible and understandable approach, it would be important to examine the results of CalWEA's method over a broader set of hours than just the two hours in August that CalWEA showed in its presentation. Further, the Joint Solar Parties have shown that our recommended 50% exceedance for solar is reasonable when benchmarked to more complex reliability metrics such as ELCC; CalWEA has yet to make this showing for its ENLR method.

3. Resource Counting for Hybrid Resources

The slice-of-day reforms to the RA program must recognize the increasing importance of hybrid resources that, typically, combine solar and storage projects into a single entity. Hybrid solar plus storage projects are attracting investments and off-takers. Hybrids comprise a substantial portion of the capacity in the CAISO's interconnection queue, because they provide dispatchable capacity. Hybrid configurations of solar and storage also reduce project costs through shared interconnection facilities and transformers, streamline interconnection studies, and improve efficiency in the use of transmission infrastructure. The flexible and dispatchable capacity that hybrids provide to LSEs is an important reason that RA reforms should use the granular Hourly Framework. As grid needs change over time, the dispatch of the storage component of hybrids can be adapted to meet those changing needs.

It is critically important that the counting rules developed in the RA reform process recognize the flexibility and adaptability of hybrid resources. The Commission already has a good starting point – the current "additive" counting rule for hybrids adopted in D. 20-06-031. Under the Hourly Framework, the current counting rule for hybrids should be further elaborated to recognize that hybrids can be configured in several ways that result in meaningful differences in the capacity that a hybrid can supply. Here are the important design considerations in developing QC values for both the storage and solar components of a hybrid resource:

- **Storage:** determine the MWh of solar energy that can be stored each day, including the energy lost in storage, by two hours before the net load peak. This calculation should recognize that DC-coupled solar-plus-storage units can store energy that otherwise would be lost, or "clipped," in the inverter. The stored energy that can be discharged should be counted for RA purposes in any hour up to the maximum hourly discharge capacity, with the storage capacity across all slices of the day limited by the amount of energy that can be stored on that day.
- **Solar:** use the hybrid project's P50 solar output minus the solar production needed to fill storage by two hours before the net load peak. Again, the amount of solar that can be counted in each hour will depend on (1) whether the hybrid is AC- or DC-coupled, (2) the amount of solar needed to fill the onsite storage, and (3) the size of the solar array relative to the capacities of the inverter(s) and the common point of interconnection.

The sum of the storage and solar QCs in any hour should not exceed the deliverable capacity at the hybrid resource's point of interconnection with the CAISO grid.

4. Transactability and the transition to slice-of-day

The members of SEIA and LSA are parties to existing power purchase agreements and other contractual arrangements that have evolved in the current RA program. The transition to a reformed RA program must recognize these legacy contracts and must be careful not to undermine their value. For these existing contracts to retain their RA value, LSEs and asset owners must continue to be able to trade RA capacity

The parties to the workshops appear to agree that the buying and selling of bundled RA products can continue under the Hourly Framework. By a "bundled" RA product is meant RA capacity that includes the hourly capacity of all of the slices in which that RA resource produces power. The greater challenge will be creating an efficient and transparent market for "unbundled" transactions for specific hourly slices. The Joint Solar Parties can accept an initial requirement for all slices to remain bundled with an RA resource; however, over time, as the program is implemented and experience is gained, the unbundling of slices of resources should be considered and designed. We agree with many parties that another, perhaps simpler, option may be to allow LSEs to trade their load requirements, as a way to balance over-procurement by one LSE with under-procurement by another in specific hourly slices. SEIA and LSA also have supported the concept of a test year for the new RA program in 2023 as a way to gauge the need for specific types of trading.

5. Use of UCAP

The CAISO has proposed that its proposed Unforced Capacity Evaluation Proposal (UCAP) should be incorporated into the new RA program.[1] UCAP represents a reform of the treatment of generator outages in the RA program. The CAISO believes that the new UCAP construct would allow it to eliminate its complicated and ineffective forced outage substitution rules, and would reflect outages in a more realistic and dynamic way than today's assumption that the single, static Planning Reserve Margin (PRM) covers all outage impacts. LSA has commented on UCAP in the CAISO stakeholder process that developed UCAP, expressing the concern that the use of UCAP would effectively de-rate the RA capacity of existing contracts that were developed and signed when all outage impacts were covered in the PRM. Provided this transition issue can be resolved, the Joint Solar Parties do not oppose the use of UCAP as part of the new RA framework.

[1] See the CAISO's January 19, 2022 workshop presentation.

6. Deliverability

Today, resources cannot count for RA capacity unless they interconnect to the CAISO system with full capacity deliverability status (FCDS). The current RA program focuses solely on the capacity needed to serve demand in the single hour of the LSE's monthly peak demand, and FCDS status examines deliverability in that single peak hour. But the "slice-of-day" concept expands the RA program to consider other hours, and under the Hourly Framework, that expansion would encompass all 24 hours. As a result, the deliverability of generation in other hours will be important as well – for example, off-peak generation has RA value if it can be delivered to charge storage facilities. Resources that may not have FCDS should qualify to provide RA capacity in off-peak hours if they obtain off-peak deliverability status (OPDS) from the CAISO.

7. Hedging

D. 21-07-024, at page 27, found that "a future [RA] framework [should] include a component that links RA to a resource's energy bidding behavior so as to increase the cost effectiveness of RA." PG&E's January 5, 2022 workshop presentation discussed a number of possible hedging mechanisms that could be included in RA contracts. The discussion at that workshop highlighted that hedging comes with a cost, such that limits on the energy bids of RA suppliers are likely to result in higher prices for RA capacity. This trade-off in cost versus risk should be better understood before a hedging element is mandated in RA contracts. In addition, if the need for hedging energy prices in RA contracts is driven by a perception that the CAISO's energy market is subject to the exercise of market power, the CAISO has existing market power mitigation measures that it can use when needed, without adding further complexity to the RA program.

8. Integration of Behind-the-Meter Resources into the RA Program

The Implementation Track, Phase 2 of R. 21-10-002, is working on qualifying capacity counting conventions for demand response resources and behind-the-meter supply resources. There are separate working groups addressing each of these sets of resources. The Reform Track of this proceeding needs to be coordinated with the Implementation Track to assure that these resources can be shown in the emerging slice-of-day program for RA reform.

