CESA
CALIFORNIA ENERGY STORAGE ALLIANCE

February 7, 2022

Re: Final and Summary Informal Comments of the California Energy Storage Alliance Regarding the Resource Adequacy Slice-of-Day Reform Workshops

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.

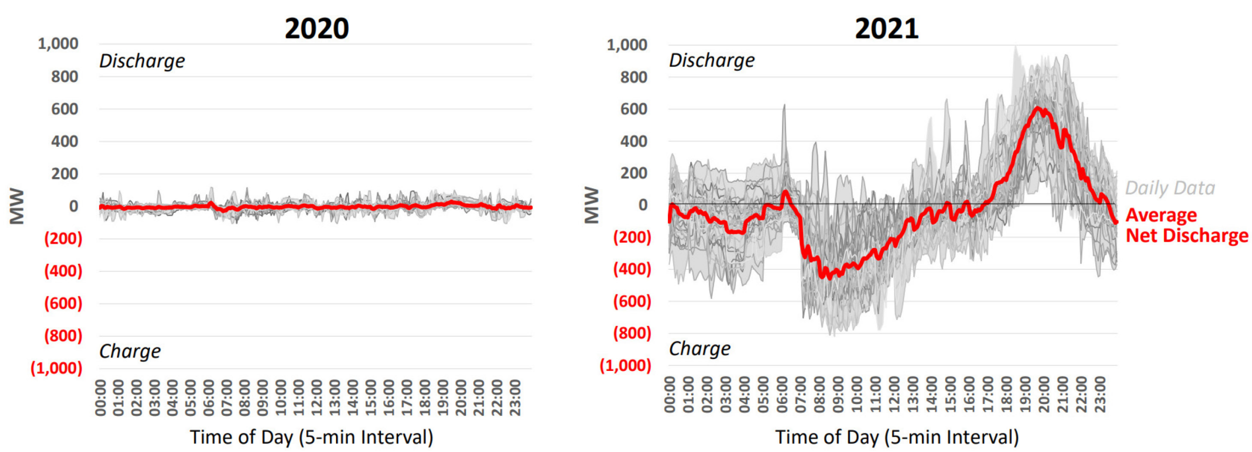
As noted in the above principles, the Commission seeks an RA framework that minimizes cost to customers, addresses hourly energy sufficiency, and advances California's environmental goals. SCE's 24-hourly SOD framework is well-positioned to meet these principles as it allows for the flexible utilization 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

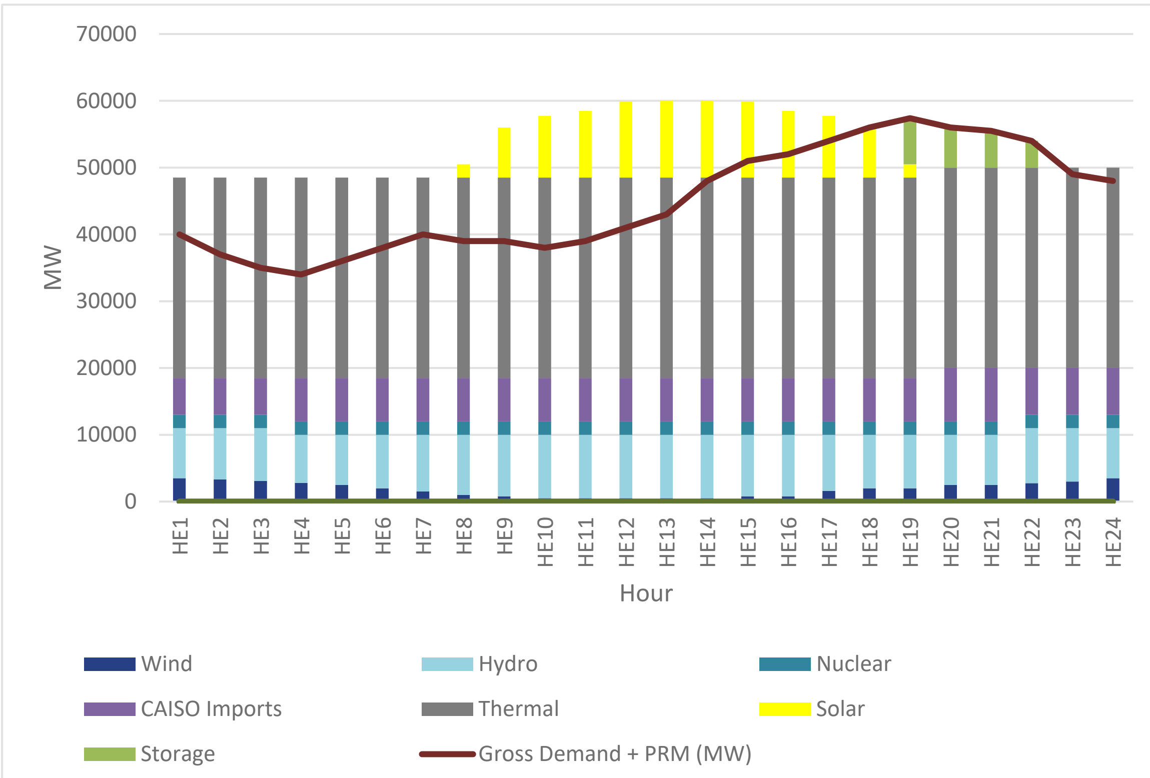
A. If charging sufficiency verification is required under the RA SOD framework, it should recognize resource-specific operational characteristics.