9. A Test Year for the New RA Program

The Joint Solar Parties recognize that the reform of the RA program is a major undertaking with numerous implementation details that still need to be worked out. Clearly, a slice-of-day approach will require more detailed RA showings than are made today, but also can allow certain existing requirements, such as the maximum cumulative capacity (MCC) "buckets" to be eliminated. SCE has made progress in developing a reporting template for the monthly LSE showings that will help LSEs to assign the capacities of the individual resources in their portfolios to each hourly slice in a month. The template checks that there is adequate capacity in each slice and that any storage can be charged from excess capacity. We hope that the template also will help the CPUC RA staff to validate that each showing is compliant. As the Joint Solar Parties discussed in our prior informal comments, we believe it would be helpful to use the 2023 compliance year for a trial run of the adopted slice-of-day program, with full implementation of a reformed RA program in the 2024 compliance year.

10. Conclusion

The Joint Solar Parties appreciate the opportunity to submit these comments and look forward to continuing to work with the parties to complete the workshop report to the Commission.

Respectfully submitted,

______/s/__________

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Vistra Corp.'s Informal Comments on Slice-of-Day Workshops

Resource Adequacy: R.19-11-009 and R.21-10-002
Initial Comments served on February 7, 2022
Revised Comments served on February 24, 2022

Submitted By	Organization	Date Submitted
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Vistra Corp. offers the following informal comments on the Slice-of-Day workshops including those held on January 5, 2022 and January 19, 2022. In addition, Slice of Day workshop facilitators have asked for the final round of informal comments to comment on all topics from the RA Framework Working Group Process and provide a summary of positions. Vistra will not be submitting a position matrix, instead these informal comments summarize our positions. We will respond to this request in the following sections:

- Vistra positions on slice of day framework generally
- Vistra positions on topics from the working group process
- Vistra position on ensuring RA transactability[1]

Vistra positions on slice of day framework generally

Vistra believes the existing Resource Adequacy ("RA") program is workable with incremental improvements to improve the capacity valuation of use-limited resources, including variable energy resources, and to set an academically robust system RA need set to meet a set planning standard.

If the Commission is set on a path to reform the structure of its RA program to add "additional slices", then Vistra recommends that one slice be added to address an empirically supported reliability risk. Between the two competing Slice of Day proposals, Vistra supports the Two Slice Framework. This framework is best aligned with our priority to add one additional slice to assess a period where there is empirical evidence of specific reliability challenges – the net peak hours.

As we compare the proposals, the 24-hourly slice proposal would not address identified reliability challenges as compared to either the Two Slice Framework, or frankly the existing framework (with improvements). However, the 24-hourly slice proposal would unnecessarily complicate the RA framework because it would reduce transparency and hurt transactability. Adopting a 24-hourly slices framework is likely to place a premium on 24-hour dispatchable thermal resources relative to other more energy limited resources in a manner that is not clearly associated with the resources' relative resource adequacy value. It will also come with increased costs to end-use consumers through requiring an extremely high reserve margin to ensure reliability and reduce market transparency into price setting. We suspect this framework will increase costs that end-use consumers will have to bear,

[1] The Slice of Day workshop co-facilitators found Vistra's transactability chapter originally submitted for inclusion in the workshop report as a proposal summary more suitable as comments than as a chapter in the report. The co-facilitators authorized Vistra to revise its informal comments to allow the transactability feedback for inclusion in the report appendix. Vistra includes the Transactability content initially served on February 7, 2022 to the co-facilitators in the new third section of these informal comments.

without any clear reliability benefit commensurate with that increased cost. We would like to avoid a situation where we will need to revisit RA reform and transition back to a framework like the status quo.

Alternatively, the two-slice framework will send the right incentives aligned to spur a RA fleet that can support load through all hours including the net peak hours without placing an outsized value on its energy availability divorced from reliability challenges. It would also result in a more transactable product that bundles a system net peak attribute into the bundled RA product resulting in a more predictable price impact. The two-slice framework could increase certainty of regulators and market operators that the RA fleet can support the system's needs during all hours, including the net peak hours, without harming the transactability of RA. For these reasons, if the Commission must select from these two options, we support the Commission adopting the Two Slice Framework.

Vistra positions on topics from the working group process

The Commission directed the workshops to cover a set of topics that we respond to briefly below.

Structural Elements

Vistra believes a better need determination, regardless of counting rules, will have the largest improvement to reliability relative to the effort expended. Said differently, if a 24-hourly proposal is adopted and allows for valuation of resources based on relaxed criteria such that participants are accepting greater risks of the resource being available or not, which exceedance introduces, this cannot be looked at in a vacuum. Instead, it must be recognized that when the Loss of Load Expectation study is run to identify the total generation capacity needed to meet a 1:10 standard that the need will be much higher to account for the less stringent counting rules. Consequently, we view the single most important element of any proposal is that it must include the need determination improvements that Vistra has been proposing throughout this process.

While Two Slice Proposal includes this proposal explicitly, we encourage the Commission to adopt the need determination proposal in either framework. Vistra provides the following feedback on the structural elements if Commission determines additional slices are necessary:

- Two seasons, four seasons, or monthly compliance periods: If CAISO's rules are changed to both (1) remove 100% Planned Outage Substitution Obligation rules and (2) allow flexibility to show planned resources on the monthly Supply Plan that are on track for achieving COD then Vistra can support longer compliance periods (2-4 seasons). However, we are skeptical that these changes will be supported. Consequently, Vistra supports retaining 12 monthly showings until these rules are changed. We request the Commission maintain monthly framework.
- Number of slices: If additional slices are added, Vistra supports a two-slice framework.
- Method for determining the system RA need: While we will provide more specifics below, Vistra believes the Commission should affirmatively adopt the need determination and allocation proposal in the Two Slice Proposal under any framework. Making progress on performing regular updates to a probabilistically determined Loss of Load Expectation study to set the total generation capacity needed to support 1:10 is imperative.
- Number of Net Qualifying Capacity values per compliance period: Vistra supports a Single NQC value for each resource for RA contracting that would be included on the annual and monthly showings. This would be one NQC value applied to all slices, which does not limit CAISO or CPUC from using historical output shapes for any additional assessments it would like to perform under a two-slice proposal.
- Coordination between CAISO and CPUC: Vistra supports better alignment between CPUC RA program and the CAISO's administration of it. CAISO has the best insight into system modelling to help inform the system RA requirements to meet grid needs at all times and at a minimum should be leveraged to identify the uncertainty scenarios to be included in the LOLE study.

We encourage the Commission to focus on approving these structural elements and directing the need determination and allocation proposal to be included in either.

Need Determination and Allocation

Vistra supports the need determination and allocation proposal in the Two Slice Framework, see the workshop report for more details on the proposal. The Two Slice Need Determination proposal to establish RA requirements through a regularly updated probabilistically determined LOLE study that incorporates uncertainty risks ensures reliability and results in more equitable outcome for ratepayers than any other alternative discussed in the workshops and best achieves all the principles laid out as follows:

- Best achieves principle 1 because a LOLE study being the basis for setting both needs:
    - Will ensure that the benchmark for the need is ***whether the total generation capacity can meet a planning standard (1:10)*** to ensure a reliable electrical grid.
    - Minimizes costs to customers because the need determination will be more precisely estimated such that the amount of generation needed will ensure reliability and ***minimize risk that a Planning Reserve Margin is overestimating this need driving up costs***.
- Best achieves principle 2 because:
    - Risks associated with loss of load are being tested for ***all 8,760 hours*** (hourly energy sufficiency tested within LOLE). All hours within the study year and the hours where there is concern with reliable operations inform the fleet needed to meet planning standard of 1 in 10.
- Best supports principle 3 by balancing granularity and precision with simplicity and ***transactability*** since this is a widely understood LOLE study method, simplifying the complexity of the design.
- Best supports principle 4 because it can be ***sooner implemented*** since this is a widely understood and employed study throughout the industry, where implementation could be accelerated through leveraging consultants in addition to CPUC or CAISO staff.
- Best supports principle 5 to result in a ***durable solution because the uncertainty risks confronting the system will dynamically be captured with each LOLE iteration and the fleet identified will reflect contemporaneous needs*** to meet the 1 in 10 standard.

Vistra provides more targeted feedback on the elements the facilitators have asked for input on:

- <u>Support a regular process to conduct LOLE:</u> Vistra strongly supports this as described above.
- <u>Gross or net load:</u> Vistra supports the Two Slice Proposal for need determination that includes a need determination proposal described above that includes a gross load forecast in a gross load requirement and a net load requirement.
- <u>Load forecast values:</u> Vistra supports the Two Slice Proposal for need determination that includes using hourly gross load values in an annual Loss of Load Expectation study to capture impact of all 8,760 hours. If a second slice is added, the Two Slice Proposal is to use a new monthly net peak forecast that is produced by CEC where the peak shift included in the new forecast is similar to that in the baseline forecast that is on an annual basis, however the monthly tables would shift the peak value to the hour identified in the Loss of Load Expectation study with the largest risk of Expected Unserved Energy for that month.
- <u>Allocation:</u> Vistra supports allocating the system RA need, and in the event a net peak need is added also the net peak need, on a peak load share basis to each Load Serving Entity. This is a

top-down approach that maintains diversity benefits across the California ISO footprint while assigning a reasonable procurement obligation to each entity based on their peak load share.

- RA obligation trading allowed: Vistra does not support adding a product that is accessible to Load Serving Entities to trade their allocated obligation among each other. At this point in time, it does not seem necessary to allow them to trade their load obligations away if they expect they will not be able to meet their obligations, mostly because it begs the question, "why"? The market benefits from more competition on both the buyer and the seller side, where it is more beneficial to have all market participants striving in good faith to procure sufficient RA to meet their obligations than to provide a mechanism whereby buyers can "opt-out" of the RA requirement through trading away their load obligations to another Load Serving Entity that may have more length in its portfolio. Our perspective is largely anchored in a Two Slice Framework. In a 24-hourly slice framework, we believe the commercial concerns are even more complicated and that it could have a significant impact on pricing.

Multi-day reliability event concerns

Vistra supports the Two Slice Proposal need determination proposal. Through using a probabilistically determined Loss of Load Expectation study that looks across all 8,760 hours, the LOLE would identify the risks of multi-day reliability events, especially if this scenario is explicitly included in the probability distribution scenarios. If it were explicitly included as an uncertainty, then the total generation capacity needed to meet 1:10 would be the result of a model that included a risk of multi-day events. This would be a conservative run that would increase the total generation capacity needed, which will need to be weighed against the benefit of doing so if this is an unlikely scenario. We believe the question of whether multi-day reliability events should be considered highlights the deficiencies of an approach that is not grounded in a LOLE study.

Resource Counting & Unforced Capacity

Vistra believes and has presented during these workshops that resource counting rules should tie the resource capacity value to a resource's ability to show up when needed and carry load through risks of loss of load. This approach best supports reliability and reduces the resource availability uncertainties that need to be accounted for in the Loss of Load Expectation study by incorporating these risks upfront.

The resource counting approach will need to be specific to the structural framework adopted. It appears to us there is an urgent need to identify the framework that will be chosen to further develop the two competing proposals - 24 hourly slices or 2 slices. Resource counting rules will need to be discussed again in a subsequent forum once the framework has been selected out of the two leading proposals. It is essential for the Commission to provide direction soon on which overarching framework and need determination approach will be selected for further development before parties commit to positions on the other elements since the best proposal will likely differ depending on which framework is selected.

We were disappointed that Unforced Capacity was not discussed until the end of the working group and not included in the workshops on resource counting. Most of the workshops have been focusing on what type of counting rules might be considered for variable energy resources or storage. At this point in time, we do not think there is a sufficient record to adopt UCAP in the CPUC RA framework. We do not support the methodology the CAISO has proposed. We are open and willing to engage in future discussions on the appropriate methodology to use. If UCAP were to be seriously considered, the underlying methodology needs to be aligned with industry practice of Equivalent Forced Outage Rate on demand. We recommend that UCAP should be included explicitly in the set of resource counting options in the future workshop for whichever framework is identified. We also believe that adopting a UCAP framework could mitigate the need to replace capacity on planned outage.

Hedging Component

Vistra provided a hedging proposal at the January 5, 2022 workshop. We propose that hedging should be an option. An energy settlement should not be bundled into the RA product, which is the most likely implementation of a hedging requirement at this time. By allowing for two potential types of offers, Load Serving Entities can select the offer type between bundled RA or bundled RA plus energy settlement that provides the best value for its customers. If the energy settlement element is bundled into the product, this can in many instances represent a less effective hedge and would increase the RA prices with the sub-optimal hedge. This would be an adverse outcome that would work counter to principle 1's goal to minimize costs to consumers. See the workshop report for Vistra's hedging proposal for more details.