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.

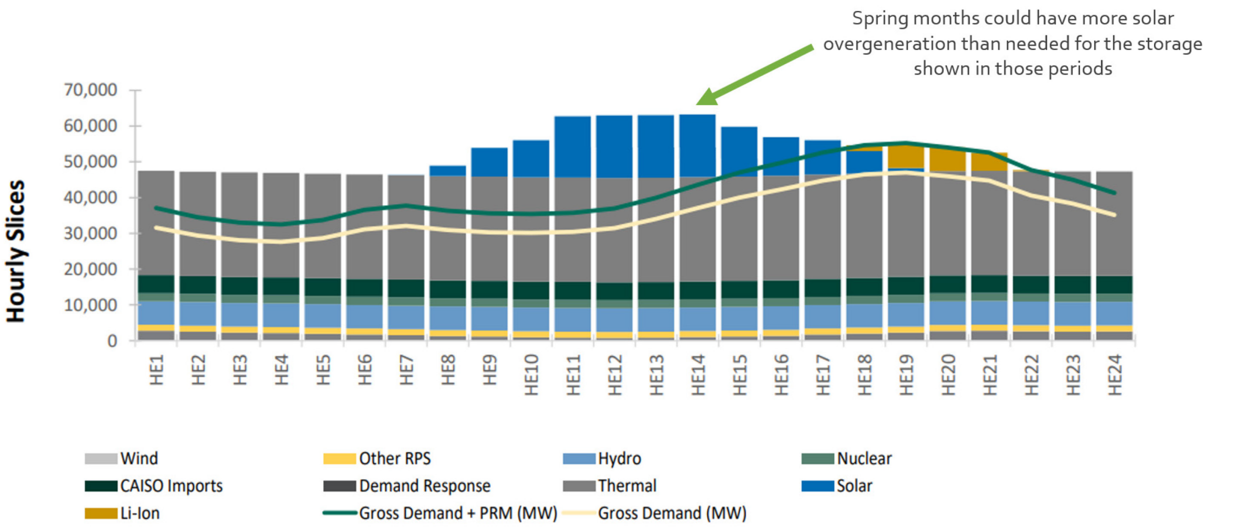
In a system that relies heavily on VERs and energy-limited assets, the interactions between weather, load, and supply are more impactful for reliability purposes. According to the Commission's IRP proceeding's modeling, the 2021 Senate Bill ("SB") 100 Joint Agency Report ("2021 SB 100 JAR"), and Strategen's *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.