Multi-Year Requirement Proposals

Vistra supports the RA reform explicitly approving multi-year RA. While multi-year bundled RA products are allowed for any contract executed through the Central Procurement Entity to meet local RA requirements, any contracts above local requirements to meet the full system RA requirements are not allowed to have terms that exceed a year. This seems discriminatory between local versus non-local RA resources and should be corrected at the earliest chance. We also find the Western Power Trading Forum and Independent Energy Producer proposal for expanding this authority to up to three-year terms as a measured and modest proposal compared to the Central Procurement Entity's authority which can approve up to 5-year terms and even longer with higher approval thresholds. While it does not completely place non-local RA on the same playing field as local RA, approving a multi-year bundled RA contracting for resources not awarded through Central Procurement Entity for at least up to three years will help bridge this gap. Further as we mentioned during the workshop, the Commission should consider that multi-year RA contributes to a framework that better achieves principle 1's goal to minimize costs to consumers since longer term contracts can be provided at greater value. It seems straightforward to approve this proposal given the benefits it should provide to end-use consumers.

Transactability of Resource Adequacy (RA) products

Vistra is very concerned that if certain key features of the RA market are not respected that adding additional slices will increase the complexity and granularity of the RA market to the extent it will harm liquidity and make transacting the product incredibly difficult. Decreasing liquidity and increasing the complexity and challenges of trading will not benefit end-use consumers. To ensure that any reform does not adversely impact consumers in this manner, the Vistra transactability proposal maintains status quo on contracting to the extent possible to support liquidity, respects existing contracts where possible, and maintains bundling of all RA attributes and all slices. See new section on Vistra position on ensuring RA transactability below for more details.

Alignment of RA penalties and California Independent System Operator backstop procurement

Vistra appreciates the presenters who covered this important topic at the January 19, 2022 workshop. We agree with the stance provided by Calpine that, "it is important to preserve similar, if not stronger, incentives under slice-of-day… Penalties should be sufficient to encourage procurement at prices that allow suppliers to recover costs even if they are only procured for a single slice".

Under a 24-hourly slice framework, we believe the penalty structure that results may need to be changed depending on how the RA pricing shifts in response to the reform. Unfortunately, we do not have a clear sight on how the pricing will shift. For example, will RA prices scale upward by a magnitude of six? If so, the current penalty structure would be too low.

Alternatively, since we have more comfort with the likely commercial impact of the two-slice framework where the pricing impact is expected to be like that where the other bundled attributes can result in a premium relative to system attribute, we believe the pricing will introduce a system net peak attribute premium. However, it is possible that applying the existing penalty structure to the larger of a LSE's shortfall between its gross peak need share and its net peak need share at the existing prices may be sufficient in the initial implementation.

This is another reason we find the Two Slice Framework more implementable in the timeline desired, it appears that we can make reasonable assumption such as taking the larger shortfall at existing penalty prices for the two-slice proposal where it would maintain the incentives needed. Under the 24-hourly slice framework it is much less clear if making this assumption would maintain these incentives or result in effectively reducing the penalties relative to the cost of procurement.

Vistra position on ensuring RA transactability

Vistra finds that the current RA construct is largely workable from the perspective of how RA contracting is performed. Any framework adopted should be done so in a way that necessitates as little change to commercial negotiation and contracting as possible. There are real reliability challenges facing the California RA paradigm necessitating change, however we believe incremental improvements can address them through improved requirement determination, improved counting rules, and additional after-the-fact "slice" sufficiency assessments if additional slices are added to the framework.

The Vistra proposal is rooted in a belief that current RA construct is largely transactable and if we move the design in a new direction that new design needs to respect current commercial reality as much as possible. Any new design should:

- Recognize the commercial reality that RA products are bundled such that when Net Qualifying Capacity (NQC) is procured it comes with the bundled RA attributes of system, local, and any applicable Effective Flexible Capacity (EFC). This will better avoid market disruptions due to fundamentally changing the way the market views capacity transactions in California. Unbundling the RA product will have an outsized impact on commercial activities as result of any new framework and should be avoided.
- Respect existing contracts such that any slice-of-day frameworks do not require renegotiating executed contracts. This will allow for a more implementable approach such that existing contracts can terminate and then any new contracts executed will incorporate any slice-of-day elements that may impact contracting.
- Maintain consistency across the California Public Utility Commission's RA and Integrated Resource Planning (IRP) programs and the California Independent System Operator's (CAISO's) administration of the RA program. This will better support forward planning on behalf of market participants and more cost-effective market outcomes by reducing regulatory uncertainty, complexity, and administrative burdens.

Any framework adopted should improve on reliability and recognize that 1) the granularity of the product should be limited and 2) as much of current contracting maintained as possible to achieve efficient and cost-effective market outcomes. To further this end, Vistra provides the following proposal focused on elements that should be incorporated into either the 24-hourly slices or two-slice proposals, if adopted. The remainder of this chapter recaps the Vistra proposals on transactability provided at the October 6, 2021,[2] workshop on structural elements and the January 5, 2022,[3] workshop on transactability.

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[2] RA Proceeding Track 3B2, Slice of Day Workshops, D.21-07-014, Vistra, October 6, 2021, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-2-vistracpuc-r1911009-3b2.pdf.

[3] Slice of Day Workshops, Hedging Component, R.19-11-009 and R.21-10-002, Vistra, January 5, 2022, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-8-vistrar1911009-r2110002vistra3b2-workshop-hedging.pdf.

Vistra Transactability Proposal

Any of the slice-of-day frameworks proposed can be set up in a manner that enhances planning reserve margins and enhances after-the-fact sufficiency assessments to address these reliability concerns, while maintaining current approaches for contracting and showings. At the workshop on January 5, 2022, Vistra presented the following illustration to illustrate a path forward to achieve this goal:

Enhancements - PRM

- Enhance system RA requirement for gross peak based on probabilistically determined LOLE study (see Gridwell & Vistra presentation at 12/1/21 workshop)
- Ensure uncertainty risks including limited energy supply conditions during a day with loss of load risks are included in the LOLE study to set RA need (see Vistra presentation at 12/17/21 workshop)

Status Quo - Contracting & Showings

- Contracts require bundled RA products and bundled slices
- RA contract amounts based on single NQC per showing period
- LSEs and Suppliers submit CAISO plans with single NQC per showing period (month/seasons)
- LSEs submit CPUC showings same as today with single NQC per showing period
- CPUC performs sufficiency assessment relative to meeting the updated gross peak RA requirement

Enhancements – CPUC Sufficiency Test

- CPUC adds a sufficiency evaluation for additional slices <u>where there is a risk of loss of load</u>
- CPUC should adjust the single NQC for the showing period to the applicable slice based on expected output (See Gridwell and Vistra presentation at 12/1/workshop re net peak options)

Vistra's transactability proposal focuses on rules that should be adopted to maintain current approaches for commercial activities, where possible. We view our transactability proposal as auxiliary to the structural decision on which slice-of-day framework the Commission will select. We believe this proposal should be integrated into any structure.

Vistra proposes that any slice-of-day framework include the following policy principles and rules to ensure transactability:

- Contracts and showings should maintain current level of complexity in commercial activities and transactions to best support liquidity
- Single NQC value per resource per showing period under contract
- RA framework should maintain bundling of products and any slices:
  - System plus local RA are attributes bundled into a bundled RA product where the combined amounts of system or local attributes sold cannot exceed the Generic NQC for the resource for the showing period.
  - Unbundling local from system would make it too difficult to ensure the RA market results in competitive and rational outcomes in a decentralized framework

- Unbundling slices would raise the need to explore whether we are abandoning a capacity requirement altogether and open debate on whether Must Offer Obligation (MOO) should not be all hours when physically available

- If additional "slice(s)" are included in the RA framework then all slices should be included in bundled RA product:
    - Unbundling slices would increase the granularity of the product that can be traded, which will reduce liquidity within the slices leading to competition concerns.
    - Unbundling slices is also likely to add the equivalent of a nested energy product within the RA paradigm, which will have impacts to the pricing for specific resources.
- Implementation should respect existing contracts where any Slice of Day rules would not necessitate re-opening contracts, while any new contract would have the new rules applied.
- Load Serving Entities (LSEs) and Suppliers will show a single NQC value per resource per showing period, consistent with their contract obligations, to the CAISO.
- LSEs will show a single NQC value per resource per showing period, consistent with their contract obligations, to the CPUC.
- By bundling all attributes and all slices, CAISO should not need to make changes to its MOO rules directly as result of slice-of-day framework adding additional slice(s).[4]

D.21-01-014 principles require transactable outcome

In its Decision on Track 3B.2 Issues: Restructure of the RA Program (D.21-07-014), the Commission identified the slice-of-day proposal from PG&E as the best framework to address its identified principles. In its Decision, the Commission identified that any framework should address the following design principles.

"An implementable Resource Adequacy framework is one that addresses the implementation details in Ordering Paragraph 1, as well as five key principles, as follows:

- *Principle 1: To balance ensuring a reliable electrical grid with minimizing costs to customers.*
- Principle 2: To balance addressing hourly energy sufficiency for reliable operations with advancing California's environmental goals.
- Principle 3: To balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity, and transactability.
- Principle 4: To be implementable in the near-term (e.g., 2024).
- Principle 5: To be durable and adaptable to a changing electric grid."[5]

To further develop slice-of-day frameworks, the Commission directed parties to hold a set of workshops covering the following elements such that the final framework results in a durable program that addresses the five key principles. The discussion elements directed under these workshops are:

- Structural Elements
- Resource Counting

[4] While the slice-of-day framework may not alone drive changes to Must Offer Obligation, this proposal should not be interpreted as stating that changes to Must Offer Obligations or Resource Adequacy resource eligibility are not needed to support a better functioning Resource Adequacy program. However, these discussions were largely not held during the workshop as this element was not explicitly directed. We recommend deferring this to the CAISO stakeholder process or future RA proceedings for incremental changes.

[5] Decision on Track 3B.2 Issues: Restructure of the Resource Adequacy Program (D.21-07-014), R.19-11-009, July 16, 2021, Ordering Paragraph 2, Page 52, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334426.PDF.

- Need Determination and Allocation
- Hedging Component
- Unforced Capacity Evaluation
- Multi-Year Requirement Proposals
- Transactability of Resource Adequacy (RA) products
- Multi-day reliability event concerns
- Alignment of RA compliance penalties and California Independent System Operator backstop procurement

The Vistra proposal addresses the workshop element included in Ordering Paragraph 1 on "Transactability of Resource Adequacy (RA) products. We developed our proposal to include a set of rules that would best support RA transactability to primarily address Commission's key principle #3, "To balance granularity and precision in meeting hourly RA needs with a reasonable level of simplicity, and transactability", and to also better address Commission's key principle #1, "To balance ensuring a reliable electrical grid with minimizing costs to customers".

The proposal simultaneously furthers the goals of both principles because ensuring transactability in a manner that it continues to support liquidity in the RA markets is critical to minimizing costs to customers. The remainder of this section will explain the proposal in detail and why transactability is key to the success of RA framework considering these two principles.

Why transactability is key to success of RA framework

Vistra encourages Parties and the Commission while considering the details of any structural reform to the California RA framework to not lose sight of the goals of Principle #1 that looks to minimizing costs to customers and Principle #3 that looks to ensure transactability of the RA product is not unduly harmed. We see the latter as critical to achieving the former. If transactability is harmed, then costs to customers will not be minimized.

Why do transactability and liquidity matter so much? They directly impact competition, without which, the value of the goods or services, in this case RA, will not be as efficient.

One of the two biggest factors harming the ability to transact the RA product is 1) moving away from the concept of a standard capacity product that allows fungibility of the product (i.e., NQC MW = NQC MW) and 2) introducing so much granularity to the product such that competition is not robust within the product requirements. Specifically, increasing slices or unbundling products will move the RA framework away from the idea that the RA contract is a standard capacity product and it will harm liquidity. Moving away from standard capacity product and harming liquidity results in a less competitive market that can result in sub-optimal outcomes for buyers and sellers.

A third factor that can harm the ability of the RA market to produce the most efficient outcomes is the ability to understand the price for a good ($/kW-month) sold relative to its contractual obligation. Increased complexity to which the buyers alone are exposed will drive resource valuations that are not transparent to the sellers. This lack of transparency will make it difficult for sellers of energy-limited resources to offer to mitigate any use-limitations to provide the best valued asset for reliability. Further, a complicated compliance framework for LSEs that is separate from the seller's obligation makes it difficult for sellers to predict commercial outcomes. Finally, the more complicated any seller's obligation, the more costly the service is likely to be, given increased compliance risks.