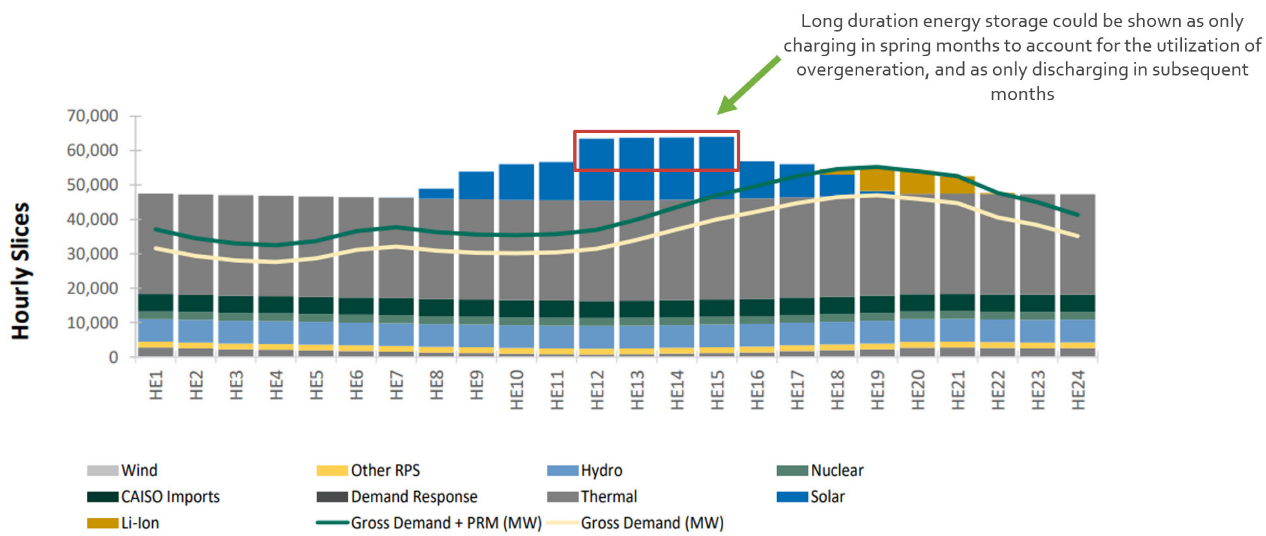
While the daily reliability needs could be easily addressed by refining the SOD framework, the same cannot be said about multi-day interactions. CESA has noted that the currently proposed 24-hour compliance framework might overlook multi-day reliability needs. Moreover, this 24-hour framework is not 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.

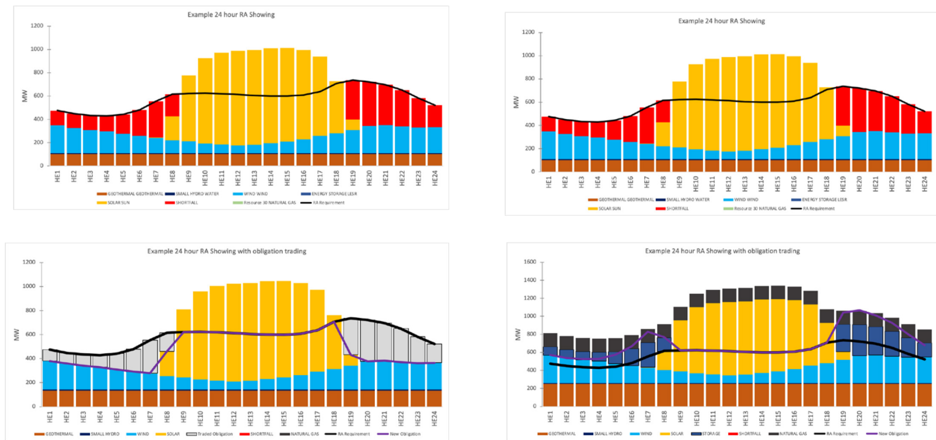
Figure 4: Illustrative Example of Load Obligation Trading

LSE A: trades away obligation, does not need to procure

LSE B takes Obligation, procures for higher requirement

Before Trade

After Trade



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 <u>*all*</u> 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. **Conclusion**

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.

Jin Noh
Policy Director
California Energy Storage Alliance

Sergio Duenas
Policy Manager
California Energy Storage Alliance