A fourth factor is that RA resources must be allowed to take planned outages to ensure they can maintain the resources at levels that can support reliable operations. Under today's rules, the CAISO enforces a 100% Planned Outage Substitution Obligation (POSO) rule where if a planned outage is submitted for needed maintenance and the seller cannot find substitute capacity to replace the RA resources on planned outage, then the CAISO will deny the planned outage. This increases RA risk since the risk of not being able to take needed outages increases potential maintenance costs and increases risks of forced outages due to plant trouble by rejecting the outage. We continue to believe that a well-functioning RA design should include rules that account for the risk of resources needing planned outages in a market where substitution is not available. Incorporating the planned-outage-without-substitution risk in the LOLE study as proposed in the two-slice proposal will negate the need for these 100% POSO rules since the capacity needed to be replaced will be procured upfront through the LOLE's total generation capacity output. If alternatively, the Commission adopts the 24-hourly slice framework, this proposal did not clearly include a mechanism to address this issue with the RA market. Future workshops would be needed to develop rules to address this issue upfront so that the 100% POSO rules can be retired. Allowing for retiring of this inefficient rule and ensuring the risks are appropriately accounted for will increase transactability and ensure more cost-effective RA outcomes.

Open issues on transactability

The 24-hourly slice proposal will need more refinements in future workshops to ensure the resulting framework supports transactability to avoid adverse impacts to customers. The two-slice proposal will better support transactability as it will have less impacts on the contracting and showings, while focusing on improvements up front to need determination, counting rules, and new slice assessments.

One of the clearest examples of how 24-hourly slices will introduce more challenges relates to the above concern that a MW of NQC will no longer equal a MW of NQC. If additional slices are added, then resources eligible for replacement under a RA contract will likely be limited since a replacement resource will have a different profile. We need to specifically recognize that 24-slices introduces the most risk that RA capacity is not fungible and reduces liquidity, harming secondary market outcomes. It will be necessary to develop additional rules in future workshops to mitigate this risk to extent possible before implementing. For example, potential adverse impacts could occur if:

- A wind resource may not be able to replace its capacity with that from a solar resource because the solar resource's energy profile will differ in shape by hour and in some hours will be less than the wind's energy profile.
- A storage resource may not be able to replace its capacity from a solar or wind resource because solar/wind's energy profiles are fixed whereas storage has flexibility to show up to its maximum output in different slices.

Vistra believes in the standard capacity product framework rather than one that creates silos where the product can only be transacted among the same or limited technologies. This outcome would harm liquidity and result in sub-optimal market outcomes that do not minimize costs to customers. It is imperative to adopt a framework that allows for RA capacity to be fungible to allow liquidity in replacement market to avoid an adverse market outcome of increasing costs to customers through reducing liquidity of the RA products being transacted and introducing this regulatory uncertainty and administrative complexity.

In addition to the above serious challenge that will need to be explored, Vistra has teed up various transactability issues during these workshops where there has been insufficient time to address these. The following are open issues under any new slice-of-day framework:

- **Decide how Central Procurement Entity's (CPE's) multi-year procurement for bundled RA, which includes system in addition to local and any applicable flex, interacts with the slice-of-day framework.** It will need to be determined how the system RA requirements will take into consideration the amount of the system RA requirement that the CPE is awarding through its bundled RA contract, which will meet a portion of the system requirements. The CPE requirements should be a subset of the system RA requirements, and this will need to be discussed in detail to avoid inefficiencies.

- **Ensure the counting rules adopted apply to the entirety of the single NQC value for each resource for each showing period.** Ensuring that there is no disconnect between capacity value for the same resource on its system attribute versus its local attribute will not only better support transactability but will better ensure reliability.
- **Applies consistent resource counting rules for the net peak assessments as the CAISO is performing in its assessments to ensure consistency across the CPUC assessments and CAISO assessments.** While the CAISO assessment is being performed for local RA today, it would not be rational for two different output profiles for variable energy resources to be used for a CPUC system RA check in the hour than the CAISO would use in its local RA check today. It would result in an inefficient administration of RA.
- **Consider multi-year requirements for Resource Adequacy. Adopting multi-year system RA requirements will allow for sellers to provide greater value through the longer strips that will also address the goal in Principle #1 to minimize costs to consumers.** Even if multi-year system RA requirements are not adopted in any initial framework, the CPUC and CAISO should begin to provide more information on what the system RA requirements would be to provide the system RA requirements for the three years in the CPE solicitation process. This would allow the market to compare the forward system requirements relative to the local RA requirement studies that are produced. At a minimum, adding the study will provide greater transparency on how the system and local RA requirements interact across the multi-year period that has already been adopted.

WESTERN POWER TRADING FORUM
INFORMAL COMMENTS ON RESOURCE ADEQUACY PROGRAM REFORM PROPOSALS

February 4, 2022

Introduction

Western Power Trading Forum (WPTF) is a broad-based energy industry trade group that advocates for competitive markets throughout the Western Interconnection. WPTF members that play an active role in the group's advocacy before the California Public Utilities Commission include wholesale marketers, load serving entities (LSEs), and developers/owner/operators of more than 16,000 megawatts of thermal, renewable, hydroelectric, and energy storage resources in California, Arizona, Nevada, and the Pacific Northwest. WPTF's positions on the proposals for Resource Adequacy (RA) program reforms addressed in these comments thus reflect the input of a large swath of California RA market participants.

In assessing the RA reform proposals being teed up for the Commission's consideration, it is important to keep in mind the problem that we are trying to solve. Indeed, the Commission would benefit from the workshop report including a one-sentence statement of the problem to guide its deliberations. To that end, WPTF proposes the following problem statement:

> The proliferation of solar generation, combined with a steady decline in dispatchable, non-use-limited generation capacity, increasingly places system reliability at jeopardy during the late afternoon and early evening hours of summer, when demand is still high and solar production falls off.

WPTF is cognizant of the Commission's concerns with maintaining reliability within the existing RA framework. However, the framework's supposed shortcomings are mainly due to its reliance on a woefully outdated planning reserve margin (PRM) and its utilization of average Effective Load Carrying Capability (ELCC) values that grossly overstate the contributions of solar resources to system reliability during the periods of greatest concern. These updates are occurring in Phase 2 of the current RA proceeding. It is possible that with such updates, the existing RA framework will once again meet the 0.1 Loss of Load Expectation (LOLE) standard. Had the Commission addressed these narrow, easily rectified problems in a timely matter, we most likely would not have had to spend the last six months in workshops trying to produce a viable alternative to the current RA framework. The Commission must *not* repeat these mistakes in implementing any new RA framework. Stated another way, it is imperative that the Commission develop a robust PRM and utilize accurate capacity values for any new RA framework and continually update them for a durable framework.

The Commission's primary considerations in evaluating the two comprehensive RA reform proposals that are now on the table—Southern California Edison Company's (SCE's) 24-Slice proposal and Gridwell Consulting's (Gridwell's) Two-Slice proposal—should be reliability, transactability, compatibility, and consistency. Any new framework should significantly enhance system reliability, should not overly complicate or otherwise impair transactions between buyers and sellers of RA compliance products, and should be compatible with existing California Independent System Operator (CAISO) validation and backstop procurement mechanisms. In addition, the resource counting conventions utilized for any new RA framework should more closely align with those used for the Commission's Integrated Resource Plan (IRP) portfolio modeling.

In these comments, WPTF addresses the extent to which the SCE and Gridwell slice-of-day proposals further or work counter to the aforesaid objectives. WPTF also addresses selected element-specific proposals, including resource counting conventions, as well as hedging and multi-year requirements. WPTF's selections in the matrix accompanying these comments are premised on the adoption of the proposed Two-Slice RA framework. For proposals that are not addressed in these comments nor selected in the matrix, WPTF's silence should not be viewed as tacit support or opposition.

Slice-of-Day Proposals

Both the SCE and Gridwell proposals would significantly enhance reliability by ensuring that shown RA resources are sufficient during all hours of the day but especially during both gross peak and net peak hours. However, Gridwell's Two-Slice proposal is simpler and thus easier to implement, will not undermine transactability, is highly compatible with the CAISO's existing processes, and utilizes resource counting conventions that are more consistent with those used for IRP modeling. The Two-Slice proposal requires additional studies to calculate ELCC values for some resources, while SCE's 24-Slice proposal requires additional implementation workshops to discuss the levels of exceedance and resource profiles. And both proposals require additional PRM modeling to be performed. However, the Two-Slice proposal can be implemented by 2024, whereas the 24-Slice proposal likely cannot be implemented until 2025.

SCE's 24-Slice Proposal

The cornerstone of SCE's proposal is its 24-hourly slices. While this attribute of SCE's proposal may be attractive, in that it would enable resource adequacy to be assessed in every hour of the day, should that become necessary, it is also overkill in that it currently is not necessary to assess adequacy in every hour and it likely will not be necessary to do so for a very long time (if ever).

WPTF's biggest concern with the 24-Slice proposal is that it entails a nearly exponential increase in administrative complexity, both with respect to RA program implementation and contracting for RA resources, without providing any reliability benefits beyond those provided by a two-slice framework. Even with the current RA framework, with its outdated PRM and ELCC values, capacity shortages have proven to be quite rare. Moreover, any capacity shortfalls that might materialize in the foreseeable future are projected to be concentrated in—indeed, are almost exclusively limited to—the late afternoon and early evening hours of summer.[1] Furthermore, the CAISO now has the ability to only validate one LSE showing—e.g., the showing for either the peak or net peak hour, with the CPUC to validate the other showing—thereby rendering the proposed showing requirements in the other 22 hours largely, if not completely, superfluous.

At least three major transactability problems arise from the granularity of RA requirements under SCE's 24-Slice proposal. The first is the need for LSEs to procure RA products to cover all hours of the day, including 22 hours that have no system reliability implications. While that may not pose a problem for the investor-owned utilities, it could prove to be particularly challenging for smaller LSEs to fill every slice without procuring far more resources than they actually need to meet their RA, IRP, and Renewables Portfolio Standard (RPS) requirements. The second is the resulting balkanization of the RA market, with the RA products associated with distinct types of resources no longer being fungible. Which leads to the third problem: the lack of standard, fungible RA products will make it far more complicated—and more expensive—for LSEs and suppliers to bilaterally transact capacity in the market (e.g., because 4-hour storage does not provide the same reliability value across the same number of slices as 8-hour storage based on the same MW value of capacity, and solar and wind resources, even if they have the same capacity value, similarly do not provide the same reliability benefits in the same number of slices due to difference in the underlying resource profiles).

SCE and supporters of its proposal attempt to downplay the complexity of the proposed 24-Slice construct by emphasizing RA resources would continue to have single monthly net qualifying capacity (NQC) values. However, the reliability contributions of individual resources would be assessed for each slice based on profiling techniques that have yet to be determined. Specifically, for wind and solar resources, their slice values would depend on their hourly generation profiles that have yet to be defined, thereby necessitating the development of profiles for each resource or resource technology. The most likely methodology for developing such profiles for wind and solar resources is the exceedance methodology. Developing exceedance-based profiles would not only be a huge undertaking for agency staff but could also be highly controversial (for the reasons discussed in the Resource Counting section below).[2] It would also result in the complete disassociation of RA capacity values for such resources from the values used for the IRP process. While the resulting capacity values used for such

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[1] While the IRP modeling has identified an exceedingly small (7 MW) capacity shortfall potentially materializing by 2030 during the morning hours of March, that is hardly a big enough concern to justify imposing hourly RA requirements on LSEs within the RA framework, as the capacity shortfall projection already assumes all capacity has been procured by LSEs and additional capacity would be required to be developed.

[2] A related complication arises from the way SCE's proposal addresses charging requirements for energy storage resources. As understood by WPTF, the hourly NQC values of storage resources would need to be negative in some hours to account for charging needs, thereby introducing yet another novel element into the RA implementation mix.

resources can still be applied for purposes of the RA framework, it would likely require increasing the PRM to ensure a 0.1 LOLE. SCE has proposed the Commission establish yet another year of workshops to develop the exceedance methodology and resource profiles prior to additional PRM analysis. This would defer RA program redesign implementation to 2025.

From WPTF's perspective, it is hard to reconcile the massively increased showing and transactional burdens associated with SCE's proposal with the insubstantial incremental benefits associated with 24 slices.

Gridwell's Two-Slice Proposal

Because it builds upon the existing RA framework, only adding that which is needed to enhance reliability (i.e., a net load peak RA assessment, updating ELCC methodologies, and PRM analysis), Gridwell's Two-Slice proposal does not entail anywhere near the same administrative and transactional complexities as SCE's 24-Slice proposal. Moreover, the proposed Two-Slice framework would bring the RA program into closer alignment with the IRP process by utilizing incremental ELCC values for new solar and wind resources. This alignment correction, combined with the recurring PRM, LOLE and ELCC updates that the Two-Slice proposal expressly incorporates, will help ensure the RA program maintains reliability under a changing resource mix just as effectively as the 24-Slice proposal.

WPTF recognizes an RA framework that addresses resource adequacy for gross and net peak hours only (as opposed to all hours), may not fully comport with the Commission's expectations. However, the Two-Slice proposal utilizes sophisticated LOLE analysis to set the appropriate PRM and meet the 0.1 LOLE standard in the same manner as the IRP. The workshop process has brought to light the unprecedented complexities associated with more granular slice-of-day frameworks that, in any case, may not be fully validated by the CAISO. WPTF therefore recommends the Commission adopt the Two-Slice proposal as a viable and fully implementable RA framework that addresses both current and foreseeable system reliability needs.

WPTF makes this recommendation with the understanding that the proposed Two-Slice framework entails its own complexities. For example, the periodic recalculation of ELCC values may require staff resources (although Energy Division staff is already tasked with refreshing ELCC values every two years). However, the resulting reliability benefits are clear and, in WPTF's estimation, easily justify the effort.

WPTF also recognizes that the Two-Slice proposal does not include an explicit mechanism requiring that sufficient excess energy is available to charge storage resources. However, the need for storage charging requirements has not been established.[3] If a charging deficiency ever materializes, the Commission should be less concerned with which LSE(s) "caused" the deficiency and more concerned that its biennial IRP did not forecast this issue and address it

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[3] Indeed, sophisticated modeling such as that performed for the IRP indicates that energy sufficiency for storage charging is highly unlikely to be a problem given the expected resource buildout during the coming decade.

earlier. And, to the extent storage charging becomes a constraint, it would be addressed under the Two-Slice proposal by adjustments to the ELCC values for storage resources (as well as resources capable of charging storage).

Load Forecast Methodology

For purposes of allocating system RA requirements to individual LSEs, WPTF recommends using either the existing pro-rata load ratio share allocation mechanism or, if a 24-slice framework is adopted, the load forecast methodology outlined by the California Energy Commission (CEC) at the December 1 workshop—i.e., a hybrid of top-down and LSE-specific load forecasts using the system load forecasts developed by the CEC for its Integrated Energy Policy Reports and individual LSE's load forecasts and historical loads. (WPTF's understanding is that both mechanisms should result in similar individual LSE requirements for the slices that are most critical.)

Resource Counting

While WPTF views resource counting as largely an implementation issue that can be resolved after the Commission determines the basic outlines of any new RA framework, it should nonetheless be a key consideration in the Commission's deliberations. Any proposed resource counting conventions that are overly generous or parsimonious to one set of resources or, worse yet, overly generous to one set of resources and parsimonious to another, has negative implications for both reliability and cost-effectiveness. The Commission's objective in adopting any new or modified resource counting conventions should be to ensure that each resource's contributions to reliability are quantified accurately, without any favors (or disfavors) being handed out based on other policy considerations.

It is unclear to WPTF whether the exceedance approach can meet the aforesaid objectivity goals given that, as even the proponents have acknowledged, selecting the level of exceedance is an inherently arbitrary exercise and is not based on any robust theoretical framework. Consequently, no party has been able to clearly establish that a specific level of exceedance accurately reflects a resource's reliability contribution. Instead, to ensure reliability, the 24-slice proponents intend to make up for any under- or over-counting of resources in aggregate due to a specific exceedance methodology by recalibrating the PRM. While this approach might conceivably ensure reliability, it will not differentiate appropriately between the reliability contributions of different resources and encourage efficient procurement of those resources.

The Commission should also seek to bring RA capacity counting and IRP modeling into closer alignment, thereby adding certainty to both the efficacy of the RA program and the accuracy of IRP modeling, while also dismantling barriers to efficient LSE procurement of new resources. Integrating incremental ELCC values into the RA framework would be an important and much needed step in that direction.

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Dispatchable Resources

There does not appear to be any compelling reliability or policy basis for penalizing generators on an on-going basis for isolated forced outage events, as would happen under the CAISO's UCAP proposal. WPTF therefore agrees with the Two-Slice proposal's treatment of dispatchable resources and recommends limiting changes to the qualifying capacity for thermal resources to ambient temperature derates.

Variable Energy Resources

ELCC is the statutorily required methodology for developing RA capacity values for wind and solar resources. It is also the most analytically robust methodology for such purposes. WPTF therefore views the Gridwell Two-Slice proposal's incorporation of incremental ELCC values, which aligns with the IRP process, as a major positive. Conversely, the SCE 24-Slice proposal's incompatibility with ELCC is a negative. (ELCC analysis produces a single capacity value across a given period and is thus unsuited for producing hourly capacity values like those required by the SCE proposal. SCE's proposal may only afford variable resources the benefit of slice-specific QC values, as the proposal does not allow for varying QC slice values for other traditional resources.)

The QC counting methodology that is most suited for producing hourly values is an exceedance methodology. However, as discussed above, developing a consensus on the "right" exceedance threshold is likely to be highly contentious and the outcome inherently arbitrary. Moreover, it could necessitate a significant increase in the PRM (if the exceedance level is set too low), which from a policy perspective may not be a viable option.

<u>Hedging</u>

WPTF fully supports the idea that LSEs should hedge their energy needs to minimize market exposure to their customers. However, the decision as to how and at what levels to hedge should be made by LSEs and not mandated as part of the RA framework. WPTF notes that neither Gridwell nor SCE included hedging as part of their respective Slice of Day proposals. During the workshops, parties, including Energy Division, were not able to clearly articulate the reason for the need to require LSEs to hedge energy within the RA framework. While WPTF speculates that the Commission may be concerned that less capacity is under full tolling agreements with the IOUs due to customer load migration to newly forming CCAs, and thus less capacity may be under control of those LSEs to bid into the CAISO market at cost-based rates, little information is available to confirm this concern. If true, then a more thorough analysis must be performed to identify the issue. The CAISO's Department of Market Monitoring (DMM) has consistently found that market prices have primarily been competitive. This finding should then shift the concern to the lack of tolling agreements or hedging by LSEs. WPTF proposes that Energy Division should report on the hedging activity of LSEs to identify exactly what the concern really is. Finally, WPTF supports SCE's proposal to defer this topic to another phase of this rulemaking after the Energy Division's report is published.

Multi-Year Requirements

WPTF is a long-time proponent of multi-year RA requirements and, per the Commission's directive in D.20-06-002, presented its proposal for expanding multi-year requirements to system capacity at the January 19 workshop. WPTF's reasons for advocating for that expansion are summarized in the workshop report's discussion of multi-year requirements.